DECIDING ON OPTIMUM SOLUTION FOR LOSS CIRCULATION CHALLENGES

Mark Savery, BR Reddy, Kris Ravi and Don Whitfill
Halliburton Energy Services

Mark Aston
BP

ABSTRACT

This paper discusses and presents results from a detailed investigation of the effectiveness of different materials to solve loss circulation challenges. This work can help to identify the attributes of loss circulation and apply the most appropriate solution.

Losses while drilling is one of the challenges faced by well construction teams. There are many procedures and products available to tackle these challenges. Opportunity for improvement lies in a better understanding of how different products solve losses and under what condition they should be used.

A fracture test device was built to study the effectiveness of different lost circulation materials, such as gunk, calcium carbonate, graphite, and mica. Fracture size, lost circulation material type, and concentration and size were the variables investigated. In addition to the conventional lost circulation materials, different chemical systems were tested. The effect of oil based and water based drilling fluid was also investigated in this study.

The effectiveness of the materials tested in resisting drilling fluid pressures and fluid influx from the formation were investigated and are discussed. The behavior of these materials when the fracture closes and the significance of that behavior are also discussed. Based on the results, mechanisms by which different products solve losses and procedures to implement these solutions are presented.

INTRODUCTION

Much to the dismay of drilling operators, lost circulation challenges have long persisted in the petroleum industry. Wasted rig time, mud losses, well abandonment, and bypassed petroleum reserves are just a few of the problems that have resulted from lost circulation. Induced fractures and problematic formations with weak zones or vugular and/or natural fractures are the culprits for mud loss. These loss zones should be blocked and sealed so the operator can maintain well control and continue drilling. Treatments designed as part of a wellbore pressure management (WPM) strategy that mitigates the lost circulation might enhance the formation strength around the wellbore. This approach is frequently referred to as wellbore strengthening and might allow deeper drilling without the need to set casing. A fully-engineered WPM approach should be employed to improve the probability of success. During the planning phase, this approach may incorporate borehole stability analysis, equivalent circulating density (ECD) modeling, leakoff flow-path geometry modeling, and drilling fluid and lost circulation treatment selection that minimizes the effects on ECD. During the execution phase, real-time hydraulics modeling, pressure-while-drilling (PWD) data, connection flow monitoring techniques, and timely application of treatments are required to minimize or eliminate losses in high-risk areas.

This paper focuses on the proper design of lost circulation treatments and how that design naturally becomes an integral part of a successful WPM strategy. Solving loss circulation by selecting the right treatment requires understanding of the pressure effects on various treatments while in the fracture. The comprehensive laboratory study presented here provides actual pressure containment data obtained in the laboratory for several lost circulation treatments, ranging from particulate lost circulation materials (LCMs) to chemical sealants. The results offer an insight into how to optimally design a treatment and incorporate it into a WPM strategy.

LABORATORY EQUIPMENT AND DESIGN

Tests were conducted using various loss circulation treatments ranging from particulate LCMs to chemical sealants. The main component of the laboratory apparatus was a Hassler cell containing a synthetic rock core. Each core had a length of 8 cm and a diameter of 2.5 cm. The cores were prepared by combining different grades of sand with a resin mixture. The mixture was charged into a plastic tube containing a centered rectangular stainless-steel plate machined with the desired fracture taper along the length of the plate. When the mixture was partially cured, the plate was pulled out, and the mixture was allowed to fully cure in the tube. Cores with different fracture geometries were prepared using this technique. In this study, the cores were formed with a width of 3 mm on the wider end (representing the wellbore side) and either 1 mm or 2 mm on the narrower end (representing the formation side). Both ends were sealed with epoxy resin to prevent fluid penetration into the core faces. Figure 1 shows two of these cores.

The synthetic rock core was fitted into a rubber sleeve enclosed in the cylindrical Hassler cell that could be maintained at the test temperature by an attached thermostat. The core was mounted so the wider end of the simulated fracture was in contact with the drilling fluid, a condition similar to that experienced during actual drilling. The differential pressure between the two ends was measured by upstream and downstream pressure transducers. The Hassler cell was connected to a pressure pump to create an impermeable fit between the synthetic rock core and the rubber sleeve. A separate sample vessel was used to charge (with nitrogen pressure) the lost circulation treatment through the simulated fracture. The test setup was designed to compare the relative capabilities of different treatments to withstand drilling fluid pressures. A drilling fluid reservoir was connected by a heating chamber to the wider side of the synthetic rock core with steel tubing. The reservoir was connected to a pump that followed a programmed flowrate and pressure. The apparatus setup is shown in Figure 2.

TEST PROCEDURE

A new core was placed inside the rubber sleeve located in the Hassler cell and an initial overburden pressure of 1,000 psi was applied to lock the core in place. Drilling fluid was circulated through the core to wet the fracture surfaces. The lost circulation treatment was then prepared by adding the proper components into the sample vessel. The mixture was stirred with a spatula for homogeneity. Next, a piston was inserted into the sample vessel and low nitrogen pressure (<50 psi) was applied initially to the piston to push the treatment through the fracture. For particulate LCM, the pill was charged through the fracture at 40 mL/min and stopped when nitrogen pressure increased to 600 psi. This pressure increase signaled particulate bridging. For chemical sealant samples, the pressure was applied until the sample extruded from the other end, indicating that the fracture was completely full of the reacted product. The Hassler cell assembly was then heated overnight at 160°F for chemical sealant tests. This step was omitted in the case of particulate LCM treatments because it was observed earlier that temperature had a negligible effect on their performance. At the end of the heating period (for LCMs it was immediately after charging the core), the pressure was released after cooling, and the test cell was temporarily disassembled from the apparatus and treatment residue was cleaned from the valves, pipes, and core faces. The test cell was reassembled and the connecting lines and valves were flushed with drilling fluid that contacted the core face. The other end of the Hassler assembly was connected to an oil reservoir designed to apply back pressure, and all the lines up to the formation end of the core were flushed with oil. At this stage, the apparatus was ready to perform the pressure containment test on the treatment still remaining in the fracture.

Drilling fluid flow was then initiated at 2 mL/min. At the same time, an overburden pressure on the rubber sleeve was continually adjusted to about 500 psi higher than the pressure applied on the drilling fluid. This ensured that any observed fluid flow under pressure was caused by the passage of the fluid through the treatment and not passage through the annular space between the core and the rubber sleeve. If the loss circulation composition withstood an initial pressure of 100 psi and no leakage was observed at the other end, the face pressure and overburden pressure were increased steadily up to the maximum operating pressure of 2,500 psi while maintaining a constant flowrate. If the flowrate of drilling fluid leakage at the other end became significant, or if there was a “catastrophic” blowout of the treatment, the differential pressure dropped to zero. The peak pressure at which the differential pressure dropped to zero was deemed the “dislodgement pressure” and was recorded. This number eventually became the indicator of product effectiveness and was used as a differentiator between lost circulation treatments. If the loss circulation composition withstood the maximum operating pressure during the forward flow procedure, the Hassler cell was reversed to measure the ability of the loss circulation treatment to withstand pressure applied from the narrow side, simulating the effectiveness of the treatment to withstand formation fluid pressure. The procedure was the same as before.

RESULTS

The first test set used only particulate LCM in a 12 lb/gal internal olefin oil-based mud. The results are shown in **Table 1**. Five LCM particulates were used in this study and had d_{50} sizes of 30, 150, 325, 600, and 800 microns, respectively. The d_{90} sizes were 135, 425, 425, 850, and 1400 microns, respectively.

The second test set involved a traditional clay-swelling chemical sealant with and without particulate LCMs (Table 2). Traditional clay-swelling sealants are often referred to as “gunk squeezes” for water-based mud applications and “reverse-gunk squeezes” for oil-based mud applications. Typically, these are dual-stream systems in which one stream consists of a carrier fluid holding a high concentration of clay and the other stream consists of the onsite mud system with no modifications. When the two streams mix in-situ, the resulting product is a high yield stress, pliable plugging agent. The two-stream mixture in this study consisted of (1) an aqueous phase containing an organophilic clay and a polymer and (2) a 12 lb/gal internal olefin/ester blend, oil-based mud. The two streams were premixed in a 1:1 volume ratio inside the sample vessel until a highly viscous consistency was achieved. The sample was then charged through the fracture and allowed to cure overnight at 160^{o}F prior to pressure testing.

The third test set involved a new, rubbery polymer chemical sealant with and without particulate LCMs (Table 3). This chemical system is also a dual-stream system in which one stream is liquid polymer slurry and the other is the activator stream. Once the polymer contacts the activator, the mixture immediately forms an intact, rubbery mass with cohesiveness, flexibility, and structural integrity (Figure 3).

The fourth test set used the some of the particulate LCM products described previously, only this time the carrier fluid was a 12 lb/gal water-based mud. The goal was to determine the effect (if any) the carrier fluid has on pressure containment ability. The results are shown in Table 4.

For every test, the fracture length (8 cm) and height (12 mm) were held constant, but two width geometries were used: 3 to 1 (3-1) mm tapered and 3 to 2 (3-2) mm tapered. The 3-1 mm width represented a “small” fracture in which typical LCM on the order of 10 microns to 600 microns might easily bridge off. Conversely, the 3-2 mm width represented a “large” fracture in which typical LCM might have difficulty bridging off. A comprehensive test suite was completed and eight key observations were noted:

1. Diversified particle sizes optimize pressure containment. It is critical to include a small-sized particle (10-50 microns) to fill in the interstitial gaps (Test 1 vs. Test 3), a large-sized (600+ microns) particle to initiate blockage (Test 2 vs. Tests 7-9), and a mid-sized particle on the order of 150-400 microns (Tests 3-9). Also, refer to Figure 4 for an actual picture of particulate bridging of an LCM combination with diversified sizes.
2. Higher LCM loading outperforms lower LCM loading. 30-lb/bbl loading (Tests 11-12) showed better pressure containment results and more reliable repeatability than 15-lb/bbl loading (Tests 13-14).
3. Particulate LCM pill performance directly relates to fracture width. The combination of calcium carbonate (d_{50} = 600 microns), graphitic carbon (d_{50} = 325 microns), and bentonite (d_{50} = 30 microns) was always effective bridging off in a 3-1 mm fracture (Tests 1-9, 11-14). However, regardless of loading, the same combination never bridged-off in a 3-2 mm fracture (Tests 10, 15). The combination of flat, oddly shaped laminate particles (d_{50} = 800 microns), graphitic carbon (d_{50} = 325 microns), and bentonite (d_{50} = 30 microns) bridged-off not only in a 3-1 mm fracture (Test 16) but also in a 3-2 mm fracture and could be repeated (Tests 17, 18). This is the only LCM pill to exhibit successful pressure containment in a 3-2 mm fracture. The 600-micron calcium carbonate particle did an excellent job initiating blockage in the “small” fracture (3-1 mm taper). However, the same particle was unable to initiate blockage in the “large” fracture (3-2 mm taper). The only particle size that worked in the 3-2 mm fracture (2,000 micron at the tapering end) was the oddly shaped 800-micron laminate particles. These LCM particulates are available to drillers today and may enhance the performance of LCM pills in challenging weak formations.
4. In fracture sizes conducive for particulate bridging, proper sizes and types of particulate LCMs at sufficient loadings are superior to chemical sealants. In both the 3-1 mm and 3-2 mm fractures, the clay-swelling sealant by itself (Tests 19-20, 25) showed lower dislodgement pressure than all particulate LCM combinations that bridged off. And while the new rubbery chemical sealant by itself (Tests 27-28) showed higher dislodgement pressures than the clay-swelling sealant and some particulate LCM treatments, the results were lower than the maximum particulate LCM pressure achieved (2,500 psi in 3-1 mm fracture).
5. A rubbery polymer sealant with structural integrity shows better pressure containment than a pliable clay-swelling sealant without structural integrity. Under the same conditions, in the same size fracture of 3-1

mm, the new rubbery polymer sealant (Tests 27-28) showed significantly better pressure containment ability than the clay-swelling sealant (Tests 19-20). For a qualitative comparison, refer to Figures 5 and 6. Figure 5 shows a clay-swelling sealant in the fracture after it has seen drilling fluid pressure. Note the mud channel creation, which indicates a potential danger that the drilling fluid could make its way to the fracture tip. This could result in an undesired effect of propagating the fracture even more. Figure 6 shows the rubbery polymer sealant. The structural integrity of the mass blocks any chance of channeling. In an actual downhole fracture, this material property would help mitigate pressure transmission to the fracture tip.

6. Adding proper sizes and types of particulate LCM to chemical sealants enhances pressure containment capability but too much can inhibit performance. Both the clay-swelling sealant and rubbery polymer sealant showed improved pressure containment when particulate LCMs were added. However, one case (Test 24) showed a lower dislodgement pressure with higher loading, indicating that too much particulate LCM might interfere with the chemical system reaction mechanism.
7. The real value for chemical sealants is realized when fracture sizes are too large for particulate bridging to occur or in impermeable formations where fluid leakoff does not occur sufficiently to allow particle bridging. Even with sufficiently wide particles, large fractures are still difficult to seal. The highest dislodgement pressure obtained in the 3-2 mm fracture using strictly particulate LCMs was only 1,482 psi (Test 18). Adding the same LCM formulation to the new rubbery polymer sealant gave even better results. This treatment was able to hold above 1,800 psi on three separate occasions (Tests 29-31). In fact, during one of these cases (Test 31), the treatment held the maximum operating pressure of 2,500 psi on both the wellbore side and formation side! This suggests that chemical sealants greatly enhance pressure containment in larger voids due to their high yield stresses. Some types of chemical sealants often have extremely high viscosities—so high in fact, that their viscosities cannot be measured using conventional laboratory equipment. However, the yield stress of these treatments can be found directly by measuring the force required to move an object of known surface area through the material. The definition of yield stress is the amount of stress required to permanently alter the shape of a solid or semi-solid material, or, more simply, the force required to get something moving. In this study, the yield stress of the rubbery polymer sealant was found to be on the order of 31,000 Pa using the direct measurement method mentioned above. This value is several orders of magnitude higher than a normal drilling fluid that could easily flow to the fracture tip and propagate the fracture farther. Treatments such as the rubbery polymer, however, can effectively seal the loss zone because the treatment can accept a significant load before moving.
8. Generally, the same observations were noted when water-based drilling fluid was used as the carrier fluid instead of oil-based fluid. As in the oil-based tests, the same choice of particle size distribution in water-based fluid provided repeatable pressure containment in a 3-1 mm fracture (Tests 32-35), but struggled to provide any in a 3-2 fracture (Tests 41-42). In addition, the water-based testing confirmed that a large-sized particulate (600+ microns) is needed to initiate blockage in a 3-1 mm fracture. All results with the large-sized calcium carbonate (Tests 32-36) showed success while all results without it (Tests 37-40) showed failure. In fact, one treatment (Test 36) bridged off without any medium-size particulates. However, this treatment yielded a lower back dislodgement pressure (500 psi) than a treatment with medium-sized particulates included (1,600 psi from Test 33).

DISCUSSION

Drilling Engineering Association joint industry experiments (DEA 13)[1] done in the mid 1980s on 30x30x30-in. blocks gave insight into the prevention of lost circulation in general and in oil-based fluids vs. water-based fluids in particular. The experiments demonstrated that an adequate loading of properly sized materials causes “tip screen out” immediately after the fracture is initiated, preventing pressure transmission to the fracture tip.[2] More recently, a joint industry project was conducted through the Global Petroleum Research Institute (GPRI 2000 Project DC3) to leverage this effort. A key insight from the GPRI 2000 Project was the significantly greater effectiveness of a special graphitic carbon vs. all other single materials used in the study. The development of specially manufactured, dual–composition, resilient carbon material has made a significant difference in the ability to pretreat effectively. One important characteristic of these materials is resiliency, a compressive property allowing it to mold itself into the fracture, promoting screen-out and pressure containment. The material can rebound upon pressure variations, thus continuing to plug the fracture completely (as confirmed in Figure 4). Field experience had indicated the superior performance of the special graphitic carbon material, but the GPRI 2000 Project contributed to the significant laboratory confirmation needed.[3]

The results from this study and the results of the two industry projects mentioned above are in agreement and also support other critical factors for success, including pretreating with selected LCM before drilling and adding (if necessary) subsequent treatments as sweeps rather than adding into the bulk drilling fluid system. This type of addition will help ensure that the wellbore sees a higher concentration of particulate materials in general, and the larger particles, in particular, to initiate blockage. These "preventive" sweeps should contain a nominal 50 lb/bbl of the selected materials. In addition, carrying smaller size LCM particulates in the active drilling fluid system when drilling through probable lost circulation zones can also minimize or eliminate losses. The size distribution selected should depend on the expected fracture size. Pretreatment can also have the added benefit of mitigating wellbore breathing and seepage losses while drilling depleted zones.[4] Graphitic carbon and sized calcium carbonate have also proven to be effective primary materials when carried as a pretreatment in the drilling fluid, and many times they are generally the main constituents of initial lost circulation treatments. The LCM carried as pre-treatment could bridge off and thus prevent smaller fractures created from getting wider during the course of drilling.

DRILLING A PERMEABLE ZONE

When logging while drilling (LWD) tools indicate that the bit is entering a possible permeable weak zone identified during the planning phase by the wellbore stability and fracture mechanics analysis, a treatment containing larger-sized graphitic and calcium carbonate material is pumped to help enhance the wellbore pressure containment (WPC) capability by building a "stress cage" around the wellbore.[5] The treatment is circulated to the weak zone where a squeeze pressure is applied to initiate and then quickly plug the fracture that is created. By preventing further pressure transmission to the fracture tip while preventing the fracture from closing near the wellbore, hoop stresses (i.e. the mechanical stresses applied in all directions perpendicular to the wellbore radius) are increased, resulting in an increase in the relative WPC capability. This new technique is based on conventional knowledge[6] but requires understanding of rock mechanical properties that allows the specific treatment to be designed with software.[7] This model quantifies fracture sizes, the impact of those fractures when subject to stress, and suggested particle concentrations to plug the fractures.

DRILLING A NONPERMEABLE ZONE

Alternatively, a chemical sealant might be more effective in a nonpermeable formation where a lack of fluid leakoff can inhibit the formation of a pressure plug while preventing fracture closure near the wellbore. One example of this application is a system that forms a clay-swellable, pliable product. Another example may be a flexible, rubbery sealant that plugs the fracture aperture as close to the borehole as possible. These are typically employed as a two-component system: the sealant material is pumped down the drill pipe, and the drilling fluid is pumped down the annulus at a rate that optimizes the volume fraction of each component. These two components mix below the bit and react before entering the lost circulation zone or created fracture. A spacer is used before and after the reactive pill pumped down the drill pipe. These systems are designed to work in water-based fluids or oil-based fluids. While very effective in curing lost circulation, in many cases a more important application is to improve WPC capabilities for improved shoe leakoff test (LOT) results or for further drilling in an openhole interval to extend a casing shoe depth.[8]

SUMMARY

Lost circulation continues to be a significant contributor to nonproductive time during drilling. However, the growth of knowledge, implementation of new planning tools, and offering of better systems hold promise in finding a solution to these challenges. The current study presents and discusses laboratory data that gives insight into WPC performance of several lost circulation treatment choices. The observations can also help optimally design lost circulation treatments for particular wellbore conditions. This study also provides a solid foundation to support WPM strategies based on borehole stability estimates, hydraulics monitoring, and fracture geometry modeling.

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Table 1
Particulate LCM Pressure Dislodgement Test Results in Oil Based Mud

Formulation (12 lb/gal Internal Olefin Mud Base Fluid)					**Performance**			
Test No.	**Bentonite (d_{50}=30μm), % bwm**	**Graphitic Carbon (d_{50}=325 μm), lb/bbl**	**Carbonate 1 (d_{50}=600 μm), lb/bbl**	**Carbonate 2 (d_{50}=150 μm), lb/bbl**	**Fracture Width, mm**	**Bridge Off**	**Forward Dislodgement Pressure, psi***	**Back Dislodgement Pressure, psi***
1	—	15	15	—	3-1	No	**—**	**—**
2	15	15	—	15	3-1	No	**—**	**—**
3	15	15	15	—	3-1	Yes	**2,500**	**200**
4	15	15	15	—	3-1	Yes	**580**	**—**
5	15	15	15	—	3-1	Yes	**2,500**	**Did Not Test**
6	15	15	15	—	3-1	Yes	**1,646**	**—**
7	15	15	15	15	3-1	Yes	**2,494**	**—**
8	15	15	15	15	3-1	Yes	**794**	**—**
9	15	15	15	15	3-1	Yes	**1,150**	**—**
10	15	15	15	15	**3-2**	No	**—**	**—**
				Suspension Agent, lb/bbl				
11	5	30	30	18.5	3-1	Yes	**2,500**	**2,500**
12	5	30	30	18.5	3-1	Yes	**2,500**	**2,500**
13	5	15	15	18.5	3-1	Yes	**2,500**	**2,500**
14	5	15	15	18.5	3-1	Yes	**1,311**	**—**
15	5	75	75	18.5	**3-2**	No	**—**	**—**
				Laminate Particles (d_{50}=800 μm), lb/bbl				
16	5	15	—	15	3-1	Yes	**2,500**	**2,500**
17	5	30	—	30	**3-2**	Yes	**1,482**	**—**
18	5	30	—	30	**3-2**	Yes	**1,388**	**—**

*Maximum operating pressure was 2,500 psi.

Table 2
Clay-Swelling Chemical Treatment Pressure Dislodgement Test Results With and Without LCM Additions

Test No.	**Bentonite (d_{50}=30 μm), % bwm**	**Graphitic Carbon (d_{50}=325 μm), lb/bbl**	**Carbonate 1 (d_{50}=600 μm), lb/bbl**	**Fracture Width, mm**	**Forward Dislodgement Pressure, psi**
19	—	—	—	3-1	**547**
20	5	—	—	3-1	**537**
21	5	—	25	3-1	**947**
22	5	25	—	3-1	**1,080**
23	5	25	25	3-1	**1,298**
24	5	50	50	3-1	**979**
25	5	—	—	**3-2**	**462**

Table 3
Rubbery Polymer Treatment Pressure Dislodgement Test Results With and Without LCM Additions

Test No.	**Chemical Activator Concentration, lb/bbl**	**Bentonite (d_{50}=30 μm), % bwm**	**Graphitic Carbon (d_{50}=325 μm), lb/bbl**	**Laminate Particles (d_{50}=800 μm), lb/bbl**	**Fracture Width, mm**	**Forward Dislodgement Pressure, psi***	**Back Dislodgement Pressure, psi***
26	—	5	30	30	3-1	**1,390**	**—**
27	50	5	—	—	3-1	**1,530**	**—**
28	100	5	—	—	3-1	**1,700**	**—**
29	50	5	30	30	**3-2**	**1,811**	**—**
30	40	5	30	30	**3-2**	**2,193**	**—**
31	33	5	30	30	**3-2**	**2,500**	**2,500**

*Maximum operating pressure was 2,500 psi.

Table 4
Particulate LCM Pressure Dislodgement Test Results in Water-Based Mud

Formulation (12 lb/gal Water Base Fluid)					Performance			
Test No.	**Bentonite (d50=30µm), % bwm**	**Graphitic Carbon (d50=325 µm), lb/bbl**	**Carbonate 1 (d50=600 µm), lb/bbl**	**Carbonate 2 (d50=150 µm), lb/bbl**	**Fracture Width, mm**	**Bridge Off**	**Forward Dislodgement Pressure, psi***	**Back Dislodgement Pressure, psi***
32	15	15	15	-	3-1	Yes	**2047***	**Did Not Test**
33	15	15	15	-	3-1	Yes	**2044***	**1600**
34	15	15	15	-	3-1	Yes	**1910***	**Did Not Test**
35	15	15	15	-	3-1	Yes	**1910***	**Did Not Test**
36	15	-	30	-	3-1	Yes	**1900***	**500**
37	15	-	-	30	3-1	No	**-**	**-**
38	15	-	-	100	3-1	No	**-**	**-**
39	15	15	-	15	3-1	No	**-**	**-**
40	15	15	-	100	3-1	No	**-**	**-**
41	-	15	15	-	**3-2**	No	**-**	**-**
42	15	15	15	-	**3-2**	Yes	**300**	**-**

*Maximum operaterating pressure reached.

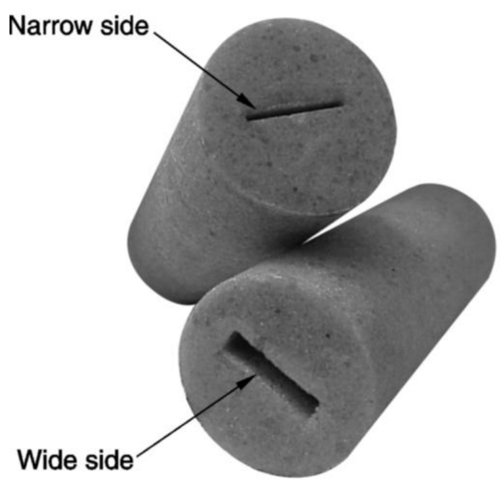

Figure 1 - Synthetic Rock Cores (with Embedded Tapered Fracture)

Figure 2 - Pressure Dislodgement Apparatus

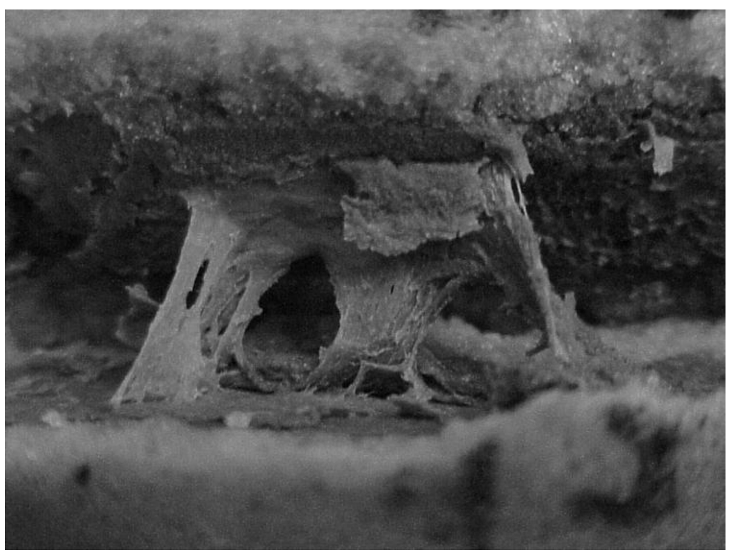

Figure 3 - New Rubbery Polymer Treatment in a Fracture

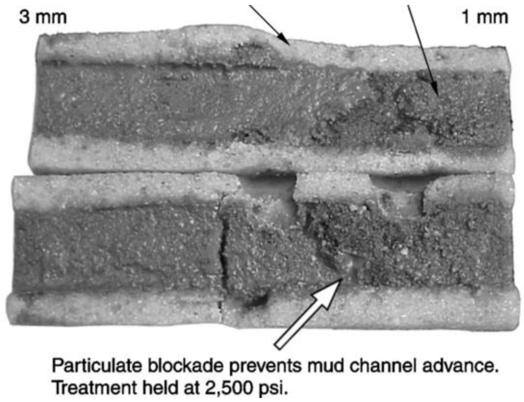

Figure 4 - Picture of Inside the Fracture (Broken Open Axially) After Pressure Dislodgement (i.e. Test 5)

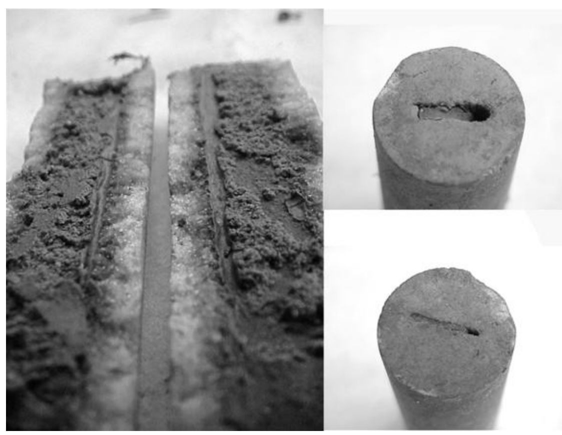

Figure 5 -Clay-Swelling Treatment Channel Creation

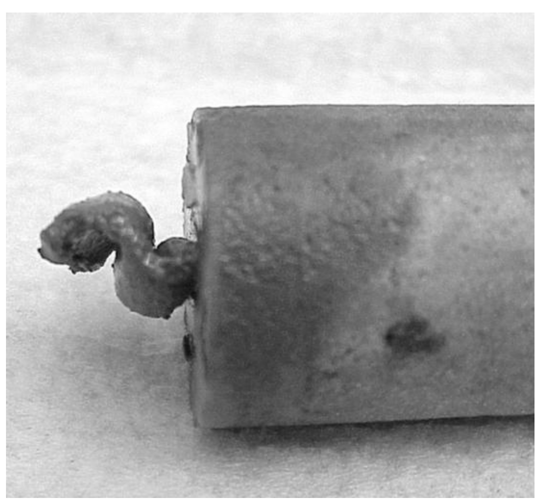

Figure 6 - New Rubbery Polymer Treatment Extrusion After a Pressure Test