Proceedings Seventh Workshop Geothermal Reservoir Engineering
Stanford, December 1981. SGP-TR-55.

FRACTURE STIMULATION EXPERIMENTS AT THE BACA PROJECT AREA

C. W. Morris & M. J. Bunyak

Republic Geothermal, Inc.
11823 E. Slauson Avenue
Santa Fe Springs, CA 90670

Abstract

The DOE-sponsored Geothermal Reservoir Well Stimulation Program group performed hydraulic fracture treatments on two wells located in Union's Baca Project Area in north-central New Mexico. The treatment in Baca 23 was conducted on March 22, 1981, utilizing a cooling water pre-pad followed by a high viscosity frac fluid carrying a mixture of sintered bauxite and resin-coated sand as the proppant. A non-productive 231-foot interval from 3,300 feet to 3,531 feet was isolated for the treatment. Post-stimulation surveys and production tests indicated a fracture had been successfully created; however, the production rates declined to noncommercial levels because of the low formation temperature in the open interval and reduced relative permeability caused by two-phase flow effects in the formation.

The second treatment was conducted in Baca 20 on October 5, 1981, again utilizing a cooling water pre-pad followed by a high viscosity frac fluid carrying only sintered bauxite as the proppant. A 240-foot interval from 4,880 feet to 5,120 feet, which was indicated to have produced only a small portion of the well's 56,000 lb/hr total mass flow, was isolated for the job. The temperature in this interval (540°F) gave Baca 20 the distinction of being the hottest well to be fractured in the United States to date. Post-stimulation tests and analyses indicate a fracture was created with a vertical height of only about 100 feet at the bottom of the open interval. The productivity of the well is poor, probably because of the low permeability formation surrounding the artificially created fracture. An acid cleanout operation is planned to remove possible damage to the fracture conductivity caused by the calcium carbonate fluid-loss additive.

Introduction

The U.S. Department of Energy-sponsored Geothermal Reservoir Well Stimulation Program (GRWSP) was initiated in February 1979 to pursue industry interest in geothermal well stimulation work and to develop technical expertise in areas directly related to geothermal well stimulation activities. Republic Geothermal, Inc. (RGI) and its principal subcontractors (Maurer Engineering, Inc. and Vetter Research) have completed seven field experiments. Two experiments have been performed in the low temperature reservoir at Raft River, Idaho (Morris, et al., 1980); two experiments in the moderate temperature reservoir at East Mesa, California; one experiment in the high temperature, vapor-dominated reservoir at The Geysers; and two experiments, reported herein, in the high temperature reservoir at Baca, New Mexico.

The Baca reservoir lies within the Jemez Crater, Valles Caldera, and is defined by more than twenty wells completed to date in the Redondo Creek area by Union Geothermal Company of New Mexico (Union). The main reservoir, 4,000 to 6,000 feet in thickness, is composed of volcanic tuffs with low permeability and a primary flow system of open fracture channels. In the Redondo Creek area, wells have encountered a high temperature (500°F+) liquid-dominated reservoir, but several wells have not been of commercial capacity, primarily because of the absence of productive natural fractures at the wellbore.

It is believed that hydraulic fracture treatments can create the fractures required to make these wells commercial and that such a well stimulation may be an attractive alternative to redrilling. The relatively large amount of reservoir data available and the high reservoir temperature made this field a good candidate for field experiments in the evaluation of geothermal stimulation techniques, fracture fluids, proppants, and mechanical equipment.

After considering several candidate wells, RGI and Union agreed that Baca 23 and subsequently Baca 20 were the best sites for the fracture treatments. These wells, shown in Figures 1 and 5, were selected because: (1) they were noncommercial or a poor producer; (2) the fracture system is present in the area as proven by the surrounding wells; (3) the wells could be recompleted to isolate the stimulation interval; (4) observation wells were available within 1,500 feet; (5) the wellsite was large enough for the frac equipment; and (6) in the case of Baca 23 the rig was already on location.

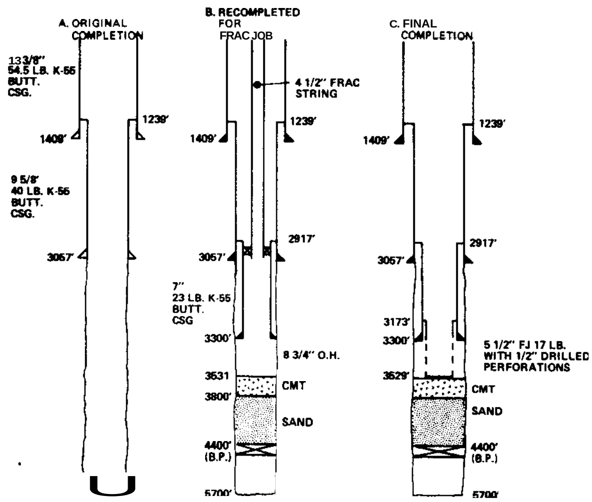

FIGURE 1 BACA 23 COMPLETION DETAILS.

The experiments were cost-shared by Union and the GRWSP. Union paid the cost of rig mob li-zation and demobilization plus the cost of recompleting the wells for the treatments. The GRWSP paid for the stimulation treatment and other directly related costs totaling about $450,000 for Baca 23 and about $581,000 for Baca 20.

Baca 23

Well Recompletion - Baca 23 was originally completed as shown in Figure 1A with a 9-5/8" liner cemented at 3,057 feet and 8-3/4" open hole to 5,700 feet. The well was flow tested and at that time would not sustain flow. An interval from 3,300 feet to 3,500+ feet in the well was selected for fracture stimulation. Good production had previously been encountered near this depth approximately 200 feet away in Baca 10. The interval is now cemented off behind casing in Baca 10. Fracturing a more shallow interval, immediately below the shoe of the 9-5/8" casing, was considered to have a substantial risk of comnunication with lower temperature formations above. The temperature in the zone selected was approximately 450°F.

Since the top of the selected interval was deeper than the existing 9-5/8" liner, a 7" liner was cemented to a depth of 3,300 feet to exclude the interval above. The lower portion of the hole was sanded back to 3,800 feet and plugged with cement to 3,531 feet to contain the treatment in the desired interval. This recompletion is shown in Figure 1B. The treatment interval was totally nonproductive after being isolated for the stimulation treatment.

Treatment Summary - A hydraulic fracture treatment was performed on the well consisting of 7,641 bbl of fluid and 180,000 lb of 20/40-mesh proppant pumped in eight stages. The stages are detailed in Table 1 and the pressure/rate history is shown in Figure 2.

TABLE 1

BACA 23 TREATING SCHEDULE

STAGE NO.	PLANNED SIZE (bbl)	ACTUAL SIZE (bbl)	PROPPANT (LB/GAL)	PROPPANT (SIZE)	FLUID
1	4,000	3,582	0	-	PRODUCED WATER WITH FLUID LOSS ADDITIVE (FLA)
2	500	502	0	-	POLYMER GEL WITH FLA
3	500	502	2	100-MESH	POLYMER GEL WITH FLA
4	500	526	0	-	POLYMER GEL WITH FLA
5	900	905	1	20/40-MESH	POLYMER GEL
6	1,000	1,000	2	20/40-MESH	POLYMER GEL
7	600	562	3	20/40-MESH	POLYMER GEL
8	58	62	0	-	PRODUCED WATER
	8,058	7,641			

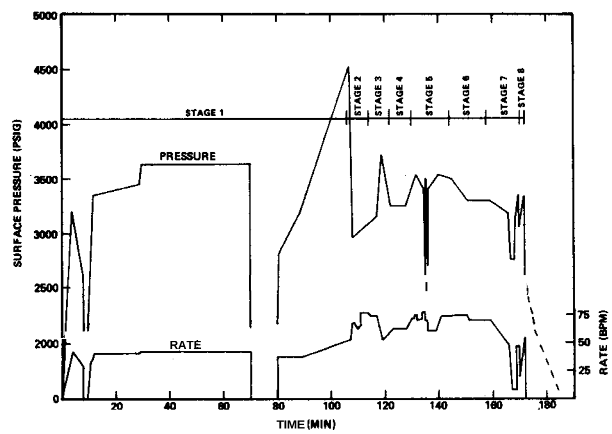

FIGURE 2 BACA 23 FRACTURE STIMULATION PRESSURE PRESSURE/RATE HISTORY.

The treatment was pumped through a 4-1/2" tubing frac string with a packer set near the top of the 7" liner as shown in Figure 1B. The frac string was necessary to isolate liner laps in the well from the treating pressure.

Although the job was basically a conventional hydraulic fracture treatment, the high formation temperature (450°F) dictated special design and materials selection requirements. Therefore, 50 percent of the frac fluid was dedicated to wellbore and fracture pre-cooling with the final 50 percent of the fluid used to place the proppant. While frac fluid properties are known to degrade rapidly at high temperature, these effects were minimized by pre-cooling, by pumping at high rates (up to 75 BPM), and by limiting the frac interval to 231 feet. Proppants were selected for their insensitivity to the high temperature (Sinclair, et al., 1980). Both resin-coated sand and sintered bauxite were used. Chemical work included compatibility studies of the frac materials with the formation fluids and the use of chemical tracers to monitor fluid returns.

The job was separated into eight stages. In Table 1 the eight stages are shown with the planned and actual stage sizes. The fluid used for pre-cooling the formation (Stage 1) was produced geothermal water stored in a pit near the location. The job ran short by 418 bbl of pre-pad water because the usable volume of the pit was underestimated. No harmful effects resulted from this short fall, however. Otherwise, the schedule was followed closely. The fluid for Stages 2-7 was a 60 lb/1,000 gal hydroxypropyl guar polymer gel pre-mixed using fresh water. The gel was crosslinked as it was pumped.

Finely ground calcium carbonate was selected as a fluid-loss additive (FLA) for Stages 1-4. About 5,700 lb of fine fluid-loss additive were used during the job. A larger fluid-loss additive consisting of 42,000 lb of 100-mesh sand was pumped in Stage 3 to slow leaks into the natural fractures of the formation.

Total proppant placed in the formation during the job was 180,000 lb. The original plan was to use a 50/50 mixture of sintered bauxite and resin-coated sand, both 20/40-mesh. The actual proportion of the proppants was 54 percent sintered bauxite and 46 percent resin-coated sand by weight.

Actual horsepower required for the job was 6,400 hhp versus the 5,880 hhp estimated by assuming an 80 BPM pump rate and 3,000 psi wellhead pressure. Higher than expected frac gradients were responsible for the increase. Frac gradients measured at the beginning, middle, and end of the job were 0.83, 0.92, and 1.175 psi/ft respectively. The buildup in frac gradient is difficult to interpret here, but nonetheless should be noted for consideration in planning and evaluating future fracture treatments.

Test Results and Analyses - During the fracture treatment, Los Alamos National Laboratory performed a fracture mapping experiment using Baca 6 as an observation well. A triaxial geophone system was placed in the well; and using techniques developed for the Hot Dry Rock Project, microseismic activity caused by the fracture job was mapped. The 14 discrete seismic events indicate northeast trending activity in a zone roughly 2,300 feet long, 650 feet wide, and 1,300 feet high. The rock failure, therefore, occurred in a broad zone and suggests the stimulation did not result in the creation of a singular monolithic fracture. These microseismic events would be expected to proceed in advance of any significantly widened, artificially created fracture and would not necessarily define a final propped flow path to the wellbore at Baca 23. Calculations of the theoretical fracture length were made assuming a 300-foot high fracture. The results suggest a fracture wing of 430 to 580 feet in length may have been created, depending on the assumptions utilized for the frac fluid, fluid efficiency, and fracture width.

As discussed above, the 231-foot interval isolated for stimulation was nonproductive prior to the treatment. This indicated that no significant natural fractures intersected the wellbore. Twelve hours after the frac job, a static temperature survey (shown in Figure 3 with a pre-frac survey) was obtained by Denver Research Institute. This survey showed a zone cooled by the frac fluids estimated to be more than 300 feet in height at the wellbore.

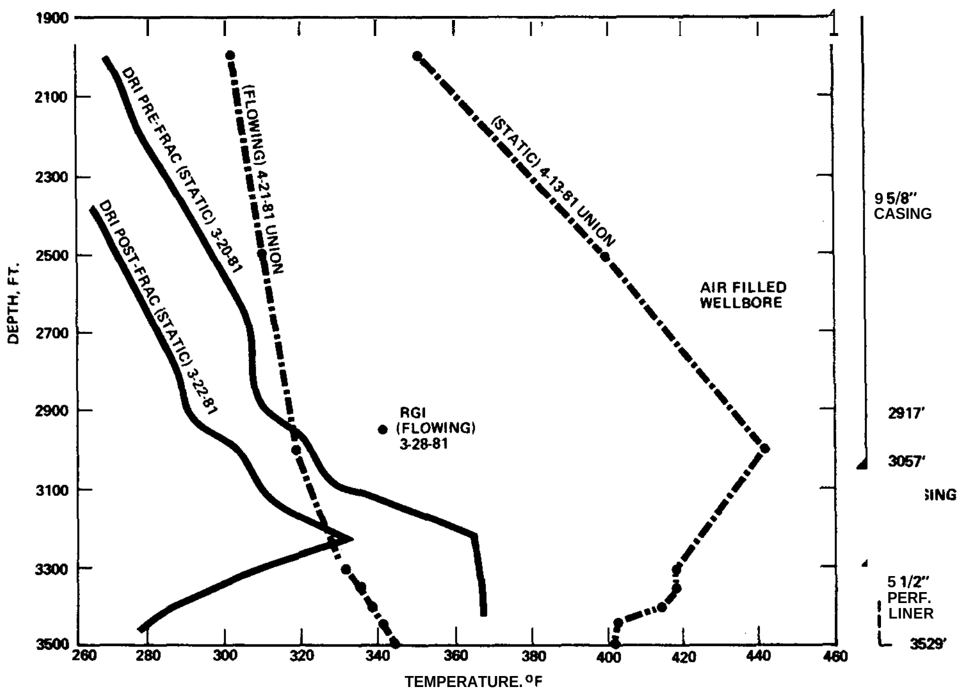

FIGURE 3 BACA 23 TEMPERATURE SURVEYS.

After the post-frac temperature survey was obtained, the frac string was pulled and the well was circulated with aerated water and allowed to flow to be sure that production of proppant into the wellbore would not interfere with subsequent testing. No significant amount of proppant was produced into the wellbore after the frac job. At this time it was determined that the well was worthy of final completion and further testing. A 5-1/2" pre-perforated liner was installed in the treatment interval as shown in Figure 1C.

On March 26, 1981, a six-hour production test through drillpipe was performed in which transient, downhole pressure and temperature measurements were obtained. A unique testing method was utilized to overcome the data gathering problems usually associated with flow testing a geothermal well. The procedure was a combination of conventional drillstem test (DST) methods (to eliminate large wellbore storage effects) and gas lift to maintain steady, single-phase flow to the wellbore. The gas lift was provided by injecting nitrogen gas at depth through coil tubing inside the drillpipe. As a result of this procedure, the well flowed at a low, steady rate (about 21,000 lb/hr) and the transient pressure data obtained downhole provided an indication of wellbore storage effects, fracture flow effects, and reservoir transmissivity.

A conventional Horner analysis (Figure 4) of the pressure buildup data yielded an average reservoir permeability-thickness of 2,500 md-ft. This compares closely with results from other noncommercial wells in the area and with the 6,000 md-ft average reservoir value obtained by Union from interference well tests (Hartz, 1976). Although the linear flow indicators were weak, the length of the fracture was calculated to be about 300 feet from the pressure versus square root of time analysis. A skin factor of -3.9 was also calculated. The maximum recorded temperature was 342°F which indicated that the near wellbore area had not recovered from the injection of cold fluids.

Following the modified DST, a 49-hour flow test was performed to determine the well's productive capacity. The results showed that the well could produce approximately 120,000 lb/hr total mass flow at a wellhead pressure of 45 psig, although the rate was continuing to decline. The chemical tracer data showed that the frac fluid stages were thoroughly mixed together in the return fluids and the frac polymer had thermally degraded by the end of this test.

Union performed a long-term flow test on the well during April-May 1981. A static temperature profile of the well prior to this test showed that the bottom-hole temperature still remained low (401°F). Temperature and pressure surveys run on April 21 (Figure 3) recorded a maximum temperature of 344°F and a maximum pressure of 120 psig at 3,500 feet. Therefore, two-phase flow was occurring in the formation, with the steam fraction estimated at more than 50 percent. This two-phase flow condition has been observed in other wells in the field.

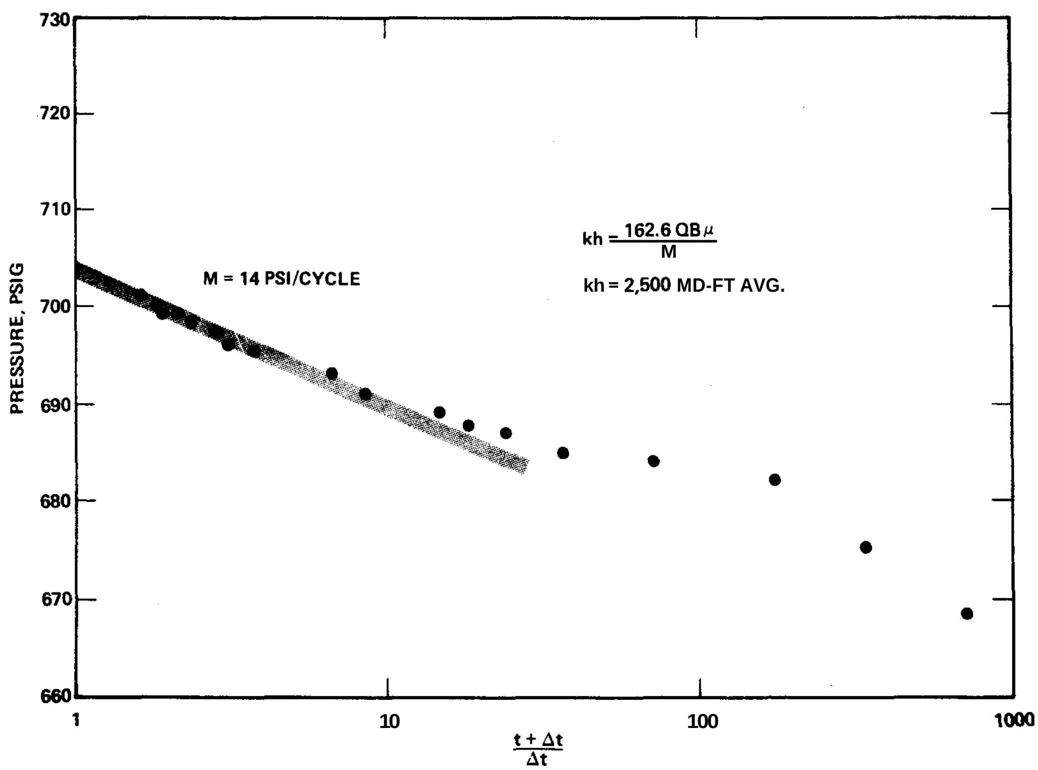

FIGURE 4 BACA 23 PRESSURE BUILDUP DATA—MARCH 26,1981

The formation cooling seen in the April 13 temperature survey is apparently a result of the temperature drop associated with flashing in the formation.

Of greater concern is the low productivity observed during this last test. The mass flow 'rate had dropped to 73,000 lb/hr (about 50 percent steam) with a wellhead pressure of 37 psig in May 1981. Since the well recovers productivity following each shut-in period and then exhibits the same decline again, the cause of the rate decline is probably not due to scaling in the formation. Partial closing of the fracture is possible, but the productivity loss is probably the result of relative permeability reduction associated with two-phase flow effects in the formation. The relatively low formation temperature in the completion interval also contributes to the well's poor productivity.

Baca 20

Well Recompletion - Baca 20 was originally completed as shown in Figure 5A with a 9-5/8" liner cemented at 2,505 feet and a 7" slotted liner hung at 2,390 feet with the shoe at 5,812 feet. The 7" slotted liner was pulled,

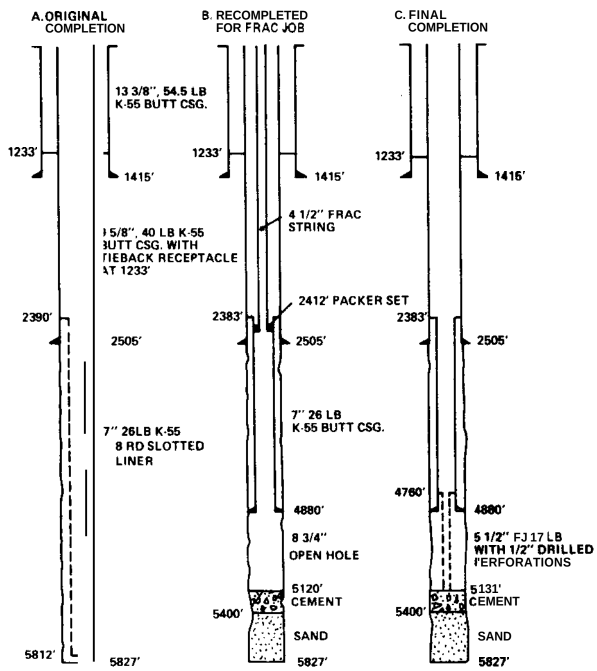

FIGURE 5 BACA 20 COMPLETION DETAILS.

lost circulation zones cured using cement plugs, and then a 7" blank liner was cemented in place at 4,880 feet in order to isolate the desired treatment interval. Since the frac interval was to be from 4,880 feet to 5,120 feet, a sand plug was placed from 5,827 feet total depth to 5,400 feet and then capped with cement to 5,120 feet. The recompletion is shown in Figure 5B. This particular 240-foot interval was chosen primarily because the best production in the area has been found near the bottom of the Bandelier Tuff and because of its high reservoir temperature (540°F).

Treatment Summary - The hydraulic fracture treatment was accomplished in the eleven stages defined in Table 2. The high formation temperature (540°F) once again dictated special design and materials selection.

TABLE 2

BACA 20 TREATING SCHEDULE

Stage No.	Planned Size (bbl)	Actual Size (bbl)	Proppant (lb/gal)	Size	Fluid
1.	2000	2000			FRESH WATER WITH FLUID LOSS ADDITIVE (FLA)
2.	500	639	0.39	100-MESH $CaCO_3$ (10,500 LB)	FRESH WATER WITH FLA
3.	500	350			FRESH WATER WITH FLA
4.	1500	1400			POLYMER GEL WITH FLA
5.	500	566	1.33	100-MESH $CaCO_3$ (31,500 LB)	POLYMER GEL WITH FLA
6.	500	500			POLYMER GEL WITH FLA
7.	1150	1168	0.46	16/20-MESH BAUXITE	POLYMER GEL
8. a	850	682	1.85	16/20-MESH BAUXITE	POLYMER GEL
b		378	2.77	16/20-MESH BAUXITE	POLYMER GEL
9.	300	450	2.11	12/20-MESH BAUXITE	POLYMER GEL
10.	750	451	4.21	12/20-MESH BAUXITE	POLYMER GEL
11.	150	151			FRESH WATER
	8700	8735			

The treatment was pumped through a 4-1/2" tubing string with a packer set at 2,412 feet, just below the 7" liner hanger. A 3,000 bbl fresh water pre-pad was used to cool the wellbore and fracture. The proppant selected was 119,700 lb of 16/20-mesh sintered bauxite, followed by 119,700 lb of 12/20-mesh sintered bauxite. The proppant was carried by a 60 lb/1,000 gal hydroxypropyl guar polymer gel mixed in fresh water. This fluid was a new high-pH crosslinked HP guar system having better stability at high temperature. The gel was crosslinked as it was being pumped. Chemical tracers were added to the injected fluid to monitor fluid returns.

Approximately 4,200 lb of 200-mesh calcium carbonate was added in Stages 1-6 to act as a fluid-loss additive. In an effort to stop leakage into the small natural fractures, 42,000 lb of 100-mesh calcium carbonate was pumped in Stages 2 and 5 in concentrations of 0.39 ppg and 1.33 ppg, respectively. The 100-mesh material was injected in "slugs" to enhance its chances of bridging on the fractures.

The majority of the treatment fluid was pumped at approximately 80 BPM. The rate was slowed to 40 BPM in Stage 10 when the proppant concentration was increased to 4.2 lb/gal. In anticipation of frac gradients of 0.9 psi/ft and higher, as seen in Baca 23, a total capacity of 11,000 hhp was made available and connected in the system. However, the actual peak hydraulic horsepower used was only 7,450 hhp because of lower frac gradients. An instantaneous shut-in pressure was measured soon after the treatment was initiated (1,000 psig) and again near the end of the job (1,300 psig), giving frac gradients of 0.63 psi/ft and 0.69 psi/ft, respectively. The pressure/rate history is shown in Figure 6.

Minor variations in the planned pumping schedule occurred during the treatment (Table 2), but all fluids and proppants were injected into the formation and the desired goal of ending the treatment at a relatively high proppant concentration was achieved. The variations occurred: (1) in Stage 7 when only 1/2 lb/gal of proppant was inadvertently added instead of the planned 1 lb/gal; (2) in Stage 8 when a higher proppant concentration was used to make up for the smaller amount used in Stage 7; and (3) in Stage 9 where the proppant concentration was increased to 3 lb/gal of the larger proppant instead of the planned 2 lb/gal. In Stage 10 the rate was slowed and the proppant concentration increased to 4.2 lb/gal to achieve a more widely propped fracture. The wellhead pressure and frac gradient were lower than expected, offering reasonable assurance that the proppant would not screen out at the lower rate and higher concentration.

<u>Test Results and Analysis</u> - During the fracture treatment Los Alamos National Laboratory again performed a fracture mapping experiment using Baca 22 as an observation well. A triaxial geophone system was placed in the well at a depth of approximately 3,000 feet and the microseismic activity caused by the fracturing job was mapped. A large number of discrete events (45) were recorded during the job, however, the orientation measurement of the tool was lost. Again the activity occurred in a broad zone which was roughly 2,000 feet long, 1,600 feet wide, and 1,700 feet high. Theoretical calculations of the artificially created fracture length would be 340-800 feet in a homogeneous matrix material, depending on the assumptions utilized for the frac fluid, fluid efficiency, and fracture height. These calculations were based primarily on the injected fluid and proppant volumes in a single, vertical fracture.

As discussed above, the 240-foot interval was nonproductive prior to the treatment, although there was a small rate of fluid loss during the well completion operations. This indicated that at least one lost circulation zone existed in the wellbore. Approximately 12 hours after the frac job the first of several temperature surveys, as shown in Figure 7, was obtained in the well. These temperature surveys showed a zone cooled by the frac fluids, estimated to be less than 100 feet in height, near the bottom of the open interval. In addition, the zone located behind the 7" liner casing at approximately 4,720 feet also indicated some cooling. This zone was apparently cooled by the workover fluids and possibly by

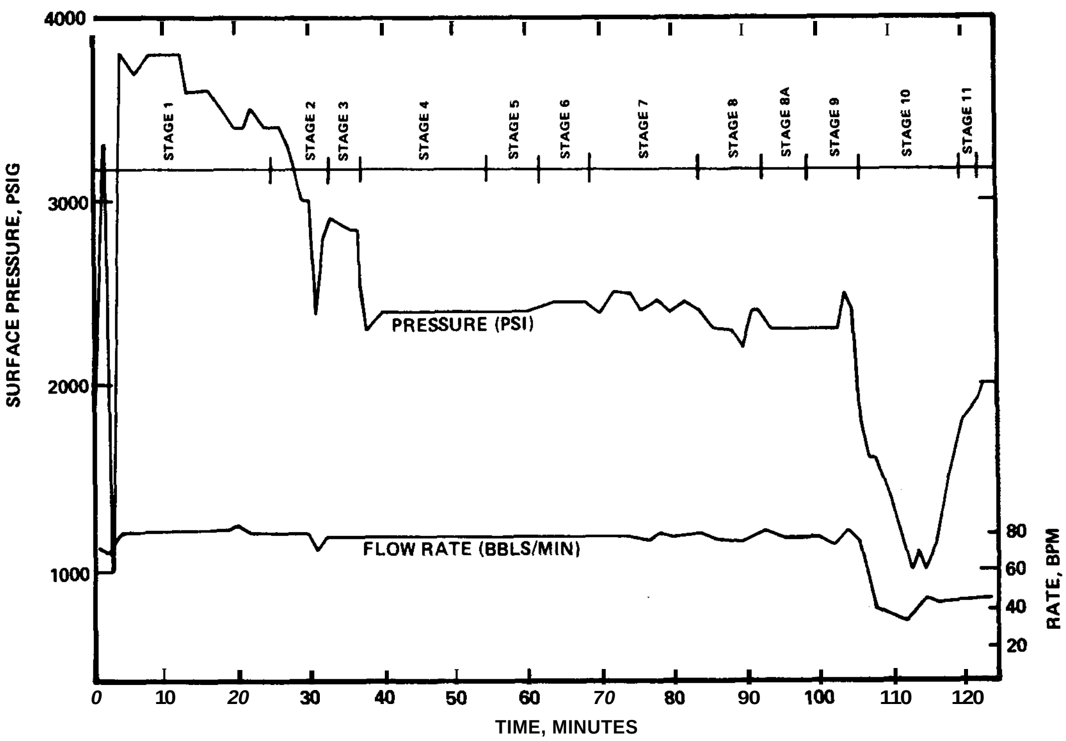

FIGURE 6 BACA 20 FRACTURE STIMULATION PRESSURE/RATE HISTORY.

the fracturing fluids; however, the communication between this zone and the open interval (if it exists) appears to be at some distance away from the wellbore. Electric log surveys were run in the open interval following the frac job. No significant new fracture zones (or high porosity) were observed, although several zones did show increased neutron porosity values.

At this time it was determined that the well was worthy of final completion and further testing. A 5-1/2" pre-perforated liner was installed in the treatment interval as shown in Figure 5C. On October 10-11, 1981, a 6-hour production test through drillpipe was performed in the same manner as the orillstem test at Baca 23. A steady rate of about 21,000 lb/hr single-phase flow was maintained to the wellbore. Transient pressure and temperature data were obtained downhole during the DST. A conventional Horner analyis of the pressure buildup data (Figure 8) yielded an average reservoir permeability-thickness of 1,000 md-ft. Evaluation of these data also indicated small wellbore storage effects and fracture (linear) flow near the wellbore. Although the indicators of linear flow were weak, the length of the fracture was calculated to be about 280 feet from the pressure data (pressure vs square root of time). A skin factor of -4.9 was also calculated. Numerical simulation of a high conductivity fracture in a low permeability formation supports this interpretation, although the solution is not unique. The maximum recorded temperature during the test was 320°F and indicated that the near wellbore area had not recovered from the injection of cold fluids. Additional temperature surveys were run in the well following the DST, as shown in Figure 7, which again indicated the fluid was entering (leaving) the wellbore in the lower part of the open interval.

Following the modified DST, a 14-day flow test was performed to determine the well's productive capacity. The well produced approximately 120,000 lb/hr total mass flow initially, but declined rapidly to a final stabilized rate of approximately 50,000 lb/hr (wellhead pressure of 25 psig) under two-phase flow conditions in the formation.

Because of the poor performance of the well, it was decided to perform an acid cleanout of the fracture. As indicated above, calcium carbonate was used as the fluid-loss additive during the hydraulic fracture treatment. This material was used with the expressed intent of performing an acid cleanout should the fracture conductivity show damage. The possibility of

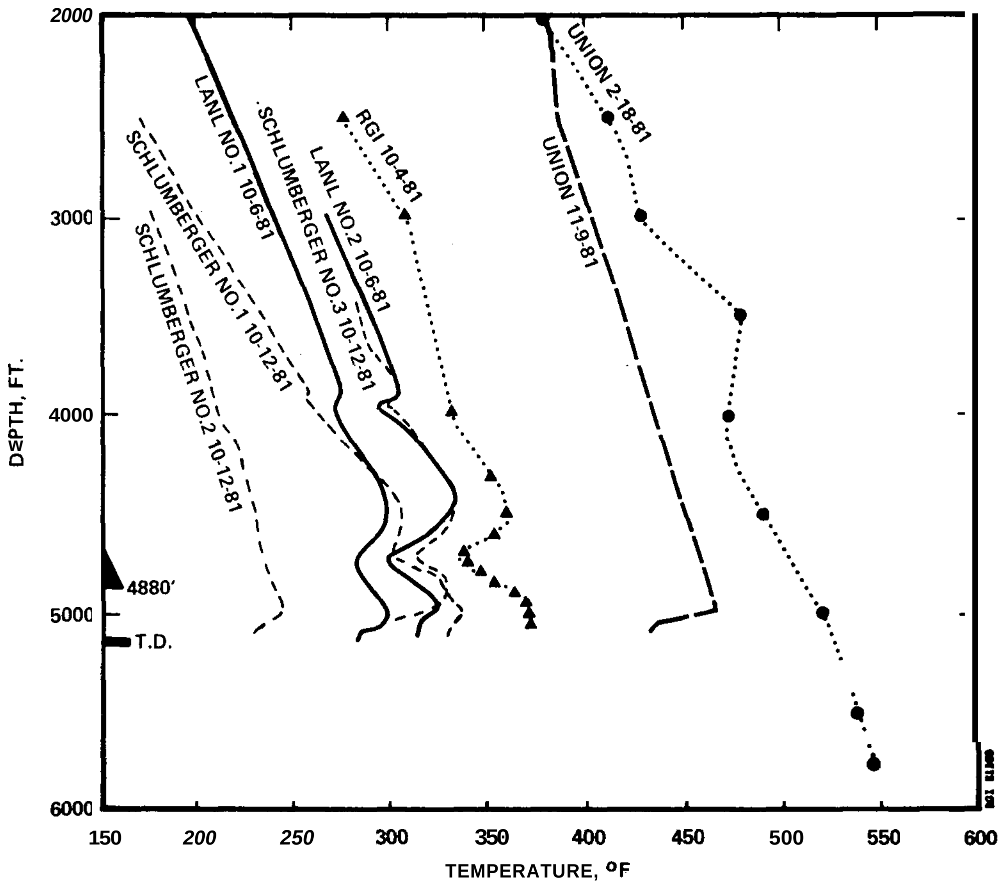

FIGURE 7 BACA 20 TEMPERATURE PROFILES–OCTOBER 1981.

such damage with insoluble fluid-loss additives (e.g., 100-mesh sand) has been a concern in prior stimulation experiments. Although the pressure data does not indicate that the fracture conductivity has been damaged, it does not preclude the possibility that the calcium carbonate has plugged the natural fractures and flow paths in the formation which intersect the artificial fracture.

Conclusions

1. Large hydraulic fracture treatments were successfully performed on both Baca 23 and Baca 20. Production tests indicated that high conductivity fractures were propped near the wellbore and communication with the reservoir system was established.

2. The productivities of Baca 23 and Baca 20 have declined to noncommercial levels since the fracture treatments. The probable cause is relative permeability reduction associated with two-phase flow effects in the formation.

3. The ability of Baca 23 to produce substantial quantities of fluid at a high wellhead pressure is limited because of the low formation temperature in the shallow treatment interval. The productivity of Baca 20 is severely restricted because of the low permeability formation surrounding the artificially created fracture.

4. Although the stimulation treatments did not result in commercial wells at Baca, the hydraulic fracturing techniques show promise for future stimulation operations and for being a valid alternative to redrilling in other reservoirs.

References

Hartz, J. D., Geothermal Reservoir Evaluation of the Redondo Creek Area, Sandoval County, NM, Union Oil Company Report, September 1976.

Morris, C. W., Verity, R. V., and Sinclair, A. R., "Raft River Well Stimulation Experiments," Geothermal Resources Council, Transactions, Vol. 4, September 1980.

Sinclair, A. R., Pittard, F. J., and Hanold, R. J., "Geothermal Well Stimulation," Geothermal Resources Council, Transactions, Vol. 4, September 1980.

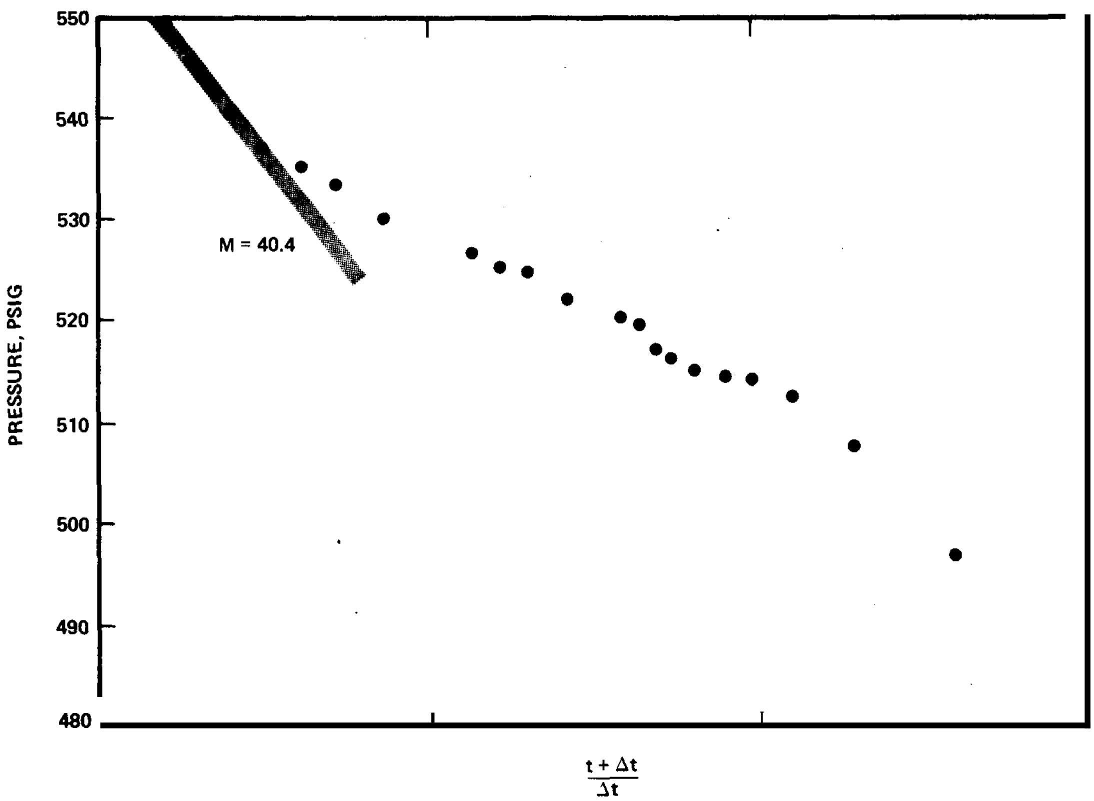

FIGURE 8 BACA 20 DST NO. 2, PRESSURE BUILDUP HORNER PLOT—OCTOBER 11,1981.