

SESSION 18

GEOHERMAL WELL STIMULATION - PROGRAM SUMMARY AND THE BEOWAWE FIELD EXPERIMENT

R. V. Verity
Republic Geothermal, Inc.
Santa Fe Springs, CA 90670

Abstract

Republic Geothermal, Inc. and its subcontractors have planned and executed laboratory studies and eight well stimulation field experiments under the Geothermal Reservoir Well Stimulation Program (GRWSP). The program, begun in February 1979, has concentrated on extending petroleum industry stimulation technology for use by the geothermal industry. The most recent experiment was in a naturally fractured Chevron well at Beowawe and involved an acid stimulation of a damaged interval which yielded a 2.3-fold increase in injectivity. Overall results to date have shown that stimulation is viable where adequate reservoirs are penetrated by wells encountering formation damage or locally tight formations. However, wells in marginal naturally fractured reservoirs have not been saved by the types of well stimulation jobs performed thus far. A recent discovery is that many wells can possibly be made outstanding producers by widening and propping compliant natural fractures. Confirmation of this constitutes unfinished business of the GRWSP, and offers one of the greatest potential opportunities for enhancing the economics of geothermal power production.

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 by extending the petroleum industry's stimulation technology for use in geothermal wells. The stimulation of geothermal wells has presented some new and challenging problems. The behavior of stimulation fluids, fracture proppants, and downhole equipment at elevated temperatures must be carefully evaluated before a treatment can be properly designed and executed. In order to avoid possible damage to the producing formations, high temperature chemical compatibility between the reservoir rocks and fluids and the stimulation materials must be verified. Perhaps most significant of all, in geothermal wells the stimulation treatment must bring about very large fluid production rates. This requirement for high flow rates represents a significant departure from conventional pet-

roleum well stimulation and demands the creation of very high near-wellbore permeability and/or fractures with very high flow conductivities over long intervals. These factors, combined with high natural formation permeabilities relative to most oil and gas reservoirs normally dictate relatively large volume, high rate treatments.

The principal aim of the GRWSP has been to improve geothermal development economics by developing stimulation as a viable, less expensive alternative to the normal practice of redrilling or replacing deficient wells. Candidate wells for the GRWSP field experiments fell into one or more of the three following categories: (1) Wells that failed to intersect major productive natural fractures in the reservoir; (2) wells that suffered man-made damage during drilling, completion, or workover operations, including mud or cement invasion; and (3) wells in matrix-type reservoirs that can benefit from the establishment of high conductivity, linear flow channels to improve flow capacity from surrounding localized regions of low permeability formation.

The first of the above situations is probably the most common and five of the eight GRWSP field experiments were performed in candidates of this type. Even in well developed, productive fields, new wells often fail to encounter sufficiently productive fractures. Redrilling in an attempt to encounter better fractures is common industry practice in such cases. The GRWSP tested both acid fracturing and hydraulic fracturing as methods of creating high conductivity fractures to connect with major productive natural fractures in the reservoir. Hydraulic fracturing with proppants was favored where large fractures with radii of the order of hundreds of feet were believed necessary to reach major productive fractures in the formation.

Formation damage by invasion of drilling mud, cement, etc., is relatively common in both fractured and matrix-type reservoirs. Because the damage is normally confined to the near-wellbore area, fracturing or chemical stimulation can be applied. However, selection of the

R.V. Verity

treatment method depends on site-specific considerations. Two of the GRWSP field experiments were done in formation-damaged wells.

One experiment was done to stimulate a low permeability region of a matrix-type reservoir. This category, being less common, received less attention, but offers opportunities for significant economic benefit by enhancing the productivity of such marginal or subcommercial wells.

Some major concerns to which the GRWSP addressed itself, are as follows:

Hydraulic Fracturing

1. Hydraulic fractures in fractured formations may merely parallel the predominant natural fractures in the reservoir and fail to effectively connect with them.
2. Rapid thermal degradation of polymer frac fluids could prevent the effective growth and propping of hydraulic fractures.
3. Conventional downhole mechanical equipment may be inadequate for fracturing in high temperature wells.
4. Available proppants may degrade in the high temperature, saline environment.
5. The possibility of excessive fluid leak-off, especially in naturally fractured formations, could result in an early termination of hydraulic fracture growth.

Acid Stimulation

1. Acid reaction rates with formation materials at high temperatures were not well known.
2. Data on the solubility of formation rocks in acids and the resulting products of reaction were needed for treatment design.
3. Some concern existed regarding whether or not fracture acidizing could provide adequate fracture conductivity for successful stimulation.

The Phase I and II activities described below have provided satisfactory answers to most of these concerns.

Phase I

Phase I was the necessary predecessor to the planned Phase II field experiments. These laboratory investigations, literature studies, and software development accomplished the following.

Technology Transfer

Conventional oil and gas stimulation technology was reviewed for applicability to geothermal conditions. Literature and current unpublished work on stimulation treatment design, evaluation techniques, stimulation materials performance, and mechanical equipment were reviewed and applicable portions were documented in GRWSP reports.

Numerical Modeling

Four existing computer codes were modified and upgraded to provide field experiment design and analysis capability. Three of the codes involved were available from other DOE projects.

Laboratory Work

A large body of data on high temperature behavior of stimulation materials was gathered and documented for the program. These results constitute a valuable data base for any high temperature well stimulation work. Proppants, frac fluids, and frac fluid additives were tested at temperatures to 500°F to establish their performance limitations in the geothermal reservoir environment.

Polymer-based frac fluids were tested to characterize by chemical methods their degradation behavior as a function of temperature and time. This novel study required development of new analytical procedures. Results helped to guide selection of frac fluids for field experiments and the same analyses were later applied to residual frac fluids produced from the field experiment wells for interpretation of experiment results.

Solubilities and reaction products of common formation materials and drilling mud clays in acetic, formic, hydrochloric, and hydrofluoric acids were studied at elevated temperatures of 347°F and 437°F. Such data on high temperature acid reactions are relatively scarce and difficult to obtain, but are important to good treatment design.

Hydrothermal stability of several commercially available scale inhibitors (for calcium carbonate) was also studied in the laboratory. Interest in scale inhibition was centered on maintaining productivity in wells subject to downhole scale deposition. This work showed that 500°F thermal stability of commercial acidic inhibitors is improved by neutralizing the inhibitor.

Reservoir Selection

Criteria were established for selecting fields and wells as stimulation candidates for GRWSP field experiments. Wells in thoroughly studied proven reservoirs were favored because: (1) Reservoir data are essential to stimulation design and are time consuming and expensive to obtain; and (2) in order for stimulation to be viable, a productive reservoir must exist.

GRWSP reports documenting the Phase I work are listed in Table 1. Republic and GRWSP sub-contractors Maurer Engineering, Petroleum Training and Technical Services (PTTS), and Vetter Research were responsible for the Phase I investigations and documentation. Maurer Engineering and Vetter Research performed literature studies and laboratory investigations on stimulation methods, design, and materials, with Maurer concentrating on mechanical aspects and Vetter on the chemistry. PTTS was responsible for documentation of technology transfer and for converting and modifying the necessary computer codes. Republic coordinated these tasks and performed the reservoir selection task.

Phase II

Phase II of the program consisted of eight field experiments with associated site specific laboratory studies. Responsibilities for the various Phase II tasks are outlined in Table 2. In general, the experiments progressed from reservoirs of lower to higher temperature. The first two stimulation experiments were performed at Raft River Idaho in late 1979. This is a naturally fractured, hard rock reservoir with a relatively low geothermal resource temperature (290°F). A conventional planar hydraulic fracture treatment was performed in Well RRGP-5 and a dendritic, or reverse flow, technique was utilized in Well RRGP-4. This technique, designed to create a branched fracture pattern, was used in RRGP-4 to enhance the chances of intersecting major natural fractures paralleling the nearby Narrows fault. Analysis of the treatment pressure history indicated that dendritic fracturing was probably not achieved. Post-treatment evaluation using the the USGS borehole televiwer and pressure buildup data indicated that a fracture 195 feet high at the wellbore and 335 feet in length was created. The well productivity was increased five-fold, but the producing rate achieved was still sub-commercial. RRGP-5, situated near the intersection of two major faults, was stimulated with a conventional hydraulic fracture treatment in a 216 foot openhole interval near the bottom of the well. The treatment was designed to obtain commercial production rates from a deep higher temperature portion of the well. Complications in the well completion stemming from the original drilling interfered with treatment and caused the fracture to channel upwards to a cooler interval. Although a high flow rate was achieved the produced fluid temperature was subcommercial

In mid-1980 two cost-shared stimulation experiments were performed at East Mesa, California. Stimulation of Well 58-30 provide the first geothermal well fracturing experience in a moderate-temperature (350°F) reservoir with matrix-type rock properties. The two treatments consisted of a hydraulic fracture of a deep, low permeability zone and a dendritic fracture treatment of a shallow, high permeability mud/cement damaged zone in the same well. Both treatments were technically and economically successful and together more than doubled the producing rate of the previously marginal producer.

In January 1981 an acid etching stimulation treatment was performed in Union's Ottoboni State 22 well located in The Geysers geothermal field of California. This experiment was also cost-shared with the operator. The treatment involved the injection of 20,000 gallons of 10% HF-5% HCl acid behind a 20,000 gallon slug of high viscosity crosslinked gel polymer fluid. This technique was intended to take advantage of the fluid mobility differences to etch discrete flow channels, or fingers, in the fracture faces. The relatively low injection pressures experienced during the treatment combined with post-treatment temperature and R/A tracer logs indicated that the acid probably was dissipated in natural microfractures over a relatively long 650-foot openhole interval instead of creating a single, large fracture as planned. This broad vertical distribution of the acid resulted in a relatively shallow penetration of the formation and the treatment had no effect on the productivity of the well.

Also in 1981, hydraulic fracture treatments were performed on two wells located in Union's Baca project area in north-central New Mexico. Both experiments were cost-shared with Union. The treatment in Baca 23 was conducted in March utilizing a cooling water prepad followed by a high viscosity frac fluid carrying a mixture of sintered bauxite and resin-coated sand as the proppant. A nonproductive, 231-foot interval in the upper portion of the Baca reservoir was isolated for the treatment. An experimental high temperature Otis packer, using EPDM elastomer elements developed by another DOE program, was used successfully in this job. The same packer was used again in the poststimulation evaluation testing. For this, a novel drillstem test method was devised by Republic to acquire downhole transient pressure data under the Baca reservoir conditions of high temperature and subhydrostatic pressure. Poststimulation surveys and production tests indicated a fracture had been successfully created and propped; however, the production rates declined to non-commercial levels because of several factors including the relatively low temperature of the interval selected, apparent low permeability in the formation surrounding the fracture, and reduced relative permeability caused by two-phase flow effects in the formation.

R. V. Verity

During the fracture treatment, Los Alamos National Laboratory (LANL) 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 indicated 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.

The second Baca experiment was conducted in Baca 20 in October 1981, again utilizing a cooling water prepad followed by a high viscosity frac fluid carrying only sintered bauxite as the proppant. In order to maximize fracture conductivity and improve on the Baca 23 results, a larger size proppant was used and a deeper, hotter interval was selected. 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 pound per hour 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. The Otis high temperature packer and special drillstem test method were used again successfully in Baca 20. In addition, a special instrument carrier was designed to house Amerada-type pressure instruments downhole during the fracture treatment. The data acquired enhanced the interpretation of the job.

Poststimulation tests and analyses indicated a highly conductive fracture was achieved with a length of over 340 feet. However, the productivity of the well was poor, probably because of the low permeability formation surrounding the artificially created fracture. Finely ground calcium carbonate introduced as a fluid-loss additive during the fracture treatment was suspected in this job and others to result in some formation plugging. However, a follow-up acid treatment in Baca 20 designed to remove this material did not improve the well's productivity. Although the results were disappointing, this follow-up acid clean out was successful in dispelling long standing concerns about the selection and application of solid fluid-loss additives.

The Beowawe field experiment, the eighth of the GRWSP, was performed in Chevron's Rossi 21-19 well in August 1983. The experiment was cost-shared with Chevron. The Beowawe reservoir is a fractured volcanic sequence with temperatures of 360-420°F. The Rossi well was non-commercial, even though it did intersect a high-temperature fluid zone. Test results showed that it was limited by near-wellbore, restricted permeability, while all the remaining Chevron wells had been tested with production rates measured in the range of 230,000 to 320,000 lb/hr. Hydraulic connectivity has been shown to exist between all the wells using pressure interference tests which further indicate the reservoir has high areal permeability properties. The stimulation experiment was a 60,000-gallon, two-stage acid treatment designed to enhance productivity of the natural fractures and to remove drilling mud residue from the fractures.

The treatment was confined to the slotted liner interval below 4,369 feet. A prestimulation injection profile survey indicated that about 80% of the injected fluid was entering the formation below a restriction in the liner at 5,480 feet. This restriction prevented logging to find the exact injection interval. The first treatment stage consisted of 500 bbl of 14.5% HCl acid displaced by 2,400 bbl of water. The second stage consisted of 982 bbl of a 12% HCl-3% HF acid solution displaced by 3,000 bbl of water. Laboratory tests on drill cuttings from Rossi had indicated an average formation solubility of 14% in HCl and 53% in HCl-HF. The hydrochloric acid stage did not by itself produce any measurable stimulation effect, but was necessary to prevent formation of insoluble calcium fluoride precipitate in the formation during the second stage. Injectivity tests performed during the experiment indicated a 2.3-fold increase in injectivity by the second stage.

Sandia Laboratories and LANL both participated in the experiment testing fracture mapping methods and providing data on the direction of fluid movement in the reservoir during the treatment. Sandia applied its surface electrical potential (SEP) method to map the movement of the treatment fluids in the reservoir. The acid solutions clearly moved outward from the well along the known predominant fracture direction. LANL was able to detect microseismic events during fluid injection using the triaxial geophone instrument in the neighboring well Ginn 1-13. This result was especially significant since the experiment was not a fracturing treatment.

Unfortunately, mechanical complications with the well precluded an adequate production test. A shallow, low temperature zone in the well had previously been perforated for testing as an injection zone. Although this zone had exhibited very low injectivity, it produced enough cold water into the wellbore to prevent initiation of flashing flow from the lower zone.

Attempts to production-test the well were abandoned after producing it for approximately 12 hours by nitrogen lift.

In order to production test the well, the shallow perforated zone will have to be plugged off by cementing or by installation of a tieback casing string. If the well is production tested, it is reasonable to expect a significant increase in productivity of the lower zone. However, the absolute level of productivity cannot be inferred from the injectivity data because the relationship of productivity to injectivity in a fractured reservoir is highly variable.

Data on the eight field experiments are summarized in Table 3 and the first seven field experiments have been documented in reports listed in Table 1.

Design of each of the eight experiments required as a basis a model, or physical concept, of the well and surrounding reservoir based on drilling and production history, petrophysical logs, production logs, reservoir testing, and laboratory data on cores and drill cuttings. Data gathering techniques do not exist to create an exact reservoir model and deficiencies occur in the field experiment data because of well problems or failures of instruments in the geothermal environment. Thus, the design and evaluation of field experiments are hampered by an incomplete knowledge of the reservoir and its response to stimulation. Typically, in commercial oil and gas operations, data necessary for stimulation design and evaluation are accumulated over a long period of drilling, reservoir testing, and stimulation treatments. The GRWSP improved on this trial and error approach by increasing emphasis on diagnostic data gathering during the treatments. Much stands to be gained however, by application of increasingly sophisticated data gathering methods to define important reservoir parameters and evaluate the response of the reservoir to stimulation. Current efforts in fracture mapping and other reservoir definition techniques hold great promise for an improved understanding of reservoirs and stimulation.

Technical Enhancements of the GRWSP

In addition to the major conclusions of the GRWSP (discussed in the following section), there were a number of technical enhancements which are worthy of note. In the course of the GRWSP work Republic and the program subcontractors: (1) Created a comprehensive data base on performance of stimulation materials at high temperature; (2) devised a new method of analysis for characterization by chemical methods of the temperature/time degradation of polymer-based fluids; (3) developed software for high temperature fracture treatment design; (4) devised a novel drillstem test method to acquire downhole pressure test data for interpretations of fracture length, fracture conductivity, and formation productivity;

R.V. Verity

(5) devised a novel method of measuring downhole pressure during a fracture treatment; (6) provided an opportunity for testing high temperature packer elastomers and logging tools developed by other DOE-funded programs; (7) encouraged continued development by private industry of treating fluids, packers, and logging tools for high temperature wells; (8) gained substantial industry support for field experiments through cost sharing.

Conclusions

The two fracture treatments in Raft River and the two in Baca were successful in obtaining significant production from previously non-productive intervals. Highly conductive propped fractures were created; however, the four treatments failed to establish commercial production due to deficiencies in either well fluid temperature or flow rate or both.

The two stimulation treatments in a matrix-type formation at East Mesa 58-30 more than doubled production from the well and constituted an economic and technical success. The lower zone treatment stimulated production from a tight sandstone formation. The upper zone treatment successfully stimulated mud and cement-damaged high-permeability sands around the wellbore.

The acid etching treatment of the Ottoboni State 22 well in The Geysers failed to increase production. It is believed likely that the treatment fluids were dissipated into formation microfractures, and therefore, failed to penetrate deep enough into the formation to enhance communication with major natural fractures.

The Beowawe fracture acidizing experiment produced a 2.3-fold increase in injectivity in a well which apparently penetrated a local region of low permeability and which may also have suffered formation damage during drilling.

With few exceptions, commercially available fluids, proppants, and equipment performed satisfactorily in the eight stimulation experiments. In many cases, special techniques such as precooling the wellbore and formation were employed to accommodate limitations of available materials and equipment. The demands of the geothermal environment placed added importance on quality control. Stimulation fluids and proppants were pretested in the laboratory and quality control checks were performed on site.

Overall it was shown that both hydraulic fracturing and acidizing can, if properly applied, be effective remedies for near-wellbore formation damage and for enhancing productivity of a well penetrating a local region of low reservoir permeability. However, in three of the four hydraulic fracture treatments at Raft River and Baca, extensive, highly conductive fractures were created and propped which failed to establish commercial productivity from the reservoir. In both Raft River and Baca, the

R.V. Verity

knowledge of the reservoir and the geometry of the created fracture are insufficient to establish for certain the proximity of productive natural fractures to the wellbore and whether or not the pattern of natural fractures is such that a hydraulic fracture can intercept them effectively. At least two methods of fracture mapping are being developed which could eliminate much of this uncertainty in future fracture treatments.

The decision to confine fracture treatments to relatively short, nonproductive intervals of the wellbore at Baca and Raft River was based on the premises that: (1) Petroleum industry fracture design technology is applicable to creating new fractures in unfractured rock; and (2) the fracture height at the wellbore face must be limited by zone isolation in order to achieve the desired fracture width (aperture) and horizontal fracture extension. This approach is conservative in that it utilizes proven fracture design technology, but necessitated recompletion of the Baca and Raft River wells to exclude about 90% of the original open interval. Because reliable methods do not exist to temporarily isolate intervals for hydraulic fracturing in the open wellbore, virtually 100% of the wells' prestimulation production was sacrificed. For the sake of experimentation, these limited interval treatments reduced the risk of a complete job failure and simplified interpretation of the results. However, in terms of the level of productivity achieved, the Raft River and Baca experiments were handicapped by the exclusion of previously productive intervals.

At least two solutions appear possible. One is to perform a series of short-interval treatments in each well, thereby creating a long stimulated interval. However, this approach is inherently expensive and, as mentioned previously, a suitable method of zone isolation does not exist. A second, and much more promising approach is to focus on stimulating existing productive fractures. Observations during the field experiments and Republic's own well testing activities indicate that fractures can widen and increase in flow capacity under fluid injection conditions. This is probably the most significant observation of the program and has led to a new concept of widening and propping natural fractures near the wellbore to enhance their fluid conductivity.

This proposed new approach takes advantage of the phenomenon of "fracture compliance" which has been observed in the GRWSP field experiments and which has been studied and described on a laboratory scale in the technical literature. Natural fractures are known to dilate during fluid injection and constrict during production, with a corresponding loss in productivity. For a sufficiently elastic, or compliant, fracture system, it is theoretically possible to prop fractures in the dilated state, thus retaining a high fluid conductivity under production conditions. Successful stimulation of this type

could increase geothermal well productivity by several-fold. Relative to other technology development work sponsored by DOE, such stimulation offers one of the greatest potential opportunities for enhancing the economics of geothermal power production. Unfortunately, the funds for testing the propping of compliant fractures are not available under the GRWSP.

Stimulation field experiments are expensive and risk prone, but offer high potential for significant economic impact on the geothermal industry. Field experiments are clearly necessary however, to develop technology of use to the industry. The geothermal industry retains a strong interest in well stimulation and the development of tools and techniques for well and reservoir data acquisition.

TABLE 1

GRWSP REPORTS THROUGH JULY 1983

1. Part I - Contract Proposal - Geothermal Reservoir Well Stimulation Program Management - EW-78--32-0114
Part II - Technical Proposal
Part III - Cost Proposal
2. Management Plan for Geothermal Reservoir Well Stimulation Program Management - March 22, 1979
3. Proposal for Producing Well Hydraulic Fracture Stimulation, Raft River Field - GRWSP - June 1979
4. Geothermal Reservoir Well Stimulation Project - Reservoir Selection Task - November 1979
5. Geothermal Reservoir Well Stimulation Program - First-Year Progress Report - February 1980
6. Proposal for Producing Well Hydraulic Fracture Stimulation Treatments - East Mesa Field - GRWSP - April 1980
7. Modification and Implementation of the M.E.T.C. Simpac Program - May 1980 (PTTS)
8. Interactive Fracture Design Model - May 1980 (PTTS)
9. Volume I - Geothermal Reservoir Well Stimulation Program - Technology Transfer - May 1980 (PTTS)
Volume II - Technology Transfer (PTTS)
Volume III - Technology Transfer (VR)
Volume IV - Technology Transfer (MEI)
10. Proposal for Producing Well Hydraulic Fracture Stimulation Treatment - Baca Project Area - GRWSP - November 1980
11. Raft River Well Stimulation Experiments - August 1980
12. Proceedings of the Geothermal Reservoir Well Stimulation Symposium - February 7, 1980
13. Proposal for Producing Well Chemical Stimulation Treatment - The Geysers - GRWSP - December 1980
14. Volume I - Geothermal Fracture Stimulation Technology Fracturing Proppants and Their Properties - July 1980 (MEI)

Volume II - Geothermal Fracture Stimulation Technology - High Temperature Proppant Testing - July 1980 (MEI)

Volume III - Geothermal Fracture Stimulation Technology - Geothermal Fracture Fluids - July 1980 (MEI)

Volume IV - Geothermal Fracture Stimulation Technology - Proppant Analysis at Geothermal Conditions - January 1981 (MEI)

15. Chemical Stimulation Treatment - The Geysers - Ottoboni State 22 Geothermal Reservoir Well Stimulation Program - February 1981
16. Hydraulic Fracture Stimulation Treatments at East Mesa 58-30 Geothermal Reservoir Well Stimulation Program - February 1981
17. Hydraulic Fracture Stimulation Treatment of Well Baca 23 - June 1981
18. Technical Proposal - Geothermal Reservoir Well Stimulation Program Extension - June 1981
Cost Proposal - Geothermal Reservoir Well Stimulation Program Extension - June 1981
19. Fracturing Fluid Evaluation (Laboratory Work) (Vetter Research) - January 1982
20. Acidification of Geothermal Wells Laboratory Experiments (Vetter Research) - January 1982
21. A Review of Surface Equipment Requirements for Geothermal Well Stimulation - February 1982
22. Status Report GRWSP - May 1982
23. Requirements for Downhole Equipment Used for Geothermal Well Stimulation - August 1982
24. Proposal for Producing Well Chemical Stimulation Treatment Beowawe Geothermal Field Experiment No. 8 - May 1983
25. Final Report - A Laboratory Study of Acid Stimulation of Drilling Mud-Damaged Geothermal Reservoir Materials - May 1983
26. Hydraulic Fracture Stimulation Treatment of Well Baca 20 - July 1983
27. Experiment 8 Final Report (to be written)
28. GRWSP Summary (to be written)

TABLE 2
PHASE II TASKS

Republic Geothermal, Inc. (prime contractor)

Overall program direction
Solicitation of geothermal operators and selection of experiment candidates
Field experiment planning and design
Field experiment execution
Field experiment reporting

Maurer Engineering (subcontractor)

Stimulation treatment design
Job-specific laboratory testing of proposed stimulation materials
Field supervision of stimulation service companies
Continuing literature review and liaison with service companies to maintain awareness of new developments
Reporting on stimulation treatment execution

Petroleum Training and Technical Services (subcontractor)

Numerical modeling for design of field experiments
Seminar in February 1980 for technology transfer

Vetter Research (subcontractor)

Job-specific laboratory testing of proposed stimulation materials
Planning, execution, and interpretation of chemical and R/A tracer studies
Chemical analysis of fluids injected and produced during field experiment stimulation and production testing.

Terra Tek (subcontractor, beginning in 1981)

Laboratory testing for acid stimulation of mud-damaged formations

TABLE 3
GRNSP SUMMARY OF EXPERIMENTS

Experiment	Location and Well	Reservoir Temperature (°F)	Reservoir Formation	Stimulation Treatment Type	Treatment Interval Height (ft)	Fluid	Proppant
1	Raft River, ID RRGP-4	290	Fractured metamorphic and intrusive rocks	Dendritic hydraulic fracture	195	7900 bbl 10 lb HP Guar/1000 gal 2 lb XC Polymer/1000 gal	Sand 50,400 lb 100-mesh 58,000 lb 20/40-mesh
2	Raft River, ID RRGP-5	290	Fractured metamorphic and intrusive rocks	Large hydraulic fracture	216	7600 bbl 30 lb HP Guar/1000 gal	Sand 84,000 lb 100-mesh 347,000 lb 20/40-mesh
3	East Mesa, CA 58-30	350	Deltaic sandstone and shale sequence	Hydraulic fracture	247	2800 bbl 60 lb HP Guar (crosslinked gel)/ 1000 gal	Sand 44,500 lb 100-mesh 59,200 lb 20/40-mesh Resin-Coated Sand 60,000 lb 20/40-mesh
4	East Mesa, CA 58-30	320	Deltaic sandstone and shale sequence	Dendritic hydraulic fracture	304	10,300 bbl 10 lb HP Guar/1000 gal 2 lb XC Polymer/1000 gal	Sand 44,000 lb 100-mesh
5	Baca, NM B-23	450	Fractured Bandelier Tuff	Large hydraulic fracture	231	3600 bbl water prepad 4000 bbl 60 lb HP Guar (Crosslinked gel)/ 1000 gal	Sand 42,000 lb 100-mesh Resin-Coated Sand 81,500 lb 24/40-mesh Bauxite 98,500 lb 20/40-mesh
6	The Geysers, CA 05-22	460	Fractured Franciscan graywacke and greenstone	Acid etching	1000	476 bbl prepad 15 lb HP Guar/1000 gal 476 bbl pad 60 lb HP Guar (Crosslinked gel)/ 1000 gal 476 bbl 5% HCl-10% HF 445 bbl displacement 15 lb HP Guar/1000 gal	None
7	Baca, NM B-20	540	Fractured Bandelier Tuff	Large hydraulic fracture	240	3000 bbl water prepad 5600 bbls 60 lb HP Guar (Crosslinked gel)/ 1000 gal	Bauxite 119,700 lb 16/20-mesh 119,700 lb 12/20-mesh
7A	Baca, NM B-20		Fractured Bandelier Tuff	Acid treatment to dissolve calcium carbonate fluid-loss additive	240	1045 bbl 11.9% HCl	None
8	Beowawe, NV Rossi 21-19		Fractured Volcanic Sequence	Acid etching and formation damage removal	1111+	Stage 1: 500 bbl 14.5% HCl 2446 bbl water displacement Stage 2: 982 bbl 12% HCl-3% HF 3019 bbl water displacement	None