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EVALUATION OF GEOTHERMAL FOAMS

by

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Background

Problems resulting from inadequate drilling fluids are the most frequently quoted reasons for high geothermal drilling costs. Severe corrosion and erosion problems are common when air drilling; yet slow drilling rates, poor filtration control, loss of circulation, and mud gelation often occur when using muds. In order to ascertain how drilling foams might be utilized in geothermal drilling to solve some of these problems (hence reducing geothermal well costs) Sandia Laboratories contracted with Maurer Engineering to evaluate drilling foams for geothermal applications and to recommend a program for developing geothermal drilling foams.

Drilling fluid related problems are the single most frequently cited reason for drilling problems in geothermal wells. The most apparent problems are the failures of the fluid to perform essential functions under high-temperature conditions. For example, gelation of conventional muds when circulation is stopped for operations other than drilling can lead to stuck pipe, aborted logging runs, stuck tools, etc. The related high pumping pressures can cause unexpected failure of casing seats or formation breakdown with consequent loss of circulation. Fluids formulated to remain reasonably stable at higher temperatures do not have adequate filtration characteristics, resulting in possible formation damage.

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Less obvious are the high direct costs which can be incurred with geothermal drilling fluids. Expensive treatment and replacement of materials are required to keep the fluid properly conditioned. Difficulties in corrosion control in geothermal environments lead to more frequent drill pipe replacement and drill pipe related problems than is experienced in non-geothermal applications.

Least obvious is the indirect cost from slower drilling, lost time for peripheral operations such as mixing mud, adding lost circulation materials, drill pipe inspection, etc.

The selection and use of drilling fluids for geothermal application requires greater care and technology than oil and gas operations. The high cost of these operations and the sensitivity of geothermal formations to irreparable drilling damage to productivity necessitates improvements in the effectiveness of drilling fluids in geothermal applications.

Where geothermal drilling allows the use of air as the drilling fluid, i.e., the Geysers area in California, the potential benefits of drilling foams may be applicable especially where formation pressure control is not a problem. Foams offer advantages over air in their increased lifting capacity, reduced compression requirements, higher bottomhole densities, and improved borehole stabilization. A broad survey of industry personnel indicates that geothermal drilling could use foams up to 80% of the time. Use of foams could increase drilling rate, decrease downtime, decrease corrosion/erosion effects, help control lost circulation, and help alleviate other geothermal drilling problems. Yet many technical problems must be overcome to accomplish these things.

Some of the other advantages of foam drilling include:

- Good Hole Cleaning
- High Drilling Rate
- Reduced Lost Circulation Problems
- Potential High-Temperature Capability
- Reduced Capital Cost

The disadvantages of mixing, breaking, and disposal of the foams along with corrosion and borehole stability have limited present applications. However, there are some borehole zones that favor the use of foam as the drilling fluid. These areas are:

1. Lost Circulation Zones Above Permeable Rock
2. Dry Fractured Rock
3. Hot Lost Circulation Zones
4. Variable Density Requirements

The shallowest and coolest environmental zone that favors the use of foam as a drilling fluid is in the upper section of the hole where the temperature does not exceed 250°F. Foam would be the favored drilling fluid if the rock was wet and fractured or had a lost circulation zone above a wet zone with a water drive. The water in the zones could preclude the use of air as a drilling fluid. The compressible nature of the foam system makes it possible to have a light fluid at the top of the hole so as to avoid lost circulation and a denser fluid below that zone to repress the water flow.

So in general, foam drilling is used when:

1. There is severe lost circulation that is difficult or impossible to control with conventional muds.

2. Air drilling is unsuitable because some hydrostatic pressure is required to stop fluid influx into the wellbore and/or fractured or broken formations make the wellbore unstable; or
3. The insulating properties of foam make it desirable.

In most foam drilling applications one of several types of foaming agents are used:

1. Alcohol Ether Sulfate. These foaming agents are formed with long chain alcohol ethoxylates which are sulfonated. They are the most widespread foaming agents and can be formulated for either fresh water or salt water solutions.
2. Alkyl Benzene Sulfonate. These foaming agents have better temperature stability than (1) above, but they are not as effective. More agent is needed per gallon of water foamed.
3. Alpha Olefin Sulfonate. These agents perform very similarly to (2) above.

In each application where foam drilling is to be considered, it is necessary to determine the amount of time the foam will be in the well and the temperature of exposure before concentrations can be estimated. Usually 1/2 to 1% foaming agent (by volume) is sufficient. Also, corrosion inhibitors can be added to control corrosion problems. The pH of the water used to generate the foams should be kept around 10 with additions of sodium hydroxide or lime.

Selection and Testing of Foams

During the course of the investigation, a total of 36 samples were submitted by 15 suppliers for testing. Eight of the submitted materials were selected for actual testing. Selection was based on availability of a sufficient amount of sample to complete all tests and timely reception of the samples. The number of samples which could be tested was limited by time restraints to eight samples. All the materials selected for testing were liquids with the exception of the LAS-90 sample, which was in solid flake form. The following materials were selected to be tested:

- AQUANESS M/A - 945
- TRETOLITE TOL-FOAM TD - 1
- TEXTILANA SULFOTEX RIF
- TEXTILANA SULFOTEX LAS-90
- BAROID SURFLO S-375
- CARDINAL CF-2
- MILCHEM AMPLIFOAM
- MAGCOBAR DRILLING SOAP B

The foamers were tested before and after exposing water solutions of the materials to 500°F at an applied nitrogen pressure of 375 psi for 16 hours. Foams were generated by injecting a solution of the foamer into an airstream in a column (API Procedure) and by stirring a solution of the foamer with a high speed mixer (Chevron Test). The volume of liquid carry-over was measured in the column test. Tests with a standard ten foot API column (API RP-46) were compared with those from a five foot column to determine if any correlation between column height and volume of foam and fluid collected existed.

When 0.15% foamer in distilled water was tested with both the five foot and the ten foot columns, the overall results were about the same. The Textilana Sulfotex LAS-90 generated the most amount of foam initially and after static aging at 500°F - 375 psi for 16 hours. The amount of foam collected with the two columns were almost identical. However, the amounts of foam collected with the other samples were less with the ten-foot column than with the five-foot column. Also, the difference in the volumes collected from the five and ten foot columns was not the same for all the samples. For example, the volume collected from the ten-foot column was 20% less than from the five-foot column with the Sulfotex RIF sample. There was hardly any reduction in volume with the LAS-90 sample. After exposure to 500°F - 375 psi for 16 hours, half of the samples did not foam at all on either column. In general, this test indicates that the LAS-90 sample foamed the most. Also, there does not seem to be a direct correlation in volume of foam collected versus column height.

When 0.75% foamer in 10% sodium chloride solution was tested, different results were obtained than when the samples were tested in fresh water. In saltwater, the LAS-90 initially produced the lowest volume of foam of all eight samples. After the samples were subjected to 500°F - 375 psi, the only sample to foam at all was the Magcobar Drilling Soap B. Again, there did not seem to be a direct correlation between volume of foam collected and column height.

The next series of tests involved using a modified version of the Chevron test. The test was designed to indicate foam quality and stability. The procedure involves adding 100 ml of a 0.5% solution of the foamer to a 1,000 ml beaker followed by

stirring at high shear for some time period. Then the maximum foam volume is read. After stirring, the time required for half of the original volume (50 ml) to drain from the foam is measured in seconds with a stop watch. The solution is restirred and the same measurements are made. After these measurements are made, 25 ml of a 1% sodium chloride solution are added to the foamer solution to act as a contaminant. Then the same foam heights and drainage times are determined again. The tests were repeated after aging the samples.

With the 0.5% foamer solution, all samples generated more foam after the addition of the salt contaminant than they did initially. However, the drainage time on all samples was reduced when the salt solution was added except for the Magcobar sample. When the samples were aged, the LAS-90 was the only sample to foam at all. The results from testing the LAS-90 before and after addition of the salt contaminant showed very little difference in foam volume and in drainage time. The foam volume and drainage time initially before salt contamination were almost identical to the aged sample results before salt contamination. A similar comparison holds for the initial and aged samples with salt contamination. Doubling the foamer concentration to 1% did not affect either foam volume or drainage time both before and after salt contamination to any extent at all for any sample. Every test run with the 0.5% sample was almost identical to the 1% sample.

The effect the samples had on surface tension was also studied. The surface tension measurements were made on fresh samples, usually right before the column tests were run. All samples prepared in distilled water effectively lowered the surface tension of distilled water alone by about 50%. The same

is true when the samples prepared in saltwater were compared to saltwater alone. The reductions in surface tension in the saltwater by the foamers were all about the same, just as in the fresh water case. However, the reduction the samples made in surface tension of the saltwater alone was not as great as in the fresh water case. Even so, no correlation could be made between surface tension and foam stability and quality.

The effect the eight samples had on the corrosion rate of mild steel coupons was also determined in fresh and in saltwater. Mild steel coupons were placed into solutions of the foamers with the same concentration as was used in the column tests. The entire contents were placed into a sealed aging cell, pressured to 375 psi with nitrogen and exposed to 500°F for 16 hours. In fresh water all the samples except the LAS-90 increased the corrosion rate of the coupons compared to fresh water alone. Similar results were obtained in saltwater. All the samples except the LAS-90 increased the corrosion of the saltwater alone.

Lastly, the pH of all the samples was determined in fresh and in saltwater, before and after aging. It was measured immediately before the surface tension and column tests. In fresh water, the pH of all the samples was reduced after exposure to 500°F - 375 psi. Initially the pH was basic, mostly between 7 and 8, for all samples but dropped considerably after exposure to 500°F. Only the pH of the Magcobar Drilling Soap B, Milchem Amplifoam and the LAS-90 remained relatively unchanged and alkaline after exposure to the temperature. Similar results were obtained in pH for the samples in saltwater. All the saltwater samples started out alkaline, but slightly less than the fresh water samples. All samples except the three mentioned above exhibited a drop in pH after exposure to 500°F.

Summary and Conclusions

Temperature stable and salt stable foams must be developed. This is exemplified by the fact that although several samples foamed after exposure to high temperature in fresh water only one, Magcobar Drilling Soap B, foamed after exposure to 500°F in the salt environment. Handling equipment must be improved including developing processes for breaking, cleaning, and reusing foam materials. Also, corrosion results indicates that corrosion characteristics must be improved through the use of inert gases or chemical additives. Numerous laboratory procedures were considered for testing foams; all have some usefulness, yet all have limitations. Probably the single most descriptive test is a modified Chevron test after high-temperature static aging. This is based on a comparison of the results obtained on the Chevron test and results from all column testing. The Chevron test was easier, simpler and faster than the column tests. This makes it more desirable for field applications. Compatibility and performance of different systems could be determined in the field using a modification of the Chevron test. However, even though present procedures are useful screening tools, better test equipment and procedures (such as a high-temperature flow simulator for foams) should be developed. Tests of representative foams gives insight into anticipated behavior of families of materials and the performance which can be expected from field drilling foams. These tests indicate that completely new materials will have to be developed in order to satisfy geothermal applications.