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RAFT RIVER WELL STIMULATION EXPERIMENTS

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ABSTRACT

The Geothermal Reservoir Well Stimulation Program performed two field experiments at the Raft River KGRA in 1979. The first well stimulation experiment, performed on Well RRGP-4, used the "Kiel"1 dendritic fracturing process. A 200-foot vertical fracture was created at the wellbore. Post-stimulation production data indicate that the Well RRGP-4 productivity was improved, but not to the hoped-for level of other wells in the field. The second well stimulation experiment, performed on Well RRGP-5, was a conventional massive hydraulic fracture treatment. A new vertical fracture of 140+ feet was created. Production tests suggested that the hydraulically created fracture intersected natural fractures very near the wellbore or intersected leg A.

Although the final well production rates were not as high as desired, the field experiments were technically successful in creating the artificial hydraulic fractures planned and have contributed significantly to the development of geothermal well stimulation technology.

INTRODUCTION

The Geothermal Reservoir Well Stimulation Program (GRWSP) was initiated in February 1979 to promote industry interest in geothermal well stimulation work and to pursue technical areas directly related to geothermal well stimulation activities. The proposed sequence of field tests was altered at the request of the U.S. Department of Energy (DOE)/Division of Geothermal Energy (DGE) to include two field experiments at the Raft River KGRA. A general evaluation of the Raft River exploration wells indicates that the location of the fluid production intervals and the production capacity are dependent on the intersection of natural fractures in the reservoir. Of the five production wells, several had been completed with multiple legs in an effort to increase production. Interference pressure tests have shown the reservoir to be heterogeneous, with possible no-flow barriers located near the present wells in the valley, and results to date have not established that communication exists between all of the existing wells. A viable geologic/reservoir model for this complex hydrothermal system has not been developed at this time. The Raft River wells did not offer a high probability for a successful stimulation experiment.

RRGE-1 and RRGE-2 are the principal production wells in the Raft River KGRA. It was planned that these wells would provide most of the fluid for the power plant and non-electric experiments. They appear to intersect a natural fracture zone with high transmissibility (with a kh of greater than 50 Darcy-feet) and have shown good communication with each other. Under these conditions, a successful stimulation job would not be expected to substantially increase the production capacity of these wells.

RRGE-3 is not as good a production well as the first two wells. In addition, this well was completed with three legs in the production interval in an attempt to intersect more natural fractures and increase productivity. The three legs reduced the probability of a successful stimulation treatment because the hydraulic fracture could easily propagate into an existing leg of the well and not extend into the formation.

Well RRGP-4 was a non-commercial well; i.e., the flow tests performed to date indicated that the well could not sustain production. This well had two legs completed in the production interval, but leg A was believed to be filled or bridged off with cuttings. Fractures have been identified in the wellbore but they do not appear to be connected with major natural fractures in the reservoir. This well was selected for the first stimulation treatment.

RRGP-5 appeared to have potential for a well stimulation treatment. Although this well had two legs, the first leg was damaged during the drilling operation by cement pumped into the wellbore and near-wellbore natural fractures. The cement damage may have reduced the flow capacity of the well substantially. It was thought that production could be improved by hydraulically fracturing through the damaged zone and re-establishing communication with the natural reservoir fractures. This well was selected for the second stimulation job.

REVIEW OF PRE-STIMULATION WELL CONDITIONS

All the Raft River production wells have
been completed within the naturally fractured zone from about 3,400' to 6,543'. The formation producing intervals are comprised primarily of siltstone, sandstone, metamorphosed quartz, quartz schist, elba quartzite and quartz monzonite. Well RRGP-4 and RRGP-5 had natural fractures intersecting their wellbores; however, RRGP-4 showed much less fracturing in the entire well (open-hole interval 3,526'-5,113') as compared to other Raft River wells and many of the fractures had been sealed by secondary cementation. Well RRGP-5 had numerous horizontal and vertical fractures throughout the open-hole section from 3,408' to 4,925'.

After leg B of Well RRGP-4 was deepened to 5,115', an attempt was made to flow the well. The well was found to be non-commercial and would not sustain an artesian flow rate greater than approximately 10 gpm. Borehole geophysical logs had recorded a maximum bottom-hole temperature of 254°F. Well RRGP-5 (leg B) productivity was tested several times after completion. The well was artesian flow tested for 72 hours at a rate of 140 gpm in November 1978. Short-term flow periods (approximately 1 hour) prior to this test obtained rates in excess of 280 gpm; however, the wellhead pressure was declining very rapidly and the well could not sustain this rate. A sustained pumped rate of 640+ gpm was obtained in a 21-day stimulation period with a bottom-hole temperature of 274°F was measured in the well; however, the production was from more shallow, cooler intervals.

STIMULATION PROGRAM

Early conclusions were that hydraulic fracturing would be the most cost effective method of stimulation and that the reservoir temperature of slightly less than 300°F could be handled with existing technology.

In preparation for the fracture treatment in RRGP-4 two major operations were performed in the well. An attempt was made to re-enter and plug leg A with cement and a 7" liner was installed in the upper part of the leg B. It was decided to plug leg A to preclude the possibility that a fracture from the deeper portion of leg B would intersect leg A. However, the attempt to re-enter leg A using directional drilling tools was not successful.

The 7" liner was then installed in leg B and cemented in the interval 3307'-4705' as originally planned. The interval from 4705'-4900' was left open for the fracture treatment. This 200' interval had been selected because it was a length that could be effectively treated and the depth was sufficient to provide the desired produced fluid temperature. The liner effectively sealed off the productive fractures in the well and the well would not flow at this point.

Several different fracturing processes were considered for RRGP-4. The Kiel Fracturing Process was selected primarily because it appeared to offer the best opportunity of intersecting the major natural fractures in the area. The conventional hydraulic fracturing treatment was that the created fracture would only parallel major fractures in the area.

The treatment consisted of four stages of 1975 bbl per stage. Each stage included two pumping periods, each of which was followed by a brief flow-back period. The alternating pumping-in and flow-back periods stress and restress the rock, rearranging the stresses in the rock to achieve a change in fracture direction. Therefore, on the second and succeeding stages of a Kiel dendritic fracturing program, it can be expected that branched or dendritic fracturing will occur. Each stage included three slugs of 100 mesh sand for fluid loss control followed by four slugs of 20/40 mesh sand. The frac fluid was a low viscosity gel containing 10 lb of hydroxypropyl guar plus two lb of XC polymer per thousand gal of water. A total of 7900 bbls of frac fluid was injected with 108,400 lbs of sand at an average rate of 50 bbl/minute.

Figure 1 is a pressure-rate history of the treatment. The erratic behavior in the first two stages is a result of some unscheduled shutdowns caused by minor equipment problems and leaks. Stages 3 and 4 proceeded with no difficulty. As shown in the figure, there is little character to the pressure curve in the last two stages except for a minor decline in pressure in the final stage. It is also important to notice the instantaneous shut-in pressures (ISIP's) following each pumping period. After the first stage, there is very little change in the ISIP, and that is an indication that dendritic fracturing was not actually occurring. In a normal dendritic fracturing job, changes in the rock stresses would be evidenced by a change in the ISIP from stage to stage.

A conventional hydraulic fracture treatment was designed for RRGP-5. Because of the nature of the fracturing in this well and because RRGP-5 is near the intersection of two major faults, i.e., the Narrows and Bridge Faults, it appeared likely that a single planar fracture in the deeper portion of the well would intercept major natural fractures. The objective of the treatment was to achieve a producing rate at least comparable to the existing rate, but from a deeper, hotter interval of about 270°F. As in the case of RRGP-4, a 7" liner was installed to exclude all but the lower portion of the original completion interval. The interval below the liner, from 4587' to 4803', was open at the time of the fracture treatment. This interval was not productive before the frac treatment.

The treatment was designed to achieve a 200 ft high by 1000 ft long fracture with a 14% fluid efficiency. A total of 7600 bbl of frac fluid was pumped. The frac fluid was of relatively low viscosity. The alternative fluid was a low viscosity gel containing 10 lb of hydroxypropyl guar plus two lb of XC polymer per thousand gal of water. A total of 7900 bbls of frac fluid was injected with 108,400 lbs of sand at an average rate of 50 bbl/minute.
viscosity gel containing 30 lb of hydroxypropyl guar per thousand gallons of water. Eighty-four thousand pounds of 100 mesh sand was used for fluid loss control and 347,000 lb of 20/40 mesh sand was injected as proppant. The relatively low viscosity frac fluid was designed specifically to allow settling of the sand within the fracture at a controlled rate. The settling rate is designed so that a proppant bank forms, propping the lower portion of the fracture at nearly the full dynamic width, and leaving the upper portion of the fracture open. The flow capacity of this open portion of the fracture is many times that of a sand-filled fracture.

Figure 2 is a pressure rate history of the treatment. During the flowback phases that were pumped, there were several unscheduled shutdowns for leaks and it was observed that the ISIP at that time was 500 psi. At the end of the job, the rate was gradually reduced in an attempt to sand out the well and leave a fully propped fracture at the wellbore. As the rate was reduced and finally pumping was stopped, it was noted that the ISIP was near zero. This short linear flow period and the resulting positive skin factor; however, this skin factor is an indicator of major fractures had been achieved.

TEST RESULTS AND ANALYSIS

A borehole televiewer survey of Well RRGP-4 confirmed the existence of a 200 foot vertical propped fracture. The fracture was oriented in an east-west direction which would parallel the Narrows Fault. In September 1979 a production test of RRGP-4 was performed. The downhole instrumentation failed about 8 hours into the drawdown phase. The well was flowed at a rate of about 60 gpm for 150 hours before shut-in. The fracture flow effects are indicated to last about 6 hours by the early time pressure versus square root of time plot. The bottom-hole pressure apparently reached the initial reservoir pressure in 15 hours of buildup time. The data show a very flat pressure curve from 15 hours to 47 hours. The conventional fracture type curve analysis (log-log plot) yields a fracture length of approximately 335' and a permeability-thickness (kh) of 800 md-ft.

The Horner plot, shown in Figure 3, indicates a skin factor of the same order of magnitude as found by the Horner analysis technique. The maximum flowing bottom-hole temperature was measured at 264°F at the shoe of the 7" liner.

In March 1980, Well RRGP-5 was flow tested again, using a downhole submersible pump. The maximum rate obtained during this test was 650 gpm. The productivity index obtained from the pressure transient data for both wells with essentially the same numerical simulation model. (RRGP-4 was given a lower near-wellbore transmissivity.) The single layer model consisted of a vertical fracture, a relatively low transmissivity near the wellbore, and a deep reservoir zone not open in the original hole.

A post-stimulation production test of RRGP-5 was performed during November 25-26, 1979 after the well had been produced several times to clean out sand. The wellhead and downhole pressure and temperature conditions stabilized very rapidly (about 2 minutes). An average rate of about 200 gpm was maintained with a wellhead pressure of about 30 psi. The pressure drawdown of 100 psi was extremely rapid (less than 1 minute) and no early-time data were obtained. A plot of the pressure buildup data versus square root of time indicates the fracture flow effect near the wellbore persists for only about 38 seconds. This short linear flow period and the resulting calculated fracture length value is so small that no single fracture flow exists. The Horner plot of the buildup pressure data, in Figure 4, shows only a short transition phase between the fracture dominated period and the late-time constant pressure period. The results indicated that RRGP-5 had a higher transmissivity than was found in RRGP-4. Estimates of the late-time formation k,h were large, i.e., greater than 100,000 md-ft.

Thus, the hydraulic fracture stimulation treatment may have re-opened existing natural fractures near the wellbore and/or intersected leg A which dissipated the injected frac fluid along fractures and energy. This latter condition would have limited the lateral propagation of the fracture and may explain the relatively low fluid temperature. The borehole televiewer survey did indicate a newly created vertical fracture at the wellbore of about 140 feet in length and oriented in a northeast-southwest direction which is parallel to the Bridge Fault. These re-opened natural fractures did not significantly affect the already high permeability of this fractured zone. The Horner analysis indicated a very large positive skin factor; however, this skin factor was not due to formation damage but rather to the limited entry nature of the completion. A limited entry, theoretical skin effect calculation yields a skin factor of the same order of magnitude as found by the Horner analysis technique. The maximum flowing bottom-hole temperature was measured at 264°F at the shoe of the 7" liner.

Both Wells RRGP-4 and RRGP-5 show remarkably similar pressure response following the fracture treatments. It was possible to reproduce the pressure transient data for both wells with essentially the same numerical simulation model. (RRGP-4 was given a lower near-wellbore transmissivity.)
constant pressure boundary located along one short side of a two-to-one rectangular drainage area. Obviously, the numerical simulation approach does not yield a unique solution to the transient reservoir pressure response, but it does provide a confirmation of the conventional and type curve pressure analysis results.

CONCLUSION

Well RRGP-4 was successfully stimulated using the dendritic fracture treatment method. The productivity index was increased from essentially zero to 0.6 gpm/psi and the produced fluid temperature increased approximately 20°F. Well RRGP-5 was successfully stimulated using a conventional massive hydraulic fracture treatment technique; however, the artificially created fracture probably intersected existing natural fractures near the wellbore and/or intersected leg A. The post-stimulation productivity index was 2.0 gpm/psi. No significant increase in productivity or fluid temperature was achieved.

REFERENCES

