U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

GEOTHERMAL TECHNOLOGIES PROGRAM

Drilling
1976 – 2006

A History of Geothermal Energy Research and Development in the United States

Cover Photo Credits

Pumpernickel Geothermal Site, Pumpernickel, Nevada
(Courtesy: Nevada Geothermal Power Inc.)

This history of the U.S. Department of Energy's Geothermal Technologies Program is dedicated to the many government employees at Headquarters and at offices in the field who worked diligently for the program's success. Those men and women are too numerous to mention individually, given the history's 30-year time span. But they deserve recognition nonetheless for their professionalism and exceptional drive to make geothermal technology a viable option in solving the Nation's energy problems. Special recognition is given here to those persons who assumed the leadership role for the program and all the duties and responsibilities pertaining thereto:

- Eric Willis, 1976-77
- James Bresee, 1977-78
- Bennie Di Bona, 1979-80
- John Salisbury, 1980-81
- John "Ted" Mock, 1982-94
- Allan Jelacic, 1995-1999
- Peter Goldman, 1999-2003
- Leland "Roy" Mink, 2003-06

These leaders, along with their able staffs, are commended for a job well done. The future of geothermal energy in the United States is brighter today than ever before thanks to their tireless efforts.

Table of Contents

List of Figures

List of Tables

Preface

In the 1970s, the publicly available information about geothermal systems was woefully inadequate. The understanding of geothermal resources and the means for their optimum development was primitive. Much of the extant information was held in private company files. Lack of information meant only a few companies invested in exploration and resource development. Utilities did not understand the geothermal resource, especially the risks and costs of development, and they were therefore reluctant to sign long-term geothermal power purchase agreements. For the same reasons, financial institutions were wary of funding geothermal energy projects. Development of the large resource base in the United States, apart from The Geysers in California, was essentially stagnant. This was the environment in which the U.S. Government's geothermal research and development (R&D) program began.

The intent of the geothermal program was to understand geothermal resources, improve geothermal science and engineering technology, and ensure that information was publicly available to geothermal stakeholders, such as developers, utilities, financial institutions, regulators, and others necessary to spur development of a vital, progressive geothermal industry. As this report will demonstrate, the intent was achieved, to the benefit not only of geothermal energy development in the United States but also around the world.

This report is one of a series issued by the U.S. Department of Energy (the Department) to document the many and varied accomplishments stemming from the government's sponsorship of geothermal research since 1976. The report represents a history of the major research programs and projects that have had a lasting impact on the use of geothermal energy in the United States and those that promise to have an impact. We have not attempted to write the definitive history of the Geothermal Technologies Program and the $1.3 billion that were expended through 2006 on geothermal research. Rather, we have brought together the collective memories of those who participated in the program to highlight advances that the participants deem worthy of special recognition.

In particular, this report examines the work done in one key area of geothermal technology development: drilling. Companion reports cover work in other areas, including Energy Conversion, Exploration, and Reservoir Engineering. The history focuses on the period from 1976 to 2006 when the Department was the lead agency for geothermal technology research as mandated by the Geothermal Research, Development and Demonstration Act of 1974. The earlier groundbreaking work by precursor agencies, such as the National Science Foundation, Atomic Energy Commission, U.S. Geological Survey, and the Energy Research and Development Administration, is cited as appropriate but is by no means complete.

Those wishing to learn more about certain topics discussed herein should consult the references listed in the report. These sources give the reader access to a much larger body of literature that covers the topics in greater detail. Another useful source of information about the Department's geothermal research can be found in the Geothermal Technologies Legacy Collection (www.osti.gov/geothermal/) maintained by the Office of Science and Technology Information.

The budget history of the federal geothermal research program during the 30-year period documented here is included as Appendix A. That portion of the budget devoted to drilling is highlighted and amounts to about $140 million in actual dollars. Funding for work in drilling ended in fiscal year 2006 with a decision by the Department to refocus limited funding resources on higher priority needs within the Office of Energy Efficiency and Renewable Energy. That decision did not preclude future work in this area, as the needs for geothermal technology development are assessed. This report summarizes the products and benefits of that earlier research investment.

Acknowledgements

While the many contributors to U.S. Department of Energy-supported geothermal drilling research and development over the years are too numerous to acknowledge by name, we wish to mention those who participated in writing this report. The primary author was John T. Finger (retired) of Sandia National Laboratories, for many years a principal investigator in the drilling program. Contributing authors include David A. Glowka (retired), Joseph A. Henfling, Arthur J. Mansure, Ph.D. (retired), Randy A. Normann, and David W. Raymond of Sandia National Laboratories. Contributors from Brookhaven National Laboratory include Thomas A. Butcher, Ph.D.; Lawrence E. Kukacka (retired); and Eugene T. Premuzic, Ph.D. (retired). Peter H. Smeallie of Research Opportunities Management wrote the section on the National Advanced Drilling and Excavation Technologies Program. Elizabeth C. Battocletti and Allan Jelacic served as the report's technical editors. These persons deserve credit for assembling a history of impressive accomplishment that will continue to reap benefits for many years to come. To the individuals whose efforts are not specifically identified in this report, the Department and authors offer their sincere gratitude.

Introduction

This report summarizes significant research projects performed by the U.S. Department of Energy (DOE)'s Geothermal Technologies Program[1] over the past 30 years to overcome challenges in energy conversion and make geothermal electricity more cost-competitive. The Energy Research and Development Administration (ERDA)[2] and later DOE, funded drilling research and development (R&D) to support geothermal development in the United States. Industry partners provided private-sector cost-share on many projects.

At the onset of DOE's efforts in the 1970s, DOE program managers were responsible for as many as 20 individual drilling projects. By the 1980s, work at the national laboratories was primarily conducted at Los Alamos National Laboratory (LANL) and Sandia National Laboratories (SNL). SNL assumed management responsibility of DOE's drilling technologies program in the early 1980s. This document focuses primarily on the research work done since the early 1980s with some discussion of research done in the 1970s. An important element of SNL's responsibility for the drilling program was its insistence on close cooperation with industry. SNL technical staff and management met regularly with panels of key industry personnel. These personnel had no contractual relationship so they could give frank assessments of SNL projects. This feedback was extremely valuable in directing (and sometimes ending) a broad range of projects.

A major component of the capital investment in a geothermal power plant is the cost of drilling and completing wells for both production and re-injection. Research directed toward reducing drilling costs has been underway since 1975. Topics have covered improved drill bits, lost circulation detection and mitigation, high-temperature instrumentation, better communication with the downhole environment, and systems studies of various aspects of the drilling process. This report gives a summary description of the projects completed. It highlights significant accomplishments and cites numerous primary references on major projects. Over the past decades, DOE's drilling technology program adopted a two-pronged approach to reduce drilling costs by:

- Developing technologies to realize incremental reductions in drilling cost.
- Pursuing higher risk, longer term R&D on advanced concepts that may ultimately lead to tremendous reductions in cost.

DOE's drilling technology program (largely through SNL) has resulted in expertise in the following technology areas:

- **Improved drill bits:** Faster penetration and longer life.
- **High temperature downhole instrumentation:** Monitor drilling process and evaluate reservoir.
- **Rig instrumentation:** Monitor operating conditions, optimize drilling performance, and identify problems.
- **Lost circulation analysis and treatment:** Mitigate lost circulation through early detection and develop new technology for plugging loss zones.
- **Slimhole drilling:** Enable cheaper exploration with smaller diameter wells.
- **Systems analysis:** Ensure that the right problems are being solved.
- **Field operations:** Demonstrate new technology in real drilling situations.
- **Program management:** Integrate a multi-discipline research program.
- **Work with industry:** Develop partnerships, contracts, and cooperative agreements with over 50 companies.

Whatever the application, holes must be drilled in the ground to access a geothermal resource. Geothermal drilling is generally more expensive and difficult than oil and gas drilling at similar depths. Because a typical geothermal power plant requires holes for both fluid production and re-injection, ***a well field often accounts for 30 percent to 50 percent of the total capital cost of a geothermal power plant project***.

Due to their ultimate magmatic origin, most geothermal reservoirs are found in igneous or metamorphic rock. Although they are loosely defined as large volumes of hot rock, significant reservoirs have been developed in sedimentary rock. Typical rock types in geothermal reservoirs include granite, granodiorite, quartzite, greywacke, basalt, and volcanic tuff.

Geothermal formations are hot (163°C to over 315°C [325°F to over 600°F]), often hard (more than 35,000 pounds per square inch [psi] compressive strength), abrasive, highly fractured, and under pressure (i.e., pressure of the pore fluids at some depth is less than the pressure of the drilling fluid in the wellbore at the same depth, even if the drilling fluid is water). Geothermal formations often contain corrosive fluids and large amounts of dissolved solids, making drilling unusually difficult. The rate of penetration (ROP) and bit life are typically low, corrosion is often extreme, lost circulation is frequent and severe, and these problems are compounded by high temperatures. Well completions are also more expensive due to extreme lost circulation and difficulties in placing and controlling the curing time of cements used in setting wellbore casing at high temperatures.

Three requirements to produce useful energy economically from a geothermal reservoir include:

1. High rock temperature.
2. Access to the geothermal reservoir from the surface.
3. A permeable formation so that the heat withdrawn by the extraction technology is replaced by convection within the formation.

Because electricity, unlike heat, can be transported over distances, electrical generation is the goal of most geothermal development. Geothermal power generation development can only successfully occur if the three items cited above exceed threshold values which vary from site to site. All existing geothermal power plants use the in situ fluid, produced through natural permeability, to transport heat.

While geothermal drilling has improved and become more effective over the past three decades geothermal wells are still significantly more expensive than comparable oil and gas wells. In a typical year, tens of thousands of oil and gas wells are drilled in the United States, compared to less than 100 geothermal wells. Virtually all the tools and techniques used in geothermal drilling derive from the oil and gas industry. The geothermal industry's small market share has not given equipment manufacturers and service companies the incentives to develop and market geothermal-specific products[3] (Figure 1).

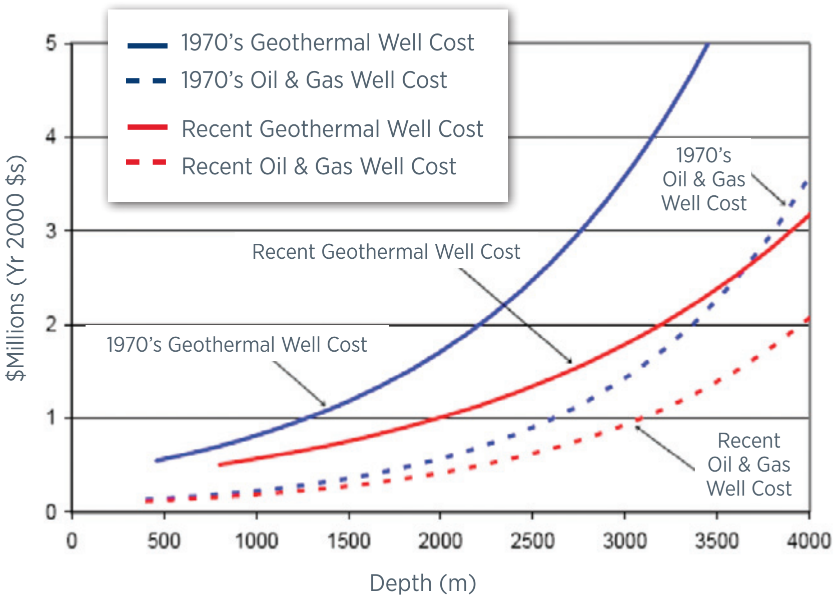

Figure 1. Trends in geothermal well cost compared to oil and gas wells

Today, geothermal power plants are generally located near surface manifestations such as hot springs, geysers, and fumaroles. Further development of the United States' geothermal resource will require deeper drilling into harder rock.

DOE's Enhanced Geothermal Systems (EGS) sub-program is poised to address the absence of sufficient fluid and permeability by creating fractures in the rock and circulating fluid from the surface. It has been estimated that 100,000 megawatts electric (MWe) could be in place by 2050 from the United States' EGS resource.[4] A diagram of an EGS power plant is shown in Figure 2. Drilling costs will be a significant barrier to EGS, and drilling research even more critical as the immense EGS resource is tapped. As a result, these more challenging EGS targets will exacerbate issues seen thus far.

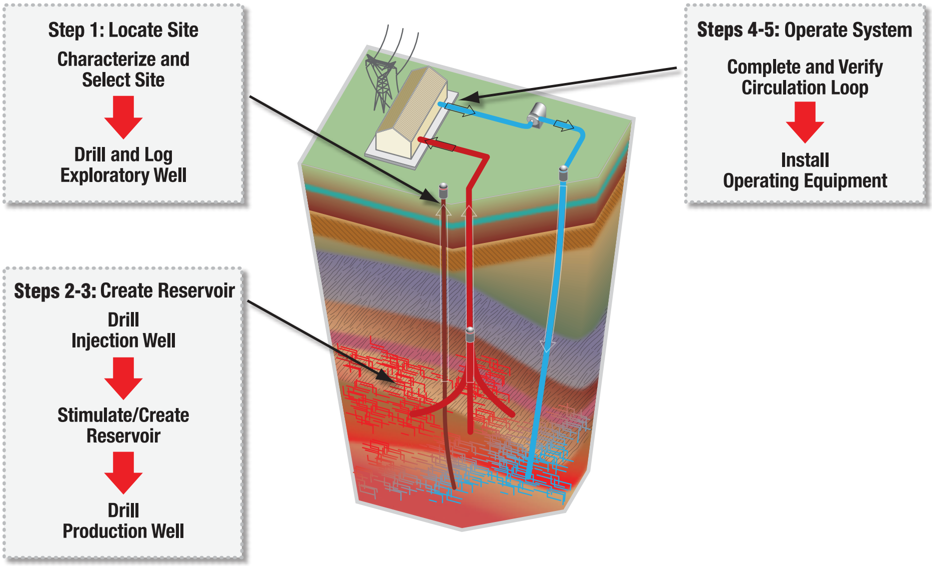

Figure 2. Diagram of an Enhanced Geothermal Systems power plant

This document summarizes drilling R&D projects carried out by DOE and national laboratory researchers since the inception of the U.S. geothermal research program in 1975. Drilling research projects are grouped primarily by drilling function, and secondarily by chronology. While all major projects are described, emphasis is placed on those judged most successful or influential.

Accomplishments and Impacts

Table 1 summarizes DOE's drilling program accomplishments that have had a direct impact on the geothermal industry. Some of them have also been adopted by the oil and gas industry. They are not ranked according to importance or priority. Each has made a significant contribution to fulfilling the goals of the federal geothermal drilling R&D program.

Table 1. Major advances resulting from the Department of Energy's geothermal energy conversion R&D programs, 1976 – 2006

Technical Area	Accomplishment	Significance	Industry Measure
Drilling (rock reduction) and drilling-related technology	Developed fundamental understanding of design and performance for polycrystalline diamond compact (PDC) bits	Analysis and experiments enabled effective, balanced bit designs	Catalyzed a $2 billion/year industry; significant industry use of PDCWEAR bit design code; "Energy 100 Award"
	Created cooperative bit test program and tested bits from four manufacturers under controlled conditions with real-time data	New bit designs performed substantially better in hard rock than original baseline design	Bit designs with highest performance are available commercially
	Designed insulated drill pipe (IDP) and successfully tested a prototype string in a geothermal well	IDP gives much lower downhole temperatures in a hot well, especially important with electronics	Insulated drill pipe has been commercialized and is available in industry
	Developed Diagnostics-While-Drilling (DWD) system to provide high-rate, real-time downhole data during drilling; demonstrated improved bit performance	Downhole forces are often very different from surface indications; DWD gives immediate feedback on dangerous or destructive conditions	Design and performance data released to industry; at least two service companies have built similar tools
	Built dynamic drilling simulator with active vibration control in SNL's Hard-Rock Drilling Facility (HRDF)	Downhole forces are often very different from surface indications; DWD gives immediate feedback on dangerous or destructive conditions	Design and performance data released to industry; at least two service companies have built similar tools

Technical Area	Accomplishment	Significance	Industry Measure
Logging and instrumentation	Cooperated with Honeywell to develop high-temperature unshielded electronics that can operate almost indefinitely at 300ºC LANL developed many high-temperature logging tools with long residence times for reservoir evaluation Designed and built an acoustic telemetry device that delivers downhole data to the surface via stress waves in the drill pipe SNL developed relatively low-cost memory tools for logging Upgraded optical fiber for long-term, high-temperature monitoring in production wells	This technology eliminates the need for fragile, expensive Dewars to protect electronic components In the 1970s few commercial tools were available for hot dry rock (HDR) conditions; project would have been impossible without tool development Data rate is ~ 10 times higher than conventional mud-pulse telemetry; acoustic tool can operate with any drilling fluid If real-time data is not required, memory tools are much simpler and cheaper than wireline logging Knowledge of production wells' temperature profiles is critical for reservoir management	SNL designed an application-specific integrated circuit to be produced by Honeywell and made available to geothermal operators or service companies; "R&D 100 Award" Commercial logging company spun off of LANL development program; HDR was critical in demonstrating the concept now known as EGS Acoustic tool has been extensively field tested and commercialized; "R&D 100 Award" Several memory tools, including the Core Tube Data Logger, were commercialized multiple times Improved doping process has been patented
Slimhole drilling	Proved small diameter holes can accurately characterize a geothermal reservoir	Slimholes provide a lower cost method for geothermal exploration	Slimhole exploration now used in industry; SNL published "Slimhole Handbook" as a reference

Technical Area	Accomplishment	Significance	Industry Measure
Improved Components	Brookhaven National Laboratory (BNL) developed high-performance cement for geothermal casing	Conventional cement did not resist high temperature or CO_2, allowing casing corrosion and early failure	Cement commercialized and proven in the field (over 1000 tons sold to date); "R&D 100 Award"
	Developed polyurethane (PU) grout system for plugging severe lost-circulation zones	PU grout is often effective where other methods fail; at Rye Patch, Nevada, grout succeeded after 20 cement plugs had failed	Enabled the successful completion of a DOE Geothermal Resources Exploration and Definition (GRED) project
	Originated the concept of a "Rolling Float Meter" (RFM) for accurate measurement of drilling fluid outflow	RFM gave improved accuracy over existing paddle meters; comparison of in- and out-flow is critical for early detection and treatment of lost circulation	RFM was used on many commercial geothermal wells during its development; design was transferred to industry and tool was commercialized
	Partnered with two companies on Low Emission Atmospheric Metering Separator (LEAMS), an improved steam separator	"Carryover," the liquid part of the steam discharge, can be a detrimental side effect of drilling and well testing	After demonstration in a geothermal field, LEAMS has been commercialized and in steady use; "R&D 100Award"

Major Research Projects

DOE drilling research activities at the national laboratories ran from 1976 through 2006. This document provides summaries of those activities that took place over 30 years of research. This research is summarized in the following focus areas:

1. Rock Penetration
2. Additional Drilling Tools
3. Logging and Instrumentation
4. Drilling Fluids and Wellbore Integrity
5. Slimhole Drilling
6. Systems Analysis
7. Analytical Studies
8. Geothermal Drilling Organization
9. Scientific Drilling Management
10. National Advanced Drilling and Excavation Technologies Program

In general, the research summary in each of these areas is given in chronological order.

1.0 Rock Penetration

Rock penetration, a mature technology, is the very definition of "drilling." Howard Hughes, Sr. patented the roller-cone bit in 1909. In the century since, there have been many attempts to develop new ways to crush and cut rock. DOE's geothermal drilling program focused on methods suited to harder, more abrasive formations characteristic of geothermal reservoirs. Bit research has had two major objectives: to drill faster and to drill longer. The projects described below addressed both goals.

1.1 Spark Drill

Soviet scientists originated the concept of using spark discharges to create shock waves in drilling mud in the mid-1960s. Rock is fractured not only by direct pressure but also by the formation and collapse of cavitation bubbles. At SNL, a laboratory-scale spark drill drilling at rates up to 30 feet per hour (ft/hr) created shock pressures of 2,000 to 10,000 times atmospheric pressure[5] with spark energies of 100-200 joules. The technology tested at SNL from 1976 to 1979 never reached the stage of a field prototype for two reasons. First, the spark drill produced a significant shock wave that was ineffective in drilling through subsurface rock under confining pressure and placed the rock in compression. Drilling efficiently through confined rock requires that the drilling mechanism place the rock in tension. Second, there was no feasible way to provide significant downhole electrical power to the drilling head.

1.2 Improved Roller-Cone Bits

From 1975 to 1980, efforts to improve roller-cone bits for geothermal use focused on improving steel bits with unsealed bearings as well as seals and lubricants for sealed bearing bits. This work was primarily contracted to TerraTek, Inc. of Salt Lake City, Utah. Enhanced unsealed bits were field tested at The Geysers[6] in northern California and showed a 30 percent increase in life. The majority of research was devoted to testing various seals and lubricants at high temperatures. Several new seal designs, including an all-metal face seal, were tested in a TerraTek, Inc. facility. The metal seals did not perform as well as the best elastomer seals. An evaluation of all tested seals and lubricants was published[7] at the project's conclusion.

1.3 Chain Bit

The chain bit (Figure 3) carried a chain or belt of metal links around the nose and up the sides of the bit body. Each chain link was set with natural diamonds, PDC cutters, or a combination of the two. Hydraulic pressure and a spring in the bit assembly advanced the chain around the nose of the bit when needed. This provided a new cutting surface without tripping the bit out of the hole. The chain advance mechanism worked well, cycling the chain dozens of times downhole during field tests. Drilling performance was erratic, however, due to problems with bit hydraulics and quality control on the diamonds. There was not adequate room on the face of the bit to provide enough cutters to avoid uneven loading. DOE supported chain bit R&D from 1978 to 1981.

Figure 3. Chain bit

PDC cutters available at the time were not as high in quality as those available now. The effects of heat and wear on the cutters contributed to the poor performance of the chain bit. The chain-bit concept was described in an early paper.[8] Additional detail is provided in a SNL annual report.[9]

1.4 Bit Hydraulics

As drilling fluid passes through the bit nozzles, it is important that it thoroughly cleans the bit face, so that the bit cutters engage fresh rock and no energy is wasted on re-grinding the cuttings. Bit companies studied nozzle placement in roller-cone bits in great detail, but the subject was not completely understood in the relatively new technology of PDC drag bits—especially since a critical factor for successful PDC operation was the cutter cooling provided by the fluid. To improve understanding of the flow patterns across the face of a PDC bit, SNL built a flow visualization test stand that could rotate a full-size bit in a transparent cell so that flow lines could be identified by various kinds of tracers (Figure 4). The test stand had 16 instrumentation channels. Convective heat transfer gauges could quantify cooling at different cutter locations with different nozzle configurations. The SNL facility was very valuable in understanding frictional heating in PDC cutters. DOE-supported bit hydraulic R&D was conducted from 1979 to 1982. Summary results were published as a Society of Petroleum Engineers (SPE) paper.[10] Additional detail is provided in SNL annual reports.[9/11/12]

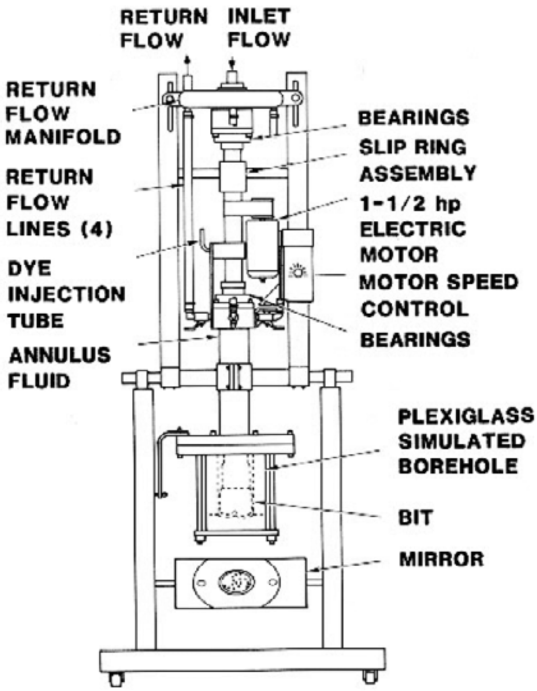

Figure 4. Bit hydraulics test stand

1.5 PDC Bits

In the late 1970s, the vast majority of oil and gas wells were drilled with roller-cone bits. The conical rollers on the bottom of these bits break rock by crushing and gouging it as the bit rotates and the cones roll across the hole bottom. The teeth on the cones are either milled out of the steel cone (for softer formations) or the tungsten carbide inserts (for harder rock and longer bit life). Both types are shown in Figures 5 and 6.

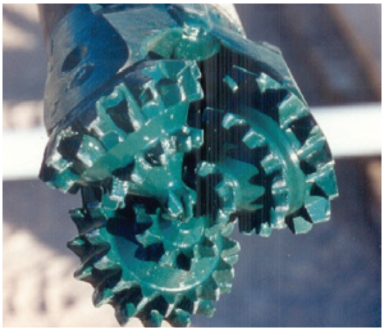

Figure 5. Mill-tooth roller-cone bit

Figure 6. Insert roller-cone bit

Drag bits, which have fixed cutters attached to the bottom of the bit and remove rock by shearing much like a machine tool cuts metal, are inherently more efficient than roller bits. Drag bits have the added benefit, especially in geothermal environments, of having no moving parts. This eliminates problems with high-temperature bearings, seals, and lubricants. However, metal drag cutters used in drilling soft formations are prone to quick wear in even moderately hard formations.

In 1977, General Electric Research Lab (GE) introduced a new synthetic material made of diamond grains sintered together with cobalt. This new material, Compax (later renamed Stratapax), could be made into various shapes and retained diamond's natural property of extreme hardness but not its weak cleavage planes. To make a cutter, a thin layer of the synthetic diamond material was deposited onto a disk-shaped tungsten carbide substrate so that the assembly, called a "compact," could be attached to the bit. Bits with this kind of cutter are generically called PDC bits (see Figure 7).

Figure 7. Early polycrystalline diamond compact (PDC) drag bits

While Stratapax appeared an ideal candidate for small element drag-bit cutters, early field results were disappointing. Compacts frequently broke or detached from their mounts. Even when they survived, they wore quickly. Figure 8 shows worn PDC cutters in a drag bit. The thin black layer on the right side of the cutter is the synthetic diamond material. Together with the carbide disc directly behind it, this forms the "compact."

Figure 8. Worn PDC cutters in a drag bit

From their humble beginnings, PDC bits now dominate the oil and gas drilling industry. PDC bit sales for 2007 were estimated at $1.9 billion, compared to $1.2 billion for roller-cone bits.[13] Although PDC bits are used in a few geothermal projects with largely sedimentary reservoirs (e.g., Cerro Prieto, Mexico), their performance in harder rocks requires improvement in order to gain broad acceptance in the geothermal industry.

To support industry R&D, DOE funded field tests and fundamental studies of rock-cutter interaction and frictional heating of the cutters through work at SNL. Improving hard-rock drilling capability for PDC bits has been one of DOE's primary missions since the beginning of the geothermal research program. Efforts toward this goal have fallen into the following groups of activities.

1.5.1 Bit-Rock Interaction

Improving the function of PDC bits in hard rock requires a clear understanding of how cutters induce failure in the rock. SNL assessed the nature of chip formation by combining finite-element modeling in rock and using the two-dimensional HONDO software analysis code with microscopic examination of cut tracks in virgin rock. These models showed that failures are primarily tensile, which is desirable because rock is much weaker in tension than in compression. Results were published in several technical papers[14-16] and in SNL annual reports.[11-12/17-21]

1.5.2 Diffusion Bonding

Many of the failures in early PDC bit testing occurred when the cutters detached from the mounting studs or bit body. This was often caused by an inadequate brazing method used to attach the cutters. SNL developed a procedure for diffusion bonding the cutters that produced more uniform attachments. The bonding process forced the compact and its mounting platform together, with a very thin layer of nickel between them, under high pressure and temperature so that atoms of the different metals actually diffused into each other. This produced bonds that were consistently strong. Nonetheless, diffusion-bonded cutters on test bits in laboratory drilling of hard, abrasive rock tended to crack and wear quickly—even though they remained attached to the bit. This performance, coupled with development of a better brazing method, led to phase-out of this project.[19/22]

1.5.3 Cutter Temperature Modeling

Frictional heating plays a major role in the wear behavior of PDC cutters. Finite-element thermal and stress models were developed for a variety of cutter configurations and exercised over a wide range of frictional heating rates, convective cooling rates, cutter materials, and rock properties.[23-25] Results were used to develop an analytical procedure for predicting the temperature of PDC cutters over a wide range of downhole conditions. The model was verified in numerous single-cutter rock tests and used with laboratory wear data to identify a critical cutter temperature (about 350°C [662°F]) above which PDC cutter wear is greatly accelerated. A series of papers was written examining the effects of factors—bit design, weight-on-bit (WOB), rotary speed, bit bounce, and type of drilling fluid—developing and quantifying concepts such as critical WOB and drillable rock strength.[26]

1.5.4 Single-Cutter Tests

The force required to push a cutter through its track in rock is a function of many variables, such as vertical force, depth of cut, type of rock, rake angle (the angle of the cutting face relative to the work), and lubricity of the drilling fluid. To model bit behavior, however, it is vital to know this force for many combinations of parameters because it relates to cutter placement on the bit, frictional heating of the cutters, wear rates, resultant lateral force on a bit cutting at given conditions, and other important quantities—all more or less related. Several series of tests to measure wear rates were conducted at GE.[27] Many single-cutter tests were also done at SNL with a milling machine modified to record three-axis forces. In another phase of GE tests, thermocouples were mounted on cutters so that measured temperatures could be compared with calculated values at the wearflat on the cutter.[24] The general use of single-cutter data is best described in an SPE paper.[28]

1.5.5 Bit Design Modeling

The principal considerations when laying out the cutter pattern on a PDC bit are: 1) The resultant of all the lateral forces (cutting forces and side forces) should be near zero so that the bit will not generate large unintentional side loads during operation; 2) All cutters should wear at a similar rate;[29] and 3) The wearflat temperature should not exceed a critical value on any of the cutters during expected operating conditions.

All three criteria were combined into a program called PDCWEAR.[30] PDCWEAR was a tool that could compare bit designs, and gain detailed information on individual cutters so that the bit design could optimally place the cutters to produce uniform cutter wear. PDCWEAR also predicted the performance of specific bit-rock combinations. The code was distributed to many bit manufacturers and is one of the major successes of DOE's geothermal research program. PDCWEAR was critical in developing the fundamental understanding of how PDC bits should be designed and operated. Research toward making PDC bits effective in geothermal drilling is still based on these criteria.

1.5.6 Full-Scale Bit Tests

Several commercial and experimental full-scale PDC bits were field tested in the early years of DOE's geothermal program at The Geysers and Imperial Valley in California, and at Baca Ranch in northern New Mexico. Full-scale bits were also tested under laboratory conditions[31] resulting in useful conclusions regarding what direction bit design should take. Further bit development at the time, however, was victim to the oil and gas bust of the early 1980s. The number of rigs in the United States dropped from over 4,500 to less than 1,000, and the number of PDC bit manufacturers dropped from over 20 to less than six. Those companies that did remain were only interested in markets in which they were highly successful—soft sedimentary oil and gas formations. Hard-rock PDC development fell off the horizon.

In the 1990s, deep gas and other harder formations became more common targets for hydrocarbon exploration and commercial interest in hard-rock PDC bits revived. DOE signed Cooperative Research and Development Agreements (CRADAs) with four bit companies to evaluate their "best effort" hard rock bits in full-scale field tests run in conjunction with SNL's DWD tool (see Section 2.4). No restrictions were placed on bit cutter size and type, cutter count, cutter placement, bit configuration, or bit hydraulics. The four CRADAs were signed with ReedHycalog (A Grant Prideco Company), Security DBS Drill Bits, Smith Bits – GeoDiamond, and Technology International, Inc.

DOE partnered with Security DBS Drill Bits, a product service line of synthetic diamond drag bit manufacturer Halliburton Energy Services, Inc., to obtain and test a conventional drag bit that had been previously used for numerous production drilling applications.

Phases 1 and 2 of the CRADA involved generating baseline hard-rock drilling data for a conventional drag-bit design that was operated with and without DWD feedback. These tasks also accomplished the proof-of-concept requirements for DOE's DWD program.

SNL transferred full data sets from the Phase 1 and Phase 2 CRADA/DWD POC tests to each CRADA partner to support its separate development of a "best effort" hard-rock bit design and DWD-based drilling strategy for demonstration in Phase 3 of the CRADA. The same constraints were used in Phase 3 as in the drilling done during Phases 1 and 2—namely drilling interval and bottom-hole assembly (BHA).[32] The Phase 1 and 2 data served as a baseline for comparison with the Phase 3 data each company received for its own bit. The high-speed, real-time data from Phase 3 were not available from any other source.

Testing to assess the relative hard-rock drilling capabilities of the benchmark PD5 drill bit—a drill bit model manufactured by Security DBS Drill Bits—and "best effort" drag bits was scheduled at the test site managed by the Gas Technology Institute (GTI, formerly the Gas Research Institute) in Catoosa, Oklahoma. The Catoosa test site (Figure 9) has a well-known hard-rock Mississippi limestone formation known as "The Wall," which is an interval of hard (compressive strength > 35 thousands of pounds psi) limestone below about 1,300 ft. The test site featured a uniform, well-characterized lithology and an experienced, test-oriented drilling crew. Industry clients commonly use The Wall for PDC bit validation tests.

Figure 9. Catoosa test site, Oklahoma

Even though the proprietary requirements of the CRADA meant that test results were reported anonymously,[33] three of the "best effort" bits performed significantly better than the baseline PD5 bit used in Phases 1 and 2 of the CRADA. Bits A, B, and C fully penetrated The Wall's Mississippi limestone formation with average ROPs of 78.2, 76.4, and 54.7 ft/hr, respectively. These values were dramatically higher than the Phase 2 average of 33.0 ft/hr for the PD5 bit. Runs for Bit D and the PD5 (Phase 1) bit ended in the Mississippi limestone at depths of 1,386 ft and 1,492 ft, respectively, when the bits could no longer advance the hole due to cutting structure damage.

Like the PD5 bit in Phase 2, "best effort" Bits A, B, and C also successfully transited the hard and abrasive Misener sandstone interval. Bit A maintained a very high (93.8 ft/hr) ROP through this formation, whereas the ROP for Bits B and C dropped to 35.2 and 13.5 ft/hr, respectively. These results compare to the Phase 2 average of 67.0 ft/hr for the PD5 bit in Misener sandstone.

Beyond the Misener sandstone, Bit A continued with high average ROP (86.5 ft/hr) in the hard Arbuckle formation, ultimately reaching a final depth of 1,913 ft before the available rig time was exhausted. In total, Bit A traveled 811.6 ft in 8.535 hr, corresponding to an overall average ROP of 95.1 ft/hr. (Overall ROP averages include footage drilled in soft intervals above and between the hard intervals.) Bit B progressed only a short distance at low ROP in the Arbuckle before drilling was suspended at 1,632 ft due to a washout in the DWD downhole tool. Bit B drilled a total of 465.6 ft in 6.311 hr—an overall average ROP of 73.8 ft/hr. The ROP for Bit C recovered somewhat in the Arbuckle, averaging 24.5 ft/hr from 1,627 ft until drilling ended at a final depth of 1,670 ft, also because of a DWD downhole tool washout. The overall average ROP for Bit C was 53.0 ft/hr. In comparison, the PD5 bit in Phase 2 reached a final depth of 1,632 ft after making 525.5 ft of hole in 12.029 hr—43.7 ft/hr as an overall ROP average. These results are summarized in Table 2. "Overall average" includes drilling soft formations above the Mississippi limestone.

Table 2. Rates of penetration for bits tested at "The Wall" at the Catoosa test site, Oklahoma

Formation (Interval depths)	Mississippi Limestone (1,252-1,549 ft)	Misener Limestone (1,578-1,650 ft)	Arbuckle Dolomite (1,605-2,200 ft)	Overall Average
PD5 "proof of concept" bit	33.0	67.0		43.7
Bit "A"	78.2	93.8	96.5 to 1,913 ft	95.1
Bit "B"	76.4	35.2	Low to 1,632 ft	73.8
Bit "C"	54.7	13.5	24.5 to 1,670 ft	53.0
Bit "D"	Low to end at 1,386 ft			

All test bits provided valuable information to their respective manufacturers for further development of hard-rock PDC bits. These tests demonstrated that real-time knowledge and control of drilling conditions greatly benefited bit performance in hard rock, which is a necessity for PDC applications in geothermal drilling.

1.5.7 Innovative Cutter Configurations

Virtually all of the early PDC research through 1990 used off-the-shelf cutters because prototype cutters were expensive and difficult to obtain. As processing technology improved, manufacturing original and complex cutter shapes became more straightforward and interest was renewed in evaluating what specific properties were important for drilling performance in hard rock.[34] DOE built two test facilities at SNL specifically for this investigation—1) a linear cutting test facility (LCTF) to measure tri-axial forces on a cutter at various cut depths, rake angles, and rock types; and 2) a laboratory-scale drilling rig, the HRDF (Figure 10). Non-standard cutters with varying parameters were evaluated at both facilities.

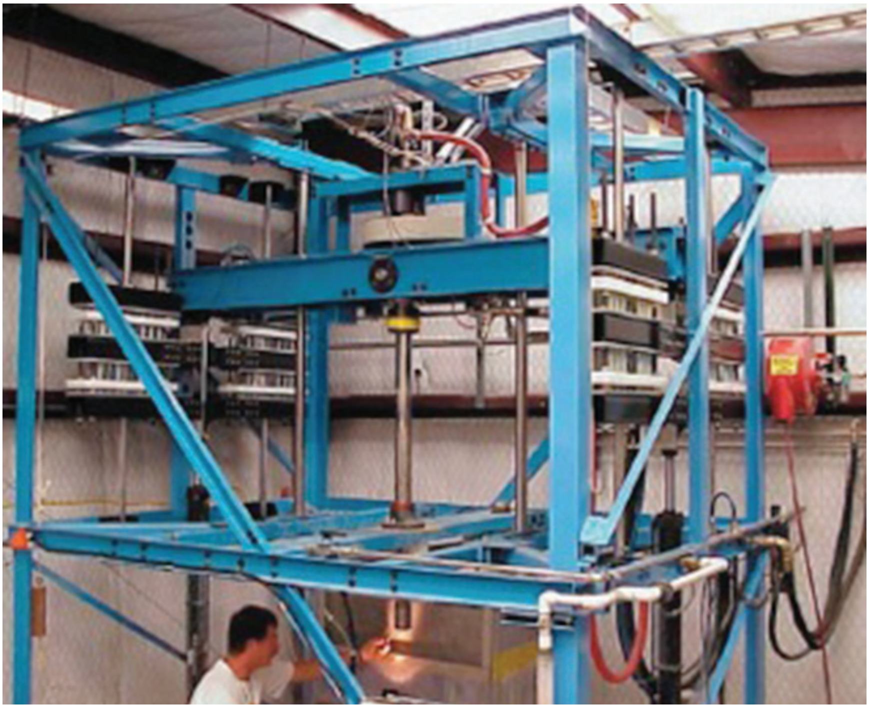

Figure 10. Hard-Rock Drilling Facility (HRDF)

Each lot of non-standard cutters consisted of about 20 identical cutters fabricated with the same design and processing specifications. Geometric variables included diamond table thickness, chamfer design, and diamond table substrate interface configuration. Material and processing variables for the diamond table included, respectively, the nominal diamond particle size or size distribution and the cubic-press line pressure that was maintained during the high-temperature cutter sintering operation. Figure 11 shows various diamond-substrate interface configurations. Lot-to-lot parameter variations for the study included four diamond grain sizes, one bimodal grain-size distribution, one tri-modal grain-size distribution, three sintering pressures, four diamond table thicknesses, three edge-chamfer configurations, and four diamond table substrate interface patterns.

Cutters from each lot were subjected to several types of testing, including linear cutting-force and rotary drilling tests at SNL and drop-impact and granite-log abrasion tests at U.S. Synthetic. U.S. Synthetic manufactured PDC cutters—including the non-standard cutters that were tested. Cutting-force tests involved tri-axial dynamometer measurements of the load components acting on a single cutter while it produced linear cuts in Sierra White Granite (SWG) on the LCTF. For each cut, force components were continuously recorded and then averaged to calculate the mean values of penetration, drag, and side loads for a given depth of cut (DOC). Measurements were taken for sharp (i.e., unworn) cutters, as well as for test cutters that had sustained wear during drilling tests on the HRDF.

Figure 11. Various diamond-substrate interface configurations

To acquire cutter wear data, a three-cutter coring bit mounted in the HRDF drilled a series of holes that passed nearly through a three-foot cube of SWG. Cutters from a given lot were installed in the bit at the inside gage, test (middle), and outside gage locations, with a borehole diameter of 3.278 inches and a core diameter of 1.222 inches. Simulations with PDCWEAR guided placement of the cutters to balance their individual contributions to the net side force on the bit. In the final design, the test and outside gage cutters were angularly located on the bit face at 114 degrees and 276 degrees, respectively, relative to the inside gage cutter at 0 degrees. All three cutters were set with the same projection above the bit face. A rotational speed of 100 revolutions per minute (rpm) and a ROP of 30 ft/hr were maintained during drilling.

Abrasion resistance was measured by turning down the outer diameter of a log of Barre Granite using a lathe equipped with a single PDC test cutter. The log was 10 inches long with an initial diameter of about 9.5 inches after truing. Testing ended when the log diameter was turned down to about 7 inches. Post-test measurements on the cutter and rock allowed determination of the "G ratio," which corresponds to the volumetric ratio of removed granite to lost test-cutter material.

Cutter impact resistance was determined using a drop-impact tester. For drop-impact tests, a cutter was rigidly mounted in a holder and then struck at prescribed impact energy by a hardened steel plate attached to the lower surface of a falling dead weight. This process was repeated up to 10 times for a given cutter at fixed impact energy. The final percentage of the diamond table surface that had spalled was measured and recorded. If the spall exceeded 30 percent of the cutter facial area after any drop, the cutter was deemed to have failed and no additional impacts were performed. For each drop, an accelerometer attached to the dead weight provided time-resolved data for the impact loading history.

Tests showed that variations in design and processing parameters dramatically affected the drilling, abrasion, and impact performance of PDC cutters under conditions consistent with the penetration of hard rock formations. Linear cutting-force data confirmed and quantified large increases in drag and penetration force components as a consequence of drilling-induced wearflat growth. Wearflat measurements from the rotary drilling tests indicated a ratio exceeding 10 for the best versus worst wear rate. This result was consistent with measurements from the granite-log tests that showed a factor of almost 13 between best and worst abrasion resistance. The drop-impact data provided evidence of a wide range of design-dependent failure rates, with excellent impact resistance being demonstrated by several cutter formulations, including one that was expected to exhibit high-wear resistance at the expense of limited fracture toughness. Several principles of cutter design emerged from compiling data from all tests:

- Thin (0.040 inch) diamond tables had poor drilling and abrasion performance.
- Thick (0.160 inch) diamond tables had poor impact resistance.
- Fine (10μm) diamond grain size provided the best drilling and abrasion results, while coarse (70μm) grain size yielded the worst results.
- Impact resistance generally improved with increasing grain size but some fine-grained cutters also had high survival rates.
- Higher cubic-press line pressures tended to improve drilling, abrasion, and impact performance.
- The bimodal grain-size distribution outperformed mono-modal grain-size distribution in abrasion tests, but underperformed for drilling.

PDC bit manufacturers used these results to change bit designs and improve hard-rock performance.

1.5.8 Impact of PDC Bit Research on Roller-Cone Bits

While PDC drag bits were not widely adopted in geothermal drilling, PDC technology was also used to improve the performance of roller-cone bits. Maintaining the gage (diameter) of the drilled hole frequently limited roller-cone bit life. The gage section of roller-cone bits was re-engineered using polycrystalline diamond material, minimizing gage control problems even in the hardest rocks, and allowing shoe-to-shoe (drill with a single bit trip) roller-cone bit life in many geothermal formations. In addition, PDC-coated tungsten carbide inserts were used across the full face of some bits with encouraging improvements in cutting structure life. Thus, PDC research improved roller-cone bit performance.

1.6 Percussion Drilling

The hard, crystalline fractured rock typical of geothermal formations is well-suited to impact drilling because there is little or no plastic deformation of the rock. Percussion drilling uses a reciprocating downhole piston and anvil assembly to apply impact loading to either a conventional roller-cone bit or a one-piece bit set with tungsten carbide inserts (see Figure 12). In 1980 and 1981, the following percussion drilling techniques were evaluated at the Drilling Research Laboratory (DRL) of TerraTek, Inc. in Salt Lake City, Utah:

- Air-powered hammers were used to drive both types of bits drilling in SWG. Penetration rates were compared with conventionally used roller-cone bits.
- A mud-powered hammer developed by the Amoco Research Center was evaluated.
- A hammer with a solid-head bit, designed for air operation, was successfully run with stable aqueous foam as the drilling fluid, showing that the greater cuttings carrying capacity was available for this application.
- An air-powered hammer was run at high temperatures (204°C-232°C [400°F-450°F]) for over 14 hours until it failed. Failure did not appear related to temperature.

Figure 12. Solid-head bits for percussion drilling

All the hammer tests showed greater penetration rates than conventional drilling under comparable conditions. The major handicaps, however, were gage wear on the solid-head bits and the necessity for accurate WOB control for all the hammers. The percussion drilling technology appeared promising for better penetration rates. Results were reported to the Geothermal Resources Council (GRC)[35] and in a peer reviewed article,[36] with additional detail in SNL Annual Reports.[18-19]

1.7 Jet Erosion Drilling

An early effort in DOE's geothermal R&D drilling program involved using high-pressure fluid jets for direct rock cutting and to augment mechanical cutting. From 1979 to 1981, most research was contracted to the University of Missouri-Rolla (UMR); Foster-Miller, Inc.; and Flow-Tech Industries, Inc. Principal activities included:

1. Evaluating erosion resistance of various materials that could be used in drilling hardware.
2. Evaluating various rock types for their susceptibility to jet cutting.
3. Conducting economic analysis to establish what performance levels would be necessary in a jet-drilling system.
4. Evaluating various methods of delivering high-pressure fluid downhole.

Research concluded that high-pressure fluid delivery technology was not advanced enough at the time to continue further study. Contractor reports by UMR,[37] Foster-Miller,[38] and Flow-Tech Industries[39] summarized test results. Additional detail is available in DOE progress reports.[11/18]

1.8 Cavitating Mud Jets

Liquid jets that produce cavitation, (i.e., bubbles created by the inertia of a moving fluid) are much more destructive to rock than conventional jets. This is because the bubbles' collapse produces micro-jets with impact pressures of over 100,000 psi—enough to fracture any rock. Interrupted high-pressure jets are much more destructive to rock than steady jet pressure. Cavitating jets were investigated for both direct rock cutting and to augment mechanical cutting by either roller-cone or drag bits (Figure 13). The majority of this work was contracted to Hydronautics, Inc. of Laurel, Maryland, and conducted intermittently from 1979 to 2005. Efforts focused on improving understanding of the fundamental nature of the cavitation process, testing various jet configurations, and developing numerical models of the different aspects of the flow regime.

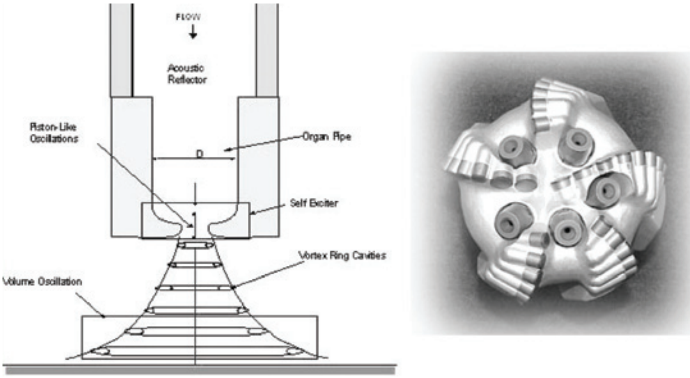

Figure 13. Diagram of a pulsating jet (left) and photo of an actual PDC drag bit with pulsating-jet nozzles (right)

The efficient design of cavitating nozzles is very complex. Ideally, cavitation should occur at the lowest possible pressure drop across the nozzle, so that operation is not limited by the drill rig's pump capacity. The bubbles formed by the jet should be large, maximizing their destructive power. As fluid flows through the nozzles, it tends to shed a train of vortices at characteristic frequencies. This effect can be used with a chamber upstream of the nozzle to produce a resonance at that frequency and amplify the cavitation effect. To make it all work together effectively, however, it is necessary to define variables related to nozzle design, resonant chamber design, rock-nozzle standoff distance, driving pressure, ambient pressure, and nozzle materials. Initial research from 1978 to 1984, produced a number of experimental results, theoretical advances, and numerical models of various parts of the flow regime. Results were documented in SNL annual reports[2-7] and in reports from Tractor Hydronautics, Inc.[40]

Subsequent cavitating mud jet R&D was continued by Tracor Hydronautics, Inc. and DynaFlow, Inc. In the mid-1990s SNL revived interest in the concept of jet-augmented PDC bits using moderate pressures that are reasonable for use on conventional drill rigs. The basis for renewed interest was reported cost savings of $20,000 to $400,000 per bit run in petroleum drilling literature. Replicating such costs savings in geothermal drilling could be possible with mud jet augmentation due to cutter-force reductions with the technique. Smaller cutter forces would reduce both abrasive wear and the dynamic bit behavior that leads to cutter impact damage.

Prototype bit design took advantage of the increased understanding of structured resonating jets. Research entailed both full-scale laboratory drilling tests and cutter-force tests on individual cutters. Drilling tests showed improved ROP, and single-cutter tests confirmed cutting-force reductions in the presence of the jets. A significant hardware advance was the development of a nozzle with a tungsten carbide backed, polycrystalline-diamond orifice.

2.0 Additional Drilling Tools

Many drilling tools influence the environment in which the bit operates and therefore its performance. SNL has worked on controlling vibration and impact at the bit because PDC bits are particularly vulnerable to these conditions. Tools for this purpose and other non-bit drilling tools are described below.

2.1 Motor Seals

Downhole motors for geothermal drilling were severely limited by the short life of bearings and seals. Thus from 1976 through 1982, research focused on evaluating various lubricants and seals for geothermal use and developing a modular, replaceable bearing package that could be used in many kinds of downhole motors. Almost all this work was done under contract, primarily at the DRL in Salt Lake City, Utah—the site of specialized equipment for seal testing, lubricant evaluation, and bearing-package testing. DOE, through a contract from SNL, funded the building and testing of the prototype bearing package.

The specific goal of 200-hour seal life at 121°C (250°F) was achieved. The best candidate seals and lubricants were identified and later commercialized by their respective manufacturers. The bearing package, however, was not a complete success. Early in the design process, the decision was made to trade sophisticated instrumentation for a field-ready package that could go to downhole testing after reaching a level of laboratory success. In retrospect, this was not a good choice because it obscured some of the failure mechanisms in extended testing. A floating piston that separated lubricant from mud, with essentially no pressure drop across it, also had intractable design problems.[41] A number of ideas for advancing these concepts are described in a SNL annual report[42] and a DOE report.[43] Cuts in program funding led to the termination of the motor seal project.

2.2 Turbodrill

Downhole motors just above the bit, which provide power to turn the bit without drillstring rotation, are advantageous for geothermal drilling for two reasons: 1) they reduce drillstring wear in abrasive tortuous holes, and 2) they are almost essential for directional drilling, where the hole trajectory must be controlled to follow a given path. Three types of motors received substantial research and development: 1) electric motors, 2) positive displacement motors, and 3) turbines.

Electric drilling motors have not been successful in the United States primarily because it is very difficult to reliably transmit substantial electric power downhole, and positive displacement motors have elastomeric elements that are vulnerable to geothermal temperatures. DOE supported turbodrill R&D from 1977 to 1980 and 1997 to 1999. Turbines, however, seem adaptable to geothermal conditions.

Maurer Engineering of Houston, Texas designed two high-temperature, high-performance turbines for DOE's HDR program, managed by LANL at Fenton Hill, New Mexico.[44] One version of the turbine was intended for straight-hole drilling in the upper part of a hole where temperatures are lower (i.e., < 200°C [392°F]). The other "geothermal" version was intended for directional drilling in conditions up to 350°C (662°F). Each version was built in two diameters—5-3/8 inches and 7-3/4 inches. Both sizes used high-torque blade designs and separate, non-elastomer bearing packages with roller thrust bearings. Because of the relationship between torque and rotary speed in a turbine (i.e., maximum torque at stall; zero torque at runaway), the turbines could be used for high-torque roller bits at 100-200 rpm and low-torque diamond bits at 600-800 rpm. The combination of large thrust bearings (which were cooled by diverting approximately 10 percent of the drilling fluid through them) and high-torque blade design also allowed high bit weights for drilling in hard rock.

The geothermal turbodrill was field tested in both the laboratory and the Fenton Hill EE-2 HDR well, where it drilled at an average rate of 23 ft/hr, compared to 10 ft/hr with rotary drilling using the same type of 12-1/4-inch insert roller bit.[45] The drilling interval in EE-2 was 57 ft (4,855-4,912 ft). The test ended due to severe gauge wear on the bit, which was most likely caused by reaming approximately 150 ft before reaching the hole bottom. It is possible that very high rotary speeds damaged the bit; there was no direct way of measuring the turbine's rotary speed while drilling.

To alleviate this problem, Maurer Engineering designed a turbine tachometer to measure rotary speed in real time while drilling.[46] The tachometer used one rotor/stator pair with partially blocked blades, producing a pressure pulse in the drilling fluid with every revolution (very similar to operation of conventional measurement while drilling [MWD] systems). Counting the pressure pulses was not entirely straightforward. Desurgers had to be used in the flow loop to damp pressure pulses from the mud pumps, and spectrum analyzers were necessary to differentiate the tachometer signals from the pump pressure spikes. These effects were accommodated, and the tachometer gave reliable readings while drilling in the EE-2 hole at depths below 10,000 ft.

In spite of the initial turbodrill's successful operation at Fenton Hill, there was still considerable rationale for a motor with higher torque and lower rotary speed. Just such a machine[47] was the product of adding a gearbox to the straight-hole turbodrill described above. The gearbox, in conjunction with revised blade design, increased torque from 950 to 7,800 ft per pound (ft/lb) and reduced speed from 1,100 to 80 rpm. Because of higher torque, the turbodrill was much easier to operate in the field, as it was less likely to stall, which was especially important when using a bent sub for directional drilling. Improved torque also allowed higher bit weights for better performance in hard rock. To demonstrate this performance in the laboratory, a 12-1/4-inch insert bit was loaded to 60,000-lb WOB with no rotation and flow rate was increased until the bit began turning. Rotation began at 300 gallons per minute (gpm)—half the rated flow rate of 600 gpm—indicating that stalling was highly unlikely, even with a bent sub.

A field test in a Petróleos Mexicanos (PEMEX) well in Mexico used the geared turbodrill to drill from 526 ft to 1,750 ft at rates of 111 to 207 ft/hr compared to 76 ft/hr with rotary drilling in offset wells. The large variation in ROP was the result of the rig crew's limitation of pump pressure and WOB during the early part of the interval. After increasing standpipe pressure from 2,800 psi to 3,500 psi and WOB from 10,500 lb to 18,000 lb (for a 12-1/4-inch PDC bit), the drilling rate improved accordingly. At 1,750 ft a friction thrust bearing failed in the turbodrill, but the builder planned to replace that design element with ball thrust bearings similar to the ones used successfully in positive-displacement drilling motors.

2.3 Insulated Drill Pipe

As drilling fluid flows down the drill pipe through the bit and up the annulus, it typically transfers heat to or from the formation. Because steel drill pipe acts very much like a counter-flow heat exchanger, the temperature of drilling fluid in the drill pipe is very close to its temperature in the annulus at the same depth. Both are close to the formation temperature. Consequently, in high-temperature formations, drilling tools in the BHA are exposed to hot or very hot fluids. This has several unfortunate effects. Elastomer components (i.e., seals and downhole motor stators) are challenged, expensive and delicate electronic steering and logging tools can be damaged or destroyed, corrosion rates increase, and the drilling fluid itself can be degraded. All of these problems can be solved or mitigated by adding insulation to the drill pipe wall so that drilling fluid reaches the bottom of the hole at a much lower temperature.

SNL first considered IDP in 1986 during the Magma Energy Program, when planning was underway for drilling into molten rock at temperatures exceeding 815°C (1,500°F). Figure 14 is a schematic of an insulated drill pipe. Calculations made at the time[48] showed IDP's benefits and necessity at extremely high temperatures. Researchers subsequently determined that IDP would be valuable even at lower, conventional geothermal temperatures. DOE contracted with two companies to produce prototype designs. Changes in program funding, however, prevented either version from reaching the hardware stage.

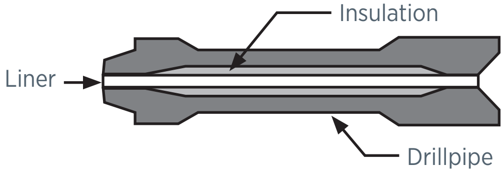

Figure 14. Schematic of an insulated drill pipe

In 1997, the Geothermal Drilling Organization (GDO) approved an IDP project (see Section 8.5). Drill Cool Systems, Inc., located in Bakersfield, California, partnered with DOE to develop a commercially viable product. SNL researchers working in Drill Cool's labs participated in several tests to measure the effective conductivity and mechanical strength of various IDP configurations. Results of the conductivity tests were used with GEOTEMP2, a thermal simulator, to predict IDP's effect in realistic drilling conditions. These calculations confirmed the potential benefit predicted in earlier analyses and are shown in Figure 15. In the fluid temperature curves, the left-hand curve is in the pipe, the right-hand curve is in the annulus.

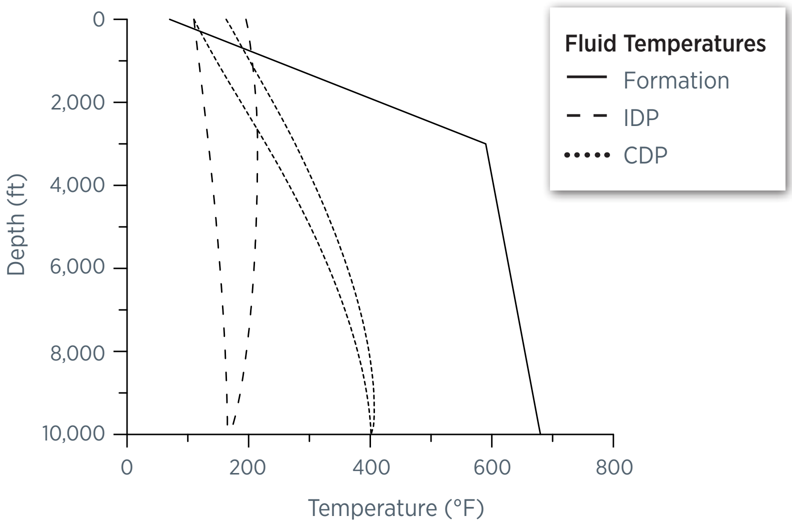

Figure 15. Comparison of drilling fluid temperatures in conventional and insulated drill pipe

This phase of IDP development culminated with a 1999 field test in a well located in the Imperial Valley in southern California. Strings of 5-inch diameter IDP and 4-1/2-inch conventional drill pipe were suspended in a borehole and water circulated through them. Fiber-optic temperature sensors inside and outside of the pipes measured temperatures in the pipe and annulus, and measurements were compared with calculated values. The test not only demonstrated that IDP had the predicted effect on drilling fluid temperatures, but also that the GEOTEMP2 code accurately evaluated the effect of changes in IDP parameters (e.g., conductivity value, diameter, etc.) This work was described to the Geothermal Resources Council,[49] the Society of Petroleum Engineers,[50] and in a DOE report.[51]

IDP design has evolved from its original form (an inner tube strong enough to support internal pressure—that is, not applying pressure to the insulation) to a version with insulating material strong enough to support significant pressure, allowing for a lighter, thinner inner tube. Although this design change mitigated all previous drawbacks, IDP has not found wide acceptance in the geothermal industry. Major points of market resistance include the additional cost and weight of the pipe, as well as the fact that insulation in the drill pipe reduces the inside pipe diameter and causes higher hydraulic pressure drops in drilling fluid circulation.

2.4 Diagnostics-While-Drilling

While there have been many attempts to use real-time downhole information while drilling and to correlate measurements at the surface and downhole, combining high-bandwidth downhole data with high-rate surface measurements is relatively rare. From 1999 to 2005, SNL pursued the development of continuous-transmission, high-bandwidth, downhole data technology known as "Diagnostics While Drilling." Routine use of DWD could reduce the cost of geothermal drilling by providing a tool that could be utilized in almost all parts of the drilling process. Data from downhole could provide a real-time report on drilling conditions, bit and tool performance, and imminent problems. The driller could then use this information to change surface parameters (e.g., weight-on-bit, rotary speed, and mud flow rate) and immediately know their effect. With the full DWD system envisioned, the driller could return control signals downhole to operate active components.

A system that provides high-speed, real-time, downhole data adds value to virtually every part of the drilling process and has far greater potential than just the original application aimed toward bit dynamics. The value of real-time data was a consensus of two workshops[52] convened by DOE and later corroborated by industry.[53] Participants at an industry forum identified improvement in real-time data processing and interpretation as the most important technology need for reducing flat time (i.e., the time the rig is over the hole with the hole not advancing). Industry was enthusiastic about the concept of a very-high-data-rate information and control channel. Some foresaw the ability to do a complete log of the hole as it was being drilled, eliminating the traditional time and expense of a wireline logging unit after drilling.

DWD system development was shaped by the nature of the measurements to be made as well as the nature of geothermal drilling. In controlling the drilling process, it is not always easy to know which downhole measurements are most critical or the frequency at which those quantities should be sampled. SNL's approach was to measure as many quantities as practical and to sample them at as high a rate as practical. This resulted in a high (200 kilo bits per second [Kbps]) transmitted data rate, providing the ability to process all data at the surface and to display downhole measurements in different combinations as conditions changed. Overall system definition was also driven by several considerations:

- To improve overall drilling performance, it was necessary to minimize damage to PDC bits, which offer significant advantages in ROP. Damage is often caused by phenomena with rapid onsets and high-frequency behavior, such as chatter and bit whirl.
- Improvements were needed in the reaction time (compared to very slow mud-pulse telemetry) for a damaging condition to be recognized.
- Geothermal drilling often used air or aerated mud as the drilling fluid, precluding mud-pulse telemetry. (Electromagnetic measurement-while-drilling [EM-MWD] had limited success with compressible fluids.)

The first application of a DWD system was aimed at bit dynamics, specifically at improving the performance of PDC bits in hard formations typical of geothermal reservoirs. SNL focused on the forces and accelerations which were relevant to bit dynamics in the prototype version of the DWD tool. Measurements made included:

- Three-axis acceleration.
- High-frequency axial acceleration.
- Angular acceleration.
- Magnetometer (for rotary speed).
- WOB, torque-on-bit (TOB), bending moment.
- Drill pipe and annulus pressure.
- Drill pipe and annulus temperature.

The DWD "sub," a generic name for any part of a drill string that lacks a specific name, was a tubular tool, 7 inches in diameter by approximately 85 inches long, with a central electronics sensor package suspended by three-legged supports inside an outer case that provided the flow channel for the drilling fluid. Strain gauges for TOB, bending, and WOB were bonded to the outer case and covered with protective shells. Other sensors were mounted in the central package. Downhole electronics received analog signals from the sensors, conditioned them, converted them to digital format, and then transmitted the data uphole through a wireline inside the drill pipe. A cutaway layout of a DWD tool is shown in Figure 16.

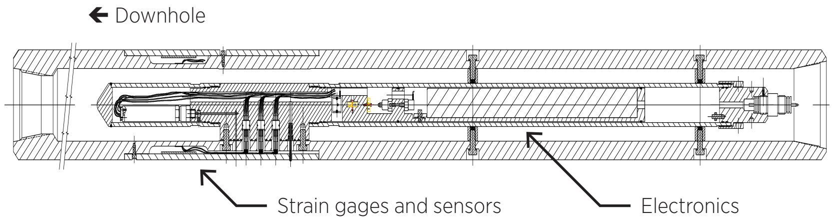

Figure 16. Cutaway layout of a DWD tool

The wireline was a conventional single-conductor cable with connections that could be made and broken while immersed in drilling fluid, and an electrical swivel that allowed the lower part of the cable to rotate relative to the upper part while still maintaining electrical continuity. In addition to being commercially available, a wireline system had at least two major advantages: 1) downhole electronics could be powered from the surface, eliminating the need for downhole batteries, and 2) the wireline could be quickly extracted from the drillstring for maintenance or repair.

After a number of preliminary tests described in detail in a DOE report,[54] the first major phase of DWD development culminated with a proof-of-concept test at "The Wall" located at the Catoosa Test Facility near Tulsa, Oklahoma. Two identical holes were drilled using identical PDC bits, eliminating as many variables as possible, so that test data analysis could focus on the effects of DWD on drilling performance.

Both holes used identical PDC bits and the same bottom-hole assemblies. Phase 1 consisted of drilling through an upper, softer interval (from approximately 800 to 1,100 ft) with a roller-cone bit to get baseline data, followed by drilling with a PDC bit from the end of that interval to a depth at which the bit would be worn or damaged to the point that it could no longer make useful progress, or to a maximum depth of 1,800 ft, whichever came first. During this drilling, downhole data was recorded but not used to control the WOB, rotary speed, or other drilling parameters.

In Phase 1, the bit run without using DWD control lasted from 1,106 ft to 1,492 ft (386 ft drilled). This run was ended by an interval of extremely rough drilling, after which the bit would not advance farther, even with significant increases in WOB. Figure 17 shows a comparison of surface and downhole WOB data from that run. It is clear that surface readings did not reflect the violent fluctuations downhole, where the bit was actually bouncing off the bottom.

Phase 2 consisted of drilling from approximately 810 ft to 1,105 ft (the same interval drilled with the roller-cone bit at the beginning of Phase 1) with a PDC bit identical to the one used in Phase 1, providing baseline comparison of PDC and roller-cone performance in relatively soft formations. At 1,105 ft, a second bit with the same body as that used in Phase 1 but refurbished with new, identical cutters was used to drill to either bit failure or 1,800 ft. Results are reported in considerable detail[54] and in an SPE paper.[55]

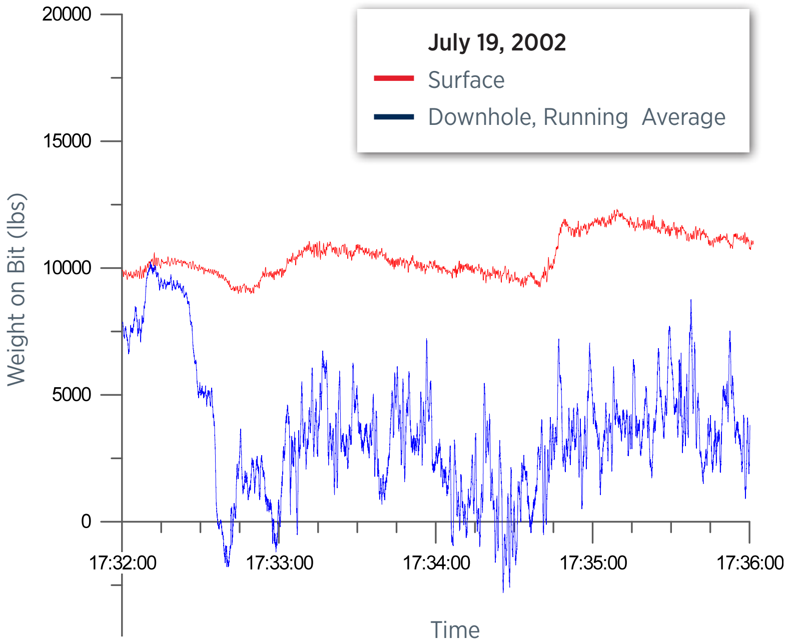

Figure 17. Comparison of surface and downhole data during high-vibration event in Phase 1

In Phase 2, with the driller using DWD feedback, the bit lasted from 1,106 ft to 1,615 ft (509 ft drilled), and still performed well at 1,615 ft. The test was terminated only because the test facility was scheduled for another client. Even though the bit lasted longer in the second run, the ROP for that run was somewhat lower than in the first run.

While the successful proof-of-concept test marked the end of the first phase of DWD development, there was considerable industry interest among bit companies, who recognized the value of real-time downhole data in bit development. DOE entered into a CRADA with four bit companies to implement cost-shared tests with them as part of their development of hard-rock PDC bits (see Section 1.5).

The DWD development program's objective was to perform a proof-of-concept test using the most basic tool design and then, if successful, to upgrade the DWD tool for high-temperature geothermal applications. The upgrade would use electronic components and sensors that provided the same functionality and measurements as the low-temperature system and qualified for continuous operation at 225°C (437°F). Because the low-temperature tool used many specialized integrated circuits not available in high-temperature versions, major design consequences ensued. The high-temperature electronics package comprised discrete components and was thus much larger, which also required a very significant mechanical re-design of the tool. (The volume of the high-temperature electronics module was approximately 6.5 times that of the low-temperature module.) Comparison of relative size between high-temperature and low-temperature DWD tools is shown in Figure 18.

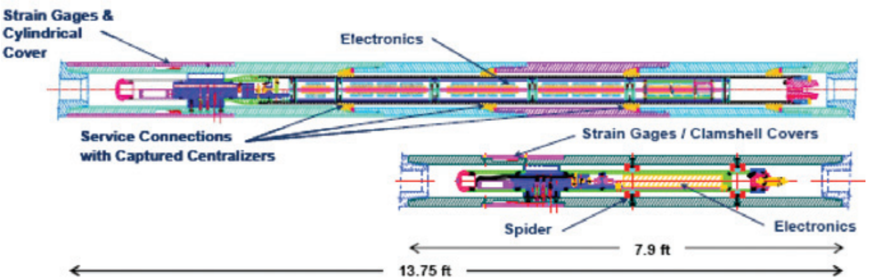

Figure 18. Comparison of relative size between high-temperature (top) and low-temperature (bottom) DWD tools

In September 2005, the high-temperature DWD was moved to Ormat Technologies, Inc.'s Galena Geothermal project in Steamboat, Nevada where it was used to drill 90 ft of 8-1/2-inch holes to a depth of 895 ft.[56] The tool performed flawlessly with no mechanical or electronic failures, and the test was considered a success. The drilling contractor's driller, who had no preliminary knowledge of the test, was skeptical of the equipment, but enthusiastic by the end of drilling, commenting that it was much easier to control WOB with the high-temperature DWD than with the inaccurate gauge normally used.

All design drawings and test data from the DWD program are available to industry, with the exception of some proprietary tests done in partnership with bit companies. Since the end of DOE's DWD program at SNL, a few service companies have developed similar capabilities, primarily for in-house research.

2.5 Drilling Dynamics Simulator and Active Vibration Control

Control of the drillstring is yet another facet of understanding the downhole environment. Having a long, compliant drillstring above the bit, in combination with the formation, hydraulics, and bottom-hole assembly, adds performance variables that can lead to a variety of vibration modes, including bit bounce, stick-slip, and whirl. These vibration problems become more frequent as drilling progresses into deeper and less favorable formations.

Drillstring vibrations have been studied for many years,[57] including mode coupling[58] and other ancillary effects.[59] Beginning in 2004, many research efforts and field investigations endeavored to develop models to quantify vibrational instability regimes arising from the interplay between the forcing function associated with rock and bit interaction (e.g., the reduction of rock by the drill bit) and the vibration of the drillstring. Field testing, however, is not the most efficient way to gather experimental data. Testing in the field is very expensive and there are many uncontrolled environmental variables such as lithology at the bit.

SNL used two approaches to investigate drillstring vibration at laboratory scale: mechanical analogs and computer-controlled servo-hydraulic systems. With a mechanical analog, the objective is to reproduce the scaled stiffness of the drillstring under consideration using spring-mass systems. This was done in a laboratory-scale drill rig at SNL, the HRDF, to introduce longitudinal compliance representative of a typical drillstring. The bit carrier had a heavy weight mounted on it. Some of the weight was held back by hydraulic cylinders, just as the driller holds back some of the drill collar weight with the brake on a real drill rig. This modification worked well. SNL reproduced bit bounce exactly analogous to phenomena observed with the DWD system in field drilling tests. Rotational compliance was also introduced using torsional springs. Coupling between the axial and rotational axes was observed during drilling tests using this system.

The mechanical analog system had drawbacks, however. It was difficult to introduce multiple modes of vibration, and the analog only represented a specific drilling situation. Any arbitrary drillstring will almost certainly require a new mechanical analog set-up. As a result, SNL pursued a model-based system in which an analytical model controlled fast-acting servo-hydraulic actuators to control the compliance. SNL computationally modeled the drillstring using real rock-bit interaction to generate the forces used as input in the model, and then predicted or prescribed how the system would respond to these forces. It then became a matter of enforcing the correct displacement at the interface between the bit and BHA using fast-acting actuators so that the bit "feels" like it is in the hole at depth. The drilling function is performed by an actual bit in a representative rock sample, yet the bit will behave as though it were attached to a long, flexible drillstring specified at the user's discretion. The HRDF was used to demonstrate a prototype system using this approach.[60]

Like the mechanical analog approach, model-based control comprised two primary equipment subsystems: a drilling simulator and a dynamics simulator. The drilling simulator consisted of a drill rig gantry with a vertically traversing frame (see Figure 19). The dynamics simulator supported the drill bit, producing the dynamic compliance of the drillstring at the bit using fast-acting actuators controlled by a model of a drillstring. The vertically traversing frame supported the dynamics simulator in the same way that fixed compliance was accommodated in the mechanical analog.

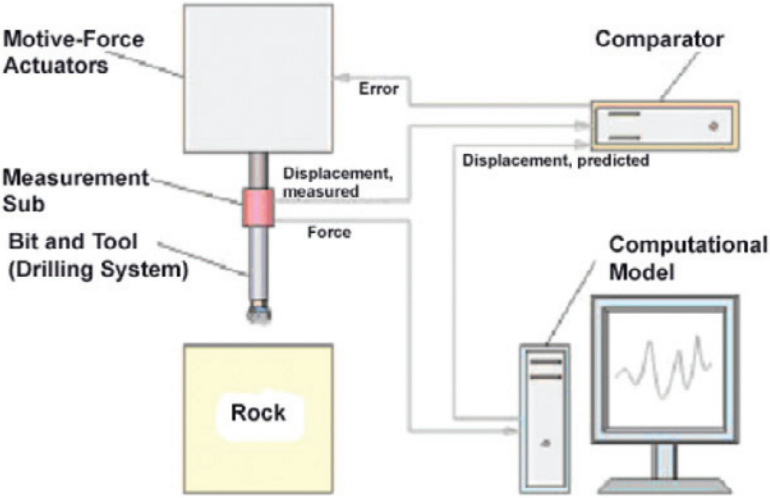

Figure 19. Drilling dynamics simulator concept

Development of a model-based system, aimed toward a proof-of-concept test, was quite complex and required development in several areas:

- **Simulation Requirements:** The frequency response of the drillstring to an arbitrary force input from the bit must be known. The objective for the prototype was to reproduce the response of the mechanical analog.
- **Predictor:** The predictor is the computational model or other rule-based algorithm that controls the dynamics simulator. The predictor runs in real-time and only has to predict the drillstring response at the next time step.
- **Dynamics Simulator:** This is the mechanical system (top drive, actuators, rock support, and sensors) that applies and controls the forces to the drillstring.
- **Servo-Hydraulic System:** Once the force and response time (bandwidth) for the actuators are determined, the hardware can be selected. SNL chose Xcite Systems actuators for the prototype system.

- **Controller:** This controls the actuators. The approach to integrate the controller that drives the dynamic simulator was designed to have a system run in parallel and completely autonomous from the drilling function performed by the drilling simulator. This autonomous system samples the measurements from the measurement sub, sends them to the predictor, transmits the predicted command to the controller, and the controller sends a command signal to the actuators.

The model-based system underwent a drilling test in SWG. The look and feel of an actual field drilling record was clearly evident in the data displays. Data taken during drilling test with the model-based system is shown in Figure 20. Torque (black), RPM (green), WOB (red), and ROP (blue) were all very similar to equivalent data taken during actual field drilling with the DWD system. The cyclic nature of the drilling was dominated by the lowest mode comprising the system. The total force on the system did not exceed the combined static and dynamic force limitation of the servo-hydraulic system. That is, the system was not force-limited by the bit-rock contact forces.

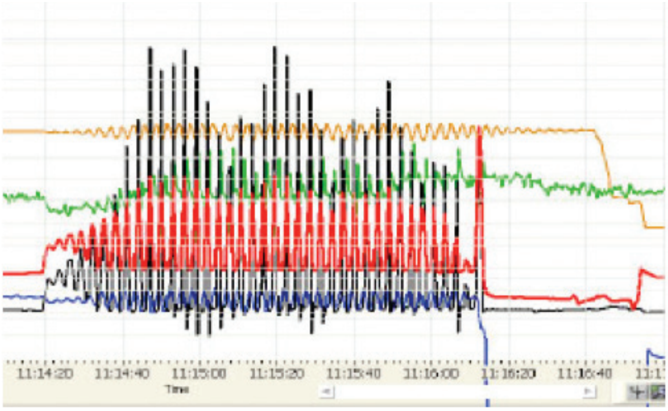

Figure 20. Data taken during drilling test with the model-based system

The test successfully demonstrated the model-based concept, showing it capable of reproducing realistic drill bit dynamics in the laboratory and exceeding the capabilities realized by simulations using simplistic mechanical analogs. The test resulted in:

- An improved understanding of how a bit interacts with a formation and the drillstring.
- Improved bit designs.
- More realistic testing capability to validate shock-vibration tolerant material developments.

- Improved evaluation of downhole hardware.
- Cost-effective evaluation of best practices.
- Influence of rock properties on the stability of the drilling process.
- Influence of drillstring modes of vibration and their effect on drill bit response.

The quantitative benefit of controlling drill string vibrations is to prolong the life of the drill bit and other components comprising the drill string. Retrieving and replacing damaged downhole tools is an extraordinarily expensive and time-intensive process, easily costing thousands of dollars of rig time plus the cost of damaged components. Reduced drill string vibration also results in enhanced rates of penetration as it allows the drill bit to operate using its intended cutting mechanism.

As this work showed, because vibration is a problem in drillstring dynamics, the next logical step was to investigate dampers in the drillstring. Dampers are commonly used in drilling, often without success. The most likely cause of their poor performance is the failure to properly select damper specifications relative to the parameters of the bit, drillstring, and formation being drilled—all of which change from well to well. A controllable damper that could be easily and quickly adjusted during a drilling operation would be desirable.

Controllable damping can be achieved with magneto-rheological (MR) fluids, which contain a suspension of iron particles and whose viscosity can be controlled remotely by application of a magnetic field. The power required is low because the controlled volume of MR fluid is low. A prototype MR damper fixture was built for the HRDF; drilling tests were run in SWG and sandstone. Bit displacements in both were roughly an order of magnitude lower with the damper than with a rigid drilling assembly.

Based on this success, a prototype drilling sub with MR damping was built and run in the HRDF, drilling into SWG. Again, comparing bit accelerations with and without the damper showed a dramatic reduction in vibration with the damper. This work was patented.[61] SNL has licensed this technology to an industrial partner that is pursuing commercialization of MR dampers for the drilling industry.

Vibrations in hard rock have been shown to be particularly damaging to bit cutting structures. The ability of a damper to suppress damaging drill string vibrations for various BHAs in different rock types is shown in Figure 21. Comparison of the solid lines in the graphic illustrates the peak vibration levels encountered in a drilling test in the HRDF in sandstone and SWG. Repeating the same tests in SWG with a damper designed for this drilling condition, the dashed line shows a significant reduction in the amplitude of bit vibration experienced by the bit.

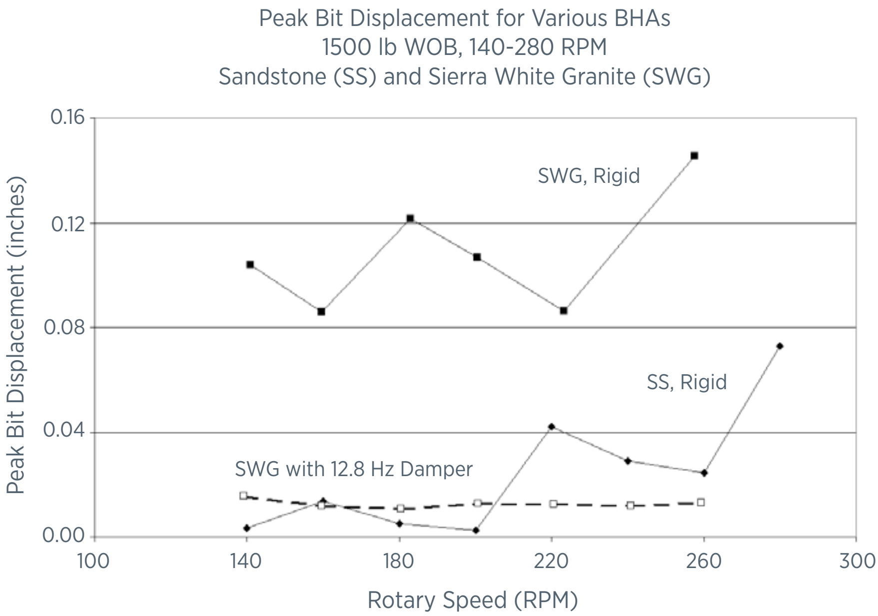

Figure 21. Peak bit displacement for various bottom-hole assemblies in sandstone and Sierra White Granite

3.0 Logging and Instrumentation

Instrumentation's critical importance is clear due to the multiple, conflicting theories about what is happening in the hole. Downhole information provides "ground truth," enabling the driller to choose which theory best fits what is actually happening underground.

The most important change in drilling technology in the last 60 to 80 years is the vast improvement in the quantity and quality of information available from down the hole. From the beginning of its geothermal R&D program, DOE recognized the vital economic and technical importance of downhole information. Economics are vital to project financing. Banks and investors need to know how many wells are needed and the size of the potential resource. A minimum upfront investment to answer these questions requires choosing the correct downhole instrumentation to accurately evaluate future drilling conditions and reservoir performance. Once a geothermal project is funded, instrumentation is needed to ensure that the technical objectives of drilling and completing the well for geothermal power production are met.

Downhole data collected while drilling characterize reservoir conditions, drilling performance, or both. Downhole data could lead to a change in drilling method to achieve greater efficiency and lower cost. It affects the decision to set casing, initiate lost circulation mitigation, and possibly even implement preventive measures to avert a disastrous loss of well control. During production, downhole monitoring presents a more accurate picture of pressure and temperature at the production horizon. This enables efficient reservoir management and maximizes the reservoir's useful life. Finally, the extensive logging and testing that usually follow drilling are critical to verifying the reservoir's value and making decisions about its further development.

The same or similar measurements are made in all kinds of drilling, and much of this technology is mature for oil and gas. High temperature, however, is the major barrier for geothermal applications. DOE has maintained a research program in logging and instrumentation since the inception of its geothermal research efforts. The results achieved are one of the cornerstones of the DOE geothermal program's success.

3.1 High-Temperature Electronics

Although other parts of a downhole instrumentation package (e.g., seals, the wireline cable head, and sensors) become more difficult in high temperatures, electronic components are the principal challenge. Commercially available electronic components are generally rated at only about 85°C (185°F), unsuitable for use in geothermal environments. This leaves three choices: 1) develop electronic components that can withstand higher temperatures, 2) shield conventional components from the high-temperature environment, or 3) use a combination of 1 and 2. While DOE has pursued each approach, most work has focused on improving electronics due to their wider applicability.

In the late 1970s and early 1980s, most electronic components were manufactured to military specifications (Mil-Spec) and guaranteed to operate at 125°C (257°F). This temperature was an absolute floor. Product screening, testing, and careful selection often identified components that could operate above 125°C (257°F). Because radiation-hardened electronics derived from SNL's weapons work also tended to be hardened against temperature, SNL's first efforts combined hybrid thick-film circuits with junction field-effect transistors (JFET).[62] There were significant successes with this approach. A temperature-logging tool was operated for 1.5 hrs in a well in northern New Mexico in 1979 at 275°C (527°F)[63]—the highest operational temperature achieved at the time by an un-cooled, unshielded tool with active electronics. This research attracted intense attention from industry. In fact a seminar in 1979 drew more than 350 attendees.[64]

In the 1990s, however, the supply of Mil-Spec components decreased dramatically as manufacturers pursued smaller, faster, cheaper commercial chips. "Industrial-specification" chips are rated to only 85°C (185°F) and do not guarantee a usable operating life time.

3.2 Dewar Tools

Electronic components can be protected from high temperature by enclosing them in a thermal flask, or Dewar, as shown in Figure 22. A Dewar functions like a Thermos® bottle, with an evacuated volume between concentric shells providing insulation for the components inside. Like a Thermos® bottle, a Dewar in a hot well will eventually[65] allow the components inside to heat up to the point where they may fail. Dewars provide only temporary protection and are expensive and fragile. SNL recognized that electronics with higher temperature limits would last longer and be more reliable when placed inside a Dewar.

Figure 22. Dewared logging tool

3.3 Memory vs. Wireline Tools

Downhole information may be recovered either in real-time or through memory storage. Real-time information is advantageous when a very dynamic situation such as drilling is in progress, especially if there is reason to believe that some downhole conditions (e.g., pressure, lost circulation, bit dysfunctions) may be harmful, hazardous, or expensive. As discussed previously, however, it is very difficult to send real-time signals to the surface from a hot environment. Even relatively static conditions, such as temperature or formation properties, are often determined with wireline because the logging contractor is already on site for other purposes. For high temperatures, in addition to the aforementioned problems with electronic components, there are also issues with the wireline cable head and sometimes even the cable itself. Wireline logging is expensive, requiring specialized trucks with winches for the electrical-conductor cable that brings the signal uphole.

If real-time data is not required, a much simpler and cheaper way of logging is a memory tool that stores data on an onboard memory as it traverses the hole, and downloads the data when the tool is brought back up to the surface. Memory tools must be battery-powered, and high-temperature batteries are problematic. However, these tools can be run on small wire or cable with a simple winch, often just the rig's own hoist, and don't require a logging service company. Memory tools for geothermal logging are nearly always enclosed in a Dewar.

3.4 Silicon-On-Insulator/Silicon-Carbide

Electronic components that can operate unprotected at geothermal temperatures by thermal flasks are the ultimate goal. Achieving that goal became possible with the advent of two technologies: silicon-on-insulator (SOI) and silicon-carbide (SiC). SOI semiconductors can operate virtually indefinitely at 300°C (572°F)[66] and SiC semiconductors above 450°C (842°F)—well above existing electronic packaging technology.

SOI is the best known way to extend electronics' performance at higher temperatures. In standard commercial electronics, each transistor is built by doping pure bulk silicon to create positive or negative regions (called PN junctions) within the bulk silicon. However, as the temperature increases, and more thermally generated electrons are freed, the PN junctions begin to function poorly or even fail. In SOI, each transistor is built on an insulating, non-conductive barrier that reduces the number of thermally generated electrons by a factor of about 100. SOI components can normally operate up to 250°C (482°F), with some operating well over 300°C (572°F). SOI operates with little or no functional degradation at 150°C (302°F), unlike bulk silicon whose performance degrades above 125°C (257°F). Figure 23 is an illustration of the electro-structural properties of SOI electronics.

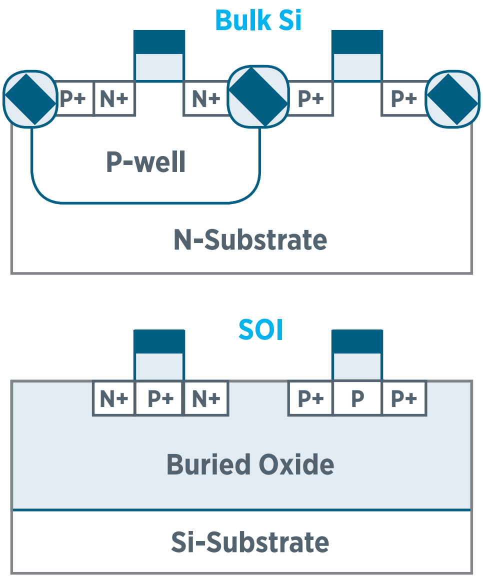

Figure 23. Electro-structural properties of silicon-on-insulator electronics

SiC devices have major advantages over silicon for handling power.[67] SiC have five times the voltage capability and twice the thermal dissipation of silicon. SiC power devices are smaller, require less cooling, and are more energy efficient than silicon for switching large currents. With SiC and SOI, electronic systems can be built with the extremely high-energy densities needed for a host of industrial applications.

Under the DOE-sponsored High-Temperature Electronics program, SNL conducted ongoing testing and evaluation research to identify and qualify suitable high-temperature components and sensors. SNL designed an electronic mud-turbine control system based on SOI-SiC technology that handled 100-300 volts (V) from the turbine while operating for hundreds to thousands of hours at an ambient temperature of 230°C (446°F).

In addition, SNL designed a custom application-specific integrated circuit (ASIC) to complement SOI components available from Honeywell International Inc. The ASIC design was fabricated at Honeywell using its SOI technology, and DOE allowed Honeywell to make the SOI device commercially available. Geothermal service companies utilized SNL component information without restriction, resulting in reduced cost to develop high-temperature unshielded tools that were not feasible even a short time prior.[68]

DOE worked with several other agencies including the National Aeronautics and Space Administration (NASA), the Jet Propulsion Laboratory, the United States Air Force, as well as the National Energy Technology Laboratory (NETL), to advance high-temperature electronics technology and field-test the SOI pressure-temperature system with long-term monitoring in three geothermal wells. SNL logged wells up to 256°C (493°F) with an unshielded tool. A test was run for 800 days in a 193°C (379°F) well.

DOE extensively promoted high-temperature electronic technology, making every effort to coordinate its own in-house development with that of commercially available products.[69]

3.5 Downhole Instrumentation for Hot Dry Rock Applications

From 1974 to 1995, LANL ran DOE's HDR program at Fenton Hill, New Mexico, The HDR program was the precursor to DOE's Engineered or Enhanced Geothermal Systems (EGS) concept in which parallel holes are drilled into hot rock lacking in situ fluid, and then artificially created fractures between the hole bottoms create a flow path where circulated fluid brings heat back to the surface.

Drilling faced a number of challenges here.[70] Holes were deep (measured depths of ~ 15,000 ft), hard (granitic basement rock below ~2,400 ft), and hot (bottom-hole temperatures above 300°C (572°F). Hole trajectories required close control; directional drilling tools and instrumentation had to operate in this harsh environment. With extended residence times in the hot environment, instrumentation had to 1) identify and accurately map fractures in the formation, 2) comprehensively characterize the physical and chemical nature of the reservoir, and 3) provide wellbore diagnostics during drilling and completion activities. Commercially available logging tools which satisfied these needs were often not available.

In response to a lack of functional tools, high-temperature instrumentation development was a major element of the HDR program for more than 15 years. Facilities included laboratories for design, assembly and calibration; autoclave testing; cable testing; and complete sonde testing. It was vital that the technical staff responsible for designing and testing these high-temperature tools, components, subassemblies, and instrument packages in the shop were also responsible for their deployment and operation in the field. Significant improvements in sonde design resulted from the staff's extensive exposure to field conditions. Under the HDR program, a number of downhole measurement tools were developed. Reports from 1978[71] and 1985[72] give a comprehensive overview of this work. Some of the logging tools developed are briefly described below.

Historically, geothermal instrumentation focused on pressure and temperature.[73] Because fractures connecting the boreholes were crucial to the success of the HDR concept, however, much of the logging tool development was directed toward instruments to detect and map fractures. The suite of acoustic-based tools included:

- Passive acoustic tools (geophones) that "listen" for the sounds of rock fracture were used to detect fracture formation during inflation or pressurization. The difference in arrival times between the P-wave and S-wave gave distance to the fracture, and there was a polarization effect that gave orientation. By using an array of geophones, an accurate picture of fractures could be developed.
- Active interrogation tools used an acoustic transmitter with a magnetostrictive source in one borehole and a receiver with a piezoelectric crystal in a separate borehole to detect fluid-filled fractures between the holes. Receiver gain could be controlled from the surface. Knowledge of the medium through which the signal passed allowed for an accurate calculation of distance between the holes.
- A televiewer uses acoustic pulses and their reflections to create a map or image of the wellbore wall (see Section 3.8). LANL's version of the televiewer, which had modular construction and used an onboard microprocessor to control data collection and transmission, was developed with Westfalische Berggewerkschaftskasse of West Germany.

A number of explosively actuated tools, for the functions described below, were also developed and used during the HDR program. The primary accomplishment of this development was the consistently safe use of thermally stable explosives with high-temperature detonators in multiple applications.

- **Back-off shots:** Used for unscrewing the drill string at a designated depth when tools below that point were stuck.
- **Acoustic-source detonator:** Could sequentially fire up to 12 detonators, generating signals for geophone calibration in adjacent wells.
- **Drill-pipe or casing cut-off tool:** Used a shaped charge to cleanly sever tubulars at designated depth.
- **Explosive fracture-initiation tool:** Used a shaped charge to initiate fractures in a specified open-hole interval. (The initial fracture is extended by hydraulic pressure.)
- **Explosive side-tracking tool:** Created a ledge in the borehole wall to provide a kick-off point for directional drilling.

Other logging tools developed and used during the HDR program include:

- **Fluid sampler:** Fluid samples taken at discrete depths are often useful in identifying reservoir properties and in recovering tracer samples.
- **Fluid injector for tracer dyes:** A metered volume of dye or acid is injected at a specified depth.

- **Caliper:** Accurate knowledge of the wellbore condition is essential for choosing a packer seat. If the hole is oversized or has breakouts, the packer's inflation element will likely rupture when it is pressurized.
- **Injector with gamma-ray detector:** Radioactive dye is released into the wellbore and the detector tracks the dye leaving through fractures. Another detector marks arrival of the dye in an adjacent hole.
- **Spinner:** Spinners measure the relative velocity of fluid flow past the tool. A spinner is usually used as a combination tool incorporating pressure and temperature, when it is known as pressure-temperature spinner (PTS) logging. Fluid velocity, as measured by the sensor, can help characterize the manmade reservoir by determining the nature and location of fractures, where and how much fluid leaves or enters the borehole, and the relative contribution of each fracture to the total reservoir.

In discussing instrumentation under these harsh conditions, it is important to remember that no logging tool is useful without the wireline that carries data to the surface and its associated cable head that connects the tool to the wireline. A number of the logging tools require multiple conductors, and the cable used at Fenton Hill, New Mexico was an armored, seven-conductor, Teflon®-insulated wireline.[74] The outer six conductors were often wired in parallel, so that the wireline simulated a coaxial cable, which was useful for some of the logging tools. Bandwidth requirements also meant that multiplexed signals were sometimes necessary, especially for the acoustic tools, so the downhole electronics for multiplexing were protected in the tools by heat shields, or Dewars.

The cable head is also crucial in providing an electro-mechanical coupling device that protects the cable's electrical conductors from the downhole high-pressure and high-temperature water environment. The cable head must also:

- Establish a transition area from the downhole fluid high-pressure environment to a dry low pressure condition.
- Provide a protected area for splicing the cable conductor ends to the high-pressure bulkhead.
- Allow the cable to separate from the cablehead (and sonde) if a sonde becomes jammed in the wellbore.
- Provide a positive gripping area (fishing neck) for overshot fishing tools in the event of cable separation.

Experience in the HDR holes also showed how essential it was that tools be calibrated in simulated downhole conditions. Temperature effects on the logging tool and wireline could create extraneous signals that could be confused with the environmental variations being logged.[75]

3.6 Wellbore Inertial Navigation System

A downhole survey tool is useful in assuring that the wellbore maintains its desired trajectory or in providing better definition if a relief well must be drilled. Under DOE's geothermal program from 1980 to 1982, an inertial navigation system developed for flight vehicles was adapted to a downhole survey tool with better positional accuracy than what existed at the time. The research produced a tool with an oven-tested electronics package that was field tested at the Nevada test site. Running in a 7,000-ft well, the survey error was less than 3 ft at total depth.

The prototype tool proved the concept. Further development could fairly easily decrease the diameter, increase the temperature capability, and improve the data rate. The prototype hardware[76] and software[77] designs were documented and a technology transfer seminar was held to introduce the design to industry.[12]

3.7 Downhole Radar

Following preliminary investigation by H-Tech Laboratories,[78] in 1984 DOE researchers began assembling and testing a downhole radar system that could map fractures without them intercepting the well bore. The system was conceived in response to SNL's request for fracture detection technology and had potential use in national security applications as well as reservoir characterization.[79] A 50-kilowatt (kW) peak power, pulsed-directional radar transmitting pulses in a known direction from a borehole was used. The transmitter and receiver rotated in place; the tool could scan for fractures in all directions from the borehole. Discontinuities in the rock interrupted and reflected the radar signals. Signals returning to the tool's receiving antenna were used to identify fractures in and around the wellbore wall.

The prototype radar was tested in an outdoor water tank at SNL; at a marble quarry near Belen, New Mexico; and in a drilled hole near an existing shaft at the Nevada test site. Known metal-plate targets existed at each site.[80] The tests gave reflections from the known targets but the system dynamic range was only about 40 decibels (dB), compared to a conventional radar dynamic range of > 100 dB. The radar went through several design changes in an attempt to improve this property,[81] but performance did not dramatically improve. Theoretical considerations indicated[82] that continuous-wave radar may have significant advantages over a pulsed system, but the concept was not pursued. Research ended in 1990.

3.8 Borehole Televiewer

In geothermal reservoirs, it is critical to know the formation's orientation, aperture (width), and fracture density. This knowledge enables the developer to direct the well's trajectory to intercept a large number of fractures and improve production, or to determine that a particular area should be abandoned. Obtaining this knowledge, however, is difficult and expensive.

Cores can be taken through the fractured zone and oriented on the surface with navigation tools, or impression packers can be expanded against the wellbore wall, then relaxed and brought back to the surface to read the "negative" image of the wall. These are slow, expensive, and cumbersome methods.

One way to continuously image the wellbore wall is to use an acoustic borehole televiewer, which uses the travel time of acoustic pulses to measure the distance from the rotating transducer to the wellbore wall. Figure 24 is a photograph of a borehole televiewer section showing the window for the rotating transducer. Since a fracture appears as a sudden drastic increase in diameter, it shows up as a distinct line on the televiewer output.[83] The televiewer also serves as a very accurate caliper gage. Figure 25 shows sample output from a borehole televiewer log. The right-hand side shows the "unrolled" picture of the wellbore wall; the left-hand side displays the same information in three-dimensional (3-D) format, showing breakouts and cavities.

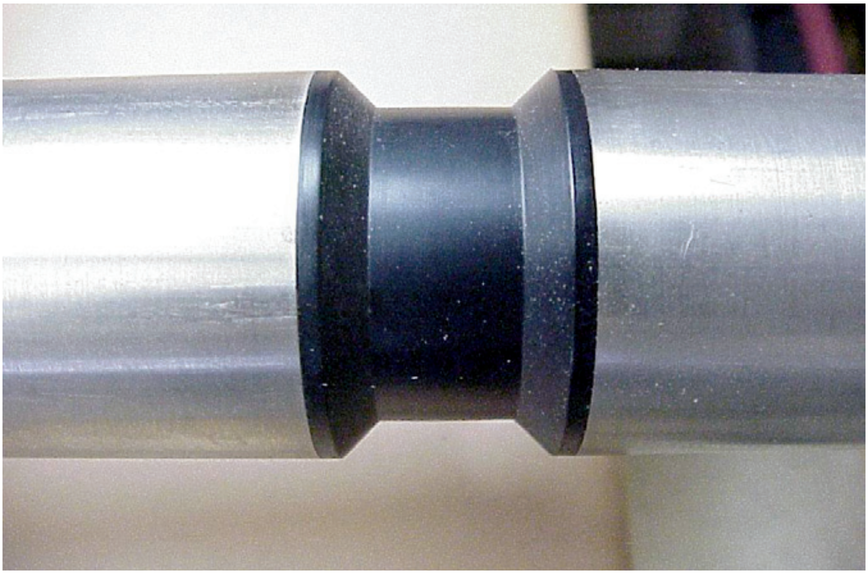

Figure 24. Bore-hole televiewer section showing the window for the rotating transducer

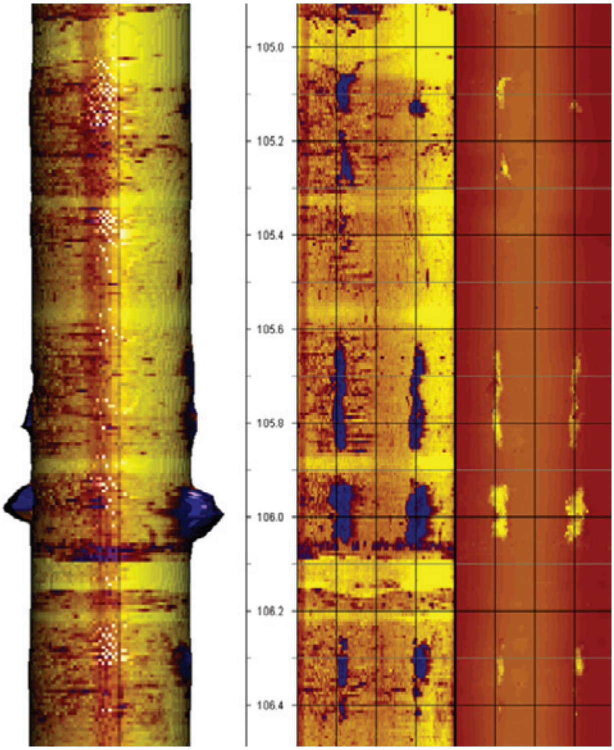

Figure 25. Sample output from borehole televiewer log

In the early 1980s, DOE developed a prototype televiewer by taking a commercially available instrument and upgrading it with Mil-Spec high-temperature electronics, seals, and materials so that it could operate (protected by a Dewar, at 275°C [527°F]) for significant periods of time. In 1985, working in partnership with two geothermal power plant operating companies, SNL developed a commercial logging tool based on the prototype (Figure 25). The televiewer manufacturer, however, redirected manufacturing toward other products and all televiewer components and design information reverted to DOE. SNL completed the proposed design modifications in-house and the tool was successfully field tested in several hot wells.[84] Two televiewer tools were built—a geothermal operator lost one in a hole in Indonesia, the other is on loan to the U.S. Geological Survey (USGS).

No domestic commercial high-temperature version of this instrument exists, although a modified version is available from a European company. A "slimhole" version of the televiewer, sized to run in 3-9/10-inch core holes, is commercially available, but not qualified for high temperatures. It was used in Phase 3 drilling at the Long Valley Exploratory Well[187] (see Section 9.4).

In 2003, DOE supported a collaborative effort between two companies, Mount Sopris Instruments of the United States and Advanced Logic Technology of Luxembourg, to develop a new-generation televiewer for use at the U.S. Navy's Coso geothermal field in California. This Dewared tool operated at 275°C (527°F) for 10 hours and at 12,000 or 20,000 psi, depending on the model. This televiewer can be purchased from Advanced Logic Technology. Results of tool performance have been published.[85]

3.9 Acoustic Telemetry

Communication between the surface and the downhole environment is critical during drilling, logging, and production. Many types of communication links have been tried over the history of drilling (e.g., electromagnetic through the earth, electrical through "wired" drill pipe, or laser pulses through glass fiber). The most commonly used today are 1) the conventional wireline, which is a conductive cable (mostly used for logging) that runs down the well and transmits an electrical signal back to the surface, and 2) mud-pulse telemetry, which uses a downhole mechanism during drilling to send a train of pressure pulses through the stream of drilling mud. These two methods have a number of drawbacks, especially for geothermal drilling:

- Drilling with a wireline in the drill pipe is inconvenient and slow.
- Mud-pulse telemetry has a very low data rate (1-3 baud).
- Mud-pulse downhole equipment will not withstand high temperature.
- Mud-pulse telemetry will not work with air, foam, or aerated mud (common in geothermal environments).
- Both wireline and mud-plus methods require another expensive service company on site.

Acoustic telemetry, on the other hand, transmits data as a string of sound waves (pressure pulses) that travel through the drill pipe from a location near the bit to the surface. Acoustic telemetry has a high data rate (over 20 baud) and operates with standard drill pipe or tubing in any kind of fluid.

DOE acoustic telemetry R&D ran from 1986 to 2003. Initial work focused on the physics associated with acoustic wave propagation in drill pipe. It was known at the time that the heavy tool joints used on drill pipe affected these signals by blocking certain broadcast frequencies, creating what are known as pass bands and stop bands. Pass and stop bands exist because drill pipe is constructed by welding heavy tool joints to light tubing. The acoustic impedance of a tool joint is about five times greater than that of a tube. DOE research focused on developing engineering analysis codes to model and display the behavior of stress waves in user-specified drill pipe, including the ability to insert various signal sources into the model and visualize their effect.

Through a rare stroke of luck, DOE acquired the original field test tapes reported in the U.S. Patent and Trademark Office (USPTO) by Cox and Chaney.[86] While Cox and Chaney's original data analysis did not demonstrate the existence of the pass and stop bands in drill pipe, routine spectral analysis of the data demonstrated a nearly perfect match to the theory. These results convinced SNL to design and fabricate a set of telemetry transducers to test drill pipe properties. Simultaneously, SNL published an analysis[87] of the acoustical properties of drill pipe including comparison to the SNL-scale model experiments and the Cox and Chaney data. This drew the attention of several oilfield service companies including Teleco Oilfield Services Inc., the company that first commercialized mud-pulse telemetry.

In 1989, Teleco signed a license agreement with DOE and started its own program to develop a drilling telemetry tool. The program ended a few years later when Baker Hughes acquired Teleco. It was obvious at the time that the original transducer designs were difficult to maintain and not sufficiently rugged. Several years later, in conjunction with Baker Oil Tools, SNL designed a simpler and more robust telemetry tool for production monitoring. The design met all expectations and demonstrated the ability to broadcast from 6,000 ft in a well with external upset ends (EUE) production tubing for extra thickness at joints. Extrapolation of these test results indicated that the ultimate range of the tool was about 12,000 ft. Baker Oil Tools licensed the tool but has not commercialized it. Figure 26 is a photograph of a downhole unit of the prototype acoustic telemetry system.

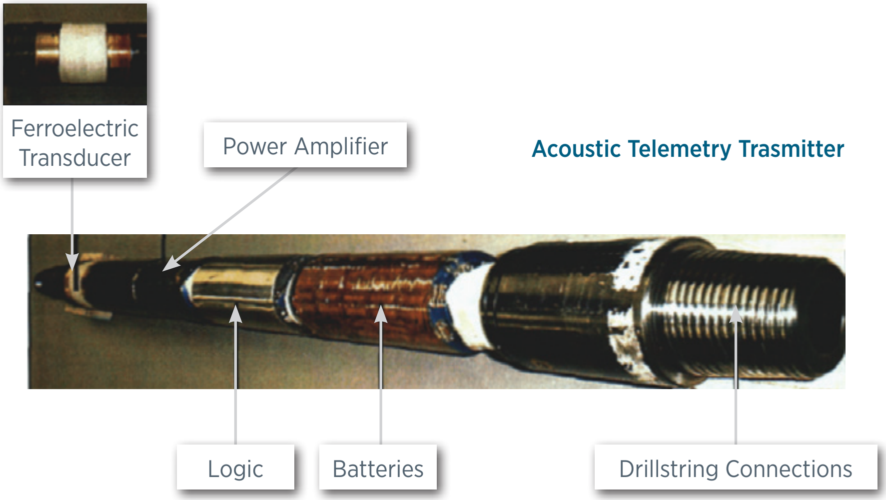

Figure 26. Downhole unit of the prototype acoustic telemetry system

3.10 The ORACLE II Tool

Development of a drilling telemetry system was a complex endeavor, but in the most simplistic sense the system can be reduced to three elements: 1) the downhole tool that senses the parameter(s) of interest, conditions those signals, and generates a stress wave that travels up the drill pipe; 2) a receiver at the surface that detects this wave, filters and digitizes the data, and sends it to digital memory, and 3) software that controls, conditions, and displays the data.

ORACLE II is a downhole acoustic telemetry tool. It is a cylindrical package that screws into the drillstring, allowing the drilling fluid to pass through the package. It contains sensors for the desired measurements (typically pressure and temperature), a Piezoelectric (PZT) ceramic transducer that generates the stress wave, batteries, and a logic system for control.

The surface receiver has three possible incarnations. First, if the pipe is not rotating, as in a production string, accelerometer data is simply fed through a wire to memory. Second, a data logger with flash memory card is strapped to a rotating pipe and data is downloaded when rotation stops. In the third case, a surface receiver with a radio frequency (RF) data link is attached to a rotating pipe and broadcasts data continuously during rotation (drilling).

The software has three major parts: 1) an embedded tool-application code in ORACLE II that works in conjunction with its micro-controller; 2) a code called BABEL that displays the raw acoustic data coming from ORACLE; and 3) a LabVIEW™-based tool set-up program that is the user interface with the system.

All of these devices and components are described in considerable detail in this project's principal reference,[88] which also lists patents, peer reviewed papers, and other related documentation.

Individual components and the complete system underwent extensive quasi-laboratory testing at SNL's ORPHEUS test range in Albuquerque, New Mexico. The system was successfully field tested at several locations including the Nisku Training Center in Alberta, Canada; an oil and gas project in eastern Alberta; three river-crossing projects in Canada; a drill stem test in Alberta; and a production test at the Rocky Mountain Oilfield Training Center (RMOTC) in Wyoming.

Building on the success of the acoustic production monitoring tool, in 1998, SNL initiated a program to develop another drilling prototype, greatly refining the design and simplifying the tool still further. About a year into development, SNL licensed the tool to Extreme Engineering of Calgary, Alberta, requesting that the company harden the tool's design for the drilling environment. The result of the work was an unqualified success. Qualification testing of the acoustic telemetry system was conducted in several different well configurations. These qualification tests were all conducted at "low" temperatures where maximum wellbore temperatures were on the order of 90°C (194°F). The tool spent 22 days downhole during 2001 and 2002 without failure, resulting in a much better understanding of well conditions' influence on the acoustic telemetry broadcast range.

The first ORACLE II field test was conducted in September 2001 at the Petroleum Industry Training site in Nisku, Alberta, Canada with the assistance of license partner Extreme Engineering. The test hole was a 3,280-ft full-cased well. The ORACLE II tool was attached directly to the drill string, mounted below a shock sub, mud motor, and jars. The test proved that the new tool would indeed work in a drilling environment.

The second test was performed at a gas well drilled by Entec Oil and Gas in eastern Alberta. The well was 2,500 ft deep. The ORACLE II tool was deployed just above the bit for a significant portion of the drilling. The amount of data taken during the drilling was limited but the test proved that the new ORACLE II tool could survive in a production drilling environment. This is believed to be the first test of an acoustic tool in a production drilling environment.

Extreme Engineering tested the ORACLE II tool in three river crossing projects in Canada. Baker Oil Tools, another licensee of SNL's acoustic telemetry property, tested the ORACLE II tool in two drill stem test applications, one in Oklahoma and another in the Tri-City area in Alberta, Canada.

SNL tested the ORACLE II tool with two different grades of production tubing at RMOTC in May 2002. The test involved running the tool to a depth of 5,000 ft and 90ºC (194°F). Tests were conducted in both nominally vertical and deviated holes. The propagation of acoustic signals through several packer assemblies was successfully demonstrated.

A commercialized telemetry system is available for rent or purchase from Extreme Engineering based in Calgary, Alberta. In addition to its commercial success, in 2003 the ORACLE II tool received an "R&D 100 Award."

3.11 Spectral-Gamma Logging Tool

Virtually all rocks contain naturally occurring radioactive elements that emit gamma radiation. Gamma emissions can be detected by a downhole logging tool that typically uses a sodium iodide crystal that emits photons when struck, providing an indication of the amount of radioactive material around the wellbore.

Different types of rocks have varying amounts of radioactive material. Among sedimentary rocks, shales have the highest concentrations, while sands and carbonates have the lowest. Among igneous rocks, more acidic rocks have higher radioactive material content. Among metamorphic rocks, radioactive content depends on the composition of the parent rock and the specific metamorphic process the rock has undergone. Hydrothermal alteration often changes the radioactive material content of geothermal reservoir rocks.[89]

Gamma emissions in geothermal reservoirs are significant because the presence of radioactive elements often signals fracture deposition of uranium salts by hydrothermal fluids. When used in conjunction with other logs such as neutron density, the gamma response can identify altered zones to signify current or previous high temperatures. When the constituents of a particular reservoir are well characterized, gamma logs can also identify specific rock formations. At The Geysers, for example, gamma logs are critical to identify fractured zones, steam-entry zones, and various formations such as greenstone, rhyolite, and argillite.[90] Gamma ray identifies transitions from one formation to the next and, in combination with density and neutron logs, can identify the specific rock.

Thorium, uranium, and potassium are the most common radioactive elements in geothermal reservoirs. The standard “natural gamma” logging tool simply counts the combined emissions from all these constituents, presenting the results as total counts. The energy displayed by each gamma strike on the detector indicates which element produced it. The spectral-gamma tool, on the other hand, apportions the counts into various “windows” that indicate a specific radioactive material, so that the dominant radioactive material can be determined at any given point in the wellbore. Like the natural gamma tool, the spectral-gamma tool also gives total counts.

From 1993 to 1997, SNL designed and built a downhole tool with Dewared electronics to provide a spectral-gamma tool for geothermal logging. It was rated to withstand 10,000 psi pressure at 350°C (662°F). The tool was calibrated near Grants, New Mexico in three wells with known radioactive content. Then it was used to successfully log portions of the S8-15 core hole in The Geysers. Although high-temperature gamma ray tools exist in the oil and gas industry,[91] there is no other existing high-temperature spectral-gamma logging tool.

Tool development work was reported in a GRC paper.[92] Actual logging results are described in a submission to *Geothermics*,[93] an international journal devoted to the research and development of geothermal energy.

3.12 Precision Pressure-Temperature Tool

Pressure and temperature are the two most important measurements in geothermal wells. Knowing the formation temperature is critical while drilling a geothermal well, assessing a potential geothermal reservoir, and monitoring its performance during production. Measuring pressure is equally important during reservoir evaluation and production. For many applications, pressure measurements must be precise. SNL developed a precision pressure-temperature (P-T) tool as one of its first projects in designing high-temperature logging devices.[94] Research was conducted from 1993 to 1998.

The first decision SNL made when designing the precision P-T tool was whether it should be a wireline or memory tool. (Pros and cons are discussed in Section 3.15.) For the relatively small target market of geothermal operators and service companies, the memory tool was the clear choice. The P-T tool had to meet several criteria:

- "Smartness," i.e., programmable to make "decisions."
- Minimal cost within the constraint of satisfactory performance.
- Transportable by ordinary passenger air service.
- Measurements traceable to national standards.
- Compatibility with diamond core hole dimensions.
- Operable to borehole temperatures of 425°C (800°F).
- Minimal personnel training required for deployment and data retrieval.
- Ruggedness and reliability.

Since work preceded the advent of SOI technology, the tool used conventional complementary metal oxide semiconductor (CMOS) electronics in a Dewar. The key element of the electronics package was a microcomputer that performed several functions. It had eight analog-to-digital input channels and several memory locations to store sensor calibrations, the tool's operating system, customized programs from the user, and data. The program included decision-making capability that could delay the start of data collection until the tool reached a certain pressure so that data memory would not be filled in the upper part of the hole. (The downhole steam sampler described in Section 3.13 used the same sort of onboard logic.) Considerable effort was devoted to making the tool easy to operate with a minimum of training or instruction.

The precision P-T tool has been used for many logs in many locations and given consistently reliable and accurate measurements. The P-T tool could be upgraded to handle other sensors and programmed in BASIC. Modifications to incorporate other tasks or decisions downhole were easily made. In addition to being commercialized by a geothermal service company, the P-T tool served as a platform for developing new capabilities and was a foundation of DOE's geothermal logging program.

3.13 Downhole Steam Sampler

Obtaining samples of formation fluids (e.g., steam and liquid) at a specific depth is important in developing a geochemical reservoir model. A chemistry profile with depth is useful to study several factors including the production of corrosive gases or liquids that could damage tubulars or turbines, the presence of noncondensable gases (NCGs) that could degrade turbine performance, and injected fluids' influence on prolonging reservoir life.

Fluid samples taken at the wellhead provide an average composition of fluids produced throughout the wellbore. Acquiring samples from a specific depth interval is difficult. Fluid samplers at the time had many problems.[95] As a result, in the early 1990s, DOE worked with Unocal Geothermal;[96] DOE Basic Energy Sciences; and Thermochem, Inc. to begin the conceptual design of a new sampler with an onboard computer to control valves and operate at high temperatures.

The prototype tool was about 2 inches in diameter and 72 inches long. It was battery-powered, easy to transport, operated by simple slickline logging equipment, and usable in slimhole wells. It had Dewar protection for the electronics and a large mass of eutectic material around the sample chamber. Steam drawn into the sampler would be cooled and condensed, greatly reducing its volume. The onboard computer could be programmed in the field to open and close valves according to a number of different triggers, such as time, temperature, and time-rate-of-change in temperature. As the tool was lowered into the well, the onboard memory created a temperature log specifying conditions at the sample points.

The prototype downhole steam sampler tool showed good repeatability while being tested in the SNL steam plant and production wells at The Geysers in California. Since it shared parts and operating principles with SNL's precision P-T tool, development and experience with the P-T tool benefited both tools.

The downhole steam sampler tool's capabilities were considered unique and especially valuable in vapor-dominated fields such as at The Geysers and in Indonesia. Thermochem later commercialized the downhole steam sampler tool with higher pressure valves. Improvements including electronics upgrades continue to be made.

3.14 Core-Tube Data Logger and Downhole Data Logger

The core-tube data logger (CTDL) was one of SNL's most popular tools (see Figure 27). It was inexpensive to build and simple to run. DOE-supported R&D on the CTDL was conducted from 1998 to 2000. Several slimhole, scientific, and gas hydrate drilling projects have used this tool. The CTDL is simply an electronics and sensor package built into a core-tube that stores data in memory. As the core-tube is lowered and retrieved by the driller to capture formation materials, the CTDL rides along, retrieving data from the logger when the core is extracted from its tube.[97] By placing the core-tube data logger inside the inner core tube, measurements of temperature, pressure, and hole inclination can be made without interfering with normal coring operation. Allowing the CTDL to ride in the core tube while drilling not only gives temperatures in the drilled interval, but it can also temperature log the entire well when the pipe is tripped for bit changes. During wireline retrieval of the core tube, tripping rates are too fast to log the well.

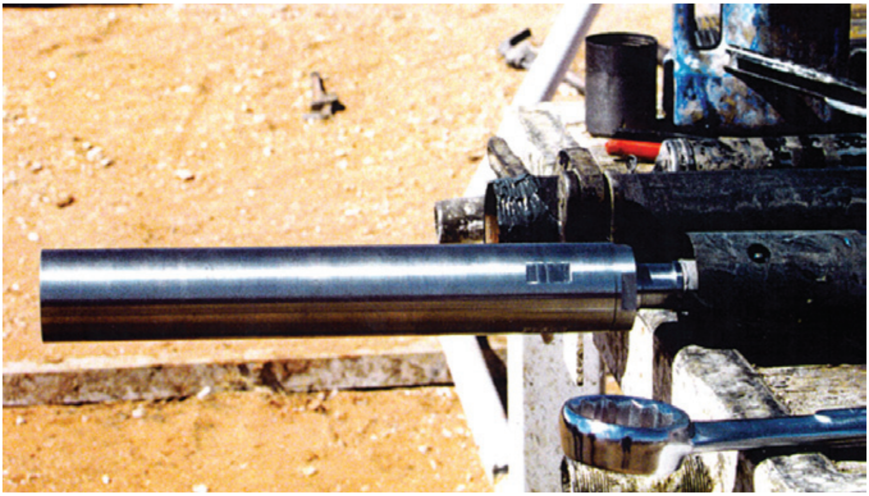

Figure 27. Core-tube data logger

As a memory tool, the CTDL had two primary advantages. First, a specialized logging truck is not needed. The memory tool can be run in and out of the hole on the rig's sand line or with a simple "slickline" winch. Second, with a relatively low first cost, an operator can purchase a CTDL and acquire temperature and pressure logs whenever desirable, avoiding expensive service company logging costs. The delay in getting data and the lack of any surface indication if the tool fails during a test are disadvantages. Nevertheless, the CTDL is an accurate and cost-effective technology. One of SNL's most popular tools, it was commercialized twice, first by Boart-Longyear and then by a partnership between Drilling, Observation and Sampling of the Earths Continental Crust (DOSECC) and QD Tech, Inc.

Developed in cooperation with Tohoku University in Japan from 2002 to 2003, the Downhole Data Logger was a modification of the CTDL. The downhole data logger tool was designed to be deployed during core or rotary drilling or in conjunction with a magnetic single shot survey. It could be deployed with or without a Dewar at temperatures of 150°C to 250°C (302°F to 482°F) for up to 10 hours. Two Phase 1 tools were produced that could be used with a Dewar or with a pressure housing (up to 5,000 psi). A Phase 2 version was planned using high-temperature electronics capable of sustained operation at 250°C (482°F) without a Dewar and up to 500°C (932°F) with a Dewar. The project did not advance to Phase 2 due to the principal investigator's death in Japan.

3.15 Optical Fiber

The conventional way to obtain a well's temperature profile is by lowering either a wireline or memory logging tool into it, and retrieving the temperature readings on the surface either as the wireline tool moves down the well or as the memory tool returns and data is downloaded. Both techniques require a winch to handle the wireline or slickline, which interferes with other drilling operations.

A relatively new way[98] of measuring temperature is to use optical (glass) fibers illuminated by pulses of laser light. Typical optical fibers used for temperature measurement are shown in Figure 28. As the laser pulse travels down the fiber, it undergoes Rayleigh and Raman scattering. Raman scattering is divided into two components: one with a shorter wavelength than the original pulse, the other with a longer wavelength. The ratio of these two components is a function of temperature and, combined with the time-of-flight for the pulse, indicates the temperature of the fiber at a known distance from the emitting laser. If the fiber is suspended in a well, or placed outside the casing, it provides a continuous, nearly instantaneous picture of the temperature distribution in the hole.

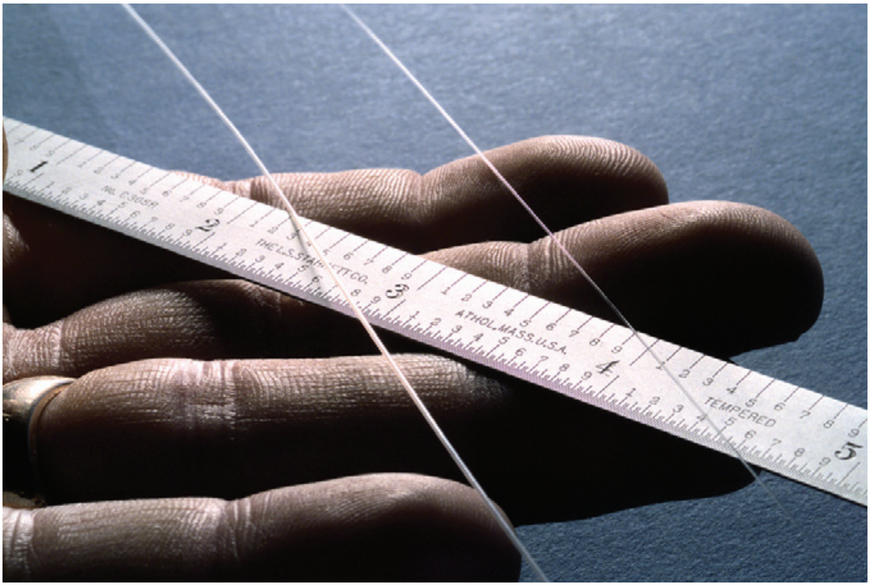

Figure 28. Typical fibers used for temperature measurement

Optical fiber temperature measurements have problems, however, in meeting the project objective of survival at 250°C (482°F) for four years with less than a 2°C (3.6°F) drift. The principal source of attenuation or degradation in the signal is free hydrogen, which tends to combine with oxygen in the glass. The graph in Figure 29 illustrates light transmission loss when optical fiber is exposed to hydrogen. Researchers sought to mitigate the hydrogen problem by identifying its sources (some of which are accelerated by high temperature), developing hydrogen getters to absorb the hydrogen, and evaluating the suitability of commercial fibers for geothermal use.

From 1999 to 2002, tests at high temperature and pressure showed that fiber without phosphorus, a common doping agent, is much more resistant to hydrogen degradation. An examination of emplacement procedures concluded that oils in stainless steel tubing normally used to protect the fiber could also produce hydrogen at high temperature. These tests were encouraging and the results were reported in detail[99] at the annual Stanford Geothermal Workshop.

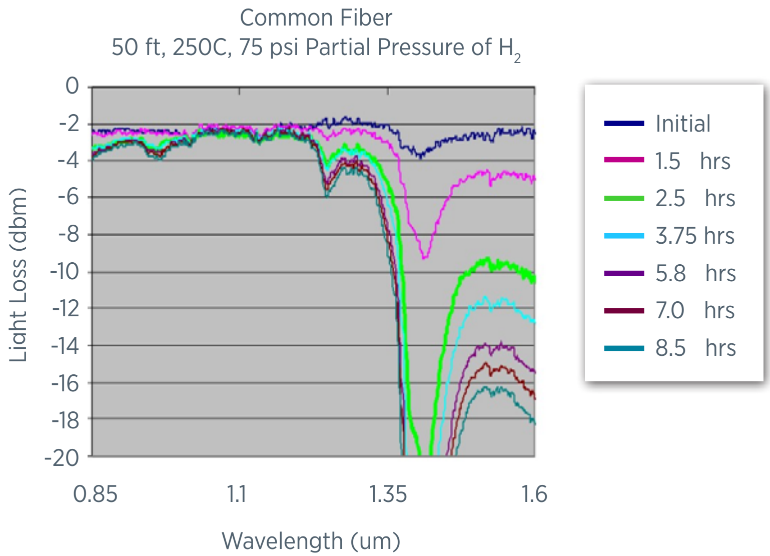

Figure 29. Light transmission loss in optical fiber when exposed to hydrogen

SNL researchers believe that optical fiber will become the industry standard for monitoring geothermal well performance if the hydrogen problem can be solved. SNL has a patent ("Downhole Geothermal Well Sensors Comprising a Hydrogen-Resistant Optical Fiber," No. 6,853,798 B1) on an improved doping material to reduce the hydrogen problem. To date, the market has been unable to justify a new fiber process to handle high-temperature geothermal wells.

3.16 Downhole Turbine-Alternator

For power, downhole drilling tools normally use either wireline power from the surface or onboard batteries. Due to the disadvantages of both, DOE contracted with APS Technologies, Inc. to develop a prototype downhole turbine-alternator to use the hydraulic energy in the circulating drilling fluid to drive an alternator and power downhole tools. The resulting tool delivered up to 150 watts at temperatures up to 200°C (392°F). The downhole turbine-alternator tool was commercialized and used in field drilling, but has not been used in geothermal wells. Research took place from 2001 to 2003.

3.17 Downhole Monitoring System for the U.S. Geological Survey and Coso, California

With DOE support, three tools using SOI technology were built for long-term use to provide highly accurate monitoring of downhole pressure and temperature.[100] Two were for the USGS to evaluate volcanic hazards. Changes in downhole pressure and temperature are associated with volcanic unrest.[101] Measurements are limited in geothermal areas, however, because commercially available transducers can withstand the temperatures for only hours to days. One of the two USGS tools with small diameter pressure housing was targeted for shallow depths in a scientific well on Kilauea volcano in Hawaii. The well collapsed shortly before the tool could be tested. The second USGS tool used SNL's "standard housing" (rated to 15,000 psi) and was deployed in several wells in Long Valley Caldera, near Mammoth Lakes, California. Both tools remain in use today. The SOI electronics give essentially unlimited life at temperatures of approximately 100°C (212°F). The third tool using SOI technology was deployed for long-term reservoir monitoring at the Coso Geothermal Field in southern California.

While system details differ slightly, all three tools contained the following elements:

- Downhole tool: The downhole tool consisted of a pressure housing (manufactured by Mitco Industries, Inc.), electronics based on SOI technology, and sensors. The original sensor package had a Quartzdyne pressure transducer, a Kulite pressure transducer, and a resistance temperature detector (RTD) probe. The downhole tool is based closely on the precision P-T tool (see Section 3.12) and uses the ASIC (see Section 3.4), which confers the capability of adding additional sensors when desired.
- Data link to the surface: For the two USGS tools, which were deployed at considerably lower temperatures, a conventional wireline data link was used. The Coso tool required long-term residence at approximately 192°C (378°F). A data link with four insulated 22 American wire gauge (AWG) wires inside stainless steel tubing resulted in a system that had metal-to-metal seals at all

points. This eliminated the problem of elastomers at elevated temperature. The hard data link allowed the tool to be powered from the surface. No batteries were required.

- Uphole data decoder: The decoder took the frequency-shift keying signal transmitted from downhole and converted it into a digital format for the data logger. The most common is the RS232 format, which is compatible with most commercial data loggers.
- Uphole data logger: Almost any commercial data logger can be used with this system, but Model CR10X by Campbell Scientific, Inc. was chosen for the Coso application.
- Data transmitter: Since most geothermal wells are in remote areas, long-term monitoring is greatly simplified when data can be sent from the wellhead to another location. The USGS tools transmitted data to offices in Menlo Park, California. The Coso installation used a National Oceanic and Atmospheric Administration (NOAA) satellite to send data virtually anywhere in the world.

The initial tool was deployed in October 2003. After approximately one year, it was removed from the well and taken to SNL for analysis. Results were mixed. Many of the components, such as the polyimide boards, worked better than expected. Other components such as capacitors did not perform as well.[102] Combining the downhole test of approximately 7,940 hours (330 days) with prior burn-in tests, the tool was exposed to elevated temperatures for a total of 8,640 hours (360 days).[103]

After incorporating improvements resulting from laboratory analysis, the tool was reinstalled in the Coso well in February 2005. Prior to final assembly, the electronics were burned in at 200°C (392°F) for 450 hours, SNL's standard practice for qualifying electronics for field deployment. With the exception of voltage regulators, all of the original SOI components were reinstalled on the new polyimide boards. The Quartzdyne pressure and temperature sensor was inspected and refurbished by the manufacturer prior to redeployment. At the completion of this test, which was limited by the availability of the well and funding, the SOI components were still completely functional with a total downhole time of 16,800 hours (700 days). This is believed to be the longest time any electronic components have remained operational under downhole geothermal conditions.[104]

The downhole monitoring system used at Coso was a versatile prototype that can be modified in many ways to provide various measurements for long-term monitoring. DOE devoted considerable effort to making the system "open source" so that it can be relatively easily built and customized by any researcher or geothermal company in need of this kind of data. The Coso tests were particularly important in that they showed the long-term reliability of SOI and manufacturer-qualified high-temperature electronics in a "real world" application. DOE worked with several manufacturers to build a complete logging tool using only commercially available components.

3.18 Logging and Rig Instrumentation as Adjunct to Field Operations

All field operations managed by SNL have utilized the SNL logging truck for downhole measurements, including polyurethane grouting (Section 4.7), slimhole drilling (Section 5.0) and scientific drilling (Section 9.0). This proved extremely useful for monitoring downhole conditions. It provided an opportunity to test new logging tools and advanced the art of rig instrumentation giving drillers better information. Most of the data sets were similar. Instrumentation on the Long Valley Caldera, California Phase 3 rig was representative. Measurements taken included drilling fluid inflow and outflow, drilling fluid temperatures, standpipe pressure, and rotary speed and torque. The associated data collection that evolved around this system has proven extremely useful in evaluating general drilling performance and is a platform for further development as other rig data are identified as useful.

4.0 Drilling Fluids and Wellbore Integrity

Perhaps no other drilling system component performs as many functions or can cause as many problems as drilling fluid. Lost circulation is the most costly problem routinely encountered in geothermal drilling. This includes the loss of drilling fluids to pores or fractures in the rock formations being drilled. (In addition to loss of drilling fluid, there are many other drilling problems such as stuck drill pipe, damaged bits, slow penetration rates, and collapsed boreholes.) Lost circulation costs represent an average of 10 percent of total well costs in established geothermal fields,[105] and more than 20 percent in greenfield development. Since well costs account for 35 percent to 50 percent of the total capital costs of a typical geothermal project, roughly 3.5 percent to 10 percent of the total costs of a geothermal project may be attributed to lost circulation. Therefore, reducing the cost of lost circulation reduces overall project costs, helping to expand geothermal energy's role in the electric utility sector.

Lost circulation can be combated in three ways: 1) Drill with a lightweight drilling fluid that has a static head less than the pore pressure in the formation; 2) Mix drilling fluid with fibrous material or particles that will plug the loss apertures in the formation; or 3) Stop drilling and try to seal the loss zones with material that can be drilled out as the hole advances. Each of these options is discussed below.

4.1 High-Temperature Muds

DOE contracted with Texas Tech University to conduct an extensive study of drilling fluids at high temperature, focusing primarily on clay chemistry in water-based fluids. Geothermal conditions change drilling fluids due to temperature and chemically complex brines that are often encountered in geothermal reservoirs. In the late 1970s, DOE research focused on examining clay samples with X-ray diffraction and electron microscopy after the samples had been autoclaved to high temperature—sometimes with the addition of common salts found in geothermal brines. Clays tested included bentonite (the most common material used in drilling), saponite, smectite, and other more fibrous clays such as sepiolite and attapulgite. Based on the understanding of morphologic changes brought about in these conditions, a high-temperature mud, HTM-1, with sepiolite, Wyoming bentonite, and a polymer additive was designed and commercialized.

The latter part of the program in the late 1980s was devoted to understanding clays' transformation to cement minerals. This is important in considering the effect of temperature, additives, and formation impurities on mud at high temperatures. Numerous combinations were tested by autoclaving at increasing temperature and then measuring fluid properties such as viscosity, gel strength, pH, fluid loss, and filter-cake thickness. X-ray diffraction and electron microscopy were also used. Results are extensively documented in SNL annual reports,[12/19/21] DOE reports,[106-108] and other publications.[109]

4.2 Lost Circulation Materials Qualification

The oil and gas industry has used many substances to plug lost circulation zones. Most used organic or cellulosic materials that cannot withstand geothermal temperatures. Lost circulation zones in oil and gas drilling also tend to be dominated by matrix permeability rather than by the much larger fracture apertures common in geothermal reservoirs. As a result, a method to evaluate and qualify lost circulation materials (LCM) for geothermal drilling was a high priority for DOE. Figure 30 shows a slot plugged with LCM.

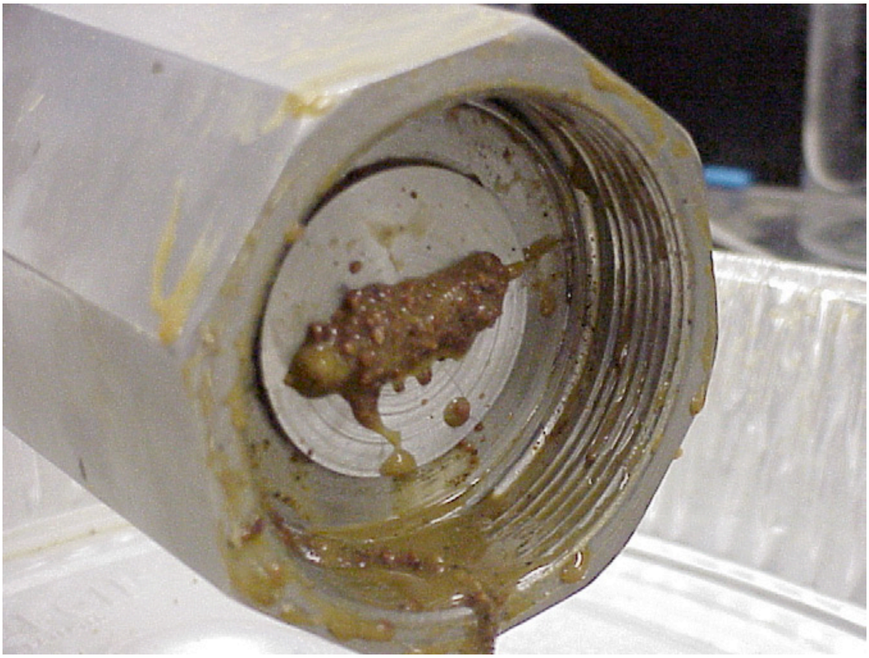

Figure 30. Slot plugged with lost circulation materials

SNL designed and built the Lost Circulation Test Facility (LCTF),[110] which incorporated a high-temperature, high-pressure flow loop with full-size wellbore sections that could be fitted with accurately simulated fractures to test plugging. A smaller slot-test facility[111] allowed preliminary screening of candidate materials before moving on to the labor and expense of full-scale tests in the LCTF. Research was conducted from 1979 to 1989.

A corollary to the test activities was developing an analytic bridging model to improve the fundamental understanding of how particles plug gaps, helping to select materials for further evaluation. Researchers tested many materials in these facilities, including nut shells, Thermoset™ rubber (ground automotive battery casings), ground rubber tires, expanded aggregate (heat-expanded rock), and ground coal. Results were reported[112] in detail and are summarized below.

- A modified version of the American Petroleum Institute (API) bridging materials tester was developed to improve the data quality of slot tests, making it a more effective tool for screening potential lost circulation materials.
- The LCTF accurately simulated dynamic flowing conditions prevalent in fracture plugging applications. Significant differences in plugging performance were noted between the LCTF and the API tester with some materials.
- A simple test system to complement the slot tests was developed to measure the material properties important in bridge plugging mechanics. The softening temperature was found to correlate well with the effects of temperature on slot-plugging performance.
- Effective theoretical models of the one- and two-particle bridging process were developed to provide accurate predictions of laboratory slot-plugging test results.
- Plugging performance plots were developed to allow a comparison of LCMs of different particle sizes and types in fractures of known widths. These plots were also developed for several commercial LCMs that had potential in severe fracture-dominated, under-pressured loss zones.
- Concentrations of granular LCM particles as high as 20 pounds per barrel (lb/bbl) can reduce filtrate loss and increase the probability of a high-pressure plug forming. However, higher concentrations are not beneficial and may be detrimental. The proportion of granules and fibers or flakes must be carefully controlled.
- An optimal granule-flake LCM mixture of 4:l weight ratio and 1:2 size ratio developed for Thermoset™ rubber. This combination was found to be superior to all other LCMs tested at low temperature but displayed reduced performance at temperatures above 93°C (200°F).

- Particle size distribution was an important factor in the bridge plugging process, as predicted by the bridging models and confirmed with laboratory experience.
- Brittle materials tended to degrade in size during exposure to dynamic flowing conditions. This could contribute to unwanted changes in drilling fluid properties and plugging characteristics.
- Random orientation of particles at the plug location was a plausible explanation for apparent variability in laboratory slot-plugging performance, although particle-size distribution also has an effect.
- The possibility that drill cuttings may modify the plugging characteristics for a given LCM treatment should always be considered.

4.3 Drilling With Aqueous Foam

Lightweight fluids, which produce a static head less than the pore pressure, have always been a remedy for lost circulation in geothermal drilling. Aqueous (water-based) foam was attractive due to its simplicity. Little was known, however, about the properties of common surfactants at high temperatures.

Beginning in 1979 and running through the late 1980s, SNL screened more than 100 surfactants at 260°C and 310°C (500°F and 590°F), looking at the effects of sodium chloride (NaCl), hydrogen chloride (HCl), geothermal brines, and de-ionized water. Several promising classes of foams were identified, and the combined effects of pressure and temperature on these surfactants were extensively investigated in an autoclave. Primary focus areas included foam stability at high temperature, rheology (for calculating pressure drops in the drill pipe and annulus), and the heat transfer properties of the foams (to model the foam temperature at any point in the wellbore.)

In addition to numerical models of foam structure and rheology, a laboratory flow loop measured pressure, temperature, and flow rate at different points. This experimentally confirmed the rheological model. This work was documented in several DOE reports[113-115] and SNL annual reports.[12/19-21]

4.4 High-Performance Cements

In most oil and gas wells, the casing is cemented in place only at the bottom, with a completion fluid between the balance of the casing and the wellbore wall. Geothermal wells, however, must have a complete cement sheath from bottom to surface. This cement has two important functions: 1) to give the casing mechanical support under sometimes-intense thermal cycling and 2) to protect the outside of the casing from corrosion by in situ fluids. Geothermal cement should have high-bond strength compared to that of the casing, impermeability, and be lightweight (at least relative to conventional cement, which has a specific gravity of approximately 1.6). Light weight is important because geothermal reservoirs are generally underpressured, which drives lost circulation even with many drilling fluids. It is often impossible to lift a column of normal-weight cement back to the surface when casing is cemented in place. Conventional oil well cements are not only too heavy for many geothermal wells, but are susceptible to attack by acids and carbon dioxide (CO_2)—both of which are common in geothermal reservoirs and degrade cement's impermeability and strength.

Based on earlier cement research (for non-geothermal applications), BNL launched a development program for geothermal cements in 1974. Early efforts focused on problem definition and basic cement R&D, which was broadly dispersed among several institutions including Battelle's Columbus Laboratories (BCL), Colorado School of Mines (CSM), Dowell Division of Dow Chemical U.S.A., Pennsylvania State University (PSU), Southwest Research Institute (SwRI), and the University of Rhode Island (URI). The R&D effort was comprised of characterization of cements then used in geothermal environments,[116-117] the extension of hydrothermal cements to higher operating temperatures,[118] and the development of new materials such as phosphate-bonded cements,[119] polymer cements,[120] and other new compositions.[121]

After property verification by the National Bureau of Standards and the API, candidate cements (all of normal density) were tested in geothermal wells at Cerro Prieto, Mexico. Even though these cements showed improvement over conventional cements, strength degradation was below the design criterion in some of them. This research was directed toward a more focused problem: cement degradation caused by acid or carbon dioxide in the reservoir fluids.

Studies in the 1980s showed[122] that criteria recommended by the API did not apply in CO_2-containing fluids. The high-silica binders that were normally considered desirable due to their high strengths and low permeability, became permeable when carbonated. The resulting casing corrosion led to failure in unacceptably short times—often less than a year. In one case, failure occurred only 90 days after well completion. BNL worked with cost-sharing industry partners Halliburton, Unocal, and CalEnergy Operating Company to develop a lightweight cement with outstanding resistance to acid and CO_2 at brine temperatures up to 320°C (608°F). Reviews of this work before[123] and after[124] 1997 are provided in detailed reports.

Reservoir conditions with carbonation problems primarily fell into two regimes: 1) high (40,000 ppm) CO_2 concentrations and low (pH ~ 5.0) acidity, or 2) high (pH < 1.5) acidity and low CO_2 concentration (< 5,000 ppm). BNL succeeded in synthesizing, hydrothermally, two new cements: calcium aluminate phosphate (CaP) cement and sodium silicate-activated slag (SSAS) cement. The CaP cements were composed of calcium aluminate cement, sodium polyphosphate, Class F fly ash, and water. They were designed to be CO_2-resistant in mildly acidic (pH ~ 5.0) CO_2-rich downhole environments. The SSAS cements were composed of slag, Class F fly ash, sodium silicate, and water. They were designed to resist a hot, strong acid containing a low level of CO_2. Both CaP and SSAS cements were economical. They used inexpensive cement-forming by-products from coal combustion and steel-manufacturing processes.

CaP development had five major goals:

1. **Good pumpability:** The set-up time of the cement must be controlled so that it does not thicken during displacement. Citric acid was found to be the most effective retarder to extend pumping time.

2. **Low density:** The cement was air-foamed and exhibited higher compressive strength than nitrogen-foamed cement of similar density. A permeability problem was solved by adding styrene acrylic emulsion to the cement.

3. **Toughness:** Adding 14 percent (by weight) milled carbon fibers to the cement increased fracture toughness three-fold, compared to unfilled cement.

4. **Bond strength:** In a thermal-cycling test, bond strength of CaP cement increased markedly during the first 100 cycles by development of a dense microstructure of hybrid phases including plate-, block-, and sheet-like hydroxyapatite, boehmite, hydrogarnet, and analcime crystals at the contact zones with the pipe's surface.

5. **Low cost:** While the cement used inexpensive materials, it was also found that the calcium aluminate cement could be cut in a 70/30 ratio with fly ash to further reduce cost.

In 1997, Unocal and Halliburton completed four geothermal wells in Sumatra with CaP cement—the first field use of this formulation. In 1999, Halliburton commercialized it under the name "ThermaLock Cement." In 2000, CaP technology received the prestigious "R&D 100 Award." Since then, more than 1,000 tons of ThermaLock have been used in geothermal, steam-injection, sour-gas, and other well completions. Its useful service life of 20 years or more means that typical annual repair costs of $150,000 per well (2001 dollars) in CO_2-rich environments can be avoided entirely. It also enables reservoirs with harsher fluids and environments to be developed.

SSAS cements have received less attention than CaP. Autoclave experiments in the lab, however, have demonstrated good performance in high-acid environment. After undergoing acid damage, the SSAS cement exhibited a self-repairing characteristic. The addition of fly ash further improved its acid resistance, making SSAS a very promising low-cost geothermal well cement in high-acid conditions up to 200°C (392°F). Research concluded in 2000.

4.5 Inert Gas Generation and Drillstring Corrosion

Due to the combination of high temperatures, oxygen, water, and formation chemistry, often including hydrogen sulfide (H_2S), corrosion is often a major problem in geothermal drilling. Conventional practice at the time was either to add sodium hydroxide or caustic soda (NaOH) to the drilling fluid so that the increased pH (i.e., 10-11) would mitigate corrosion, or to use other corrosion-control chemicals to coat the drill pipe with an oxygen barrier. Chemicals were expensive, however, costing several thousand dollars a day. They were also not always effective. Corrosion rates, and consequently drill pipe life were often an order of magnitude worse than in oil and gas drilling. This lead to an amortized daily cost for pipe replacement of more than $1,000 (1982 dollars). SNL R&D worked to eliminate oxygen from the drilling fluid and develop new more corrosion-resistant alloys.

To determine whether inert gas would be beneficial, a test using nitrogen as the aerating fluid was conducted in a geothermal well in northern New Mexico beginning in 1979. While corrosion rates on test coupons in the wellbore decreased ten-fold, the cost of trucking and vaporizing liquid nitrogen was prohibitive. DOE contracted with Foster-Miller Associates (now Foster-Miller, Inc.) to design and build a diesel exhaust-gas purifier to deliver 2,000 standard cubic feet per minute (scfm) of nitrogen with less than 50 parts per million (ppm) of oxygen. This volume was consistent with the drilling practices of the reservoir. Scoping-level economic analysis indicated that the cost of the system would be about $4,000 a day (1982 dollars), competitive with the cost of drill pipe replacement plus corrosion-control chemicals. Research concluded in 1982 and was reported to the GRC[125] and in a DOE report.[126]

Alloy investigation focused on the behavior of duplex-phase iron-silicon (Fe-Si) steels in an H_2S environment. The primary measurements recorded were crack-growth rate during fatigue tests in air and H2S-rich brine. These measurements in the experimental alloys were compared with those in conventional Grade E drill pipe material under the same conditions. Some combinations of alloy and quenching treatment were superior to Grade E steel.[19]

4.6 High-Temperature, High-Pressure Viscometer

The cuttings-carrying capacity of a drilling fluid (at a given velocity) primarily depends on its viscosity. However, most conventional viscosity-test instruments (viscometers) cannot operate under geothermal conditions. This is particularly important because, for most water-based muds, viscosity decreases with temperature up to a critical point (usually between 93°C and 160°C [200°F and 320°F]) at which it suddenly gels and becomes unusable. In 1979, SNL designed and built a portable viscometer[127] that would measure fluid properties at temperatures to 260°C (500°F) and pressures to 12,500 psi. This product was commercialized, i.e., drilling fluid companies used it to evaluate their muds. Demand was insufficient, however, to widely produce and market the product. R&D ended in 1981.

4.7 Polyurethane Foam Grout

Beginning in the early 1980s, SNL investigated the concept of plugging lost circulation zones with polyurethane foam. Early attempts were not successful.[128] However, subsequent encouraging laboratory work and the increased use of polyurethane grouting in civil engineering projects[129] stimulated new interest in the technology.

An opportunity for field evaluation arose when DOE awarded Mt. Wheeler Power a Geothermal Resource Exploration and Definition (GRED) cooperative agreement to test the productivity of the intersection of the Rye Patch, Nevada fault with a major thrust fault zone, identified by a 3-D seismic survey. Testing this potential production zone required reopening a well that had been temporarily abandoned because of total lost circulation with high cross flows. Twenty cement plugs, including 15 conventional, two thixotropic, and three with foam cement, were unsuccessfully tried to plug the lost circulation zone. Mt. Wheeler sought SNL's assistance in using polyurethane grouting to re-open the Rye Patch well.

Re-drilling the Rye Patch well through the casing point above the intermediate reservoir provided an opportunity to demonstrate to the geothermal industry the advantages of drilling lost circulation zones with a dual-tube reverse circulation rig (illustrated in Figure 31) from Lang Exploration Drilling Company rig number LM120.[130] The previously installed 13-3/8-inch surface-casing shoe was set at 607 ft. Total depth drilled before temporary abandonment was 977 ft, approximately 370 ft of open hole below the casing. At drilling suspension, a bridge plug with cement above it was set in this casing. Because of this plug, the polyurethane grouting had to be integrated with the GRED drilling rather than prior to drilling.

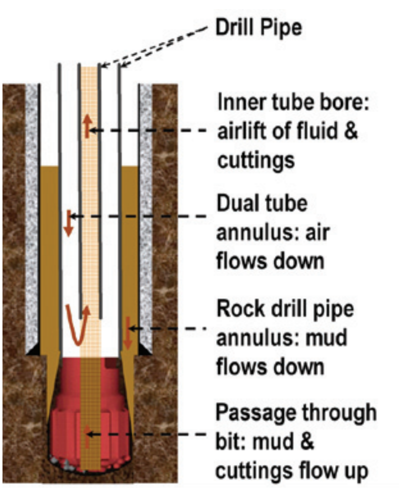

Figure 31. Diagram of dual-tube reverse circulation

Although the major lost circulation zone, with cross flow, between 728 ft and 735 ft could not be plugged by conventional methods, SNL assumed that zones below it were amenable to normal cementing practice. The planned remediation used a packer and fast-reacting, two-part polyurethane pumped from the surface down hoses strapped to the outside of the drill pipe (Figure 32). While the packer and hoses could have been lowered into the well on a cable, the drill pipe was chosen as more reliable because one can push, pull, or rotate drill pipe in case of a blockage or obstruction. Two-part polyurethane (as opposed to a one-part prepolymer that reacts when exposed to water) allowed faster reaction times and more control of reaction rate and placement.

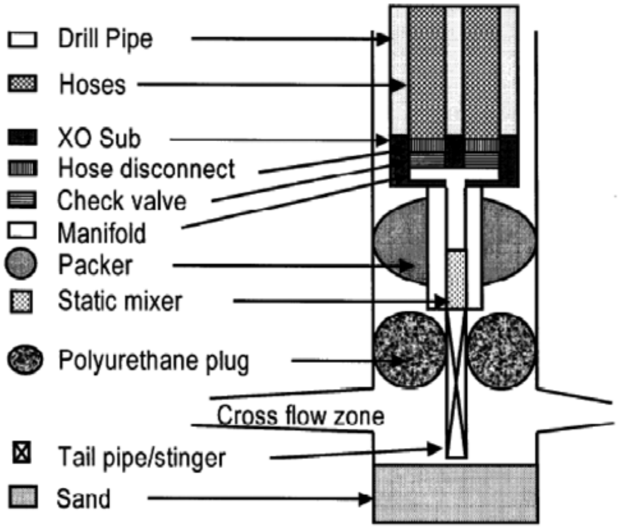

Figure 32. Diagram of foam-injection apparatus for Rye Patch remediation

The length of the interval that needed to be sealed suggested that more than one plug might be required. The first plug reduced the cross flow, partially sealing the interval and allowing a second injection of polyurethane to specifically target the fluid entry point. For both jobs, the polyurethane grouting assembly was run in, inflated, deflated, and pulled out of the hole without a problem. The packers were retrieved and could be reused. Twenty-five feet of aluminum stinger and attached capillary tubing were glued into the hole and drilled out (Figure 33) without a problem. Forty-one feet of borehole was restored to near bit gage. After the polyurethane grouting, a conventional cement plug could have sealed the loss zone deeper in the well.

The polyurethane grouting at Rye Patch showed that the process could be used to seal geothermal lost circulation and cross flow zones that are difficult to plug by conventional cementing techniques.[131] The injection process used (adapted from dam remediation/mine dewatering), while not intended to be optimal, was compatible with good drilling practice.

Figure 33. Packer with stinger ready to run in hole

The success at Rye Patch triggered a more rigorous laboratory study of polyurethane-based grouts[132] aimed at improving chemical, hydrolysis, and thermal stability. Because lost circulation zones are commonly encountered at much greater depths and higher temperatures than those at Rye Patch, greater survival temperatures were of interest. Simplification of the deployment techniques would encourage use of this technique. A single-component grout (activated by contact with water) would dramatically reduce the complexity of the equipment and broaden the reaction time window.

SNL screened a variety of isocyanate reaction products and a few other polymers to develop materials with no special handling requirements (considered non-hazardous by the Department of Transportation), and ready to pump with a viscosity of 200 centipoises. The goal was a polymer that, once placed, would be hydrothermally stable for six weeks at temperatures exceeding 149°C (300°F), and sufficiently stiff to drill with conventional means. Mountain Grout instant set polymer (ISP) performed well at temperatures up to 107°C (225°F), but little reliable information was available on the stability of polyurethane under more severe geothermal well conditions.

Through a systematic approach of many potential chemical combinations, SNL developed polymers that tolerated hydrolysis for eight weeks at 260°C (500°F) and met material, handling, cost, and placement criteria. Commercially available and competitively priced raw materials suggest that the standard polyurethane prepolymer and the variations tested would offer two weeks of useful life at 135°C (275°F). In addition, various alterations in chemistry and testing of final compositions at 163°C, 177°C, 204°C, 232°C, and 260°C (325°F, 350°F, 400°F, 450°F, and 500°F) also demonstrated survival from hydrolysis for eight weeks. These new polymer grouting systems thus possess most of the desired characteristics.

With confirmation that reliable and inexpensive polymers suitable for plugging high temperature geothermal lost circulation zones could be formulated, focus turned to the delivery system—specifically encapsulating the polymer so that it could be pumped down the well like traditional LCM. Like setting cement plugs, the delivery system used at Rye Patch required deployment hardware be brought to the location at the time the plug was set. A preferred approach would be to have polymer LCM on location ready to be deployed by the "mud hands" without the need for any additional equipment beyond that available on the rig. Encapsulation of the polymer within a barrier that breaks down or degrades at the appropriate time and temperature, thus releasing the polymer would be an ideal way to achieve this goal. Initial laboratory experiments validated the concept of using encapsulation.

Success at Rye Patch was not due just to the material used, but also to the emplacement process. The combination of the material and the process allowed a successful "squeeze job" in spite of the cross flow that washed away ordinary cement before it could set. This stimulated a series of laboratory tests on the use of sodium silicate to control the setting of cement. These tests showed that sodium silicate and cement behave differently in fractures than porous media, explaining the failure of past attempts to plug geothermal lost circulation zones with sodium silicate and cement using techniques from the oil and gas industry.[133] About this time several industry-funded tests of novel cementing employing tremie pipes and sodium silicate were conducted.[134] This resulted in a variety of opportunities to work with industry on applying the lessons learned at Rye Patch to sodium silicate and cement.

4.8 High-Temperature Packer

LANL managed DOE's HDR program at Fenton Hill, New Mexico from 1974 to 1995. The HDR program was a pursuit of the concept in which two parallel holes are drilled into hot, impermeable rock and artificially created fractures between the two holes create a flow loop. Cold water is then pumped down one hole and gains heat passing through the fractures, and the resulting hot water returns up the other hole to drive a power plant. Because fracture creation was essential to this process, some method of zone isolation was necessary to control the fractures' location.

Conventional oilfield packers could not function in the high temperatures, so LANL constructed special packers in 1982 and tried three field tests. None were successful. Consequently, researchers examined two advanced packer designs: 1) an elastomer-and-steel expansion element to be used as a single packer[135] and 2) an expandable metal tube that would plastically deform and permanently seal against the wellbore or casing[136] used in a straddle-packer configuration.

The elastomer-steel packer design criteria included differential pressure of 5,000 psi, exposure to 260°C (500°F) temperature before fracturing, and sudden cooling to 38°C (100°F) during injection. This design was used for 10 packer runs in 1985, with good performance in four runs. In one run the packer sealed as planned but could not be retrieved. This system was far too complex for industry application, but it was thought at the time that a commercially viable, high-temperature, high-pressure version could evolve from it.

The expanding metal packer underwent 13 proof-of-concept tests aimed at investigating or solving one or more potential defects: loss of seal with elastic rebound after inflation pressure is released; low collapse resistance of the thinned wall; rupture if inflated in oversize hole or in a breakout; and high pressure required to inflate the packer. Most of these tests used American Iron and Steel Institute (AISI) 304 stainless steel as the ductile expansion material. Tests showed enough promise to conclude that a metal packer could be developed for field use, although major technology developments were still required.

Experience with both types of packers emphasized the importance of choosing the proper seat for a packer. Oversize holes or intervals with breakouts (i.e., irregular cavities in the wellbore wall caused by localized stresses) were almost certain to cause rupture in the packer element, so an accurate caliper log was extremely valuable. Research concluded in 1991.

4.9 Lost Circulation Materials

Lost circulation problems can generally be divided into two regimes differentiated by whether the fracture aperture is smaller or larger than the bit's nozzle diameter. For smaller fractures or for matrix permeability, the wellbore can theoretically be sealed by pumping solid or fibrous plugging material mixed with the drilling fluid. This method, however, is much less effective with larger fractures. Larger fractures were often treated with cement plugs, which required significant time and material (see Section 4.1). As a result, several groups investigated cementitious mud. As implied by the name, cementitious mud is drilling fluid that contains cement and other materials to satisfy certain criteria including compressive strength above 500 psi after two hours cure, permeability to water < 10 millidarcies, and volume increase with curing.

BNL found that rapid-setting, temperature-driven cement could be formulated by mixing conventional bentonite mud with ammonium polyphosphate, borax, and magnesium oxide.[137] Significant compressive strength was developed by such admixtures in less than two hours when sufficient concentrations of the magnesium oxide accelerator were used. Setting time decreased with temperature. Furthermore, the material expanded approximately 15 percent upon setting. These setting characteristics were ideal for plugging major-fracture loss zones, but more control over the setting process was necessary to ensure that the cement would not set up inside drill pipe during field application. R&D was conducted from 1986 to 1990.

4.10 Drillable Straddle Packer

In conventional geothermal lost circulation treatment, the lower end of an open-end drill pipe is positioned near the suspected loss zone to pump a given quantity of cement (typically 300 cubic feet) downhole. The objective was to emplace enough cement into the loss zone to seal it, however, this does not always occur. Due to its higher density relative to the wellbore fluid, the cement often channels through the wellbore fluid, settling at the bottom of the wellbore. If the loss zone is not on the wellbore bottom, the entire wellbore below the loss zone must often be filled with cement before a significant volume of cement flows into the loss zone. Consequently, a large volume of hardened cement must often be drilled to re-open the hole, wasting time and contaminating the drilling mud with cement fines. Furthermore, due to the relatively small aperture of many loss zone fractures, the loss zone may preferentially accept wellbore fluids into the fracture instead of the more viscous cement. This causes dilution of the cement in the loss zone and loss of integrity of the subsequent cement plug. As a result, multiple cement plugs are often required to plug a single loss zone, with each plug incurring significant time and material costs.

Beginning in 1989, the drillable straddle packer (DSP) was developed to improve the effectiveness and reduce the cost of a typical cement treatment by maximizing the volume of cement flowing into the loss zone, minimizing the volume of cement remaining in the wellbore and reducing dilution of the cement caused by other wellbore fluids flowing into the loss zone. As illustrated in Figure 34, a packer assembly on the end of the drillstring carries two fabric bags that straddle the loss zone and provide zonal isolation. The bags are protected by a removable shroud on the trip in. After releasing the shroud, the bags are inflated with cement by the differential pressure that develops across the cement ejection ports in the packer tube between them. This differential pressure is easily controlled from the surface by controlling the cement flow rate. The highly flexible bags seal against the wellbore wall, thereby forcing most of the cement to flow into the loss zone. Because the loss zone is already under-pressured with respect to the wellbore, a very low-pressure sealing capability will effectively force-feed the loss zone with cement. A bag pressure capability of 20-40 psi is sufficient in most cases.

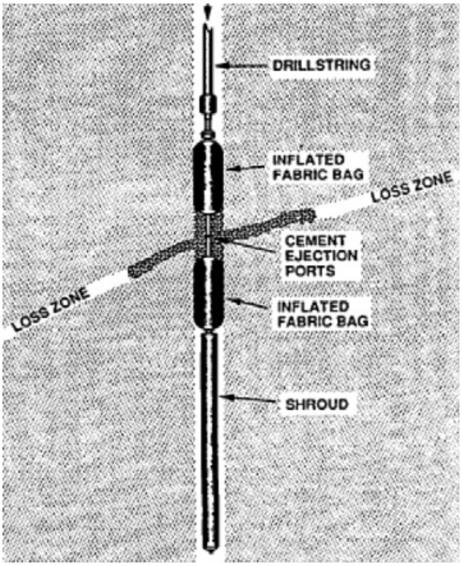

Figure 34. Drillable straddle packer concept

After pumping a specified volume of cement, the straddle packer assembly is disconnected from the drillstring and left in the wellbore while the drillstring is tripped out of the hole.

The packer assembly (shown in Figure 35) is constructed of drillable materials, e.g., aluminum, fiberglass, and, in low-temperature applications, chlorinated polyvinyl chloride (CPVC) plastic. It is drilled through after the cement sets and the drilling operation resumes.

Using a drillable straddle packer as described may reduce the cost of a lost circulation treatment by 10 to 36 percent using conventional cement, and 21 to 44 percent using cementitious mud.[138] The lower estimates result from assuming that half as much cement per treatment is required when using the straddle packer due to increased effectiveness. The higher estimated cost savings result from assuming that the straddle packer reduces the number of treatments

Figure 35. Straddle-packer assembly

required to plug a severe loss zone, from two treatments to one. The greater savings from decreased rig costs, associated with the use of cementitious mud result from the assumption that cementitious mud solidifies within three hours while conventional cement requires eight hours to set. A further advantage with the straddle packer, not included in these estimates, is the reduction in drilling mud conditioning costs that results if less cement must be drilled out of the wellbore. Cement fines are quite damaging to drilling mud properties.

A vigorous development and testing program produced a low-cost drillable straddle packer that could be used in geothermal wells. Full-scale laboratory testing found that this packer technique is superior to the industry standard open-end-drill-pipe technique for placing cement into a geothermal well loss zone. Laboratory tests were conducted using standard industry cement pumping equipment and techniques to evaluate and compare lost circulation treatment technologies. Documented test results show that the DSP can successfully pack-off a wellbore and seal against the wellbore walls. This 30 to 40 psi differential pressure seal is adequate to force cement into a loss zone and seal the remainder of the wellbore sufficiently to prevent production zone contamination and/or excessive use of cement during lost circulation treatments.

SNL identified a high-temperature flexible fabric for the DSP bag able to withstand differential burst pressures of 50 psi and wellbore temperatures of 232°C (450°F). Techniques to fabricate the packer bags that employ standard industry procedures and processes were also developed.

A full-scale test bed, the Engineered-Lithology Test Facility (ELTF) (shown in Figure 36), was designed, constructed, and used to conduct 10 full-scale open-ended drill pipe (OEDP) and DSP experiments. The ELTF was designed to be adaptable for other full-scale geology experiments where a controlled engineered lithology and real-time or recoverable test results were required. Tests were conducted with OEDP at the ELTF to provide a baseline prior to the DSP tests. These OEDP tests provided important insights into the difficulty of placing cement plugs in geothermal lost circulation zones. The large diameters of geothermal wells and large fracture apertures of geothermal lost circulation zones increased the likelihood that the density contrast between cement and geothermal drilling and formation fluids would cause the cement to migrate away rather than setting up where it could plug the loss zone. Simply increasing the well diameter from a typical of oil and gas well to that of a geothermal well was enough to destabilize cement lost circulation plugs so that they did not remain where placed.[139]

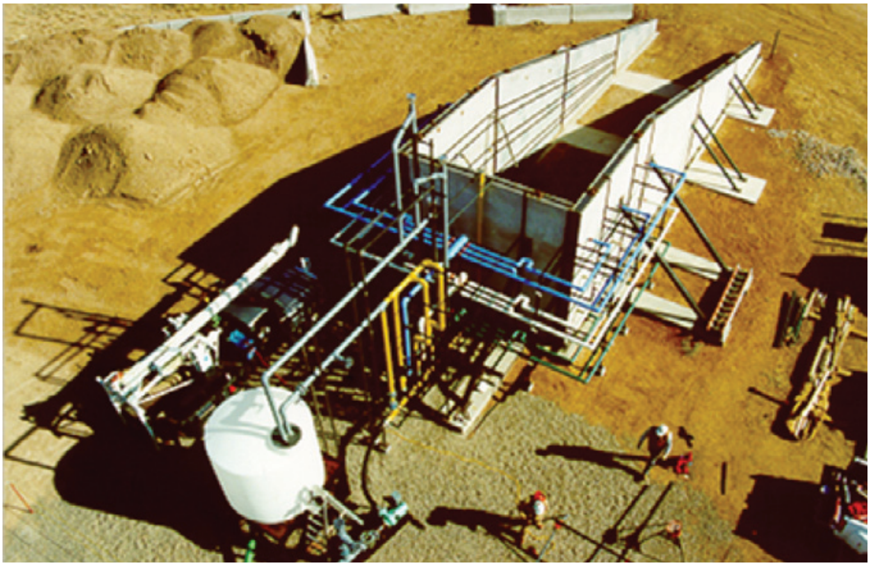

Figure 36. Engineered Lithology Test Facility

Testing DSP operation at geothermal well temperatures was not completed. All DSP components, however, are or could be made from materials able to withstand temperatures of 232°C (450°F) or higher. Most prototype DSP assemblies have been fabricated and assembled at SNL. Using costs based on estimated time and material requirements and shop rates, a prototype DSP with two bags and a polyvinyl chloride (PVC) shroud cost less than $2,000 (1995 dollars). This is somewhat higher than the initial low-cost goal, but costs should be lower when the DSP achieves larger production runs. Complete design drawings of the DSP, with test documentation, are provided in a DOE report.[140] While the DSP has not been tested in the field, the packers used at Rye Patch, Nevada (see section 4.7) were designed and deployed using techniques prototyped during DSP development, and thus much of the DSP technology has been proven in the field. Research on the DSP ended in 1999.

4.11 Rolling Float Meter

A key to effectively treating lost circulation is early detection. In- and outflows of drilling fluid to and from the wellbore must be accurately known. Historically, conventional drilling practice measured inflow by multiplying the number of mud-pump strokes by the calculated swept volume in the pump. Outflow was measured with a "paddle meter," which placed a broad-tailed lever in the mud-return channel so that it would be deflected by the flow of fluid in the trough. Neither of these methods, especially for outflow, is accurate. Research by SNL worked to refine both in- and out-flow measurements in order to improve the timely detection of lost circulation.

The rolling float meter (RFM) developed at SNL accurately measured the outflow rate of well drilling fluids[141] in a partially filled return line pipe. Commercially available non-intrusive inflow meters, such as the clamp-on Doppler ultrasonic flow meter, were successfully employed on drill rigs to measure fluid inflow rates.[142] These commercial inflow meters were evaluated and compared to the industry-standard pump-stroke counter inflow measuring technique. Comparing the real-time inflow and outflow rates while drilling, provided the fast response delta flow (inflow minus outflow) needed to detect and treat lost circulation.

During development of the RFM from 1991 to 1998 several design configurations were examined before settling on the original field-prototype design as shown in Figure 37. Using this design, several prototype units were built and loaned to interested drilling and well logging companies for field testing and evaluation. Basic elements of these prototype units were a rotating polyurethane-foam float wheel, with a counterbalance, attached to a horizontal support shaft and mounted in a sheet-metal housing. A pendulum potentiometer was attached to the horizontal shaft in the housing to measure the angle (and thus the fluid depth) between the float wheel and the return pipe. Figure 38 shows the rolling float meter in SNL's test facility. After testing, the loaned meters were returned to SNL for post-test evaluation. Results of these tests were mixed.

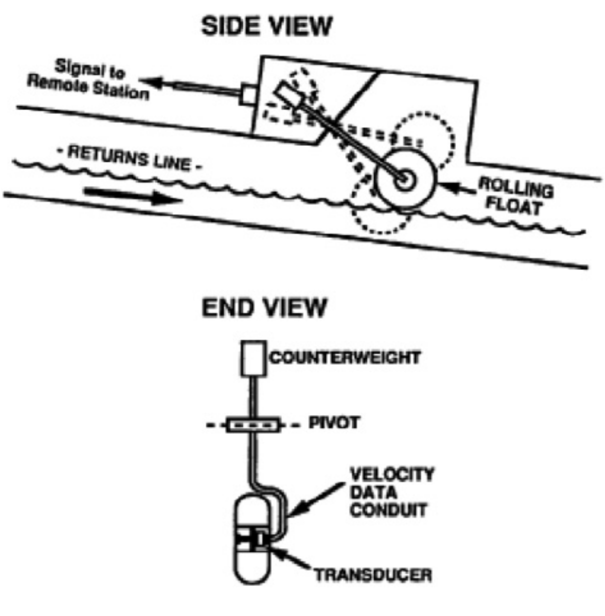

Figure 37. Schematic of a rolling float meter

When the RFM was loaned, SNL provided an instruction manual on installation, calibration, and operation. Since this was still a developmental tool, however, instructions were not always followed as intended and routine RFM maintenance was sketchy to nonexistent. Researchers found that the field-prototype design was not as robust as needed for the rough handling encountered around drill rigs. Damage to the loaned units was common. The meter was also exposed to worse-than-expected environmental conditions while drilling (e.g., high mud temperatures, abrasive cuttings, and corrosive fluids). Examination of the polyurethane foam float wheel revealed that the foam was eroded away during operation due to the return mud's and cuttings' abrasiveness, especially at high temperatures.

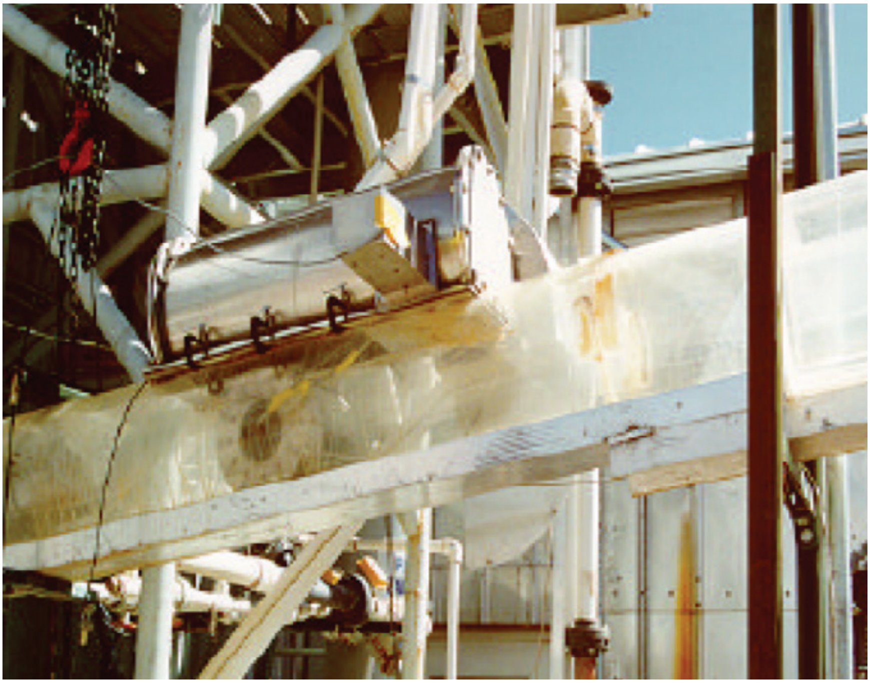

Figure 38. The rolling float meter (RFM) in SNL test facility

Industry users suggested additional features to improve the RFM design and make it more useful and acceptable. One user, Inteq, Inc., made the prototype RFM housing sturdier so that it could be employed on return lines where a sudden over-pressure, like that from a well kick, would not damage the meter housing. Several features of this design were incorporated into a design upgrade for a more robust RFM.

To improve the wear resistance of the float wheel investigators fabricated a wheel from thin sheet metal instead of foam. The shape selected was similar to the prototype polyurethane foam wheel; the material was type 304 stainless steel. An adjustable stop plate that allowed the wheel to be positioned close to, but not touching, the bottom interior diameter (ID) of the return line was also added. This permitted the wheel to begin rotation at a much lower flow rate, improving its useful range. Accumulations of mud and other debris on the wheel sometimes necessitated field adjustments to the counterbalance to maintain desirable wheel stability. This mechanism was also modified to make adjustment easier.

These changes, along with improvements to the sensors, were incorporated into a modified rolling float meter (MRFM) that was evaluated in the field in four slim holes and two large-diameter geothermal wells. The instrument provided reliable, accurate drilling fluid outflow measurements in a partially filled return line pipe, which could be used to monitor drilling fluid flow rates, from less than 50 to 1,000 gpm or more, while drilling a well.

The RFM design underwent continuous improvement during development, resulting in a rugged, adaptable end product that can function reliably under the severe environmental conditions of a geothermal drill rig, while providing simplicity and ease of installation, maintenance, and operation. Test results and detailed design features are documented in a DOE report.[143] The RFM has been commercialized in the drilling industry.

5.0 Slimhole Drilling

While exploration is by its nature inherently uncertain, it is preferable to drill an inexpensive rather than an expensive dry hole. Historically, geothermal exploration has been done by drilling large-diameter (8.5 to 12.25 inches at the production interval) wells, and then attempting to produce steam or brine while simultaneously measuring fluid temperature and downhole pressure. Flow tests, which typically last from days to weeks, directly evaluate the energy output of a well and determine whether the geothermal reservoir is viable.

Geothermal exploration is expensive,[4] and there is significant environmental impact from the roads, large drill sites, and fluid-handling requirements. When data from a smaller slimhole is adequate to evaluate the reservoir, exploration is much cheaper. DOE's slimhole drilling program was created to determine: 1) whether drilling a smaller hole is really cheaper and 2) whether a smaller hole can provide an accurate prediction of reservoir productivity. The answer to both of these turned out to be "yes."

Drilling slimholes is cheaper than drilling production-size wells. The rigs, casing and cementing, crews, locations, and drilling fluid requirements are smaller. Site preparation and road construction in remote areas are significantly reduced with slimholes. Lastly, it is unnecessary to repair lost circulation zones before drilling ahead.

Core rigs used for slimhole drilling (and by the minerals industry to explore for ore bodies) have diamond bits that cut a thin-kerf hole 2 to 6 inches in diameter with corresponding core diameters of 1 to 4 inches. Figure 39 shows a diamond-impregnated core bit used in slimhole drilling. Cores are wireline-retrieved, and the drillstring is not tripped except to change bits. Because the cuttings produced by diamond bits are very fine and make up a smaller fraction of the hole volume than in rotary-rig coring, minerals-type core drilling can advance the hole even with complete lost circulation. Figure 40 shows a typical fracture in geothermal production zone, which often produces total lost circulation.

Figure 39. Diamond-impregnated core bit used in slimhole drilling

After drilling an exploratory geothermal slimhole, it is essential to evaluate the reservoir's potential. The two most important reservoir qualities are temperature and resistance to fluid flow. Because permeability is a point measurement and most geothermal production is through fractures, flow resistance is quantified as permeability integrated over some wellbore length (e.g., transmissivity).

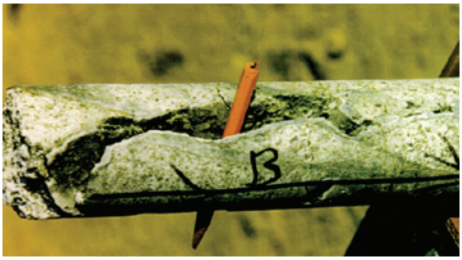

Figure 40. Typical fracture in geothermal production zone, which often produces total lost circulation

Reservoir temperature can usually be determined fairly easily, either through logs after drilling and completion, or from logs or maximum-reading thermometers during drilling. (Most geothermal drilling permits require periodic downhole temperature measurements as a criterion for when it is necessary to set casing.) Because of the low circulation rates used for slimhole core-drilling (typically 12-20 gpm), the formation temperature recovers from the cooling effect of drilling much more quickly than in conventional rotary drilling where mud circulation is usually several hundred grams per meter.

Estimating or measuring transmissivity is more complicated, although lost circulation during drilling is a qualitative indication of formation transmissivity. The best method to determine this is to discharge the well if the combination of temperature, depth, and fluid level allows self-energized production from the wellbore. In many cases, however, either the temperature or the depth do not allow self-supporting flow from the well. Thus, transmissivity is evaluated with an injection test.

DOE's slimhole drilling program focused on demonstrating two major properties of slimholes relative to production-diameter wells: 1) flow or injection tests on slimholes can accurately predict production characteristics of production-diameter wells in the same reservoir, and 2) slimhole drilling is cheaper than a comparable large-diameter well in the same location. A combination of analysis, field experiments, and field drilling operations was used. Early calculations[144] showed the possibility of predicting flow in production wells based on slimhole tests. These were later confirmed by field results from U.S. and Japanese[145-146] geothermal reservoirs.

DOE also managed four field drilling projects in different reservoirs: Steamboat Hills, Nevada; Vale and Newberry Caldera, Oregon; and Fort Bliss, Texas. All four projects were drilled with core-drilling rigs and cost-shared (three with geothermal operators, one with the U.S. Army). They verified the economic advantages of slimhole drilling under widely varying conditions.

The experiences of DOE's slimhole drilling program were published in the "Slimhole Handbook,"[147] which was distributed to industry and is used as a textbook in Iceland's United Nations Geothermal Training Program. Slimhole exploration is now widely used by the geothermal industry.

5.1 Steamboat Hills, Nevada

In 1993, DOE, through SNL, partnered with Far West Capital/SB Geo, Inc. to drill a continuously cored hole to 4,000 ft, in search of a deeper, hotter reservoir than the one in production at the time.[148] While the postulated reservoir did not exist, the slimhole successfully demonstrated production flow tests from a resource at about 815 ft. The flow tests also showed that relatively cheap and simple surface instrumentation could give adequate measurements of the well's flow rate and enthalpy. Figure 41 shows a slimhole production flow test at Steamboat Hills.

Figure 41. Slimhole production flow test at Steamboat Hills, Nevada

5.2 Vale, Oregon

In 1994, Trans-Pacific Geothermal Corporation drilled a conventional exploratory well in the Vale Known Geothermal Resource Area (KGRA). In 1995, DOE cost-shared an exploratory slimhole, approximately two miles from the previous hole, with Trans-Pacific.[149] This was a "hybrid" drilling operation—the upper 3,000 ft of the hole was rotary-drilled with a large core rig; the remainder (total depth [TD] of 5,825 ft) of the hole was continuously cored using the same rig. Completed to the same depth as the slimhole, the presence of the earlier nearby hole, gave a direct comparison of costs and highlighted the specific reasons for the slimhole's lower cost. The downhole temperature (about 143°C [290°F]) and permeability were low, precluding further exploration at the site. Figure 42 shows the drill rig at the Vale site.

Figure 42. Drill rig at Vale, Oregon

5.3 Newberry Caldera, Oregon

In 1995, California Energy Company, Inc. (CECI, now CalEnergy) drilled several production-size wells on the flanks of Newberry Caldera.[150] CECI and DOE shared the cost of two slimholes. The first slimhole was drilled by CECI and logged by SNL. SNL managed the drilling of the second slimhole in consultation with CECI. The objectives for the second hole were to drill to a depth determined by the expected temperature at TD, set casing at that depth, and then directionally drill toward the postulated resource thought to be beneath the center of the crater. The temperature at TD (4,840 ft) of the first slimhole was about 210°C (410°F). The geothermal gradient in the lower portion of the second slimhole was almost identical, but the maximum temperature at TD of 5,360 ft was only 177°C (350°F). The temperature was marginal for geothermal development, and the almost complete lack of permeability meant that there was little expectation of a useful geothermal resource at the site. Again, however, slimholes characterized the reservoir at a much lower cost than production-size wells.[149] Figure 43 shows the drill rig at Newberry Caldera. The same model rig was used at Steamboat Hills, Nevada and Fort Bliss, Texas.

Figure 43. Drill rig at Newberry Caldera, Oregon

5.4 Fort Bliss, Texas

The U.S. Army was interested in using possible geothermal resources for either power production or water desalination near Fort Bliss. While in the planning stages of exploration, the Army approached DOE for input on the structure of the program, which led to a work-for-others (WFO) contract for assistance on the exploratory holes. Assistance included consultation and management of drilling operations, numerous temperature logs during and after drilling, and project documentation.

The drilling eventually resulted in four holes, ranging from just over 2,000 ft to almost 4,000 ft, with maximum temperatures of 77°C to 89°C (170°F to 192°F), on the McGregor Range (an integral part of the Fort Bliss Range Complex, in southern New Mexico).[151]

The drilling program gave the Army detailed documentation on the project, including core samples of the lithology penetrated by the holes, records of drilling behavior (e.g., water level in the hole, changes in ROP, etc.), and multiple temperature logs for each well (both during and after drilling). A suite of geophysical logs (gamma ray, neutron, sonic, and resistivity) was also run after drilling completion.

Field experiences with slimhole drilling showed that costs were 45 to 65 percent of conventional drilling cost, and logging and measurement techniques were adequate to characterize a geothermal reservoir.

6.0 Systems Analysis

When addressing a large, complex goal such as reducing geothermal drilling and completion costs, it is useful to break the problem down into several smaller components and solve each individually. Two principles of this approach are important. First, focus must be placed on those problems whose solutions will have the greatest impact, and second, solutions to the individual problems must be integrated into the complete system. For example, if a new drilling method doubles the ROP, the drill rig pumps, fluid cleaning system, and mud-logging capabilities must be able to keep up with the increased performance. In 1981, DOE redirected the geothermal research program[4] toward longer term R&D. Several system-level studies were undertaken in an effort to integrate and focus the geothermal program. Several are described briefly below.

6.1 Geothermal Well Models

A major difficulty in trying to attain a generic objective such as reducing geothermal well cost is that geothermal wells in different areas are different. Compare two of California's most important geothermal resources: The Geysers and Imperial Valley. Wells in The Geysers are mud-drilled down to a caprock formation where casing is set, and then air-drilled into the reservoir, which produces dry steam. Typical problems derive from the abrasive, highly fractured rock in the production interval, which causes rough drilling, low bit life, and twist-offs. To avoid damage to the production zone, drilling is often done while producing live steam, essentially drilling with a controlled blowout. On the other hand, in the Imperial Valley wells normally penetrate sedimentary formations that are relatively easy to drill. However, produced brines are so corrosive that titanium (Ti) casing is required. Ti casing of 8-5/8-inch diameter is estimated to cost $582/ft.[152] Normal production casing in the Imperial Valley is 16-inch, and correspondingly more expensive. A technological improvement that could greatly cut costs in The Geysers may not affect costs at all in the Imperial Valley.

From 1980 to 1982, DOE conducted an extensive investigation of eight geothermal areas primarily in California to identify critical cost drivers at each location. The investigation was primarily focused on collecting historical drilling cost data, which was hindered by the fact that such data were often incomplete, proprietary, or inaccurate (i.e., cost records on a specific well could vary by 40 percent, depending on the source). Based on data from approximately 35 wells, models of representative, trouble-free wells in each area were constructed[153] using four steps: 1) establish a casing program for the well; 2) define a sequence of operations for drilling the well; 3) estimate a time required for each operation; and 4) assign costs (fixed charges and time-related expense) for each operation.

The cost data and well models were used in conjunction with a SNL-developed code[154] that simulated drilling a well to examine the impact of technological improvements on well cost.[155] Baseline comparisons of the trouble-free well model with historical data showed reasonable agreement and gave confidence that this was an effective way to assess technology impact. A parallel study[156] of trouble frequency and severity gave a basis for estimating the industry-wide magnitude of costs associated with various kinds of problems. The strategy of using cost models to predict the impact of technology improvements continued through the life of DOE's geothermal research program, as described in more detail below.

6.2 Cost Models

Developing cost models has focused on collecting more field data from operators, and improving ways to analyze, display, and make use of the data. This entails three actions:

1. Establish baseline geothermal drilling costs in different reservoirs so performance improvement can be evaluated over time.
2. Identify and rank the most important cost drivers in geothermal drilling, enabling R&D to target high-payoff projects.
3. Use field data to calibrate a well-cost spreadsheet that quantifies the impact of technology improvements on drilling.

In 2000, DOE signed Non-Disclosure Agreements with the three major geothermal operators in the United States to obtain access to their databases of historical drilling cost records. The records, many of which were in the software format RIMbase, were extremely valuable because they not only gave overall and itemized well costs, but also included daily drilling reports with detailed information about what actually happened on the drill rig each day. Using these records, hypothetical "optimum" wells were constructed for various fields. An optimum well is defined as a trouble-free well that has the best demonstrated drilling performance in terms of rate-of-penetration and bit life. Principal cost drivers are identified by examining the differences between an optimum and average well for the same field, and would be a primary target for drilling research.

Because optimum wells are based on best demonstrated practice, it is also possible to model improved drilling performance (e.g., better drill bits, more effective lost circulation control) to define an "advanced" well that has even lower cost than the optimum well. This technique can also show the sensitivity of well cost to various kinds of technology improvement—another way of guiding drilling research.[157] Figure 44 shows time comparisons for "optimal" and "average" wells, specifically the amount of time needed for the various activities that make up the drilling process. Since many costs are directly related to the time consumed, this is a reasonable way to visualize cost and to see its sensitivity to better drilling performance.

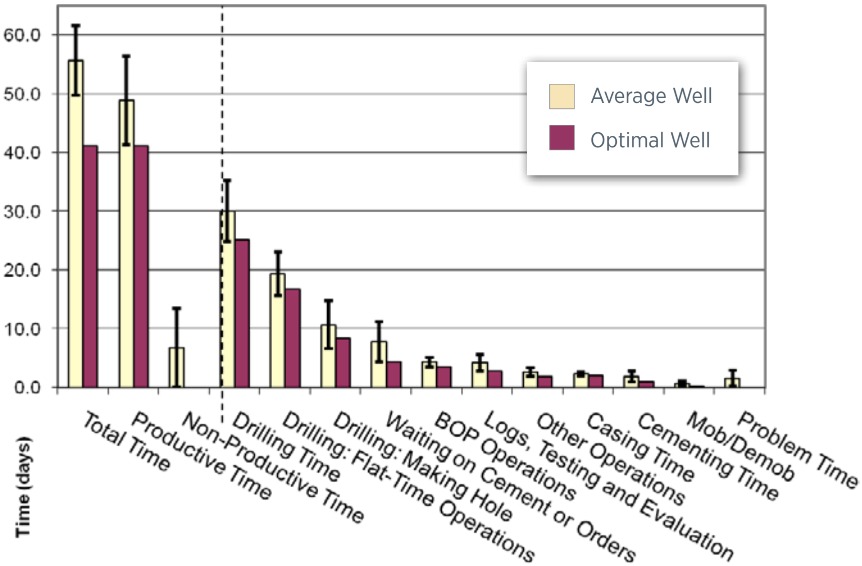

Figure 44. Time comparisons for "optimal" and "average" wells

Real-life technological impact on the drilling world can be seen by comparing 1970s drilling costs for geothermal and oil and gas wells to recent costs.[158] The comparison shows that not only have geothermal drilling costs decreased over the last 30 years (adjusted to 2000 dollars) but they have decreased more than oil and gas drilling costs have decreased.

Several approaches to well-cost analysis have evolved into a spreadsheet-based model called Wellcost Lite.[4] Wellcost Lite can quickly evaluate the effect of improving the penetration rate by 25 percent, eliminating lost circulation. In fact, Wellcost Lite can evaluate any combination of changes in drilling practice or performance. The model has a relatively simple input and output format, and various input files can be stored so as to build a "library" of standard well designs and performance levels. This greatly simplifies a quick estimate of the cost impact from a given performance improvement, assuming that all the consequences of that improvement are well understood.

Cost modeling has been a critical element in the management of DOE's geothermal research program. It continues to show its value in helping to understand the impact of technology.

6.3 Advanced Drilling Systems

In addition to cost modeling's focus on conventional drilling, it is critical to examine truly radical drilling technologies that could make revolutionary improvements in the speed, cost, or reliability of drilling.

Books have been written describing novel drilling methods.[159-160] Industry has tried many innovations with various degrees of success. DOE's approach was to examine technologies that had been proposed as advanced drilling systems—from those that actually had considerable field experience to those that were primarily conceptual with some analysis and laboratory-scale experiment behind them. Such methods included coiled tubing, jet-assisted or pure jet, projectile-assisted, microwave-assisted, mud hammer, thermal spallation, spark drill, explosive drill, rock melters (e.g., e-beam, laser, electrical resistance), and pulsed-laser water jet.

In 1995 and 1996, DOE evaluated each of these advanced drilling systems vis-à-vis six basic drilling functions: 1) energy transmission, 2) rock reduction, 3) debris removal, 4) wellbore maintenance, 5) well control, and 6) completion. DOE compared the results to a baseline system which was essentially conventional rotary drilling. This yielded the advantages and disadvantages of each system, and helped to identify the technology needed to make the systems viable. For example, many of the advanced drilling systems required multi-conduit drill pipe and electric power transmission downhole.

In considering the economic analysis of the advanced drilling systems, it is very difficult to estimate performance of a drilling method that has never progressed beyond bench-scale experiment. The alternative was to estimate the cost of deploying such a system and then to derive the performance that would be required if the total well cost did not exceed conventional drilling. For this comparison, the same hole interval (12-1/4-inch diameter from 4,000 to 8,000 ft) was used for estimating each system's cost and calculating its required performance. Because this was a systems approach, the end-of-interval costs were also included (i.e., casing, cementing). This reinforced the idea that the correlation between ROP and total well cost is not as strong as intuition might suggest. Systems which increase the ROP have much greater impact in drilling situations where the rate is normally low, such as very hard rock. This work was documented in a report[-161] that contains much more detail about technical aspects of the systems examined, as well as the assumptions and calculations involved in the conclusions.

6.4 Slimhole Power Generation

The conventional view of geothermally produced electricity involves large, multi-megawatt (MW) power plants. The World Bank currently considers 5-MW plants as “mini-geothermal,” but there is a significant market niche for units down to the 100-kW to 1,000-kW range. Analyses[162-163] concluded that holes as small as 3 inches in diameter can drive a 100-kW generator, and somewhat larger holes (but still “slimholes” because they are not greater than the arbitrary limit of 6-inch diameter) can produce well over 1,000 kilowatts-electric (kWe).

In remote settlements far from the electric grid and mining operations, small-scale geothermal power plants (SGPPs) using hot fluids from slimhole wells can replace expensive diesel generators. The cost of getting fuel to remote diesel generators could drive electricity prices above 50¢/kWh. Researchers have estimated,[164] however, that a 300-kW unit using 120°C (248°F) brine could produce electricity for about 11¢/kWh (1992 dollars) even without the additional cost savings from slimhole drilling.

In addition to the price advantage, SGPPs are more environmentally benign than fossil-burning plants, which is crucial in view of climate change concerns and burgeoning electricity demand in the developing countries.

6.5 Drilling for Geothermal Heat Pump Installation

Geothermal heat pumps (GHP), also known as ground-source heat pumps (GSHP) are much more efficient than air-source units such as conventional air conditioners. A major obstacle to their use, however, is the high initial cost of installing the heat exchange loops into the ground, which typically requires drilling holes 100 ft to 400 ft deep. Drilling for GHP loop installation is most often done by water well drillers. Water well drilling is a mature technology generally uncomplicated by the standards of geothermal or oil and gas holes.

In 1996, in an effort to identify drivers that influence installation cost, SNL researchers visited a number of sites to assess the state-of-the-art in drilling for GHP loop installation.[165] Figure 45 shows drilling for a GHP installation in Oklahoma.

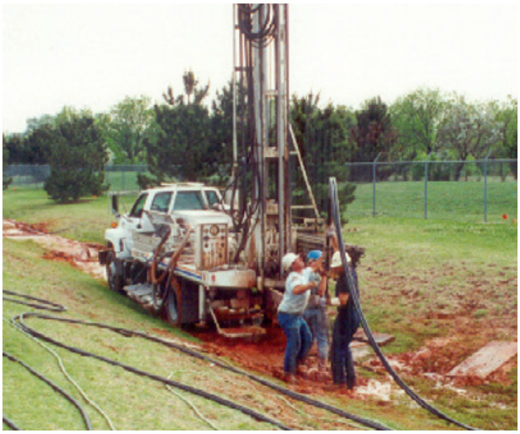

Figure 45. Drilling for geothermal heat pump installation in Oklahoma

While investigators saw many different rigs and techniques, there were few obvious opportunities for technology to make a significant impact on drilling cost.

To measure the effect of various drilling improvements, researchers constructed a spreadsheet based on estimated time and material costs for all the activities required in a typical loop-field installation. By substituting different, improved values into specific activity costs, the effect on total project costs could be seen. By examining various components of the installation process, for example, it was clear that increasing ROP generally did not have a great benefit. Conversely, better logistics—drilling many holes at the same location or improved heat transfer between the loops and the formation—could yield significant savings by reducing the number of required holes.

A related area of research at BNL addressed the improvement of grouts for filling the void between the heat pump loops and the borehole wall.[166] Prior to BNL's research, conventional practice in heat pump loop grouting was to use simple bentonite slurry or neat cement. Experiments showed, however, that these materials had relatively low thermal conductivity, even with perfect contact with the loops and the wellbore wall. Clearly, better heat transfer would mean that fewer feet of heat exchanger would be needed and fewer feet of hole drilled.

BNL scientists focused on improving three properties of grout: thermal conductivity, bond strength, and shrinkage. The need for better thermal conductivity is straightforward, but numerical modeling and field experiments also showed that bentonite grout, after emplacement, tended to shrink and lose bond from the loops. These effects caused voids in the grout that degraded heat transfer.

An improved high-performance grout, called Mix 111, was developed in the laboratory and validated with field trials in different geologic formations. The composition of Mix 111 is cement, silica sand, small amounts of bentonite and super-plasticizer, and water. Field tests showed that its thermal resistance was 30 to 35 percent less than bentonite grout, leading to significantly lower loop lengths. The mix is cheap, simple to assemble, easily pumped, and stable over long periods of time. It also resolved environmental concerns over ground-water contamination in New Jersey and Tennessee, and was specifically recognized in the licensing requirements of those states. Mix 111 was patented and transferred to industry.

6.6 Wellbore Lining

A technology that could line a wellbore, at least partially, while it is being drilled would have significant advantages compared to conventional steel casing cemented into place after each drilling interval is completed. Cost savings resulting from reduced lost circulation problems, better wellbore stability, a lower probability of stuck pipe, and the ability to seal certain zones without a full string of casing would greatly improve the economics of geothermal drilling. Motivated by a National Advanced Drilling and Excavation Technologies (NADET, see Section 10.0) research topic related to lost circulation in geothermal wells in 2001 and 2002, SNL undertook an examination of how alternative wellbore lining methods could be deployed.

SNL's analysis considered several possible ways the lining could be visualized—continuous lining-while-drilling with either metal or chemical means, or step-wise lining-while-drilling with either metal or chemical means. Some of the conceptual approaches (e.g., expandable tubulars) were widely used commercially, although not for the uses envisioned. Others were barely past the laboratory experimental stage. The reference report on the project[167] summarized each concept, describing the state-of-the-art in that concept (as of 2002), and suggesting further research.

7.0
Analytical Studies

Good quality software can predict, correct, and direct the results of laboratory and field work, a trend that will only accelerate. In addition to the extensive analysis carried out in support of hardware development projects, DOE's geothermal drilling program supported several analytical studies with the specific objective of providing a software tool that could be applied in different scenarios to assess the impacts of technological advancements. While complementary, analytical studies differ from the systems analysis work described in Section 6.0.

7.1 GEOTEMP

GEOTEMP software, a wellbore thermal simulator, was originally written in the early 1980s.[168-169] SNL later updated it as GEOTEMP2.[170] GEOTEMP is a finite-difference code that calculates vertical and radial conduction in the rock, casing, and cement; conduction through the drill pipe; and convection at the wellbore wall and inside and outside the drill pipe. Input variables included flow rate, well configuration, bottom-hole assembly, bit nozzle size, fluid properties (density and viscosity), penetration rate, and geothermal gradient. Allowable scenarios included a circulation-only (forward or reverse) condition, injection, production, or drilling ahead. Output gave temperatures at vertical intervals determined by the mesh size (typically every 200 ft) in the drill pipe, in the annulus, and at various radial distances from the wellbore in the formation.

Although GEOTEMP2 generally compared well with actual data and other wellbore simulators, its use was limited. It did not accept a change in casing inside diameter (i.e., it did not model a liner) or handle aerated or oil-based mud well. Calculated return temperatures were lower than indicated by field experience, and the temperature information required for input was often unavailable in the field. Despite these limitations, GEOTEMP was a useful tool to evaluate the effect of changes in drilling parameters, tubular conductivity, well configuration, or geothermal gradient. Commercial simulators give more flexibility and better results, but are typically part of very expensive well-design packages. GEOTEMP2 has been distributed for free to many geothermal companies and researchers. Its use for scoping calculations remains widespread.

7.2 Casing Stress and Collapse

SNL's casing stress and collapse project from 1981 to 1985 had two phases: 1) initial demonstration to show that conventional finite-element thermal stress analysis could be applied to geothermal casing, and 2) a more detailed investigation of planar, radial buckling. The first phase used transient thermal modeling to derive temperature distribution in casing and cement during cyclic well shut-in and flow. It then used a structural code to calculate stresses in the casing and cement from those temperatures related to the initial stress-free temperature.

The second phase followed an analysis of Euler buckling[171] and examined the likelihood of casing buckling under conditions of incomplete cementing in a non-vertical well. The failure mechanism was assumed to be high pressure generated by superheated liquid trapped in voids in the cement outside the casing wall. Research sought to answer two questions: "Will the casing buckle?" and "If the casing buckles, how severe will the deformation be?" This study considered only the first question.

Various amounts of cement support (defined by the circumferential angle of competent cement behind the pipe) to the casing were considered. The collapse pressures of different casing sizes at those angles were plotted. Those pressures could then be correlated with a temperature profile of the well, and regions susceptible to collapse could be identified.[20] This analysis only considered "perfect" casing, and so was never developed into an actual software tool that could reliably predict casing collapse. However, the completed work aided in understanding several factors such as wear caused by drilling below the casing point and the amount of casing unsupported by cement that affect casing performance during well operation.

7.3 Drill-String Dynamics

The survival of any downhole equipment is clearly determined by the shock and vibration experienced at the drill bit. The mechanical interaction of a rotating drillstring with the wellbore, however, is very complex. Not only is the combination of drill pipe, collars, stabilizers, and bit geometrically complicated, but the multiple forcing functions that drive the assembly's motion are variable, diverse, and unpredictable.

Following a 1981 exploratory study in which Jordan, Apostal, Ritter Associates, Inc. (JAR) established the feasibility of developing a finite-element model to describe drillstring dynamics, DOE contracted with the company to carry out the development. The project was cost-shared with an industry consortium composed of NL Industries, Inc. and Superior Oil Company in Phase 1, and ARCO and Conoco in Phase 2. The project ran from 1981 to 1987. It comprised three major phases: 1) assembly of subsystems into a bit-rock interaction model, 2) refinement and extension of that model, and 3) extension of the bit-formation model into a full drillstring-wellbore model.

Phase 1 produced a bit-formation model called GEODYN.[172-173] While it only represented the bit and bit sub in a straight hole, GEODYN was a major advance over other existing models. A series of verification runs was made with GEODYN, varying hole size, hole shape, and formation properties. The results reflected realistic bit behavior and confirmed that the solution algorithm was correct. Comparisons with experimental modal-response measurements also correlated well.

In Phase 2, the original code was modified into GEODYN2,[174] which expanded the capability to include the entire bottom-hole assembly, running in a curved 3-D wellbore. Again, there were numerous verification runs, with good agreement to theoretical predictions, and there were more laboratory and field experiments to acquire data for comparison. All results were satisfactory, but GEODYN2 was never used for actual analysis of field phenomena or for well planning. GEODYN2 could run on a personal computer today, but in the 1980s a main-frame computer was required. This meant that the code could never be used in a field situation, even with the early satellite communication systems available at the time. The theoretical description[175] and user manual[176] for GEODYN2 are still available; commercially available software has likely superseded the code.

Several service companies continued work on drillstring vibrations and now offer commercial services both in downhole measurement tools and interpretation software. DOE's efforts thus catalyzed the development of downhole vibration analysis in the drilling industry.

8.0 Geothermal Drilling Organization

A joint DOE-industry body, the Geothermal Drilling Organization (GDO), was created in 1982 to develop and fund near-term technology development projects.[177] Approximately 25 geothermal companies—operators, drilling contractors, and service companies—were GDO members, nominating and voting on projects. Projects required two industry sponsors, one that had to be an operator, and at least 50 percent cost-share from industry. SNL administered DOE funds to assist these projects and provided development support.

The GDO was a highly participatory group open to direct input from large and small companies alike. It was a favorite of the geothermal industry and brought many new tools to the marketplace. A representative description of GDO projects follows.

8.1 Expert System for Lost Circulation

The necessity for accurate inflow and outflow measurements was discussed in Section 4.11; the raw data must be interpreted. With practice and experience, a good driller or drilling engineer should be able to use this data to detect and diagnose drilling hydraulic problems, such as lost circulation and gas or steam kicks. The adeptness with which the driller or drilling engineer uses this information, however, depends on his or her familiarity with drilling conditions in the field. The driller and drilling engineer need accurate raw data and, if possible, interpreted data to help them make good decisions.

Expert system software that monitors inflow and outflow rates along with other rig parameters (e.g., weight-on-bit, drilling torque, rotary speed, penetration rate, pump speed, and standpipe pressure) and identifies anomalies, helps the driller or drilling engineer interpret the hydraulic drilling data. All of this data is presently recorded during most geothermal drilling operations. Even if the driller or drilling engineer is not required to follow the instructions suggested by the software, logical analysis of the situation would greatly assist in decision-making.

SNL originated the concept of a lost circulation expert system in 1996, and it became a GDO project when a major operator became interested in it. The system developed by Tracor[178] (later Marconi Electronic Systems and then BAE Systems North America) was based on the company's existing system for gas-kick detection. It was tested with a data set collected during actual geothermal drilling, accurately identifying lost circulation and mud pump and flow sensor problems. Work continued through 1999,[179] with additional capabilities added to the software, through another phase of development. When the GDO program ended, the Gas Research Institute (now the Gas Technology Institute) continued the project.

8.2 Retrievable Whipstock

A reliable and retrievable whipstock was needed to sidetrack geothermal wells. A combination anchor and whipstock provides a means of sidetracking in a cased hole while preserving the ability to produce from below the kick-off depth. AZ Grant International (now part of Smith International, Inc.) developed and successfully field tested a 13-3/8-inch combination anchor and whipstock in 1996. Portions of the assembly underwent extensive testing in the company's facilities in Tulsa, Oklahoma and Houston, Texas. The assemblies were commercialized and are available from Smith International, Inc.

8.3 Rotating-Head Rubbers

A rotating head, which allows drilling with pressure in the annulus, is used on some geothermal wells, especially at The Geysers where drilling is routinely continued while producing live steam. It is difficult to maintain rubber seals in the heads, where high temperatures and pressures degrade them rapidly. A GDO project in 1996 and 1997 worked to develop a better seal. AZ Grant International optimized a butyl elastomer suitable for geothermal use. As a spin-off of this program, nitrile and other elastomers were optimized for use in hydrocarbon extraction. These items are commercially available from Smith International, Inc.

8.4 Valve-Changing Tool

Sponsored by Smith International, Inc. and Puna Geothermal Ventures in 1997, the valve-changing tool was essentially a high-temperature, high-pressure packer that could shut off production from a well so that the wellhead master valve could be repaired or replaced. Shutting off the flow without cooling the well is desirable because "killing" the well can damage the formation and casing. Previous packers were rated to 1,000 psi and 204°C (400°F); the new tool was usable to 6,000 psi and 315°C (600°F). The new tool was successfully field tested on the Big Island of Hawaii and is commercially available from Smith International, Inc.

8.5 Insulated Drill Pipe

Sponsored by CalEnergy and Drill Cool Systems, Inc. from 1997 to 1999, the insulated drill pipe GDO project is described in detail in Section 2.3.

8.6 Geysers Casing Remediation

Unocal approached DOE in January 1998 with problems in several of its wells at The Geysers. Approximately 50 to 60 wells were experiencing severe casing deformation—usually at a geologic boundary. The deformation not only threatened the viability of the producing wells, but it also jeopardized the ability to properly plug and abandon them. This affected not only Unocal, but also all operators in The Geysers fields and other geothermal fields. A plan was quickly developed and adopted as a GDO project in 1998.

A principal requirement for any repair scheme is to plug the well below the repair area. This is often difficult because the casing deformation restricts the size of tools that can be run in the hole. For example, the Beigel-3 well had 13-3/8-inch casing deformed to such an extent that it would only pass a 4-1/2-inch diameter tool. This expansion ratio eliminates many kinds of packers that might be set to position a cement plug. In cooperation with Halliburton Energy Services, SNL led the development of at petal-basket packer[180] that could be deployed on coiled tubing through the deformed section. The packer then expanded to hold a cement plug (see Figure 46). This specialty item is now commercially available through Halliburton.

Figure 46. Petal-basket packer for The Geysers casing remediation

8.7 Low Emission Atmospheric Metering Separator

When a geothermal well is tested or produced, fluid is sometimes released as a two-phase mixture of vapor and liquid. This discharge passes through a steam separator where vapor is vented to the atmosphere and liquid is disposed of or reinjected into the reservoir. In the conventional and widely used cyclone separator, fluid produced from the well enters the separator tangentially to its cylindrical surface through a horizontal tube about halfway up the side of the tank. The fluid then forms a vortex inside the separator. Steam escapes out of the tank's open top, and liquid collects in the tank's bottom where it drains out through a line that typically leads to a weir box for measuring flow rate. However, a significant fraction of the liquid can be entrained or suspended in the vapor and borne away from the separator to fall on the surrounding area. This "carryover" can contain silica, salts, boron, arsenic, and, in the case of hydrogen sulfide abatement, concentrated caustic and chemical by-products that may be harmful to agriculture, equipment, or the environment. Remediation can be expensive. Geothermal power plant operators in the Imperial Valley often made substantial payments to nearby farmers.

Developed from 1998 to 2000, the Low Emission Atmospheric Metering Separator (LEAMS) uses internal baffles and diverters to reduce the amount of carryover emitted during testing.[181] Development of a LEAMS prototype was cost-shared by DOE and industry partners Two-Phase Engineering, Drill Cool Systems, and Coso Operating Company. Figure 47 shows a LEAMS on the right. A conventional cyclone separator is on the left.

After Drill Cool Systems and Two-Phase Engineering completed the prototype, SNL oversaw a field test[182] to evaluate its efficiency at the Coso geothermal field in California. Test results were positive—all qualitative (e.g., perception of carryover from walking under steam plume) and quantitative (e.g., rain gauges, exhaust particle, brine flow) measurements confirmed that the LEAMS was more effective than the cyclone at removing carryover. The prototype LEAMS was converted into two trailer-mounted separators that were commercialized after the test. In 2003, the LEAMS project received the prestigious "R&D 100" Award.

Figure 47. Low Emission Atmospheric Metering Separator on the right; conventional cyclone separator on the left

8.8 Additional GDO projects

GDO undertook additional projects with varying degrees of commercial success. Those which have not been commercialized are described briefly below.

8.8.1 Foam Cement

Under-pressured formations not only cause problems with lost circulation, but often make cementing casing more difficult because, due to cement's higher density relative to the drilling fluid, the formation cannot withstand the annulus pressure of the cement column. This same density situation also complicates the use of cement as a lost circulation treatment, so there is considerable motivation for development of lightweight cement. One candidate was aerated cement with nitrogen injected into it to reduce its effective weight. Field trials of nitrogen foam cement in lost circulation plugs at Coso showed some promise. A persistent loss zone was partially sealed, but the application procedure was not adequately understood and controlled. The GDO foam cement project was directed into other cementitious lost circulation materials and investigation of bond logs for foam cement.

8.8.2 Mud Hammer

While percussion drilling showed advantages in ROP in several geothermal formations (see Section 1.6) there was no commercially available hammer that operated with liquid drilling fluids. Novatek International, Inc. tested several versions of a mud hammer that showed significant gains in ROP at atmospheric pressure. In a pressurized wellbore that was a more realistic simulation of drilling, however, performance gains were much smaller. There were also some difficulties with adjusting the valve timing to give optimum blow frequency on the bit.

8.8.3 Air Motors

Steam-producing reservoirs, such as those at The Geysers, must be drilled with air in the production zones to avoid damage to the fractures. Both positive-displacement and turbine-type motors underwent development testing, including field drilling trials, for this application. Neither reached commercial status. The air turbine successfully drilled short intervals in holes in New Mexico and in limited trials at The Geysers, but had persistent problems with the gear reduction assembly that converted the turbine's extremely high rotary speed to a lower speed suitable for drilling.

The crux of positive displacement motor (PDM) development was to find a suitable elastomer for the motor's stator, but in the one drilling trial at The Geysers the motor was no longer capable of drilling after reaming for 8.5 hours. Disassembly at the surface indicated a fire inside the motor that destroyed most of the stator. Although the PDM was not successful during the GDO project, Baker Hughes INTEQ continued PDM development after cessation of the GDO, and its air motors are now used at The Geysers.

9.0 Scientific Drilling Management

Due to collective drilling expertise developed over the course of DOE's geothermal research program, SNL often provided drilling management of and technical support to scientific drilling projects sponsored by other agencies. Even though these projects did not explicitly address geothermal drilling, there was considerable cross-fertilization of ideas that benefited both the scientific projects and DOE's drilling research. Several of these projects were especially valuable in developing high-temperature logging tools because they provided the only available environment for testing tools under realistic conditions. A representative list of these scientific drilling projects follows.

9.1 Inyo Domes and Craters

One of the volcanic features along the eastern front of the Sierra Mountain Range near Mammoth Lakes, California is the six-mile Inyo eruptive chain that produced the Obsidian Dome and the Inyo Craters located in Long Valley Caldera. This line of relatively small craters is a remnant of eruptions from the same magmatic intrusion. Geologically, the Inyo Craters are young, about 600 years old. Earlier drilling into the domes was successful, achieving scientific objectives, but the Inyo drilling culminated with a hole beneath South Inyo Crater. The scientific drilling project's objective in 1987 was to examine the intrusion boundary with the host rock via slant drill, with continuous coring, completely through the dike to retrieve sections of the dike boundaries on both sides.[183] The unique operation concluded successfully. Comparable sampling has not been done anywhere else in the world.

9.2 Valles Caldera, VC-2B

In 1988, an exploratory hole to evaluate the geothermal resources beneath the Valles Caldera Sulfur Springs area in northern New Mexico was coordinated by the Continental Scientific Drilling Program (CSDP), and funded by DOE's Office of Basic Energy Sciences, USGS, and the National Science Foundation. The hole was expected to be challenging because of the high temperature of approximately 315°C (600°F) and depth of roughly 6,000 ft. For scientific objectives, it was also important to have continuous core of the formations traversed. Figure 48 shows drilling at well VC-2B in New Mexico.

What was then the largest wireline coring rig in the world was used to drill a hole that penetrated an active hydrothermal zone, including volcanic and sedimentary rock, ending in the granite basement. The project was a scientific success. Core recovery was exceptionally high at approximately 99 percent. There were significant engineering benefits to DOE's geothermal research from experience with lost circulation materials and with rig instrumentation for better efficiency and safety.[184] Valles Caldera did not proceed to commercial development.

Figure 48. Drilling at VC-2B in northern New Mexico

9.3 Weeks Island, Louisiana

One storage cavern of the Strategic Petroleum Reserve (SPR) is located at Weeks Island, just south of New Iberia, Louisiana. The SPR caverns are solution-drilled into massive salt beds. Each cavern contains tens of millions of barrels of crude oil. In 1994, an SPR security guard discovered a very large sinkhole above the cavern through which fresh water was seeping into the cavern. This was concerning because the water, being heavier that the oil, might displace oil stored in the cavern back to the surface. In addition, the fresh ground water could enlarge its channel by dissolving the salt, thus increasing its flow rate into the cavern.

Figure 49. Slant-drilling into the sinkhole at Weeks Island, Louisiana

In 1994, an immediate effort was launched to define the size and sub-surface location of the sinkhole, so that remedial action could be planned. A major part of the effort involved drilling a number of holes to core the salt-sediment-ground water interface and provide seismic tomography for 3-D mapping of the sinkhole.[185] All objectives were met. A subsequent freeze-wall around the sinkhole controlled water influx while oil was transferred to another cavern. SNL provided drilling and project management of slant-drilling into the sinkhole, as shown in Figure 49.

9.4 Long Valley Exploratory Well, Phase 3

In 1998, Phase 3 of the exploratory well at Long Valley Caldera was a continuation of earlier drilling under the Magma Energy Program[186] and then hydrothermal exploration co-sponsored by the California Energy Commission (CEC).[187] Support for Phase 3 came from DOE, the CEC, the International Continental Drilling Program (ICDP), and USGS, each with a somewhat different agenda. DOE, through SNL, wanted to test new geothermal tools and techniques in a realistic field environment. The CEC wanted to evaluate the energy potential (specifically energy extraction from magma) of Long Valley Caldera. The ICDP was studying the evolution and other characteristics of young, silicic calderas. USGS planned to use this hole as an observatory in its Volcano Hazards Program.

Phase 3 began drilling at approximately 7,200 ft and was targeted to go as deep as time and budget allowed, with continuous coring into the young silicic caldera. Wireline coring with tools common to the mining industry were to be used for this job, but the conventional HQ-size (i.e., a size [diameter] of wireline coring tools) core rods were not strong enough to reach the planned target of approximately 12,000 ft. The problem was solved with a hybrid drillstring using high-strength pipe in the upper end and core rods in the lower end. Even with the larger upper pipe, there was far too much annulus in the 13-3/8-inch casing (the well completion at the end of Phase 2) so a bushing casing string was run from the surface to the beginning of Phase 3 drilling.

Figure 50. Hybrid coring system hanging in big-rig derrick at Long Valley, California

As a result of the novel operation, coupled with a hybrid drilling system composed of a core-drilling assembly hung in the derrick of the large drill rig (see Figure 50) that had been on the site since Phase 1, SNL engineering staff gained a great deal of valuable experience in deep core drilling. The highly fractured nature of the formation led to short core runs and far more tripping time than expected. The budget was expended at a final depth of 9,832 ft. In spite of the shortfall, the Long Valley, Phase 3 project was successful from an engineering standpoint, and received significant international exposure.[188]

10.0 National Advanced Drilling and Excavation Technologies Program

Drilling and excavation are essential to industries other than the geothermal industry. Mining, oil and gas production, building underground tunnels and infrastructures, remediating toxic waste sites, and storing hazardous materials in deep geological formations all require extensive breaking and removing of rock. The process of drilling and excavation is complex and expensive and exponentially more costly as drilling goes deeper. Producing geothermal energy from deep wells at a competitive cost requires major breakthroughs in drilling technology.

Recognizing that the budgets of companies involved in geothermal drilling as well as the DOE geothermal budget could not support the costly R&D necessary to produce such drilling advances, the DOE geothermal program convened a steering committee in early 1992 to formulate a program for advanced drilling and excavation technologies.

Simultaneously, DOE asked the National Research Council (NRC) to determine what would be needed to foster major advances in drilling technologies. Issued in the spring of 1994, the report called for a sustained federal R&D program with industry contributing technological and financial resources.[189] The report recognized the importance of an inter-industry approach to drilling R&D, calling for research to stimulate major drilling advances and support continued incremental improvements to existing drilling systems and processes.

Other federal agencies including the National Science Foundation, USGS, NASA, the Environmental Protection Agency, the Department of Defense, the Nuclear Regulatory Commission, and the Department of Transportation took note. Under the leadership of the DOE geothermal program, an informal interagency drilling group began meeting in the early 1990s. The group developed plans to undertake an interagency research initiative to support advanced drilling R&D. The National Advanced Drilling and Excavation Technologies (NADET) program was “born” in 1995.

The NADET program was created to stimulate and facilitate "research, development, demonstration, and commercialization of advanced technologies for industries that depend critically on drilling and excavation operations and for the manufacturers that supply those industries."[190]

NADET's goal was straightforward: To create a new generation of advanced, environmentally sound drilling and excavation technologies by 2010. NADET would foster cooperative and collaborative support for research among the industrial entities, as well as the various government agencies involved with drilling and excavation. NADET research efforts would concentrate on technical issues common to all the industries of drilling. This cross-fertilization would in time lead to the development of a critical mass of talent and support needed to sustain a long-term program aimed at major advances.

A risky venture with admirable goals, NADET was based on a new reliance on industries to collaborate and support non-proprietary research. The NADET planners were not naïve in describing an integrated, revolutionary drilling development program. They recognized that:

> *The development and implementation of revolutionary drilling technologies will be a long-term, high-risk endeavor. Thus, despite the prospect of major advances and widespread benefits, there is no revolutionary drilling work underway at present. Industrial drilling research, though of very high quality, is confined to very short-range projects to solve the problems of the day…A revolutionary drilling R&D program…will require solid motivation and a long-term commitment quite independent of today's short-range mindset.*[191]

NADET's approach to advanced technological development included short- and long-term projects with technical issues common to all industries performing drilling and excavation and a focus on total system development.

In early 1995, DOE and the Massachusetts Institute of Technology (MIT) Energy Laboratory entered into a cooperative agreement to create the NADET Institute. The NADET Institute administered the broad NADET program overseen by an operating committee composed of technology leaders from industry, academia, and government. The NADET Institute existed until 2000.

10.1 Outreach and Institute Workshops

From the outset, it was important that the NADET Institute implement a vigorous outreach program. Aware that its innovative approach to funding collaborative research might be a difficult concept to "sell," and that most companies viewed drilling and excavation in terms of their own corporate interests, the NADET Institute embarked on a vigorous campaign to reach out to industry, academia, and government. "The NADET News" complemented and later supplanted the quarterly newsletter issued by the DOE geothermal program.[192]

The NADET Institute also convened six workshops from 1995 through 1997 (see Table 3). In addition to informing workshop participants about NADET, the workshops helped identify needs and opportunities for NADET to address.

Table 3. National Advanced Drilling and Excavation Technologies Program Workshops, 1995-1997

Workshop	Findings
(1) Advanced Mining Technology October 5-6, 1995	• Mining should move from a deposit focus to an extraction technology focus • Workshop developed list of barriers to new technologies; not one was technical in nature • Concluded that the development of new, lower cost, environmentally friendly mining methods must continue
(2) Advanced Geothermal Drilling October 10-12, 1995	• Provided advice in developing a request for proposals (RFP) for NADET-selected R&D • Proposals should state how the product will fit within the total drilling system, demonstrate solid industry participation, and be reviewed by an industry panel
(3) Advanced Tunneling April 25, 1996	• A truly continuous, integrated, boring-lining system is needed • Capability to explore ahead of the bore • Innovative ground improvement technologies • Use small-scale trenchless projects as stepping stones to later larger scale projects
(4) Advanced Sensing May 1, 1996	• Real payback will come in infrastructure-related projects • See ahead of the bore for other constructed works • Ability to map the edge of a pollution plume
(5) Advanced Oil and Gas Drilling June 28, 1996	• Goal is for higher productivity wells not necessarily drills • Drilling technology should not be treated as a separate issue • Oil and gas companies have an established practice of sponsoring collaborative research which should be accounted for in NADET planning
(6) Environmental Drilling and Excavation April 1-3, 1997	• Horizontal drilling needs are important including trenchless technologies • Drilling for remediation purposes as well as drilling for waste storage purposes are principal areas of interest

10.2 Research Initiatives

In early 1996, to initiate its research program, the NADET Institute issued an RFP seeking new ideas for lowering drilling costs. Since project funds for this initial round of research came from DOE's geothermal program, projects were required to demonstrate new ideas for lowering the costs of geothermal and other drilling operations. DOE received 61 initial statements of interest and requested full proposals from 15 applicants. Table 3 lists the seven proposals that subsequently received awards.

Table 4. National Advanced Drilling and Excavation Technologies Program proposals awarded by the Department of Energy, 1997

Project Title	Implementing Company	Project Purpose
(1) Advanced Geothermal Turbodrill	Maurer Engineering	To develop an advanced high-temperature turbodrill for drilling hard rocks at high drilling rates.
(2) Improvements to PDC Drill Bits by Microwave Processing of Cemented Carbide and Diamond Composition	Intercollegiate Materials Research Laboratory, Penn State University, and Dennis Tool Company	To determine whether newly developed microwave sintering technology will produce an improved PDC bit.
(3) High Performance Mini-Disc Bits with Water Jet Flushing	Colorado School of Mines and Excavation Engineering Associates	To develop the use of very small disc-type cutters to slice the rock creating tension failures and causing chips to pop off the rock face.
(4) Systems Analysis of Alternative Geothermal Wellbore Lining Methods	SNL National Laboratories and Livesay Consultants	To examine the alternatives to the conventional practice of lining a wellbore with steel pipe or casing sealed in place by pumped cement after a long interval of drilling a constant diameter hole.
(5) Development of a Mud Jet-Augmented PDC Bit for Use with Conventional Rig Pressures	SNL National Laboratories, Security DBS, Dynaflow, and TerraTek	To develop and demonstrate effectiveness of a mud jet-augmented PDC bit that drills with improved penetration rates and bit life in hard rock using mud pump pressures.
(6) Binderless Nanophase Cutter Materials for High Rate Hard Rock Drilling	Diamond Materials Inc.	To examine performance of Binderless Polycrystalline Diamond types of materials for geothermal drilling conditions.
(7) The Development of New Brazing Processes for the Attachment of TSP Diamonds to Drag Bits	Technology International, Jet Propulsion Lab, Colorado School of Mines, and SNL National Laboratories	To develop unique, high attachment shear and impact strength thermally stable polycrystalline (TSP) diamond cutters that allow greater cutter exposure.

Five of the grants were awarded second-year funding in 1998. In addition, in 1995 DOE's geothermal program also awarded seven Small Business Innovation Research (SBIR) grants to conduct feasibility studies of lowering drilling costs that resulted in six phase two grants.

10.3 Difficulties with Finding Support for Inter-Industry, Inter-Disciplinary Research

From the perspective of government, drilling is integral to many mission-oriented agencies, but it is not at the forefront of the agencies' concerns. In its short existence, NADET Institute staff and organizing committee members met with scores of industry representatives and government officials, inviting them to join the Institute and support cooperative, non-proprietary research. With few exceptions, industry was not interested. While most companies recognized the possible long-term benefits, they did not consider working with other industries to develop technology that could potentially be used by their competitors as being in their best interests.

The NADET Institute closed in 2000. Many of its functions were transferred to the newly formed Institute for Advanced Drilling (IAD). The IAD continued NADET's outreach work until it was closed in 2005.

Conclusion

At the beginning of DOE's geothermal R&D program, the U.S. geothermal industry was small and struggling to gain acceptance from utilities and financial institutions, which had only a rudimentary understanding of the costs and risks associated with geothermal energy projects. There was little solid data in the public domain on which reliable analyses of geothermal reservoirs as viable energy resources could be based. Reluctance to support geothermal projects financially was causing stagnation in the nascent geothermal industry. In addition, there was only limited understanding of the nature of geothermal systems and of how they could be gainfully used.

The DOE-funded research on drilling described in this report—along with the work described in companion reports on Energy Conversion, Exploration, and Reservoir Engineering—had an immediate and profoundly positive effect by stimulating development of the modern geothermal industry. This achievement was realized through performance of collaborative projects in which DOE-funded scientists and engineers from the national laboratories, academic institutions, and the private sector worked with colleagues in companies, other government agencies, and institutions in other countries to address the full range of problems inhibiting economic geothermal development. Research priorities were continually assessed and updated in close collaboration with industry to ensure that project results would be of practical use. The success of DOE's program can be seen in today's vital and progressive geothermal industry.

Over three decades, from 1976 to 2006, the Department's supported a wide range of R&D to overcome challenges in drilling with the goal of making geothermal electricity more cost-competitive. Over three decades, DOE's support of drilling R&D focused on areas such as rock penetration, drilling tools, logging and instrumentation, drilling fluids and wellbore integrity, slimhole drilling, systems analysis, analytical studies, the Geothermal Drilling Organization, scientific drilling management, and the National Advanced Drilling and Excavation Technologies Program. This work contributed to a decrease in the cost of geothermally generated electricity, and many of the government-supported technologies were adopted and commercialized by the U.S. geothermal industry.

The Department continues to support research and development activities and industry partnerships to encourage and help the U.S. geothermal community to meet these challenges, building on the technical research base of the past 30 years. This technical base provides the information and understanding necessary to create more efficient, reliable, and economic technologies, enabling the U.S. geothermal industry to compete for baseload electricity generation. It is hoped that this summary of prior work in drilling R&D will allow future geothermal developers and researchers to translate past efforts into future accomplishments.

Appendix A:
Budget history of the federal geothermal research program, 1976 – 2006

Notes on Budget Table

The following discussion is provided to clarify the meaning and intent behind the estimates given in the Geothermal Program budget table (Fiscal Years 1976 – 2006). Despite the precision of the table, the reader is cautioned not to accept the amounts quoted in any single fiscal year as a fully accurate representation of the funds spent on a given technical area. The reasons for this caution will become apparent from the notes. However, over the entire period covered by this history, the totals are considered reasonably accurate.

1. The funding history covers FY 1976 through FY 2006 inclusive. FY 1976 includes funding for the "transition quarter" in which the Federal fiscal year was advanced three months from June 30 to September 30. All funds are in current year dollars in thousands; no adjustments were made to cover the time value of money.

2. The Program budgets were divided among the four major technical research topics comprising the focus of the history: Exploration, Drilling, Reservoir Engineering, and Energy Conversion. For convenience, subsets of Reservoir Engineering---Geopressured-Geothermal, Hot Dry Rock and Enhanced Geothermal Systems—are listed separately to identify funds spent on those topics versus Hydrothermal Reservoir Engineering. The technical areas covered by these research topics are summarized in the Table of Contents of each history.

3. Additional line items are included for completeness. They lie outside the four research areas as defined, but they appear in the Program budget for extended periods. Those line items are mentioned briefly here:

    - **Capital Equipment** – Tools and equipment needed to carry out research, typically at the national laboratories, are identified as capital equipment. Over time, this line was either reported independently within each program area (e.g., equipment for Geopressured Resources) or included as an aggregate total for the entire program. The aggregate total is used in this budget table. In some instances this may lead to discrepancies in budget amounts between what is listed here and amounts given by other sources. The differences are minor, since capital equipment was typically a small percentage of the total budget for any line item.

    - **Program Direction** – This line covers the personnel expenses of DOE staff used to plan, implement, and manage the Geothermal Program. After FY 1995, Program Direction was aggregated at the level of the Office of Energy Efficiency and Renewable Energy, eliminating this line from the Program budget.

- **Baca Demonstration Plant** – This major project was planned as the first commercial-scale (50 MWe) liquid-dominated hydrothermal power plant in the U.S. The project was located at the Valles Caldera, New Mexico, as a government-industry partnership. The industry partners were Unocal Geothermal and Public Service of New Mexico. The project was canceled in 1983 after attempts to find adequate hydrothermal resources to support the 50 MWe plant were unsuccessful.
- **Environmental Control** – During the formative years of the Program, research was sponsored on a number of environmental topics that could have a detrimental impact on geothermal development. Topics studied to varying degrees included: hydrogen sulfide emissions, other non-condensible gas emissions, liquid effluents, land use, noise, induced seismicity, and subsidence. Environmental monitoring networks were established, notably at The Geysers, Imperial Valley, and the Gulf Coast, to collect data on subsidence and seismicity. Research was performed on environmental mitigation technology, especially hydrogen sulfide abatement.
- **Geothermal Heat Pumps** – While use of heat pumps had been a minor secondary topic for much of the Program's history, the topic became a major program element for a five-year period (FY 1995 – FY1999) when a large education and outreach effort was conducted to acquaint the public with the environmental and efficiency benefits of this technology. Research on heat pump technology was limited but did include advancements in impervious grouts and improved performance models.
- **GeoPowering the West** – This was an education, outreach, and technical support effort, launched in 2000 and patterned after the successful Wind Powering America initiative.
- **Other** – A potpourri of activities not covered elsewhere are included here, such as policy, planning, and analysis done by the Program and short-lived projects such as non-electric (direct use) demonstrations. These activities are not covered in this history.

4. The source of the budget amounts reported here is the annual DOE budget request to Congress, often referred to as the President's Request or the Congressional Budget Request (CBR). In most cases, the amounts shown are "Actual" funds budgeted for a given line item as stated in the CBR. The "Actual" funds are not necessarily the amounts appropriated by Congress for that fiscal year—differences can arise due to reductions, rescissions, or other adjustments to the budget subsequent to initial appropriations.
5. The CBR is submitted early in the calendar year, shortly after the President's State of the Union message, in order to give Congress the time needed to prepare appropriations bills before the start of the new fiscal year on October 1. Due to this scheduling of the CBR, "Actual" expenditures are reported with a two-year lag. For example, if we wished to know the actual amounts budgeted in FY 1989, they would be found in the FY 1991 CBR. FY 1989 would have ended on September 30, 1989, four months before the submission of the FY 1991 CBR to Congress. Sufficient time would have elapsed to allow a final accounting of FY 1989 expenditures, in most cases to the nearest dollar. This explains why

the funds are typically reported to 4-5 significant figures, rounded to thousands. Note that in this example the FY 1990 CBR would not be a source of complete information about FY 1989 expenditures because the FY 1990 CBR would have been submitted in early 1989, before the end of FY 1989. Therefore, the "Actual" funds reported in the CBR are considered the best source of expenditures for the fiscal year in question.

6. A major problem in using "Actual" CBR amounts stems from the fact that neither the Program nor the CBR were constant over the course of time. The Program's organization changed on a number of occasions during its 30-year history, and the format and content of the CBR changed as well. Probably the greatest impact on recreating the budgets for the topical research areas was the fact that in many cases the amounts spent on exploration, drilling, reservoir engineering, and energy conversion were aggregated under some generic title. For example, during the 1980s the major categories of Geothermal Program funding were: Hydrothermal Industrialization, Geopressured Resources, and Geothermal Technology Development. Hydrothermal Industrialization included sub-topics such as field demonstrations, test facilities, state resource assessments, and industry-coupled drilling. Technology Development covered many diverse research sub-topics such as hot dry rock, advanced drilling, geochemical engineering and materials, energy conversion, and geoscience. In some cases, the expenditures for these topical areas (e.g., hot dry rock) were reported, and the budgeted amounts could be properly allocated. However, the CBR did not always report "Actual" expenditures to that level of detail, and the amounts had to be inferred from the "Request" amount given in the CBR for the fiscal year in question. These amounts could become problematic when CBR formats changed or major programmatic reorganizations were instituted between the year of the "Request" and the "Actual" reporting year.

7. Another complicating factor was the merging of technical areas under a generic topical area. For example, the line item, "Geoscience Technology," subsumed the research topics of exploration and reservoir engineering. The amount of budget devoted to each element was usually not specified in the CBR. The problem is particularly vexing for budgets dating from FY 1999 when budget line items such as "University Research", "Core Research", "Technology Deployment", and "Systems Development" came into use. Fortunately, Program budget records apart from the CBR for this period are fairly complete, allowing assignment of funding to the appropriate research areas.

8. Despite the aforementioned caveats, many of the budget estimates are judged to be accurate. Geopressured-Geothermal was a unique line item in the budget that could be easily tracked from year to year in the CBR. Funding for Hot Dry Rock was reported separately for the life of that program. The same can be said for Capital Equipment, Program Direction, Baca Plant, and Geothermal Heat Pumps. Of the four research topical areas, Drilling Technology had the best record of budget representation over time, followed by Energy Conversion. Due to their technological similarities, Exploration and Reservoir Engineering could be difficult to distinguish. As stated above, the funding for the topical areas in any given year may reflect some uncertainty, but the aggregate totals over 30 years do provide a good estimate of relative funding levels.

Geothermal Program Annual Budget *($000)*

	Exploration	Drilling	Reservoir Engineering	Hot Dry Rock	EGS	Geopressured-Geothermal	Energy Conversion
1976	$6,280	$4,206		$5,274		$1,182	$21,209
1977	$9,000	$3,500		$5,280		$6,620	$22,350
1978	$17,600	$2,870		$5,400		$17,100	$40,630
1979	$31,270	$9,000	$8,500	$15,000		$26,600	$33,169
1980	$15,506	$8,800	$5,100	$14,000		$35,700	$30,294
1981	$25,224	$12,545	$6,547	$13,500		$35,600	$24,920
1982	$3,450	$3,036	$2,650	$9,700		$16,686	$28,858
1983	$2,360	$1,710	$400	$7,500		$8,400	$29,641
1984	$2,713	$2,640	$10,172	$7,540		$5,000	$1,105
1985	$3,215	$3,585	$5,623	$7,444		$5,226	$2,280
1986	$4,094	$2,415	$5,497	$7,631		$4,426	$1,250
1987	$0	$1,350	$5,595	$8,000		$3,940	$1,065
1988	$455	$1,775	$5,355	$5,770		$4,955	$1,580
1989	$0	$2,250	$4,085	$3,500		$5,930	$1,935
1990	$0	$2,140	$3,761	$3,290		$5,523	$1,601
1991	$6,925	$2,435	$5,543	$3,627		$5,884	$2,155
1992	$1,300	$2,700	$7,100	$3,600		$4,916	$5,300
1993	$2,080	$5,635	$5,517	$3,600			$4,520
1994	$2,597	$3,400	$6,466	$1,300			$6,403
1995	$5,977	$6,267	$4,620	$4,000			$5,090
1996	$8,700	$5,899	$0	$1,900			$5,200
1997	$9,818	$5,030	$0	$400			$5,900
1998	$5,600	$6,900	$4,387				$5,119
1999	$4,084	$4,934	$6,782				$4,150
2000	$1,475	$5,500	$7,025		$3,049		$3,405
2001	$2,700	$5,500	$5,600		$1,700		$4,745
2002	$3,000	$5,084	$5,336		$1,580		$4,111
2003	$4,163	$5,717			$5,915		$8,111
2004	$3,000	$6,000			$6,680		$5,226
2005	$3,534	$4,060			$6,788		$5,180
2006	$3,734	$4,128			$5,928		$3,592
Total	$189,854	$141,011	$121,661	$137,256	$31,640	$193,688	$320,094

Capital Equipment	Program Direction	Baca	Environmental Control	Geothermal Heat Pumps	Geopowering the West	Other	TOTAL
$704			$1,301			$2,958	$43,114
$1,500			$2,500			$2,300	$53,050
$2,500		$12,000	$3,600			$4,500	$106,200
$3,000	$663	$7,450	$516			$10,500	$145,668
$3,200	$1,100	$20,500	$1,300			$12,200	$147,700
$1,310	$2,376	$12,050	$2,600			$19,959	$156,631
$860	$1,600	$2,124	$500				$69,464
$250	$1,250					$5,963	$57,474
$0	$1,000					$100	$30,270
$400	$1,025					$900	$29,698
$481	$701						$26,495
$0	$780						$20,730
$0	$835						$20,725
$795	$826						$19,321
$426	$782						$17,523
$401	$889					$2,479	$30,338
$821	$1,000			$200			$26,937
$900	$1,000						$23,252
$873	$970		$1,000				$23,009
$886	$1,000		$967	$5,000		$4,000	$37,807
				$5,300		$2,400	$29,399
				$6,482		$2,000	$29,630
				$6,400		$288	$28,694
				$6,420		$1,780	$28,150
						$2,882	$23,336
					$1,600	$4,778	$26,623
					$3,200	$4,724	$27,035
					$3,521	$963	$28,390
					$2,738	$981	$24,625
					$3,128	$2,666	$25,356
					$2,658	$2,722	$22,762
$19,307	**$17,797**	**$54,124**	**$14,284**	**$29,802**	**$16,845**	**$92,043**	**$1,379,406**

Appendix B: Patents

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Abbreviations & Acronyms

AISI	American Iron and Steel Institute
API	American Petroleum Institute
AWG	American wire gauge
ASIC	application-specific integrated circuit
BCL	Battelle's Columbus Laboratories
BHA	bottom-hole assembly
BNL	Brookhaven National Laboratory
CaP	calcium aluminate phosphate
CEC	California Energy Commission
CECI	California Energy Company, Inc.
CO2	carbon dioxide
CPVC	chlorinated polyvinyl chloride
CSM	Colorado School of Mines
CMOS	complementary metal oxide semiconductor
CSDP	Continental Scientific Drilling Program
CRADA	Cooperative Research and Development Agreement
CTDL	core-tube data logger
dB	decibels
DOE	Department of Energy
DOC	depth of cut
DWD	Diagnostics-While-Drilling
DSP	drillable straddle packer
DRL	Drilling Research Laboratory
DOSECC	Drilling, Observation and Sampling of the Earths Continental Crust
EM-MWD	electromagnetic MWD
ERDA	Energy Research and Development Administration
ELTF	Engineered-Lithology Test Facility
EGS	Enhanced Geothermal Systems
EUE	external upset ends
ft/hr	foot per hour
ft/lb	foot per pound
gpm	gallons per minute
GTI	Gas Technology Institute
GE	General Electric Research Lab
GDO	Geothermal Drilling Organization
GHP	geothermal heat pumps
GRC	Geothermal Resources Council
GRED	Geothermal Resources Exploration and Definition
GSHP	ground-source heat pumps
HRDF	Hard Rock Drilling Facility
HDR	hot dry rock
HCl	hydrogen chloride
H2S	hydrogen sulfide
ISP	instant set polymer
IAD	Institute for Advanced Drilling
IDP	insulated drill pipe
ID	interior diameter
ICDP	International Continental Drilling Program
Fe	iron
JAR	Jordan, Apostal, Ritter Associates, Inc.
JFET	junction field-effect transistors
kW	killowatt
Kbps	kilo bits per second
kWe	kilowatts-electric
KGRA	Known Geothermal Resource Area

LCTF	linear cutting test facility
LANL	Los Alamos National Laboratory
LCM	lost circulation materials
LCTF	Lost Circulation Test Facility
LEAMS	Low Emission Atmospheric Metering Separator
MR	magneto-rheological
MIT	Massachusetts Institute of Technology
MWD	measurement while drilling
MW	megawatt
MWe	megawatt electric
Mil-Spec	military specifications
MRFM	modified rolling float meter
NADET	National Advanced Drilling and Excavation Technologies
NASA	National Aeronautics and Space Administration
NETL	National Energy Technology Laboratory
NOAA	National Oceanic and Atmospheric Administration
NRC	National Research Council
NCG	noncondensable gases
OEDP	open-ended drill pipe
ppm	parts per million
PSU	Pennsylvania State University
psi	per square inch
PEMEX	Petroleos Mexicanos
PZT	Piezoelectric
PVC	plyvinyl chloride
PDC	polycrystalline diamond compact
PU	polyurethane
PDM	positive displacement motor
lb/bbl	pounds per barrel
P-T	pressure-temperature
PTS	pressure-temperature spinner
RF	radio frequency
ROP	rate of penetration
RFP	request for proposal
R&D	research and development
RTD	resistance temperature detector
rpm	revolutions per minute
RMOTC	Rocky Mountain Oilfield Training Center
RFM	Rolling Float Meter
SNL	SNL National Laboratories
SWG	Sierra White Granite
Si	silicon
SiC	silicon-carbide
SOI	silicon-on-insulator
SBIR	Small Business Innovation Research
SGPP	small-scale geothermal power plants
SPE	Society of Petroleum Engineers
NaCl	sodium chloride
SSAS	sodium silicate-activated slag
SwRI	Southwest Research Institute
scfm	standard cubic feet per minute
SPR	Strategic Petroleum Reserve
TSP	thermally stable polycrystalline
3-D	three-dimensional
Ti	titanium
TOB	torque-on-bit
TD	total depth
USGS	U.S. Geological Survey
UMR	University of Missouri-Rolla
URI	University of Rhode Island
V	volt
WOB	weight-on-bit
WFO	work-for-others

References Organized by Major Research Project Area

These additional references are publications produced by DOE laboratories from the inception of the program through May 2007. They are not specifically cited in the body of the report. They are grouped in the same functional divisions as the report, but with an additional category of "Project Management" which contains many progress reports and program plans that illuminate the evolution in the direction of drilling research.

Many of the later SNL Reports referenced in this history are available online at http://infoserve.SNL.gov. If the document was produced for a conference or journal (usually denoted by a "C" or "J" at the end of the report number), then copyright issues will limit distribution, and some files are large enough to be a problem for private internet accounts. However, a great deal of information is available through this resource. A number of papers were written for presentation at conferences of the Society of Petroleum Engineers (SPE) and can be downloaded (for a fee) from the SPE e-Library at www.spe.org/elibrary. Other papers were written for the Geothermal Resources Council (GRC). The majority of these are available at www.geothermal.org/databases.html. GRC papers are free to GRC members, and available for a small fee to non-members. A broad source for publications from all DOE laboratories is www.osti.gov/bridge.

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