FRACTURE TESTING AND THE DEVELOPMENT OF UNIQUE DRILLING FLUID ADDITIVES FOR IMPROVED WELLBORE STABILITY AND REDUCED LOSSES

M. W. Sanders, S. Young and J. Friedheim
M-I SWACO

ABSTRACT

Increasing wellbore complexity and associated pressure to improve drilling economics has heightened awareness on preventing lost circulation. Consequently, the industry is focusing more closely on wellbore stability and improvements in wellbore strength, and on the elimination casing strings where possible. In addition the drilling of depleted zones in the same section as normally pressured formations has increased the focus on maintaining wellbore integrity and minimizing losses.

The development and engineering of unique drilling fluid additives that can help improve wellbore stability and minimize fluid losses into drilling-induced fractures has been a key in achieving the desired operational goals.

The authors discuss the design of these unique drilling fluid additives and the treatment techniques required to ensure optimal wellbore stability and minimal induced fracture losses, along with the engineering techniques required to ensure successful application of such treatments.

INTRODUCTION

Invert emulsion mud's (IEM) always have been the systems of choice when drilling demanding wells requiring a highly inhibitive fluid, capable of ensuring high rates of penetration (ROP), good lubricity and the lowest potential for stuck pipe. One potential drawback to the use of these fluids (and to a lesser extent, water-based fluids) is the high cost associated with fluid loss. In today's technically demanding wells such losses commonly occur into fractures, either drilling-induced or naturally occurring.

Fracturing during drilling operations typically occurs in permeable rock such as sandstone, impermeable rock typified by shale formations, or depleted sands and carbonates. Typically, fractures in a formation are induced by drilling overbalanced or by generating an increase in equivalent circulating density (ECD) that exceeds the tensile strength of the rock in a sensitive lithological area. These fractures allow drilling fluid to be lost from the wellbore. In dealing with these losses, adding mud to maintain circulation of the well, remediation of the loss zone and lowering the mud weight to decrease the ECD compounds well costs.

Induced fractures in relatively impermeable formations commonly have been more difficult to heal than fractures in permeable zones. The main characteristics of shale and other low-permeable rock, which contribute to difficulty in sealing, are very low tensile strength and very low permeability (minute pore sizes). This ensures very low fluid leak-off rates, resulting in potential fracture initiation points being exposed to the full pressure exerted by the drilling fluid and the inability of the fluid to generate a stable plug inside a formed fracture.

Impermeable formations can readily exhibit fractures which will continue to extend beyond the near-wellbore region, resulting in extensive losses and a high potential for wellbore instability. Bridging and sealing these induced fractures by lost circulation material (LCM), cement, plugs etc. require sealing the width of the fracture with solids. Once an initial bridge is formed, additional particles accumulate to form a seal, which in turn helps reduce mud flow through the fracture, thus isolating the tip and preventing further fracture extension. The tangential stress, or hoop stress, exerted by the bridge at or near the wellbore can prevent further fracturing by increasing the stability of the near-wellbore region via compression.[1,2] One of many theories that prevails within the industry on wellbore stabilization suggests that by combining these tangential stresses among sealed radial fractures, wellbore stability can be improved by building a so-called "stress cage" in the near-wellbore region.[3]

Another component of wellbore stabilization theory is fracture closure stress (FCS), whereby formation stability can be enhanced by engineering an increase in FCS that is greater than the ECD while drilling.[2] This is achieved by generating a blockage within the fracture, near the wellbore, which exerts tangential stress and ideally allows the width of the fracture to increase. A seal must be maintained at this point, and one having the ability to expand while maintaining its integrity as the near wellbore compresses to accomodate the increase in fracture width. In addition, the seal must remain to prop open the fracture and continue to exert tangential stress in the near-wellbore region to maintain any beneficial effect.

The characteristics of fractured impermeable rock contrasts with those of permeable zones. Induced fractures in permeable rock formations typically are found within a depleted sand or carbonate. Such fractures normally are more easily “sealed” or “closed” than fractures induced in tight sands, siltstones, and shales. This is due, in large part, to permeable formations having a higher potential for filtrate loss and matrix plugging. Field data compiled from lost-circulation events within permeable formations suggests that leak-off to the matrix plays a vital role in healing these loss zones. Reducing fluid loss (pressure transmission) through a sealing bridge while promoting leak-off into the permeable formation behind the bridge promotes closure of the fracture behind the blockage. The fracture tip will also then become isolated from hydraulic pressure. Thus, pressures behind the plugging material can potentially fall to pore pressure, preventing extension of the fracture.

Two methods have evolved that can be used to minimize losses to induced fractures:

1. Preventative treatment involves adding LCM in low concentrations to the drilling fluid to control fractures as they develop in a potential loss zone. The formation can be pressured regularly to build hoop stress and seal small induced fractures as they develop. The benefit of this method is that large fractures theoretically will not occur and losses will be reduced. The difficulty in engineering such preventative treatment lies in the removal of the correctly sized LCM by the solids-control equipment on circulating the treated drilling fluid.

2. Rem**e**dial treatment involves drilling until a loss is encountered. At this point, a high concentration LCM pill is squeezed into the loss zone. The remedial treatment approach can result in high losses before circulation is regained and/or an inability to effectively seal fractures and control the loss resulting in expensive wellbore loss remediation operations.

Regardless of the technique used, wellbore lost circulation and stability issues from drilling-induced or natural fractures can result in heavy economic losses. To help alleviate the problem, an extensive laboratory study[4] was undertaken to study fracture plugging dynamics and also to identify the optimum characteristics of LCM material for both sealing and strengthening impermeable rock.

The result was the development of test apparatus that could mimic a fracture in impermeable rock, and the subsequent evaluation of literally dozens of materials and LCM blends. This in turn led to the identification of key properties of an LCM and the development of unique additives for improved wellbore stability and lost circulation.

This paper describes the development and operation of the impermeable fracture tester and details the significant observations and summarizes the major conclusions of this study.

DEVELOPMENT AND OPERATION OF THE FRACTURE TEST APPARATUS

Given the prohibitive cost and difficulty of testing large size cores, the initial step called for the development of laboratory-scale equipment that could easily and cost effectively mimic a fracture in impermeable rock. An opposed piston design was ultimately developed and found to yield relatively consistent measurements of pressure, conduction loss, and fracture opening. In turn, this provided the ability to screen a number of materials that could potentially seal and prop fractures of variable width, and with a high degree of test repeatability.

The fracture test device used two matched 2.5-in. (6.35-cm) diameter corrugated aluminum platens to simulate formation fracture faces with the fracture gap being set using three set-screws (Figure 1). Furthermore, the fracture faces were sandblasted to increase the level of surface irregularities, and hence frictional effects, allowing for better particle adhesion and to encourage bridging. Natural materials were used in the early days of development. However, it was deemed necessary to change to machined metal surfaces given issues experienced with reproducibility when using natural rock as fracture faces.

Three high-precision syringe pumps, used in conjunction with two accumulator/reservoir vessels, were employed to control the drilling fluid and fracture-tip pressures within the fracture cell, while keeping the fracture closure pressure constant. Given that these pumps could accurately measure fluid volumes, both delivered and received, with microliter precision, they were also used for monitoring both the volume of filtrate collected from the fracture tip and also the fracture-closure volume. The latter was used for estimating any propping within the fracture cell. The fracture test apparatus could operate to a maximum pressure of 1,250 psi. A schematic for this device is shown in Figure 2.

Operation of the impermeable fracture test apparatus involved pumping a test fluid from the mud reservoir (labeled MR1 in Figure 3) through the open fracture of the fracture cell (FC) and into the fracture-tip accumulator cell (MR2). The test fluid was pumped at a constant flow rate of 0.5 mL/min while maintaining constant fracture tip (to simulate pore pressure) and fracture closure pressures of 25 and 125 psi, respectively. These values were selected based upon experience with the instrument. The fluid pressure at the beginning of a test (or starting pressure) was 25 psig and this was maintained at or above this value by the constant flow of fluid into the fracture cell. The effects of the fluid and/or bridging material on a fracture of pre-determined width could then be determined by monitoring the mud pressure, which is variable and dependent upon the quality of fracture seal.

The fracture test apparatus was designed to be capable of the following functions:

- Establish fracture closure (or sealing) pressure
- Apply constant pressure at fracture tip
- Inject particulate containing drilling fluid into fracture at controlled rate
- Measure pressure of injected fluid
- Measure fracture opening (from Δvolume of closure pressure pump)
- Measure volume of fluid lost to fracture tip

To achieve these functions, three main data values were used: (1) mud pressure (i.e., fluid pressure applied to the fracture), (2) conduction loss (i.e., fluid lost into the fracture through the fracture tip), and (3) change in fracture width. An example of how this data is presented graphically is given in Figure 4. This represents a test run on an IEM containing a proprietary ground cellulose product at a concentration of 20 lb/bbl (57 kg/m^3).

The line showing *mud (or fluid) pressure* can be interpreted, once a seal forms, as the sealed pressure on the wellbore side of the fracture. Initial mud pressure is 25 psig and a fixed 0.5 mL/min flow rate pumps the test fluid through the open fracture towards a fracture tip which is held at a constant backpressure of 25 psig. (The initial fracture width in this case has been set at 530 microns (µm)). As the bridge is formed, mud pressure increases.

The middle line graphically represents the *conductivity loss* (or tip loss) of the test fluid as it flows into and through the fracture. Initially, the value increases steadily with time as whole mud is lost to the fracture. Once the initial bridge forms, the conductivity loss is reduced and the slope of the line approaches zero. This reduction in slope corresponds to the building and integrity of a fracture seal, allowing an increase in fluid pressure to occur.

The bottom line on the plot represents the *change in fracture width* from the initial width of 530 µm. As the pressure builds and the seal remains, the fracture width increases until the strength of the seal is exceeded, as shown by the drop in fluid pressure and a reduction in fracture width. Fluid is lost to the fracture tip when the seal partially fails as shown by the rise in conductivity.

In this example, the fracture seal moves and is pushed further into the fracture with time. However, since it does not fail completely, upon failure, the seal begins to re-build. Fluid pressure continues to increase (with seal slippage) until a maximum of approximately 900 psig sealing pressure and a 125 µm fracture width increase is achieved. At this point, the seal has exceeded its ability to deform and fails catastrophically. Upon failure at 655 µm, fracture width returns to the initial point and the mud pressure begins to rise again as a new seal forms. In some tests, the change in fracture width does not return to zero upon seal failure. This could mean that the fracture has been held open beyond its initial width by residual sealing material built up within the fracture. The amount of fracture width change that remains after a seal failure is designated as *propped width*. Propping applies permanent FCS. In other words, additional "hoop stress" is gained without the need for applied mud pressure. An example of this is given in

Figure 5, which shows the results of an IEM containing a blend of custom ground nut and proprietary graphite materials developed as part of this study. In contrast, a poorly performing material will not form a steady seal (pressures are low) and fluid is lost at a constant rate to the tip. An example of this, for mica, is given in Figure 6.

LABORATORY TESTING AND RESULTS

Literally hundreds of fracture tests were carried out using this apparatus with a view to evaluating the relative performance and key characteristics of various types of LCM. The results have enabled a basic characterization of the important elements of LCM to be achieved, in addition to providing a means of differentiating between materials likely to be and those not likely to be successful in sealing fractures in impermeable zones. Many of these results, and their key findings, have also been verified by using other, larger scale, test apparatus such as the high-pressure fracture test rig shown in Figure 7. This particular device uses a 15-cm core of rock and operates at a pressure of up to 11,000 psi, measuring the pressure taken to both initiate a fracture, and subsequently, to reopen the fracture with the test fluid containing the LCM material. Results from the device are shown graphically in Figure 8.

A 13-lb/gal (1,558 kg/m^3), API barite-weighted IEM with an Oil-to-Water Ratio (OWR) of 80:20 was selected as the drilling fluid of choice for the majority of tests performed. This weight and OWR corresponded to a concentration of ± 850 g/L barite. A small number of unweighted fluids were also tested.

Dozens of materials and blends of LCM were evaluated. Materials tested included cellulosics, synthetic elasotomers, rubber, polyethylene, polypropylene, mica, glass, graphite and petroleum coke-based materials, iron-based compounds and calcium carbonate. Shapes tested included particulates, short fibers, long fibers, platelets, gels, flakes, films, and irregular/regular spheres. Other test criteria included surface texture, material hardness, resilience, bulk density and size.

Tests were performed over a range of fracture sizes ranging from 280 to 1,100 µm, although the bulk were carried out at between 500 and 530 µm, a size deemed “typical” by many within the industry through a combination of anecdotal evidence and numerical modeling. This size also appeared to minimize sealing contributions from the weighting agent itself.

A summary of the major conclusions of this project is outlined below.

Characteristics of Successful LCM

In many respects, lost-circulation issues in permeable formations can be approached in a more liberal way given the ability of these zones to allow leak-off of carrier fluid into the formation. Leak-off of drilling fluid readily immobilizes material *en masse* into the loss zone without the need for fracture extension and the inter-particle adhesion needed to build a seal. Hence, a more diverse collection of materials to seal fractures and pores can be used. However, there are a number of key characteristics that have been found to be important to the overall performance of an LCM.

- Size
- Range of sizes
- Shape (spheroidicity)
- Aspect ratio
- Surface texture
- Concentration
- Compressive strength
- Bulk density
- Resiliency (compression/expansion)

1. Particle Size and Size Distribution: Larger sizes allow for increased FCS through an increased ability to bridge wide fractures. However, too many large particles, without a range of smaller particles present to seal the gaps will lead to increased conductivity to the fracture tip. Fine particle sizes decrease conductivity, but do not increase fracture closure stress directly. Size and the distribution of sizes (particle-size range or PSD) are therefore the most critical factor for the performance of an LCM. The maximum size required will be determined

by the anticipated fracture width to be bridged, with a good linear spread of particles below this upper size to ensure optimal bridging of smaller fractures, and build of an efficient seal or bridge in the largest fractures.

2. Particle Shape and Texture: Spheroidal-shaped particles have been shown to provide optimum close packing, flexible bridging, and constrict the size of flow paths through a seal. Particles exhibiting a "roughness" in texture have been shown to be more efficient in sealing, possibly due to the surface roughness, providing a good anchor point for additional sealing materials. High aspect materials, such as mica, where there are extreme differences between geometric dimensions, do not function well.

3. Particle Concentration and Bulk Density: Typically, if the above characteristics are optimized, a more rapid and improved seal can be formed with an increased particle concentration in the fluid. For API barite-weighted fluids, a typical minimum concentration to form an effective seal has been found to be 20 lb/bbl. Materials with a low bulk density have an advantage in that a greater number of particles are present for the weight of material added.

4. Particle Compressive Strength: Materials exhibiting a high compressive strength will provide a more efficient seal. The relative strength of a material also reflects its ability to prop a fracture.

5. Resiliency: The ability of a material to compress and expand does appear to play a role in the overall performance of an LCM with regard to fracture propping and sealing. However, a high level of resilience does not preclude the need for other characteristics such as particle shape, texture, concentration and distribution.

The best materials shown by testing for consistently sealing fractures were sized synthetic graphite, specifically sized ground nut hulls, specifically sized proprietary ground cellulose particles and calcium carbonate. Blends of these materials can be used to optimize particle size distribution, resulting in a more successful seal.

Characteristics of Unsuccessful LCM

Particle morphology and aspect ratio dictate in large part how well, or how poorly, a material will perform as an LCM. Round materials such as sized proppant, fibrous materials such as chopped glass fiber, or materials with high aspect ratios such as mica or flakes do not generally perform well. Some of these materials can build a seal, but the conductivity loss to the fracture is typically continuous and sealed pressure is low, with limited gains in fracture width increase. Fibrous and filament-type materials in particular are to be avoided, as when added to typically successful blends they will significantly reduce the sealing ability of the fluid.

Other ineffective products include elastomers, rubbers, and ground plastics. Elastomers and rubbers will progressively extrude under pressure to form flow paths in the sealing bed. This type of deformation was also observed in ground polypropylene but at higher pressure than the rubbers.

Very coarse particles (over 1.5mm) also can stunt sealing performance in a fracture. Too many large particles will increase the fracture conductivity by disrupting sealing beds. Very coarse particles can be used in a formulation, but their effectiveness decreases rapidly beyond 5 to 10 lb/bbl.

Scanning Electron Microscope (SEM) images of acceptable and unacceptable and materials can be seen in Figure 9.

API Grade Barite

The most commonly used solid added to most drilling fluids in the oilfield is barite. Drilling fluids weighted with standard API grade barite may benefit with respect to fracture sealing performance from the presence of these solids. However, barite alone cannot seal larger fractures without the presence of larger solids. Sealing larger fractures involves combining barite with larger size particles to form a seal which ideally has the ability to deform and expand.

API barite specifications[5] dictate that no more than 30 wt% is less than 6 µm and no more than 3 wt% is greater than 75 µm. Initial tests with the fracture test device using a 13-lb/gal IEM suggested that API barite, in lab formulated fluids, will help bridge and seal narrow fracture widths (< 280 µm) with no other solids present given its relatively high concentration within the fluid. This is shown graphically in Figure 10. In this example, the seal develops rapidly with only minor slippage and with little or no conductivity. The fracture width builds to an additional ±70 µm above the initial set, at which point the seal fails at ±430 psig. However, the fracture width does not return to the initial 280 µm setting, indicating that residual barite has adhered to the fracture surface and propped the floating piston off of its stand-off pins. The second pressure curve builds to a higher pressure with increased fracture width. This seal reaches a maximum pressure of approximately 470 psig before failure. Reduced conductivity loss in a fracture relies on the rapidity at which a seal is formed as well as the tightness of the seal once the fracture is bridged. API grade barite has been found to perform well on both counts. Barite sealing could not be replicated at the same fracture width when a finer grind of barite was tested.

Graphitic-Based Material

Certain types of graphitic-based materials have long been recognized as effective sealants for induced fractures. It was assumed this was due to the hard and resilient characteristics of these products. Testing of various LCM materials has confirmed that specifically designed graphitic materials are indeed highly efficient at sealing fractures; however the role of resiliency was shown to have a more minor role. Figure 11 shows the sealing effect of 20 lb/bbl of a unique synthetic graphite blend added to a similar 13-lb/gal barite-weighted fluid as tested previously without LCM. In this case, two tests were run and plotted side by side to demonstrate test reproducibility.

In this test, using a 530 µm fracture width, a combination of barite and graphite allows a seal to be formed that is flexible enough to allow the fracture to open to 740 µm and able to withstand an applied pressure of 950 psig. On analysis of the seal formed, the high concentration of barite allows the seal to form fast and packs the seal tightly, which gives smaller spaces between particles and narrower throats and much reduced conductivity loss rate, making the seal virtually impermeable to fluid loss to tip.

After testing, seal components consisting of barite and synthetic graphite were removed from the fracture cell and examined under magnification. The seal had a remarkable capacity for deformation while still retaining a structural integrity that allowed it to stop or slow conductivity in an increasing-width fracture.

LCM Blends

Particle size distribution has proven to be a key factor in the performance of LCM in sealing induced fractures within impermeable zones. However, due to the limited particle-size control achievable with standard grinding, most materials do not have a PSD that will perform well in a large fracture. Acquiring better sealing performance can be done using blends of materials which have the necessary particle properties of shape, surface texture, and resistance to deformation. When combined, blends can demonstrate improved performance over the individual blend components by enhancing particle size distributions in key size ranges. Blending compatible materials can yield an optimization of performance and improve results.

Blending can have significant advantages over the use of a single LCM product. Effective blending allows an oil company operator to use what is available at the well site to achieve desired results. Even if a particularly effective LCM is not available, having the flexibility to best utilize combinations of available products can be an advantage. Blending can also “stretch” the performance of value-added LCM, which can improve operational costs when using preventative treatment methods to drill through largely impermeable formations where the likelihood of induced fractures occurring is high. Since a large percentage of added material is removed every circulation, using high concentrations of a key LCM product as an extended preventative measure can become too costly. Blending allows an operator to control costs with more inexpensive LCM while potentially providing better sealing and increased stability.

Fracture testing revealed that blending accentuates the positive performance aspects of each component and can address the limitations of the respective components. For example, the strength of ground nut hulls and calcium carbonate is in sealing pressure and increasing fracture width, but the most glaring weakness of these materials, especially carbonates, is conductivity to tip. An important strength of coke and graphite LCM is the substantial reduction in conductivity relative to carbonates and nut when properly sized. Therefore, combinations of nut or calcium carbonate with graphite continually produced very good results on the fracture test device. The end result is that blends of materials can achieve enhanced results relative to treatments which use only one LCM additive.

A disadvantage of blending entails one of the key advantages mentioned previously. The use of blends coupled with the wide array of materials available in the industry can lead to the inclusion of blend components that do not effectively increase performance, such as waste cardboard, cellophane, bagasse (sugar cane fiber), and glass fiber. These LCM will increase the stability marginally at best, and in many cases can detract from the absolute efficiency of the treatment. Materials such as mica are readily available and very inexpensive, but given the physical aspects of the material, it provides little additional stability in the wellbore due to continuous conductivity and limited sealing pressure. In essence, the shape of the particles disturbs the sealing bed. Despite the relative lack of performance, mica continues to be used in the field because of its associated costs. Blends should only contain components which will enhance the implementation of the treatment and not negatively affect the sealing of fractures.

DISCUSSION

The fracture-test apparatus developed for this study has given great insight into the effectiveness of LCM in impermeable zones. Apart from the ability to rapidly and inexpensively test the sealing effectiveness of various materials, the most significant benefit from this equipment is the control and measurement of changes in fracture width. Stress cage theory relies on the development of increased fracture closure stress imparted by a seal on the fractured formation. Thus, results from this device can be used to help optimize LCM types and concentrations for wellbore stabilization and strengthening. The tester also gives an indication of propped width within sealed fractures caused by LCM that has been pressed into the fracture. Propped fracture widths can be used to determine a measure of residual prop which will remain even when well circulation has stopped and hydraulic pressure is reduced.

Project testing revealed the critical importance of particle sizing in the sealing of fractures. Appropriate size distribution is the key aspect of a successful LCM because it will allow for the sealing of fractures in a wide range of initial widths. Applying a material or blend of LCM with a broad distribution of particle sizes that can seal a range of widths will be more effective in sealing induced fractures than a narrow distribution. Optimization of sizing for particular widths should be achieved through laboratory testing combined with well data and the use of bridging software.

Preventative treatment methods involving continuous addition of LCM to the mud to maintain particle concentration and size distribution provide the best chance for success in controlling losses in impermeable zones prone to fracturing. Testing concluded that high concentrations of high-performing material will increase sealing capabilities over a broad range of fracture widths by sealing faster and producing increased fracture width, while total concentrations reduced below 15–20 lb/bbl will decrease this performance markedly. Applying LCM preventatively has the potential to reduce major loss incidents by rapidly sealing fractures initiated in the near wellbore while also potentially improving overall wellbore stability.

Remedial treatment will require more material to provide sufficient control of the fracture width and the material must be suited to the fracture encountered. Large-volume losses treated by remedial treatment methods will require a high-concentration pill (50–100 lb/bbl) of broad-distribution LCM with an emphasis on the percentage of larger particle sizes (0.8–1.5mm) present in the treatment.

API barite has been shown to contribute to fracture sealing, and in laboratory testing, provided a seal without any other LCM material present to approximately 300 μm. Thus, API grade barite could be used on its own for sealing small fractures if present in sufficient concentrations, and at the very least, may be regarded as a contributory sealing material for reducing fluid conductivity. However, for most field situations, treatments should contain at least 10 lb/bbl of a complimentary LCM, although 15–20 lb/bbl would be preferred. More material should be added per circulation in case of heavier losses to a total of 20–40 lb/bbl.

The best LCM treatments involved blends of various grades of the most effective additives, namely, calcium carbonate, ground nut, graphite and graphite/coke blends. Unique additives were also developed as part of this project and these were based primarily on graphitic blends. Broad-range particle size distributions combined with material properties such as resilience, compressive strength and particle morphology all contributed to the successful performance of these unique additives over a large range of fracture sizes. These products were also found to have an enhanced performance when combined with complimentary LCM materials.

In addition to the knowledge gained concerning the performance characteristics of successful lost circulation materials, the results also provided further laboratory evidence of current wellbore stability theories that prevail within the industry.

REFERENCES

1. Aston, M.S., Alberty, M.W., McLean, M.R., de Jong, H.J. and Armagost, K.: "Drilling Fluids for Wellbore Strengthening," SPE 87130, SPE/IADC Drilling Conference, Dallas, 2-4 March 2004

2. Dupriest, F.E.: "Fracture Closure Stress (FCS) and Lost Returns Practices," SPE 92192, SPE/IADC Drilling Conference, Amsterdam, 23-25 February 2005.

3. Alberty, M.W. and McLean, M. R.: "A Physical Model for Stress Cages," SPE 90493, SPE Annual Technical Conference, Houston, 26-29 September 2004.

4. Fracture Studies Joint Industry Project (JIP). Internal project partnered by BP, Shell, Statoil, Norsk Hydro, ConocoPhillips, Chevron, Eni, Schlumberger and M-I SWACO, 2004–2006.

5. *API SPEC 13A: Specification for Drilling-Fluid Materials,* 15th Edition, American Petroleum Institute, 1993.

ACKNOWLEDGMENTS

The authors would like to thank the management of M-I SWACO for permission to publish this paper. Thanks are also extended to those companies involved in the recent Fracture Studies JIP, namely, BP, Shell, Statoil, Norsk Hydro, ConocoPhillips, Chevron, Eni and Schlumberger.

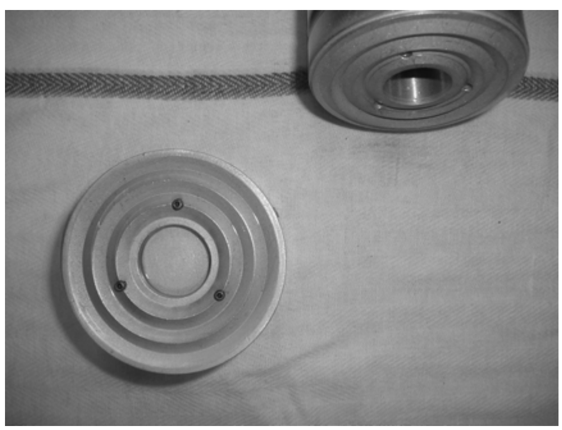

Figure 1 - Corrugated Aluminium Platens of the Fracture Tester
(The positions of the three set-screws can be seen near the center.)

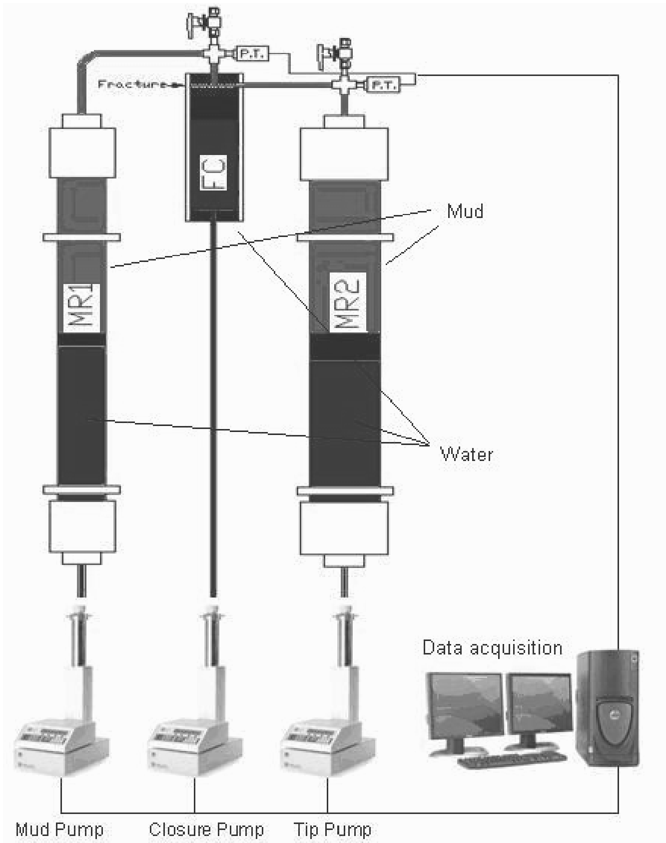

Figure 2 - Schematic of Impermeable Fracture Test Device The test apparatus consists of a mud reservoir (left cylinder, MR1), fracture cell (center cylinder, FC), and fracture-tip accumulator (right cylinder, MR2).

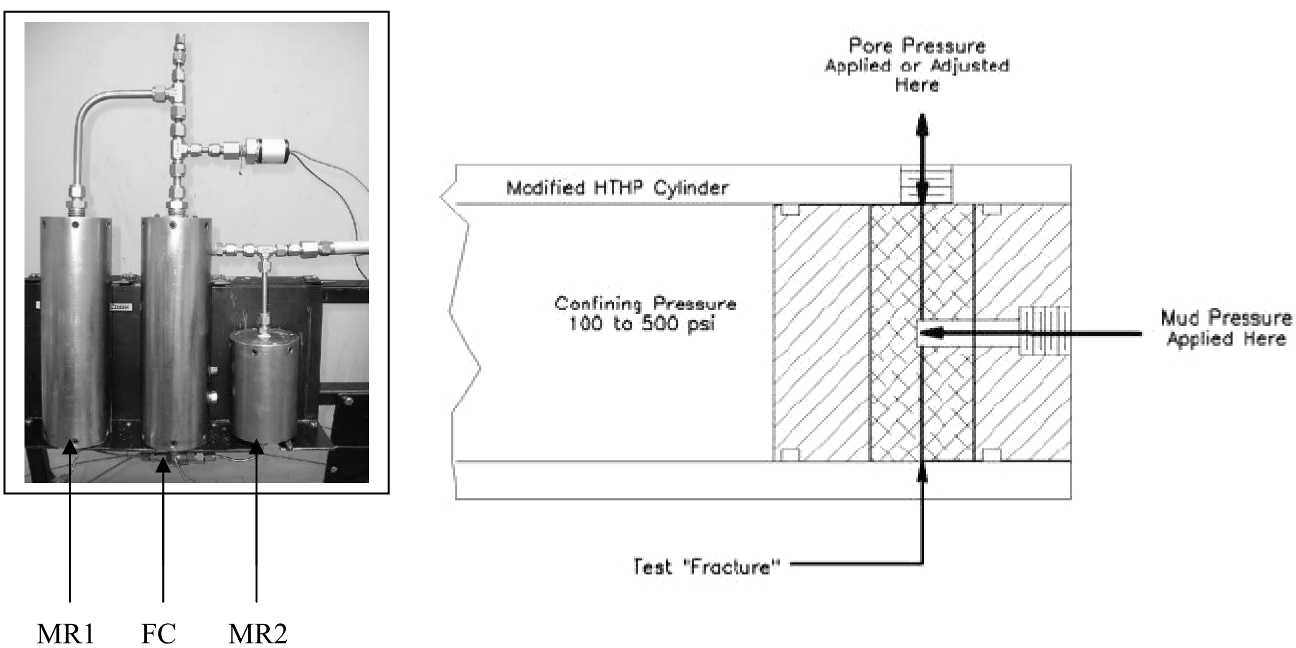

Figure 3 – Fracture Cell Apparatus with Schematic of Fracture Cell

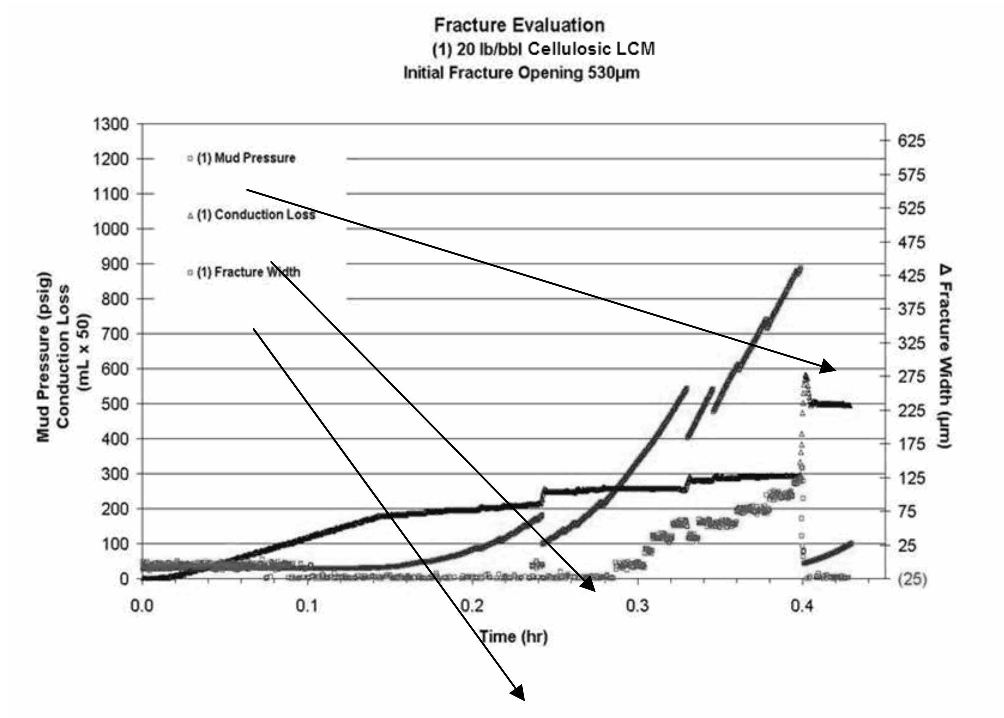

Figure 4 – Fracture Evaluation of a Proprietary Cellulosic LCM Against a Fracture Size of 530 µm

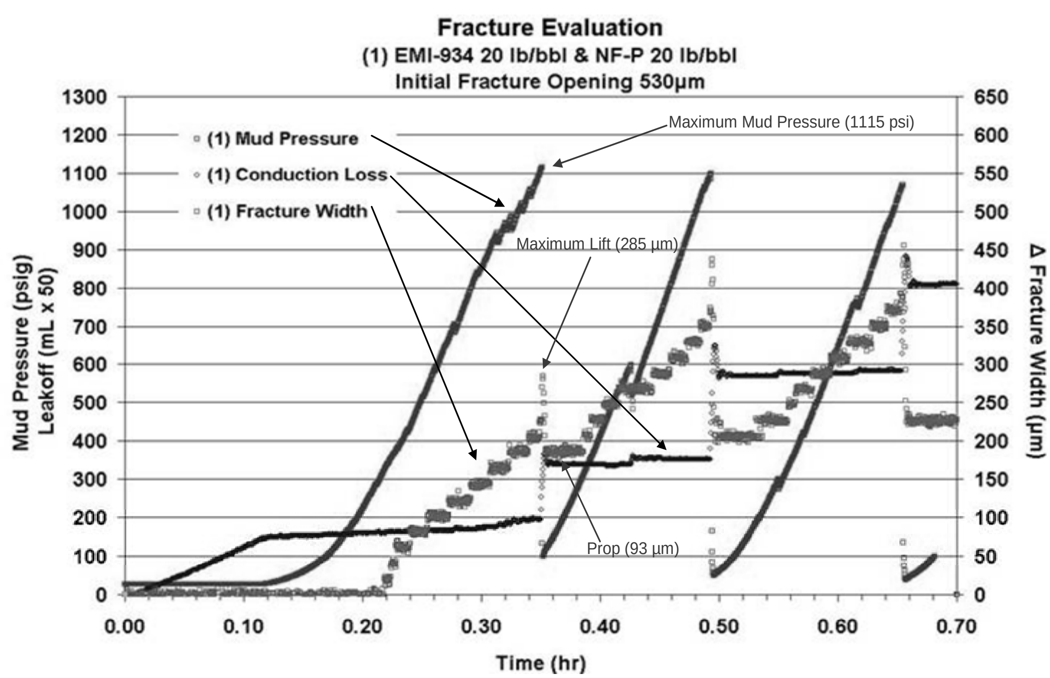

Figure 5 – Fracture Evaluation of a Proprietary Graphitic-Nut Blend against a Fracture Size of 530 µm

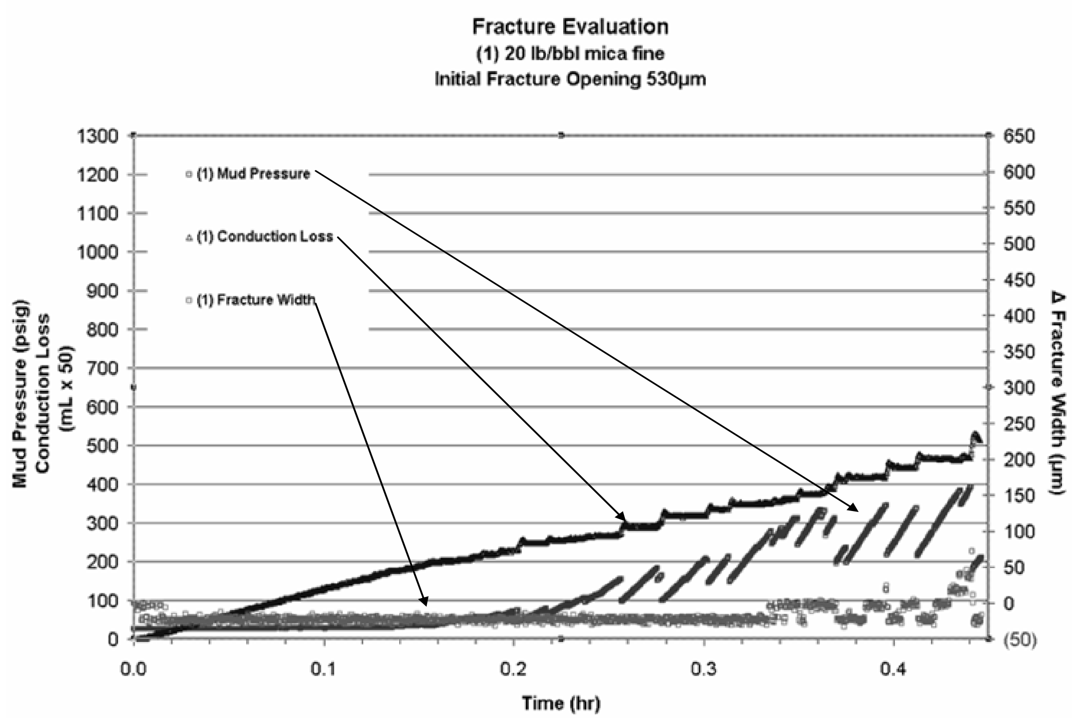

Figure 6 – Fracture Evaluation of Mica Against a Fracture Size of 530 µm

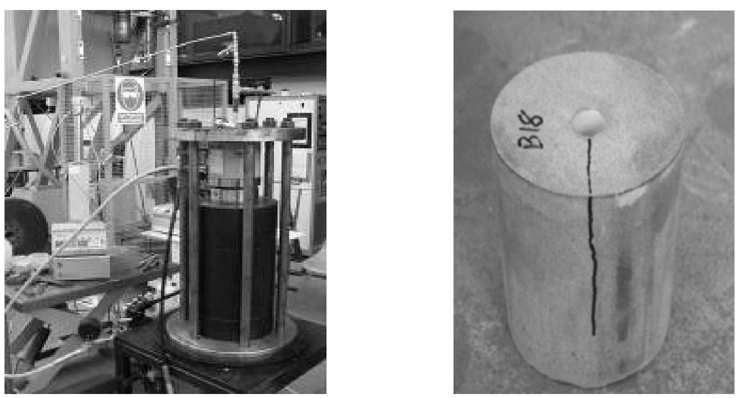

Figure 7 – High-Pressure Fracture Testing Equipment and Pre-Test Core

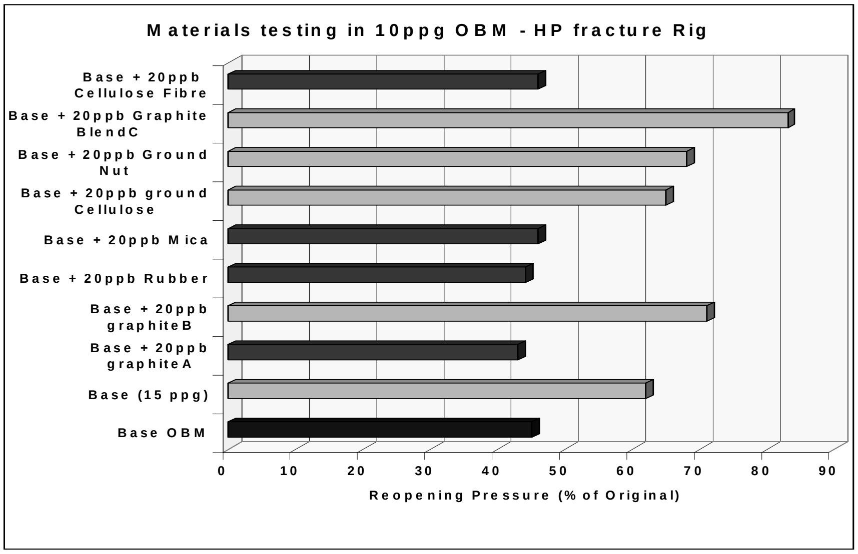

Figure 8 – Comparative Results from the High-Pressure Fracture Tester Showing the Fracture Re-Opening Pressures (as a percentage of the original) Post-Treatment with LCM.

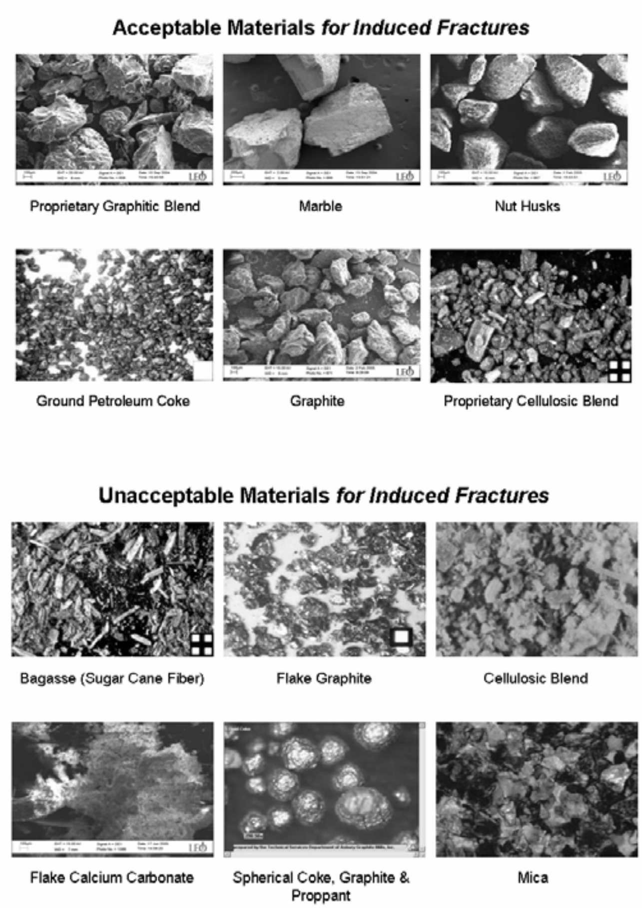

Figure 9 – Examples of Acceptable and Unacceptable Materials for Sealing Induced Fractures

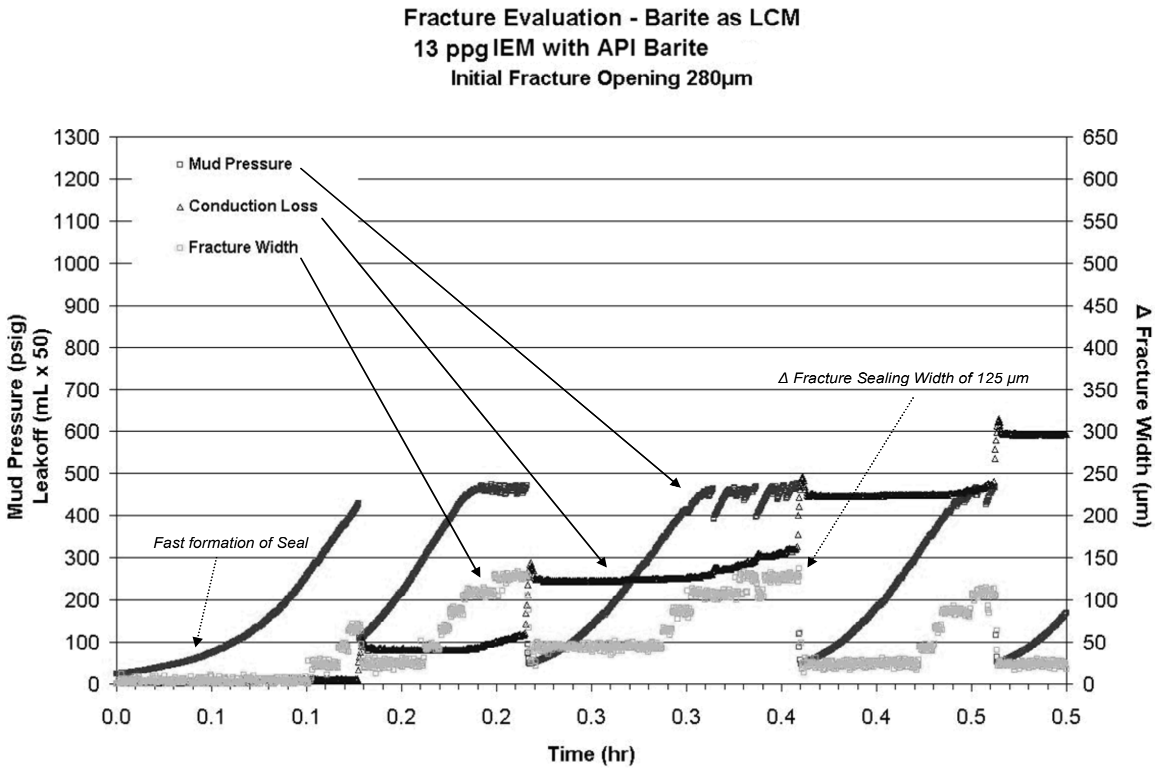

Figure 10 – Fracture Evaluation of API Barite Against a Fracture Size of 280 µm

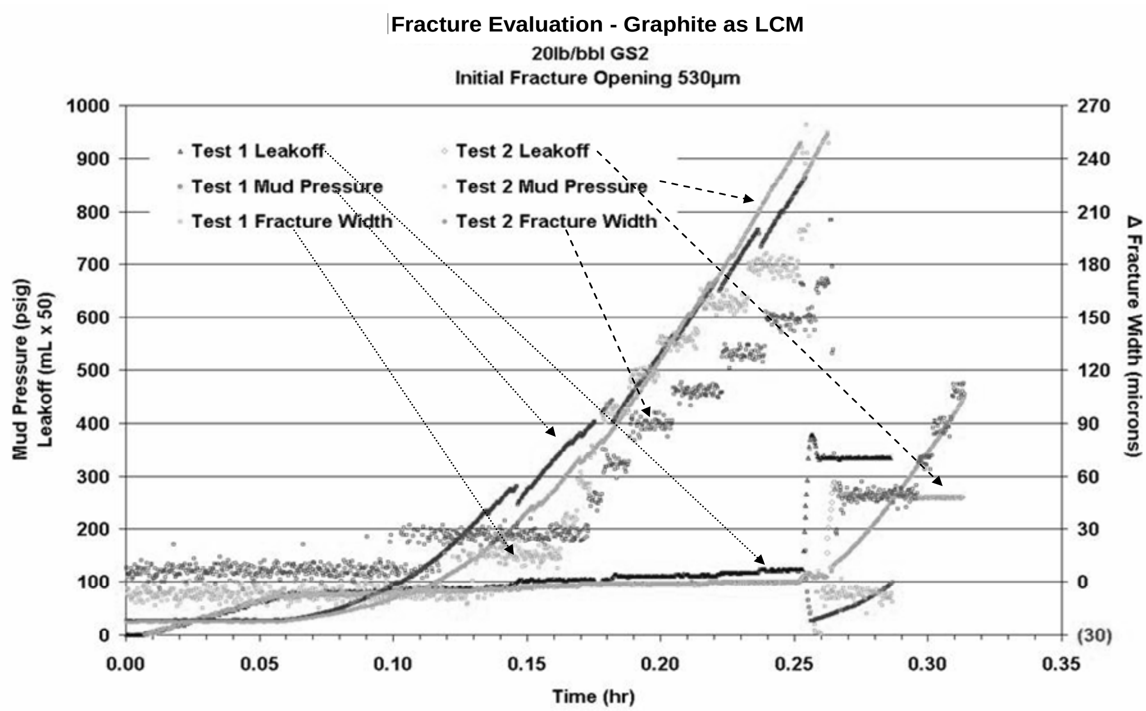

Figure 11 – Fracture Evaluation of a Proprietary Graphite-Based LCM Against a Fracture Size of 530 µm