THE DOE GEOTHERMAL WELL STIMULATION PROGRAM

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INTRODUCTION

The stimulation of geothermal wells presents some new and challenging problems. Formation temperatures in the 300-500°F range can be expected. The behavior of frac fluids and proppants at these temperatures in a hostile brine environment must be carefully evaluated before performance expectations can be determined. In order to avoid possible damage to the producing horizon of the formation, the high-temperature chemical compatibility between the <u>in situ</u> materials and the frac fluids, fluid additives, and proppants must be verified. Perhaps most significant of all, in geothermal wells the required techniques must be capable of bringing about the production of very large amounts of fluid. This necessity for high flow rates represents a significant departure from conventional oil field stimulation and demands the creation of fractures with very high flow conductivity or large fracture surface areas in the case of matrix permeability dominated formations.

Stimulation treatments have been conducted in formations which produce hot water as a result of both matrix permeability and from natural existing fracture systems. The following targets of opportunity are of particular interest to this program:

- Wells that require additional drainage area because of insufficient formation permeability.
- Wells that did not intersect nearby major fracture systems.
- Wells that suffered man-made damage during drilling or completion operations including mud or cement invasion.
- Wells that require periodic remedial treatment as a result of fluid production related damage.

Although numerous criteria have been established for the selection of candidate wells, the most significant is definite proof of a good producing reservoir. These data are normally obtained from offset well production.

PROPPANTS

Although sand is generally used as a proppant today and it has been the most widely used in the past, it is not strong enough to withstand the conditions in geothermal wells at elevated temperatures. Sand is definitely affected by temperature, particularly when tested in hot water or brine at various closure stresses. Figure 1 shows the effect of temperature on common frac sand (20/40 mesh). These results are short term results and only suggest the severity of long term field results.

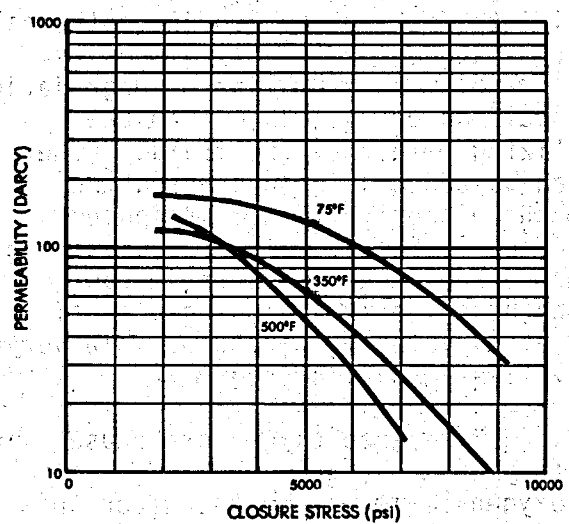

Fig. 1. Temperature Effects on 20/40 Brady Texas Sand.

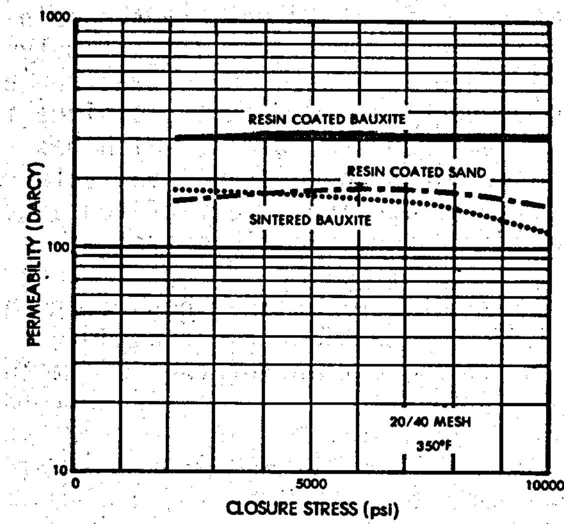

Fig. 2. Permeability vs. Closure Stress for Temperature Insensitive Proppants.

There are several mechanisms that can destroy sand grains in the fracture. First, the sand is brittle and point-to-point loading can cause brittle failure. Second, sand is full of microfractures and faults which weaken the sand. Finally, when sand is stressed in a corrosive medium like hot water, stress corrosion cracking appears to destroy the sand at low closure stresses. High temperatures and high stresses combine to bring out the worst properties of sand and tend to emphasize the fact that sand is inadequate as an effective proppant under high-temperature conditions.

The strongest proppant tested to date is Resin Coated Bauxite. It shows no temperature sensitivity or permeability decrease under load. The Resin Coated Sand is not temperature or load sensitive but does have a slightly lower permeability at any closure stress due to a slightly different distribution of particle sizes. Figure 2 shows the permeability of Resin Coated Bauxite and Resin Coated Sand under varying closure stress to 10,000 psi at 350°F. No temperature differences or sensitivities were found so tests at all temperatures gave the same results shown in Fig. 2 within experimental scatter. One important point is that the resin coated materials are cohesive; therefore, once emplaced in the fracture, flowback is reduced during production. Although slightly crushable, the Sintered Bauxite is much stronger than sand and effectively inert in hot brines. Figure 2 shows how Sintered Bauxite permeability behaves under increasing closure stress. It exceeds Resin Coated Sand at lower closure stress but drops below Resin Coated Sand at 10,000 psi.

FLUIDS

Many fluids and fluid systems have been tested for geothermal wells. Water soluble polymers are the main viscosifiers for application in geothermal wells. Above 250°F almost all polymer systems show a decline in viscosity. There are many techniques that can be used to delay this decline or degradation in properties. One such technique is the addition of 5% methanol to the polymer water solutions, which has a stabilizing effect on the fluid. Other proprietary products are available which can be added as high-temperature stabilizers. The effect of temperature on the viscosity of some proposed polymer-water frac fluid systems is illustrated in Fig. 3. The rapid decline in viscosity of polymer "A" at temperatures above 200°F could result in poor proppant placement in a high-temperature geothermal stimulation treatment. Laboratory testing of proposed frac fluids at elevated temperatures is a very significant element of the DOE geothermal well stimulation program.

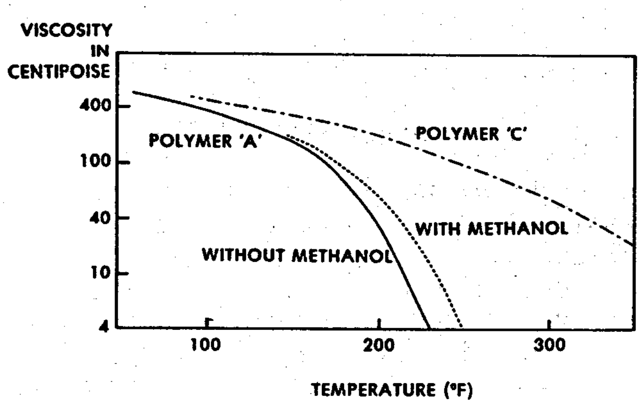

Fig. 3. Polymer-Water Frac Fluid Viscosity vs Temperature.

Dissolved oxygen can cause polymer degradation but by adding an oxygen scavenger to the water this effect can be minimized. The type and amount of polymer determines the speed and extent of degradation. Polymers used in fracturing are of these basic types: polysaccharides, modified celluloses and polyacrylamides. These particular polymers were chosen because of their unique ability to viscosify water, and at the same time to reduce tubular friction and have a good tolerance to brine. An ideal frac fluid would have the properties of high viscosity for proppant carrying, low pumping friction, wide chemical compatibility, and low cost. In the case of geothermal wells, an ideal frac fluid would retain its desirable properties at the high temperature until it has done its job of placing the proppant in the fracture.

PLANAR AND DENDRITIC FRACTURING

Conventional fracturing is an attempt to make a planar, vertical fracture in the producing formation. This occurs when the pressure and fluid flow is sufficient to break the formation in its plane of weakness. After the planar fracture is created, a proppant is carried into the fracture to keep it open and conductive for subsequent production. In geothermal wells, large tubular goods are available and the producing formations are reasonably shallow so that high flow rates can be used to create the planar fractures. Along with efficient fracture creation, convective cooling can be achieved to keep the working fluid cooler than the ambient formation temperature. Fluid systems that complement the high flow rate fracs are chosen for each particular application. Each formation's permeability, porosity and temperature also affects the selection of the fluid system's physical properties such as its viscosity. The complex chemistry caused by the high-temperature water requires complete chemical compatibility testing.

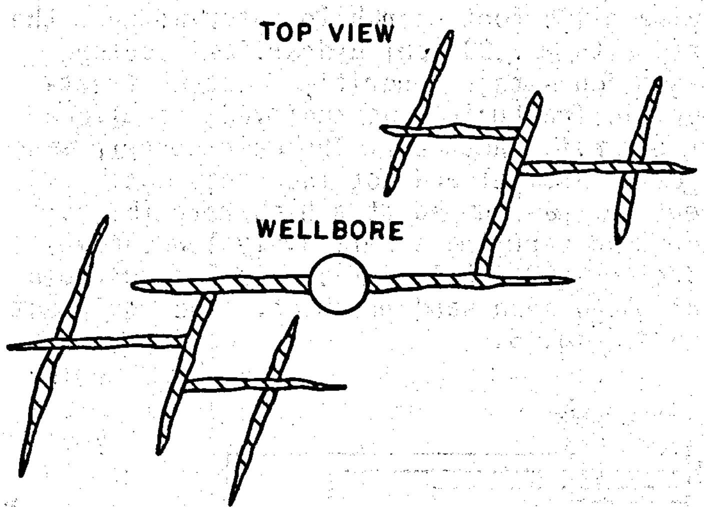

Fig. 4. Idealized Schematic of a Dendritic Fracture (after Kiel).

The main proponent of branched or dendritic fracturing has been Kiel. An estimated 750 Kiel fracs have been run to date. Dendritic fractures are caused by pulsing the formation which causes formation spalling and diversion of the fracture wings by downhole stress modification. Methods to predict the extent and direction of the fractures are still being worked upon; however, the best results have been reported in naturally fractured formations where major and minor fracture systems already exist but may not have flow capability. Usually 5 or more stages are used with each stage utilizing a low-viscosity fluid, sand slugs, and several flow-back periods. High flow rates and friction reduction are used to advantage on these treatments. An idealized schematic of a dendritic fracture system is depicted in Fig. 4.

STIMULATION TREATMENTS AT RAFT RIVER

Raft River is a moderately low-temperature (260-290°F) hydrothermal resource. Wells RRGP-1 and RRGP-2 are the best producing wells in the field and appear to intersect a natural fracture zone with high transmissibility, having a permeability thickness (kh) of greater than 50 Darcy-feet. Wells RRGP-3, RRGP-4, and RRGP-5 are less productive and were all considered for stimulation. Wells RRGP-4 and RRGP-5 were chosen as the best two candidates because RRGP-3 is further from the best producing wells and its mechanical configuration is very complex. There are two major faults running through the field. The Narrows Fault lies between Wells RRGP-1 and RRGP-2, and trends roughly east-west. Well RRGP-4 is approximately 1/2 mile south of RRGP-1 and the Narrows Fault. The Bridge Fault is on the east side of the field and trends northeast-southwest. Well RRGP-5 lies between the two faults, near their intersection.

Before stimulation, RRGP-4 was essentially non-productive. RRGP-5, however, was capable of flowing at a stabilized rate of 140 gpm and produced more than 600 gpm with a pump. This is adequate productivity, but the production came from the upper portion of the completion interval, and the produced fluid temperature of 255°F was undesirably low. Based on the performance of the better wells in the field and the proximity of Wells RRGP-4 and RRGP-5 to the Bridge and Narrows Faults, it was considered likely that highly productive fractures existed near the wells. Hydraulic fracture treatments in the deeper intervals were chosen as the best means to connect the wells with major productive fractures and to achieve the desired produced fluid temperatures of 270°F or greater. Although on the upper temperature margins of conventional oil field fracturing technology, no special techniques or materials were thought to be necessary for Raft River.

Well RRGP-4 was recompleted leaving a 195 foot open-hole interval near the bottom of the well which was stimulated with a 7,900 bbl hydraulic fracture treatment. The technique employed was a four-stage dendritic fracture treatment. It was chosen because, if dendritic fracturing was achieved, it offered the best chance of intersecting major natural fractures. The main concern was that a single, planar fracture might only parallel and not intersect the principal natural fractures. The treatment was pumped at a high rate (50 bpm) and utilized a light polymer gel frac fluid carrying a relatively low concentration of proppant. The treatment included 50,400 lbs of 100-mesh sand added for leak-off control and 58,000 lbs of 20-40 mesh sand proppant. The equipment layout for the frac treatment is shown in Fig. 5.

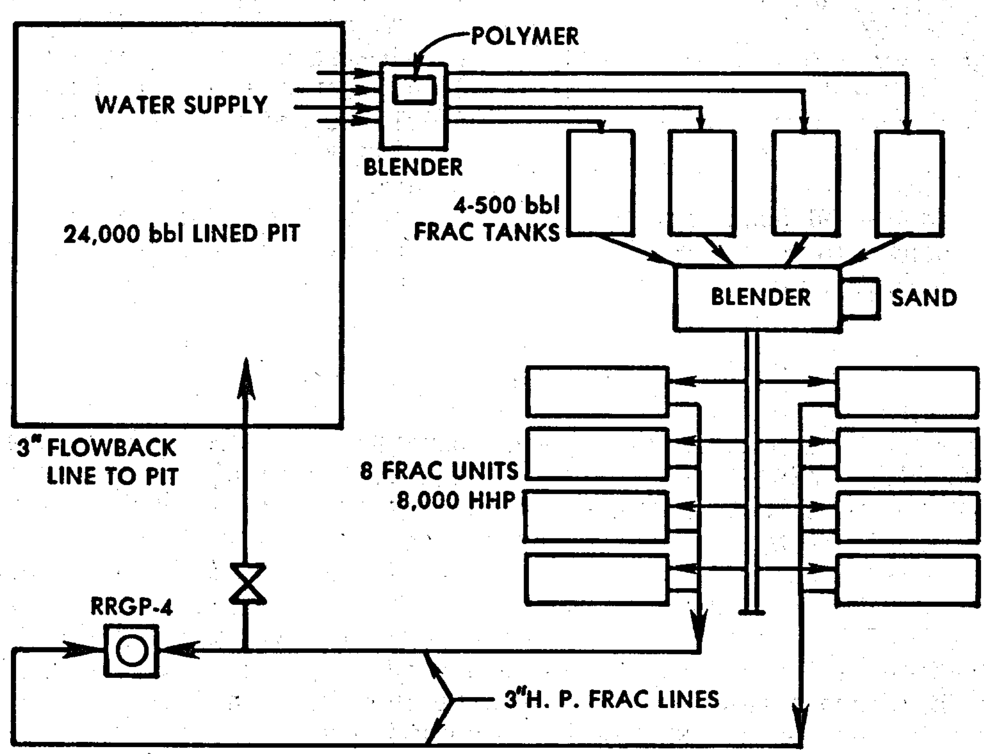

Fig. 5. Equipment Layout for RRGP-4 Frac Treatment.

Following the treatment, the U.S. Geological Survey ran their high-temperature acoustic borehole televiewer and observed that the created fracture extended the full 195-foot height of the open interval and was oriented approximately east-west, parallel to the Narrows Fault. In the post-stimulation flow test, the well produced at a stabilized rate of 60 gpm with a downhole fluid temperature of 270°F. This rate represented at least a five-fold increase over the pre-stimulation rate, but was still sub-commercial. The produced fluid temperature is significantly higher than past measurements.

This fact suggests that the new artificial fracture is producing fluid from a deep reservoir zone not open in the original hole. The chemical data further support this interpretation. The extent of polymer degradation determined chemically is consistent with fluid production from a higher temperature zone.

Conventional fracture type curve analysis (log-log plot) yields a fracture length of approximatlely 335 feet and a kh of 800 millidarcy-feet. The Horner plot of the same pressure buildup data has two straight line segments, one during early time (less than 15 hours) and one during later time (greater than 15 hours). These two segments give kh values of 1,070 millidarcy-feet and 85,000 millidarcy-feet, and suggest the presence of more than one permeability zone in the vicinity of the wellbore. Also, a negative skin factor (minus 6.0) indicates a stimulated zone close to the wellbore.

Well RRGP-5 originally had good productivity from the upper portion of the completion interval. The goal of the treatment for this well was a similar or higher productivity, but from a deeper, hotter interval. The well was recompleted similar to RRGP-4 in preparation for this stimulation treatment. The recompletion consisted of cementing 7 in. casing which excluded the existing producing interval and left a 216-ft open-hole interval near the bottom of the well. A more conventional, large fracture treatment designed to create a single propped fracture was selected for RRGP-5. The treatment consisted of 7,600 bbl of a relatively low viscosity polymer gel with 84,000 lbs of 100-mesh sand for leak-off control and 347,000 lbs of 20-40 mesh sand proppant. Near the end of the treatment, the pumping rate was gradually reduced in an effort to sand the well out and leave the fracture well-propped near the wellbore. As the rate approached zero, the wellhead pressure dropped to zero psi indicating that communication with the reservoir fractures had been achieved. Also, a significant pressure response was noted in RRGP-1.

Following the treatment the USGS borehole televiewer showed that the created fracture spanned the upper 135 feet of the open interval. The fracture was oriented northeast-southwest, parallel to the Bridge Fault. In the post-stimulation production test, the well stabilized very rapidly at a 200 gpm rate with a 30 psia wellhead pressure. The produced fluid temperature was unchanged from the pre-stimulation flow. Following the natural flow test, a pump was installed in the well and it produced more than 650 gpm. Chemical analysis of the produced fluid indicated a relatively low rate of polymer degradation in the reservoir, confirming that the frac fluid traveled upward into a cooler portion of the reservoir.

Pressure buildup and temperature data also suggest strongly that the fracture treatment went upward to the original producing interval. The Horner plot of the pressure buildup data shows only a short transition phase between the fracture dominated period and the late time constant pressure period. Estimates of the late time formation kh were large--greater than 100 Darcy feet. The Horner analysis indicates a very large positive skin factor. This skin factor is not due to formation damage but rather to the limited entry nature of the completion.

In summary, RRGP-4 and RRGP-5 were successfully recompleted and fracture treated, although the desired stimulation results were not achieved. Well RRGP-4 was stimulated from a PI of essentially 0 to 0.6 gpm per psi. Well

RRGP-5 has a post-stimulation PI of 2.0 gpm per psi and no significant increase in productivity or temperature was achieved. The artificially created fracture probably intersected existing natural fractures near the wellbore. Summaries of the stimulation treatments are presented in Tables I and II.

TABLE I

RRGP-4

4-STAGE KIEL FRAC 8/20/79

FRAC FLUID:	7900 BBLS 10 LBS H.P. GUAR/1000 GAL 2 LBS XC POLYMER/1000 GAL
SAND:	50,400 LBS 100 MESH 58,000 LBS 20/40 MESH PROPPANT
RATE:	50 BPM
INTERVAL:	*4705'-4900'*
FRAC HEIGHT:	200'

TABLE II

RRGP-5

CONVENTIONAL (PLANAR) FRAC 11/12/79

FRAC FLUID:	7600 BBLS 30 LBS H.P. GUAR/1000 GAL
SAND:	84,000 LBS 100 MESH 347,000 LBS 20/40 MESH PROPPANT
RATE:	50 BPM
INTERVAL:	*4587'-4803'*
FRAC HEIGHT:	135'

STIMULATION TREATMENTS AT EAST MESA

Two hydraulic fracture stimulation treatments were successfully performed in Republic Geothermal East Mesa well 58-30. East Mesa is located in an area of anomalously high heat flow on the east flank of the Salton Trough, at the southeast corner of the Imperial Valley of California. East Mesa is a moderate temperature reservoir producing from a sandstone and siltstone rock matrix. Several features of the East Mesa field made it an excellent choice for the next field experiments. The reservoir is known in more detail than most other geothermal reservoirs. This in-depth knowledge provides a sound basis for designing and evaluating stimulation treatments. This moderate geothermal reservoir temperature range (320°-350°F) is the next step in the evaluation of the fracture fluids, proppants and mechanical equipment. The selection of a matrix type reservoir is also important at this stage of the program. Fracture geometry has been successfully predicted in matrix type reservoirs in the petroleum industry, and the existing interpretive techiques should transfer to geothermal reservoirs. Furthermore, the reservoir fluids, with a total dissolved solids content of about 2000 mg/l are not expected to chemically interfere with the stimulation fluids or tracers.

Well 58-30, selected for these experiments, is ideally suited mechanically. Unlike many other geothermal wells at East Mesa and elsewhere, it is completed with a cemented, jet perforated liner. This affords an opportunity to isolate zones of a size that can be effectively treated and evaluated. The first treatment was a conventional planar type hydraulic fracture of a 250 foot low permeabilty sandstone interval near the bottom of the well. This zone has good sand development, but the permeability has been severely reduced because of authigenic cementation by carbonate minerals. Porosity is still high enough, however, to provide good storage capacity. A fracture treatment of this zone is intended to create a much larger effective drainage area surrounding the well in a manner similar to conventional oil and gas well stimulations, and thereby enhance the flow capacity. The treatment consisted of 2,800 bbl of a viscous crosslinked polymer frac fluid and 163,000 lbs of sand. The fluid was pumped at an average rate of 40 bpm during the treatment with B-J Hughes as the service company.

The second treatment was a dendritic fracture treatment in a more shallow, higher permeability, 300 ft interval of the same well. This upper zone, drilled with a predominantly bentonitic mud system, has good sands (high porosity and permeability) which show permeability impairment near the wellbore. A mini-frac of these zones will break through the mud and cement damage near the wellbore such that fluid can more easily flow into the well from the formation. The treatment consisted of 10,300 bbl of low viscosity frac fluid and 44,000 lb of 100-mesh sand pumped in 5 stages at an average rate of 48 bpm. The job was terminated before the planned 8 stages and 15,600 bbl because the rate/pressure history of the job indicated there was little to be gained by pumping the last three stages. The 100 mesh sand was used as fluid-loss control agent in the 50 md permeable sandstone interval that was fractured.

From July 25 to August 2, 1980 the well was production tested to evaluate the fracture experiment on the upper zone. The lower section of the well, from 6,547 to TD, was sanded back to prevent flow from the lower frac zone. The well flowed an average of 135,000 lbs per hour with a wellhead pressure of 33 psig. A wireline unit was utilized to monitor the reservoir pressure buildup. Reservoir pressure buildup data show the total open interval permeability-thickness was 9,881 md-ft, or approximately a 2.5 fold increase in productivity for the upper frac zone. This analysis indicates the shallow hydraulic stimulation treatment of the high permeability, upper interval was very successful. The upper zone treatment to correct near wellbore damage is of particular importance because such mud and cement damage is believed to be a common cause of impairment in Imperial Valley wells.

Well clean-out operations were initiated in August to remove the sand covering the lower frac zone. The coil tubing (used to inject nitrogen) parted and left approximately 5,170 ft of tubing in the hole. Fishing and clean-out operations are in progress. A production test of the entire wellbore will then be performed to evaluate the lower frac job. Summaries of the stimulation treatments are presented in Tables III and IV.

TABLE III

EAST MESA 58-30 (DEEP ZONE)
CONVENTIONAL (PLANAR) FRAC 7/3/80

FRAC FLUID:	2800 BBLS CROSSLINKED POLYMER GEL 20 LBS CALCIUM CARBONATE/1000 GAL (FLUID LOSS ADDITIVE IN PREPAD AND PAD)
SAND:	44,500 LBS 100 MESH 59,200 LBS 20/40 MESH 60,000 LBS 20/40 MESH "SUPERSAND"
RATE:	40 BPM
INTERVAL:	6587'-6834' (247')
FORMATION:	350°F-15md

TABLE IV

EAST MESA 58-30 (SHALLOW ZONE)
5-STAGE KIEL FRAC 7/6/80

FRAC FLUID:	10,300 BBLS 10 LBS H.P. GUAR/1000 GAL 2 LBS XC POLYMER/1000 GAL 20 LBS CALCIUM CARBONATE/1000 GAL (FLUID LOSS ADDITIVE)
SAND:	44,000 LBS 100 MESH
RATE:	48 BPM
INTERVAL:	4952'-5256' (304')
FORMATION:	325°F-50md

CONCLUSIONS

An effective stimulation treatment requires the interaction of four separate items.

- Frac fluids
- Proppants
- Equipment
- Planned and Properly Engineered Schedules

While there are good fluid systems and proppants, only judicious combinations and a well thought out schedule which uses all of these materials and available equipment to best advantage is an optimum stimulation treatment. Generally, high flow rates and convective cooling can be used either with conventional (planar) fracturing or with a dendritic fracturing technique. Many of todays fluid systems have been tested to above 400°F. Some fluids have survived quite well. Current tests on proppants have shown temperature sensitivities in sand; however, there are resin coated materials and sintered bauxite which are not temperature sensitive. Much more work is required in the specific application of fluid systems and proppants to the actual hydrothermal wells since the temperature, water chemistry and formation properties vary greatly.