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Geothermal Technology Development Program Annual Progress Report

October 1983 — September 1984

James R. Kelsey, Editor

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GEOTHERMAL TECHNOLOGY DEVELOPMENT PROGRAM
ANNUAL PROGRESS REPORT

October 1983-September 1984

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Geothermal Technology Development
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ABSTRACT

This report describes the status of ongoing Research and Development (R&D) within the Geothermal Technology Development Program. The work reported is sponsored by the Department of Energy/Geothermal Hydropower Technology Division (DOE/GHTD), with program management provided by Sandia National Laboratories. The program emphasizes research in rock penetration mechanics, fluid technology, borehole mechanics, diagnostics technology, and permeability enhancement.

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1. SUMMARY

Introduction

The high cost of drilling and completing geothermal wells is an impediment to the timely development of geothermal resources in the United States. The Geothermal Hydropower Technology Division (GHTD) of the U.S. Department of Energy (DOE) has initiated a development program aimed at reducing well costs through improvements in the technology used to drill, complete, and log geothermal wells. Sandia National Laboratories (SNL) has been selected to manage this program for DOE/GHTD. Based on analyses of existing well problems, research goals have been set for the program.

To meet these goals, technology development in a wide range of areas is required. The near-term goal is being approached by improvements in conventional, rotary-drilling technology. The long-term goal will require the development of advanced drilling and completion systems. Research is being conducted in high-risk areas that are not being addressed by private industry due to the lack of near-term payoffs and small market potential.

The Geothermal Technology Development Program is organized into five subelements--Rock Penetration Mechanics, Fluid Technology, Borehole Mechanics, Diagnostics Technology, and Permeability Enhancement. Work is conducted under these subelements in accordance with overall program priorities and available resources. System analysis efforts are also undertaken, as necessary, in order to define geothermal technology needs and to evaluate the potential impact of new technologies on the cost of geothermal energy production. Near the end of FY 1984, responsibility for

the research projects under the Permeability Enhancement subelement was transferred to Sandia National Laboratories' new Geothermal Research Division. FY 1985 and future activities and progress of the Permeability Enhancement projects will be reported by the new division.

This report encapsulates the activities within the ongoing research and development (R&D) program for the 1983 fiscal year. Appendix A lists published comprehensive reports on completed projects and presentations made on program work during this reporting period. The reports are available from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161.

Highlights

Management

- Program Coordination. The Second Annual Geothermal Program Review was held in Washington, D. C., 11-13 October 1983. The DOE-sponsored meeting included reviews by the various national laboratories of their ongoing programs that are supported by the Geothermal Hydropower Technologies Division of DOE. Sandia National Laboratories' programs reviewed included Magma Energy Extraction, Advanced Drilling Research, and Geothermal Hard Rock Penetration Research. In addition to the DOE and laboratory personnel, approximately 50 industry representatives were in attendance.

Dr. Eugene Frankel of the House Science and Technology Committee was briefed on Sandia National Laboratories' Geothermal Technology Development Program on 14 December 1983.

- Program Review. Comprehensive presentations describing the activities of the Geothermal Technology Development Program were prepared and presented to the Geothermal Technology Industry Review Panel and the Division of Geothermal and Hydropower Technology, Department of Energy, on 8-9 February 1984 in San Diego, California. The review described ongoing research and planning of the DOE/Sandia program. Panel recommendations have been incorporated into the R&D program.

- Technology Transfer. The high-temperature/high-pressure viscometer developed a few years ago at Sandia continues to be utilized and evaluated

in a variety of research activities. Three prototypes of the instrument were fabricated at Sandia and loaned to various industry and research institutes. Currently, one is being used in-house at Sandia and another at Texas Tech University. During FY 1984, the third prototype was returned to Sandia by Halliburton and was subsequently made available for a short-term loan to Phillips Geothermal to aid in their research into geothermal drilling fluids. Superior Oil has also used the device in their research efforts. Fann Instruments is expected to begin marketing Sandia's design in the near future.

- Geothermal Drilling Organization. The first meeting of the Geothermal Drilling Organization was held at the Union Oil Research Center in Brea, California on 20 March 1984. Representatives from 12 geothermal operating companies met with DOE and Sandia representatives to discuss the formation of an official group to cost share (with DOE) projects of mutual interest. Sandia will act as the technical representative for DOE.

Systems Analysis

- Advanced Drilling Technology Study. This study was conducted to identify additional project areas in which government support could make a significant contribution. The primary motivation for government involvement in drilling research is to ensure adequate drilling capability for efficient exploitation of the resources that will be needed in the future. Several attractive R&D projects were identified and are summarized in Section 2.

Rock Penetration Mechanics

- Development of Improved Cavijet® Nozzles. The equations describing the collapse of a bubble near a solid wall were derived, and the process was numerically simulated. It was found that as bubble diameter increased, the effects of jet stagnation pressures near the wall became more pronounced. Larger bubbles collapsed faster, producing a microjet that contained significantly more erosive power. This finding supports the need to develop nozzle designs that produce highly structured jets in which large cavitation bubbles are formed periodically, rather than unstructured jets that produce smaller, randomly generated bubbles (see Section 3.1).

- Development of High-Temperature, High-Pressure Seals. Initial designs of the high-temperature/high-pressure plunger seal and check valve were completed, and preliminary tests were conducted. Material and fabrication problems were encountered in these early tests, and redesign work was initiated. The seal designs and test results are discussed in Section 3.2.

- Drill String Dynamics. GEODYN, a code capable of modeling the dynamic response of a drill bit interacting with a nonhomogenous formation (Phase I), was completed during FY 1984. Section 3.5 describes the GEODYN verification runs and their results.

- Thermal Spallation Drilling System. This technology was evaluated by conceptually designing and costing a theoretical flame jet drilling rig. The drilling capabilities and economics of the rig were then compared to a conventional rotary drilling rig. The conceptual design procedure and cost estimation are detailed in Section 3.6.

- Thermal Studies of Polycrystalline Diamond Compact Drag Tools. In studies conducted during FY 1984, an upper bound for the rock strength drillable without causing thermally accelerated wear was established, and the effects of thermal and mechanical loading on PDC bit life were evaluated. Drilling precautions and design considerations that may increase bit life were recommended (see Section 3.7).

Fluid Technology

- Aqueous Foam Drilling Fluids for Geothermal Applications. A mathematical model was developed for predicting the temperature profile in aqueous foams. The model is described in Section 4.1

- Wellbore Thermal Code. The thermal wellbore simulation code, GEOTEMP2, was revised in FY 1984 and used to simulate wellbore cooling by fluid circulation and fluid injection. Results of the fluid circulation studies indicated that lower wellbore temperatures are produced by higher flow rates, low soil thermal conductivity, and high-viscosity fluids. From the fluid injection study, it was determined that the fluid must be allowed to infiltrate over most of the wellbore rather than over a small region to be an effective cooling technique. These two simulations are described in Section 4.2.

- Drilling Fluid/Cement Studies. A new study, Phase III, was underway as the fiscal year ended and is summarized in Section 4.3. Unlike the previous Phase II study, which examined the behavior of purified and low-concentration montmorillonite fluids, the goal of Phase III was to determine how real muds behave under field conditions. A commercial bentonite and a saponite (the Mg analog of montmorillonite) were tested with all their impurities at an 8% concentration.

Borehole Mechanics

- Lost Circulation Test Facility. The lost circulation material, Thermo-Set Seal, was used in 109 tests, and the Lost Circulation Test Facility was improved. The results of the tests and the facility modifications are described in Section 5.1. A lost circulation plugging tool was also demonstrated. The demonstration results and tool description are included in Section 5.1.

- Lost Circulation Plugging Model. Modeling of lost circulation material (LCM) plugging mechanisms indicated that fluid yield stress may be responsible for self-sealing possibilities and that fluid dynamics predicts favorable particle orientations. Also, a plugging mechanism was identified that is a self-generated, sustained instability caused by a two-phased flow environment (see Section 5.2).

Diagnostics Technology

- Lost Circulation Zone Mapping Tool. Design modifications to convert the Acoustic Borehole Televiwer (ABT) to a Lost Circulation Zone Mapping Tool were established, and field testing of the ABT was conducted in geothermal wells. The design modifications and the results of the field tests are described in Section 6.1.

- Radar Fracture Mapping. Field and laboratory experiments have confirmed the feasibility of developing a borehole radar system for detecting geothermal fractures located away from the borehole. Design of the radar tool and construction of testing facilities have been initiated. The experimental results and tool specifications are presented in Section 6.3.

Permeability Enhancement

- Surface-Electric-Potential Fracture Mapping. A scale-model surface-electric-potential experiment was designed during the fiscal year. The proposed geoelectric test facility, which uses a hemispherical electrolyte tank to model a conductive half-space, is detailed in Section 7.1.

- In Situ Stress. Two investigations of in situ stress determination methods were conducted: (1) a determination of in situ stress from anelastic strain recovery (ASR) measurements and a comparison of these stresses to hydraulic fracture measurements, and (2) an analysis of the effects of geological discontinuities on the propagation of hydraulic fractures. The results of these studies are contained in Section 7.3

- High Energy Gas Fracture Field Test. Field tests to evaluate the High Energy Gas Fracture techniques for use in increasing the productivity of geothermal wells were begun. The results of the first test are described in Section 7.4.

- Analytical Model for High-Energy Gas Fracture. Development of a predictive model for high-energy gas fracture was begun. The applicability of a material cracking model to a water-filled borehole was evaluated, and the results are presented in Section 7.5.

2. SYSTEMS ANALYSIS

During FY 1984, systems analysis efforts focused on areas of investigation that would assist in defining geothermal technology needs. In this report period, a study of advanced drilling research needs was completed, and a report of the study was published as Reference 1. A summary of the study report follows.

The purpose of the Advanced Drilling Technology Study, sponsored by the DOE, was to identify additional project areas where government support should be applied and potentially could make a significant contribution.

This study emphasized drilling for the extraction of energy resources. This approach was taken because of several factors: the mission of the DOE sponsor, the importance of drilling in the extraction of energy resources, and the tendency of advances to originate in the "oil patch" and then find subsequent application in other drilling. The inputs from the study came primarily from the open literature and from interactions with those in industry who are associated with drilling research. Industry leaders were queried because they continually evaluate the direction in which technology must move and they identify critical research tasks. Although the perspectives and emphases of government and industry are different, the thoughts and rationale of these individuals were helpful.

Approximately 80,000 oil and gas wells are drilled annually in the United States, and these have a total drilled footage (1981 figures) of 119 million meters (389 million feet). This drilling far exceeds the oil and gas drilling done in the rest of the free world (Figure 2-1). In addition, roughly 700,000 water wells are drilled in the U.S. each year, with a total footage exceeding 30 million meters (100 million feet). Very little of this drilling for resource extraction requires state-of-the-art drilling techniques. All of the water wells and most of the petroleum wells are

Figure 2-1. Free World Well Completions (Oil & Gas, 1980)

shallow onshore wells in the contiguous 48 states. The wells that require high technology, and thus expensive tools and services, are the proportionately few offshore, remote, or deep wells.

Figure 2-2 shows the relationship between well depth and cost. Total cost rises very rapidly for well depths greater than 1,524 meters (5,000 feet). Figure 2-3 shows the comparative costs for offshore and onshore wells, and Figure 2-4 shows the trend toward utilizing a greater portion of offshore gas resources.

Future drilling for energy resources is likely to be much different from most current drilling. The United States will continue to rely heavily on oil and gas for its energy needs, but the easy-to-extract resources are finite and dwindling. These resources will gradually be replaced by deep, remote, or alternative resources. The growing exploitation of these resources will place demands on current drilling systems in the areas of better information describing the drilling process, improved control of the drilling operation, ability to operate in taxing environments, and capabilities to produce new hole orientations and geometries. The current wells that are most similar in technology requirements to these anticipated future wells are the expensive offshore or remote wells and the few wells that are currently drilled for extraction of alternative resources.

Figure 2-5 illustrates one prediction for U.S. oil and gas production between now and the year 2020.² The changing emphasis from conventional to unconventional sources is apparent. The unconventional resources that will be exploited during the next few decades will place widely varying demands on drilling and extraction systems (Table 2-1).³

Historically, the free world's wells have been drilled by U.S. companies, people, and technology. However, foreign companies and governments, especially from France, Norway, and Japan, are expanding their role in developing and applying new drilling technologies. This is not surprising since only a very small portion of the free world's reserves are in the U.S. (5%), as shown in Figure 2-6. In addition, a much greater proportion of European wells are offshore than are U.S. wells (30% vs. 2%).

Figure 2-2. Effect of Well Depth on Cost for U.S. Oil and Gas Wells

Figure 2-3. Comparative Costs for Onshore and Offshore Wells in 1981

Figure 2-4. Portion of Gas Produced from Offshore

Figure 2-5. Comparison of Domestic Oil & Gas Production from Old and New Technologies

Table 2-1

Drilling Requirements for Future Resources

<u>Directional Drilling Performance Requirements</u>	<u>Conventional Oil & Gas</u>	<u>Unconventional Oil Recovery</u>			<u>Unconventional Gas Recovery</u>		
		<u>Heavy Oil</u>	<u>Tar Sands</u>	<u>Oil Shale</u>	<u>Tight Gas</u>	<u>Methane From Coal</u>	<u>Coal Conversion</u>
<u>Hole Configuration Requirements</u>							
High angle - long lateral	X				X		
High angle - shallow target			X			X	X
Lateral drain holes		X	X	X		X	X
Horizontal holes		X	X			X	X
Precision vertical holes				X	X		
Large dia. shallow holes		X	X	X			
<u>Instrumentation Requirements</u>							
High accuracy survey tools	X			X		X	X
Reliable telemetry systems	X	X	X	X	X	X	X
Coal seam interface sensor						X	X
Measurement while drilling systems	X				X		
<u>Drilling Requirements</u>							
Multiple hole reentry capability		X	X		X	X	
Thruster systems	X	X	X			X	X
Borehole stability technology		X	X	X		X	X
Cuttings removal technology	X	X	X			X	X
Fluids	X	X	X	X			
Analysis and control of drilling systems	X	X	X		X

Figure 2-6. Free World Oil Reserves (1980)

In spite of the relatively few high-technology domestic wells, new drilling tools and capabilities are being developed by numerous U.S. companies. The major service companies continually work to improve their products, and current development areas include measurement while drilling (MWD), bits, motors, automation, and use of computers. In the "drilling industry" no one company markets the entire drilling system, and so technology development proceeds piecemeal, with no organization focusing on system improvements. Nonetheless, the drilling system is evolving through significant improvements to its component pieces.

The primary motivation for government involvement in drilling research is to assure adequate drilling capability for efficient exploitation of the resources that will be needed in the future. In addition, there are areas besides energy extraction that may require development of technology. These include waste isolation, defense concepts such as the MX missile system, and nuclear testing. Government-sponsored development for these purposes would also provide two concurrent benefits. It would aid cheaper and more efficient extraction of current resources, and it might help U.S. companies to remain competitive in drilling technology development.

In sponsoring drilling research and development to meet these goals, the government can undertake three different types of projects. First, it can identify and carry out those piecemeal, or evolutionary, developments that will not be done in the private sector. These tasks would center around improvement of current drilling systems and might include areas such as basic research or materials development to aid in dealing with severe environments. The second type of project would be to investigate selected new drilling systems that would basically change the way that wells are drilled. These revolutionary changes to drilling technology would have to be selected carefully to ensure their potential for significant impact. The final type of project is traditional. The government can continue to sponsor large-scale programs that require development of new drilling technologies. Examples include: large-hole drilling for nuclear testing, drilling to support defense programs, scientific drilling into the earth's crust, and early support of the development of alternative resources such as geothermal, methane from coal, etc.

Several attractive research and development projects that fall in these three areas were identified. These include:

1. Research, both analytical and experimental, into rock failure and rock-cutter interactions
2. Development of sensors that "see" beyond the wellbore and, in particular, that can sense what is ahead of a drill bit
3. Development of new materials and downhole components for high-temperature, corrosive environments
4. Development of nondamaging, fail-safe wall anchoring and bit thrusting systems
5. Research into novel hole-lining techniques.

3. ROCK PENETRATION MECHANICS

Research in rock penetration mechanics is directed toward a basic description of rock penetration by candidate advanced drilling systems. Understanding the behavior of polycrystalline diamond compact (PDC) drag bits in relation to rock fracture and wear mechanisms is receiving major emphasis, but other research areas, including improved materials and advanced rock penetration concepts such as hybrid bits using cavitating jets, will be pursued until they can be accurately evaluated. For effective participation in a coherent geothermal technology development program, this work must have the breadth to identify the most promising concepts and the depth to incisively analyze those concepts.

3.1 Development of Improved Cavijet® Nozzles

Contractor: Tracor Hydronautics
Principal Investigator: G. L. Chahine (301) 776-7454
Contract Period: 18 February 1980 to 30 November 1984
Contract Numbers: 13-5129, 68-8419 and 52-3636 (Sandia)
Technical Consultant: D. Glowka (505) 844-3601

Project Objective

The objective of this project is to develop design procedures for cavitating jet nozzles that effectively cut rock at lower pressures than those required with conventional waterjet nozzles.

Background

One of the goals of the Geothermal Technology Development Program is the development of an advanced drilling system for hard-rock formations. Mechanical drill bits augmented with high-pressure waterjets have been identified as one likely component of such a system. With the recognition that the cutting efficiency of high-pressure waterjets is a strong function of nozzle design, this work has been sponsored since 1978 to develop procedures for designing nozzles that optimize the use of the erosive power available in high-pressure liquids.

The most erosive water jets have been found to be those that cavitate. Cavitation occurs when turbulent vortices or eddies in a high-speed jet attain circulation velocities high enough to drop the fluid pressure below its vapor point, resulting in the formation of vapor cavities or bubbles. Upon bubble collapse in the presence of a pressure gradient, high-speed microjets develop. This microjet may contain sufficient energy to produce impact pressures greater than 690 MPa (10^5 psi), which is high enough to fracture rock surfaces. The optimal production of large and, hence, destructive cavitation bubbles with nozzle pressures between 13.8 and 55.2 MPa (2,000 and 8,000 psi) was adopted as the design goal for nozzles developed in this project.

The project's first phase, which included determining the effects of drilling mud on the cutting performance of cavitating jets (Cavijets®) was completed at the end of FY 1979. The results of this initial phase indicated that augmentation of mechanical bits with cavitating mud jets is feasible and might substantially improve drilling performance, even with conventional rig pressures of <27.6 MPa (<4000 psi).⁴ An associated effort was started in late FY 1979 to determine the feasibility of designing cavitating jet nozzles that resonate passively to produce nozzle-pressure pulsations. Such pulsations produce higher jet impact pressures and structure the jet flow field such that larger cavitation bubbles are produced periodically, thereby increasing cutting efficiency. This work was completed in July 1980, with the findings suggesting that additional research should result in viable pulser-nozzle systems.⁵ Continuation of the investigation of downhole pressure-pulsing nozzles was included in the follow-on Phase II project on cavitating jets, which was initiated in February 1980.⁶ The Phase II work, directed at improving the performance of cavitating jets, continued throughout FY 1981. The work included development of theories for vaned nozzles, organ-pipe nozzle acoustics, jet-structuring mechanisms, and boundary pressures induced by the structured jet. Laboratory rock erosion experiments in air and water were conducted to confirm the theories and to assess the feasibility of the organ-pipe nozzle. The influence of tube geometry, Mach number, and cavitation number on the degree of structuring was also determined experimentally for approximately 30 nozzle shapes. FY 1981 ended with the discovery that the critical Strouhal number can be controlled by nozzle design and that some nozzles apparently depend on cavitation for self-excitation and others do not.⁷

Phase II of the project was completed during FY 1982. This phase of the project resulted in the development of nozzle systems with incipient cavitation numbers two to six times higher (hence, greater jet erosivity at greater hole depth) than those obtained with either conventional Cavijet® nozzles or typical commercial bit nozzles. Also, adaptability of the Organ-Pipe Cavijet® to the physical constraints of existing bits was demonstrated, and the potential of self-resonating structured jets for improved bottomhole cleaning (hence, better drilling) was established. The technology developed in Phase II was transferred to industry and other interested

agencies through presentations at technical conferences.⁸⁻¹⁰ A final report on Phase II was published as Reference 11.

The results of the first two phases indicated that structured cavitating jets can effectively increase drilling rates, but in order to attain improvements required for an advanced drilling system, higher nozzle pressures may be necessary. Nozzle-design work aimed at pressures just higher than conventional, 27.6 to 55.2 MPa (4000 to 8000 psi), was begun. An analytical, rather than experimental, approach was taken in Phase III, which was begun in mid-FY 1982. The goals established for this phase were (1) to develop analytical techniques to predict the flow-field characteristics of cavitating jets and the upstream resonance characteristics of pulsing jets, (2) to use high-speed motion and still photography of cavitating jets to evaluate the success of the prediction techniques developed, and (3) to apply the prediction techniques developed to design Organ-Pipe Cavijet® or other nozzles for operation with a high-pressure drop across the nozzle and to determine their rock cutting performance in the high-pressure cell (HPC).

By the close of FY 1982, progress had been made in the analytical modeling efforts. The growth and collapse of an isolated ring vortex, such as that produced by a structured jet, was numerically modeled. It was found that the collapse rate of a cavitation bubble in the center of a ring vortex decreases as the vortex circulation velocity increases. Since cavitation bubble inception more readily occurs at higher circulation velocities, this implies that an optimum circulation velocity should be sought. Progress was also made toward modeling the interaction of ring vortices in the jet and the collapse of toroidal cavitation bubbles near a solid wall, such as the rock surface.¹²

Phase III work continued in FY 1983. Efforts were concentrated on the numerical simulation of jet structuring to investigate the feedback mechanism, the use of analytical techniques for predicting the flow field characteristics of pulsing jets, and the development of flow field visualization studies.

The numerical simulation of the structuring of small vortices showed that an optimal nozzle lip thickness exists for a given set of jet characteristics. This analysis will provide design guidelines for nozzle exit geometry. Also studied were the effects of modulating the nozzle pressure at a preferred frequency. It was found that the structuring of small vortices into larger ones is most efficient when the jet pressure is varied sinusoidally at a frequency corresponding to a given Strouhal number.

Progress was made in the modeling of the flow downstream of the nozzle where vortices interact with one another and with the wall on which the jet impinges. It was shown that the radial location of vortex impingement can be controlled by the nozzle standoff distance and the pulsation frequency. The same analysis was used to compute tangential velocities and pressure distributions on the wall. Positive spikes in tangential velocity were found to correlate with negative spikes in pressure, indicating that improved bottom-hole chip cleaning should result with structured jets due to enhanced shearing and lifting forces.

Numerical studies of the process of cavitation-bubble collapse confirmed the experimental finding that as the bubble collapses, a microjet is formed that is aimed in the direction of the pressure gradient.

During FY 1983, the flow visualization apparatus was designed, assembled, and operated to provide experimental support to the concepts dealing with jet structuring and vortex-nozzle interaction. The photographs provided qualitative verification of the numerical results.

Phase III work conducted during FY 1983 was reported in References 13 through 18.

FY 1984 Activities

The derivation of the analytical equations describing the collapse of a toroidal bubble near a solid wall was completed early in FY 1984. The method of matched asymptotic expansions was used to derive the equations, which were then solved numerically as a function of time.

The effects of several parameters on the bubble-collapse process were studied, with the most interesting result being the effect of initial bubble size. As the initial bubble diameter increases, the effects of jet stagnation pressures near the wall become more pronounced. Larger bubbles collapse faster, with the result that the microjet that develops as a consequence of the collapse contains significantly more erosive power. This finding demonstrates the need to develop nozzle designs that produce highly structured jets in which large cavitation bubbles are formed periodically, rather than unstructured jets that produce smaller, randomly generated bubbles.

One of the deficiencies of the flow modeling performed in this program to date is the assumption of inviscid flow. An analysis was conducted during this reporting period to determine the limitations of this assumption on the accuracy of the computer results and to investigate models for including fluid viscosity. A criterion was developed for determining when viscous effects are important in the vortex formation process that produces cavitation bubbles. It was determined that viscosity can be easily incorporated into the analysis for computing vortex formation; however, once a cavitation bubble is formed in the center of the vortex, the problem becomes much more complex. Considerable effort would thus have to be expanded before viscous effects could be fully included in the models.

By mid-FY 1984, the funded contract work on this project was completed. A review of the program was conducted at Sandia in May, 1984. It was recognized that significant progress has been made by Hydronautics in developing an understanding of structured, cavitating jets and in developing guidelines for designing nozzles to cut rock in deep drilling using fluid pressures of 27.6 to 55.2 MPa (4,000 to 8,000 psi). Numerical models have been constructed for several regions of interest, including fluid flow in the resonating chamber upstream of the orifice, through the orifice, between the orifice and the rock surface, and along the rock surface. These studies have enabled several design guidelines to be developed regarding resonating chamber geometry, orifice geometry, and nozzle-rock standoff distance. In addition, a clearer understanding of the role played by the external acoustic field in collapsing cavitation bubbles has

evolved, leading to some interesting ideas on focusing the acoustic energy to achieve more rapid erosion of the rock surface. These efforts, in conjunction with experimental work, have resulted in a more thorough understanding of the mechanics of cavitation and its effects on the flow field, providing practical parameters for nozzle design.

The project assessment indicated that additional work is needed to further improve the understanding of the dynamics of these complex flow fields and to optimize nozzle design. Before proceeding with further refinements, however, it was deemed necessary to compile the results obtained to date, to design and build a state-of-the-art nozzle for operation at 48.3 MPa (7,000 psi), and to compare the nozzle's rock-cutting performance with that of a conventional waterjet nozzle under the same conditions. It was felt that if significant rock penetration could be achieved with the cavitating jet nozzle, the possibility would then exist for developing a "pure-jet" drill bit that operates at pressures far below the 69 to 104 MPa (10,000 to 15,000 psi) typically required to achieve penetration of hard rock using conventional nozzles.

These tests were performed in late FY 1984 in Hydronautics' high-pressure test cell. A rock specimen was submerged in water under elevated pressure and rotated beneath a stationary waterjet nozzle. Ambient pressures of 6.9 to 13.8 MPa (1,000 to 2,000 psi) were used, together with nozzle pressure drops of 48.3 MPa (7,000 psi). Both Indiana limestone and Georgia gray granite were used as the initial test specimens.

It was found that both nozzles are effective in cutting these rocks under these particular test conditions. Using nozzle/rock translation speeds of 36 cm/sec (14 in./sec), both types of jet produced depths of cut on the order of 0.5 cm (0.2 in.) in both rock types. This result was expected with the Indiana limestone, which has a compressive strength less than the jet stagnation pressure under these conditions. The result was rather surprising with the granite, however, since it has a uniaxial compressive strength greater than 172 MPa (25,000 psi). Evidently the surface of the granite was riddled with microfractures, which the high-pressure

fluid was able to hydraulically extend. With both of these rock types, any effects of cavitation were apparently overwhelmed by the erosive effects caused by jet impact.

Subsequent tests with Tennessee marble produced quite different results. This rock is hard (compressive strength greater than 117 MPa [17,000 psi]) but does not contain the microfractures associated with crystalline rocks such as granite. As a result, hydraulic fracture extension and erosion due to jet impact were not expected to be as prevalent when 48.3-MPa (7,000-psi) jets were used. The tests showed, in fact, that cavitation does play a larger role with this rock type. The volume of material removed by the cavitating jet greatly exceeded that produced with the conventional jet, although both jets were far less effective in cutting this rock type than the first two rock types.

At the close of FY 1984, consideration was given to redirecting the cavitating-jet-nozzle development program. The reasons for the redirection are twofold. First, the high-pressure nozzle tests described above indicate that cavitation alone is not sufficient to significantly reduce the nozzle pressures required to effectively cut hard, unfractured rock. Thus, an advanced drilling system based on a "pure-jet" drill bit is still not possible without employing pressures beyond current technological limitations (i.e., pumping abrasive fluids such as drilling muds). Second, the thermal studies of PDC bits indicate that drag cutting of hard-rock formations may be practical if the more severely stressed cutters on the bit face are provided with jet assistance to reduce cutter loads and to improve cooling and lubrication. As a result, the decision to pursue a hybrid-bit design has been made, and several questions related to nozzle design for such a bit have arisen.

In order to determine the nozzle pressures required to provide adequate assistance to a PDC bit, a single-cutter test program has been designed. Cavitating jet nozzles, optimized for several operating pressures between 13.8 and 51.7 MPa (2,000 to 7,500 psi), are needed for this program. Studies of the dynamics of cavitating jets that specifically focus on the interaction of the jet with an adjacent PDC cutter are necessary.

Also, questions related to the flow passages upstream of the orifice, as limited by incorporation into a bit body, must be answered. The next phase of the cavitating-jet-nozzle development program will focus on these issues.

3.2 Development of High-Temperature, High-Pressure Seals

Contractor: Foster-Miller Associates, Inc.
Principal Investigator: Khushroo Captain (617) 890-3200
Contract Period: 1 October 1983 to 31 December 1985
Contract Number: 47-1095 (Sandia)
Technical Consultant: B. Caskey (505) 844-8835

Project Objective

The objective of this project is to design and test high-temperature, high-pressure piston plunger seals and check valves for application in a downhole pressure intensifier for use in geothermal waterjet drilling.

Background

One of the most promising techniques of breaking rock in geothermal well drilling is the use of a waterjet. But high pressures, approximately 103 MPa (15,000 psi), are required for efficient waterjet cutting, and surface equipment capable of providing the necessary flow rates and pressures are not practical at these pressures because of safety constraints. Hence, an innovative concept for using a high-pressure waterjet technique in geothermal well drilling is needed. Earlier studies¹⁹ have indicated the feasibility of the development of a pressure intensifier (pressure transformer), installed downhole, that would be capable of providing 103 MPa (15,000 psi) from a 21 MPa (3,000 psi) surface source. Standard rig mud pumps can safely produce the necessary surface pressure. The most critical problem in the design of a downhole pressure intensifier is the performance of the seals in the device. Successful development of high-temperature, high-pressure seals would not only provide a sound basis for a downhole intensifier design, but would also advance the state of the art in dynamic seals for other high-temperature, high-pressure applications.

The goal of this development effort is to design and test candidate high-temperature, high-pressure piston plunger seals and check valves capable of functioning satisfactorily in a downhole pressure intensifier

under geothermal drilling conditions. The components must operate in a water-based drilling mud containing 2% abrasive sand particles (larger than 74 microns) at a fluid temperature of 149°C (300°F). A minimum operating life of 200 hours and survival for 60 days at temperatures in the 260°C (500°F) range is also prescribed for the components. The seals will be designed for a piston plunger that is 2.5 cm (1.0 in.) in diameter, has a 61-cm (24.0-in.) stroke, reciprocates at 60 strokes per minute, and pumps the drilling fluid at 103 MPa (15,000 psi). The maximum leak rate through the seal will not exceed $0.63 \times 10^{-5} \text{ m}^3/\text{s}$ (0.1 gal/min) at a pressure drop across the seal of 103 MPa (15,000 psi). The check valve will also have a pressure drop across it of 103 MPa (15,000 psi) and must accommodate, when open, a flow rate of $25 \times 10^{-5} \text{ m}^3/\text{s}$ (4.0 gal/min) with less than a 0.69-MPa (100-psi) pressure drop. The valve must operate at 60 open/close cycles per minute and have a maximum leak rate, when closed, of no more than $0.63 \times 10^{-5} \text{ m}^3/\text{s}$ (0.1 gal/min).

The procurement actions required to establish this project were begun in FY 1983, and a project contractor had been selected by the close of the fiscal year.¹⁶

FY 1984 Activities

The new project to develop high-temperature, high-pressure seals for use in downhole high-pressure waterjet equipment for drilling geothermal wells was begun early in FY 1984. During the fiscal year, the initial designs of the plunger seal and check valve were completed, the first plunger seal and check valve were fabricated, the test facility was constructed, and testing of the seal and valve was begun. Conceptual designs of the plunger seal and the check valve are depicted in Figures 3-1 and 3-2, respectively. A schematic of the test rig is shown in Figure 3-3.

Check Valve -- In initial tests, the check valve was flow tested for 70 hours at flows in the 0.0006 to $0.0009 \text{ m}^3/\text{s}$ (10 to 15 gal/min) range and at temperatures ranging from 93° to 149°C (200° to 300°F). The drilling mud used consisted of water with 5% by weight of Aqua Gel and 3% by volume of silica. Subsequent disassembly and inspection of the check valve

Figure 3-1. High-Temperature, High-Pressure Plunger Seal Concept

Figure 3-2. High-Temperature, High-Pressure Check Valve Concept

Figure 3-3. Piston Plunger Seal and Check Valve Test Rig

revealed: (1) no erosion of the SiC extrusion dam or valve seat, (2) considerable erosion of the elastomeric plug near its trailing edge, and (3) erosion of the valve body in the region adjacent to the trailing edge of the elastomeric plug. The erosion was attributed to a significant flow restriction at the trailing edge of the elastomeric plug when in the fully open position. The valve body was machined to eliminate the flow restriction and retested. In the next test series, high-pressure 103-MPa (15,000-psi) sealing tests using water were successful; the leak rate was essentially zero. However, tests with the same drilling mud used earlier in flow tests were not successful. The valve did not seat and passed the entire output of the high-pressure intensifier with a pressure drop of less than 0.7 MPa (100 psi). While a higher flow rate might have caused the valve to seat, it was considered probable that the average leak rate would still be above the desired rate. In the valve design, the Teflon plug contacts the SiC seat before the SiC plug makes contact. It appeared that the seating spring pressure did not cause the Teflon to form a satisfactory seal when mud was present. The stiffness of the Teflon or binding (caused by grit) between the valve plug guide and the valve plugs were suspected as the source of the sealing problem. Additional tests are planned with increased clearance in the guide assembly and modified Teflon plug designs. The redesign and fabrication of the modified check valve were in progress as FY 1985 came to a close.

Plunger Seal -- A problem was encountered with the plunger seal design before actual fabrication began. In trying to electron-beam weld two sample pieces of Ferrotic CS-40, cracks and porosity developed in the weld area. Several attempts were made to produce a good weld but were not successful. The inability to produce an acceptable weld in the Ferrotic led to a modification of the seal design to include two 316 stainless steel collars brazed to each half of the Ferrotic seal in the area of the zero clearance gap. These collars were to be electron-beam welded 330° around the circumference. The 30° unwelded portion acts as the zero clearance gap, as in the original design. Subsequently, this design was considered impractical because the magnitude of the difference in the coefficients of thermal expansion of these materials prohibited a competent brazed joint. The next approach for fabricating the plunger seal was to braze the two

halves of the Ferrotic CS-40 seal together. For this approach to be successful, the end of one seal half must be lapped to produce a slightly raised section in the area of the "zero clearance joint." That surface and the opposite surface on the mating half must be treated so the braze filler material will not wet them. Cutting the longitudinal splits in each half prior to brazing was expected to prevent brazing alloy from being drawn into the zero clearance joint.

Following fabrication of the SiC rod for use as the plunger in the plunger-seal test rig and installation of the rod and Ferrotic seals in the test rig, static sealing tests (conducted with water as the working fluid) showed excessive leakage from each of the two seals. The failure of the seals to perform properly was attributed to problems encountered during fabrication brazing operations. The brazing alloy had migrated into the zero clearance gap and bonded the two seal halves in that region, preventing the seal from constricting and eliminating any leakage gap between it and the plunger. The seal design was modified, using Ferrotic sleeves trapped in an Invar collet. Use of the Invar collet permits the halves of the seal to be joined by electron beam welding, ensuring no obstruction of the zero clearance gap. New seals were being fabricated as this reporting period ended, and testing of the redesigned plunger seals was expected to resume early in FY 1985.

3.3 Rock Mechanics for Polycrystalline Diamond Compact Cutters

Sandia National Laboratories

Technical Consultants: J. Finger (505) 844-8089
D. Swenson (505) 844-9398

Project Objective

The project objective is to understand the rock/cutter interaction well enough to predict and optimize the performance of PDC bits. The approach to this goal has been to conduct analytical and experimental investigations of a single drag cutter in virgin rock.

Background

This project was begun in November 1978. Initial efforts included the modification of a two-dimensional, finite-difference model, designated TOODY, to investigate the rock/cutter interaction problem.²⁰ Work continued during FY 1979 on (1) the calculation of cutter stresses including the effect of rake angle, depth of cut, and confining pressure of drilling mud and (2) the rock failure mechanism, using the biaxial fracture model available in the TOODY code.²¹ In FY 1980, code modifications--dealing with finer zoning, larger rock, and longer run time--improved calculations that identified four steps in the rock fracturing process.⁶

During FY 1981, work on rock fracture modeling was directed to experimental verification of the rock material model and to comparison of the fracture pattern in the model prediction and in laboratory experiments. The model was transferred from the TOODY finite-difference code to the HONDO II finite-element code in order to lower costs and provide for greater flexibility, boundary conditions, and shear as well as tensile failure. Verification of the material model was attempted by using the constitutive relations for Berea sandstone in HONDO and by loading sandstone blocks in the laboratory under different confining stresses. The verification tests showed good qualitative agreement, although calculated failure loads were considerably less than the experimental failure loads. This discrepancy was attributed to the granular behavior of the material model after failure.⁷

Analytical and experimental work to understand the drag-bit cutting process continued during FY 1982. A series of single-cutter experiments were conducted at a fixed cutter speed and at three depths of cut in Tennessee marble and Westerly granite. Although there were similarities in the extent and type of damage that developed in the two rock types, some subtle variations that reflect differences in the rock type, structure, and mechanical behavior were apparent. Development of the two-dimensional, finite-element code also continued during FY 1982 in the effort to model the rock-cutter interaction and the chip formation process. Features added to the model included plastic deformation and formation shear cracks in compression. In this evolutionary stage, the model predictions remained quite sensitive to the assigned structures of the cutter/kerf interface. Nonetheless, the model predicted that chip formation is produced by the development of tensile fractures and that subsurface tensile fractures should be produced that dip in the direction of tool displacement. The latter prediction was in good agreement with the observations noted in the marble and granite experiments.¹²

During FY 1983, work continued to further understanding of the drag-bit cutting process, and a report was published documenting the analytical and experimental efforts under the project.²² Experiments to investigate the development of damage as a function of depth of cut were conducted. The resulting fracture patterns in both marble and granite, as revealed in sections by a fluorescent dye penetrant, compared favorably with the code predictions. The model, while unable to capture all of the features of the cutting process and material behavior, nonetheless has the capability to predict overall behavior and the effects of major changes in loading. The most significant indications from this model were that indentation-type loading is one of the major fracture-forming mechanisms of drag bit cutting, and that a change in the cutting process from a tensile fracture process to a shear process could be expected when the cutting process was confined.

Hence, with respect to research into the mechanics of cutting, it was concluded that the laboratory tests conducted do not simulate actual cutting conditions, and the model was least reliable at laboratory test conditions (atmospheric pressure). The present model was considered most applicable to actual drilling conditions, where the rock is confined by drilling mud. Therefore, a primary objective was identified to bring the laboratory test conditions closer to actual drilling conditions. Comparisons could then be made between the model and tests under simulated cutting conditions. In consonance with these conclusions, a new project was established to test single drag cutters under simulated downhole pressures.¹⁶

FY 1984 Activities

Additional work under this project was deferred during FY 1984 pending availability of data from the new project to characterize the PDC-cutter/formation interaction under simulated downhole pressures (Section 3.8).

3.4 Improved Cutter Materials

Contractor: (to be determined)
Principal Investigator: (to be determined)
Contract Period: (to be announced)
Contract Number: 59-4933 (Sandia)
Technical Consultant: J. Finger (505) 844-8089

Project Objective

The objective of this project is to develop a new cemented carbide suitable for application in geothermal drilling.

Background

Previous research on cemented carbides has identified sub-stoichiometric niobium carbide (NbC) with cobalt binder as the most promising candidate for use in drill bit inserts.^{16,23} Although the combination of toughness and hardness was not as good for NbC as for WC, the wear resistance of NbC was high and SEM examination of worn NbC samples indicated that the wear mechanism may be different from tungsten carbide. The relatively low fracture toughness of NbC was due, in part, to the sample fabrication method used in the earlier work, so the cold-pressing and sintering technique normally used in bit insert manufacture should produce samples with improved toughness. These factors showed that niobium carbide had potential for further development, and the availability of a cheap, non-strategic material that could substitute for tungsten carbide might have a major effect on the drilling industry.

FY 1984 Activities

During FY 1984, a decision was made to extend the investigation of new cemented carbides that could replace tungsten carbide. Procurement actions were initiated to contract for the continuation of the investigation of niobium carbide. This work will concentrate on developing a fabrication process, evaluating the process, fabricating and evaluating test specimens, and fabricating NbC drill bit inserts for possible field test in roller

cone bits. The procurement actions were still in progress as FY 1984 came to a close. The project work was expected to begin in the early part of FY 1985.

3.5 Drill String Dynamics

Contractor: Jordan, Apostol, Ritter Associates, Inc.
Principal Investigator: Jerold A. Baird (401) 294-4589
Contract Period: 1 March 1982 to 30 October 1984
Contract Number: 68-3061 (Sandia)
Technical Consultant: B. Caskey (505) 844-8835
M. Stone (505) 844-5113

Project Objective

The objective of this project is to develop a computer program for use in solving the drill string dynamics problem, including the interaction of the drill bit and the formation. The wellbore/drill string simulation is being developed in order to specify the dynamic environment near the bit sufficiently for design of advanced downhole equipment.

Background

An exploratory study by Jordan, Apostol, Ritter Associates, Inc. has established the technical feasibility of satisfactorily developing a finite-element computer model to solve the drill string dynamics problem. During FY 1981, the planning of a program to develop the drill string model was completed. The program concept was structured into three phases: (1) development of subsystems and assembly into a bit/formation interaction model, (2) refinement and extension of the model, and (3) incorporation of the bit/formation model into a complete wellbore/drill string simulation. Efforts were initiated to establish a cost-sharing/joint-development agreement with industry for carrying out the program. These efforts were still under way as FY 1981 came to an end.⁷

Agreement was reached by mid-FY 1982 among industry participants for the cost-sharing/joint development of the drill string dynamics computer model. The bit/formation interaction phase of the drill string system model was begun during the latter part of FY 1982 with the subsystem formulations for stiffness, mass, damping, body-force description, bit rotation, formation, and solution algorithm being completed by the end of the reporting period.¹²

Phase I of the drill string dynamics program, bit/formation interaction, was brought to completion during FY 1983. The bit/formation model is identified by the acronym, GEODYN. Phase I efforts included (1) the development of the finite elements and associated algorithms necessary to provide a PDC bit-bit sub model idealization; (2) the characterization of the geometry, boundary conditions, and phenomenological description of the PDC bit-formation interaction; (3) the idealization of the formation response; and (4) the integration of these tasks into a computer program whose main solution algorithm provides the capability of modeling transient dynamic bit motions to account for the nonlinear, time-dependent loading, and boundary-condition response characterizing the problem. During the latter part of FY 1983, verification and qualification of the GEODYN model were begun using simple test runs and SNL test data. Also during FY 1983, work was begun on Phase I documentation, to include a user instruction manual.¹⁶

FY 1984 Activities

The Phase I developmental effort was completed during FY 1984, and verification runs of the code were made. Phase I GEODYN provides the capability to model the dynamic response of a PDC bit interacting with a nonhomogeneous formation. The code was installed on SNL's VAX 11/780 and CRAY 1 computer and was sent to the National Energy Code Center at Argonne National Laboratory. The center has checked the code tape and is prepared to distribute it to requestors.

To demonstrate the program's capabilities, 12 verification runs were made to determine the effects of hole-size, hole-shape, and formation-property variations. The program proved capable of predicting consistent results for hole-size variations. Penetration, bit torque, bit spiralling, and side-wall interaction contact frequencies were all influenced by the hole size. Of the three formation effects modeled, the hole size in many instances was the dominant variable (especially for small hole clearances). The response accompanying bottom-surface profile variations was most noteworthy for penetration predictions and general bit motion (i.e., spiralling and retracing). Finally, the variation of formation hardnesses was

observed to influence the penetration response, the bit-torque response, the bit motion (i.e., spiralling and retracing), and to a degree, the side forces.

The Phase I work was reported in References 24 through 27. A summary of the activities reported follows.

The code verification runs were performed on a CRAY 1 computer to assess the program's ability to model formation, hole-size, and hole-shape effects. The bit-drill string model utilized for this purpose is briefly detailed in Table 3-1. The model configuration utilized is not intended to simulate the entire interactive response of a bottom-hole assembly (BHA). The operating parameters (e.g., rotational speed) are also listed in this table.

The characteristics of the wellbore geometry and material variations are listed in Table 3-2. Figures 3-4 and 3-5 should be referred to when reviewing the wellbore characterization. Each varied wellbore model has been assigned a verification run number that will be referred to in subsequent discussions. All runs simulate atmospheric pressure and do not account for rock removal at the formation interface surfaces. Such a capability will be added during a later phase of program development. It should be noted that the bit body both moves eccentrically in the hole and tilts (i.e., node points 180 degrees apart experience different penetration displacements) during the bit's rotation.

Penetration and Bit-Torque Response -- Table 3-3 summarizes the average penetration response of the bit (i.e., the movement of the bit's center apex node point downward toward the formation), the weight-on-bit (WOB) response actually experienced, and the bit-torque response arising from interactive formation forces. The following discussion will highlight the pertinent observations made concerning the verification cases run and will cite the effects produced by varying the hole size, the hole-bottom surface profile, and the material-property variations within the bottom surface.

Table 3-1

Bit-Drill String Model and Operating Conditions
for Verification Simulation

- 32 8-node bricks used to model Smith 22.35-cm (8-3/4 in.) bit
- 16 beams used to characterize the 6.1 m (20 ft) of 16.5-cm (6.5-in.) OD, 5.7-cm (2.25-in.) ID drill collar
- 39 face cutters are modeled for the bit
- 16 wear buttons are modeled for the bit
- 4 gauge cutters are modeled for the bit
- 252 finite element degrees of freedom (D.O.F.) after tying
- Boundary Constraint Spring Stiffnesses
 - X and Y translational are 2.4×10^7 N/m (138,000 lb/in.)
 - Z translational is 3.5×10^6 N/m (20,000 lb/in.)
 - Z and Y rotational are 2.8×10^4 N·m/rad (255,000 lb·in./rad)
 - Z rotational is 2.2×10^4 N·m/rad (196,000 lb·in./rad)
- Rotational speed is 340 RPM
- Timestep size is 1 millisecond
- Externally applied vertical load rate of 714 kg/s (1,575 lb/s) was imposed for 2.67 seconds, with total load then held constant
- Number of modes used for modal reduction is 19, which corresponds to the 6th bending mode and a natural frequency of 355.4 Hz
- Formation Grid Spacing
 - Bottom
 - $\Delta X = 0.635$ cm (0.25 in.)
 - $\Delta Y = 0.635$ cm (0.25 in.)
 - Side Wall
 - $\Delta \theta = 10^\circ$
 - $\Delta Z = 1.27$ cm (0.50 in.) (on wall)
 - Side Incline
 - $\Delta S = 0.635$ cm (0.25 in.) (along incline)
 - $\Delta \theta = 5^\circ$

Table 3-2

Wellbore Model

Verification Simulation Run Number	Bottom Shape (See Figure 3-1)				Hole Size [Nominal Diameter = 22.23 cm (8.75 in.)]		Location Hard Quadrants (See Figure 3-5)
	Cone Height (cm/in.)	Cone Diameter (cm/in.)	Flat Diameter (cm/in.)	Incline Angle (deg.)	Diametral Clearance (cm/in.)	Diameter (cm/in.)	
1	1.138/0.4479	12.444/4.8991	17.576/6.9195	52.51	0.064/0.025	22.353/8.8005	None
2	1.138/0.4479	12.444/4.8991	17.576/6.9195	52.51	0.064/0.025	22.353/8.8005	1,2
3	0	0	22.353/8.8005	52.51	0.064/0.025	22.353/8.8005	None
4	0	0	22.353/8.8005	52.51	0.064/0.025	22.353/8.8005	1,2
5	1.050/0.4136	12.093/4.7611	17.862/7.0325	52.51	0.351/0.138	22.640/8.9135	None
6	1.050/0.4136	12.093/4.7611	17.862/7.0325	52.51	0.351/0.138	22.640/8.9135	1
7	0	0	22.640/8.9135	52.51	0.351/0.138	22.640/8.9135	None
8	0	0	22.640/8.9135	52.51	0.351/0.138	22.640/8.9135	1
9	0.980/0.3857	11.809/4.6491	18.147/7.1445	52.51	0.635/0.250	22.925/9.0255	None
10	0.980/0.3857	11.809/4.6491	18.147/7.1445	52.51	0.635/0.250	22.925/9.0255	1,2
11	0	0	22.925/9.0255	52.51	0.635/0.250	22.925/9.0255	None
12	0	0	22.925/9.0255	52.51	0.635/0.250	22.925/9.0255	1,2

Figure 3-4. Bottom Shape

Figure 3-5. Nonuniform Example Wellbore Model

Table 3-3
Summary of Penetration, WOB, and Bit-Torque Response

Verification Simulation Run Number	Penetration		WOB		Average Bit Torque (N•m/lb•in.)
	Average Penetration, At Constant WOB (cm/in.)	Deviation At Constant WOB (cm/in.)	Average Constant (kg/lb)	Deviation (kg/lb)	
1	0.234/0.092	±0.013/0.005	1701/3750	±45/100	1219/10,800
2	0.196/0.077	±0.025/0.010	1837/4050	±91/200	1072/9500
3	0.279/0.110	Negligible	1531/3375	± 9/20	1197/10600
4	0.239/0.094	±0.013/0.005	1701/3750	±45/100	1118/9900
5	0.262/0.103	+0.025/0.010 to -0.015/0.007	1633/3600	±68/150	1072/9500
6	0.236/0.093	±0.030/0.012	1701/3750	±91/200	1016/9000
7	0.292/0.115	±0.013/0.005	1633/3300	±45/100	1129/10000
8	0.274/0.108	±0.013/0.005	1588/3500	±68/150	1050/9300
9	0.269/0.106	+0.015/0.007 to -0.013/0.005		+136/300 to - 68/150	
10	0.229/0.090	±0.030/0.012	1724/3800	± 91/200	960/8500
11	0.295/0.116	±0.013/0.005	1486/3275	± 45/100	1016/9000
12	0.267/0.105	±0.015/0.006	1610/3550	± 91/200	1016/9000

First, consider the apex node point's time-history penetration response illustrated in Figure 3-6 for verification Run 6. An average penetration of 0.236 cm (0.093 in.) at an average constant WOB of 1,701 kg (3,750 lb) (after 2.67 seconds of loading) was modeled. This figure is typical of the time-history penetration responses observed for all verification runs. The corresponding bit-torque time history for verification Run 6 is illustrated in Figure 3-7. The penetration-response variations simulated in the verification test runs will be described first.

The first comparison to be made addresses the effect of hole size on penetration response. It is possible to assess this effect by comparing sets of data (Runs 1, 5, and 9; or Runs 3, 7, and 11, etc.) in which the same bottom-surface and material characterizations are employed (refer to Table 3-2). The GEODYN results indicate a pronounced increase in penetration when the hole clearance was increased from 0.063 cm to 0.350 cm (0.025 in. to 0.138 in.) with all other formation modeling parameters held constant. However, the penetration increase between the 0.350-cm (0.138-in.) and 0.635 cm (0.250 in.) hole-clearance cases was not nearly as significant. Clearly, hole-clearance response effects are present and result in increased penetration with increases in hole clearance. This increase in penetration is attributable to less frequent contact of the bit and side walls of the hole for the larger hole clearances. The fact that the increases between 0.351-cm (0.138-in.) and 0.635-cm (0.250-in.) hole clearance are reduced may suggest that a "preferred" hole size exists and is closer to that modeled by a 0.351-cm (0.138-in.) hole clearance (e.g., a hole clearance of 0.635 cm [0.250 in] may be too large).

The effect of bottom-surface rock-hardness variations on bit-penetration response was also simulated in the verification runs. This effect can be seen by comparing results for Runs 1 and 2, Runs 3 and 4, Runs 5 and 6, etc. The incorporation of harder quadrants in the formation model produced a decrease in penetration at a higher effective WOB in addition to increasing the variation of penetration about the average value. Such a result was anticipated and is consistent with field experiences.

Figure 3-6. Penetration Response for Run 6

3-7. Bit-Torque Response for Run 6

The last formation model parameter simulated by the verification runs was bottom-surface profile variability. Both a completely flat bottom-surface profile and a combined conical, flat, side-incline bottom-surface profile were modeled. This parameter variation may be evaluated by comparing response results for alternate verification run pairs (1 and 3; 2 and 4; etc.). In all cases, the computed penetration was greater at a reduced WOB for the flat-bottomed profile. This response is consistent with the fact that fewer cutters are in contact with the bottom surface (those within indented portion of bit do not contact the surface).

Bit-torque response may be related to formation modeling variations in the same manner as that used to describe penetration response. In all instances, an increase in hole size resulted in a decreased average bit torque being simulated. Such a decrease arises from the less constrained nature of the bit's motion in the larger hole sizes.

The bit-torque response arising from bottom-surface formation hardness variability was similar to that observed for penetration response. In all runs, the average bit torque at constant WOB either remains the same or decreases when the hard-formation quadrants are modeled. This response is consistent with the previously mentioned penetration response and implies that coupling between penetration response and bit-torque response occurs.

The influence of bottom-surface profile variations on bit-torque response does not seem to be as pronounced as size or hardness variability. The bit-torque responses simulated suggest that the flat-bottom profile generally results in a slightly higher bit torque being modeled. This observation is consistent with the increased penetration responses being predicted. It is possible that bit tilting, in addition to limited cutter contact within the bit's indented region, produces some of the anomalies associated with these response results.

Bit Motion -- A total description of the bit's motion (including tilting, rotation, and translation), although characterized by the GEODYN program, will not be given. However, to show how the bit moves during the verification runs, three figures have been included that illustrate

the motion of the bit's apex node point in the X and Y directions (see Figure 3-5). These figures are each a different hole clearance and will be discussed in that context. Response variations attributable to formation-hardness variations or bottom-surface profile will be noted when appropriate.

The path followed by the bit's apex node point during the constant WOB portion of loading in a hole characterized by a 0.064-cm (0.025-in.) hole clearance (Verification Run 2) is illustrated in Figure 3-8. For this particular verification run, and all others with a 0.064-cm (0.025-in.) hole clearance, the bit center was observed to translate rapidly through all four bottom surface quadrants during each individual rotation of the bit. Slight variations in the apex point's deflections were noted when hard quadrants were incorporated and surface profiles were modified. It was obvious, however, that the overall motion was dominated by the high frequency of bit/side-wall contact occurrences arising from the small clearances modeled.

The motion response associated with the 0.351-cm (0.138-in.) hole-clearance verification runs differs considerably from that just described. Figure 3-9 illustrates the apex point's path during constant WOB loading for verification Run 7. No rapid translational motions between quadrants occur. Instead, a general counterclockwise spiral develops and the bit rotates clockwise. This general motion was observed for verification Runs 6, 7 and 8, differing only in that a more rapid rate of progression was observed for the flat-bottom profile and that a shift toward larger deflections occurred in quadrant 2 (see Figure 3-5) when quadrant 1 was modeled as a harder material. It is believed that this counterclockwise spiral effect occurs because the formation is predominantly interacting with the bit's outer surface (i.e., wear buttons, gage cutters, outer face cutters).

The motion response associated with verification Run 5, however, differs from the other 0.351-cm (0.138-in.) hole-clearance cases. In this run, the apex point was observed to spiral counterclockwise during increased loading, but when constant WOB conditions occurred, it began to retrace the preceding apex point paths in quadrant 4. This observed

Figure 3-8. Motion Response of Bit's Apex Point for Run 2

Figure 3-9. Motion Response of Bit's Apex Point for Run 7

response clearly demonstrates that both formation hardness and bottom-surface profile variations do affect the bit's behavior in concert with the hole size. It should be noted that this retracing phenomena was observed only when the conical formation surface was modeled. A similar effect is shown in Figure 3-10 for the 0.635-cm (0.250-in.) hole-clearance condition. It is believed that this response occurs when a portion of each individual bit revolution causes the outer bit surface to contact the outer wall, with yet another portion bringing the inner surface (cutters in inverted cone region) in contact with the formation's cone. The motion produced would be at first counterclockwise and then clockwise. Bit tilting can contribute to and accentuate this retracing phenomena.

An illustrative example of the apex point's motion for a 0.635-cm (0.250-in.) hole clearance (verification Run 10) is shown in Figures 3-9 and 3-10. A clockwise spiral occurs preceding retracing quadrant 2. The clockwise spiral would seem to indicate that such a hole clearance allows interaction with the formation cone to be predominant. The eventual retracing phenomena likely occurs as a consequence of the formation hardness effect being coupled with a surface-profile response. The uniform formation hardness case (Run 9) shows a consistent clockwise spiral motion. The flat-bottom profile, verification Runs 11 and 12, responded quite differently from Runs 9 and 10. Run 11 is characterized by a counterclockwise spiral motion. Run 12 demonstrates a much more random motion generally occurring in quadrant 4.

Bit Side Force Response -- Figures 3-11 and 3-12 have been provided to demonstrate the program's ability to model the force interaction of the ghost cutters with the formation. These two figures illustrate the effective (i.e., summation of all interaction forces) bit side forces in the X and Y directions for verification Run 7. Several interesting observations regarding these specific results can be made. First, it should be noted that no side force is predicted for approximately the initial 0.150 seconds of loading. This can be explained by the fact that the bit's movement about the hole center was not large enough to bring it into contact with

Figure 3-10. Motion Response of Bit's Apex Point for Run 10

Figure 3-11. Bit Side Force Response in X-Direction for Run 7

Figure 3-12. Bit Side Force Response in Y-Direction for Run 7

the hole side-wall formation. During this period, however, the face cutters located on the bit flat are interacting in a balanced sense (i.e., summation of the friction forces in the X and Y directions are zero) yet are present because bit-torque increases are occurring.

A second aspect of these results that should not be overlooked is the direct correlation between the bit's location (see Figure 3-9) and the magnitudes and direction of the bit side force (see Figure 3-11). This correlation was observed in all instances and serves as an internal verification check on the solution algorithm.

A third issue worthy of discussion is the high-frequency chatter observed in the side-force plots. Clearly, there are many instances where the deviation from the average value is of a higher magnitude than the average value. This behavior illustrates the complexity of the bit-drill string structural response as well as the intermittent nature of formation contact. In conjunction with this chatter phenomena, it should also be recognized that at certain periods during loading the magnitudes of these deviations are significantly higher than at other periods. The periods of increased activity (i.e., large magnitude deviations) seemed to be affected most by the formation hardness variations for the conical bottom-surface models. The inclusion of hard quadrants in each such instance changed the magnitudes and the portion of loading (e.g., from 1.0 to 1.5 s in one case to 1.75 through 2.25 s for the other) at which increased activity occurred. The largest deviation observed in these analyses was attributable to side-wall impact (verification Run 6). In contrast to these dramatic effects, certain portions of the flat-bottom force curves are nearly sinusoidal, suggesting pure frictional drag in a synchronistic drill string whirl mode.

Code Qualification -- Sandia continued the Phase I GEODYN code qualification program throughout FY 1984. As reported in Reference 16 for the drill string/bit modal frequencies, the code predictions and experimental data continued to compare very favorably during transient and frequency response (single cutter impact) investigations. Some of these results are depicted in Figures 3-13, 3-14, 3-15, and 3-16. Qualification efforts on the rotating sub and bit and on drilling into rock were getting underway as

Figure 3-13. GEODYN Qualification Results, Transient Response Comparisons

Figure 3-14. GEODYN Qualification Results, Frequency Response Comparisons

Figure 3-15. Comparison of Experimental and GEODYN Results,
0 rpm Case Filtered to 40 Hz

Figure 3-16. Frequency Response Comparison, 0 rpm Configuration, Tangential Response

the fiscal year ended. The code qualification work for Phase I was expected to be completed and Phase II was scheduled to begin during FY 1985.

The Phase II effort, bottom-hole assembly (BHA) analysis, to develop and integrate a transient, dynamic bottom-hole assembly capability into the GEODYN model was underway as the fiscal year ended. CONOCO and ARCO were preparing to join NL Industries, Superior Oil, and Sandia in the cost-sharing/joint development of the Drill String Dynamics Model early in FY 1985 during the Phase II effort.

3.6 Thermal-Spallation Drilling System

Contractor: Resource Technology, Inc.
Principal Investigator: R. Rinaldi (918) 743-2985
Contract Period: October 1983 - July 1984
Contract Number: 68-3057 (Sandia)
Technical Consultant: James R. Kelsey (505) 844-6968

Project Objective

The objective of this project is to assess the feasibility, economics, and technical problems of applying thermal spallation techniques to drilling deep holes in various types of rocks.

Background

Thermal-spallation drilling techniques have been widely applied in the past and continue to be used for the formation of shallow blast holes needed in the removal of taconite ore and in hard-rock quarrying operations. Recently, efforts to apply the technique to achieve greater borehole depth have had some success. Drilling experiments in granite have produced a 22.9-cm (9-in.) diameter borehole, 335 m (1,100 ft) deep, at an average penetration rate of 16 m/h (52 ft/h) and a 38.1-cm (15-in.) diameter borehole, 131 m (430 ft) deep, at an average penetration rate of 7.6 m/h (25 ft/h). These results, especially the high-penetration rates, suggest significant benefits if the thermal-spallation technique could be applied to the drilling of deep boreholes for hot-dry-rock, geothermal, and oil/gas wells.

Although the effectiveness of thermal spallation in drilling shallow holes in hard rock portends an attractive potential for drilling deep holes, the actual feasibility of adapting the technique to deep well drilling remains unclear. Many technical and economic issues such as the mechanics of the spallation process, the range of rock types subject to spallation, the compatibility with current drilling equipment and procedures, the requirements for new devices and procedures, the technical

limitations, and costs in comparison to conventional drilling are unknown or not adequately defined. Hence, a thorough analysis, on a total system basis, of extending the spallation technique to deep-well drilling is warranted. Since available background information indicated that some technical data existed that could be used to assess the applicability of the spallation technique to deep-hole drilling, a decision was made in FY 1983 to conduct a system analysis of spallation drilling using a high-temperature flame before committing significant resources to any R&D effort to extend the technology to deep-well drilling.

This project was established during FY 1983 and by the close of that fiscal year contractual arrangements had been made and work was scheduled to begin in FY 1984.¹⁶

FY 1984 Activities

The project was completed in FY 1984 and a report on the study was prepared.²⁸ A summary of the study follows.

The evaluation of the technology was performed by conceptually designing and costing a theoretical flame-jet drilling rig. The design process reviewed a number of different concepts concerning the various components needed and then chose those pieces of equipment that best suited the needs of the system and that had the best chance of being properly developed.

The drilling capabilities and the economics of this rig were then compared to a conventional rotary drilling rig by theoretically drilling two holes of approximately 4,572 m (15,000 ft) in depth. This comparison was done by use of a spread-sheet-type computer program.

Design Overview -- To effectively evaluate flame-jet drilling, a conceptual design of a drilling system that can either rotary drill or flame-jet drill as needed was developed; this approach was required because not all rocks can be spalled with a flame jet. This requirement was accomplished by integrating a thermal-spallation drilling system into a conventional rotary drilling system. The design consisted of three groups of equipment: components used only for rotary drilling, elements used only for flame-jet drilling, and components common to both types of drilling.

When evaluating the combined rig concept, it became apparent that the two rigs had to be analyzed as a single drilling system consisting of a number of modules that could be integrated when needed or set aside when not being used. Further, it became necessary to transfer the drilling function from one system to the other easily and with little loss of time. Thus, a systems approach that defined the function of each subsystem, its individual requirements for operation, its relationship to the other subsystem, etc., was used.

The system was designed to be capable of drilling the two wells illustrated in Figure 3-17. These wells are approximately 4,572 m (15,000 ft) and 4,267 m (14,000 ft) deep, respectively, with each deviating out as defined in Figure 3-18. Typical geological strata to be drilled and typical hole diameters and casing programs are also defined in Figure 3-17. Hole deviation requirements for both models are shown in Figure 3-18.

Conventional rotary drilling was used in the geological strata that is not conducive to thermal-spallation drilling. The conventional drilling was done by a rotary rig with a depth rating of 4,800 to 5,500 m (16,000 to 18,000 ft). A rig of this size was needed to install the long casing strings required to rotary drill through the cement left inside the casing after a cementing operation (flame-jet drilling cannot be used inside the casing because of the possibility of burning through the casing or damaging it) and to perform any surface drilling operations. The rig was standard in design except for those portions that were modified to convert to flame-jet operations.

In the granitic rock, spallation drilling techniques appear to be superior to rotary drilling as far as penetration rates are concerned. Therefore, thermal-spallation drilling techniques were used in these zones. Thermal-spallation operations were done by a flame-jet rig capable of using an air/fuel system, an oxygen/fuel system, or an air-oxygen/fuel system.

Figure 3-17. General Well Models

Figure 3-18. Hole Deviation Requirements Well Model No. 1 and Well Model No. 2

A summation of the design specifications follows:

- One control system for both drilling methods.
- Depth rating of 4,880 to 5,490 m (16,000 to 18,000 ft). This includes mud system, power system, hoisting capability, etc.
- Complete, self-supporting system with one prime power system, full mobility, etc.
- Complete capability to drill deviated holes.
- Complete capability to rotary drill to full depth.
- Complete capability to thermal-spallation drill to full depth.
- Quick and efficient capability to change from one drilling system to the other.
- All downhole equipment will be designed to effectively operate and survive in stabilized hole temperatures.

The envisioned rig design integrated a flame-jet drilling system into a conventional rotary drilling rig as noted in Figure 3-19. The concept consists of five main systems and/or components as follows:

- Surface System
- Umbilical System
- Downhole Burner System
- Control System
- Auxiliary Equipment

Each system or component incorporated a number of subsystems, all of which were modular in design and integrated so that the user could drill with either conventional rotary equipment or flame-jet equipment as needed. In the succeeding parts of this study, each system and auxiliary component was reviewed and/or conceptually designed to the degree that permitted an understanding of its capabilities and its design constraints.

Surface System -- In general, the conventional rotary drilling modules were standard oil-field equipment and required no modification for use in this system.

The flame-jet drilling modules included the equipment for the oxygen system. This equipment was readily available. The main components were

Figure 3-19. Thermal-Spallation Drilling Rig Block Diagram

the liquid oxygen storage tank, a high-pressure pump, and the high-pressure vaporization system.

The common modules of the surface system, those used for either flame-jet drilling or conventional drilling, included the air system, the water system, the fuel system, the power system, and miscellaneous components such as fire and welding equipment. The air and water systems were standard systems. The only modification required for the power system was an expanded control system because of the additional motors of the flame-jet system. One central fuel system was used to supply fuel to both the prime movers and the flame-jet burners. The miscellaneous components (fire fighting equipment, welding equipment, wire line system, etc.) were all standard oil field equipment.

Umbilical System -- The purpose of the umbilical system is to transfer the working fluids for flame-jet drilling from the surface system to the downhole burner system, and to provide a physical and electrical control link between these two systems. It is used only for flame-jet drilling operations. The main components of this system are

- Umbilical
- Transportation Reels
- Auxiliary Components

Most of these components do not exist in the form required for this type of operation. Thus, a design and test program must be conducted prior to using any of this equipment in the field.

The umbilical is the main component of the umbilical system. Its function is to provide a means for transporting air, oxygen, fuel, and water from the surface to the downhole burner system. In addition, it provides a physical means for transmitting electrical control signals and acts as a mechanical link between the two systems.

The design of this component was extremely complex because of the number of physical constraints placed upon it as follows:

- It must resist both abrasion from the flow of rock particles up the wellbore and abrasive action against the wellbore, especially when tripping into or out of a deep, deviated well.
- It must withstand a minimum temperature of 93°C (200°F).
- It must be flexible to facilitate transportation and handling.
- It must have a high tensile-load-carrying capability and a high burst strength.
- It must be oxygen resistant because one line will be exposed to an air/oxygen mixture and the outer surface will be exposed to high temperature combustion gases, steam, and a small amount of unburned oxygen.

In addition to these design problems, a very significant manufacturing problem exists. Most hoses of the type required for this system are manufactured in short lengths of less than 152 m (500 ft). Thus, special and probably very expensive, manufacturing processes must be developed. Conversation with manufacturers of hoses indicated that this may be a critical problem.

Other problems of concern include (1) the design of hose connectors that can effectively grab onto a hose that is hung in tension, (2) the destructive effect on the umbilical of the slip mechanism when it is closed in an emergency, and (3) the external configuration design of the umbilical so that a bladder type blowout preventer (BOP) can be closed on it in an emergency.

Several conceptual designs for the umbilical system were considered. They were

1. A series of concentric hoses, the exterior hose being a steel wrapped load carrying member.
2. Similar to 1, except that the inner hoses are bundled.
3. The drill string is used as the load carrying member, and the extra fluid carrying lines would be strapped to its side. A

derivation of this design, as conceived by the Linde Division of Union Carbide, utilizes casing cut in half and placed around the hose bundle.

4. Similar to 1 and 2, except that flotation modules are incorporated in the umbilical to reduce the tensile load problem.

Considering the merits and problems of all of the above systems, the second concept was used in this study (Figure 3-20). The selection was based on the fact that it was simpler and probably less expensive than the first design, and it was far more protective of the hoses involved than the third design.

The elements of the umbilical hose consist of

- Combustion Air/Oxygen Line
- Water Line
- Fuel Line
- Electric Power Cable
- Electric Communication Cable
- Boost Air Line

These elements were packaged into an umbilical according to Figure 3-20. Each element was designed in accordance with calculated flow rates and the design constraints previously discussed.

The transportation reels provide a means for transporting the umbilical hose sections from one well location to another. The reels are mounted on skids so that they can be transported by truck and then left at the well site.

The reel skids must be designed to provide:

- Capacity - 610 m (2,000 ft) of 16.5-cm (6.5-in.) OD umbilical with a 122-cm (48-in.) bend radius.
- Level wind system for controlled reeling.
- Power and braking system for reel rotation.
- Rotary valving and associated equipment to allow injection of down-hole air/oxygen, water, fuel, power, and electrical communications into the reeled or moving umbilical.

Figure 3-20. Umbilical Line Design Characteristics

A winching mechanism to provide controlled movement of the umbilical into or out of the well bore is required. This device must be capable of gripping or attaching itself to the umbilical while allowing the required controlled movement. It must be capable of handling a tension load of at least 385,600 kg (850,000 lb), which consists of the weight of the umbilical plus an overpull factor. In addition, the device must be securely mounted on the surface or attached to the conventional rotary rig substructure so that the weight of the umbilical, when hung in the well, does not physically move it.

Several mechanisms may be capable of performing this function if they were properly modified or redesigned. The first device is a pipe tensioning system used to lay subsurface pipe offshore, Figure 3-21, which could be adapted to handling an umbilical.

The second system, Figure 3-22, is a device by a French company specifically for handling umbilicals. The system uses traction mechanisms to grab the umbilical and move it as required.

The third system, Figure 3-23, is a traction winch. This device is used for pulling in or paying out cable under load. Many of these devices have been used successfully for laying cable offshore or providing a tension load on a cable.

It would be necessary to modify one of the above systems, or a combination of the above systems, to develop a mechanism that will perform the stated function. Of the systems noted, the traction winch should be evaluated first, as there is little that can be done to change the basic concept of the other two systems and thereby reduce their overall size and complexity.

The auxiliary components consist of the following subsystems:

- Umbilical Guide Structure
- Slip/Grasp Mechanism
- Fishing Tools

Figure 3-21. Pipe Tensioning System (Western Gear Corporation)

Figure 3-22. Flexible Pipe and Winching Mechanism (Foraflex, S. A.)

TOP VIEW

SIDE VIEW

END VIEW

Figure 3-23. Traction Winch (Western Gear Corporation)

The umbilical guide structure guides the movement of the umbilical from the end of the winching mechanism to a position that places it axially vertical above the well bore.

The slip/grab mechanism is used to grab and hold the umbilical in a fixed, static position in the well bore. It would be used to hold the umbilical in place in the event the winch mechanism failed or required repair when the umbilical is in the hole. A mechanism that can quickly grab and hold the umbilical without damaging it must be designed.

A set of fishing tools will be required for use with the umbilical. These tools will be used for working on the umbilical while it is in the hole. These tools will be used to retrieve the umbilical if it gets stuck or breaks off in the hole, or to cut the lower part if it cannot be freed.

Downhole Burner System -- The downhole burner system consists of the flame-jet burner and the necessary controls and guidance equipment required for the burner to function properly. This combination of equipment will be assembled in a manner similar to that of Figure 3-24. The main components of the assembly are:

- Burner
- Motor
- Valving/Control System
- Sensor System
- Steering Tool
- Thruster

Most of these elements either exist in working form or have been conceptually designed. Thus, even though a design effort will be required to obtain the system in the configuration desired, there is a technology base on which to build.

The burner is the most essential element of the flame-jet system. It produces the high-temperature, high-velocity flame jet by ignition of a mixture of fuel and an air/oxygen blend in a combustion chamber. The application of the flame-jet exhaust against the face of the rock initiates the thermal-spallation process.

Figure 3-24. Downhole Burner System

Considerable work has been done on the devices by the thermal-spallation drilling industry, thus conceptual design of the burner will not be necessary. Design work, however, will be required to determine the effects of and design requirements for a variable air/oxygen and fuel mixture. Combustion chamber design, nozzle configuration, flame geometry, etc., must all be investigated to determine optimum configuration. In addition, the equipment must be designed to operate continually and effectively in ambient downhole temperatures and work must be done to develop a reliable ignition system that will provide burner shutoff or restart when the burner is deep in the hole.

The function of the motor is to provide an axial rotating or oscillating motion to the burner. It is claimed that this motion will assist the hole-making process, particularly if a multinozzle burner is used. In addition, the rotary motion assists the shell reamers in sizing the hole and scraping away molten rock. Because it is beyond the scope of this report to discuss the merits of rotation, it will be assumed that this motion is necessary. The only serious design problem anticipated is designing the motor for high-temperature application. One possible solution to this problem is to water cool the motor by running the burner water lines around the motor. Another possible solution is to eliminate the electric motor completely and replace it with a small turbine operated by the flow of water from the burner water line.

The purpose of the valving/control system is to provide, as required, the necessary fluids for the combustion process. Combustion fluids must enter the combustion chamber at set flow rates and pressures. The design of this system is fairly simple. Most of these components are available today, and surface control can be obtained by two-way transmission of data between this system and the surface via the control cable.

The sensor system obtains and transmits position and geological data to the surface. This data consists of azimuth, inclination and tool face orientations, downhole temperature and pressure, and any additional inspection or logging-type information. The data is transmitted to the surface via the umbilical control cable.

Instrumentation and sensors to obtain this type of information are available. Packaging the instruments into an acceptable downhole container does not appear to be difficult. The temperature requirement does, however, present a serious design problem. A cooling analysis of the total downhole burner system may be required as opposed to an analysis of individual subsystems.

Steering tools are downhole devices or systems used to change the lateral direction of the drilling bit or burner. This type of tool will be necessary if any directional drilling is required, or if there is any chance that the bit or burner will wander out of hole-direction limitations when vertically drilling or burning. A number of these devices have been designed and successfully used in the field (Figure 3-25), but to find a system that is compatible with the downhole burner system will require a design effort. Further, the system must be capable of operating at the elevated temperatures specified.

Thrusters are downhole tools that place an axial load or thrust on the bit without the use of drill collars. The tool performs this function by grabbing the well wall and then applying an axial load to the bit. The well wall in turn absorbs the reaching thrust. These tools are primarily used for highly deviated or horizontal holes. Several of these devices have been built and used for experimental purposes (Figure 3-26).

For flame-jet drilling, this tool will be used for a different purpose: to stabilize the burner with regard to the well axis and direction, and in addition, to provide a way of absorbing reactive torque. The thruster, if designed properly, can provide these capabilities. From an analytical view point, it should be possible to modify available thruster designs to provide the needed requirements of the downhole burner assembly. As in the case of all other components, temperature requirements will present serious problems that must be overcome.

Control System -- The control system incorporates the controls necessary to operate both the conventional rotary rig and the flame-jet rig. Through this incorporation, both sets of controls are combined into one unified system. A schematic of this concept is noted in Figure 3-27.

Figure 3-25. Steering Tool (SMF International)

Figure 3-26. Thruster (Exxon Production Research Co.)

Figure 3-27. Conventional Rotary/Flame-Jet Drilling Rig

The basic elements of this concept are:

- Driller's Control Console
- Subsystems
- Cables, Connectors, Junction Boxes

The controls for the conventional drilling rig are similar to those of any standard drilling rig. No modification to these components is necessary except for the primary power distribution system, which must be redesigned to incorporate the ability to switch power, as required, from the conventional drilling system to the flame-jet system.

The controls for the flame-jet system would use a computer to monitor and correct fluid flow rates so that optimum combustion conditions will be obtained. Because of the distance between the downhole burner system and the surface controls, the necessary pressure, temperature, and flow rate sensors must be placed in the downhole valving/control system.

In addition to fluid control, the surface controls also monitor and control burner-feed rate, burner rotation, and burner angular movement. Other controls for monitoring and correcting surface systems will also be required. Data for these controls are obtained from the various downhole subsystems. Sensors and controls are placed on these systems as required. These data are transmitted between the various systems by a series of cable connectors, etc.

Overall evaluation of the control system indicates that no major design problems should be encountered. However, a design program will be required.

Rig Cost Summary

An estimated cost, exclusive of development costs, was made for each of the various systems and components of the thermal-spallation drilling rig. As previously stated, these costs were based, when possible, upon vendor information and engineering design judgment. Thus, error in cost estimation is possible. It can be stated that in all probability the cost

of the conventional drilling system is fairly accurate, while the cost of the flame jet may be as much as 10% to 15% too low. A tabulation of all costs involved is noted in Table 3-4.

Economic Evaluation -- A comparative evaluation of the economic characteristics of conventional drilling and flame-jet drilling operations is required to determine the economic advantages of flame-jet drilling. To obtain this information, a computer program capable of comparing both systems was developed and run to obtain comparative data.

The computer program chosen to evaluate the drilling system is designed for CP/M-based microcomputers and is structured on a spread-sheet-type format for easy problem solving. To use this program, four separate drilling models were established that would allow the required comparative analysis. These models are based on their theoretical drilling of the wells noted in Figure 3-17. A conventional drilling program model and a flame-jet drilling program model were developed for each well by fully defining, on a step-by-step basis, all the activities and operations that are required to drill the well with the stated system. In addition, the drilling activities and the respective time and cost factors for each drilling model were categorized.

To operate the model, the drilling time and/or cost of every drilling activity and/or operation is defined. The data were based on information previously established in this study or upon quotes and information received from suppliers. In addition, a variable cost factor for each drilling activity or operation was calculated. Variable costs are those costs that vary for each operation, depending upon the type of drilling system used. These costs are compiled from the drilling hourly rates, standby rates, fuel costs, supervision costs, etc.

The final output of each model program is the total or cumulative hours and costs required to drill each well in the manner specified.

Evaluation of the final data output of each of the four models indicated a large economic advantage of flame-jet drilling over conventional

Table 3-4

Thermal-Spallation Drilling Rig Cost Summary

(Note: No Development Costs are Included)

A. System/Component Cost:1. Surface System

• Conventional Drilling Modules

Mast, Substructure and Accessories	\$ 800,000	
Drawworks and Accessories	415,000	
Rotary and Traveling Equipment	260,000	
Mud Pump and Components	840,000	
Drill String	770,000	
BOP	325,000	
Handling Tools	92,000	
Miscellaneous	50,000	

• Flame-Jet Drilling Modules

Oxygen System	15,000	
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• Common Modules

Air System	745,850	
Water System	37,000	
Primary Power System	1,200,000	
Fuel System	13,000	
Miscellaneous	115,000	\$ 5,677,850

2. Umbilical System

• Umbilical	2,327,000	
• Transportation Reels	544,000	
• Winching Mechanism	1,000,000	
• Auxiliary Components		
Umbilical Guide Structure	30,000	
Slip/Grab Mechanism	75,000	
Fishing Tools	200,000	4,176,040

3. Downhole Burner System

• Burner	5,000	
• Motor	30,000	
• Valving/Control System	25,000	
• Sensor System	40,000	
• Steering Tool	75,000	
• Thruster	125,000	300,000

4. Control System

• Driller's Console		
Conventional Drilling Controls	68,700	
Flame-Jet Drilling Controls	60,000	
• Subsystems	40,000	
• Cable, Connectors, Junction Boxes	25,000	193,700
		450,000

Total System Component Cost

\$10,797,590

B. Specific Drilling System Cost:

1. Conventional Rotary Drilling System Cost	\$ 5,247,600
2. Flame-Jet Drilling System Cost	5,549,990

Total System Cost

\$10,797,590

drilling. The advantage of the flame-jet system appeared to be based on its high penetration rate, the reduced number of trips because of the long life of the burner, and the decreased trip time due to the use of the umbilical. In addition, the reduced time required to drill the wells eliminates a great deal of variable cost and time. Thus, although a higher variable rate is required for the flame-jet operation, the reduced time to drill the well and the other cost gains greatly enhance the economic advantage of the flame jet.

A review of the final data output indicates the following points:

- The use of air or oxygen in the combustion system does not appear to be a major economic factor.
- The use of sophisticated downhole tools is another area in which economics does not appear to be a major factor.
- The main economic factors involving equipment in the flame-jet system are the umbilical, the winching mechanism, and the boost air system.
- One factor not considered in the economic models was maintenance and repair costs.

Summary -- The results of this comparison indicate that flame-jet drilling performs significantly better than conventional drilling, in both total time and cost when used below 1,219 to 1,524 m (4,000 to 5,000 ft). These results are due primarily to the high penetration rate or drilling speed, the reduced number of trips due to the long life of the burner, and the decreased trip time due to the use of an umbilical. Above this depth, conventional rotary drilling performs better because of the lower cost of equipment involved.

The significant time and cost advantages of flame-jet drilling must be tempered by the fact that they are based on the assumption that the main components of the flame-jet rig can be realistically designed and that they will operate efficiently and reliably. Other factors that will temper these results are the assumptions concerning the "spallability" of the rocks in the formation. If a nonspallable rock is encountered, the flame system must be tripped to allow the rotary system to drill through this

section and then tripped back out when spallable rock is encountered. In the past, umbilical systems have been used successfully for drilling operations to depths of 1,829 to 2,134 m (6,000 to 7,000 ft). However, below those depths, the problems of an umbilical system become increasingly severe, to the point where the design becomes questionable, if not impossible. By level of design difficulty, the three most significant problem areas are the umbilical, the winching mechanism, and the fishing tools. Component-design difficulties are further compounded by the downhole temperature problem that must be addressed.

In general, the design problems of the system can be categorized into two groups: those that will require extensive research and development programs, such as the problems stated above, and those that relate to operational needs, but in fact can be solved. This second group includes the choice of an air/fuel system or an oxygen/fuel system, the need for burner rotation, the need for steering tools, and other similar problems. When considering any type of design program for this concept, the problems of the first group must be resolved first.

From a utilization standpoint, the drilling of holes for hot-dry-rock geothermal operations and the drilling of caverns for waste material disposal may present reasonable markets for the utilization of this technology.

Assuming these two market areas exist and the fact that it is possible to design flame-jet equipment that will operate to 1,829 (6,000 ft) or 2,134 m (7,000 ft), it becomes necessary to determine the utilization of these markets by depth. Below these depths, the design constraints mentioned above become increasingly severe. Thus, it becomes necessary to determine the number of hot-dry-rock reservoirs by depth and reservoir quality first. In essence, a marketing program must be done to determine the size and economics of the resource by depth so that these factors can be weighed against the cost of developing a new drilling system.

After significant depth ranges have been determined, and if a realistic market exists, research should then be done on the three main design problems. If these problems can be realistically resolved for the depth

levels established, flame-jet drilling could be seriously considered and its other inherent problems more fully evaluated.

Considering all of the above, flame-jet drilling offers the possibility of greatly reducing drilling costs in certain types of rock. The use of umbilical systems below 1,829 to 2,134 m (6,000 to 7,000 ft) for this type of application does not appear practical. Therefore, a different approach for transporting fluids and controlling the burner must be developed. A possibility might be a concentric pipe/downhole fluid separator system.

If a realistic market exists for deep flame-jet drilling, it appears advisable that prior to working on other elements of flame-jet drilling, a realistic and reliable approach to communicating with the burner system should be conceptually designed. These problems must be realistically resolved before flame-jet drilling could be considered an economic possibility.

Due to other priorities of the Geothermal Drilling Research Program, no further activities are planned for this project.

3.7 Thermal Studies of Polycrystalline Diamond Compact Drag Tools

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Project Objective

The objective of this project was to develop a numerical-analytical model to predict temperatures in PDC drag bits under downhole conditions and to determine the effects of these temperatures on bit life.

Background

The frictional heating studies of PDC cutters were begun in the latter half of FY 1979²¹ and continued during FY 1980.⁶ By the end of FY 1981, development of the preliminary analytical model was completed and comparisons of calculated temperatures and experimental data had been made. Analytical work focused on the development of a two-dimensional heat-transfer model to predict the average cutter temperature over the surface in contact with the rock. This model was used to examine three cutter configurations--mildly worn, moderately worn, and severely worn--with different cutting speeds, cooling rates, friction coefficients, and rock properties. The analysis demonstrated the sensitivity of the temperature distribution to the various parameters and identified the coefficients that needed better experimental definition.⁷

Phase I of this work was completed in FY 1982, and the results were published in References 29 and 30. The model developed was found to be in reasonable agreement with experimentally measured wearflat temperatures. Analysis of the data showed that the cutter temperatures vary directly with the friction force on the wearflat and approximately as the one-half power of the cutting speed. The data also showed that the ability of liquid drilling fluids to reduce friction is far more important in reducing operating temperatures than is their ability to provide cutter cooling.¹²

Phase II of the project to expand the numerical-analytical model was also begun during FY 1982, employing more general boundary conditions in

the study of the effects of such factors as a thicker PDC diamond layer, bit bounce, and cyclic heating and cooling. The different boundary conditions included enlargement of the thermal models to contain a portion of the bit body, thus removing the assumption of constant-temperature surfaces used in Phase I. Transient thermal modeling and thermal stress modeling were under way by the end of FY 1982, along with sensitivity studies of various parameters that control cutter temperatures.

In FY 1983, Phase II work to expand the numerical-analytical model for temperature analysis of PDC drag bits was completed, and a report of the study was published as Reference 31. A critical cutter wearflat temperature of 350°C (662°F) was determined to be the maximum operating temperature that can be tolerated without causing thermally accelerated cutter wear. A relationship was developed for determining the critical weight-on-bit, above which the cutter wearflat temperature exceeds this level. The effects of several design and operating parameters on the critical weight-on-bit were analyzed; it was concluded that a diamond layer thickness twice that conventionally used can significantly increase the weight-on-bit that can be used without exceeding the critical wearflat temperature. Analysis of transient effects associated with events such as bit bounce from drill string vibration indicated that bit bounce can significantly increase cutter temperatures from their steady state values during the critical fraction of the cycle when the cutters are in contact with the rock. Finally, a preliminary analysis of thermal stresses induced in PDC cutters under downhole conditions showed that the thermal stresses can reach levels high enough to cause yielding of the cutting structure. As FY 1983 ended, Phase III studies were begun to investigate in greater depth the relationship of temperature to the wear mechanism.¹⁶

FY 1984 Activities

The Phase III work was completed during the fiscal year, bringing the project to a close. An upper bound on the rock strength drillable without causing thermally accelerated wear was established, and numerical analyses to determine the effects of thermal and mechanical loading on PDC bit life were conducted. This second study led to the recommendation of several drilling operation precautions and microstructural design considerations

for the cutter material in order to increase bit life. Reports on both studies and their results were published as References 32 and 33. A summary of the work follows.

Maximum Drillable Rock Strength -- Previous work²⁹ has shown that the mean temperature across the wearflat of a stud-mounted PDC cutter may be approximated with the equation (see Table 3-5 for symbol nomenclature)

$$\bar{T}_w = T_f + \frac{\mu F V f}{\left[A_w \left(1 + \frac{3\sqrt{\pi}}{4} k_2 f \left(\frac{V}{\chi_2 d} \right)^{1/2} \right) \right]} \quad (1)$$

This equation can be used to define drilling conditions that cause the wearflat to exceed the critical temperature of 350°C (662°F), resulting in accelerated wear. The parameter of greatest interest in this equation is the weight-on-cutter or penetrating force, F , since the drillability of any rock is a strong function of bit weight. As defined in the earlier Phase II work³¹, the critical weight-on-bit is the maximum bit weight that can be used in a given drilling environment without causing wearflat temperatures to exceed 350°C (662°F) and thereby to experience accelerated wear.

When contact stresses at the cutter/rock interface are less than the compressive strength of the rock, penetration is achieved only by minor crushing and wear of the rock surface.³² This results in extremely low penetration rates and rapid cutter wear. At higher bit weights, the rock beneath the cutter is crushed on a larger scale, and penetration rate increases monotonically with bit weight. Therefore, for significant rock penetration to begin, bit weight must be high enough for compressive stresses at the cutter/rock interface to exceed the rock compressive strength. This idea is expressed mathematically as:

$$F/A_w > S \quad (2)$$

If the mean wearflat temperature, $\bar{T}_w$, in Equation 1 is set equal to its critical value of 350°C (662°F) and Equation 1 is solved for F and substituted into Equation 2, a relation is obtained for determining the

Table 3-5

Symbol Nomenclature

A_w	= cutter wearflat area - cm^2 (in^2)
c_2	= rock specific heat - $\text{kJ/kg}^\circ\text{C}$ ($\text{Btu/lb}_m^\circ\text{F}$)
d	= cutter wearflat length - cm (in.)
f	= thermal response function - $\text{cm}^2^\circ\text{C/W}$ ($\text{ft}^2 \text{ hr}^\circ\text{F/Btu}$)
F	= weight-on-cutter - N (lb_f)
F_c	= horizontal cutter force - N (lb_f)
F_{cr}	= critical weight-on-cutter - N (lb_f)
F_f	= cutter/rock friction force - N (lb_f)
k	= cutter material thermal conductivity - $\text{W/cm}^\circ\text{C}$ ($\text{Btu/hr ft }^\circ\text{F}$)
k_2	= rock thermal conductivity - $\text{W/cm}^\circ\text{C}$ ($\text{Btu/hr ft }^\circ\text{F}$)
q_1	= frictional heat flux into cutter - W/cm^2 ($\text{Btu/ft}^2 \text{ hr}$)
S	= rock compressive strength - MPa (psi)
$S_{\max}$	= maximum rock strength drillable without accelerated cutter wear - MPa (psi)
t	= time - seconds
T_f	= fluid temperature - $^\circ\text{C}$ ($^\circ\text{F}$)
T_w	= mean cutter wearflat temperature - $^\circ\text{C}$ ($^\circ\text{F}$)
V	= cutting speed - m/s (ft/s)
ρ_2	= rock density - gm/cm^3 (lb_m/ft^3)
μ	= friction coefficient between cutter and rock
χ_2	= rock thermal diffusivity - $k_2/\rho_2 c_2$ - cm^2/s (ft^2/hr)

maximum strength rock that can be drilled without causing accelerated cutter wear:

$$S_{\max} = \frac{(350^{\circ}\text{C} - T_f) \left[1 + \frac{3\sqrt{\pi}}{4} k_2 f \left(\frac{v}{x_2 d} \right)^{1/2} \right]}{\mu V f} \quad (3)$$

The significance of this equation is illustrated with an example. $S_{\max}$ is plotted in Figures 3-28 and 3-29 for the mildly and moderately worn cutter configurations shown in Figure 3-3. The assumptions used to compute $S_{\max}$ correspond to typical geothermal drilling conditions and are (1) a gage cutter on a 22.2-cm (8-3/4-in.), 40-cutter PDC bit, (2) an average friction coefficient of 0.07 for water and 0.16 for air, and (3) a downhole drilling fluid temperature of 100°C (212°F). The resulting values of $S_{\max}$ are shown for thermal conductivities spanning the range encountered in geothermal formations. Unconfined compressive strengths of geothermal rock types are also shown for comparison in Figure 3-29. (These are generally lower than strengths that occur under downhole confining stresses).

Figures 3-28 and 3-29 provide an approximate indication of the types of rock that can be drilled with a PDC bit under various conditions without causing thermally accelerated cutter wear. In the case of a mildly worn cutter, virtually any rock type can be drilled at low rotary speeds with either water or air cooling. Even under extremely low volumetric wear rates, however, a PDC cutter does not drill very far before a wearflat larger than that of the mildly worn configuration develops.

As the wearflat area grows, weight per cutter must be increased to maintain the same compressive stresses at the rock surface; but for the same stress level, a larger wearflat runs hotter.²⁹ This explains the reduction in $S_{\max}$ seen between Figures 3-28 and 3-29. Note that with a moderately worn cutter, hard rocks (unconfined compressive strength greater than 137.9 MPa [20,000 psi]) are drillable without thermally accelerated wear, provided bit rotary speeds are low and cutter cooling rates are high. The adverse effects of air drilling are clearly demonstrated in Figure 3-29.

Figure 3-28. Maximum drillable rock strength for mildly worn gage cutters on an 8-3/4 in., 40-cutter PDC bit. [$k_2=0.019\text{--}0.036 \text{ W/cm}^\circ\text{C}$; $\chi_2=0.008\text{--}0.015 \text{ cm}^2/\text{s}$; $T_f=100^\circ\text{C}$; air-cooled: $\mu=0.16$, $f=0.261 \text{ cm}^2^\circ\text{C/W}$ ($h=0.05 \text{ W/cm}^{20}\text{C}$); water-cooled: $\mu=0.07$, $f=0.0643$ ($h=1.0$)]

Figure 3-29. Maximum drillable rock strength for moderately worn gage cutters on an 8-3/4 in., 40-cutter PDC bit. [$k_2=0.019\text{--}0.036 \text{ W/cm}^\circ\text{C}$; $\chi_2=0.008\text{--}0.015 \text{ cm}^2/\text{s}$; $T_f=100^\circ\text{C}$; air-cooled: $\mu=0.16$, $f=1.42 \text{ cm}^2^\circ\text{C/W}$ ($h=0.05 \text{ W/cm}^{20}\text{C}$); water-cooled: $\mu=0.07$, $f=0.325$ ($h=1.0$)]

Only extremely soft rocks can be drilled with air at rotary speeds above 100 rpm. At speeds typical of downhole turbines (500 to 1000 rpm), hard rocks cannot be drilled without causing accelerated wear, even with excellent cooling.

The results shown in Figures 3-28 and 3-29 scale directly with the difference between the critical wearflat temperature, 350°C (662°F), and the downhole drilling-fluid temperature, T_f . For example, if cooling towers are used to precool the drilling fluid down to 50°C (122°F), rather than the 100°C (212°F) value assumed in these figures, S_{max} should be multiplied by a factor of $(350-50)/(350-100) = 1.2$. Thus, rock types 20% stronger than those shown in these figures can be drilled without accelerated wear.

The results also scale with the friction coefficient, but in an inverse fashion. Lower coefficients than those assumed in Figures 3-28 and 3-29 will increase the rock strength that can be drilled. Several possibilities for lowering friction and extending PDC bit life exist; these include the use of oil-base muds, polymer friction reducers, and hybrid PDC/waterjet bits.

Effects of Thermal and Mechanical Loading on PDC Bit Life -- The preceding results are based upon the empirical finding that thermally accelerated wear of PDC cutters occurs when wearflat temperatures exceed approximately 350°C (662°F). In order to understand the causes of this phenomenon, an extensive literature search was conducted. It was found that PDC cutter materials during rock cutting are susceptible to wear by structural fatigue, impact shock and fatigue, thermal shock and fatigue, and abrasion. All of these mechanisms are intensified at elevated temperatures due to reduced mechanical strength and increased thermal stresses.

Further numerical modeling was therefore performed in order to determine the conditions under which the various wear mechanisms are intensified and to identify any mitigating measures that might be taken to prevent thermally accelerated cutter wear. Stresses throughout the cutter assembly

were computed under various conditions and compared with material strengths to identify possible failure zones.³³

Cutter temperature distributions were numerically computed using transient boundary conditions at the wearflat designed to simulate actual drilling conditions. Thermal histories for the process of placing the bit on bottom and applying weight while rotating were computed. The cutter weight required to produce a desired steady-state wearflat temperature was computed from Equation 1, using the values for typical rock drilling conditions.³³ This cutter weight was then used to compute the magnitude of the transient wearflat heat flux, q_1 , according to the equation

$$q_{1\ i} = \left[\frac{\mu F V}{A_w} - \left[(\bar{T}_w)_{i-1} - T_f \right] \frac{3\sqrt{\pi}}{4} k_2 \left(\frac{V}{\chi_2 d} \right)^{1/2} \right] \quad (4)$$

where i signifies the i th time step and $i-1$ the immediately preceding one.³¹ The cutter was initially assumed to be in thermal equilibrium at the fluid temperature. The cutter weight was assumed to be applied as a step function at time $t=0$.

Thermal shock caused by a sudden, complete loss of cutter weight was simulated by suddenly changing the wearflat heating boundary conditions to convective cooling, after the cutter temperature had reached its steady-state value. Temperature distributions were then computed until the cutter cooled back down to the fluid temperature.

Stress distributions were computed using a general purpose finite element program. The cutter was modeled using two-dimensional planar finite elements assuming plane stress conditions.

The model boundary conditions were chosen to simulate the kinematic restraint provided by the bit body upon the carbide stud. The vertical boundaries of the bit body segment surrounding the stud were assumed to be fixed in both coordinate directions. Mechanical loads, which are the result of the cutting process, were applied to the model as shown in Figure 3-30. For each set of conditions, the weight-on-cutter, F , was computed as

Figure 3-30. PDC Cutter Configuration

described in the previous section and distributed over the cutter wearflat as a uniform normal stress, F/A_w . The friction force, F_f , was distributed as a shear stress over the wearflat. The cutting force, F_c , was distributed as a normal stress over the surface element nearest the wearflat on the leading diamond face.

The magnitudes of F_f and F_c were computed as follows. It was found that, with single cutter force data obtained under dry cutting conditions, the ratio of the horizontal to vertical cutting forces, $(F_f + F_c)/F$, has a typical value of 0.8. Thus,

$$F_c \cong 0.8 F - F_f . \quad (5)$$

The friction force is given by

$$F_f = \mu F \quad (6)$$

where the value of μ is taken to be 0.1 for water and 0.3 for typical air drilling conditions.³¹ Substituting Equation 6 into 5 gives the result for air:

$$F_c \cong F/2$$

(7)

It was then assumed that, although the friction force increases when using air instead of water, the cutting force does not change. Equation 8 should thus represent typical conditions for both air and water drilling.

Temperature distributions computed at each step in the transient thermal analysis were used as boundary conditions in the structural analysis. Temperature magnitude affects material properties, and gradients produce transient thermal forces that are applied to each element in the structural model.

Typical values were used for the temperature-dependent WC-Co and PDC material properties. Affected by the temperature variation are elastic modulus, yield stress, coefficient of thermal expansion, and post-yield hardening slope.

The Von Mises stress criterion was used to determine yielding of the WC-Co and diamond materials. This is an effective stress criterion that allows a multiaxial stress state to be compared directly with a uniaxial stress-strain curve for the determination of yielding. In cases where the material yielded, the effective plastic strain was also computed. The maximum principal stress distribution was computed from the stress components in order to locate tensile regions in the cutter and to determine the stress amplitudes and fatigue conditions in the bulk material.

Thermal and mechanical boundary conditions were applied that correspond to wearflat temperatures of 350° and 700°C (662° and 1292°F) produced during both water and air drilling. These temperatures bound the range for which PDC cutter wear resistance must be improved in order for conventional PDC bits to drill hard, abrasive rock economically.

The analyses were done assuming a cutter velocity of 1 m/s (3.28 ft/s). This is the approximate velocity of a cutter near the gage of a 22.2-cm (8-3/4-in.) bit drilling at 100 rpm. The cutter forces under these conditions were computed as described earlier.

The bit weight required to achieve a given cutter temperature increases with cutter wear, but at a rate less than proportional to the wearflat area. As a result, the normal contact stress between the cutter and the rock is actually lower with the moderately worn cutter. The mildly worn cutter should therefore achieve more rapid penetration at a given wearflat temperature. Air drilling greatly reduces the bit weight required to reach a given wearflat temperature. Because air drilling at a given bit weight may be faster in some formations than water drilling, no general conclusions can be drawn at this time about the effects of cooling on penetration rate for a fixed wearflat temperature.

The first results discussed are the cutter stresses that develop in the early stages of drilling. The mean wearflat temperature response for the mildly worn cutter due to rotating under an applied bit weight is shown in Figure 3-31. For both final equilibrium temperatures (350° and 700°C [662° and 1292°F]), the wearflat heats up much faster for water drilling because of the higher cutter weights required. With water cooling of the cutter, the wearflat approaches its steady-state value within one second, whereas with air cooling, it may take more than one minute.

Figure 3-31. Computed Wearflat Temperature Response for a Mildly Worn PDC Cutter in the Early States of Drilling (Initial Temperature = 50°C)

Cutter stresses in general were found to increase with wearflat temperature. The maximum stresses during drilling thus occur after the cutter

has reached thermal equilibrium. Stress distributions with water and air cooling were found to be very dissimilar. This is attributed to the differences in applied mechanical loads as well as differences in temperature distributions. With water drilling, thermal gradients on the order of $600^{\circ}\text{C}/\text{cm}$ ($2800^{\circ}\text{F}/\text{in}$) develop near the wearflat, and the bulk of the cutter and bit body remain at moderate temperatures. With air drilling, the entire cutter experiences elevated temperatures. This results in a reduction in thermal gradients of an order of magnitude.

Figure 3-32 shows the maximum principal stress distribution for the mildly worn cutter under water cooling conditions that produce a near wearflat temperature of 700°C ($1,292^{\circ}\text{F}$). The vertically cross-hatched regions are regions in which compressive stresses exist in all directions. Horizontally cross-hatched regions are regions in which tensile stresses exist in at least one direction. As seen in this figure, a compressive stress state exists in the center of the cutter and in the wearflat region, while at least one component of tensile stress develops in all other regions of the cutter.

The compressive stresses near the wearflat arise due to the interaction of thermal and mechanical loads. By comparing the compressive stresses with the temperature-dependent compressive strength of WC-Co and diamond, it was found that yielding actually occurs in the WC-Co under these conditions. The yielded regions for both the mildly and moderately worn cutters are shown in Figure 3-33. Note that the effective plastic strain is larger in the mildly worn cutter by a factor of 2.5, but the moderately worn cutter has a greater volume of yielded material due to the large thermal field developed with a larger wearflat.

Compressive yielding is highly undesirable in hard, brittle materials. Such yielding in WC-Co produces microvoids in the structure that serve as fracture initiation sites. Fractures are easily propagated in the presence of tensile stresses of even small magnitudes. As shown later, such tensile stresses in the wearflat region can develop during other stages of drilling.

Figure 3-32. Computed Maximum Principal Stress Distribution During Steady-State Water Drilling

Figure 3-33. Computed Regions of Plastic Strain During Steady-State Water Drilling

The tensile stresses seen in the diamond layer in Figure 3-32 develop as a result of the differential thermal expansion between the WC-Co and the diamond. The WC-Co expands more due to its higher expansion coefficient, which both bends and stretches the diamond layer. The maximum stress is actually just below the assumed diamond tensile strength at the local temperature in this case. If mechanical loads are suddenly removed without changing the thermal field, it is found that the maximum tensile diamond stress increases by 100%. Thus, the maximum tensile stresses due to thermal loading alone are greater than those caused by the combination of thermal and mechanical loading.

Small tensile stresses also develop along the back side of the cutter stud and along the angled clearance face to the left of the wearflat. The existence of these tensile stresses is attributed to two mechanisms. First, material in this region is placed in tension by the expansion of the hot wearflat region. Second, bending-induced strain caused by differential thermal expansion between the diamond and the WC-Co substrate near the wearflat places the clearance face in tension. These tensile stresses also increase in magnitude when the cutting forces are suddenly removed without changing the thermal field.

The stress distribution within the moderately worn cutter is similar. The wearflat stresses are slightly reduced due to lower distributed mechanical loads, while the diamond stresses exceed the tensile strength due to the larger thermal field developed by the moderate wearflat.

For the condition where the maximum wearflat temperature reaches only 350°C (662°F), the effective stress is about half that occurring at 700°C (1,292°F), so no yielding of the cutter in the wearflat region is observed. Tensile stresses in the diamond layer are also reduced at the lower temperature by about 40%. The severity of stresses at temperatures above 350°C (662°F) thus correlates with the accelerated wear experienced above this critical level.

With air as the coolant, the maximum principal stress distribution at 700°C (1,292°F) in the mildly worn cutter changes, as shown in Figure 3-34.

Figure 3-34. Computed Maximum Principal Stress Distribution During Steady-State Air Drilling

The entire diamond layer is now in tension, with much of it exceeding its tensile strength at these higher temperatures. Differential thermal expansion at the bimaterial interface is more severe due to the elevated temperature along the interface. Note that the maximum principal stress is tensile even at the wearflat. The tensile stresses at the wearflat are primarily a product of differential thermal expansion.

Stresses along the clearance face are also higher for air cooling. An analysis using a uniform expansion coefficient throughout the cutter indicated that this increase was due only partly to the diamond layer bending stresses. The stress distribution in the upper part of the cutter assembly model (see Figure 3-30) indicates that the fixed vertical boundaries of the bit-body portion of the model induce large compressive forces in the bit body and in the upper portion of the cutter stud. The expansion of the lower portion of the stud is less restrained, and as a result, tensile stress concentrations appear at the upper corners of the exposed stud. It is the interaction of these compressive and tensile strains that are responsible for the rest of the tensile stresses along the wearflat and clearance face. In reality, the bit body may have more freedom to expand than the assumed boundary condition implies; however, these effects are likely to be present to some extent and could cause fracturing of the stud at the bit body as well as increased fracture propagation along the wearflat.

The 350°C (662°F) air drilling case showed similar trends but reduced stress levels. Nevertheless, the maximum principal stress in the diamond layer with air cooling at 350°C (662°F) is very near that developed with air at 700°C (1292°F). The occurrence of tensile stresses at the wearflat and of high diamond stresses, even at the lower operating temperature, could be one reason why air drilling is so detrimental to cutter life.

The previous analyses considered only the heating phases of the cutting cycle. Rapidly cooling a cutter from an elevated operating temperature can cause additional thermal stress problems. Shown in Figure 3-35 is the wearflat temperature response during rapid quenching with water from 350°C (662°F) and 700°C (1292°F). The maximum principal stress distribution in the mildly worn cutter during cooling from 700°C (1292°F) occurs at $t = 0.24$ s and is shown in Figure 3-36. The temperature distribution at the same time is shown in Figure 3-37. The tensile stresses in the diamond are seen to increase when the mechanical loads are removed. This increase is greater for the moderately worn cutter due to the increased volume of material at elevated temperature. In this case, these tensile stresses exceed the tensile strength in some regions. Tensile stresses also develop along the wearflat and reach their maximum soon after cooling begins. This is due to the fact that the wearflat is now cooler than the adjacent material, as shown in Figure 3-37. Wearflat tensile stresses actually exceed the tensile strength of WC-Co for both worn cutter configurations. As cooling progresses, the wearflat stresses decrease in magnitude, but the size of the tensile zone increases. Finally, the tensile zone shrinks as the cutter nears thermal equilibrium. There are residual tensile stresses on the order of 200 MPa (29,010 psi) remaining as a result of the plastic deformation that occurred during heating. Again, these stresses are larger in magnitude for the mildly worn cutter, but the moderately worn cutter has a larger volume of residual stress.

The stresses developed during cooling from 350°C (662°F) with water are shown in Figure 3-38. The tensile stresses due to thermal shock are still present but are reduced in magnitude from those produced at 700°C (1292°F), especially along the wearflat and the clearance face. Since there was no yielding during the heating phase at 350°C (662°F), no residual tensile stresses were produced.

Figure 3-35. Computed Wearflat Temperature Response for a Mildly Worn PDC Cutter During Rapid Cooling from a Steady-State Water Drilling Condition

Figure 3-36. Computed Maximum Principal Stress Distribution During Rapid Cooling from a Steady-State Water Drilling Condition

Figure 3-37. Computed Temperature Distribution During Rapid Cooling from a Steady-State Water Drilling Condition

Figure 3-38. Computed Maximum Principal Stress Distribution During Rapid Cooling from a Steady-State Water Drilling Condition.

Results indicate that thermal shock effects are more severe for the moderately worn cutter due to the larger volume of material that reaches elevated temperatures during frictional heating and due to the additional cooling surface provided by the moderate wearflat. The thermal loads developed during cooling with air do not produce any additional tensile stresses of significance.

The development of destructive tensile stresses along the wearflat during rapid cooling with water prompted an analysis in which bit weight was reduced slowly over a period of 30 s while allowing the cutter to cool gradually from 700°C (1292°F). The thermal response is shown in Figure 3-39. Structural results indicate that the wearflat remains in compression throughout the cool-down phase. Shown in Figure 3-40 is the maximum principal stress distribution at the same wearflat temperature as that which produced the largest thermal stresses in the case where bit weight was suddenly removed (Figure 3-36). The maximum principal stress at the wearflat in the case with gradual bit weight reduction is compressive instead of tensile. This is caused by the fact that some mechanical loading is maintained throughout the cool-down phase. In addition, the temperature distribution shown in Figure 3-41 reveals that the gradual weight reduction maintains the necessary thermal gradients in the cutter to keep the wearflat in compression.

Conclusions -- The above results indicate that several measures can be taken during drilling to increase bit life.

1. A general recommendation can be made to prevent excess cutter temperatures by using moderation in applying bit weight. This should reduce abrasive wear, prevent plastic deformation of the cutting structure, and reduce the occurrence of thermal shock and fatigue.
2. An obvious precaution to take whenever possible is to use water or drilling mud instead of air. This will allow the use of more bit weight and will help keep thermal tensile stresses under control. Bit weight should be maintained at constant levels by using shock subs and/or drill string designs that prevent bit bounce and reduce impact and fatigue conditions.

Figure 3-39. Computed Wearflat Temperature Response During Gradual Reduction in Weight-On-Cutter from a Steady-State Water Drilling Condition

Figure 3-40. Computed Maximum Principal Stress Distribution During Gradual Reduction in Weight-On-Cutter from a Steady-State Water Drilling Condition

Figure 3-41. Computed Temperature Distribution During Gradual Reduction in Weight-On-Cutter from a Steady-State Water Drilling Condition

3. A recommendation for use under conditions leading to elevated wearflat temperatures (such as hard-rock or high-speed drilling) is to reduce bit weight slowly, rather than suddenly, when the bit is pulled off-bottom for any reason. A linear reduction in bit weight from its drilling value to zero over a period of 30 s is sufficient to eliminate computed tensile stresses resulting from thermal shock.
4. In cases where impact loading or tensile stresses in the WC-Co are prevalent, the only apparent means for improving high-temperature strength is to develop a substitute binder material with greater high-temperature strength or to improve the existing microstructure by eliminating internal flaws and voids.
5. Plastic straining of the cutter material in the wearflat region under severe operating conditions could be eliminated by improving the high-temperature yield strength and hardness of the cemented carbide.

6. Improving the thermal conductivity and reducing the thermal expansion coefficient and elastic modulus of the cemented carbide would reduce the level of thermal stress that develops in any given environment.
7. Matching the thermal expansion coefficient of the PDC and WC-Co to reduce tensile stresses on the diamond face could greatly improve the diamond's wear resistance.
8. Because of the large tensile stresses that may develop in the cutter due to the constraint provided by the bit body during air drilling, it would be desirable to reduce the thermal expansion coefficient of the bit body as much as practical. Under such conditions, bit bodies cast in cemented carbide may be preferable to steel bodies because of the substantially lower coefficient of the first material.
9. In the case of polycrystalline diamond, the ultimate tensile strength and thus fracture resistance is improved with a reduction in diamond grain size.
10. Using structurally perfect WC grains and reducing or eliminating residual porosity in the composite by hot isostatic pressing (HIP) are virtually the only means available to increase surface layer fracture resistance without increasing Co content and thereby reducing bulk strength of the cemented carbide.

Many of these conclusions relate to improvements in material properties. Such improvements, however, are likely to occur only as a result of long-term research and development. As a result, immediate or short-term improvements in the ability of PDC bits to drill hard, abrasive rocks are possible only if the drilling environment can somehow be made less severe. Because of the dominant role played by thermal loading in accelerated wear processes, work should concentrate on reducing cutter temperatures to below the critical level.

The three variables controlling cutter temperatures that can be affected to any reasonable degree are the friction coefficient, the cooling coefficient, and the weight-on-cutter or penetrating force. Previous work

by other investigators has shown that the penetrating force required to cut hard rock with drag cutters can be reduced by as much as 75% by directing waterjets onto the rock surface ahead of the cutter. Such force reductions are possible using nozzle pressure drops less than 69 MPa (10,000 psi) and should be sufficient to allow PDC cutters to drill hard rock without thermally accelerated wear. Waterjets are also capable of reducing friction at the cutter/rock interface and improving cutter cooling, both of which would improve cutter wear resistance.

As FY 1984 came to a close, the decision had been made to investigate the feasibility of using waterjet assistance downhole. Consideration was being given to the possibility of conducting single cutter tests under atmospheric and elevated ambient pressure in order to determine the nozzle pressures required to adequately reduce PDC cutter forces. If the concept proves to be workable, meaning that pressures in the range 27.6 to 55.2 MPa (4,000 to 8,000 psi) are sufficient, then work will proceed toward designing, building, and testing a hybrid PDC/waterjet drill bit for geothermal formations.

3.8 Polycrystalline Diamond Compact Single-Cutter Testing Under Simulated Downhole Pressures

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Principal Investigator: John F. McLaugh (918) 749-7888
Contract Period: December 1983 - December 1985
Contract Number: 58-0395 (Sandia)
Technical Consultants: D. Glowka (505) 844-3601
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Project Objective

The objective of this project is to characterize the PDC cutter/formation interaction under simulated downhole pressures.

Background

Comprehensive research on PDC cutter performance and formation interaction was begun in FY 1979 and has continued through this fiscal year, both by outside contractors and within SNL. The research work has addressed fabrication processes, thermal studies of the cutter, cooling of the cutter, full-scale PDC-bit laboratory and field experiments, modeling of the cutter/formation interaction, friction coefficients between the cutter and the formation, and PDC-bit design. The results of this earlier work has been reported in References 6, 7, 12, 20, 21, 22, 29, 30, and 34.

In research efforts conducted to date at SNL, on PDC cutter/formation interaction, experiments have been performed under atmospheric pressure. There is extensive evidence, however, that most rocks become stronger and fail more plastically when subjected to elevated confining pressures. The need exists to study these effects as they relate to drag cutting with PDC cutters. Data obtained under elevated pressures will provide a basis for improved bit design and reveal the utility of results obtained under atmospheric pressures.

FY 1984 Activities

At the beginning of FY 1984, a contract was placed with John Melaugh, a Tulsa, Oklahoma, consulting engineer, to refurbish an existing test cell and conduct single-cutter tests under elevated pressures. The test cell, owned by Tulsa University Drilling Research Projects, is capable of containing borehole, confining, and pore pressures as high as 103 MPa (15,000 psi). Since the test facility has not been used for several years, extensive work has been required to overhaul and upgrade the system to permit more efficient and reliable data collection.

A schematic of the test cell is shown in Figure 3-42. A cylindrical rock specimen is prepared by encasing the outer cylindrical surface in urethane rubber to prevent fluid flow through this surface and to force any porous flow to enter and exit the rock specimen through the flat end faces. The specimen is placed in the test cell and the borehole/confining pressure applied. The pore pressure at the bottom of the rock specimen is adjusted to its desired value, and rotation of the rock is established at the desired speed. The cutter is then brought in contact with the top rock surface at either a preset depth-of-cut or a penetrating force. Cutter force measurements are recorded for the first rotation of the rock specimen.

A test matrix has been established as shown in Table 3-6. Two rock types will be used, both of which are relatively hard. (Tennessee marble has an unconfined compressive strength of 117 MPa [17,000 psi], that of Nugget sandstone is 124 MPa [18,000 psi]). These rock types were chosen because they have been used extensively at SNL for atmospheric pressure tests, and the results will thus be amenable to direct comparison. Mildly and moderately worn PDC cutters will be used to determine the effects of cutter wearflat area on cutter forces. Some tests will be performed at atmospheric pressures in both an air and a water environment. Other tests with water will employ elevated borehole/confining and pore pressures up to 34 MPa (5,000 psi).

For each test condition, penetrating (vertical) and drag (horizontal) forces acting on the PDC cutter will be measured for depths-of-cut ranging from 0 to 0.15 cm (0 to 0.06 in.). From this data, friction coefficients

Figure 3-42. Single-Cutter, High-Pressure Test Cell

Table 3-6
Single-Cutter Test Conditions¹

Test Series	Fluid	Rock ²	Cutter ³	Borehole ⁴ Pressure, Mpa (psi)	Pore Pressure Mpa (psi)
A	Air	TM	mildly worn	0	0
B	Air	NS	mildly worn	0	0
C	Air	TM	moderately worn	0	0
D	Air	NS	moderately worn	0	0
E	Water	TM	mildly worn	0 ⁵	0
F	Water	TM	mildly worn	17.2 (2,500)	0
G	Water	TM	mildly worn	34.5 (5,000)	0
H	Water	TM	mildly worn	34.5 (5,000)	34.5 (5,000)
I	Water	NS	mildly worn	0 ⁵	0
J	Water	NS	mildly worn	17.2 (2,500)	0
K	Water	NS	mildly worn	34.5 (5,000)	0
L	Water	NS	mildly worn	34.5 (5,000)	34.5 (5,000)
M	Water	TM	moderately worn	0 ⁵	0
N	Water	TM	moderately worn	17.2 (2,500)	0
O	Water	TM	moderately worn	34.5 (5,000)	0
P	Water	TM	moderately worn	34.5 (5,000)	34.5 (5,000)
Q	Water	NS	moderately worn	0 ⁵	0
R	Water	NS	moderately worn	17.2 (2,500)	0
S	Water	NS	moderately worn	34.5 (5,000)	0
T	Water	NS	moderately worn	34.5 (5,000)	34.5 (5,000)

Notes:

1. All tests run at the same sliding speed of approximately 1 m/s (3.3 ft/s)
2. TM = Tennessee Marble; NS = Nugget Sandstone
3. Mildly worn cutter--wearflat extends through diamond layer only
Moderately worn cutter-- wearflat extends through WC substrate but not into cutter stud
4. Rock confining pressure equal to borehole pressure for all tests
5. Test cell filled with water, no external pressure applied

at the cutter/rock interface can be computed and the relationships between cutter forces and depth-of-cut determined. The rock and chip samples will be returned to SNL, where they will be sectioned and examined to determine rock damage characteristics and chip morphology. Such information, when combined with results obtained from similar tests at atmospheric pressure, should help determine the mechanisms of drag cutting of rock under downhole conditions. This understanding will allow development of rock-breakage models that can be used to design more efficient PDC bits.

All FY 1984 activities concentrated on refurbishing and upgrading the test cell and associated equipment. Pumps, plumbing, and control valves were cleaned and overhauled. The rock-sample holder for the test cell was redesigned to incorporate a thrust bearing in order to permit higher penetrating forces to be used than had been used in previous tests. Because of the amount of space required by the thrust bearing, it was necessary to redesign the dynamometer that holds the cutter and measures cutter forces. Rewiring of the dynamometer required the installation of new feed-through connectors for passing signal wires through the wall of the pressure vessel.

The systems for controlling both the test-cell pressures and the cutter penetrating force were upgraded to provide automatic control with a minicomputer. A minicomputer was chosen and purchased for this purpose as well as to provide data acquisition. Considerable time was also spent developing software for control and data acquisition. Finally, an uninterruptable power supply was designed and fabricated to prevent loss of data in the event of power spikes or failures.

At the end of FY 1984, system refurbishing and upgrading were continuing. It was anticipated that the system would be ready for conducting experiments by late spring of 1985.

3.9 Evaluation of the Effects of Electrical Currents on Drill Bit Wear

Sandia National Laboratories
Technical Consultant: J. Finger (505) 844-8089

Project Objective

The objective of this project is to investigate the effect of electrical currents generated during drilling on bit wear.

Background

Laboratory work by Professor S. A. Hoenig at the University of Arizona has suggested that drill bit wear decreases with reduced drilling current. In order to explore this phenomenon further, full-scale bit tests were planned, in conjunction with Professor Hoenig, in FY 1983 to test two identical milled-tooth, roller-cone bits; one to be run with an insulating collar and one without the collar. The bits will be used to drill granite, and tooth wear will be measured at regular intervals. After completion of the drilling, the bearing wear of each bit will be measured and compared.

FY 1984 Activities

The materials to conduct this investigation are on hand, and SNL's laboratory drilling rig was retrofitted with an improved data collection system during FY 1984. However, efforts under this investigation have been rescheduled for FY 1985 in order that higher priority experiments could be conducted during this fiscal year in the drilling rig facility.

4. FLUID TECHNOLOGY

The general goal of Fluid Technology research is to develop drilling fluids specifically tailored to solve problems commonly encountered in geothermal drilling. The projects include extensive study of properties of aqueous foams used in drilling applications and development of analytical tools modeling fluid flow in the wellbore. Research into high-temperature clay morphology, methods to convert clay to cement, and techniques to improve bit cleaning and cooling is also being conducted.

4.1 Aqueous Foam Drilling Fluids for Geothermal Applications

Sandia National Laboratories

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Project Objective

This project will identify or develop aqueous foams for use as drilling fluids in the underpressured formations characteristic of many geothermal areas. The foams will be capable of operating in elevated temperature environments and will exhibit chemical and foaming stability and anticorrosive and antioxidant properties.

Background

The laboratory development phase of the foam project was begun in mid-FY 1979 after publication of a survey report that outlined the technical approach to development of the foam. A laboratory apparatus was built for conducting surfactant screening tests, and during FY 1980 surfactant screening was carried out at 260°C (500°F) and at 310°C (590°F).²¹ The effects of NaCl, HCl, brines, and deionized water on the drainage time, cell structure, and pH of the surfactants at the test temperatures were observed. More than 100 surfactants were evaluated, and several, representing all general classes, demonstrated stable characteristics in all test environments. At the close of FY 1980, preparations were under way to acquire an autoclave in order to test the most promising surfactants at high pressure and high temperature.⁶

During FY 1981, the effects of temperature and pressure on the behavior and stability of foam were extensively investigated in the autoclave. In addition, stability of individual foam bubbles was investigated by studying bubble coalescence using a spinning drop interfacial tensiometer, and thermal conductivities of foams were determined using a bench-scale foam generator and thermal probes. Test facilities were also assembled to study the rheological properties of aqueous foams and the heat-transfer

characteristics of flowing foam. The high-pressure/high-temperature stability tests led to the discovery that increasing the pressure caused a large increase in the liquid drainage time, i.e., increased stability.

Investigation revealed that this effect arose from the decreased average bubble size, even at constant liquid/gas volume ratios, in foams made at high pressures. Rheological models of the liquid drainage in foams as well as experimental data established that cell size has a large effect on liquid drainage times. Also, all foams showed a large decrease in stability as temperature was increased. In the spinning drop interfacial tensiometer tests, all surfactant systems tested were affected adversely by elevated temperatures, and none of the systems produced stable thin films at temperatures above 98°C (208°F). The studies of foam thermal conductivity were completed and reported in Reference 35. By the end of FY 1981, a simple model had been developed for predicting the wellbore temperature distribution for drilling a geothermal well with drilling foam, and assembly of hardware to conduct rheology and flowing foam heat-transfer tests was nearing completion.⁷

Research to develop aqueous foams for geothermal drilling continued during FY 1982. High-temperature/high-pressure stability tests of foams using additives to improve stability identified a biopolymer, Kelco K1D-97, that increased the drainage time of a C₁₂₋₁₄ alpha olefin sulfonate surfactant by three to five times at 140°C (284°F). Construction of the foam flow heat-transfer loop was completed, and verification of the experimental facility was begun. Construction of the foam rheology test facility was also completed, and shakedown experiments with the facility were started. Development of an aqueous foam rheological model was also begun by the end of FY 1982.¹²

The three primary areas of investigation during FY 1983 remained (1) foam stability at high temperatures, (2) rheology of foams, and (3) heat-transfer characteristics of foam. Reports on the efforts in each area were prepared and published in References 36, 37, and 38.

Stability measurements and the study of viscosity-increasing additives on the most promising surfactants, such as the alpha-olefin sulfonates, were continued in FY 1983. The work in the rheology of aqueous foam included investigations of compressibility, shear-thinning viscosity, yield stress and slip at the wall, and development of models to explore the role of various physical parameters on foam drainage and to provide guidance for the design of drainage experiments. The model indicated that improved foam stability is related to small cells, liquid holdup in the films, and slow film drainage kinetics. Modifications of the experimental foam heat-transfer facility were initiated during FY 1983 after problems were encountered early in the experiments. In addition, a quasi-steady model was developed for predicting the temperature profiles of aqueous foams circulating in geothermal wellbores. Comparison of the model to the finite difference code GEOTEMP was favorable for times longer than 24 hours.¹⁶

FY 1984 Activities

The studies of aqueous foams continued throughout FY 1984 in three primary areas of investigation; (1) foam stability at high temperatures, (2) rheology of foams, and (3) heat-transfer characteristics of foam.

Foam Stability -- Foaming and stability measurements continued to be made on a comprehensive number of surfactants at ambient conditions, at high temperatures and pressures, and in different chemical environments. Alpha olefin sulfonates performed well in all environments except the sodium chloride/calcium chloride brine, and the 310°C (590°F), 0.1 M hydrochloric acid. Other surfactants including the quarternary ammonium chlorides, coco betaines, alkyl aryl sulfonates, alkyl ethoxylates, and several proprietary surfactants have also shown promise. The stability measurements on the most promising surfactants are continuing to include the study of the effects of viscosity-increasing additives (clays). The effort is aimed at developing a surfactant with broader capabilities than the alpha-olefin sulfonates and conducting a field test of the surfactant.

Foam Rheology -- Work in the rheology of aqueous foam includes investigations of compressibility, shear-thinning viscosity, yield stress and slip at the wall, and development of theoretical models to explore the role

of various physical parameters on foam drainage and to provide guidance for the design of drainage experiments. The structural parameters under study include liquid volume fraction, cell size, film thickness, and liquid-volume-fraction distribution. During FY 1984, a theoretical microstructural model of foam rheology was developed. Dissipation was included by assuming that the Newtonian liquid films separating cells experience pure stretching. The interfacial tension of the gas liquid interfaces was assumed to be constant in the simplest version of the model but surface viscosity and surface elasticity have also been incorporated. At small strains, the foam is a linear viscoelastic material. The foam response to oscillatory shear and stress relaxation have been explored and the appropriate moduli calculated. For large strains, the coalescence and disproportionation of the Plateau borders must be accounted for so that cells can separate from each other and the macroscopic structure experience flow. At specific cell orientations and at moderate strain rates, the motion of the network is periodic. The relevant material functions are obtained by averaging the instantaneous stresses over a cycle. In this way, the viscosity and normal stress differences in simple shearing flow and the tensile stress in extensional flow are obtained. At sufficiently large strain rates, viscous forces dominate surface tension forces, the cells become highly distorted and, presumably in real systems, the films would rupture, leading to material failure. Thus, by incorporating viscous forces into a microstructural model, the range of material response from linear viscoelasticity through "steady" flow through imminent material failure can be explored. The model predicts the effect of foam structure on the yield stress, the viscometric material functions, and failure criteria. The fluid mechanics in the films is treated in only an approximate manner and the foam structure is highly idealized; however, the model provides a rational basis for comparison with experimental data and represents a significant extension of previous work. A computer-generated movie that illustrates the deformation of foams at the cellular level in shearing, extensional, and other flows has been prepared. The movie graphically illustrates several deformation mechanisms at the cell level.

Heat Transfer -- During FY 1984, the Foam Flow Heat-Transfer Loop (FFHTL) was modified extensively. The metering pump used to move the water to the foam generator proved to be unsatisfactory because of large flow pulsations. A pulsation dampener was used to remove some of the pulsations; however, the resulting flow was still not adequately steady. This metering pump was replaced with a 0.57 m^3 (150 gal) water tank that was pressurized to nominally 0.69 MPa (100 psi) by means of a pressure regulator connected to the building air supply. The air blanket is maintained at a constant pressure by the regulator. Water is withdrawn from the tank through a cavitating venturi which maintains a constant flow rate depending only on the upstream pressure. The complete flow loop is shown in Figure 4-1.

The temperature profile at the exit of the 3.1-m (10-ft) long test section can be used to infer the heat-transfer rate to the foam. Temperature profiles have been measured using a chromel/alumel thermocouple mounted to a micrometer adjusted traversing mechanism. The temperature probe was fabricated by welding 0.076-mm (0.003-in.) diameter thermocouple wire and flattening the resulting bead to 0.127 mm (0.005 in.); the lead wires were brought out through a 1.59-mm (1/16-in.) diameter tube. Figure 4-2 presents representative temperature profiles for a liquid volume fraction of 0.15; the temperature has been made dimensionless by $\theta = (T - T_{CL}) / (T_W - T_{CL})$ where T_{CL} is the centerline temperature and T_W is the wall temperature. The Peclet number (Pe) is defined as $Pe = \bar{u}D/\alpha$ where $\bar{u}$ is the average velocity, D is tube diameter, and α is the thermal diffusivity. The temperature profiles exhibit a boundary layer character. As the velocity increases, the boundary layer becomes thinner. The experimental temperature profiles confirm the earlier analytical result that the thermal boundary for flowing foam develops very slowly because of the low thermal diffusivity. Aqueous foams could be characterized as a very poor heat-transfer medium. For geothermal drilling applications, this means that the foam in the outer part of the annulus could approach the local formation temperature and suffer a decrease in performance.

A mathematical model has been developed for predicting the temperature profile in aqueous foams. This model assumes that the shear-stress law for

Figure 4-1. Schematic of Experimental Apparatus

Figure 4-2. Representative Temperature Profiles

foam can be represented by the Bingham plastic model; a certain value of the shear stress must be exceeded before the foam deforms. Due to the high viscosity and low thermal diffusivity of foams, the velocity profile develops much more rapidly than the temperature profile. Figure 4-3 compares the model with the experimental data for $Pe = 53,489$. The Pe for the model was adjusted until the 95% boundary layer thickness agreed between the model and the experimental data. The rationale behind this adjustment is that the foam thermal diffusivity for the experiment was calculated from a model based on static foam experiments conducted at SNL. It is not known if the foam of this experimental series has the same bubble-size distribution as the earlier work because of differences in foam generator and test section pressure. At present, the computer model does not account for the fact that the experimental temperature profile was taken approximately 13.97 cm (5.5 in.) downstream of the end of the isothermal test section. This 13.97-cm (5.5-in.) section has a near adiabatic boundary condition because the pipe walls have low thermal conductivity and the outside of the pipe is well insulated. The experimental profile demonstrates the adiabatic boundary condition while the computer model has a specified temperature boundary condition. Over the central portion of the temperature profile where the 13.97-cm (5.5-in.) adiabatic section does not seriously alter the temperature profile, there is reasonably good agreement between the computer model and the experimental data. Future additions to the computer model will include the ability to have an adiabatic section after the isothermal section.

Pressure drop as a function of flow rate has been measured for several liquid volume fractions; these results are summarized in Figure 4-4. At the present time, only the measurements for a liquid volume fraction of 0.20 are reasonably complete. The Bingham plastic model suggests that for large wall shear stress (or pressure drop), the average velocity is a linear function of wall shear stress. The limited amount of data seems consistent with this linear relationship. At low values of wall shear stress, the yield stress of the foam becomes very important and theory indicates a curved relationship between velocity and wall shear stress. Unfortunately, the wall shear stress is not close enough to the yield stress to allow an estimate of yield stress from the experimental data. At

Figure 4-3. Comparison of Temperature Profile for Experiment ($Pe = 53,489$) and Model ($Pe = 24,000$)

Figure 4-4. Average Velocity as a Function of Wall Shear Stress

the present time, measurement of the low flow rates cannot be made with sufficient accuracy to obtain data in this range; this problem will be solved by purchasing some additional flow meters and pressure transducers. After the complete range of liquid volumes has been explored, the velocity versus wall shear stress data will be used to determine a foam viscosity versus liquid volume fraction model.

Future plans include additional temperature profiles and pressure drop data for the flow rate and liquid volume fraction range of interest. As more data are obtained, the computer model will be further refined. Models will also be developed for predicting flow in geothermal wellbores.

4.2 Wellbore Thermal Code

Sandia National Laboratories
Technical Consultant: L. Duda (505) 844-2377

Project Objective

The objective of this project was to correct, revise, and update the advanced Wellbore Thermal Code, GEOTEMP2.

Background

The development of the thermal wellbore simulator, GEOTEMP2, for prediction of transient wellbore temperatures during drilling, circulating, injection, and production in geothermal wells was completed in FY 1981. Complete documentation of the code and the final research report were published as References 39, 40 and 41. The key features of the GEOTEMP2 Code are (1) a finite difference scheme using cylindrical geometry and axial symmetry and (2) fully transient heat conduction for both the wellbore flowing stream and the formation. The wellbore fluid flow options include injection and production, forward and reverse circulation, inlet temperature change, flow-rate change, fluid properties, multiple fluids in the wellbore, different drilling fluids (mud, air, or nitrogen), and two-phase steam injection or production.

Since the code's publication, several problems and errors were detected during exercise of the simulator. During FY 1983, the errors were corrected and the preparation of a revised GEOTEMP2 user manual and code listing began.¹⁶

FY 1984 Activities

During FY 1984, the GEOTEMP2 computer code was revised and used to simulate wellbore cooling by the circulation of various fluids at various flow rates. Final reports on this effort were published as References 42 and 43. Also during the fiscal year, a simulation was conducted of cooling by fluid injection. A summary of this work follows.

Circulation Cooling -- Computer calculations of transient temperatures using the GEOTEMP2 computer code were made on four geothermal well models. The four well models studied were Baca, Salton Sea, East Mesa, and a deep well in the Salton Sea area. Calculations were done using the wellbore models at flow rates of 6.3, 16, 32, and 63 ℓ/s (100, 250, 500, and 1000 gpm) for a one-day circulation time and a one-day shut-in period using water as the circulating fluid. In addition to this, calculations were done for the Baca and Salton Sea well model using either fluids other than water or modified wellbore geometries.

For the Baca well model, calculations using three values of the soil thermal conductivity, k , were made to observe the effect of k upon the downhole temperatures (Figure 4-5). It was found that lower values of k produced lower temperatures down the well during circulation and delayed the warming of the fluid after shut-in. Calculations were made with a water circulation time of 20 days. It was found that downhole temperatures were cooler both during circulation and following shut-in. The observed temperature differences between 1 and 20 days were greatest for the highest flow rate while soil thermal conductivity had a smaller effect. At a flow rate of 63 ℓ/s (1000 gpm) a temperature difference of 50°C (122°F) was obtained 5 hours after shut-in, and this difference was maintained through the rest of the one-day shut-in period.

In addition to water, two other circulating fluids were used in the Baca well model. A mud with a viscosity of 0.015 Pa·s (15 cp) and the same density as water was found to produce lower downhole temperatures during circulation and cooler temperatures at a specified time after shut-in than in the comparable case using water. This difference was attributed to the reduced heat-transfer rate of the mud with respect to water. Calculations were made using air as the circulating fluid at flow rates chosen to correspond to the mass flow rates of the calculations made at water flow rates of 16 and 63 ℓ/s (250 and 1000 gpm). The results of the calculations showed that air is completely ineffective as a cooling agent since bottom-hole temperatures were reduced less than 10°C (50°F) from the undisturbed temperature at the highest flow rate.

Figure 4-5. Bottom-Hole Temperatures as a Function of Time During Circulation and Following Shut-In at Four Flow Rates and Three Soil Conductivities for the Baca Well Model. k is the soil thermal conducting units of $\text{W/m}\cdot\text{K}$ ($\text{Btu/ft}\cdot\text{hr}\cdot^\circ\text{F}$).

For the Salton Sea well model, calculations were made at four water flow rates using $k = 1.73 \text{ W/m}\cdot\text{K}$ ($1.0 \text{ Btu/ft}\cdot\text{hr}\cdot^\circ\text{F}$). The results, as in the Baca well model, showed that the greater flow rates produced greater cooling. Bottom-hole temperatures tended to reach a value of one-half the difference between the undisturbed temperature and the minimum temperature achieved during circulation at a time approximately 3 hours after shut-in.

Two modifications were made to the wellbore geometry of the Salton Sea well model. In the first modification, the fourth casing, which extended from the surface to the bottom of the hole, was removed. The calculations showed that the removal of the fourth casing did not alter the minimum bottom-hole temperatures obtained after one day of circulation (Figure 4-6). However, the shape of the warming curves was affected so that the bottom-hole temperatures reached a value of one-half of the difference between the undisturbed temperature and the temperature after one day of circulation at a time of 5 hours, rather than 3 hours as in the original calculations, following shut-in. The second modification to the standard wellbore consisted of reducing the tubing diameter by a factor of about two. In these calculations the downhole temperatures were found to be significantly cooler than for either the standard wellbore or the three-casing case (Figure 4-7). Cooler bottom-hole temperatures were found but the time required to reach a temperature of one-half the difference between the undisturbed value and the minimum value was comparable to the standard wellbore and the three-casing case. The much cooler temperatures were attributed to the greater fluid velocity within the tubing due to the reduced tubing diameter. The cooling effect for this case was more pronounced at the lower flow rates than at the higher flow rates.

For the East Mesa well model, four flow rates were studied using a soil thermal conductivity value of $1.73 \text{ W/m}\cdot\text{k}$ ($1.0 \text{ Btu/ft}\cdot\text{hr}\cdot^\circ\text{F}$). The flow rate of 6.3 l/s (100 gpm) was found to be ineffective in cooling the wellbore in agreement with the results of the previous well-model calculations. The warming times following shut-in were comparable to results from the other well models though the temperatures tended to be cooler due to the lower maximum undisturbed temperature compared to the Baca or Salton Sea well model.

Figure 4-6. Downhole Temperature Profiles Inside the Tubing at Times of 0, 2, 5, 10, 12, 16, and 24 Hours Following Shut-In at Four Flow Rates for the Salton Sea Well Model. Three casings were used in the wellbore. The dashed line is the undisturbed temperature gradient.

Figure 4-7. Downhole Temperature Profiles Inside the Tubing at Times of 0, 2, 5, 10, 12, 16, and 24 Hours Following Shut-In at Four Flow Rates for the Salton Sea Well Model. A reduced tubing diameter was used in the wellbore. The dashed line is the undisturbed temperature gradient.

For the case of the deep Salton Sea well model, the downhole temperatures were found to be considerably higher than for the other well models. This result is due to the much greater depth, which allows the fluid more time to warm, and to the shape of the undisturbed geothermal gradient, which heats up the fluid at shallow depths thus reducing the potential cooling effect at greater depths.

Conclusion -- Some conclusions about the cooling effect of circulation can be made as a result of this study. It is necessary to note that the calculations reported here treated heat transport only by conduction within the soil formation. In a real reservoir, other heat-transport processes, such as convection of the fluid away from the wellbore or the presence of substantial fluid flow in the reservoir, can significantly modify the temperatures observed in the wellbore. The conclusions that can be drawn from this study are

- Higher flow rates produce the greatest cooling within the wellbore.
- Low flow rates, on the order of 6.3 l/s (100 gpm) or less, are particularly ineffective at cooling the wellbore.
- Low soil thermal conductivity values produce lower wellbore temperatures due to the reduced rate of heat transfer.
- High-viscosity fluids, such as drilling muds, give lower wellbore temperatures because of the lower heat-transfer rate.
- Air or gas are ineffective as a cooling fluid.
- The bottom-hole temperatures of deep wells tend to be much warmer than for a shallow well during and after circulation, holding all conditions the same, due to the greater equilibration time of the fluid in the wellbore.
- Downhole temperatures are not directly proportional to circulation time; the minimum downhole temperature is asymptotically approached as a function of time with short circulation times quickly approaching the limit.
- The shape of the undisturbed temperature profile has a significant effect upon the downhole temperatures; high initial gradients tend to warm the fluid on the way down thus reducing the amount of cooling further down the hole.

- An increased fluid velocity in the tubing, whether due to higher flow rates or a reduced tubing diameter, tends to decrease the downhole temperatures in the wellbore.

Fluid Injection Cooling — In this study, two wells from the Salton Sea were simulated.⁴⁴ The first is a shallow well having a depth of 1,400 m (4,593 ft) and a bottom-hole temperature of 330°C (626°F). The second is a deep well of depth greater than 3,000 m (9,843 ft) and a bottom-hole temperature of 380°C (716°F). In each well the effect of changing the fluid flow rate and fluid properties upon the wellbore temperatures were studied for the case of heat transfer by conduction within the rock formation. The rate of warming of the fluid at the bottom of the hole after shut-in, when injection was simulated, was compared to the circulation case.

Even though circulation is an effective method for wellbore cooling, temperatures will rapidly rise once circulation has stopped.⁴³ The problem is that the rock formation surrounding the wellbore is generally not cooled very much by heat conduction when fluid is circulating in the wellbore. The rock may be cooled to a lower temperature at a greater distance from the wellbore if the fluid is injected or can be transported by convection into the rock. The results of calculations simulating injection at the bottom of the hole are shown in Figure 4-8 for the shallow well. After shut-in, the temperatures rapidly increase for the circulation case, but for injection the warming rate has been substantially slowed. For example, the bottom-hole temperature for the 16-l/s (250-gpm) flow rate has increased only 30°C (86°F) at one day following shut-in compared to a temperature rise of 185°C (365°F) for the conduction case.

Figure 4-9 shows the calculations for the deep well. Qualitatively, the results are similar to the shallow well case except for the higher temperatures due to the greater well depth. Fluid injection even a short distance (less than 1 m [3.3 ft]) into the formation is an effective method to maintain cool wellbore temperatures for a reasonable time after shut-in. It is important to note that these calculations were done for fluid injection only at the bottom of the well. The fluid in the wellbore above this point was not affected by the injection and thus warmed quickly after

Figure 4-8. Bottom-Hole Temperatures Inside the Tubing for the Shallow Salton Sea Well. The solid lines show temperatures for one day of circulation followed by shut-in for the pure conduction case. The dotted lines are the shut-in temperatures when fluid was injected at the bottom of the hole.

Figure 4-9. Bottom-Hole Temperatures Inside the Tubing for the Salton Sea Elmore Well for Circulation and Shut-In and for Circulation and Injection

shut-in. Hence, to be an effective cooling method, the fluid must be allowed to infiltrate over most of the wellbore rather than over a small region.

4.3 Drilling Fluid/Cement Studies

Contractor: Texas Tech University
Principal Investigator: N. Guven (806) 742-3110
Contract Period: 1 October 1981 to 30 November 1984
Contract Number: 68-4752, 37-2331, and 47-7665 (Sandia)
Technical Consultants: L. Duda (505) 844-2377

Project Objective

The objective of this project was to study the formation of cement minerals in drilling fluids by observing the rheological changes in bentonite-based muds before cement formation.

Background

This project is a follow-on effort to the extensive studies previously conducted to develop a fundamental understanding of clay particle morphology under the influence both of various chemical species and elevated temperatures similar to the conditions encountered during geothermal drilling activities. On the basis of this understanding, clay-based geothermal drilling-fluid systems, complete with the additives dictated by downhole conditions, were designed for use in geothermal drilling. The results of this earlier work were published as Reference 45.

Phase I of the study of the formation of cement minerals in drilling fluids was completed in FY 1982. The study included experiments on the effect of additives on the viscosity of bentonite drilling fluid, and the data showed that salts and hydroxides of potassium provide excellent control of the fluid viscosity at high temperatures. The addition of lime was found to increase the fluid pH and promote the high-temperature reaction between bentonite and lime, with the precipitation of tobermorite, the common cement mineral. Phase II was begun near the end of FY 1982 to study the factors that control cement setting in bentonite drilling fluids and to investigate the accelerating and retarding effects of additives on the conversion of clay minerals to cement minerals.¹²

Phase II of the study of clay to cement conversion was completed in FY 1983, and preparation of a final report on Phases I and II was begun. The Phase II work conducted in FY 1983 was concerned with the effects of additives on cement reactions in bentonite drilling fluids. The fluid preparations were autoclaved under increasing temperature and constant pressure with the systematic addition of various additives. The changes in the physical properties and in the rheology of the fluids were measured and then correlated with the high-temperature mineral reactions in the fluids. The data showed that neither the addition of gypsum or free silica promotes the mud-to-cement conversion. However, the addition of 1% CaCl_2 to the bentonite/lime fluid lead to the total conversion of bentonite to tobermorite.

Also during FY 1983, an evaluation of the mineralogical and rheological properties of three different samples of Australian bentonite was conducted. The samples were very similar in mineralogical composition, but differed significantly in their high-temperature rheological properties. This difference was attributed to varying amounts of nonmineral constituents, possibly polymers.¹⁶

FY 1984 Activities

During the fiscal year the final report on Phases I and II was prepared for publication as Reference 46 and a new effort, Phase III, was initiated. A summary of the FY 1984 investigation follows.

The Phase II studies on bentonite fluids and on its conversion to cement was carried out in fluids containing a purified bentonite with a montmorillonite content of 98%. Because of the purified materials, the fluids were prepared at unrealistically low concentrations in order to avoid gellation. These purified and low-concentration fluids were necessary to understand the high-temperature reactions of montmorillonite. The purpose of the Phase III studies, which began in FY 1984 and were continuing as the fiscal year ended, is to see how the real muds behave under more realistic (field) conditions. A commercial bentonite, such as the one known under the trade name "Federal bentonite" from Wyoming, was tested with all its impurities at 8% concentration.

Saponite is the magnesium analog of montmorillonite; although the latter has been the most popular material (from Wyoming), saponite has not yet been considered for use in drilling fluids. Saponite occurs in large quantities in the Western United States (especially in Nevada). A commercially available saponite from Nevada was evaluated in a similar manner as the Federal bentonite.

The fluid systems examined during FY 1984 are listed in Table 4-1. These fluids were autoclaved at the temperature range 149° to 316°C (300° to 600°F) under 110 MPa (16,000 psi). The high-temperature rheology of these fluids was evaluated with a FANN 50C viscometer before and after autoclaving. Other fluid properties such as plastic viscosity, gel strength, yield point pH, CEC (cation exchange capacity), fluid loss, etc. were also measured. A summary of the results obtained during the fiscal year follows.

Table 4-1

Fluid Systems Tested During FY 1984

1. 8% Federal Bentonite
in distilled water	9. 8% Saponite in
in distilled water
2. 8% Federal Bentonite
1% Lime	10. 8% Saponite
1% Lime
3. 8% Federal Bentonite
1% CaCl_2	11. 8% Saponite
1% CaCl_2
4. 8% Federal Bentonite
1% CaSO_4	12. 8% Saponite
1% CaSO_4
5. 8% Federal Bentonite
1% Na_2CO_3	13. 8% Saponite
1% Na_2CO_3
6. 6% Federal Bentonite*
1% Na_2SO_4	14. 8% Saponite
1% Na_2SO_4
7. 8% Federal Bentonite
1% K_2CO_3	15. 4% Saponite*
1% K_2CO_3
8. 10% Federal Bentonite*
1% KCl	16. 8% Saponite
1% KCl

* The clay concentration was changed to a higher or lower value in order to have meaningful viscosity for the fluid.

Pure Bentonite and Saponite Fluids -- A pure 8% Federal bentonite fluid showed a rheology profile as expected from a bentonite. The rheogram in Figure 4-10 shows a broad viscosity "hump" for the pure 8% Federal bentonite fluid. This viscosity hump, however, disappears when the fluid is autoclaved at high temperatures (149° to 316°C [300° to 600°F]) as displayed in Figure 4-10. In fact, the fluid that was autoclaved at 149°C (300°F) shows a stable viscosity ranging from 0.017 Pa·s (17 cps) at 38°C (100°F) to 0.01 Pa·s (10 cps) at 121°C (250°F), and increasing back to 0.02 Pa·s (20 cps) at 260°C (500°F). The plastic viscosities, the yield point, and gel strength of the 8% Federal bentonite fluid showed a significant increase with higher temperature. Similarly, the fluid losses (API filtrate and HP-HT filtrate) became higher with the increasing temperature.

The 8% saponite displayed a viscosity of 0.024 Pa·s (24 cps) at room temperature before the heating. The viscosity was slightly increased at 93°C (200°F), and it sharply decreased above that temperature; it became extremely thin above 149°C (300°F) as illustrated in Figure 4-11. This drastic reduction of viscosity was also found in the autoclaved 8% saponite fluids (Figure 4-11).

Bentonite/Lime and Saponite/Lime Fluids -- The viscosity profile of a 8% bentonite/1% lime fluid before and after autoclaving is displayed in Figure 4-12. The viscosity of the untreated fluid suffered large viscosity reductions when the temperature was raised above 38°C (100°F). The autoclaved bentonite/lime fluids displayed little viscosity at high temperature with the exception of the fluid that was autoclaved at 204°C (400°F). As shown in Figure 4-12, the latter fluid shows a small viscosity "hump" at 149°C (300°F).

The addition of lime to the saponite fluid affected very little the viscosity of the fluid before autoclaving. As indicated by Figure 4-13, the saponite/lime fluid displayed a viscosity maxima at 232°C (450°F). The autoclaved saponite/lime fluids behave like the bentonite/lime fluids. They showed very little viscosity after the autoclaving at 149° to 260°C (300° to 500°F) temperature range. It is interesting to note the fluid

Figure 4-10. Viscosity Profile of a Fluid Composed of 8% Federal Bentonite in Distilled Water after Autoclaving at Temperatures Marked Next to the Curves

Figure 4-11. Viscosity Profile of a Fluid Composed of 8% Saponite in Distilled Water after Autoclaving at Temperatures Marked Next to the Curves

Figure 4-12. Viscosity Profile of a Fluid Composed of 8% Federal Bentonite and 1% Lime

Figure 4-13. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% Lime

regained considerable amounts of viscosity when it was autoclaved at 316°C (600°F).

Bentonite/CaCl₂ and Saponite/CaCl₂ Fluids -- The addition of 1% calcium chloride to the bentonite fluids was detrimental to the viscosity of the fluids that were autoclaved at 149° to 316°C (300° to 600°F). The rheological profile of the 8% bentonite/1% CaCl₂ fluids are given in Figure 4-14. Only the untreated fluid showed some viscosity (around 0.005 Pa·s [5 cps]) without any significant variation between 21° to 260°C (70° to 500°F), as indicated in Figure 4-14.

Figure 4-14. Viscosity Profile of a Fluid Composed of 8% Federal Bentonite and 1% CaCl₂

The addition of 1% calcium chloride to saponite fluid drastically reduced the viscosity for the unheated fluid and for the fluids that were autoclaved at 204° and 316°C (400° and 600°F). As shown in Figure 4-15, the fluids autoclaved at 149° and 260°C (300° and 500°F) displayed a remarkably stable viscosity, especially after autoclaving at 260°C (500°F).

Bentonite/CaSO₄ and Saponite/CaSO₄ Fluids -- The addition of 1% CaSO₄ to the 8% bentonite or to 8% saponite exerted similar effects on the fluid rheology. The viscosity profiles are represented in Figures 4-16 and 4-17. The initial viscosities of these fluids were rather low and they became extremely thin with increasing temperatures.

Bentonite/Na₂CO₃ and Saponite/Na₂CO₃ Fluids -- An 8% bentonite/1% Na₂CO₃ fluid displayed a rather favorable viscosity profile from 21°C (70°F) to 149°C (300°F). As illustrated in Figure 4-18, the fluid showed a pronounced viscosity hump from 149° to 232°C (300° to 450°F). However, where the fluid was autoclaved, especially at 260° or 316°C (500° or 600°F) prior to the FANN 50C measurements, the fluid showed very little viscosity.

The 8% saponite/1% Na₂SO₄ fluid before autoclaving showed a different viscosity profile from that of the above bentonite fluid. A smaller viscosity hump developed between the temperature range 21°C to 121°C (70° to 250°F); the viscosity drastically dropped above 121°C (250°F). Thus, the behavior of the saponite fluid is in contrast to that of bentonite fluid. This suggests that a mixture of bentonite/saponite in the fluid may show rather favorable viscosity. High-temperature autoclaving of the saponite fluid caused drastic thinning; the fluid autoclaved at 316°C (600°F) became extremely thin as shown in Figure 4-19. Within the temperature range of 149° to 260°C (300° to 500°F), the autoclaved fluids displayed a small "hump" but at progressively higher temperatures than the fluid before autoclaving.

Bentonite/Na₂SO₄ and Saponite/Na₂SO₄ Fluids -- The addition of 1% Na₂SO₄ considerably depressed the viscosity of the bentonite fluid before the autoclaving. As shown in Figure 4-20, this fluid displayed a noticeable viscosity maximum at 204°C (400°F). The bentonite/Na₂SO₄ fluids

Figure 4-15. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% CaCl₂

Figure 4-16. Viscosity Profile of a Fluid Composed of 8% Federal Bentonite and 1% CaSO₄

Figure 4-17. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% CaSO₄

Figure 4-18. Viscosity Profile of a Fluid Composed of 8% Bentonite and 1% Na₂CO₃

Figure 4-19. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% Na₂CO₃

Figure 4-20. Viscosity Profile of a Fluid Composed of 6% Federal Bentonite and 1% Na₂SO₄

showed a very different profile after autoclaving (Figure 4-21). The autoclaved fluids had a rather high initial viscosity, but they became rather thin above 93°C (200°F). For instance, the fluid autoclaved at 260°C (500°F) had a viscosity of 0.0277 Pa·s (27.7 cps) at 24°C (75°F), but the viscosity steadily dropped to 0.0056 Pa·s (5.6 cps) at 260°C (500°F).

The detrimental effect of Na₂SO₄ on the fluid rheology was even worse for the saponite fluid. Figure 4-21 shows that all the fluids in this system displayed high initial viscosities, but they drastically dropped with the higher temperatures.

Bentonite/K₂CO₃ and Saponite/K₂CO₃ Fluids -- The addition of 1% K₂CO₃ drastically reduced the viscosity of the unautoclaved fluid below 121°C (250°F) as indicated by Figure 4-22. The fluid developed a viscosity maximum of 0.0115 Pa·s (11.5 cps) at 177°C (350°F). The autoclaved fluids did not show any viscosity hump but they were rather thin except for the fluid autoclaved at 149°C (300°F). The viscosities of the saponite fluid before autoclaving was higher than those of bentonites at temperatures below 66°C (150°F). As shown in Figure 4-23, the saponite fluid became extremely thin above 121°C (250°F). The fluids autoclaved at 149° and 204°C (300° and 400°F) showed initial viscosities around 0.019 to 0.022 Pa·s (19 to 22 cps) but they sharply dropped above 66°C (150°F). The fluids autoclaved at 260° and 316°C (500° and 600°F) became extremely thin.

Bentonite/KCl and Saponite/KCl Fluids -- The addition of 1% KCl to bentonite and saponite fluids destroyed the fluid viscosities as illustrated in Figure 4-24 and 4-25. The bentonite fluid before autoclaving still maintained some viscosity in the range of 0.005 to 0.006 Pa·s (5 to 6 cps). After autoclaving the fluids became extremely thin.

Figure 4-21. Viscosity Profile of a Fluid Composed of 4% Saponite and 1% Na₂SO₄

Figure 4-22. Viscosity Profile of a Fluid Composed of 8% Bentonite and 1% K₂CO₃

Figure 4-23. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% K_2CO_3

Figure 4-24. Viscosity Profile of a Fluid Composed of 10% Bentonite and 1% KCl

Figure 4-25. Viscosity Profile of a Fluid Composed of 8% Saponite and 1% KCl

5. BOREHOLE MECHANICS

The Borehole Mechanics program emphasizes research concerning borehole stability during drilling, completion, and maintenance. Specific areas of interest include lost circulation, lining and cementing the well, and casing structural failure.

5.1 Lost Circulation Test Facility

Sandia National Laboratories
Technical Consultants: G. Loeppke (505) 846-0301
B. Caskey (505) 844-8835

Project Objective

The first objective of this project was to construct a facility having the capability to test lost circulation materials and techniques under simulated geothermal conditions. The subsequent objective is to use the facility to evaluate materials and techniques for use in solving problems associated with completion and lost circulation in geothermal wells. The final objective is to recommend the proposed solutions that stand the best chance for success in the field; thus, the facility will serve as a final screening facility before field testing.

Background

A substantial portion of the cost associated with drilling and completing a geothermal well can be attributed to lost circulation problems and poor cement displacement. Lost circulation that occurs during drilling may increase the drilling costs by 15% or more, while incomplete cementing jobs can result in loss of the well. The efforts to establish a test facility and a materials/techniques evaluation program to develop solutions to lost circulation/cementing problems were begun in mid-FY 1980. A survey of industry was conducted to determine whether suitable test facilities were available. Only one facility, a Halliburton test apparatus, was found with capabilities similar to those required for this project. However, the Halliburton facility was scheduled for exclusive long-term use in cement studies by a major oil company. Also, the facility had an operating temperature of less than 121°C (250°F), which is below the temperatures that may be encountered in geothermal wells. Because of the lack of availability and the limited temperature, it was concluded that a new, high-temperature facility that could be devoted to lost circulation material studies was required. The design of the facility was under way by the end of FY 1980.⁶ The detailed design of the test facility was completed during

FY 1981. The fabrication and procurement of components continued throughout FY 1981, and modification of the laboratory building to accommodate the facility was begun.⁷

The modification of the laboratory building was completed in FY 1982, and procurement, fabrication, and assembly of components and subsystems continued throughout the fiscal year. A control and instrumentation system, including the necessary computer software and hardware, was designed, assembled, and installed to provide the required control, monitoring, data gathering, and display of the operation of the test facility. As FY 1982 came to a close, final assembly and connection of all subsystems were under way in preparation for system shakedown tests.¹²

During FY 1983, the assembly of the Lost Circulation Test Facility was completed, and the facility was successfully proof-tested. Also, a series of tests of a lost circulation material (Thermo-Set Seal) was begun. A description of the facility and its operation was published in Reference 47, and a report of the initial lost circulation material test results appears in Reference 48. The shakedown tests conducted in early FY 1983 illuminated some problems during the operation of the facility, and consideration was being given to the design of a second generation test vessel as the fiscal year ended.

Tests, begun during FY 1983, of the plugging ability of the lost circulation material Thermo-Set Seal were still in progress as the fiscal year ended. The initial tests demonstrated that Thermo-Set Seal would reliably plug slot sizes up to 1.6 times the average particle size of the largest 25% of the particles.¹⁶

FY 1984 Activities

During FY 1984, the Thermo-Set Seal test series were completed, and improvements to the Lost Circulation Test Facility, including a new test vessel, were undertaken. In addition, a tool for plugging lost-circulation zones was demonstrated.

Thermo-Set Seal Tests -- A total of 109 tests was run using Thermo-Set Seal material, the most promising material found in earlier modified API slot tester evaluations. The tests included coarse, medium, and fine material grades; differential pressures of 0.7 to 4.1 MPa (100 to 600 psi); cross-flow from 0 to 1.0 m/s (0 to 200 ft/min); ambient temperature (except one test at 93°C [200°F]); impermeable core with modified API slot sizes from 0.102 to 1.27 cm (0.040 to 0.250 in.); and concentrations of 14.3, 28.5, and 57.1 kg/m³ (5, 10, and 20 lb/bbl) in bentonite mud having a viscosity of 0.03 ± 0.005 Pa·s (30 ± 5 cp). The results of the Thermo-Set Seal material tests are presented in Tables 5-1, 5-2, and 5-3 and showed (1) the coarse grade behaved differently than the medium and fine grades, (2) no significant plugging effect due to slot orientation, (3) no observable effect due to cross-flow, and (4) Thermo-Set Seal will reliably plug slot sizes up to 1.6 times the largest particle sizes.

Lost Circulation Test Facility Improvements -- The Lost Circulation Test Facility, Figure 5-1, is a full-scale test facility built to investigate the mechanics and constraints of lost circulation and to evaluate LCMs under simulated downhole geothermal wellbore conditions. The initial features of the facility included a test vessel to simulate a wellbore, a full-scale mud and cementing system, auxiliary equipment required for cementing and mud-flow operations, and a control system capable of monitoring and analyzing all component and experimental operations. The system test capabilities include a maximum wellbore temperature of 204°C (400°F), a maximum allowable working pressure of 7.9 MPa (1,150 psi), and a variable pumping rate up to 0.02 m³/s (280 gal/min) at 6.9 MPa (1,000 psi). The simulated wellbore is 50.8 cm (20 in.) in diameter and 81.3 cm (32 in.) in length.

Experience with the Lost Circulation Test Facility surfaced problems with regulator contamination, pumping capability, flow-rate measurement, and system clean up. The test vessel was also found to be more suited to qualitative than quantitative analysis. In order to overcome the shortcomings observed during operation of the test facility, design of a second-generation test vessel was begun in FY 1984. The new design provides for annular flow, flow velocity to 1.0 m/s (200 ft/min), elimination of

Table 5-1

Lost Circulation Test Results - Thermo-Set Fine

Test Number	Differential Pressure MPa (psi)	Cross Flow, m ³ /s (gal/min)	Mud Pump Flow, m ³ /s (gal/min)	Slot Size cm (in.)	LCM Concentration kg/m ³ (lb/bbl)	Filtrate Accumulated m ³ (gal)	Results	Remarks
1	1.5 (220)	.010 (153)	.010 (165)	.102 (.040)	14.3 (5)	.015 (4)	Plugged	
2	1.5 (220)	.009 (138)	.009 (150)	.102 (.040)	14.3 (5)	.015 (4)	Plugged	Held up to 4.3 MPa (630 psi)
3	1.4 (200)	.016 (247)	.016 (259)	.102 (.040)	14.3 (5)	.019 (5)	Plugged	System possibly contaminated with medium or coarse particles
4	1.4 (200)	.016 (251)	.017 (263)	.102 (.040)	14.3 (5)	.019 (5)	Plugged	System possibly contaminated with medium or coarse particles
5	1.4 (200)	.009 (141)	.010 (153)	.102 (.040)	14.3 (5)	.019 (5)	Plugged	System possibly contaminated with medium or coarse particles
6	1.5 (215)	.004 (68)	.005 (80)	.102 (.040)	14.3 (5)	.019 (5)	Plugged	System possibly contaminated with medium or coarse particles
7	1.9 (280)	.014 (217)	.015 (232)	.102 (.040)	14.3 (5)	.015 (4)	Plugged	System possibly contaminated with medium or coarse particles
8	1.4 (200)	.011 (182)	.013 (205)	.152 (.060)	14.3 (5)	.170 (45)	No plug	
9	1.4 (200)	.008 (132)	.010 (155)	.152 (.060)	14.3 (5)	.151 (40)	No plug	
10	1.4 (200)	.005 (80)	.006 (103)	.152 (.060)	14.3 (5)	.136 (36)	No plug	
11	1.4 (200)	.002 (29)	.003 (52)	.152 (.060)	14.2 (5)	.148 (39)	No plug	
12	1.4 (200)	.0009 (14)	.002 (37)	.152 (.060)	14.3 (5)	.148 (39)	No plug	Intended to be a zero crossflow test
13	1.4 (200)	.011 (174)	.012 (197)	.152 (.060)	28.5 (10)	.121 (32)	No plug	
14	1.4 (200)	.008 (134)	.009 (157)	.152 (.060)	28.5 (10)	.068 (18)	Plugged	Slow leak
15	1.3 (190)	.005 (73)	.006 (95)	.152 (.060)	28.5 (10)	.102 (27)	Parplug	Partial plug
16	1.4 (200)	.002 (34)	.004 (57)	.152 (.060)	28.5 (10)	.117 (31)	Parplug	Invalid due to regulator
17	1.4 (200)	0	.002 (25)	.152 (.060)	28.5 (10)	.151 (40)	No plug	Zero crossflow test
18	1.4 (200)	.005 (74)	.006 (97)	.152 (.060)	28.5 (10)	.117 (31)	Parplug	
19	1.4 (200)	.011 (167)	.012 (190)	.152 (.060)	57.1 (20)	.095 (25)	Parplug	
20	1.3 (195)	.009 (137)	.010 (158)	.152 (.060)	57.1 (20)	.110 (29)	No plug	
21	1.3 (183)	.005 (81)	.006 (99)	.152 (.060)	57.1 (20)	.136 (36)	No plug	
22	1.4 (200)	.002 (27)	.003 (50)	.152 (.060)	57.1 (20)	.121 (32)	No plug	
23	1.3 (188)	0	.001 (20)	.152 (.060)	57.1 (20)	.132 (35)	No plug	Zero crossflow test
24	1.4 (200)	.011 (172)	.012 (185)	.102 (.040)	57.1 (20)	.030 (8)	Plugged	No gel strength recorded

Table 5-2

Lost Circulation Material Test Results - Thermo-Set Medium

Test Number	Differential Pressure MPa (psi)	Cross Flow, m ³ /s (gal/min)	Mud Pump Flow, m ³ /s (gal/min)	Slot Size cm (in.)	LCM Concentration kg/m ³ (lb/bbl)	Filtrate Accumulated m ³ (gal)	Results	Remarks
1	1.4 (200)	0	0	.102 (.040)	28.5 (10)	.011 (3)	Plugged	First test in facility
2	1.4 (200)	0	0	.305 (.120)	57.1 (20)	.204 (54)	No plug	
3	1.4 (200)	0	0	.305 (.120)	28.5 (10)	.015 (4)*	Plugged	
4	1.6 (230)	.014 (230)	0	.406 (.160)	28.5 (10)	.023 (6)*	Plugged	
				.508 (.200)		.155 (41)*	No plug	
				.305 (.120)		.042 (11)*	No plug	
				.406 (.160)		.061 (16)*		
				.508 (.200)		.155 (21)*		
5	3.5 (500)	.004 (60)	0	.406 (.160)	28.5 (10)	.140 (37)	No plug	
6	3.5 (500)	.006 (100)	0	.406 (.160)	57.1 (20)	0	Plugged	
7	1.7 (250)	.016 (257)	.019 (300)	.254 (.100)	14.3 (5)	.015 (4)	Plugged	
8	1.4 (200)	.009 (148)	.013 (200)	.305 (.120)	14.3 (5)	.144 (38)	No plug	Contaminated mud may have caused plugging
9	1.4 (200)	.006 (98)	.009 (150)	.305 (.120)	14.3 (5)	.079 (21)	Plugged	Regulator malfunction
10	0.7 (100)	.004 (63)	.006 (100)	.305 (.120)	14.3 (5)	.076 (20)	No plug	Pressure at end no differential
11	1.4 (200)	.009 (146)	.013 (200)	.305 (.120)	14.3 (5)	.155 (41)	No plug	
12	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	14.3 (5)	.087 (23)	Plugged	
13	1.4 (200)	0	.003 (50)	.305 (.120)	14.3 (5)	.117 (31)	No plug	
14	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	14.3 (5)	.095 (25)	No plug	
15	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	14.3 (5)	.034 (9)	Plugged	
16	1.4 (200)	0	.003 (50)	.305 (.120)	14.3 (5)	.061 (16)	Plugged	*Partial plug
17	1.4 (200)	0	.003 (50)	.305 (.120)	14.3 (5)	.132 (35)	* Plug	
18	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	14.3 (5)	.163 (43)	No plug	
19	1.4 (200)	0	.003 (50)	.305 (.120)	14.3 (5)	.163 (43)	No plug	
20	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	14.3 (5)	.167 (44)	No plug	
21	1.4 (200)	0	.002 (35)	.305 (.120)	14.3 (5)	.167 (44)	No plug	
22	1.4 (200)	.007 (106)	.010 (160)	.305 (.120)	28.5 (10)	.182 (48)	No plug	
23	1.4 (200)	.006 (91)	.009 (145)	.305 (.120)	28.5 (10)	.174 (46)	No plug	
24	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	28.5 (10)	.182 (48)	No plug	
25	1.4 (200)	0	.003 (50)	.305 (.120)	28.5 (10)	.174 (46)	No plug	Temperatures were not recorded
26	1.5 (220)	.006 (88)	.009 (142)	.305 (.120)	57.1 (20)	.144 (38)	No plug	
27	1.4 (200)	.003 (46)	.006 (100)	.305 (.120)	57.1 (20)	.185 (49)	No plug	
28	1.4 (200)	0	.003 (52)	.305 (.120)	57.1 (20)	.167 (44)	No plug	
29	1.8 (255)	.007 (115)	.010 (155)	.203 (.080)	14.3 (5)	.163 (43)	Plugged	
30	1.4 (200)	.004 (67)	.006 (100)	.203 (.080)	14.3 (5)	.098 (26)	Plugged	
31	1.4 (200)	.0004 (7)	.003 (40)	.203 (.080)	14.3 (5)	.182 (48)	No plug	Slow leak
32	1.4 (200)	0	0	.203 (.080)	14.3 (5)	.144 (38)	Plugged	
33	1.4 (200)	.001 (18)	.003 (50)	.203 (.080)	14.3 (5)	.170 (45)	No plug	
34	1.4 (200)	.007 (118)	.009 (150)	.203 (.080)	28.5 (10)	.091 (24)	Plugged	
35	1.4 (200)	.004 (68)	.006 (100)	.203 (.080)	28.5 (10)	.083 (22)	Plugged	
36	1.4 (200)	.001 (18)	.003 (50)	.203 (.080)	28.5 (10)	.049 (13)	Plugged	
37	1.4 (200)	0	0	.203 (.080)	28.5 (10)	.061 (16)	Plugged	Mud pump off
38	2.8 (400)	.008 (129)	.011 (175)	.203 (.080)	28.5 (10)	.068 (18)	Plugged	
39	2.8 (400)	.003 (50)	.006 (96)	.203 (.080)	28.5 (10)	.151 (40)	No Plug	
40	2.8 (400)	.0006 (9)	.003 (55)	.203 (.080)	28.5 (10)	.178 (47)	No plug	
41	2.8 (400)	.005 (81)	.008 (127)	.203 (.080)	28.5 (10)	.136 (36)	Plugged	
42	2.8 (400)	.005 (84)	.008 (130)	.203 (.080)	28.5 (10)	.019 (5)	Plugged	
43	2.8 (400)	.007 (104)	.009 (150)	.203 (.080)	28.5 (10)	.049 (13)	Plugged	
44	2.8 (400)	.003 (54)	.006 (100)	.203 (.080)	28.5 (10)	.091 (24)	Plugged	
45	4.1 (600)	.013 (206)	.080 (260)	.203 (.080)	28.5 (10)	.121 (32)	Plugged	
46	3.5 (500)	.007 (115)	.010 (165)	.203 (.080)	28.5 (10)	.189 (50)	No plug	Temperatures were not recorded
47	4.1 (600)	.002 (28)	.005 (82)	.203 (.080)	28.5 (10)	.178 (47)	No plug	
48	3.2 (470)	.007 (107)	.010 (155)	.203 (.080)	28.5 (10)	.102 (27)	Plugged	
49	2.4 (350)	.002 (36)	.005 (80)	.203 (.080)	28.5 (10)	.185 (49)	No plug	

* Calculated

Table 5-3

Lost Circulation Test Results - Thermo-Set Coarse

Test Number	Differential Pressure MPa (psi)	Cross Flow, m ³ /s (gal/min)	Mud Pump Flow, m ³ /s (gal/min)	Slot Size cm (in.)	LCM Concentration kg/m ³ (lb/bbl)	Filtrate Accumulated m ³ (gal)	Results	Remarks
1	1.4 (200)	0	0	.305 (.120)	57.1 (20)	.034 (9)	Plugged	Plug held with .019 m ³ /s (300 gal/min) crossflow
2	3.5 (500)	0	0	.305 (.120)	57.1 (20)	.034 (9)	Plugged	
3	1.4 (200)	0	0	.305 (.120)	28.5 (10)	.042 (11)	Plugged	
4	1.4 (200)	0	0	.305 (.120)	14.3 (5)	.042 (11)	Plugged	
5	4.1 (600)	0	0	.305 (.120)	28.5 (10)	.015 (4)*	Plugged	Annulus Plugged
				.406 (.160)		.034 (9)*		
				.406 (.160)		.061 (16)*		
6	2.1 (300)	0	0	.305 (.120)	28.5 (10)	.015 (4)*	Plugged	Held 2.1 MPa (300 psi) for 20 min.
				.406 (.160)		.019 (5)*		
				.508 (.200)		.087 (23)*		
7	2.1 (300)	.007 (120)	0	.635 (.250)	14.3 (5)	.132 (35)	No plug	
8	2.1 (300)	.007 (120)	0	.635 (.250)	28.5 (10)	.110 (29)	No plug	
9	0.7 (100)	0	0	.635 (.250)	57.1 (20)	.026 (7)	Plugged	Held 6.2 MPa (900 psi) and .009 m ³ /s (140 gal/min) flow rate
10	0.7 (100)	0	0	1.27 (.500)	57.1 (20)	.144 (38)	No plug	
11	0.7 (100)	0	0	1.27 (.500)	57.1 (20)	.117 (31)	No plug	
12	0.7 (100)	.008 (130)	0	1.27 (.500)	114.1 (40)	.114 (30)	No plug	
13	1.4 (200)	.012 (185)	.019 (300)	.635 (.250)	28.5 (10)	.110 (29)	Plugged	First test using mud pump
14	1.4 (200)	.005 (85)	.013 (200)	.635 (.250)	28.5 (10)	.155 (21)	Plugged	
15	1.4 (200)	0	.006 (100)	.635 (.250)	28.5 (10)	.064 (17)	Plugged	Plug held with .019 m ³ /s (300 gal/min) flow rate
16	1.4 (200)	.012 (185)	.019 (300)	.635 (.250)	28.5 (10)	.136 (36)	Plugged	
17	1.4 (200)	.005 (85)	.013 (200)	.635 (.250)	28.5 (10)	.170 (45)	No plug	
18	1.4 (200)	0	.006 (100)	.635 (.250)	28.5 (10)	.023 (6)	Plugged	
19	1.4 (200)	.012 (185)	.019 (300)	.635 (.250)	28.5 (10)	.045 (12)	Plugged	
20	1.4 (200)	.005 (85)	.013 (200)	.635 (.250)	28.5 (10)	.136 (36)	Plugged	
21	1.4 (200)	.008 (133)	.019 (300)	.889 (.350)	28.5 (10)	.167 (44)	No plug	
22	1.4 (200)	.002 (33)	.013 (200)	.889 (.350)	28.5 (10)	.170 (45)	No plug	
23	1.4 (200)	0	.006 (100)	.889 (.350)	28.5 (10)	.170 (45)	No plug	
24	1.4 (200)	.010 (164)	.019 (300)	.737 (.290)	28.5 (10)	.167 (44)	No plug	
25	1.4 (200)	.010 (164)	.019 (300)	.737 (.290)	28.5 (10)	.170 (45)	No plug	
26	1.4 (200)	.004 (64)	.013 (200)	.737 (.290)	28.5 (10)	.197 (52)	No plug	
27	1.4 (200)	0	.006 (100)	.737 (.290)	28.5 (10)	.170 (45)	No plug	
28	2.4 (350)	.007 (120)	.019 (300)	.737 (.290)	28.5 (10)	.159 (42)	No plug	
29	2.1 (300)	.001 (20)	.013 (200)	.737 (.290)	28.5 (10)	.163 (43)	No plug	
30	1.4 (200)	.011 (175)	.019 (300)	.686 (.270)	28.5 (10)	.155 (41)	No plug	
31	1.4 (200)	.005 (75)	.013 (200)	.686 (.270)	28.5 (10)	.151 (40)	No plug	
32	1.4 (200)	0	.006 (100)	.686 (.270)	28.5 (10)	.151 (40)	No plug	
33	1.4 (200)	.011 (180)	.019 (300)	.660 (.260)	28.5 (10)	.163 (43)	No plug	
34	1.4 (200)	.005 (80)	.013 (200)	.660 (.260)	28.5 (10)	.163 (43)	No plug	
35	1.4 (200)	0	.006 (100)	.660 (.260)	28.5 (10)	.170 (45)	No plug	
36	2.4 (350)	.003 (40)	.013 (200)	.660 (.260)	28.5 (10)	.144 (38)	No plug	93°C (200°F) heated mud

* Calculated

Figure 5-1. Lost Circulation Test Facility

entrance effects, improved data quality, evaluation of gravity effects (pumping direction includes vertical through horizontal), quick slot clean out, quick change of slot size, flow visualization, and a capability for other applications such as mud or foam rheology. The design also provides for the interchange of uniquely instrumented centerpieces that can be tailored for a variety of experiments such as flow visualization/modeling. The new test vessel is depicted in Figure 5-2, and the installation is shown in Figure 5-3. Additional improvements to enhance data quality were also undertaken in FY 1984. The improvements included new flow meters, a suction stabilizer, and a revised flow loop. By the end of the fiscal year, the improvements had been completed to include fabrication and installation of the new test vessel, and facility pressure safety qualifications were being conducted. Evaluation and development of lost circulation materials were scheduled to resume early in FY 1985.

Lost Circulation Plugging Tool -- In the late 1970s, SNL began investigating the properties of polyurethane at high temperatures for use as a material in solving lost circulation in geothermal wells. Laboratory tests of the polyurethane foam, conducted at the Southwest Research Institute in cooperation with Poly Plug, Inc., produced results indicating the suitability of polyurethane foam systems as plugging agents in high-temperature geothermal wells.⁴⁹ Subsequent to the laboratory materials tests, Poly Plug, Inc. developed a concept for in-hole mixing and for placement of a range of closed-cell rigid foams for loss-zone control. Based on the concept, Poly Plug, Inc. designed and fabricated a prototype tool for use in wellbores. In FY 1984, a demonstration of the tool was conducted at SNL.

The prototype device is a self-contained, rigid-foam placement tool (Figure 5-4), approximately 9.1 m (30 ft) long and 20.3 cm (8 in.) in diameter and is fabricated from a drillable aluminum alloy. The design provides for (1) storage and delivery of the tool in a charged condition, (2) two separate chambers for the two-component polymer reactants, (3) attachment to the end of the drill string, (4) capability to pump mud through the tool if required, (5) downhole activation and mixing of the chemicals, and (6) easy servicing and recharging at the well site for

Figure 5-2. New Test Vessel for the Lost Circulation Test Facility

Figure 5-3. New Test Vessel Installation

Figure 5-4. Self-Contained, Rigid-Foam Placement Tool

subsequent use if necessary. In addition, the design allows the drilling fluid to flow through the tool during tripping. The chemicals are made from a variety of low-density polymers and are selected for the temperatures expected to be encountered. The tool is easy to use, largely eliminates special equipment, and minimizes personnel training.

After a lost-circulation zone is identified, the tool is prepared for use by charging the two chemical chambers through separate filler tubes. After charging, the tool, which is attached to the end of the drill string using standard threaded couplings, is lowered by the drill string to the lost-circulation zone. Each of the two-component reactants remains separated during the trip to the lost-circulation zone. If necessary during tripping, a period of mud pumping can be included in the operation, with the fluid passing through a central channel that extends the length of the tool. This feature also avoids pulling a wet string.

After the tool is positioned with the chemical disbursing head, or "stinger," extending into the lost-circulation zone, functioning of the tool is initiated by dropping an activator ball down the drill string. On reaching the device, the activator ball shuts off the mud flow through the central channel. The resulting pressure shears pins, opening a port to a channel leading to two connected pistons, one at each chemical chamber. The fluid pressure drives the pistons, discharging the chemicals via exhaust tubes through the mixing mechanism. The reacting chemicals expand through multiple ports in the disbursing head and into the loss zone.

When the chemicals have been discharged from their chambers, pumping pressure is increased. This increase in pressure reopens the central flow channel in the tool, restoring mud flow through the tool. After removal from the drill string, the tool is readily serviced on the surface for reuse by recharging the two chemical chambers, replacing the mixing mechanism, and cleaning out the multiple ports in the disbursing head.

Expansion of the chemical plug into the loss zone is accomplished in a matter of minutes. During the expansion process, the chemical mixture generates its own driving power to penetrate the loss zone. The setting

time of the chemical (which can be adjusted by selecting the appropriate reactants) is minutes in contrast to hours for cement.

The demonstration of the prototype tool was performed at ambient temperatures (21°C [70°F]) using an above-ground, simulated "loss zone" formation, fabricated from a 6.1-m (20-ft) high, 0.9-m (3-ft) diameter cardboard tube filled with water and river gravel. A "wellbore" in the center of this "formation" was simulated with 15.2-cm (6-in.) steel pipe, which had a 1.2-m (4-ft) section of expanded metal with a 1.27-cm (0.5-in.) mesh near the middle to represent the "loss zone." The test setup used to demonstrate this rigid-foam placement tool is illustrated in Figure 5-5. The 15.2-cm (6-in.) diameter, 6.4-m (21-ft) long, 318-kg (700-lb) tool was suspended above the test setup with the foam disbursing head or "stinger" extending into the borehole. The demonstration tool charge of chemicals was 54 kg (120 lb) or 0.05 m^3 (1.6 ft^3). In the test, the tool was operated by pressure from a nitrogen bottle at 2.9 MPa (425 psi). A photograph of the tool suspended above the simulated formation/borehole and ready for activation is shown in Figure 5-6. After discharge of the chemicals and removal of the tool, the cardboard tube was cut away, allowing the loose gravel to fall away revealing a rigid, 0.45-m^3 (16-ft^3) mass of gravel and polyurethane foam ($\sim 0.6 \text{ m}$ [2 ft] in diameter and 1.5 m [5 feet] in length) around the wellbore at the loss zone (Figure 5-7). The chemical reaction time was 1.75 minutes. The volume expansion ratio of the chemicals was calculated as 7:1, and the foam density was 204 kg/m^3 (12.76 lb/ft^3). Samples taken from the stabilized mass were subjected to unconfined strength tests in a compression tester (Figure 5-8). An unconfined sample reached 11.3 MPa (1,640 psi) before failure. A much higher strength can be expected under the confined conditions down hole.

Figure 5-5. Schematic of Test Setup Used to Demonstrate the Rigid-Foam Placement Tool

Figure 5-6. Photograph of Test Setup for Demonstration of the Rigid-Foam Placement Tool

Figure 5-7. Photograph of River-Gravel Mass Stabilized by Polyurethane Foam Discharged from the Rigid-Foam Placement Tool

Figure 5-8. Sample of Stabilized Mass Being Tested for Unconfined Strength

5.2 Lost Circulation Plugging Model

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Project Objective

The objective of this program is to develop an increased understanding of wellbore fluid dynamics and to investigate particle orientation near fractures.

Background

Efforts were begun in FY 1983 to develop an analytic model of the "plugging" mechanisms involved with lost circulation material (LCM). An incompressible finite element code, NACHOS, was used to model the LCM with mud and the annulus/fracture geometry. Variables such as flow velocity and pressure differential across the fracture were included. Initial results were encouraging--calculations showed that the viscosity of the mud increases in the vicinity of the fracture. Parametric studies will be performed for a range of LCM concentrations and particle-size distributions. Laboratory experiments will be run as required to facilitate and verify the model. Upon completion, the model will aid in designing solutions to specific lost circulation problems.¹⁶

FY 1984 Activities

Additional studies were performed in FY 1984 using the NACHOS code. The viscometric flow model simulates the fluid dynamics in the region of an isolated crack. The precise geometry consists of a vertical annulus concentrically intersecting a thin, horizontally-oriented, disk-shaped fracture. A Bingham fluid is forced to flow in the annulus due to an axial pressure gradient. The nature of the radial flow in the crack has been investigated. The analysis shows that for this geometry, there are cases in which the radial velocities are zero, i.e., the crack seals. The existence of such cases is, however, limited to fluids with a high yield stress, cracks of thin width, and small differences between downhole

annular fluid pressure and surrounding formation pressure. From this computer model analysis, preliminary conclusions indicate that fluid yield stress may be responsible for self-sealing possibilities, and fluid dynamics may predict favorable LCM particle orientation needed for plugging action. The studies using single-phase and multi-phase models were continuing as this reporting period ended.

Also during FY 1984, the BDM Corporation began Phase I of a three-phase program providing technical support to SNL's LCM projects. Phase I will address LCM plugging mechanisms, and planned work includes a literature search and subsequent development of physical and mathematical models pertinent to LCM environments.

By the end of the fiscal year, BDM had surveyed available experimental data, reviewed applicability of the Enskog dense phase equation set, and investigated "clogging" processes. The Enskog formulation of dense two-phase dynamic equations, coupled to an incompressible liquid equation set, describe the LCM flow environment. A one-dimensional model along with linearized perturbation theory was applied to the flow equations to ascertain the dominant physical plugging processes.

Preliminary indications revealed a potential "cascading" mechanism--yielding plugging, initiated by the pressure differentials along the liquid phase's streamlines. Consequently, the particulate phase's inability to respond instantaneously may cause an accelerated particulant migration into the high-solidity regions, i.e. "clogging." However, this process is countered by an increased particulate pressure--a dense solid-phase. Thus, the relative rate at which these two mechanisms countermand one another defines an envelope in which loss zones may be plugged. This physical mechanism is not a bridging process in which a few particles wedge themselves in a crack, but rather, a self-generated and sustained instability generated by the two-phase flow environment.

The completion of Phase I studies and the initiation of the Phase II effort, the examination and application of two-phase flow physics/models to LCM plugging mechanisms and environments, were expected in FY 1985.

5.3 Casing Collapse

Sandia National Laboratories
Technical Consultant: M. Stone (505) 844-5113

Project Objective

The objective of this project is to investigate the planar radial buckling of commonly used casing employed in a geothermal well environment.

Background

Geothermal well casing is exposed to significant thermal variations as the well is drilled, produced, placed in standby mode, and idled for work-over operations. These variations in wellbore temperature lead to thermally induced stresses that may exceed structural limits and result in failure. This program effort is aimed at analyzing these conditions to determine the proper completion practices required to minimize thermally induced failures.

In an earlier effort, Euler buckling of geothermal well casing was studied, and the results were reported in Reference 50. The report provides preliminary calculations on the buckling phenomenon. Generally, it was found that thermally induced buckling in N80 casing would not be serious if minor adjustments to increase casing stability were made such as applying either a tension preload or additional internal pressure while cementing. However, buckling would be detrimental for K55 casing, and full lateral support would be necessary. The effect of wall contact was found to be beneficial for closely confined pipe strings and of no great detriment when hole gaps were large, provided pipe ovalation was unimportant. The weakness in bending of all American Petroleum Institute (API) screw joints appeared to be the structural limitation.

The study of planar radial buckling of typical well casing under geothermal conditions was completed during FY 1983, and preparation of a report on the investigation was begun. Two sources of external pressure on

the casing were identified: creep of the geologic formation and the generation of superheated steam. A finite element analysis was performed on the casing using fixed elastic-plastic temperature material models. Casing deflection was monitored at the node corresponding to the point of largest radial deflection. Collapse was found to occur when the stresses through the casing thickness exceeded the yield stress, in effect forming a plastic hinge.¹⁶

FY 1983 Activities

During preparation of the report on the FY 1983 investigations, a decision was made to expand the study to consider additional cases in which the amounts of competent cement surrounding the casings is varied (see Figure 5-9, the angle θ). These analyses were still in progress as FY 1984 ended. A report on this additional work will be included in the FY 1985 annual report and in the final report of the project.

Figure 5-9. Typical Plane Section of Casing with Less Than Competent Cement

6. DIAGNOSTICS TECHNOLOGY

The central goal of Diagnostics Technology research is the development of high-temperature capabilities for well-logging equipment and instrumentation. This program element also includes research into areas aimed at increasing the capability to measure and evaluate downhole conditions. The tools and techniques developed as a part of this effort are basic support devices for the other program elements, yielding definition of the downhole environment for better system definition.

6.1 Lost Circulation Zone Mapping Tool

Sandia National Laboratories
Technical Consultant: T. Bauman (505) 844-8885

Project Objective

The objective of this project is to develop a wire-line tool capable of locating and defining features of fractures that intersect the borehole.

Background

Under a project completed in FY 1982, the Acoustic Borehole Televiwer (ABT) was successfully upgraded for operation at high temperatures and pressures, and the capability of the instrument to operate at temperatures up to 280°C (536°F) and at pressures up to 31 MPa (4,500 psi) for seven hours was demonstrated in full-scale laboratory and field tests. The field tests of the upgraded ABT proved the tool was valuable for casing inspection as well as for fracture characterization in geothermal wells. The technology developed was transferred to industry (Simplec Manufacturing Company) for use in the design of new commercial televiwers. The results of the project were reported in References 12 and 51.

Design modifications of the ABT were initiated in FY 1983 in an effort to modify the tool for mapping of lost circulation zones. The modifications included the addition of a temperature sensor to aid in lost circulation zone location and of a second frequency sensor to allow a few inches of penetration into the formation. Initial field tests in the Salton Sea area to map a loss zone in a Union Oil Company geothermal well produced photographs consistent with the estimated condition of the casing. However, when the tool was lowered to 625 m (2,050 ft), the cablehead insulation melted, terminating the tests. Electrical and mechanical design modification of the tool and a search for a more suitable high-temperature wire line were continuing as FY 1983 ended.¹⁶

FY 1984 Activities

During this reporting period, additional field testing of the ABT was conducted in the Imperial Valley of Southern California, and design of electrical and mechanical modifications of the ABT for development of a lost circulation zone mapping tool continued.

Field Tests -- During the FY 1984 field tests, the ABT was operated successfully in three geothermal wells in the Imperial Valley. A total of approximately 427 m (1,400 ft) of hole was logged, with the maximum temperature at the tool exceeding 249°C (480°F). Both cased holes and open holes were logged--the pictures taken in casing showed collars, scratches in the casing, and corrosion spots, while open-hole pictures showed fractures and caliper information. This information was used to locate potential trouble spots in the casing and to determine density, dip, and strike of the fractures. Wire-line problems experienced in FY 1983 were avoided by using a high-temperature cable.

The display formats from the Imperial Valley tests provided excellent pictures of actual lost circulation zones. One of these zones was in a well drilled through a Sandstone formation that was moderately hard with a fine-to-medium grain structure. Circulation was lost at approximately 991 m (3,250 ft). Drilling was continued, and by the time 1,004 m (3,295 ft) was reached, a volume of 42.6 m³ (268 bbl) of drilling fluid was lost in 30 minutes. Lost circulation material was added, the bit was pulled out of the hole, and a flow check still showed volume loss. A cement plug was set, tapped at 957 m (3,140 ft) and drilled to 983 m (3,225 ft). Casing was set and cemented to 983 m (3,225 ft), and the hole was then drilled to 1,004 m (3,295 ft) where drilling of the formation began again. It was estimated that, if a tool were available to quickly define this loss zone and provide information as to a proper lost circulation material, 3 days drilling time could have been saved out of a total of 16.

Subsequently, an attempt was made to characterize the loss zone using the ABT. Although the zone had been previously cemented and drilled through, it was found that fluid was still being lost to the formation at

991 m (3,250 ft) when the well was used as an injection well. A temperature log of the well (Figure 6-1) shows cool fluid being injected with a gradual rise in temperature as depth increases due to normal temperature gradients. At the bottom of the casing, a small temperature drop occurs followed by a rapid increase in temperature from about 125° to 260°C (257° to 500°F) in an interval of 61 m (200 ft). After using the temperature log to identify the area of fluid loss into the formation, a televiwer log was run (Figure 6-2). At 992 m (3,253 ft), a large fracture approximately 5.1 to 7.6 cm (2 to 3 in.) wide can be seen in the reflectivity log, with the caliper log showing several centimeters (inches) of open fracture beyond the wellbore. In order to obtain this information, two logs were run. A temperature log was run going down hole at the rate of about 0.15 m/s (30 ft/min) followed by a televiwer log that was run coming up the hole at a rate of 0.03 m/s (5 ft/min).

Design Modifications -- The mechanical design of the modifications required to upgrade the ABT for use in quickly locating and defining lost circulation zones was completed, and contracting was in process for fabrication of the modified mechanical hardware as FY 1984 came to a close. The electrical design and fabrication work required to modify the ABT for mapping lost circulation zones was also initiated within SNL and was nearing completion at the end of the fiscal year. The modifications and additions made to the ABT to achieve the necessary lost circulation mapping capabilities include (1) the addition of a platinum RTD temperature probe, (2) provisions for three selectable transducer rotational speeds of 180, 360, and 540 rpm (the current ABT has one speed--180 rpm), (3) provisions for logging speeds of 0.025, 0.051, and 0.076 m/s (5, 10, and 15 ft/min) (the current ABT must log at 0.025 m/s [5 ft/min]), (4) the substitution of a receiver automatic gain control (AGC) for the current 10 step gain control, and (5) the addition of a 400 kHz transducer frequency to the 1.3 MHz currently available.

The addition of a platinum RTD temperature-sensing probe will allow a temperature survey to be run while logging into a well, quickly identifying the area of lost circulation zones. Once the loss zones are identified, the mapping tool can be switched to the televiwer mode to provide detailed

Figure 6-1. Temperature Log of Imperial Valley Well

991 m —
(3250 ft)

994 m —
(3260 ft)

REFLECTIVITY

CALIPER

Figure 6-2. Lost Circulation Zone Characterized by
Acoustic Borehole Televiewer Log

"pictures" of the loss zones. Because televiewer data must be run while logging up hole, the addition of the temperature log will require only one logging trip.

The current ABT transducer rotational speed requires a relatively low logging speed of 0.025 m/s (5 ft/min) in order to provide sufficient vertical overlap of the acoustic beam. Because of excess circumferential overlap, rotational speed may be increased by a factor of three with a small loss of resolution. With this higher rotational speed, a logging speed of 0.076 m/s (15 ft/min) can be used to save expensive rig downtime. If higher resolution data is required to characterize a loss zone, the mapping tool can still be run at the lower speed of 0.025 m/s (5 ft/min).

The current ABT requires the selection of 1 of 10 discrete gain steps from the uphole control panel. With the addition of an AGC to the downhole electronics, an improved receiver dynamic-range capability is provided. The AGC circuitry will reduce operator functions when selecting the proper downhole gain in order to obtain useful information. By eliminating the electromechanical stepping switch used for gain selection, the ability to change gain in either direction without cycling completely through all 10 gain steps in order to decrease gain by one step will be provided. A more reliable operation is also provided by the AGC.

The option of selecting a second transducer frequency of approximately 400 kHz will allow better penetration of drilling mud. At this lower frequency, the possibility also exists to view fractures a few meters (feet) away from the borehole, or possibly penetrating casing to inspect cement-bond integrity. The lower acoustic frequency does have the disadvantage of a larger acoustic beam width, and hence, slightly less resolution. With the capability to select the desired transducer frequency, the operator will have the option of either high resolution or a more penetrating acoustic beam.

The design and fabrication of the new electronic components are expected to be completed early in FY 1985. Assembly of the Lost Circulation Zone Mapping Tool, laboratory testing, and field testing are scheduled for the next reporting period.

6.2 Acoustic Cement-Bond Diagnostics

Sandia National Laboratories

Technical Consultants: Hsi-Tien Chang (505) 844-7588

Fred Wolfenbarger (505) 844-7306

Project Objective

The objective of this project is to develop high-temperature technologies for use in the design and fabrication of an acoustic cement-bond logging instrument for operation at temperatures up to 250°C (482°F).

Background

There are currently no commercially available high-temperature cement-bond and casing integrity logging systems for geothermal wells with maximum temperatures in excess of 250°C (482°F). Most commercial logging tools, developed for the oil and gas industry, become unreliable above 150°C (302°F) in actual field tests. As a consequence, geothermal well operators must cool the well in order to run surveys. The thermal shock from cooling could cause well damage to both casing and cement. Also, loss in production time due to cooling prior to logging is expensive. Hence, a distinct need exists for development of high-temperature logging capabilities to support the timely growth of geothermal energy. In response to this need, SNL began an upgrade research program in late FY 1980, focusing on improvement of the temperature capabilities of the acoustic cement-bond logging tool. The program description and development approach were described in Reference 52.

Work to develop high-temperature circuits suitable for use in the design of an upgraded, geothermal acoustic cement-bond logging instrument continued during FY 1981 and was reported in References 7 and 53. The FY 1981 efforts included successful operation for approximately 150,000 cycles at 10 pps of a redesigned Spryton tube. The tube used bismuth for the anode and cathode in a new trigger circuit design. Evaluations of various commercial electronic components to determine maximum operating temperatures were also conducted. The design of a 1:15 pulse transformer using Silectron and magnet wire was completed by the end of FY 1981.

Design efforts on the acoustic cement-bond logging instrument continued throughout FY 1982. Improved circuit design and component selection resulted in the temperature-caused variation in the output voltage and current of the transmitter system being reduced from 30% to 10%. The receiver circuit design was completed by January 1982 and included a Harris Semiconductor 2600-1 operational amplifier that worked satisfactorily at temperatures up to 250°C (482°F). Transmitter/receiver breadboard circuits were successfully tested in an oven at temperatures up to 250°C (482°F) for 2 hours. Subsequently, the layout for a printed circuit board design was completed. The design of the transmitter and receiver transducers, acoustic isolator system, and mechanical housing for the tool was also begun in FY 1982 and was continuing at the close of the fiscal year.¹²

During FY 1983, the initial design of the transmitter and receiver, the acoustic isolator system, and the mechanical housing was completed, and fabrication of the prototype cement-bond logging tool got under way. A summary of the tool design efforts was reported in Reference 54.

Laboratory experiments identified a magnetostrictive transmitter and a piezoelectric receiver as the best approach for an acoustic cement-bond tool capable of operating at high temperature. The acoustic isolator is made of sections of steel pipe with cross sections designed to induce acoustic discontinuities, thus reducing the acoustic transmission along the instrument.¹⁶

FY 1984 Activities

Development of the cement-bond logging tool continued throughout FY 1984. Activities included component testing, design refinement, component fabrication, and progressive tool assembly and checkout. The majority of the changes made were in the mechanical components and were aimed at facilitating the assembly/disassembly of the tool.

The preliminary housing for the high-temperature cement-bond logging tool was fabricated and attempts were made to install the transmitter and receiver along with related wiring. Redesign of some parts was necessary to facilitate the mounting of interconnecting sockets. Teflon parts for

both the transmitter and receiver were reshaped to encompass the magnetostrictive and piezoelectric transducers. Connectors were added to the original design to facilitate easier removal of the transmitter and receiver. The thickness of the metal housing units for the transducers was reduced to increase the acoustic output signal. The acoustic signal must be optimized by reducing the thickness of the transducer housings, but the strength of the material must also be retained for the high pressures that will be encountered. Some parts were machined to reduce the overall weight of the tool. Subcomponent fabrication procedures and techniques were also developed during the tool assembly phase, with the correction of all observed weak mechanical features nearing completion by the end of this reporting period.

The receiver for the high-temperature cement-bond logging tool was originally designed using an input from a pulse generator. Subsequent tests, using the signal from the piezoelectric transducer and 4,572- or 6,096-m (15,000- or 20,000-ft) RC cable simulators, revealed the circuit lacked sufficient current output to obtain an adequate signal on the surface. In order to correct this problem, another stage was added using two 2N6656 transistors to the output to increase the current to a usable signal level at the surface. A breadboard receiver was tested in an oven for operation at 250°C (482°F) prior to fabrication on a circuit board. The receiver is built with discrete electronic components capable of withstanding the high temperatures encountered in geothermal wells. Special high-temperature solder containing silver or antimony was used to connect the components on the circuit board.

By the end of FY 1984, the transmitter and receiver circuits had been built and tested at temperature. Delivery of the final mechanical housing was expected in the early part of FY 1985, and final tool assembly, laboratory testing, and field tests were scheduled for the next reporting period.

6.3 Radar Fracture Mapping

Sandia National Laboratories
Technical Consultant: Hsi-Tien Chang (505) 844-7588

Project Objective

The objective of this project is to develop a high-frequency technique for the location of fractures in the vicinity of boreholes from downhole measurements in a single wellbore.

Background

A survey of the technical literature indicated that various previous experiments reported findings that some hard rocks act as a low-loss dielectric at 30 to 300 MHz, the VHF frequency. This low-loss dielectric characteristic suggested that electromagnetic waves might propagate tens of meters through some rocks and provide detectable radar returns from brine-filled fractures.

Drilling in the Valles Caldera, New Mexico geothermal resource area resulted in dry holes not far from producing wells. While a fracture system apparently existed in the area, failure to locate and intercept the fractures from dry holes led, in part, to abandonment of the efforts to exploit commercially the geothermal resources in the region. Since the capability to characterize fractures in the vicinity of boreholes (but not intersecting the boreholes) offers the potential to convert a dry hole to a producing well or to increase production from geothermal wells, a decision was made in FY 1983 to start a research effort aimed at adapting high-frequency technology to fracture location from a single borehole.

Project work was begun in mid-FY 1983 with a simple field experiment to confirm the radar fracture detection concept. A section of granite was selected that had an existing flame-cut slot and the slot was filled with salt water to simulate a brine-filled fracture. A transmitter consisting of two dipole antennas arranged to provide a directional signal toward the fracture was installed, as was a receiver, in a borehole opposite the

fracture. The radar returns from the simulated fracture were detectable in boreholes located at distances of up to 12 m (39 ft) from the fracture. These results indicated for the first time the feasibility of developing a downhole VHF radar for use in a single borehole for detection of fractures located away from the borehole.

Analysis of acoustic data from the same hole showed a significant sensitivity in the received signal to the rotational position of both the acoustic source and the receiver. Also, the centering of the probes in the borehole influenced the received signal. The data also revealed significant reverberations contributed by various wave modes in the borehole that may cause masking of the acoustic data. Based on these findings modifications of the test apparatus were initiated. Rigid, lightweight tubes were attached to the transmitter and receiver probes to permit rotation of the probes to known positions with respect to each other and the target when emplaced in the boreholes. Modification of the probe centralizers to permit accurate centering of the probes in the boreholes was planned, as was modification of the digital field data-acquisition software to permit onsite evaluation of the recorded data.

Planning also was begun to design and construct an experimental apparatus for a laboratory test facility to perform electric field pattern measurements for a simulated borehole EM directional antenna for remote detection of fracture zones.¹⁶

FY 1984 Activities

During FY 1984, additional field and laboratory experiments were conducted to investigate design and fabrication approaches in the development of a radar fracture mapping tool. The results of this work were published in References 55 and 56, and are summarized below. In addition, Southwest Research Institute began design work based on Sandia's VHF borehole directional antenna concept in support of the development of a borehole radar system. The specifications for the proposed system are: (1) beamwidth - 75 degrees, (2) directivity - 20 db front-to-back ratio, (3) maximum diameter of the borehole system - 20 cm (7.9 in.), (4) bandwidth - 30 to 300 MHz, (5) peak power output (selectable - 10 and 40 kW), and (6) pressure limit - 20.7 MPa (3,000 psi).

Field Experiment -- A second field experiment was conducted at a granite quarry near Marble Falls, Texas to determine the feasibility of an acoustic, downhole technique for location of fractures in the vicinity of boreholes. The frequency used in this test was about 5 kHz; a frequency well above the seismic frequency commonly used in reservoir evaluations. An existing flame-cut slot in the granite at the test site was filled with water to simulate a fracture. A high-energy piezoelectric transmitter was located in a borehole 8 m (26.3 ft) from the water-filled slot, and a commercial piezoelectric transducer was used as a receiver in a borehole 4 m (13.1 ft) from the slot. Both transducers could be rotated for maximum transmission or reception for either the compressional wave or the shear wave. During the experiment, reflections from the simulated fracture were obtained with the transducers oriented only for shear wave illumination and detection.

The test results suggested that a high-frequency shear wave can also be used to detect fractures located away from a borehole. Such a high-frequency acoustic technique could provide not only a higher data rate, but also a better resolution than conventional seismic survey systems; hence, fracture location should be more accurate. Shear wave technique can be used in a conductive formation as a complement technique when the electromagnetic losses are too severe to be practical.

Laboratory Experiments -- Laboratory experiments were conducted to investigate the feasibility of designing and fabricating a directional VHF (30 to 300 MHz) antenna to physically fit into a small borehole. The study was carried out in a test chamber containing a 15-cm (5.9-in.) diameter borehole surrounded by sand that could be moistened with water or brine to adjust the dielectric constant and electrical conductivity. Electric field measurements were made for an eccentrically positioned monopole, a corner reflector, and a two-element array for a number of possible configurations. Using an eccentric monopole, the best beamwidth obtained was 78° and the front-to-back ratio was 3.5 db. The front-to-back ratio was increased to 8.5 db by arranging two element arrays in such a way as to provide the optimum radiation pattern. However, the best results were achieved using a corner reflector of 60° beamwidth and 13 db front-to-back ratio. Based on

the study results, design and fabrication of a VHF directional antenna that will fit into a 15-cm (5.9-in.) diameter borehole appeared feasible.

Tool Design -- Based on SNL's VHF borehole directional antenna design, Southwest Research Institute began supporting the development of the borehole radar system for detecting geothermal fractures located away from the borehole. Concurrent with the overall design work, the initial phase of the development also includes construction of an outdoor antenna development facility for use in designing and testing the directional antennas. This facility will be an extension of a much smaller test facility at SNL. Design of the directional antennas, transmitter, receiver, downhole, and uphole sections of the control system, and data control communication subsystem were begun in FY 1984. Construction and testing of breadboard circuits of the transmitter, receiver, and control circuitry were also in progress as the fiscal year came to a close. These circuits contain (1) a 10-kW transmitter, (2) a 40-kW transmitter, (3) a 1700-V downhole power supply, (4) a receiver, (5) a surface control unit, (6) an uphole control system, and (7) a downhole control system. The electrical design of the system and construction of the antenna-development facility were nearing completion as FY 1984 ended, and mechanical design work was expected to start early in FY 1985.

Field Experiment -- A second field experiment was conducted at a granite quarry near Marble Falls, Texas to determine the feasibility of an acoustic, downhole technique for location of fractures in the vicinity of boreholes. The frequency used in this test was about 5 kHz; a frequency well above the seismic frequency commonly used in reservoir evaluations. An existing flame-cut slot in the granite at the test site was filled with water to simulate a fracture. A high-energy piezoelectric transmitter was located in a borehole 8 m (26.3 ft) from the water-filled slot, and a commercial piezoelectric transducer was used as a receiver in a borehole 4 m (13.1 ft) from the slot. Both transducers could be rotated for maximum transmission or reception for either the compressional wave or the shear wave. During the experiment, reflections from the simulated fracture were obtained with the transducers oriented only for shear wave illumination and detection.

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7. PERMEABILITY ENHANCEMENT

The goal of permeability enhancement is to develop the technology and methodology required to increase the production rates or injection rates of geothermal wells. Work under this program includes definition and evaluation of existing reservoir production/injection zones to determine the nature of the formation permeability, quantification of the geometry of fractures intersecting the wellbore as well as their extent, definition of performance requirements and identification of research needs for enhancing the permeability of geothermal wells, and development of the specific technology to meet these performance requirements and needs.

7.1 Surface Electrical Potential Fracture Mapping

Sandia National Laboratories

Technical Consultants: C. M. Hart (505) 844-4344
H. E. Morris (505) 846-4732
D. Engi (505) 844-4831

Project Objective

The objective of the surface electrical potential fracture mapping project is to develop a surface technique for mapping fractures that intersect the wellbore.

Background

The surface-electrical-potential system (SEPS) measures variations in resistivity contrasts resulting from the flow of a conductive fluid into the earth. This system, essentially a mise-a-la-masse (excitation of the mass) technique,⁵⁷ utilizes the stimulation well as a current source electrode and an outlying well as a current sink. Hole-to-surface resistivity measurements are made by injecting bipolar pulses of current into the stimulation well and measuring the resultant distribution of electrical potential on the earth's surface. A rigorous analysis of potential distributions resulting from a penetrating electrode has been presented by Muskat.⁵⁸

The surface distribution of equipotential lines surrounding the pole source buried in a laterally isotropic earth (a homogeneous halfspace) is in the form of concentric circles with the stimulation well as their center (Figure 7-1). The presence of a conducting body alters the potential distribution as depicted by Figure 7-2. During stimulation, the well casing, along with the associated reservoir matrix, when filled with a conducting fluid, acts as a changing current injection electrode. As the stimulation treatment progresses, the electrode geometry changes and the electrical potentials measured at the surface reflect this changing shape.

Figure 7-1. Principle of the Mise-a-la-Masse Method⁵⁷

The SEPS data are taken by periodically recording the induced potential differences at the earth's surface between an infinite reference probe and the data probes placed every 15° circumferentially around the stimulation well. Background data are taken to establish the induced potential levels around the well prior to the stimulation treatment. These data then become the reference data for detecting the changes produced when the conductive fluid alters the electrical geometry. If the electrical potentials before, during, and after the stimulation are compared, diagnostic information about the directional nature of the treatment is obtained.

This technique has been used in the evaluation of hydraulic stimulation treatments in oil and gas reservoirs but had not been applied in a geothermal well or during an acid stimulation until FY 1983. At that time, as a part of DOE's comprehensive 8-well geothermal reservoir well stimulation program, Republic Geothermal Inc. and its contractors performed a two-stage chemical stimulation treatment intended to remove the near-wellbore restriction suspected to exist in a production well. The SEPS was fielded during the acid-stimulation experiment in an attempt to determine the sensitivity of the technique to chemical treatments of geothermal wells and to map the directional nature of the treated zone.

Figure 7-2. Distortion of Equipotential Lines Due to the Presence of a Conductive Anomaly

Analysis of the data produced results that demonstrated the feasibility of using the surface-potential technique to map fractures intersecting boreholes. The data indicated that the stimulation indeed altered flow patterns. Because of the high conductivity of the in situ fluid, the system was also able to detect two major conductive paths before any acid injection.¹⁶

Maps of the potential distribution are able to reflect the geometry of the subsurface conductive body in a qualitative sense and the use of multiple source holes and electric field and resistivity maps makes it possible to infer the likely locations and three dimensional shapes of the bodies causing the anomalies. However, delineation of the conductive mass in a quantitative sense requires further analyses.

FY 1984 Activities

During FY 1984, modeling techniques (numerical and physical) were evaluated and it was determined that a physical model best suited the needs of the SEPS program. A review of the geophysical and power-system literature revealed important physical-modeling guidelines and precautions, which were assessed prior to the design of the SEPS scale-model experiment.

Physical-Modeling Guidelines -- Of the different analogic techniques attempted, the electrolytic tank has been proven to be the approach most readily adaptable to the solution of electric-field problems. An electrolytic solution in a large tank can be used to simulate a conductive half-space, with various conductive or resistive targets immersed in the tank serving as the anomalies to be mapped.

Established guidelines include

- (1) Tank dimension. The size of the electrolytic tank is directly related to the minimum scale factor that can be used. The most successful modeling results have been reported when each of the system's physical dimensions have been reduced in size by the same scale factor. It has also been shown empirically that only 30 to 40% of the tank can be used for testing without introducing error.

- (2) Tank construction. Tanks should be constructed of non-conducting materials, leak-proofed to avoid changes in the electrolyte level during testing, strongly braced to withstand the weight of the electrolyte, and located away from vibrations and covered to minimize surface ripples.
- (3) Electrolyte. For most problems, tap water can be used. For long-term tests, tap water should be treated. A number of solutions have been used; copper sulfate, sodium chloride and sulphuric acid are effective.
- (4) Measurement probes. The most widely accepted material for potential-measurement probes is nichrome wire that is insulated except at the tip.
- (5) Current-return electrode. The physical return electrode varied significantly among researchers; the simplest configuration consisted of a small metal plate located at one edge of the tank, just below the water line. The physical dimensions of the return electrode do not appear to affect test results if placed an appropriate distance far from the modeling array.
- (6) Power source. Up to 50 V has been safely used in electrolytic tank experiments. Early researchers recognized possible distortion due to polarization effects if DC was used. Therefore, either normal frequency or DC with some reversing arrangement has been suggested.

Physical-Modeling Precautions -- Problems associated with physical-modeling attempts appear to be universal and easily categorized:

- (1) Boundary problems. Boundary problems frequently arise because tanks of adequate size are not readily available. Again, superior results have been documented for experiments that have reduced in size, by the same scale factor, all physical dimensions of the system.
- (2) Interface impedance. The phenomenon of electrical polarization at each electrode is equivalent to having a capacitance and resistance (in parallel) in series with the electrolyte. It is,

therefore, a source of error but can be largely eliminated by using a bipolar, high-frequency power supply. The impedance of the electrode-electrolyte interface is negligibly small at high frequencies, increases with decreasing frequency, and settles to some high value at DC. The desired frequency varies with the target material, shape, size, and its disposition relative to the measurement array. Thus, without a properly chosen frequency, results must be viewed with suspicion.

- (3) Resistivity contrasts. Metals generally have too high a conductivity to be used in simulations. Blocks of carbon and graphite have been used to model conductive bodies, but they also have conductivities much larger than those required to adequately scale a ratio of resistivity between a formation and a conductive body. Without the appropriate scaling of this resistivity ratio, modeling results will be overly optimistic and limiting aspect ratios for the geoelectric cannot be estimated from the modeling experiments.
- (4) Meniscus effects. Errors arise due to surface tension of the electrolyte, which causes a meniscus to form at the electrodes and probes. This can become an insignificant effect by appropriately preparing the probe surfaces.
- (5) Layering. The most difficult problem to address is that of layering. The validity of modeling strata of different conductivities in an electrolytic tank has been determined (Reference 59). The multilayered scale model should be designed so that the layers do not mix, and it is preferable to incorporate a capability to easily alter the conductivities of strata. In a two-layer scenario, the depth of the second layer should be large compared to the depth of the top layer to minimize distortion caused by the outer electrode having the same radius for both layers. Likewise, for multiple layers, descending layers should be scaled appropriately. The likelihood of problems associated with such distortions is also reduced significantly when the scale model is

very small compared to the size of the electrolytic tank or when the electrolytic tank is very large.⁶⁰

- (6) Electrolytic conductivity. A lack of uniformity arising from inadequate mixing, differential variations in temperature between deep and shallow zones, and diffusion of any products of oxidation may result in non-uniform electrolyte conductivity. This result can be minimized by careful design, and a simply constructed conductivity meter will help detect any remaining local variations during testing.

Model Objectives -- The SEPS was shown, through full-scale field testing, to be highly sensitive to major in situ conductive zones. Data have also provided convincing evidence that it should be possible to map dynamic electrodes as well as stationary conductive anomalies once the responses of SEPS are well understood. Available mathematical models, although not validated, also show promise for this technique in this application. However, data generated from current numerical models and that obtained from full-scale experimentation are not always consistent. Thus, during FY 1984, a systematic investigation was proposed that makes use of a carefully designed geoelectric test facility for physical scale modeling. The use of physical models presents a means of controllable and flexible experimentation with which numerical modeling output and empirical data can be compared.

The Electrolytic Tank -- It is axiomatic that for any finite electrode buried in a uniform earth the equipotential surfaces will eventually approach hemispheres as the observation point is moved away from the electrode. Furthermore if a conducting surface is introduced at any equipotential surface the field configuration will be unchanged. If that surface is then connected to some source which maintains it at its original potential, the region exterior to the surface (tank) may be removed without changing the fields inside.

In applying this to the case of the electrolytic tank, consider a hemispherical electrode, placed at the surface of a semi-infinite earth of radius r_1 (Figure 7-3). If a voltage is applied to this hemisphere with

Figure 7-3. Equipotential Lines Due to a Hemispherical Electrode Immersed in a Semi-infinite Earth

respect to infinity, all the equipotential surfaces will be hemispheres. A second hemisphere introduced at radius r_2 will not change the equipotentials. The resistance between the two hemispheres can be shown to be

$$R = \frac{\rho}{2\pi} \left(\frac{1}{r_1} - \frac{1}{r_2} \right) \quad (1)$$

where ρ is the resistivity of the medium. Similarly, by letting r_2 go to infinity and replacing r_1 with r_2 it can be shown that

$$R_e = \frac{\rho}{2\pi r_2} \quad (2)$$

where R_e represents the portion of the resistance from r_2 to infinity. If a voltage V_o is applied between the two hemispheres a current I will flow where

$$I = \frac{V_o}{R} = \frac{2\pi V_o}{\rho} \frac{r_1 r_2}{r_2 - r_1} \quad (3)$$

If the voltage at some other point, for example at radius r , is measured with respect to the outer hemisphere, the potential of this point with respect to infinity may be obtained by simply adding a voltage

$$V_e = IR_e = \frac{I\rho}{2\pi r_2} \quad (4)$$

Thus, a hemispherical tank of radius r_2 may be used to hold the electrolyte. Potentials measured within the electrolyte with respect to the tank may be converted to potentials with respect to infinity by simply adding the quantity V_e .

A hemispherical surface is closest to an ideal shape--that is, the shape of an equipotential surface in the semi-infinite earth. Therefore, a hemispherical electrode permits the use of a minimum tank size for a given grid size. A below-ground electrolytic tank not only provides the necessary support for a large volume of electrolyte but also affords a simple, practical approach to construction since established excavation procedures can be used. Excavation with a tolerance of ± 7.6 cm (± 3 in) and trimmed to a smooth surface is possible.⁶¹

To prevent electrolyte leakage, it is recommended that the hemisphere be lined with a vinyl liner. An extensive survey of vinyl indicated that Hypalon (high-density polyethylene) exhibits the most desirable properties for a leak-proof liner.⁶¹

Although the ideal shape for the outer electrode is a hemisphere, the fact that a hemisphere is a double curved surface that can only be approximately developed makes it difficult to construct. The hemigore method of development divides the hemisphere into an equal number of sections (hemigores). The development of only one section is required since it can be used as a pattern for the remaining sections. The greater the number of sections, the more accurate the development and the more hemispherically perfect the electrode. Figure 7-4 shows the proposed hemigore construction for the geoelectric-simulation facility. The outer electrode consists of 10 hemigore electrode assemblies, each containing 100 equal-area, electrically isolated subsections, for a total of 1,000 subsections that can be instrumented. Each of the 10 hemigores has a 4.1-m (13.3-ft) base and is approximately 10.2 m (33.4 ft) from base to tip. These numbers were determined from a scaling-factor investigation.

The 10 hemigores are to be made from Hypalon, while the attached subsections will be constructed from 304 stainless steel, which has

Figure 7-4. Hemigore Electrode Assembly

superior corrosion properties that make it appropriate for long-term testing. This metal is readily available in large, thin sheets and should conform to the hemispherical contours. Using this design, the 10 hemigores can be assembled before lowering them into the hemisphere and, should repair be necessary, removed from the tank without disassembling the entire hemisphere. The hemigore assemblies will be based around an anchored support at the surface to prevent slippage.

Scale Factors — There were several inputs in choosing the scale factors for the model grids. One major criterion was the maximum size grid that could be accommodated in a given size tank. Since the maximum grid dimension for an SEPS scale model is the well depth, the scaled length of the simulated casing becomes a limiting factor (since this dimension can only occupy 30 to 40% of the tank dimension). Also, in choosing a scale factor, the size of wire that is practical for experimentation is an important consideration. If the scale factor is too large, the wire becomes too delicate to work with. Although it has been shown that it is not necessary to scale the measurement probes on the same factor as the other scale model dimensions (References 62 and 63), scale model experiments have proven most successful when all other dimensions are identically scaled. With this constraint, the largest practical scale factor is 1,000:1. For a 1,524-m (5,000-ft) well-depth simulation (which is not uncommon in hydrofracturing) an appropriately scaled tank radius is approximately 6.4 m (21 ft).

Target and Target Support Structure — The test grids and target are to be constructed using removable plastic (or plexiglass) frames. This approach permits the grids to be constructed away from the tank and installed as needed. The plastic grid and target support structure will be suspended from above on the hemispherical tank's center line using four large wooden posts (telephone poles) anchored around the edges of the tank. The plastic target itself (the simulated wellbore and underground anomaly) will be hollow (filled during testing with fluid of a specified electrical conductivity) with multiple copper contacts penetrating the insulator providing an electrical interface between the electrolyte and the target fluid.

Electrolyte -- Chemically treated tap water will be used as the electrolyte. The swimming pool industry has mastered the use of compatible alloys, chemical quasi uniform heating and mixing procedures for large volumes of water. Their knowledge will be applied when formulating the electrolyte. Also, pool water allows human access to the tank for troubleshooting purposes without having to drain the large volume of liquid.

Instrumentation -- The SEPS field instrumentation will be scaled for use in the physical model with the exception of the potential probes. The potential measurements will be taken using ni-chrome wires, implanted in the plexiglass target grid support, barely penetrating the surface of the electrolyte.

Modeling Tank Enclosure -- To prevent exposure to natural elements, the simulation facility will be enclosed by a 7.6 to 9.1 m (25 to 30 ft) hemispherical inflatable building. Such a protective covering is inexpensive, easily installed, non-conducting electrically, and large enough to accommodate the overload support structure.

Geoelectric Test Facility -- Artist's conceptions of the proposed geoelectric simulation facility resulting from these investigations have been drawn from carefully laid-out blueprints. Figure 7-5 shows the detail of the hemigore method of hemisphere development, the electrolyte injection and return port design, the overhead support structure and working deck, and various ancillary structures. Figure 7-6 depicts the inflatable protective covering and its associated entry building, the SEPS field instrumentation trailer from which data will be taken and pulse power will be supplied, the target grid plexiglass structure, and the target itself. The complete proposed facility is pictured in Figure 7-7.

Due to other priorities in the permeability enhancement subelement of the Geothermal Drilling Research Program, no further activities beyond the conceptual phase of this project are planned.

Figure 7-5. Major Components of the Geoelectric Test Facility

Figure 7-6. Inflatable Protection Covering for the Geoelectric Test Facility

Figure 7-7. Complete Geoelectric Test Facility Concept

7.2 Geothermal Well Fracture Permeability Studies

Sandia National Laboratories
Technical Consultant: D. Glowka (505) 844-3601

Project Objective

The objective of this project is to determine the fracture characteristics required to impart a desired productivity to a given geothermal well.

Background

Production or injection rates of existing wells can usually be increased by enhancing the permeability of the production/injection zone. In the case of oil and gas wells, this enhancement is accomplished by increasing the near-wellbore permeability, using such techniques as hydraulic fracturing, gas or foam fracturing, and explosive fracturing. In geothermal wells, however, much higher production/injection rates require that this increase come from establishing fractures that connect the wellbore to existing reservoir fracture systems. The differences between geothermal reservoirs and oil and gas reservoirs preclude the use of much of the technology developed for the oil and gas industry, and due to the small size of the geothermal industry (0.1% of energy production), there are currently no economic incentives for industry involvement in the necessary research.

In the case of production, the need for enhanced permeability has been recently evidenced by the experience in the Valles Caldera in New Mexico. Several commercially productive wells were drilled adjacent to several "dry holes." Apparently, the nonproductive "dry holes" do not intersect the existing reservoir fracture systems, and previous attempts have not been successful in creating connecting fractures. In order for geothermal areas like the Valles to be technically viable energy resources, a reliable technique for enhancing permeability is needed. The mechanics of fractured production are not understood sufficiently to enable stimulation treatments to be designed for geothermal wells with any confidence of success.

Enhancement techniques will also be needed in injection wells in order to allow for disposal of the geothermal brine once the heat energy has been removed. Reinjection is needed to assure that the reservoirs are not depleted of fluids by the production process, to prevent subsidence of the surrounding terrain, and to avoid surface environmental damage from the produced fluids. Since reinjection wells must accept comparable or larger flow rates than production wells, they must also intersect existing reservoir fracture systems.

Previous efforts at well stimulation have generally been unsatisfactory, producing minimal or no increase in flow rate. Thus, there is an apparent need for additional research aimed at understanding the previous tests and developing the technology required to successfully enhance the permeability of geothermal wells. An integral part of such a research program will be the development of analytical techniques to provide tools for the evaluation of potential new technologies for permeability enhancement and to characterize formation fracture systems for optimum production/injection.

The project entered the planning stage in FY 1983. Two major tasks were outlined: to determine by means of an experimental program the fracture characteristics attainable with both hydraulic fracturing (planar fractures) and high-energy gas fracturing (radial fractures), and to determine the fracture characteristics required to impart a given productivity to a geothermal well by developing a numerical model.¹⁶

FY 1984 Activities

Due to funding limitations, progress on this project was maintained at a low level of effort during FY 1984. A procedure was developed for computing geothermal well productivities using an existing numerical code named MARIAH. This two-dimensional finite element porous flow computer code was developed at Sandia for other purposes; however, its applicability is general enough to permit its use in the present application.

A separate computer program was written to generate node points and elements for the finite element models analyzed with the code. This program allows the number, orientation, length, and width of artificial

fractures to be specified, as well as the wellbore and reservoir diameters. It then computes node point locations, forms radial and circumferential element rows, and assigns different permeabilities to the fracture and matrix elements. This program allows rapid generation of models and thus the ability to efficiently determine the effects of different fracture geometries on well productivity.

By the close of FY 1984, two types of artificial fracture systems were being considered, planar and multiple. Fractures in both cases are modeled as discrete cracks having a higher permeability than the surrounding matrix. The planar fractures are assumed to extend some distance in both directions from the wellbore in a vertical plane perpendicular to the minimum principal in situ stress. The multiple fracture system is assumed to consist of vertical fractures in four planes (eight total fractures) spaced at 45° intervals around the wellbore and extending some distance into the formation, which is less than that for the planar fractures. These fracture models represent simple approximations to the fracture systems that develop with hydraulic fracturing and high-energy gas fracturing (HEGF) treatments, respectively. By exercising these models under the same conditions as the pretreatment case for a given formation type, the effectiveness of both treatments in improving well productivity can be determined for a variety of conditions.

Three general types of geothermal rock formations are being considered: (1) unfractured formations where wellbore production prior to stimulation is due entirely to porous flow through the rock matrix, (2) highly fractured formations in which closely spaced fractures of relatively high permeability enhance the overall hydraulic conductance of the formation, and (3) formations in which large fractures or fault lines provide highly conductive flow paths of limited lateral extent relative to the fracture direction.

Highly fractured formations are modeled as a porous flow matrix with anisotropic permeability. Such a model assumes uniform natural fracture spacing with a higher effective reservoir permeability parallel to the fractures than normal to them. It further assumes that fracture spacing is on the order of the wellbore diameter or less. Because the computer code

employed allows permeability to be specified in any two perpendicular directions, it is also possible to determine the effects of different angles between the natural and artificial fracture systems.

For cases in which a highly conductive natural fracture runs near but does not intersect the wellbore, the fracture is modeled within the finite element mesh as a discrete crack. The greatest advantage of the multiple artificial fracture system is thought to be in low-permeability formations where multiple fracturing would connect the wellbore with natural fracture systems that cannot be reached with hydraulic fracturing due to in situ stress conditions.

Near-wellbore formation damage due to drilling-mud invasion or mineral precipitation during the reinjection can be simulated by assigning a lower permeability to elements near the wellbore. The effects of the two types of fracture treatments on correcting formation damage can thus be easily estimated.

The program written for generating model nodes and elements is being generalized to allow modeling of arbitrary natural fractures. This will permit various artificial and natural fracture system geometries to be analyzed in order to determine the conditions under which the two artificial fracture treatments provide significant improvements in geothermal well productivity.

Work in FY 1985 will concentrate first on computing well productivities for the systems described above under steady-state conditions. More accurate models are needed, however, for fluid flow in multiple fracture systems. The computer code employed allows rock permeability to be a function of local fluid velocity, thus it will be possible to model the fracture flow as turbulent channel flow. Friction factors for these models will be estimated or, if possible, measured with flow tests between two adjacent boreholes connected by fractures at the Nevada Test Site. The effects of natural production on productivity increases due to stimulation will also be included in the modeling. Generalization of the results will be attempted in order to provide a working model for determining the types of fractures needed to effectively stimulate a given geothermal well.

7.3 In Situ Stress

Sandia National Laboratories
Technical Consultant: Larry Teufel (505) 844-8680

Project Objective

The object of this project is to evaluate in situ stress determination methods, such as anelastic strain recovery, for use in geothermal reservoirs.

Background

A reliable and inexpensive technique to determine in situ stress is of economic importance to the geothermal industry because knowledge of the in situ stress state is required for stimulation design and production engineering of a geothermal reservoir. In situ stress is the predominant factor that affects the azimuth and geometry of hydraulic fractures used to stimulate many reservoirs, influences the interaction of the hydraulic fracture and natural fractures, and affects the transport characteristics of both induced and natural fractures.

The anelastic strain recovery (ASR) method could be a reliable, less expensive alternative to the hydraulic fracture method for determining in situ stress at depth, particularly in geothermal reservoirs, where routine measurements of all three principal stress directions and magnitudes are needed prior to stimulation. Early ASR determinations using sandstone cores taken from vertical wells 2 to 3.5 km (6,560 to 11,480 ft) deep were in good agreement with open-hole hydraulic fracture stress measurements.

FY 1984 Activities

Two investigations were carried out in this reporting period: (1) a determination of in situ stress from ASR measurements and a comparison of these stresses to hydraulic fracture stress measurements, and (2) an analysis of the effects of geological discontinuities on the propagation of hydraulic fractures.

Comparison of In Situ Stress from ASR and Hydraulic Fracture --

Anelastic strain recovery measurements were made on four cores from the Rollins Sandstone taken from one of the DOE's Multi-Well Experiment (MWX) wells near Rifle, Colorado. The Rollins Sandstone, a massive homogeneous, fine grain, calcite-cemented sandstone, is one of the lower blanket sandstone units of the Mesaverde group. At the MWX site, these beds are flat lying.

Immediately upon retrieval, the core was sealed with polyurethane wrapping to prevent moisture evaporation. Measurements were made in a temperature controlled environment to minimize thermal effects. The ASR-related displacements were determined with spring-loaded, clip-on gages. Since the cores were from a vertical wellbore, only three independent displacement measurements were required to determine the directions and magnitudes of the two principal horizontal strains. Three gages were mounted at 45° to each other in the horizontal plane of each core. The vertical strain was determined by mounting a gage parallel to the center axis of the core.

The anelastic strain recovery of one of the four instrumented cores is presented in a strain relief-time plot of the temperature-corrected vertical and principal horizontal strains in Figure 7-8. The principal horizontal stress magnitudes were calculated from the principal strain recovery magnitudes, overburden stress, and Poisson's ratio of the rock using a viscoelastic model.⁶⁴

Open-hole, hydraulic fracture, and stress measurements were also conducted in the MWX well in the Rollins Sandstone. One of the tests was conducted in an interval where oriented core was obtained so that direct comparisons of these stress measurements with the ASR method could be made.

The principal horizontal in situ stresses, as determined by the ASR method, were within 12% of the magnitudes determined from hydraulic fracturing (Table 7-1). Although the ASR calculated stress magnitudes are about 5 MPa (725 psi) greater than the hydraulic fracture stress measurements, the difference between the principal horizontal stresses is essentially the same for both methods, 2.6 to 2.8 MPa (377 to 406 psi). Two

Figure 7-8. Strain/Recovery/Time Curves of the Temperature Corrected Principal Strains

Table 7-1

Comparison of In Situ Stress Measurements in the Rollins Sandstone
Determined by Strain Recovery Method and Open-Hole Hydraulic Fracture Tests

	<u>Strain Recovery</u>	<u>Hydraulic Fracture</u>
$\sigma_{H_{\max}}$ MPa (psi)	54.5 (7905)	49.6 (7194)
$\sigma_{H_{\min}}$ MPa (psi)	51.9 (7528)	46.8 (6788)
$\Delta\sigma_H$ MPa (psi)	2.6 (377)	2.8 (406)
$\sigma_{H_{\max}}/\sigma_v$	0.97	0.88
$\sigma_{H_{\min}}/\sigma_v$	0.92	0.83
Azimuth $\sigma_{H_{\max}}$	N63W $\pm$ 8°	N50W - N70W

possible explanations for the overestimation of the in situ stress by the ASR method are (1) the effective overburden is calculated too high, or (2) the effective pore pressure is too high.

There is also good agreement between the orientation of the principal horizontal stresses as determined from the ASR method and the oriented impression packer in the hydraulic fracture interval. Although the fracture azimuth determined by the impression packer was not conclusive because of the nature of the hydraulic fracture at the wellbore, additional confirmation of the maximum horizontal stress direction was made from borehole seismic detection and mapping of the propagation of three large hydraulic fractures in the overlying, paludal zone from a nearby well. The average fracture azimuth mapped for the three fractures was N67°W $\pm$ 8°.

It was concluded that the anelastic strain recovery method seems to be a reliable technique to determine the directions and magnitudes of the principal in situ stresses in deep formations. The method has the potential to be used as a practical, low-cost tool to aid in the design of massive hydraulic fractures or other rock mechanics problems where the in situ stress state at depth is required.

Influence of Geologic Discontinuities on Hydraulic Fracture Propagation -- Also during FY 1984, a study was conducted of the effects of geologic discontinuities on hydraulic fracturing and proppant transport. The effects of joints, faults and bedding planes were observed in mineback experiments in ash fall tuff at the DOE's Nevada Test Site, and in a series of laboratory experiments. A summary of the observations follows.

Effects of Joints -- Even in the most homogeneous of the ash fall tuff formations, the hydraulic fractures were observed to diverge considerably from the usual picture of a planar feature; multiple stranding, fracture meandering and large scale surface roughness are common occurrences. In the vicinity of geologic discontinuities, the situation was often worse. Frequently there was, rather than a planar fracture, a zone of multiple fracturing, sometimes up to 5 to 10 m (15 to 30 ft) wide.

Effects of Faults -- Faults also exhibited a significant influence on fracture geometry and morphology. Fractures often terminated near faults and when they did propagate across, an orientation change was frequently noted. Invariably, this could be attributed to a change in stresses across the fault and not the fault plane itself. Usually, the fractures propagated a short distance across the fault and terminated.

Effect of Bedding Planes -- The effects of unbonded bedding planes were observed in a mineback fracture experiment using colored-sand proppant. For example, a fracture appeared to terminate at a parting plane (zero bonding plane) but actually propagated 2 to 5 cm (1 to 2 in.) across. The colored sand was observed all the way up to the parting plane so the fracture was fairly wide, even though it ended such a short distance above. The stresses above the parting plane were 0.7 to 1.5 MPa (100 to 200 psi) greater than the stresses in the lower layer, but this would have allowed the fracture to propagate a short distance (less than 1 m [3.3 ft]) above the parting plane based on a previous analysis. On the other hand, since the fracture did penetrate across the plane, a large flaw site was available for continued propagation, yet this did not occur. This is a situation where two effects act in concert: There is sufficient friction on the parting plane to allow the fracture to reinitiate on the other side, but

not enough transmitted stress to allow it to propagate easily in the higher stress layer above. Thus, the two factors together--bedding plane and stress contrast--act to provide an excellent containment feature. Of course, in cases where the friction is less, the bedding plane alone could provide a good fracture barrier.

Effects of Discontinuities on Proppant Transport -- Although geologic discontinuities may considerably alter fracture geometry, their effect on proppant transport may be even more severe. Forcing sand through such features as narrow, multi-strand fractures or offsets will be much more difficult than through a single hydraulic fracture. The consequence will certainly be higher fracturing pressures, and quite often screen-out may occur.

Laboratory Results -- A series of laboratory hydraulic fracture experiments was conducted to examine the effect of joint orientation and differences in the magnitudes of the principal horizontal stresses. The hydraulic fracture experiments were made in true, triaxial compression using prismatic specimens of Coconino sandstone that contained preexisting joints.

Artificial single joints in each of the hydraulic fracture specimens were made with a wire-line saw to cut the joints at prescribed angles of 30°, 60°, and 90° to the intended direction of hydraulic fracture propagation, parallel to the direction of maximum horizontal stress.

Table 7-2 summarizes the experimental conditions and results of the hydraulic fracture experiments. Three types of interactions between hydraulic fractures and pre-existing joints were observed in these tests. The hydraulic fractures either (1) crossed the joint, (2) were arrested by opening and dilating the joint as indicated by fluid flow along the joint, or (3) were arrested by shear slippage of the joint with no dilation and fluid flow along the joint.

The different types of interactions were a function of the horizontal differential stress and the angle of approach of the hydraulic fracture to the pre-existing joint.

Table 7-2

**Summary of Experimental Conditions and Results for
Hydraulic Fracture Tests on Jointed Coconino Sandstone**

Test No.	Joint Orientation	$\sigma_{H \max}$	$\sigma_{H \min}$	$\Delta\sigma_H$	Result
		MPa (psi)	MPa (psi)	MPa (psi)	
3	30°	6.9 (1000)	3.4 (500)	3.4 (500)	Dilated joint
4	30°	10.3 (1500)	3.4 (500)	6.9 (1000)	Dilated joint
7	30°	13.8 (2000)	3.4 (500)	10.3 (1500)	Shear slippage
5	60°	6.9 (1000)	3.4 (500)	3.4 (500)	Dilated joint
9	60°	10.3 (1500)	3.4 (500)	6.9 (1000)	Dilated joint
6	60°	13.8 (2000)	3.4 (500)	10.3 (1500)	Crossed joint
11	90°	6.9 (1000)	3.4 (500)	3.4 (500)	Dilated joint
8	90°	10.3 (1500)	3.4 (500)	6.9 (1000)	Crossed joint
12	90°	13.8 (2000)	3.4 (500)	10.3 (1500)	Crossed joint

Analysis -- Simple analyses were conducted to determine the effect of some ancillary parameters affecting the hydraulic fractures at geologic discontinuities (e.g., permeability of joints, frictional properties, deviatoric and normal stresses, joint spacing, treatment pressure, and fluid viscosity). These analyses are detailed in Reference 65.

7.4 High-Energy Gas Fracture Field Test

Sandia National Laboratories
Technical Consultant: D. Glowka (505) 844-3601

Project Objective

The objective of these field tests is to determine the feasibility and utility of employing the high-energy gas fracturing (HEGF) technique to increase the productivity of geothermal wells.

Background

SNL has developed a technique to induce multiple fractures in dry wellbores using pelletized artillery propellant to generate high-pressure gas. The rate of borehole pressurization can be tailored to any given rock formation by varying the proportions of two propellant types and the size of the charge. The pressurization rate controls the fracture pattern that develops. If the rate is low, such as with hydraulic fracture treatments, fractures are produced only in the plane perpendicular to the minimum principal in situ stress. Such artificial stresses may not intersect natural fracture systems, which tend to be oriented in the same direction. If the pressurization rate is very high, as with the detonation of high-order explosives, crushing of the rock near the wellbore occurs, effectively reducing near-wellbore permeability. An intermediate pressurization rate can be produced by the HEGF technique, which causes multiple fractures to develop and propagate in several different directions from the wellbore. Some of these fractures may intersect natural fractures and thereby significantly increase well productivity.

Previous work concentrated on developing the technique for dry-hole applications such as natural gas production in Devonian shale. Tests conducted in a tunnel 487 m (1,400 ft) underground at the Nevada Test Site produced fractures in up to four planes (eight total fractures) at roughly 45° intervals around the wellbore. Field tests in Devonian shale proved the technique in downhole applications, causing significant improvement in gas production for the two wells tested.

The HEGF technique has not been proven in liquid-filled wellbores, although current understanding of the phenomena does not reveal any inherent limitations. There are, however, significant differences that must be addressed. The most significant is the lack of free volume between the propellant canister and the wellbore wall. In dry-hole applications, this free volume is a parameter in determining the pressurization rate, because the combustion gases are free to expand into this region. When this region is filled with water that is essentially incompressible, the inherent pressurization rate will be much higher. The possibility also exists for the water to quench the burning propellant and/or to vaporize to steam, thereby extracting energy from the combustion gases. The purpose of the tests, begun in FY 1984, was to test the technique in water-filled boreholes in order to determine the magnitude of these potential problems and to devise solutions. These tests are thus considered to be the first step in determining the feasibility of the technique for treating geothermal wells.

FY 1984 Activities

Preparations were begun in mid-1984 to test the HEGF technique in water-filled boreholes. Because of the capability to directly observe the created fracture patterns by mineback, the G-Tunnel complex at the Nevada Test Site was chosen for these tests. The tunnel is approximately 427 m (1,400 ft) deep at the test location, providing in situ stresses of sufficient magnitude to affect fracture orientation. The rock type at this location is ash-fall tuff.

Four tests were initially planned. In the first two, the effects of the annular volume between the propellant canister and the borehole wall were to be investigated by using two different canister sizes in a 10.2-cm (4-in.) diameter borehole. These cannisters, each 2.4 m (8 ft) long, were to be filled with the slower burning of two propellants. The third test was to have been identical to the first, except that the faster burning propellant was to be used. The fourth test would combine the optimal canister size and mixture of propellant types to produce the best multiple fracture system possible.

Test preparations for the first two tests were completed by drilling two boreholes 12.2 m (40 ft) into the tunnel wall at a slight inclination from the horizontal plane. These holes were filled with water prior to each respective test. A third borehole placed approximately 1.8 m (6 ft) from the first two served as the host for an instrumentation package for measuring stresses and acceleration in the rock mass during the tests.

By the end of FY 1984, only the first test had been conducted. The propellant canister used had an inner diameter of 3.8 cm (1.5 in.). Problems were encountered in igniting the propellant with this configuration. Due to the limited diameter of the canister, it was not possible to use a centralized rapid ignition propagator (RIP) ignitor for uniformly initiating propellant combustion throughout the canister. Instead, three bridge wire detonators were spaced over the 2.4-m (8-ft) canister to serve as point initiators. This configuration had been tested successfully in dry holes but proved difficult to use effectively in a water-filled hole.

Four attempts were made before ignition was finally obtained. In the first three attempts, the initiators fired but did not ignite the propellant. Potential problems with packaging and emplacement procedures were identified and corrected. On the fourth attempt, the propellant ignited, but only about one-third of the propellant burned before the combustion was quenched by water entering the breached canister.

The measured pressurization rate was much higher than that obtained in similar dry-hole tests, probably due to the lack of free volume between the canister and the borehole wall. Furthermore, the magnitude of the pressure pulse was greatly reduced due to the fact that such a small amount of propellant actually burned. As a result, the created fracture pattern was expected to be very limited. The change in fluid transmissivity, as measured by pumping water into the borehole before and after the test, was indeed too small to be considered significant. Subsequent mineback of the test bed showed only a single 7.6-cm (3-in.) long fracture wing oriented perpendicular to the minimum principal in situ stress.

At the close of FY 1984, the second test was under preparation for firing. This test employed a 8.1 cm (3.2 in.) ID canister, that allowed a centralized RIP ignitor to be used. No problems with ignition or combustion were expected with this configuration. Additional tests with the smaller canister were also being planned. These tests were to be conducted in one of SNL's explosives test facilities, using water-filled steel pipe to simulate the wellbore. The objective in this case was to test alternate ignition schemes so that complete combustion could be achieved with the smaller canister. In situ tests with the smaller canister are considered essential to the understanding of scaling effects on multiple fracturing in water-filled boreholes.

7.5 Analytical Model for High-Energy Gas Fracture

Sandia National Laboratories

Technical Consultant: J. Jung (505) 844-6764

Project Objective

The objective of this program is to develop a predictive capability for determining the type of rock fractures (i.e., hydraulic, multiple fractures, or borehole crushing), the number of cracks, and the length of the cracks that will be obtained from high energy gas fracture, all as a function of the type and amount of the propellant and borehole geometry.

Background

Previous analytical efforts were reasonably successful in predicting the type of rock fractures and the crack geometry obtained as a result of HEGF in dry boreholes, i.e., boreholes not filled with water. The results of these studies were published as References 66, 67, and 68. The analytical capability consisted of two major parts--the material cracking model and the propellant burn model. The thermodynamics of burning propellant in a water-filled borehole was not explicitly included in the burn model when it was developed. Therefore, during FY 1984, a study began to evaluate the applicability of the burn model to the water-filled borehole problem, and the behavior of the crack geometry model to the new loading situation.

FY 1984 Activities

During FY 1984, the cracking model was examined for its sensitivity to finite element mesh variations, and pretest analyses of two experiments were performed using the existing model.

Behavior of the Cracking Model -- One aspect of the material cracking model not addressed in the previous work was its sensitivity to mesh variations and refinements. To test the effects of mesh variations, the data for the "Rowan" computation reported in Reference 66 was used for four analyses that differed only in their mesh definitions. Table 7-3 gives a summary of the mesh configurations.

Table 7-3

Summary of Mesh Configurations

<u>Mesh No.</u>	<u>Radius of Outer Border, m (in.)</u>	<u>Number of Elements in Radial Direction</u>	<u>Number of Elements in the Circumferential Direction</u>
1	6.4 (250)	10	12
2	6.4 (250)	15	18
3	25.4 (1000)	40	12
4	25.4 (1000)	40	12

Plots showing the crack patterns associated with each of these meshes at 0.0015 s after the propellant was ignited are shown in Figures 7-9, 7-10, 7-11, and 7-12. Comparing the crack patterns from meshes 1 and 2 (Figures 7-9 and 7-10), the similarity in the patterns are good with both analyses producing three major lines of radial cracks, although there are some angular differences among the corresponding crack lines.

The difference between meshes 3 and 4 is the number of significant figures used to define the nodal point locations. Seven significant figures were used for mesh 3 and four significant figures for mesh 4. Surprisingly, three lines of cracks formed for mesh 3 (Figure 7-11) and two lines of cracks formed for mesh 4 (Figure 7-12). This mesh sensitivity is most likely due to the tensile stress failure criteria that produces a crack when a specified tensile stress is exceeded.⁶⁷ Small variations in the element locations could cause slight shifts in the area where the limiting tensile stress is exceeded first. Once a crack forms, it helps to cause an entire line of cracks to follow.

Although there are some differences among the analyses that appear to be attributable to a sensitivity of the mesh used, the material cracking model is capable of distinguishing among the various fracture regimes in a qualitative sense.⁶⁶ The fracture modeling of the rock is an area that can be improved.

Figure 7-9. Crack Pattern for Mesh 1

Pretest Analysis of the GT1 and GT2 Experiments -- To help evaluate the adequacy of the propellant burn and cracking models for water-filled borehole problems, pretest analyses of the GT1 and GT2 experiments, with and without water, were performed. Because the burn model was written for air-filled borehole problems, the effect of the water could only be approximated by decreasing the free volume of the borehole by an amount equal to the volume of the water. Any thermodynamic effects due to the water, such as water vaporization, were omitted. The parameters describing the GT1 and GT2 tests are given in Table 7-4.

Figure 7-10. Crack Pattern for Mesh 2

Figure 7-11. Crack Pattern for Mesh 3

Figure 7-12. Crack Pattern for Mesh 4

Table 7-4

Parameters Describing GT1 and GT2 Tests

Test	Propellant	Borehole Diameter m (in.)	Tool Diameter m (in.)	Assumed In Situ Stresses, MPa (psi)		
				σ_x	σ_y	σ_z
GT1	M5B	0.1 (4)	0.05 (2)	5.4 (780)	8.6 (1250)	10.3 (1490)
GT2	M5B	0.1 (4)	0.08 (3)	5.4 (780)	8.6 (1250)	10.3 (1490)

The calculated pressure-time histories of GT1 and GT2 are shown in Figures 7-13 and 7-14, respectively. These figures clearly show higher pressure rise times (after the propellants were ignited at 0.001 seconds) when the free volume of the borehole is reduced to account for the water. This effect is much more dramatic for GT1 than GT2 because there is more space between the tool and borehole wall in the former case.

The crack patterns predicted by the above computations are given in Figures 7-15, 7-16, 7-17, and 7-18. For GT1, the presence of water resulted in two lines of cracks (Figure 7-15) as opposed to a single line of cracks for a comparable air-filled borehole (Figure 7-16). Both the water-filled and air-filled borehole analyses for GT2 resulted in one major crack with some secondary cracks (Figures 7-17 and 7-18).

The development of a fracture-mechanics-based model was planned for FY 1985. Included in the plans for the upcoming study were

- (1) The calculation of the dynamic stress intensity factors (or energy release rates) for each crack tip and the explicit propagation of these cracks through the finite element mesh, and
- (2) The improvement of the propellant burn model to more adequately model the effects of water in the boreholes.

Figure 7-13. Borehole Pressure Versus Time for GT1

Figure 7-14. Borehole Pressure Versus Time for GT2

Figure 7-15. Crack Pattern for GT1, Water-filled Borehole

Figure 7-16. Crack Pattern for GT1, Air-filled Borehole

Figure 7-17. Crack Pattern for GT2, Water-filled Borehole

Figure 7-18. Crack Pattern for GT2, Air-filled Borehole

7.6 Geothermal Well Stimulation Review

Contractor: Republic Geothermal, Inc.
Principal Investigator: B. Verity (213) 945-3661
Contract Period: July 1984 - April 1985
Contract Number: 25-0868 (Sandia)
Technical Consultants: James R. Kelsey (505) 844-6968
James C. Dunn (505) 844-4715

Project Objective

The objective of this project is to analyze technology development needs for geothermal stimulation.

Background

Attempts to enhance permeability in geothermal wells within the U.S. have been unsuccessful to date. The need for a comprehensive study of technology-development needs for geothermal stimulation was recognized, and, as a first step, a decision was made to gain the experience and guidelines of industry to focus the development of technology to solve the problems in geothermal well stimulation.

FY 1984 Activities

In mid-FY 1984, a contract was awarded to Republic Geothermal, Inc. to conduct the permeability-enhancement study. The study is (1) reviewing the DOE-sponsored Geothermal Reservoir Well Stimulation Program, (2) developing guidelines for selection of stimulation methods, (3) identifying diagnostic tools and techniques for well and reservoir data acquisition, and (4) reviewing productivity enhancement by stimulating near-wellbore natural fractures. The study was still in progress as the fiscal year ended, and a report on the project was expected by mid-FY 1985.

7.7 Oil and Gas Well Stimulation Review

Contractor: Santrol Products, Inc.
Principal Investigator: R. Sinclair (713) 681-2265
Contract Period: February 1984 - November 1984
Contract Number: 58-3881 (Sandia)
Technical Consultants: James R. Kelsey (505) 844-6968
James C. Dunn (505) 844-4715

Project Objective

The objective of this project is to define the state of the art in oil and gas stimulation technology as it applies to geothermal wells.

Background

The need for permeability enhancement in geothermal wells is evidenced by the past experience of adjacent productive and nonproductive wells. A reliable method of well stimulation would greatly improve the economics of geothermal resource development. Permeability stimulation in the oil and gas industry is accomplished by increasing near-wellbore permeability with techniques such as hydraulic, chemical, thermal, or explosive fracturing. To determine the potential applicability of these techniques to geothermal wells, a decision was made to conduct a study to define the state of the art in oil and gas stimulation technology as it might apply to geothermal operations.

FY 1984 Activities

In FY 1984, Santrol Products, Inc., under contract to Sandia, began a study of the state of the art of well stimulation in the oil and gas industry. The study is investigating (1) types of well stimulation techniques, (2) technical areas of geothermal well stimulation research, (3) materials for geothermal well stimulation, and (4) previous geothermal well stimulation field experiments. As FY 1984 came to a close, the study was nearing completion, and a report was expected in November 1984.

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APPENDIX A

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