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Proceedings

GEOTHERMAL PROGRAM REVIEW VI

"BEYOND GOALS AND OBJECTIVES"

APRIL 19-21, 1988
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INTRODUCTION

The Geothermal Technology Division (GTD) of the U.S. Department of Energy (DOE) is the lead federal agency charged with conducting R&D to develop technology to economically exploit the nation's large geothermal resources. GTD sponsors a balanced mix of R&D projects through other government agencies, national laboratories, universities and private contractors. As part of its program planning and evaluation function, an annual review of the overall R&D program is held. Participants at these annual program reviews include DOE headquarters and field office management, DOE supported researchers, interested state and local government representatives, and the private sector geothermal community. The following proceedings document the Sixth Annual Geothermal Program Review (Program Review VI).

Program Review VI, entitled **Beyond Goals and Objectives**, was held April 19-21, 1988 in San Francisco, California. The focus of this year's meeting was the integration of planned and ongoing R&D within the context of recently formulated "Programmatic Objectives" of GTD. These Programmatic Objectives define specific, time-marked milestones designed to reduce the cost of delivered geothermal power to the consumer. These cost-driven objectives provide the context for optimizing the mix of R&D projects within the GTD portfolio over the next five years. The specific objectives balance industry's near-term need for improved technology with the government's role in funding high-risk, long-term R&D.

Program Review VI was comprised of six sessions, including an opening session, four technical sessions that addressed each of the major DOE research areas, and a session on special issues. The technical sessions were on Hydrothermal, Hot Dry Rock, Geopressured and Magma resources. Presenters in the technical sessions discussed their R&D activities within the context of specific GTD Programmatic Objectives for that technology, their progress toward achieving those objectives, and the value of those achievements to industry. The "Special Issues" presentations addressed several topics such as the interactions between government and industry on geothermal energy R&D; the origin and basis for the programmatic objectives analytical computer model; and international marketing opportunities for U.S. geothermal equipment and services.

The unique aspect of Program Review VI was that it was held in conjunction with the National Geothermal Association's Industry Round Table on Federal R&D. The Round Table provided a forum for open and lively discussions between industry and government researchers and gave industry an opportunity to convey their needs and perspectives on DOE's research programs. These discussions also provided valuable information to DOE regarding industry's priorities and directions.

The exchange of views and information at Program Review VI noted the following important concerns for government/industry partnership for geothermal energy development:

- Due to shifting national priorities and changing federal budgets, only geothermal R&D projects that are consistent with rational, measurable objectives should be supported.
- Sophisticated analytical tools, such as the IM-GEO Cost-Of-Power Model, should be utilized to determine what is being and can be accomplished by federal R&D.
- Specific time-marked quantitative objectives for geothermal technology improvement will provide benchmarks to assess reductions in the delivered cost of geothermal power.
- The ability to quantify impacts of R&D achievements on the delivered cost-of-power should enhance industry's ability to assess the usefulness of federal R&D activities.
- All members of the geothermal community must cooperate to the fullest extent possible in achieving defined goals and objectives so that we may share the benefits that lie ahead.

Program Review VI accomplished its stated goal through the dedication and hard work of the speakers, session chairpersons, and organizers who shared their knowledge and efforts, as well as the meeting participants who contributed their experience and perspectives to the meeting. Special thanks are extended to Lanier Lohn, President of the National Geothermal Association, and David Anderson, Executive Director of the Geothermal Resources Council, for coordinating and collocating their Round Table with Program Review VI. Also special thanks must go to the session chairpersons -- Susan Prestwich of the Idaho Operations Office, George Tennyson of the Albuquerque Operations Office, and Ralph Burr of the Geothermal Technology Division in Washington -- who put a great deal of effort into organizing and conducting their sessions. Finally, I want to express my appreciation to John Crawford of the San Francisco Operations Office and Carole Beeman of the Meridian Corporation, whose exceptional assistance with the planning and implementation of Program Review VI helped make the meeting a success.

The technical papers and commentary of invited speakers contained in these Proceedings have been compiled in the order in which they were presented at Program Review VI.

Ted Mock

Dr. John E. Mock
Director
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SESSION I

OVERVIEW

CHAIRPERSON: JOHN E. MOCK, DIRECTOR
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RENEWABLE ENERGY CONTRIBUTION TO THE NATIONAL ENERGY FUTURE

Robert L. San Martin
Deputy Assistant Secretary for Renewable Energy
U.S. Department of Energy

Good morning. Let me add my welcome to all of you to the sixth annual DOE Geothermal Program Review. Also, welcome from DOE. I think we have an impressive schedule of presentations set for the next few days, which should lead to some valuable discussion and interchange. These annual review meetings have become an integral part of the research and development program and provide a forum through which researchers and program administrators can exchange information on the most up-to-date research activities. It is through this merging of information that we can explore and develop future research direction and determine the most promising path to advancing technology. By doing so we come closer to our goal of integrating renewable energy technologies into the nation's energy system.

The immediacy of the need for additional energy supply options does not seem so apparent during this current period of stable and relatively low oil prices. This condition, however, can lead to increased demand, to accelerated resource depletion and to greater oil import dependence. In addition, demand for electricity continues to rise with the GNP -- 2 to 3 percent per year over the long term. Current electric utility conditions of excess capacity, rising costs, and rate shocks from high-cost plants coming on line are prompting many utilities and utility regulatory commissions to focus on short-term economics, avoiding capital intensive projects. While there is a degree of uncertainty in forecasting the need for future generating capacity, the DOE predicts that by the mid 1990's, the combined effects of increased demand and retirement of ageing and uneconomic plants will lead to a significant short-fall in generating capacity.

Renewable energy technologies have inherent advantages and can fulfill a unique role in the total energy picture. The technical accomplishments that are emerging are making renewable systems increasingly compatible with the energy needs and preferences of the nation. For example, the trends in the utility industry regarding restructuring, financial concerns, capacity uncertainties, and the need for more efficient and more predictable generating options are all conditions to which renewable electric power technologies can respond. The ability to add small increments of generating capacity relieves the utility of the financial risk burden that exists when adding large conventional plants. Future cost uncertainties of RE systems are significantly lower than conventional fossil fuel systems. Energy storage technologies will facilitate the integration of renewable technologies with the utility and allow the use of stored energy during peaking or other shortage periods.

Another emerging trend in renewable energy systems is its dispersed application, either interconnected with an electric distribution grid or as a stand alone system at some remote location.

The U.S. renewable energy base is enormous in magnitude. The renewable energy technologies' characteristically clean energy conversion processes have lesser environmental impact than more conventional energy sources.

These trends illustrate the advantages of renewable energy resources in our nation's future. These systems can meet the needs of the evolution occurring in the electric industry, of the demand side management innovation occurring, and of the expanding environmental standards of today. While this all points to a greater adoption of renewables into the future energy system, this expansion cannot occur without some essential ingredients in the technology development process. These include a long-term research commitment, industry input and collaboration, and effective technology transfer.

Research has made significant progress but many challenges remain. Development of new concepts and materials, refinements to known technologies, and the resolution of system integration issues will lead to improved and competitive supply options. This requires a sustained research effort that is well planned, with defined goals and objectives, based on research findings and accomplishments to date.

The Geothermal Program has been quite successful in this regard through its efforts in the development of a geothermal research agenda based on program objectives that reflect industry's needs, government policies, and funding priorities. The three interrelated levels of objectives that were developed address the attainment of competitive cost goals, providing a simple, consistent means for expressing research objectives. One level of objectives was developed for geothermal electric generation; the second level addresses performance improvements of major system components; and the third set of objectives targets improvements in efficiency and reliability. These specific objectives will drive the research program towards our technical goals.

We are fortunate to have an active renewable energy industry that has a strong record of investing in research and development, both independently and in cooperation with government. The involvement of industry in the planning, review, and implementation of research projects is essential. All of us are currently faced with budgetary constraints in research and development, but through cooperative efforts we can pool our resources to carry forward this necessary research.

Industry obtains much information from government-funded scientific research and engineering development activities. Government collaboration with utilities, the Electric Power Research Institute, the service companies, the Geothermal Drilling Organization, drilling equipment companies, and resource owners have provided numerous opportunities to innovate and validate technical concepts. Collaboration not only ensures that R&D efforts are directed towards useful goals, but also results in the most efficient means of transferring technology.

Technology transfer efforts promote the exchange of knowledge before and throughout the research process. Many new renewable energy technologies have or are nearing market competitiveness. Technology transfer is increasingly important to the future growth of the renewable energy industry. Through the publication of hundreds of papers and through meetings such as these where information is shared, we are furthering the technology's expansion beyond the laboratory walls.

We must not restrict our vision of the energy future to domestic matters. Renewable energy technologies have an important role to play internationally. We continue to find numerous opportunities to introduce and expand renewable energy use in world markets. The Committee on Renewable Energy Commerce and Trade (CORECT) has helped to identify many of these market opportunities and to assist exporters in meeting these markets. Developing countries show significant potential for renewable energy because they often lack transmission and distribution grids and other conventional energy sources. Renewable energy systems can often meet their energy needs at a lower cost than conventional alternatives, which have high infrastructure and recurrent fuel costs.

I believe that the future opportunities for renewable energy systems are very promising, both domestically and internationally. Our aim in developing renewable technologies is to <u>expand</u> our energy supply options. Our energy security advantage will be in having a <u>balanced</u> energy system in which we have a choice of several viable supply sources. In competition and in combination with all other energy options, renewable technologies offer the flexibility and reliability to achieve a stable and efficient energy future. Geothermal energy has an important role to play in this energy future; it is already one of the more significant renewable energy contributors today. The research progress being reported at this meeting is impressive and will continue to be an essential driving force in advancing geothermal technology toward additional commercial achievement. The geothermal research plan has been developed based on specific objectives, making the attainment of our goals challenging but achievable.

I am very indebted to the leadership brought to this program by Ron Loose and Ted Mock. I hope all of you take full advantage of the give and take during this review meeting to learn from others' experiences and share your own findings. Through this process we can develop our most effective research agenda and ensure a greater role for renewable energy in our nation's future.

INDUSTRY PERSPECTIVE

ON

THE FEDERAL GEOTHERMAL R&D PROGRAM

Jim Combs
President and Chief Operating Officer
Geothermal Resources International, Inc.

ABSTRACT

The geothermal industry is changing. We can no longer simply drill wells and sell steam or hot water to utilities as a fuel source for their power plants, but must now build transmission lines as well as construct and operate power plants in order to sell electrical power. Although we are a small and fragile industry, in the true entrepreneurial spirit, we can develop geothermal resources and provide electricity. Nevertheless, there is an ongoing need to improve the available technology and further reduce the costs associated with the development of geothermal power. Industry cannot afford the cost nor manpower needed for a successful research program; however, by working together cooperatively, exchanging ideas and information, industry and the federal R&D program can continue to make geothermal energy a viable, economic, energy option for the United States.

INTRODUCTION

In order to adequately present the industry perspective on the federal geothermal R&D program, at least five separate topics must be explored. These topics include (i) the current status of energy supply and demand, (ii) the current state of the geothermal industry, (iii) the current DOE geothermal research and development program, (iv) the views of the geothermal industry on long-term technical needs, and (v) the government/geothermal industry cooperative research programs.

First, I will try to portray the geothermal industry as it exists today within the energy picture; as we view the industry in our company (GEO) and where GEO anticipates the industry is headed. When anyone begins to talk about the energy picture, the best way to establish the situation is to discuss what has happened in the last several years with respect to drilling activities in the United States. In Figure 1A, the average number of active rigs is plotted as a function of time from 1978 through 1988. During 1978 in this country, there were about 2,300 rigs drilling for oil and gas as well as geothermal resources. The number of active rigs increased to about 4,000 in 1981 and has declined since that time. As of mid-April of 1988, there are about 900 rigs which are actively drilling in the United States. Therefore, it is quite evident that in the U.S. we are not producing the amount of crude oil that we were developing back during the late 1970s and early 1980s. From Figure 1B, it can be seen that the U.S. crude oil production has a similar trend from 1978 to 1988 as that presented for active rigs, i.e., there was a large increase in 1985 and things have gone down hill since then. However, as can be seen in Figure 1C, the total crude oil demand has not followed the same type of curve. In 1978, we were consuming about 19 million barrels per day of crude oil. The demand in the 1982 to 1984 time frame decreased to about 15 or 16 million barrels per day based primarily on conservation efforts. However, in 1988, the demand is in excess of 16.5 million barrels per day. With domestic rig activity and production declining, where do petroleum products come from? They come from imports. Crude imports during the last energy crisis were about 6 million barrels per day. In 1988, crude imports have increased to over 5 million barrels per day. In 1978, crude oil imports represented about one-third of our energy use in this country as it is now again in 1988; however, the active rig count has dropped from 2,300 to 900. Thus, the finding rate for new domestic oil is expected to continue to drop in the early 1990s. There definitely is a need in the U.S. for the continued development of alternative energy sources rather than just depending on domestic oil and gas and the petroleum products that we are importing.

Another important aspect of the energy picture is represented by the projections which are made about what the future demand growth rates for electricity will be in the U.S. This has been one of the aspects that has produced a dilemma for anyone who is in the business of developing energy resources whether it be wind energy, solar energy, geothermal or oil and gas. As can be seen in Figure 2A, over the past few years, most groups have projected that the demand for electricity would grow at about 2 to 2.5% per year. Therefore, if the projected demand for electricity is plotted versus the projected electricity supply, as in Figure 2B, sometime in the early 1990s, the projected electricity supply is less than the demand. In other words, there is shortage of electricity in the early 1990s and a subsequent need for new capacity. However, the projected need for new capacity may occur before the early 1990s in some areas of the country.

The California Energy Commission (CEC), the organization responsible for supply/demand projections for the State of California, has projected over the last several years that the growth rate in electricity demand will be somewhere in the range of 1.8 to 2.0% per year; however, circumstances have not followed their projections. For example, Southern California Edison (SCE) has recently reported that their electricity demand grew at 4.7% during last year. The Pacific Gas and Electric Company (PG&E) demand numbers are expected to be published soon and the rumor is that their demand growth is up over 4%. Low demand growth projections published over the last several years are one of the reasons why new energy sources have not been developed. However, as has been noted, we are not going to have to wait until the 1990s for increases in the demand growth rates. In other words, the need for new electrical capacity is happening now.

Geothermal energy has a bright future because it can compete in terms of price and reliability with other fuel sources utilized for the production of electricity. This is based to a considerable extent on the fact that geothermal electricity can be base load power, can be cost effective when built as small units, can be constructed in short time-frames, and therefore can track the incremental changes in demand of a utility.

Most of the utilities in the U.S. spent many years getting themselves psyched totally into the nuclear mentality. Nuclear power plants were going to be the salvation of the future; they were not going to cost that much to run, and they were to provide a secure energy source for the future. There is a definite need for nuclear power in the U.S. as well as other types of power. Unfortunately, most nuclear power plants took many more years than had been anticipated to license and to build. They have cost many millions of dollars more than anyone would ever have anticipated. An additional problem is that nuclear facilities could not meet the demand growth rates that have existed over the past several years. Most nuclear power plants must be built in sizes of 1,000 to 2,000 megawatts in order to be economical, the so-called economy of scale. The problem arises in that once the 1,000 megawatt power plant is brought on-line then the utility must wait until its demand catches up to the newly installed 1,000 megawatts of capacity. Thus, the timing and pricing of nuclear energy do not mesh quite as well as the utilities have anticipated that they would. For example, right now the electricity which is coming out of The Geysers in northern California is priced at about 6¢ per kilowatt hour--geothermal electricity--in the PG&E system. Whereas the nuclear power from Diablo Canyon, which PG&E attempts to portray to the public as low-cost and non-worrisome, has a cost of about 15¢ per kilowatt hour. We as ratepayers continue to pay for such ill-conceived choices the utilities have made over the past several years.

The future for the geothermal industry is exciting. One of the primary reasons is that geothermal power plants can be rapidly built in size increments to match the demand. If a utility needs an increase of say 20 megawatts for the next year, a 20-megawatt geothermal facility can be constructed and will be economical to build. The geothermal industry does not need to build a 1,000-megawatt geothermal facility for it to be economically viable.

THE CHANGING INDUSTRY

The major geothermal power plants and the primary hydrothermal systems are depicted on Figure 3. It can be noted that all are situated in the western United States. This has been one of the arguments against the development of geothermal energy in that it appears to be confined to the western United States. In other words, this would seem to imply that geothermal energy cannot make a significant impact on a national level. However, for example, today in the PG&E system about 10 to 12% of their electricity demand comes from geothermal. Certainly, it only takes 10 of those 10% to make up 100% of the demand. Once the industry begins to develop other geothermal areas in the western U.S. to provide a larger supply of electrical power from these areas, geothermal may be capable of producing at least 10% of the total U.S. demand.

One of the major facts that we have learned over the last several years in the geothermal business is that early on we were led to believe a fallacy, that is, if we went out and drilled geothermal wells and proved that we could provide steam or hot water, then we could go to a utility and could sell this fuel source. The newly secured fuel source would then be used by the utility to justify development of a power plant. The utility would develop electricity and the geothermal operator would get paid for the steam or hot water that they were producing from the geothermal reservoir. In most of the proven geothermal areas delineated in Figure 3 by the circles, GEO, as well as other geothermal developers represented in this room today, has gone out and drilled geothermal wells that have cost anywhere from $0.5 million to as much as $3.5 million per well. Unfortunately, most of those wells are sitting out there with no one doing anything with them. It must have appeared to the casual observers that the geothermal industry was continuing along a path of developing the geothermal resource thinking that they could sell the steam or hot water in the same way that one could if one drilled an oil and gas well; i.e., one would simply back a truck up to the wellhead and load the oil into the truck and then would go sell the oil anywhere one wanted to. Similarly, if enough natural gas was discovered, somebody would build a pipeline to the well field. It turns out that one cannot truck or pipe hot water or steam very far before it will lose its energy content. Consequently, the geothermal industry is confined to where their resource is found and someone must be willing to build a power plant to use the resource at that location.

The circumstance that has been one of the most important to operators and developers of geothermal energy over the past several years is the Act that was passed by the U.S. Congress in 1978. The

Public Utilities Regulatory Policies Act of 1978 (PURPA) made it possible for a non-utility to develop a resource and produce electricity out of the resource to be sold to a utility as long as certain guidelines were met. Thus, over the last few years, the geothermal industry no longer is in the position of simply drilling wells and selling steam or hot water to a utility that builds a power plant. The industry has had additionally to take on the financial burden of building the power plant and associated transmission line in order to sell electricity to the utilities. The situation was made tolerable in California for the geothermal developer when the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) devised what are known as Standard Offer No. 4 Contracts. These are electrical power sales contracts with a 10-year purchase price for the energy as well as payments for firm capacity. Therefore, if a developer decided to build a geothermal power plant and was not a utility and needed to raise money in the financial community to be able to pay for the development of the facility, a 10-year guaranteed revenue stream was available so that financial entities could evaluate the risk of financing the development of the geothermal resource and the attendant power plant. A number of PURPA facilities have been and are being built throughout the western United States.

However, in 1984, the CEC in concert with the CPUC terminated the Standard Offer No. 4 Contracts in California because of the potential problems that the CEC envisioned for the utility industry. Additionally, other obstacles have been thrown into the path of the geothermal industry including the following examples: (i) a 50-MW size limitation on geothermal facilities or an 18-month permitting process with the CEC, (ii) lack of transmission for the electrical power that the geothermal industry is developing because the resource and the market do not coincide; and (iii) expiration of federal leases and no power sales contracts to utilize the geothermal resources that have been proven.

The geothermal industry continues to attempt to respond to the need for this alternative energy resource but the number of companies that are involved is decreasing.

THE GEYSERS OF NORTHERN CALIFORNIA

The Geysers area in northern California is depicted in Figure 4. The dark areas are the areas that GEO has leased for development; the star represents the 55-MW PG&E Unit 15 that we provide steam to; the light area is the steam field from which we are providing steam to the 130-MW Coldwater Creek Geothermal Power Plant being completed by the Central California Power Agency; the dots represent about 1,800 megawatts of power plants owned and operated by PG&E, Northern California Power Agency (NCPA) and California Department of Water Resources (DWR) which are supplied with steam by other geothermal operators. The one exception to power plants that are owned and operated by utilities is the 80-MW Santa Fe Geothermal Power Plant which was completed as a result of PURPA. The electrical power from this PURPA facility is sold to PG&E by the developer.

Up until a couple of years ago, there was a continuing program to build additional power plants at The Geysers. For example, GEO had negotiated a contract with the Central California Power Agency (CCPA) under which GEO was to prove up an additional 55 megawatts of geothermal steam each year and the CCPA group would provide a steam sales contract and construct another power plant. In addition to the first two, GEO proved the third one. CCPA decided they did not need the energy beyond that of the first two and thus, GEO had spent some $10+ million proving the resource for a third power plant and then had no steam sales contract. Similarly, Unocal/Thermal had a proven geothermal resource for PG&E Unit 21 and were proving additional steam resources for Units 22, 23 and 24, when PG&E determined that for several reasons they would not move forward with the construction of the four 110-MW power plants. Unocal/Thermal had spent tens of millions of dollars proving the availability of the geothermal resource to provide fuel for the power plants which have not been constructed.

As discussed earlier, the geothermal operators in The Geysers had traditionally developed the steam and sold it to the utilities who were responsible for constructing the power plants and producing the electricity. Today, other than for the completion of the 130-MW Coldwater Creek Geothermal Power Plant by CCPA, a utility, there are three power plants which will be built and brought on-line during 1988 and 1989. The three new facilities are the result of PURPA and Standard Offer No. 4 Contracts. Two of them are located in the southeastern portion of The Geysers and are being developed by Geysers Geothermal Company; one at Bear Canyon of about 20 megawatts and one at West Ford Flat of about 30 megawatts. The third which is the 20-MW Aidlin Power Plant will be developed by GEO and Mission Power Engineering Company, a subsidiary of Southern California Edison, and is located in the western portion of The Geysers. Thus, it appears that a strategically important geothermal resource, The Geysers, that has a capacity of several hundred additional megawatts, is basically on hold at this point in time because there are neither contracts to sell steam nor any contracts to sell electrical power on a long-term basis to the utility industry. Hopefully in the next few years, maybe even before the next energy crisis in the U.S., additional contracts will be available for further development of The Geysers steam field.

Another adverse circumstance that has occurred during the past few years for the geothermal operators at The Geysers is the decline in the steam price. The price that PG&E pays for steam in any given year varies in direct proportion to the actual cost of fossil and nuclear fuels for PG&E during the preceding year. The declines in fossil fuel prices, together with the commencement of full commercial operation of the Diablo Canyon nuclear power plant of PG&E in 1986 have caused the price that PG&E pays for steam at The Geysers to decrease from 3.91¢/kWh in 1984 to 1.44¢/kWh in 1988. This tremendous decline in steam price has had an adverse effect on the financial condition of the geothermal operators in The Geysers; therefore curtailing much of the R&D efforts of industry.

Although new development is problematic and the price paid for steam has declined significantly, there is a continuing need for additional steam to fuel the existing power plants in The Geysers. With the need for additional steam, is the necessity for research efforts to reduce drilling costs, to economically produce the reservoir, to understand the evolution of the reservoir, etc. The Geothermal Drilling Organization (GDO) is the first joint government/industry effort to address the research needs associated with the development of geothermal resources. The present GDO projects, including the borehole televiewer, the air turbine for directional drilling, the foam lost circulation tool and the elastomer testing, must receive continued support by DOE as well as the geothermal industry. As The Geysers reservoir continues to mature and the areal extent is expanded, new problems continue to arise. Specifically, there is a need in the federal geothermal R&D program for a continued effort in the area of injection technology and corrosion research. Industry can provide the laboratory for these research efforts but there is a need for government support and participation. Although research on stimulation has been dropped from the DOE research program, it should be supported and pursued jointly with industry because of the need for geothermal wells in which to carry out experimentation. The Geysers is a valuable national energy asset which must be developed under the watchful eye of a well planned joint industry/government research effort.

One of the things that has been demonstrated by the geothermal industry is that within a year and a half or at most two, we can drill the wells and build the power plant to develop increments of 20, 30 or even 50 megawatts of electrical power. This is not only happening in The Geysers but throughout the western U.S. Importantly, one of the interesting phenomenon that has been observed over the last several years is the fact that as reservoir temperature is reduced, there are a lot more reservoirs to be explored and developed as can be seen in Figure 5. As technology has been improved, the industry can begin to now look at developing geothermal systems being fueled by hot water resources which are at temperatures less than 170°C. With the decrease in temperature requirement, there are a great number of additional reservoirs that can utilized.

THE IMPERIAL VALLEY OF SOUTHERN CALIFORNIA

One of the most important geothermal provinces that is being developed today is in the Imperial Valley of Southern California (Figure 6) and that development is primarily because of PURPA and the availability of Standard Offer No. 4 Contracts. In the Imperial Valley, there are hot-water geothermal reservoirs which have been developed for electrical power that range from high temperature (400°C+)/high salinity (250,000 ppm TDS) to low temperature (150°C)/low salinity (5,000 ppm TDS). One of the initial joint government/industry research programs was the Geothermal Loop Experimental Facility at Niland. The results of the technologies jointly developed by industry and government have made it possible to generate electricity from the hypersaline brines. At the south end of the Salton Sea (Figure 6), the 34.5-MW Vulcan Power Plant was developed by Magma Power Company; the other circle represents the 10-MW Salton Sea Power Plant which was designed and constructed by SCE while the steam field was developed by Unocal. Unocal has recently purchased the power plant and plans to expand its capacity by about 20 megawatts. In addition to those two plants which are operating, Unocal is now in the process of completing an additional 49-MW power plant and three additional 34-MW power plants are being jointly constructed by Magma and Mission Energy Company, a subsidiary of SCE. The Unocal facility will be completed in 1988 as will one of the Magma/Mission power plants. The additional two, 34-MW facilities being developed by Magma/Mission, will be completed in 1990.

At the bottom of Figure 6, there are two facilities, the 45-MW Heber Double Flash Power Plant of Dravo which is still operating. The second facility, the Heber Binary Power Plant, which is another type of technology, has now been closed because of disputes between the field operators (Chevron and Unocal) and the public utility (San Diego Gas & Electric Company) which had constructed the facility. Two plants, actually three as of today, are on line in the East Mesa area. The original binary power plant developed by Magma in 1979 and now owned by GEO, generates a little less than 10 megawatts. Two other facilities put together by Ormat, an Israeli group, one of 30 megawatts and one of 20 megawatts. The two darker circles represent a couple of facilities that will be an additional 37 megawatts which are being developed by GEO. There are still available another 80 megawatts of Standard Offer No. 4 Contracts in the Imperial Valley; however, all three of those run out in November of 1989 or 1990. So there will probably not be any additional development in the Imperial Valley until some new power sales contracts become available.

Another interesting aspect associated with the development of the geothermal resources of the Imperial Valley is the problem of transmission. Although there were from 400 to 600 megawatts of power sales contracts which were let by Southern California Edison (SCE), all of the industry participants with time realized that there was no way to get the electricity to SCE. The closest SCE interconnect was about 115 miles north of the Imperial Valley near Palm Springs at a place called Mirage. Therefore, the geothermal groups that have been developing the power plants (Unocal, Magma, GEO, Chevron, Ormesa and a couple of other partners) were forced to join together to pay for and have constructed a transmission line out of the Imperial Valley so that the geothermal operators would have the ability to deliver the electrical power for sale to SCE.

OTHER DEVELOPMENT AREAS

As can be seen on Figure 3, there are several other areas in the Western United States where geothermal power plants are generating electricity. One of the more important ones is the Coso Hot Springs area in east central California (Figure 3), California Energy Company, Inc. has developed the resource and constructed a 25-megawatt power plant.

They are building two additional power plants and anticipate completion of about 200 megawatts in eight power plants by the 1990 time frame.

Another important power plant is the 50-megawatt power plant that is being built by Oxbow Geothermal in the center of Nevada in the Dixie Valley area (Figure 3). Oxbow ran into one of the problems that is a significant one for the geothermal industry at this point in time and that is the problem of transmission. Oxbow had a contract to sell 50 megawatts of power to Southern California Edison (SCE) but Oxbow had to build a transmission line of 220 miles from Dixie Valley, Nevada to Bishop, California to intertie with the transmission system of SCE in order to deliver the electrical power for sale. For this geothermal project, the power line has been permitted and built, the power plant is in start-up mode, and possibly by mid-summer of 1988 will be putting out 50 megawatts to the grid of SCE.

As was pointed out earlier, there are other small facilities throughout the Western United States, the industry had anticipated that many more would be under development. However, as noted earlier, the industry is basically on hold right now because there is no ability to sell steam or hot water to anyone. No utilities are interested in buying steam or hot water as well as there are no contracts at this point in time to sell electricity to the utilities and certainly the final customer for the sale of geothermally generated electrical power is the utility industry.

RESEARCH NEEDS

The continued development of hot-water geothermal resources in the Imperial Valley as well as throughout the Western United States is dependent upon an ongoing federally supported R&D program. The companies involved in the development of geothermal resources have both limited resources and limited staff, but problems continue to arise. Industry can identify research needs as a feedback mechanism to amplify and modify the federal R&D program and can provide laboratory environments with geothermal exploration and development wells through various avenues such as the Geothermal Drilling Organization.

Specific areas of research that are needed include the solutions to the problem of calcium carbonate scaling in wells and surface equipment whether (i) by methods of rapid, inexpensive, cleaning, (ii) the use of inhibitors or (iii) other, yet to be tried, methods. Deposition of scale in geothermal wells, surface pipes, and other equipment is a major factor in the high capital and operating costs in some geothermal systems. The development of more reliable downhole pumps is being addressed by at least one supplier, Johnson Pump Company, but there is a continuing need for federally sponsored research on equipment and systems used to move geothermal fluids from the subsurfaces reservoir to the surface energy conversion system.

Many areas of research with respect to the production and long-term management of hot-water reservoirs need to be addressed including fluid production, well maintenance, reservoir simulators for pressure, temperature and geochemical monitoring and prediction, scrubbing of noncondensible gases from the geothermal fluids, tracer tests, injection technology and brine treatment. Although many methods have been successfully developed to locate and characterize oil and gas reservoirs, these methods have proven to be only partially successful when applied to geothermal systems. Determining the location and performance characteristics of geothermal reservoirs requires knowledge of their structural geology, hydrogeology, porosity, permeability, as well as geochemical and thermal properties. Obtaining these data requires drilling, followed by well measurements that include geophysical logging, flow testing, fluid sampling and analysis as well as detailed modelling. More effective methods and technologies for collecting and interpreting these data will markedly improve the understanding of geothermal reservoirs and thereby reduce many risks when siting wells for power plants and predicting long-term reservoir performance.

Injection of geothermal fluids is often advantageous and usually required for environmental reasons. Injection can improve the longevity and efficient use of a geothermal resource by maintaining reservoir fluid levels and pressure. However, injected fluids can cause premature breakthrough of cool fluids to producing geothermal wells. Research is needed on optimizing injection practices because of the requirements for improved understanding of interactions between injected fluids and reservoir rocks. For example, injected fluids can produce reduced permeability caused by mechanical plugging or through precipitation of minerals in the reservoir.

EXPLORATION

Along with the developed areas that have been examined, industry must keep some exploration areas in inventory. For GEO, one of the most important exploration areas is in the so-called Cascades of Oregon (Figure 7A). For the past few years, industry participants have drilled core holes to find out if there was a geothermal resource in the Oregon Cascades. It turns out that industry was constantly fooled because of the great amount of groundwater which flows in from the surface and therefore it did not appear that there was any anomalous heat associated with the Oregon Cascades. It has been learned that there was quite a bit of heat associated with the Cascades when Mt. Saint Helens blew her top several years ago. Many of the doubting Thomases decided that maybe there really is a potential geothermal resource and there might be a possibility of developing it.

The lack of geothermal data for the Cascades and the consequent reluctance of the utility companies to plan for future geothermal development can all be traced to the single phenomenon known as the "rain curtain." This term refers to the zone of hydrologic disturbance where cool meteoric water percolates downward and spreads laterally, therefore masking the surface expression of geothermal activity. In recognition of this situation, the

DOE initiated a joint industry/government research program, the Cascade Deep Thermal Gradient Drilling Program. The purpose of the research program was to support industry efforts in the Cascades and the objectives were to cost share with industry for the drilling of gradient holes which would penetrate the "rain curtain" and obtain deep thermal, lithologic, and structural data. In exchange for the cost sharing, industry participants would release the data to the public for the benefit of all of the geothermal industry as well as the scientific community.

GEO concentrated on the Newberry Volcano situated approximately in the middle of Oregon (Figure 7B). At Newberry, GEO has drilled five, 1,000- to 1,200-meter deep, core holes to determine if there is a geothermal resource in the area. Two of the core holes, GEO N-1 and GEO N-3 were drilled under the DOE Cascades Drilling Program. Data and core from both of these holes are in the public domain. The data and observations will hopefully lead to an enhanced understanding of the "rain curtain" phenomenon; to subsequent refinements in geothermal exploration techniques for use in the Cascades; and finally, to an increased understanding of Cascade geothermal systems and their potential for economic exploitation for electrical power production. Depending on whether GEO can overcome the environmental concerns that have been initiated; whether GEO is able to overcome the development of a new national geological monument; and whether GEO is able to obtain a power sales contract from a utility, GEO will drill the first wildcat geothermal production well sometime in 1989 at the Newberry Volcano.

SUMMARY

In summary, the geothermal industry is changing; we can no longer simply drill wells and sell steam or hot water to utilities as a fuel source for their power plants. The geothermal developers such as GEO must now build transmission lines as well as construct and operate power plants while continuing to try to make an economic return on our investment. There is a new age coming about in the electrical power production business and certainly it will occur in the 1990s, i.e., many of the independent power producers like GEO will continue to challenge the efforts of utilities as well as work with the utility industry to produce electrical power.

We would argue that in the true entrepreneurial spirit, we can develop geothermal resources and can provide electricity--a baseload level of electricity--from an alternative energy source which will be economical and environmentally acceptable. We are a small and fragile industry. Our research objectives are not fixed. They will change as additional data and experience are gained. There is an ongoing need to improve the available technology and further reduce the cost of developing geothermal power. Industry cannot afford the cost nor manpower needed for a successful research program; however, by working together cooperatively, exchanging ideas and information, industry and the federal R&D program can make geothermal energy a viable, economic, energy option for the United States.

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U.S. Department of Energy, 1987, Energy Security: A Report to the President of the United States, March, 1987, Report No. DOE/S0057, 240 pp. plus Appendices, Public Comments and References.

FIGURE CAPTIONS

Figure 1 Yearly statistics from 1978 to 1988 for (A) U.S. drilling rig activity, (B) U.S. crude oil production, (C) U.S. total crude oil demand, and (D) U.S. crude oil imports (Beck, 1988).

Figure 2 Projections of (A) electricity demand growth rates and (B) projected electricity supply and demand (U.S. DOE, 1987).

Figure 3 Major geothermal electricity generating plant sites (names at edge of map) and location of hydrothermal convection systems (circles) in conterminous United States with indicated subsurface temperature above 150°C (modified from Renner, et al., 1975).

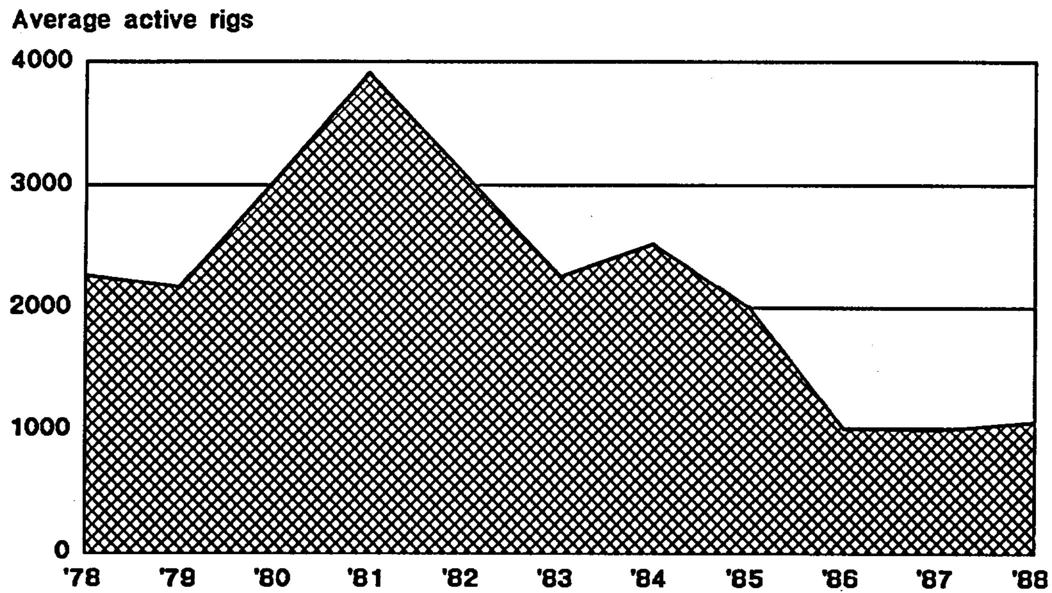
Figure 4 Geothermal facilities at The Geysers area in Northern California.

Figure 5 Frequency versus reservoir temperature for geothermal reservoirs.

Figure 6 Geothermal facilities in the Imperial Valley of Southern California.

Figure 7 Cascade Volcanoes in Oregon (A) and location map for geothermal exploration core holes of GEO at Newberry volcano (B).

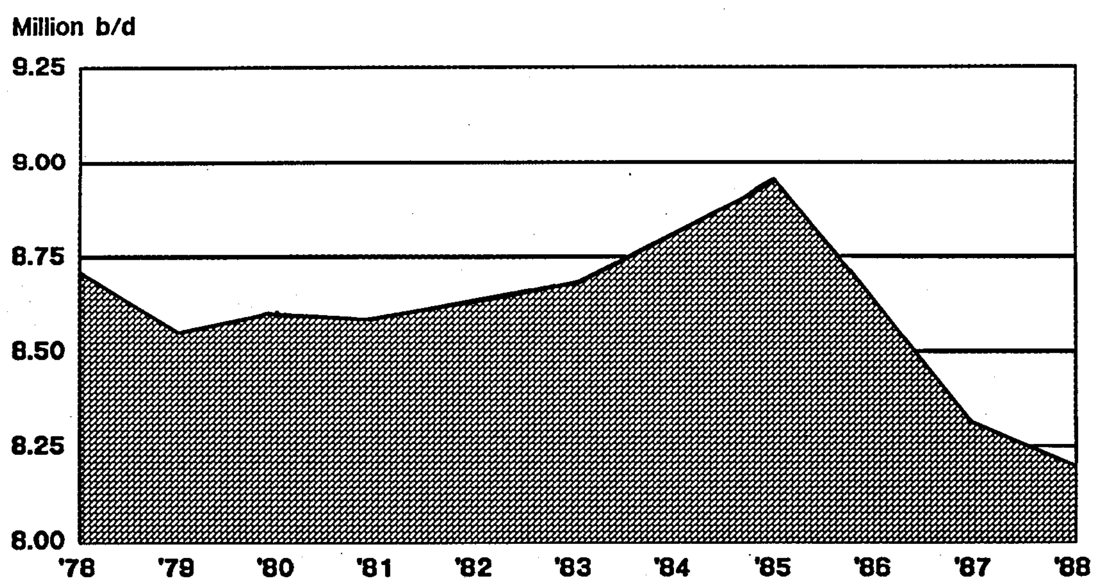
U.S. DRILLING RIG ACTIVITY



Source: Oil and Gas Journal, 1988

FIGURE 1 (A)

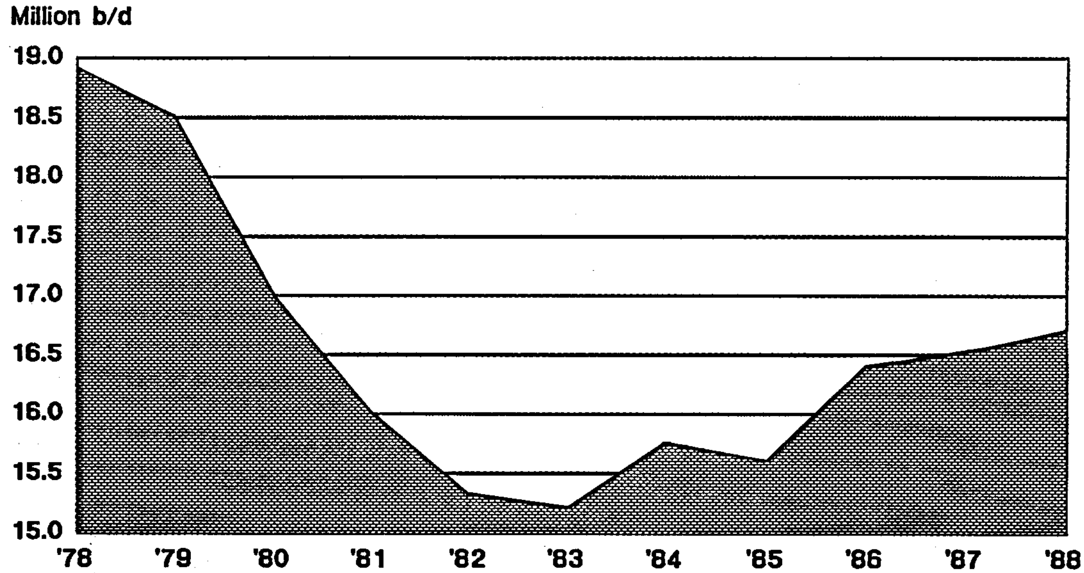
U.S. CRUDE OIL PRODUCTION



Source: Oil and Gas Journal, 1988

Figure 1 (B)

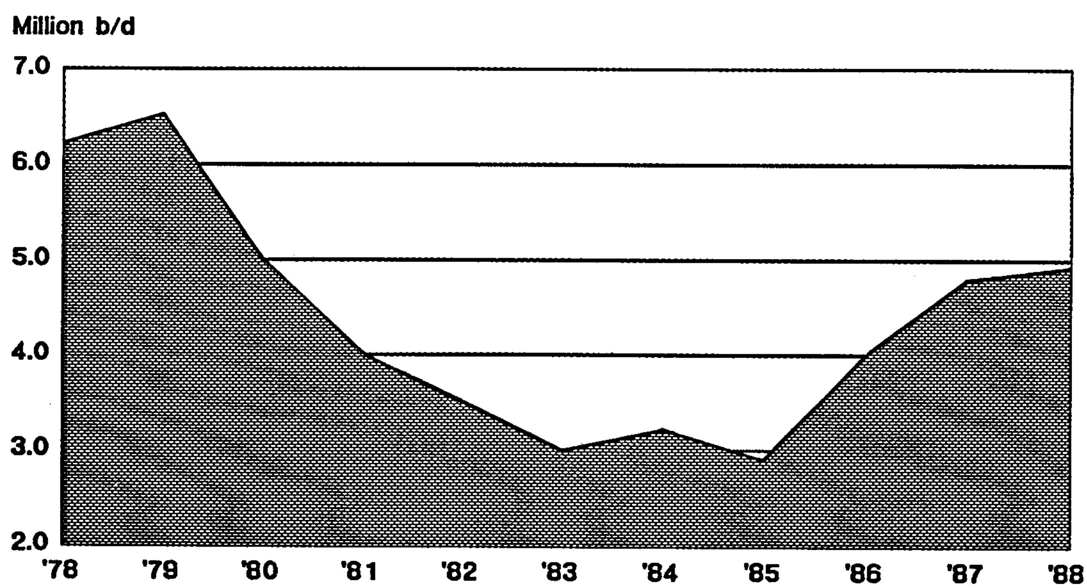
U.S. TOTAL CRUDE OIL DEMAND



Source: Oil and Gas Journal, 1988

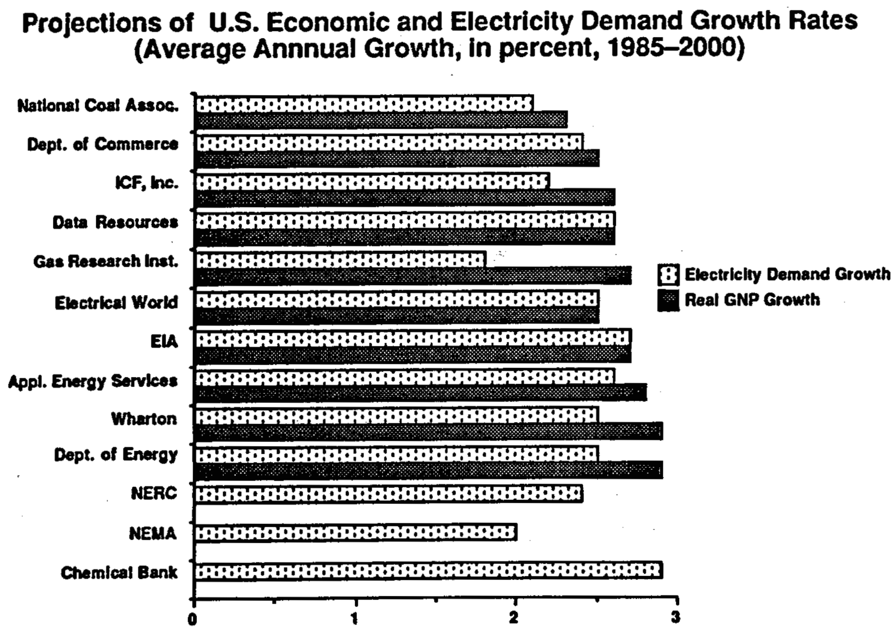
Figure 1 (C)

U.S. CRUDE OIL IMPORTS



Source: Oil and Gas Journal, 1988

Figure 1 (D)



Source: Energy Security, DOE, March, 1987

Figure 2 (A)

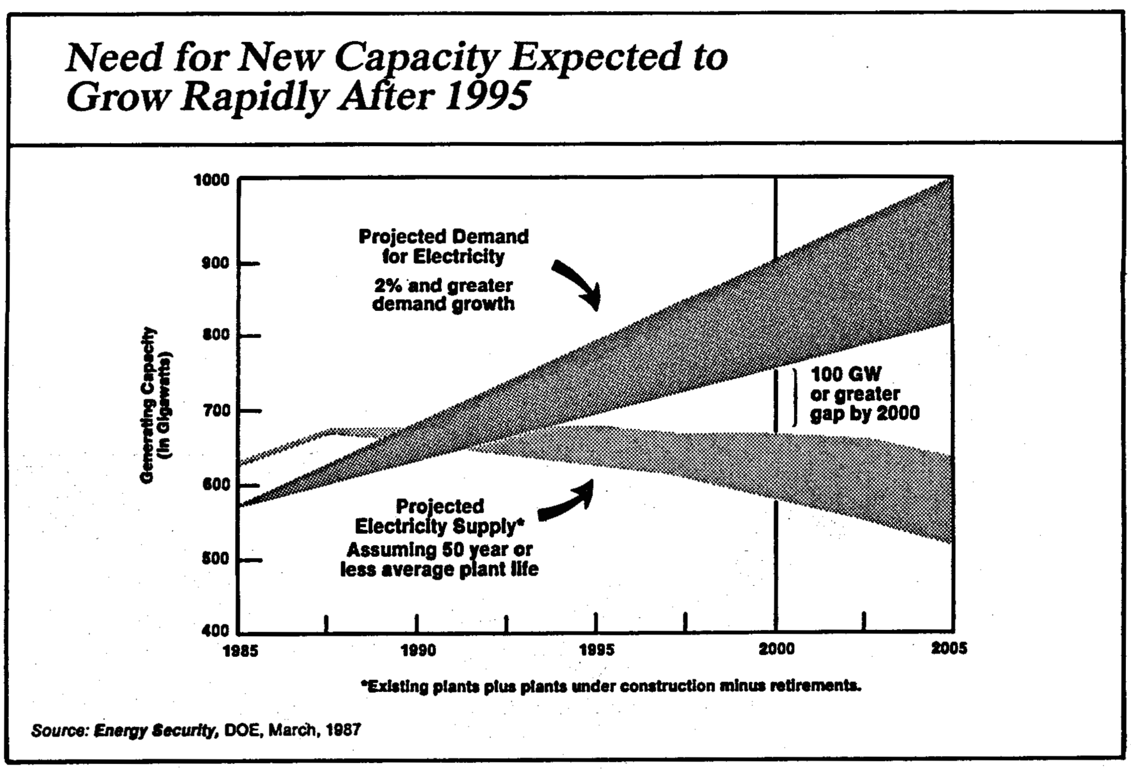


Figure 2 (B)

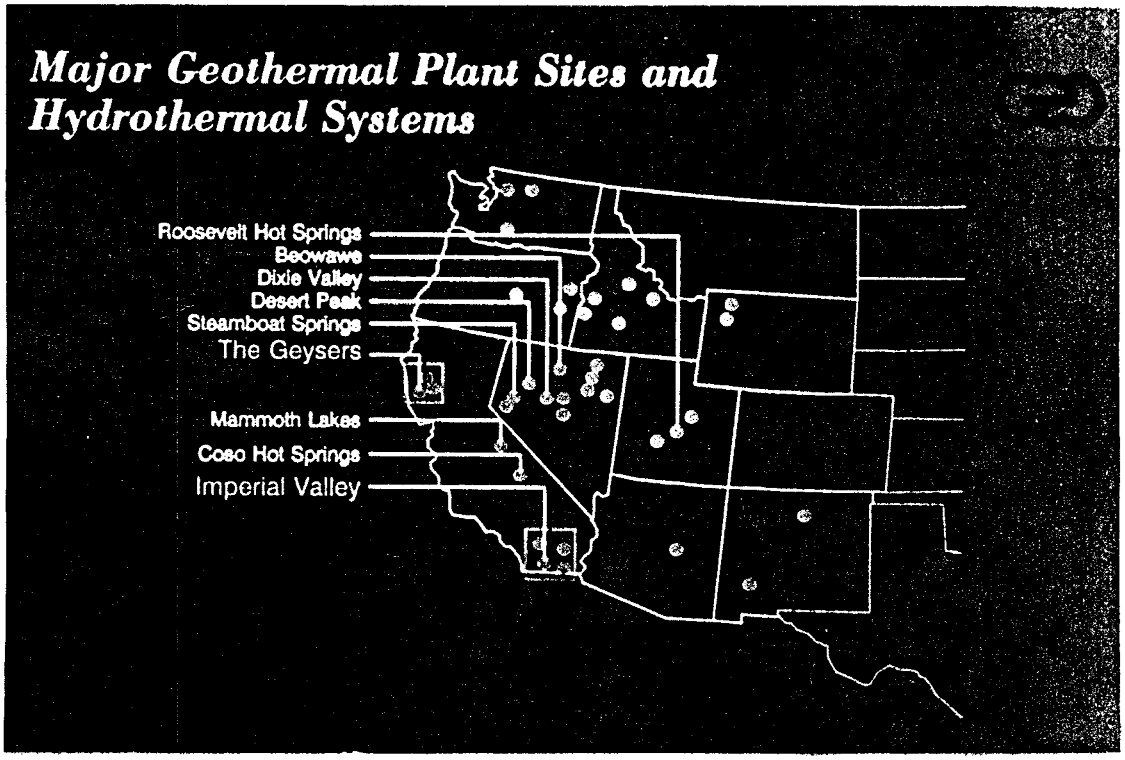


FIGURE 3

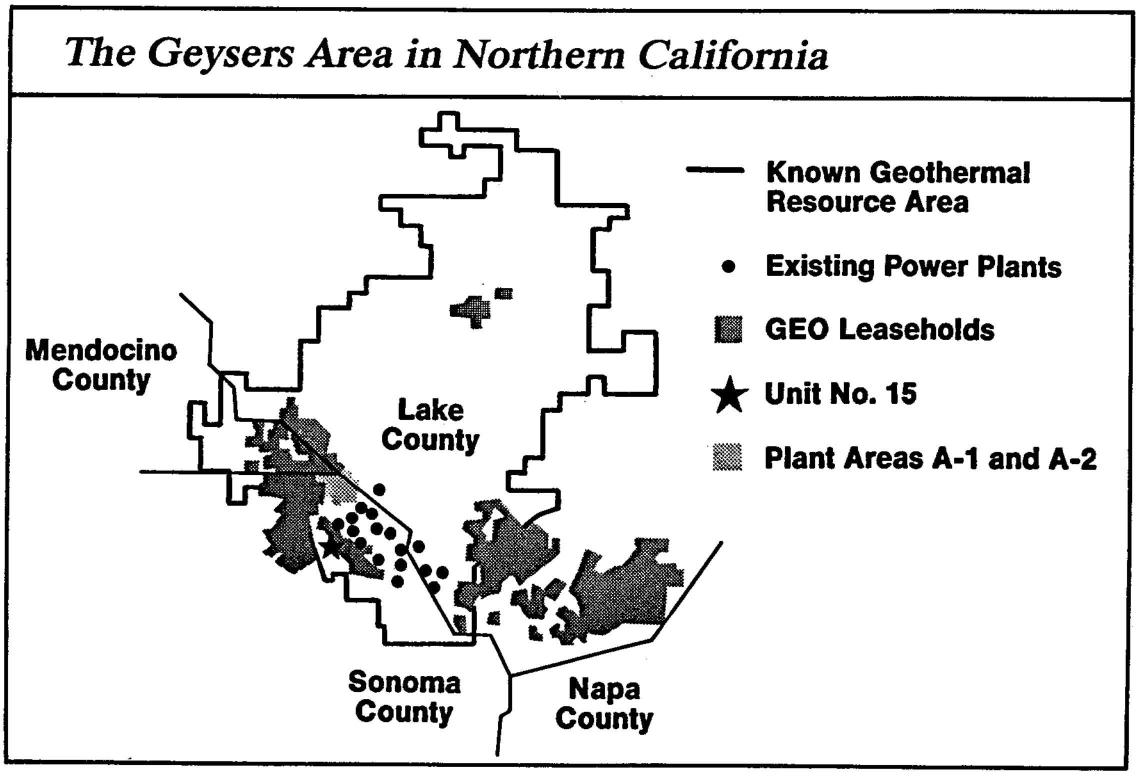


Figure 4

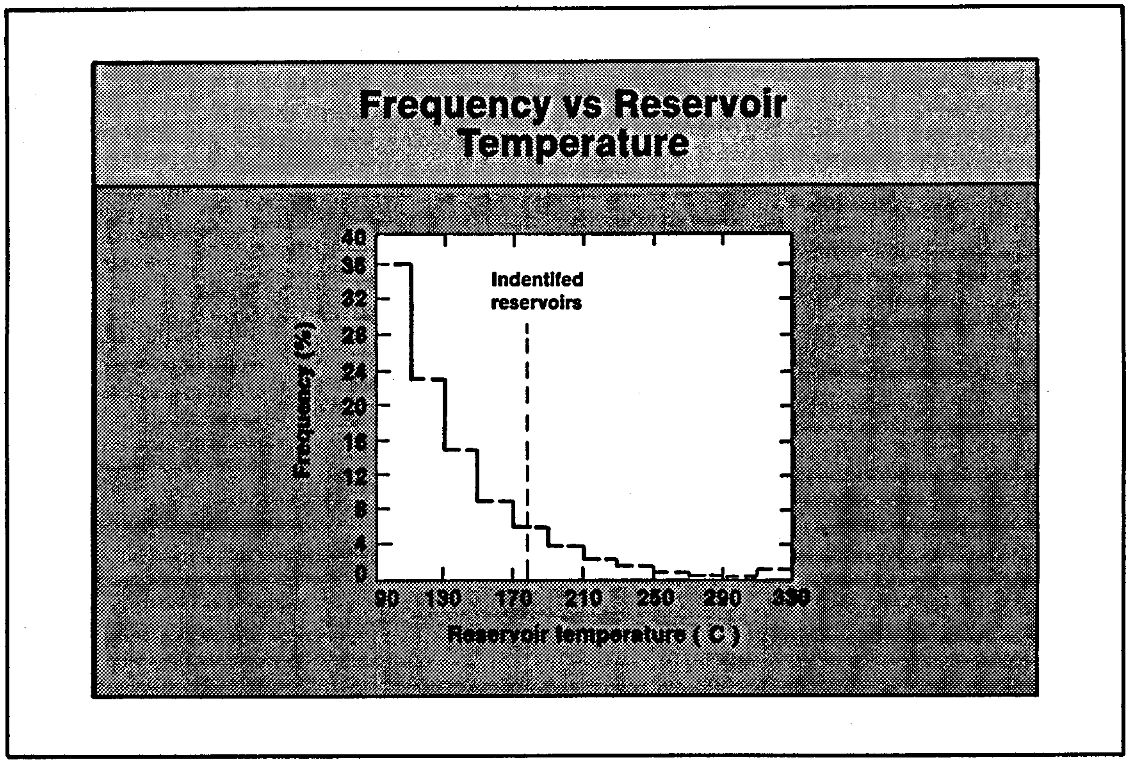


Figure 5

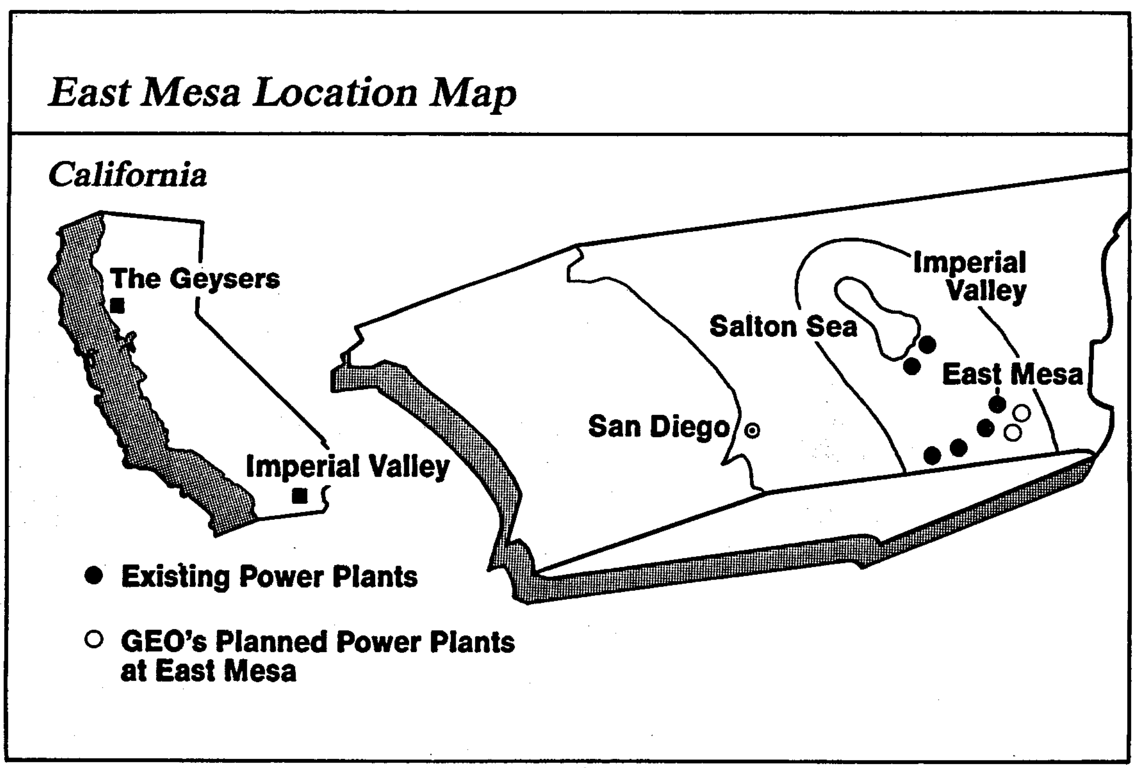


Figure 6

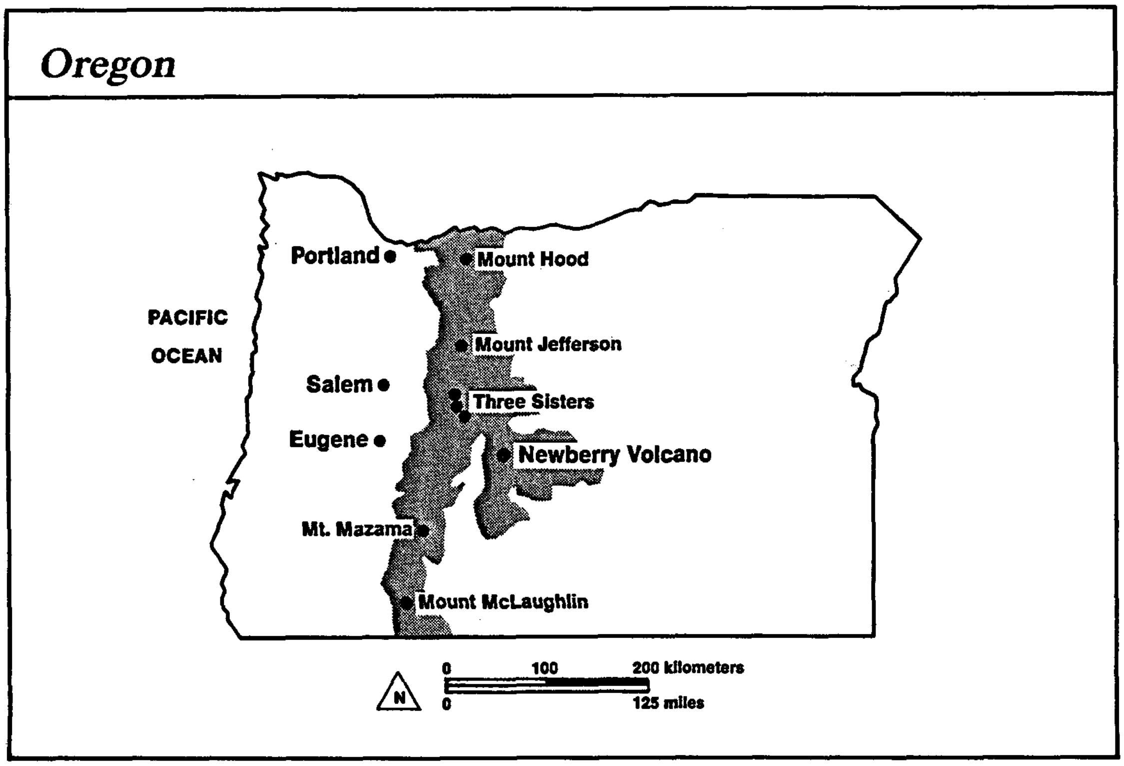


Figure 7 (A)

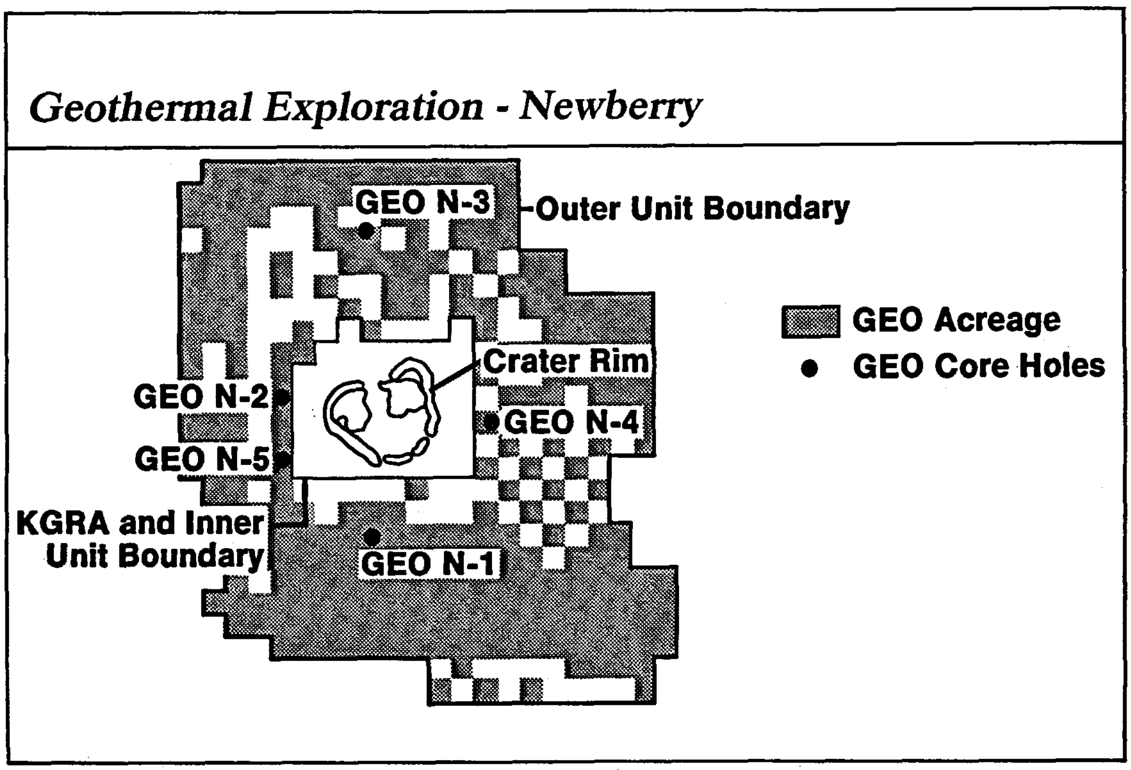


Figure 7 (B)

BEYOND GOALS AND OBJECTIVES

John E. Mock, Director
Geothermal Technology Division
U.S. Department of Energy

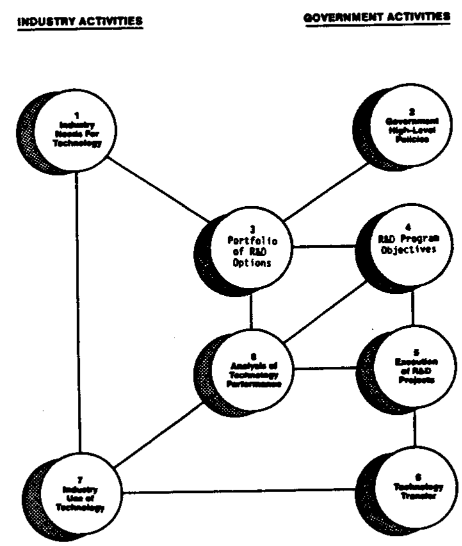
My function here this morning is to set the theme for Program Review VI -- Beyond Goals and Objectives. I will introduce specific, time-marked, quantitative objectives for geothermal technology improvements which I expect, once they are refined and approved, to drive all of the Geothermal Technology Division's research over the next five to seven years. If these objectives are achieved, they will result in quantifiable reduced costs of geothermal power by the mid-1990's.

We are here for a coordinated programmatic and management review of ongoing and planned research within the context of these objectives. They are set forth in a document entitled "Draft Statement of Programmatic Objectives of the Geothermal Technology Division, U.S. Department of Energy," dated March 23, 1988. We will be pleased to make the document available to anyone here who does not already have a copy.

The contents of this document were developed over the last year in a highly systematic manner, primarily by our headquarters staff with limited field assistance. We need your help in refining the objectives, both here at Program Review VI and in the coming weeks. We earnestly solicit input from all concerned parties -- researchers, suppliers, manufacturers, producers, users, and financiers. We want to develop final GTD programmatic objectives that are understandable, measurable, attainable, acceptable, and, most important, contribute to reductions in the cost of geothermal power.

EXHIBIT 1

INTERACTIONS BETWEEN GOVERNMENT AND INDUSTRY ON RESEARCH AND DEVELOPMENT IN GEOTHERMAL ENERGY



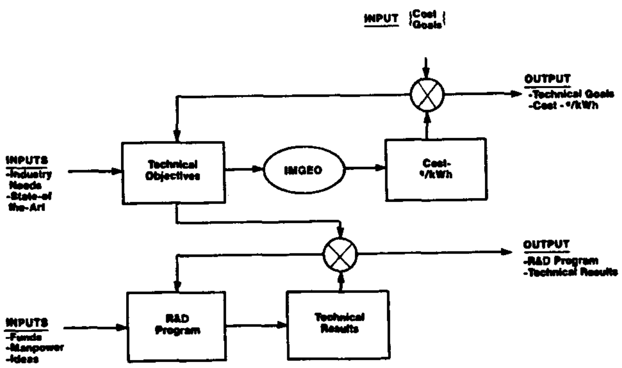
Government/Industry Interaction in Selection/Implementation of Objectives

The choice of GTD's objectives are driven by two unique factors -- industry's need for improved technology on the one hand, and government policies that determine which research areas are suitable for federal support. These factors appear as Nodes 1 and 2 in Exhibit 1 which shows the flow of interactions between government and industry in GTD's research and development program. These two factors can exert conflicting pressures on the program: industry's needs are the product of near-term market opportunities and economic considerations, while GTD's direction must also take into account the nation's long-term energy security. Of necessity, the resultant portfolio of objectives, Node 3 in Exhibit 1, reflects the influence of both factors. From the available options, GTD selects those which comprise its research and development program, Node 4. That selection is based on anticipated technology performance and criteria such as feasibility, cost schedule, and likelihood of achieving the objectives. The program functions through research activities executed by industry, universities, and national laboratories (Node 5). The results are passed along to industry through a variety of technology transfer mechanisms (Node 6). The real utility of improved technology can only be gauged from practical application by industry (Node 7). In turn, operating experience enables industry to identify further technology improvements (Node 1), and it also gives GTD essential information with which to analyze performance (Node 8). Analysis of performance then becomes the means for judging whether the objectives have been successfully achieved in addition to its role in objective selection.

GTD uses information provided by industry as a feedback mechanism to modify the R&D program (Node 4). If need be, objectives are adjusted to reflect actual operating experience. Or that experience may dictate changes in the choice of research options (Node 3) or the manner in which the R&D projects are executed (Node 5). This process has functioned for a number of years on a largely informal basis.

Cost-of-Power Model

Analysis of technology performance is a critical step in determining GTD's objectives, and therefore the content of its program. However, until recently, the analysis was qualitative, necessitating considerable subjective judgment on the part of our program managers. That degree of subjectivity has now been reduced by the introduction of a quantitative cost-of-power model called "Impacts of Geothermal Research," or IM-GEO.* The model simulates interactions among the major cost components of a hydrothermal electric plant and permits the cost savings of technology improvements to be estimated. It is thus a very important new planning tool for setting and verifying quantitative hydrothermal objectives. Its role in the planning process is illustrated in Exhibit 2.



WHAT IS OUR OVERALL RESEARCH MANAGEMENT STRATEGY?
EXHIBIT 2

The model is based on eight site-case simulated reservoirs. The characteristics are defined in terms of fluid production properties, rather than the more fundamental geophysical properties. The data include estimates of uncertainties associated with major reservoir characteristics. Each site case represents a composite of characteristics encountered at real U.S. reservoirs in a particular region. The range of characteristics and associated uncertainties are believed to be a reasonable representation of the U.S. reservoirs that industry is now developing, or will be developing, in the 1986-1995 time-frame.

Models for the other resource types--geopressured, hot dry rock, and magma -- are currently under development. Once these models achieve an adequate degree of reliability, they will be used to formulate quantitative objectives for those elements of the program. In the meantime, the objectives for the advanced systems which I will introduce today were set by GTD program managers through consultation with DOE field R&D managers and industry specialists. They will be reviewed and revised as indicated when the models are completed.

*Sandia National Laboratories, March 1987

Objectives Hierarchy

A typical geothermal energy project has several well-defined cost components. The GTD objectives hierarchy is structured to reflect those components in a manner which corresponds closely to industry practice and the structure of the cost-of-power model. Four major cost components are recognized:

- Resource Analysis - finding and defining a geothermal energy resource
- Fluid Production - producing geothermal fluid and maintaining production
- Energy Conversion - extracting useful energy (and byproducts) from the fluid and ultimately disposing of the fluid
- Other Operations - any cost factors which lie outside the first three components.

Each of these components is made up of several cost elements, and those elements contain numerous cost factors, which themselves can be subdivided. Ultimately, every single cost of equipment, material, and service can be itemized in a multi-tiered, project cost "tree." For purposes of this discussion, we need only consider the top three tiers or levels of the tree as shown in Exhibit 3.

EXHIBIT 3

GENERIC GEOTHERMAL ENERGY PROJECT COST TREE APPLYING TO ALL RESOURCE TYPES

TIER I
GEOTHERMAL ENERGY PROJECT

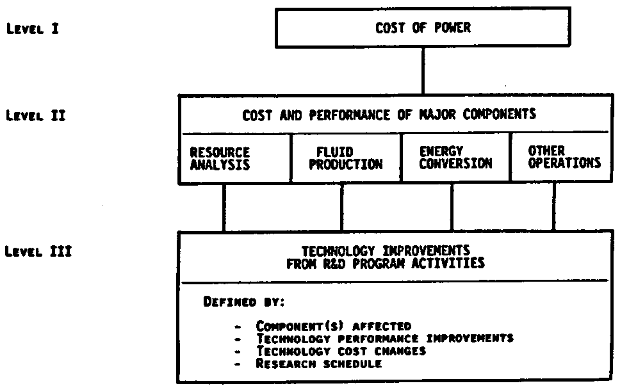
TIER II

RESOURCE ANALYSIS	FLUID PRODUCTION	ENERGY CONVERSION	OTHER OPERATIONS
TIER III			
- Geoscience	- Drilling & Completion	- Working Fluid & Heat Exchangers	- Leasing
- Exploration	- Stimulation	- Turbine & Generator	- Permitting
- Reservoir Engineering	- Injection	- Heat Rejection Subsystem	- Transmission
	- Well Maintenance	- Fluid Control & Disposal	- General Environment & Safety
	- Brine Treatment	- Non-Thermal Products	- System Optimization
	- Pumps & Fluid Transport		- Finance

The three tiers of the cost tree provide the basis for defining three levels of research program objectives. These levels are illustrated in Exhibit 4 along with their expected impacts. Level I objectives represent the cumulative impact of the program on total cost of power, allowing analysts and decision-makers to estimate the future cost of power from geothermal energy systems. Level II objectives include the impacts on each major component of the cost tree and indicate how much improvement is likely to occur within each one as a result of federally-funded research. Level III objectives define the technical improvements expected from each element of the research program, specify the expected degree of improvement,

EXHIBIT 4

THREE TIERS OF COST TREE PROVIDE BASIS FOR DEFINING THREE LEVELS OF GEOTHERMAL RESEARCH OBJECTIVES



prescribe the technical direction of individual research activities, and comprise the technical yardstick by which progress can be measured. The magnitude of the impacts of Levels I and II are derived from the Level III objectives through use of the cost-of-power model.

At Levels II and III the usual impact of achieving an objective is that performance improves and costs decrease. However, other desirable impacts are possible, including increases in costs of a component to deliver a performance advantage that would reduce costs elsewhere in the system. For example, binary cycle plants with improved thermal efficiency are likely to cost more than current plants per unit of gross installed capacity. But because they reduce the amount of geothermal fluid required, they yield large cost savings in the production/injection field and will, in some cases, cost no more per unit of net installed capacity because less power will be consumed in brine production. In addition, it should be noted that the various impacts are multiplicatively interdependent although sensitivity analyses can determine which technology improvements will have the greatest overall impacts.

Exhibits 5 through 8 are resource specific cost trees and illustrate the cost elements targeted by GTD research for hydrothermal, geopressured, hot dry rock, and magma resources, respectively.

The relationship of the major hydrothermal cost tree branches to our programmatic categories and tasks is illustrated in Exhibit 9.

Levels I and II Objectives

The Level I objectives for the geothermal R&D program are shown in Exhibit 10. The cost target range is expressed as levelized in 1986 dollars.

EXHIBIT 5

HYDROTHERMAL COST ELEMENTS TARGETED BY GTD RESEARCH

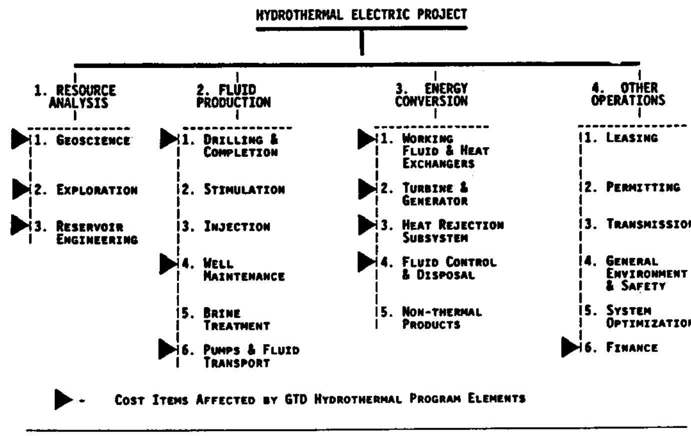


EXHIBIT 6

GEOPRESSURED-GEOTHERMAL COST ELEMENTS TARGETED BY GTD RESEARCH

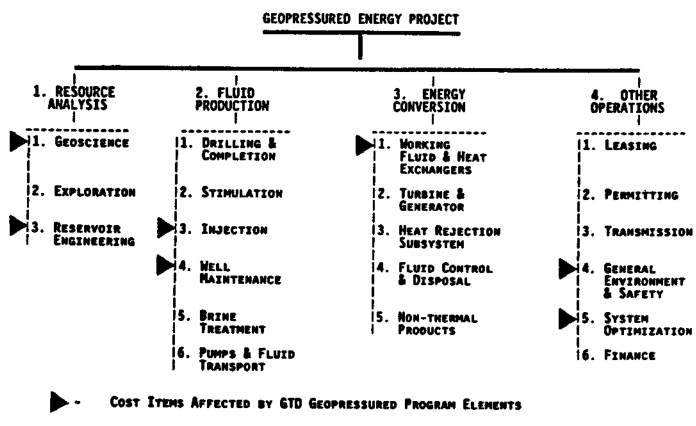


EXHIBIT 7

HOT DRY ROCK COST ELEMENTS TARGETED BY GTD RESEARCH

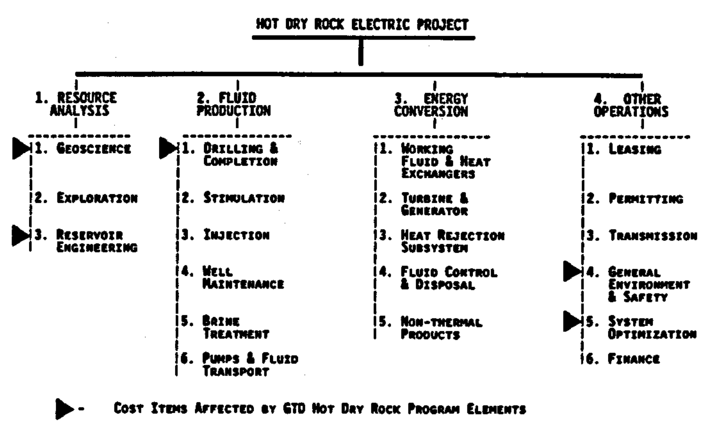


EXHIBIT 8

MAGMA ENERGY COST ELEMENTS TARGETED BY GTD RESEARCH

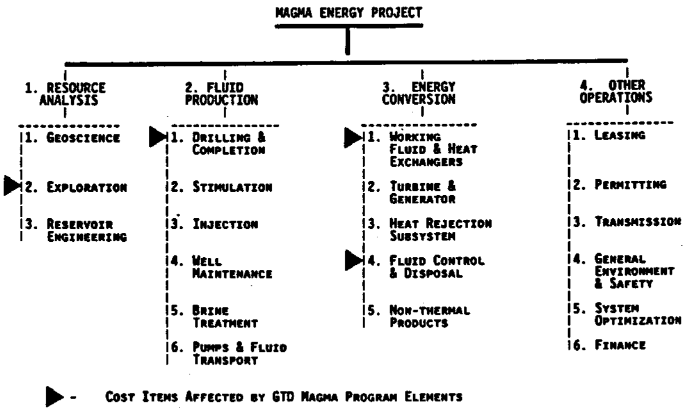


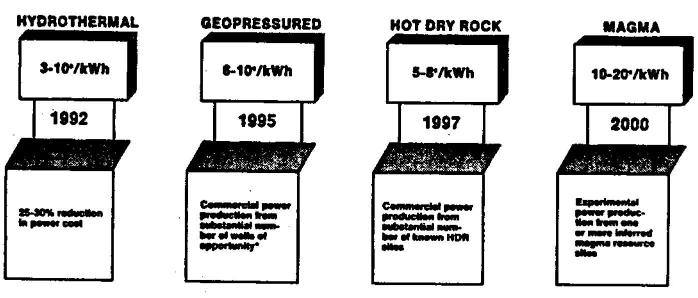
EXHIBIT 9

RELATIONSHIP OF MAJOR HYDROTHERMAL COST TREE BRANCHES TO PROGRAMMATIC CATEGORIES/TASKS

- HYDROTHERMAL RESOURCE ANALYSIS
  - RESERVOIR DEFINITION
  - EXPLORATION TECHNOLOGY
  - INJECTION
  - SALTON SEA SCIENTIFIC DRILLING PROJECT
  - HARD ROCK PENETRATION
- HYDROTHERMAL ENERGY CONVERSION
  - CONVERSION/HEAT CYCLE RESEARCH
  - CONVERSION/ADVANCED BRINE CHEMISTRY
  - CONVERSION/MATERIALS RESEARCH
- HYDROTHERMAL FLUID PRODUCTION
  - HARD ROCK PENETRATION
  - GEOTHERMAL DRILLING ORGANIZATION
  - CONVERSION/ADVANCED BRINE CHEMISTRY
  - CONVERSION/MATERIALS RESEARCH
- HYDROTHERMAL OTHER OPERATIONS
  - GEOTHERMAL LOAN GUARANTY PROGRAM

EXHIBIT 10

LEVEL I OBJECTIVES FOR THE GEOTHERMAL PROGRAM
(Cost Target Range Is Expressed As Levelized In 1986 Constant Dollars.)



* Usually abandoned oil and gas wells.

What do these projected costs really mean? If we compare them to the published average across-the-board fossil and nuclear costs, they mean very little. Every geothermal plant is a new plant, built with today's dollars. On the other hand, the average conventional power generation cost statistics include those of some plants built 20-35 years ago. Thus, to put the Level I objectives into a more meaningful perspective, the California Energy Commission was asked to estimate prices that would be competitive for new power supplies in California supplied by conventional fuels if new supplies were needed. In this context, the Level I cost objectives would compete very well, as can be seen in Exhibit 11.

EXHIBIT 11

COMPARISON OF LEVEL I GEOTHERMAL COST OBJECTIVES WITH COMPETITIVE PRICES FOR A NEW POWER SUPPLY IN CALIFORNIA SUPPLIED BY CONVENTIONAL FUELS

COMPETITIVE PRICE RANGE FOR A NEW POWER SUPPLY IN CALIFORNIA*	¢/kWh	LEVEL I COST OBJECTIVES FOR GEOTHERMAL POWER**	¢/kWh	YEAR
COAL	5 - 8	HYDROTHERMAL	3 - 10	1992
NUCLEAR	5 - 16	GEOPRESSURED	6 - 10	1995
OIL (STEAM POWER PLANT)	4 - 8	HOT DRY ROCK	5 - 8	1997
		MAGMA (EXPERIMENTAL)	10 - 20	2000

* Estimates supplied by California Energy Commission on March 24, 1988, as to the prices that would compete if new supplies were needed. There are currently no coal plants in California. Prices are in constant 1986 dollars.

**Expressed in 1986 dollars.

The basis for the Level I hydrothermal objective is that the technology is not available for economic exploitation of the large bulk of the identified hydrothermal reservoirs in this country where the temperature is below the economic range of flash plants. Some very small binary units--most around 2 MWe or less in capacity -- are operating successfully with low-temperature brines. However, in these cases, economics are dictated by size and very favorable site-specific conditions--e.g., sufficient heat at very shallow depths, use of existing wells -- that are not generally available. While the success of these small plants is to be applauded, even a multiplicity of installations of this size will not permit geothermal energy to reach its full potential as a viable energy supply option. While industry will profitably use small capacity facilities as "ice breaker" plants at undeveloped reservoirs, and such units are very useful in filling small incremental power demand, more favorable economics for larger binary plants (e.g., 10-100 MWe) are the key to meaningful expansion in geothermal utilization. To achieve the Level I cost goal, it will be necessary to bring about economies across the board -- from reservoir characterization to drilling and field development to the binary power cycle itself.

These economies are the focus of the Level II hydrothermal objectives established through the use of the IM-GEO model which are shown in Exhibit 12.

EXHIBIT 12

EXPECTED IMPACTS ON THE LIFE-CYCLE COST OF POWER FROM LEVEL II HYDROTHERMAL OBJECTIVES (BY 1992)

MAJOR BRANCHES	% REDUCTION
RESOURCE ANALYSIS	16 - 22
FLUID PRODUCTION	10 - 13
ENERGY CONVERSION	
BINARY PLANTS	8 - 20
FLASH PLANTS	2 - 6
OTHER OPERATIONS	NO DIRECT IMPACT

The Level I geopressured energy cost target range is founded on the assumption that major technological advances are not required; available petroleum industry technology is adequate to exploit the resource. Given this assumption, the research program focuses on fairly narrow technical issues unique to geopressured resources, such as the burden of handling huge volumes of brine.

However, before industry will be prepared to tap this large source of energy, improvements will be required in the understanding of the behavior of geopressured reservoirs over extended periods of time. These improvements are the focus of the Level II geopressured objective -- specifically to decrease uncertainty in reservoir performance theory to enable predictions of characteristics (i.e., reservoir size and longevity, hydrocarbon content, salinity) with 90 percent confidence over a 10-year operating period by 1992.

The economic feasibility of utilizing hot dry rock resources will depend largely upon sustaining adequate flow at low impedance, minimizing fluid losses, and maintaining controlled thermal drawdown of the man-made reservoir. Thus, the Level II hot dry rock objective is to evaluate the performance of system operating characteristics of the Fenton Hill Phase II reservoir (i.e., thermal drawdown, energy output, reservoir impedance, and water consumption) by 1993.

The economic feasibility of using magma energy will depend largely on the cost of energy extraction wells and the effectiveness of downhole heat exchange processes. Thus, the Level II magma objective is to improve the technology for locating and characterizing magma bodies by drilling into molten rock by 1994.

Level III Objectives

As discussed above, Level III objectives serve several functions:

- Define the technical improvements expected from each R&D component
- Specify the expected degree of improvement
- Prescribe the technical direction of individual research activities
- Comprise the technical yardstick by which progress can be measured
- Furnish the basis on which the cost-of-power model derives Levels I and II objectives.

At their level in the objectives hierarchy, Level III objectives are quite numerous, as shown in Appendix A, because they represent the anticipated results of individual program activities. For example, the Level III objective of the development of a high-temperature radar fracture mapping tool is to improve well siting through better identification of fractures by 1992. The Appendix A list is your first stop in analyzing the validity of the draft objectives and assisting us in finalizing them.

Cost Impacts Expected from Objective Achievement

The overall reduction in the cost of power expected from reaching the aggregated hydrothermal research objectives is about 32 percent for the resource-weighted average across the eight cases in the hydrothermal cost-of-power model scenario. When various uncertainties in the technical analysis of the cost impacts of the objectives are considered, it is reasonable to predict that the overall cost impact will be on the order of a 25 to 35 percent reduction in the average cost of power from U.S. hydrothermal reservoirs that will be developed in the 1992 to 1997 period.

The largest cost reductions are anticipated to result from improvements in resource analysis technology and drilling and completion technology. The relatively high impacts projected from these two areas of research underscore the degree to which knowledge about the interactions of technology and the physical characteristics of a reservoir is a relatively new area of science and engineering. Power plant technology is comparatively mature, but significant economic gains are expected from the adaptation of supercritical cycle design to binary power plants.

The expected busbar cost impacts of these improvements are shown in Exhibit 13 for a range of temperatures. Cases A and B are premised on moderate brine-chemistry conditions, similar to those encountered in the Heber, California, field. Case C is premised on severe brine conditions similar to those encountered at the Salton Sea. Costs of electricity are presented as busbar costs levelized in 1986 constant dollars.

Only those projects whose levelized busbar cost of power falls below 5.5 cents/kWh, the lower horizontal line in Exhibit 13, would have been cost-competitive with a new coal-fired plant in the West in 1986. In 1997, costs of competitive electricity could be as high as 8.2 cents/kWh, the upper horizontal line.

EXHIBIT 13

COST IMPACTS OF HYDROTHERMAL OBJECTIVES, BY RESERVOIR TEMPERATURE

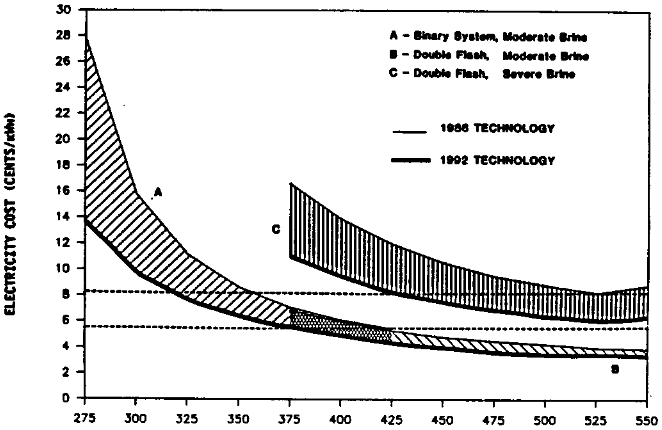


EXHIBIT 14

POTENTIAL COST REDUCTION DUE TO R&D BY REGION

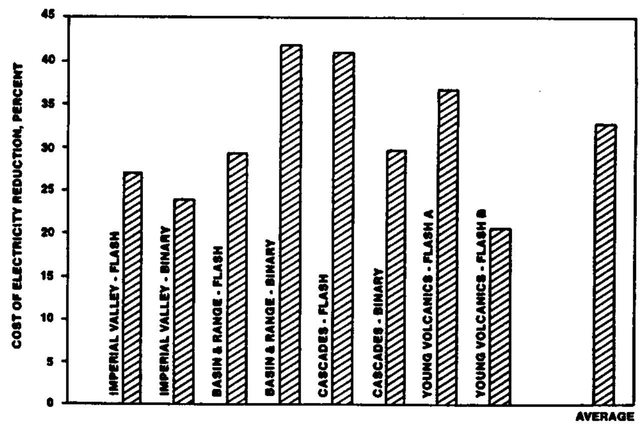
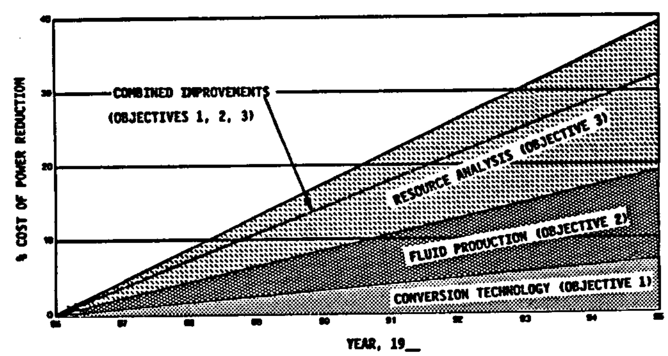


EXHIBIT 15

RELATIVE POTENTIAL IMPACTS OF GTD RESEARCH VIA HYDROTHERMAL SUBSYSTEMS

LINEAR ACHIEVEMENTS OF OBJECTIVES FROM 1986-1995



The least expensive liquid-dominated hydrothermal systems promise to deliver electricity at about 3 to 4 cents/kWh, which falls well within the competitive range. Moreover, substantial fractions of the identified hydrothermal resources lie near the economic threshold. In this situation, every improvement in technology helps industry reduce costs, which brings more of the resource into the region of economic feasibility. This indicates the value of continuing to improve hydrothermal technologies.

With 1986 technology, the economic threshold requires a reservoir temperature of about 400^{o}F. With 1992 technology that meets our objectives, the economic threshold can be met at about 325^{o}F.

Most of the hydrothermal reservoirs that will be brought into competitiveness by these improvements are lower temperature reservoirs, which will employ improved binary technology. But, as shown for Case C in Exhibit 12, significant cost reductions are also expected for flash plants at higher-temperature reservoirs with severe brine conditions.

Region-specific estimates of the impacts of the research objectives are of interest because they portend the degree to which severe conditions currently encountered in some regions will be ameliorated by the economic impacts of improved technology. The estimated region-specific cost impacts of the research objectives, as analyzed by the cost-of-power model, are shown in Exhibit 14.

The relative potential impacts of GTD research on hydrothermal subsystems are shown in Exhibit 15. The impacts are projected out to 1995 because a technology transfer period is anticipated subsequent to objective achievement in 1992.

<u>Strategies for Implementing the Objectives</u>

We have discussed so far how and why the quantified objectives were set, how we expect to verify their accomplishments, what the accomplishments are expected to be, and the projected impacts they will have on the geothermal power market. Now, we must address how we implement objective accomplishment.

As I said in the beginning, I expect the refined and approved objectives to drive <u>all</u> of GTD's R&D efforts over the next five to seven years. In order to make that happen, I believe we must ask our researchers to:

- Re-think their implementation strategies in light of the stated R&D objectives in their topic area.
- Identify priority projects on the basis of cost-effectiveness and quantifiable impact on objectives.
- Apply the highest degree of activity in projects proposed for funding.
- Be prepared to make a preliminary quantitative estimate of the impact of a proposed project on cost of power (Level I objective), cost and/or performance of

a major component (Level II), <u>or</u> a technology improvement (Level III).

By addressing these remarks to the researchers, I do not intend to place the full burden of the accomplishments of our objectives on them. All of us in this room are members of the geothermal community. As such, I hope that we will all cooperate to the fullest extent possible in achieving our goals and objectives so that we may share the benefits that lie beyond.

APPENDIX A

LEVEL III HYDROTHERMAL OBJECTIVES

(Cost Tree Components Rearranged According to Budget Line Items)

CATEGORY/TASK	TECHNOLOGY	IMPACT	PERCENT IMPROVEMENT	TARGET YEAR
RESERVOIR TECHNOLOGY				
• Reservoir Definition	Siting of exploration wells	Increase success rate	15	1992
	Siting of production wells (reservoir identification and confirmation)	Improve	20	1992
• Brine Injection	Long-term reservoir decline predictions	Decrease uncertainties	25-35	1992
	Injection well maintenance	Reduce costs	30	1992
• Exploration Technology	Detecting and confirming geothermal reservoirs in the Cascades and other young volcanic regions	Improve methods	-	1990
	Model for fracture permeability in the Cascades	Formulate	-	1990
• Salton Sea Scientific Drilling Project	Evaluating deep production zone	Evaluate	-	1989
HARD ROCK PENETRATION				
- Lost Circulation Control	Lost circulation control	Reduce costs associated with lost circulation episodes	30	1992
- Coring Technology	Deep coring	Reduce costs	15	1992
- Drill String Dynamics	Drilling production related wells	Reduce costs	5 (through more accurate completion zone siting)	1992
	Deep and directionally drilled wells	Reduce costs	10	1992
- Radar Fracture Mapping Tool	Well siting	Improve accuracy (through better identification of fractures)	-	1992

LEVEL III HYDROTHERMAL OBJECTIVES, Continued

CATEGORY/TASK	TECHNOLOGY	IMPACT	PERCENT IMPROVEMENT	TARGET YEAR
- Wellbore Diagnostics Tool	Moderate-temperature wells	Reduce costs	1 (through 25% reduction in uncertainties in downhole and wellhead measurements)	1989
	High-temperature wells (>250°C)	Decrease uncertainties in downhole and wellhead measurements	50	1992
	Well cementing materials	Service lifetime of 30 years at 400-600°C	-	1991
- Geothermal Drilling Organization	Wells	Reduce costs	5 10	1990 1992
CONVERSION TECHNOLOGY				
• Heat Cycle Research	Binary plants	Increase net geothermal fluid effectiveness	20	1992
	Conventional binary plants/ supersaturated vapor turbine expansions	Increase net geothermal fluid effectiveness	8	1992
	Direct contact heat exchangers	Extend use to hypersaline brines	-	1992
• Heat Cycle Research	Heat rejection system	Reduce cooling water make-up requirements (while retaining performance comparable with conventional wet cooling)	20	1991
• Advanced Brine Chemistry	Field surface equipment/scale deposition	Reduce costs	20	1992
	Production well maintenance	Reduce costs	20	1992
	Power plant maintenance and equipment replacement/scale deposition	Reduce costs	20	1992
	Surface disposal of sludge	Reduce costs	25	1995
• Materials Research	Corrosion-resistant and low-fouling heat exchanger tube material	Reduce costs to no more than 3 times that of carbon steel	-	1991

LEVEL III GEOPRESSURED OBJECTIVES

OBJECTIVE	TARGET YEAR
Develop techniques to increase confidence in the ability to locate and evaluate geopressured resources. (These techniques should be of sufficient quality that at least 90% of wells recompleted for geopressured development are subsequently shown to be economic.)	1992
Determine the drive mechanisms for the design well reservoirs	1991
Develop a test procedure which has sufficient accuracy to predict the capability of any geopressured reservoir to be produced for a period five times as long as the test period	1992
Prove the long-term injectability of large volumes of spent fluid into injection wells	1992
Develop a modified scale inhibition procedure	1989
Determine source and flow mechanisms for the liquid hydrocarbons and methane obtained from producing geopressured reservoirs	1991
Determine if fluids can be disposed of in an environmentally acceptable manner	1995
Develop surface fluid handling facilities (pumps, separators, valves, compressors, etc.) which can be safely operated from a remote monitoring location	1993
Develop material specifications, equipment specifications, and maintenance procedures which will guarantee over 95 percent annual availability with only a two-week annual shutdown for routine maintenance	1993
Develop hybrid conversion technology with thermal efficiency at least 20% greater than that from separate combustion and geothermal power cycles	1992

LEVEL III HOT DRY ROCK OBJECTIVES

OBJECTIVE	TARGET YEAR
Improve instrumentation and hardware to control, locate, and measure fracture propagation in hot dry rock reservoirs	1995
Establish reservoir mapping techniques to locate drilling targets for production wells	1995
Evaluate the large Phase II reservoir at Fenton Hill to determine its drawdown characteristics	1993
Complete studies on water-rock interactions and their effects on the flow through a hot dry rock reservoir	1993

LEVEL III HOT DRY ROCK, Continued

OBJECTIVE	TARGET YEAR
Develop technology to monitor changes in reservoir volume and temperature and confirm monitoring data using tracers	1994
Complete detailed reservoir analyses and confirm modeling of hydraulic and thermal performance of the Phase II system	1995
Determine means to locate accurately the intersection of fractures with the wellbore	1997
Develop cement formulations that result in low-density, moderate-strength, zero free-water cements for casings	1995
Verify that the environmental and social consequences of HDR development are acceptable	1997
Determine if the performance of the Fenton Hill reservoir, when considered as a unit reservoir in a commercial-scale project, could support production of electricity at an economical busbar cost	1995

LEVEL III MAGMA OBJECTIVES

OBJECTIVE	TARGET YEAR
Understand the nature of geophysical anomalies at the Long Valley caldera using actual well observation data and verify the depth and lateral extent of a magma body	1992
Evaluate performance of materials in the corrosive and volatile-rich magma environment for use in drilling tools	1992
Design and develop technology capable of drilling into magma at temperatures of at least 900^{o}C and total depths of 5 km	1992
Predict rates for dissolution of silicate minerals and the composition of fluid in a rock-to-water heat exchanger system and evaluate the potential for loss of permeability due to precipitation of secondary minerals	1995
Evaluate heat transfer effectiveness between a magma body and water circulating the energy extraction wellbore	-
Evaluate magma degassing hazards associated with drilling and energy extraction at Long Valley	-

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Regional Aspects of Geothermal Energy Development

Martha Dixon, Director
Conservation and Renewable Energy Division
San Francisco Operations Office
U.S. Department of Energy

Let me first tell you a little bit about the DOE San Francisco Operations Office:

SAN is a multi-program DOE field office whose mission is to support the accomplishment of the DOE defense and energy missions, through the oversight and management of assigned laboratories and university and industrial contractors.

SAN's major functions include R&D program and project management, business management, institutional management of National Laboratories, and regional responsibilities.

SAN has 300 Federal employees and manages the work of some 13,000 contractor employees. The SAN budget for FY 88 is approximately $1.7 billion.

SAN's major facilities are at Lawrence Livermore National Laboratory, Stanford Linear Accelerator Center, Lawrence Berkeley Laboratory, and the Energy Technology Engineering Center.

SAN's programs include Defense, Energy Research, Nuclear Energy, Fossil, Conservation and Renewables, and Environment, Safety and Health.

A breakdown of SAN's FY 88 budget shows that about half goes to National Defense and Defense-related activities, including "traditional" nuclear weapons R&D, the Strategic Defense Initiative, and the applications of lasers to Inertial Confinement Fusion and Special Isotope Separation. Large pieces of the pie go to High Energy Physics, Basic Energy Sciences, and Nuclear Energy. Nuclear Energy includes work on Power Reactors, Space Reactors and Uranium Enrichment by means of Atomic Vapor Laser Isotope Separation (AVLIS).

Saving the best for last, SAN has a good-sized budget in Conservation and Renewables, $131M in FY 88. That's where our Geothermal Program activities fit.

Now let me tell you why it is very appropriate to have this Geothermal Program Review here in California again. Program Review III was held in El Centro in 1984. This is "where the action is!"

SAN is located at the heart of the U.S. geothermal energy resources, commercial development, and research. Immediately north lies The Geysers immense dry steam field, with about 26 power-plants. Further north lie the Oregon geothermal resources at Klamath Falls, Newberry Caldera, and the Cascades volcanic chain (including Mt. St. Helens). To the east are Nevada's hydrothermal fields with power plants operating at Beowawe, Desert Peak, Steamboat Springs, and Brady Hot Springs. To the south in California lie Coso Hot Springs, with the hottest (341°C) moderate depth (6,533 ft.) well in North America and Imperial Valley with two power plants at East Mesa, two at Heber, and two at Salton Sea. South of the California border lie Mexico's major hydrothermal fields. Far to the west lie active volcanoes on the island of Hawaii, with one 3 MW power plant operating at Puna, on the East Rift of Kilauea Volcano. In all, SAN is surrounded by some 98.2% of the geothermal electric power production in the United States and much of the U.S. direct heat use.

Let me close by reminding you that geothermal energy development faces not only major technical and fiscal obstacles, but also environmental or even "religious" challenges, such as alleged violations of Hawaiians' sacred goddess Pele. You may have seen recent notices to this effect published in many newspapers such as the New York Times and the San Francisco Chronicle. This kind of challenge is not unique to geothermal energy. In fact, every energy source, old and new, must cope with various types of social challenges -- but it is one that must be addressed and resolved as we move forward.

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SESSION II

HYDROTHERMAL RESEARCH PROGRAM OBJECTIVES

CHAIRPERSON: SUSAN PRESTWICH
GEOTHERMAL PROGRAM MANAGER
IDAHO OPERATIONS OFFICE
U.S. DEPARTMENT OF ENERGY

INCREASING RESERVOIR CONFIRMATION AND WELL SITING CONFIDENCE THROUGH HYDROTHERMAL EARTH SCIENCE RESEARCH

Dennis L. Nielson, Joseph N. Moore and Phillip M. Wright
Earth Science Laboratory
University of Utah Research Institute

ABSTRACT

Research in geology, geochemistry and geophysics is being conducted for the purpose of increasing reservoir confirmation and well siting confidence. Past accomplishments include (1) improvements in geologic models of hydrothermal systems and in understanding the physical and chemical processes in these systems, (2) development of models of chemical and alteration zoning in hydrothermal systems, (3) development of algorithms for two- and three-dimensional geophysical data interpretation, and (4) development of new geophysical instrumentation and techniques for siting wells. The importance of this research lies in the fact that the costs of reservoir confirmation and of drilling the production and injection wells are a substantial portion of total geothermal development costs. The high costs are the result of both the high costs of drilling and the high risk of failure of a confirmation, production or injection well. Research to develop better methods and reduce the risk of failure in confirmation and well siting have the potential for lowering the cost of hydrothermal power significantly.

A coordinated program of research is being conducted primarily by the University of Utah Research Institute, Lawrence Berkeley Laboratory, Lawrence Livermore National Laboratory, Idaho National Engineering Laboratory and Stanford University. Topics in geology, geochemistry and geophysics are included. Geological work includes (a) geophysical well logs to determine the in-situ stress field, and (b) study of the uses of hydrothermal alteration mineralogy in determining fluid flow paths. Geochemical research includes (a) determining reservoir fluid flow patterns through integration of chemical and fluid inclusion data, and (b) developing a better understanding of the distribution of trace element and mineral occurrences in hydrothermal systems. Geophysical research includes (a) development of seismic and electrical borehole geophysical techniques for mapping fractures, (b) petrophysical measurements on reservoir and host rocks to improve interpretation of well logs and surface geophysical data, and (c) use of satellite and airborne remote sensing in detecting fracture trends and hydrothermal alteration patterns.

INTRODUCTION

Siting successful geothermal wells is far from easy. Even within such well-known geothermal areas as The Geysers, California, where the experience of locating and drilling hundreds of wells is available, the success rate for production-well drilling is perhaps only 80 percent. For wildcat geothermal drilling in relatively unknown areas, the success rate is much lower, 10 to 20 per cent. The problem usually is not so much in finding heat as it is in finding fluids in producible amounts. Because there is no known way to detect from the surface the particular permeable zones at depths of hundreds of meters that can produce thermal fluids, exploration techniques are mostly indirect and provide only circumstantial evidence of the existence and location of a reservoir.

The geothermal industry needs new field and data interpretation techniques to improve their ability to site geothermal wells for reservoir confirmation and installing the production and injection well fields.

GEOLOGIC TECHNIQUE DEVELOPMENT

Geological research at UURI is concerned with understanding fracture controls on geothermal systems and the formulation of predictive models for fracture intersection in high-temperature geothermal systems. The research plan for this topic is ambitious and funding limitations prohibit a comprehensive treatment of the topic at any one time. The work involves determination of present stress orientation, determination of past stress orientations, the theoretical analysis of the superposition or rotation of stress fields on existing faults, and the influences of hydrothermal processes on the formation and preservation of permeability along faults and fractures.

Present Stress Orientation

The state of stress in the earth's crust is defined in terms of three principal stress directions, the greatest, least, and intermediate principal directions. The orientation of these directions determines the character and orientations of fracturing in rocks. In extensional environments, the greatest principal stress is vertical. This is a prime environment for geothermal systems since extension creates open space through which fluids circulate. Fracturing forms along steeply dipping normal faults that are so common in the Basin & Range.

A number of methods are available for the determination of stress orientations. The method we are presently researching utilizes borehole breakouts or ellipticity that is determined from geophysical well logs. This method makes use of the recognized phenomena that borehole ellipticity is a function of the orientation of the greatest and least horizontal principal stresses. In extensional environments, we can safely assume that the least horizontal principal stress is equivalent to the least principal stress. Due to concentration of strain around the borehole, the maximum axis of ellipticity develops parallel the least principal stress direction.

Studies of stress in the lithosphere have shown relatively constant orientations over thousands of square miles within the same geologic provinces. An initial evaluation of breakout data from active geothermal systems (Allison and Nielson, 1987) has demonstrated a much more complex picture, with individual wells showing changes in stress orientation across faults. Different wells in the same geothermal system show vastly different orientations that are often related to their proximity to mapped faults. However, in some systems, it has been found that the present stress orientation differs from that which would be inferred from observation of faults in the area.

Past Stress Orientation

Faults exposed at the surface may represent the effects of either past or present stress systems. These orientations are documented either by geologic mapping or remote imagery such as the studies from satellites that will be discussed later in this paper. Confirmation that mapped faults represent the present stress orientations can be demonstrated through the use of borehole breakouts as described above. Faults developed in a paleo-stress environment can also provide excellent pathways for geothermal fluids. A prime example is the production of fluids from Roosevelt Hot Springs geothermal system in Utah where the most productive fractures are associated with the Negro Mag fault system. These faults were formed with the least principal stress oriented north-south rather than the present environment of east-west extension. Similarly, faults formed in a previous stress environment produce geothermal fluids at Cove Fort, Beowawe, and Coso among the systems that we have investigated.

Rotation of Stress Orientation

From the above discussion, it is clear that the orientations of stress in active geothermal environments change with time. Often we have concluded that this is a result of the interaction of a locally derived stress field, perhaps associated with the emplacement of magmas in the subsurface, and the regional stress environment. During different periods in the structural development of an area, one stress field dominates. However, once a fault or fracture system is formed in rocks, this feature becomes a zone of weakness that responds to stresses even if those stresses are not in an orientation that could form the fractures in unaffected rock. Thus, changes in orientation are able to either open or close pre-existing fractures and enhance or even terminate geothermal activity along those fractures. This is one of the topics on which we have deferred work due to the limitations of time.

Influences of Hydrothermal Processes on Fracture Permeability

Fractures that produce geothermal fluids are most commonly formed through tectonic processes, and active tectonism is often thought to be required to maintain permeability along those fractures. In addition to opening fractures, howe er, it is also critical that those fractures be preserved. Destruction of permeability may result from changes in stress orientation as discussed above, but more commonly, permeability is destroyed through the process of hydrothermal alteration and sealing. Although the composition of hydrothermal fluids is certainly a component in the preservation of fracture permeability, the character of the fractures may also play an important role. Again, this work has been deferred by time limitations and by a desire to build more of a fracture data base than is presently at hand.

Hydrothermal processes are also capable of enhancing fracture permeability. We have recently completed a very detailed study of the formation of permeability through natural hydrofracturing or hydrothermal brecciation (Nielson and Hulen, 1987; Hulen and Nielson, 1988). This appears to be an important process in the upper portions of geothermal fields, and at a small scale, can effect wells intersecting geothermal fractures.

GEOCHEMICAL TECHNIQUE DEVELOPMENT

The development of detailed hydrologic models of geothermal reservoirs requires information on fluid processes and chemistries in three dimensions. Only part of the data needed to generate these models can be obtained directly from chemical analyses of the fluids discharged from geothermal wells and hot springs. Exploration wells are typically unproductive or produce fluids contaminated with drilling mud. Production wells, on the other hand, are frequently completed over intervals of hundreds to thousands of feet, and the samples that are obtained from them represent averages of different fluids. Thus, it is generally not possible to obtain detailed information on the change in chemistry with depth even within single wells.

Reservoir Characterization and Monitoring

Fluid inclusions contained within geothermally deposited minerals represent an important additional source of the chemical and thermal data needed to develop sufficiently detailed hydrologic models suitable for exploration and development purposes. Fluid inclusions are small cavities that contain samples of the fluids present during mineral deposition. In order to test the application of fluid inclusion studies to the development of detailed hydrologic models we have initiated studies of four geothermal systems: Coso, East Mesa, Heber, and Los Azufres. These studies represent cooperative efforts with California Energy Co. Inc., GEO Operator Corp., Chevron Resources Co., and the Comision Federal de Electricidad, respectively. The application of fluid inclusion data to the Salton Sea geothermal system where both matrix and fracture dominated flow occurs was recently discussed by Moore and Adams (1988).

Systematic study of fluid inclusions in quartz, calcite, and anhydrite has demonstrated that in each of these systems, there is a close correspondence between the temperatures recorded by these minerals and the present measured temperatures (i.e., Echols et al., 1986). Such a relationship implies that the fluids trapped within the inclusions are also related to the present thermal system and that the compositions and temperatures of the inclusions can be used to evaluate the effects of various reservoir processes. These relationships are being used to map zones of boiling, dilution, and conductive cooling within the reservoir.

In order to calibrate the fluid inclusion data, and further quantify the effects of the processes discussed above, we have sampled the production fluids at Heber and obtained high-quality chemical data from Coso and Los Azufres. These data are being used to calculate the composition of the discharged fluids prior to flashing, and at Heber and Coso, will provide the baseline data needed to asses the effects of production.

Mineralogical and Trace Element Investigations

Mineral and trace element zoning is frequently used to qualitatively estimate temperatures within the geothermal reservoir. Our current studies have been directed toward evaluating the mechanisms responsible for the deposition of arsenic and on quantifying the relationship between sericite chemistry and temperature.

Our studies indicate that the concentration of arsenic in geothermal waters varies inversely with the partial pressure of H_2S and directly with temperature. The concentration of arsenic is regulated by reactions involving pyrite. Thermodynamic modelling suggests that its deposition in pyrite is controlled by local fluctuations in redox conditions (Ballantyne and Moore, 1988a).

Sericite, occurring as illite or interlayered illite/smectite is ubiquitous in geothermal systems. In contrast to previous studies which have considered non-expanding illite as solid solutions of muscovite, paragonite, and pyrophyllite, we have modeled them as mixtures of muscovite and smectite (Ballantyne and Moore, 1988b). Calculations based on the available analyses indicate that the smectite content of sericite does provide a reasonable estimate of temperature and that equilibria involving sericite controls the aqueous concentrations of sodium, potassium, and calcium.

GEOPHYSICAL TECHNIQUE DEVELOPMENT

Geophysical techniques are being developed in an integrated program at the Lawrence Berkeley Laboratory, the Lawrence Livermore National Laboratory and at the University of Utah Research Institute. Program focus for the majority of the effort is provided by the search for new methods of detecting permeability in the subsurface, primarily in fractures. One of the most promising areas of inquiry in permeability detection is the use of borehole geophysics for seismic and electrical surveys. Borehole-to-borehole and borehole-to-surface surveys increase the radius of investigation around a well substantially from that available through conventional well logging methods, and has the potential for detecting permeable zones in the walls of a borehole. Other geophysical methods being pursued include petrophysical and petrochemical measurements on rocks for the purpose of understanding the relationships between surface geophysical survey responses, well log responses and the rock properties. We are using data from the Cascades range in Oregon and Washington for this work. The potential uses of satellite remote sensing are also being investigated. Computer processing of digital imagery can often enhance imagery to bring out faults and fractures, lithology and hydrothermal alteration.

Borehole Geophysics

It is important to understand the difference between geophysical well logging and borehole geophysics. In well logging, the instruments are deployed in a single well in a tool or sonde, and the depth of investigation is usually limited to the first few meters from the wellbore. By contrast, borehole geophysics refers to those geophysical techniques where energy sources and sensors are deployed; (1) at wide spacing in a single borehole, (2) partly in one borehole and partly on the surface, or (3) partly in one borehole and partly in a second borehole. Thus, we speak of borehole-to-surface, surface-to-borehole and borehole-to-borehole surveys. The depth of investigation is generally much greater in borehole geophysical surveys than it is in well logging. Only one of the several borehole geophysical techniques, namely vertical seismic profiling (VSP), has been developed to any extent. The petroleum industry has funded relatively rapid development of VSP over the past several years. LBL has recently been working on applications of the technique to geothermal problems. Although, electrical techniques have been conceived for borehole use, few applications have been made to date.

Vertical Seismic Profiling. Laboratory and theoretical work have recently produced a model which relates apparent shear-wave anisotropy to the properties of a fracture and to the way in which energy is propagated across a fracture. The S-wave velocities for propagation perpendicular to and parallel to the fracture are functions of the spacing and the stiffness of the fracture(s). With this new model and an estimate of the fracture stiffness, one can estimate the bulk average fracture spacing by measuring the velocity anisotropy. LBL carried out a test in cooperation with GEO Operator to determine the applicability of this model at The Geysers in the fall of 1984 (Majer et al., 1988). Compressional-wave and shear-wave vibrators were used with a three-component geophone in a steam well. An S-wave velocity anisotropy of 11 percent was measured, and this anisotropy was consistent to first order with effects expected from the known dominant fracture set in the greenstone caprock overlying the dry steam production zone. Evidence of a decreased value of Poisson's ratio was also found as the production zone was approached, a phenomenon suggested in previous microearthquake studies and interpreted in terms of the increasing dry steam fraction in the pore spaces of the rocks.

Althou h the experiment must be considered to be a success, much work remains to be done in interpreting actual field data in terms of fracture properties. The method appears to be highly promising.

Electrical Borehole Geophysics. During the last several years, both UURI and LBL have been developing methods to model the various possible electrical geophysical methods for detection of fractures and permeable zones in and adjacent to a borehole. The purpose of these modelling studies is to determine which of the electrical methods might be best applied to the problem. Previous to this work, essentially no studies had been published on the problem. The DOE sponsored work has resulted in the evaluation of most of the electrical methods and the publication of about a dozen papers. We are essentially at the stage where we can design and build a field data acquisition system. Computer work at the present time is directed toward developing methods to interpret field results, and significant advances have been made in the past months.

Forward modeling of the cross-borehole resistivity, magnetometric resistivity, controlled source audiomagnetotelluric and time domain electromagnetic methods indicate that these techniques may be used successfully to determine subsurface conductivity structure. The resolution of each technique is dependent upon the transmitter-receiver configuration and the target geometry. Results from inversion algorithms applied to the resistivity method show promise for having the ability to determine accurately the conductivity and structure of subsurface features.

Petrophysical and Petrochemical Properties of Rocks

As a result of the coring projects in the Cascades, undertaken by DOE in cooperative agreement with GEO Operator, Thermal Power and California Energy over the past three years, we now have approximately 14,000 feet of core along with drilling and geophysical well log data from four holes. Precise temperature logs of the holes by Dr. Dave Blackwell of Southern Methodist University under DOE funding, have been instrumental in determining the thickness of the zone of cold water flushing, an important parameter in deciding how deep to drill to obtain heat flow and geothermal gradient data that are meaningful in terms of geothermal exploration. The basic result is that one should anticipate having to drill as deep as 3000 feet to get beneath the zone flushed with cold surface water. Current work on the core and the data base is directed at interpretation of the geophysical well logs and the surface geophysics in terms of the properties of the rocks actually encountered by drilling.

UURI has selected samples from each of the four DOE-sponsored holes and from a corehole at Medicine Lake, furnished for our use by Geysers Geothermal. We have been measuring petrophysical and petrochemical properties of these samples for comparison with geophysical data. To date, our measurements include electrical resistivity, induced polarization, cation exchange capacity, porosity, magnetic susceptibility and mineral composition with emphasis on hydrothermal minerals. We intend to supplement these data with measurements of thermal conductivity and mechanical strength, and to also collect data on the fabric of the rock. Our goal is to be able to interpret exploration data better in terms of the subsurface geology in this volcanic environment.

Satellite Remote Sensing

The use of satellite remote sensing in geothermal exploration and development has received very little attention to date. However, Landsat 4 and 5 Thematic Mapper data are available for a number of areas where the geothermal geology is known or under evaluation, providing an opportunity to evaluate the use of these relatively new satellites for geothermal work. UURI has obtained digital images for the Los Azufres, Mexico, and Coso, California geothermal areas, and is in the process of processing and interpreting these images. Processing includes the generation of false-color images representing any combination of three of the available seven channels of data from the Thematic Mapper, or of ratios of bands. The possible combination of images is large, and one of the items of research is how to create the best image for interpretation in terms of detection of fracturing and for hydrothermal alteration. We have progressed the most on the Los Azufres image. A great deal of detail is apparent from the image, including a synoptic overview of the faulting that controls the permeability in the geothermal system. The image also shows the presence of two or three large, circular volcanic features, with the known Los Azufres system in the center.

The nature of these features is not known for certain at the present time. They could be caldera features, or alternatively they could be the erosional expression of doming resulting from intrusion of magma in the subsurface. They appear to be old features compared to the dome on which Los Azufres sits. Proper interpretation of their nature may help understand the structure of Los Azufres better. In May or June, our Mexican colleagues are due to come to Salt Lake City to work with us on interpretation.

IMPACT ON COST OF POWER

The impact of Reservoir Confirmation research on the cost of power has been evaluated using the Geothermal Cost of Power Model IM-GEO version 3.02 (Meridian, 1988). The research discussed in this paper improves the success ratio of wells at the wildcat, confirmation, and production stages. By influencing this expensive steps in the geothermal development project, a small amount of research has a relatively large impact on final costs. The research also reduces the risk in estimating reservoir parameters. Specific examples for the multi-region weighted average case are that the fluid inclusion research could show a 7.4% cost reduction and a risk reduction of 17.4%. The borehole geophysics research could result in a 9% cost reduction and a 20% risk. Research on the state of stress in geothermal systems can be responsible for a 9% cost reduction and a 24.3% risk reduction. The impact of the research varies by region with the state of stress research varying between a 5.7% cost savings for an Imperial Valley flash system and 13.8% for a Cascades flash system.

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REDUCING LONG-TERM RESERVOIR PERFORMANCE UNCERTAINTY

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ABSTRACT

Reservoir performance is one of the key issues that have to be addressed before going ahead with the development of a geothermal field. In order to select the type and size of the power plant and design other surface installations, it is necessary to know the characteristics of the production wells and of the produced fluids, and to predict the changes over a 10-30 year period. This is not a straightforward task, as in most cases the calculations have to be made on the basis of data collected before significant fluid volumes have been extracted from the reservoir.

The paper describes the methodology used in predicting the long-term performance of hydrothermal systems, as well as DOE/GTD-sponsored research aimed at reducing the uncertainties associated with these predictions.

INTRODUCTION

One of the main objectives of the research and development activities supported by the DOE Geothermal Program is to contribute to the reduction of the cost of electricity generated from hydrothermal resources. As described by the Impacts of Geothermal Research Model (IM-GEO; Traeger et al., 1988) one of the four major cost components of a hydrothermal energy project is related to resource analysis, that is, the effort to find and define a resource.

Resource analysis includes the evaluation of the reservoir. This paper discusses the general approach for predicting reservoir behavior, and the research being done under the DOE Hydrothermal Research Program toward reducing long-term reservoir performance uncertainties. The work described is part of a coordinated research program carried out primarily by Idaho National Engineering Laboratory (INEL), Lawrence Berkeley Laboratory (LBL), Lawrence Livermore National Laboratory (LLNL), Stanford University, and University of Utah Research Institute (UURI).

BACKGROUND

In evaluating geothermal systems one has to keep in mind their complex and dynamic nature. Even in their natural state, before fluid production begins, these systems show continuous mass (fluids and chemical species) transport and (conductive and convective) heat transfer (Donaldson et al., 1983). Other important physical processes active in geothermal reservoirs include phase changes (boiling and condensation), dissolution and precipitation of minerals, and stress changes caused by pore-pressure changes. Most of these processes are coupled. For example, phase changes disturb chemical equilibria, often resulting in precipitation/dissolution of minerals that could then alter porosities and permeabilities of the reservoir rocks. This could in turn, affect the mass transport in the system (Bodvarsson et al., 1986).

Considering that each geothermal system tends to have individual characteristics, it is difficult, even dangerous, to apply a universal evaluation strategy. Because of the complexity of the systems and the coupling between different reservoir processes, one has to rely on modeling studies to be able to respond to questions such as:

(1) What is the generating potential of the system?
(2) How fast will the production wells decline?
(3) How will the average enthalpy and chemistry of the produced fluids change with time?
(4) What are the effects of injection on well production and long-term reservoir performance?
(5) Where should the production and injection wells be located in order to optimize the exploitation of the field?

These questions must be answered to establish whether the development of a given hydrothermal system will be economically attractive. During the discovery or exploratory phase of a project, questions about field performance can only be addressed with a significant degree of uncertainty, since very little reservoir and well performance data are available. Even later, during the acceptance stage of a project when extensive well testing occurs (Drenick, 1988), no exact answers can be given; generally there is still a lack of long-term (> 1 year) performance information. Thus, initially the reservoir engineer will tend to give conservative estimates that might later be revised as additional data become available.

Conservative estimates could make a project uneconomical or result in the selection of a small and less-efficient power plant. However, these constrained estimates could reduce the risk of constructing surface installations that eventually may become inefficient due to lack of fluid reserves, low well deliverabilities, or changes in fluid characteristics.

Under DOE's Geothermal Program, the methodology for evaluating hydrothermal systems is continuously improving. However, one has to remember that the reliability of long-term predictions of reservoir performance will have to be based on the availability of a sufficient volume of quality field data (i.e., the quality of the predictions will never exceed that of the data).

METHODOLOGY FOR EVALUATING HYDROTHERMAL SYSTEMS

The reservoir engineer addresses the problem of predicting the future behavior of a geothermal system by characterizing it through the analysis of all available information, by carrying out and interpreting well tests, and by performing simulation studies. A pivotal part of this approach is the development of a conceptual model representing the up-to-date knowledge of the system and its dynamics (Bodvarsson et al., 1986). The model should identify (1) the main recharge and discharge areas; (2) the lithology and geologic structures that control the movement of fluids in the subsurface; and (3) the most relevant processes active in the system and where they possibly occur.

After a plausible and coherent model of the system has been developed, it is necessary to choose a mathematical model that can realistically simulate and correctly compute the performance of the reservoir and wells. There are various methods to model these behaviors, applicable at different stages of a geothermal project; from simple curve-fitting techniques to complex distributed-parameter numerical models. The choice of method depends on the amount and type of data available, and on the specific issues the model is supposed to address (Bodvarsson et al., 1986).

The first step in the evaluation of a geothermal system is to model the natural state. Very valuable insight into the characteristics of the system can be learned from natural state modeling. For example, information can be gained on formation permeabilities, boundary conditions for fluid and mass flow, and the thermodynamic state of the fluids throughout the system. The initial simulation work must be based on the conceptual model developed earlier and should quantify (or constrain) some of the reservoir parameters. By modeling the natural state one will obtain a consistent set of initial and boundary conditions for the next step in evaluating a geothermal system, the exploitation modeling study (Bodvarsson et al., 1986.)

The prediction of long-term performance of a given field, that is, the estimation of its total generating capacity, well rate decline and changes in produced fluid characteristics, and the evaluation of alternative reservoir management plans, has to be based on an exploitation model. The model incorporates all relevant field information, such as reservoir properties (permeabilities and porosities), thermodynamic state of the system (distributions of pressure, temperature, phase saturation and chemical characteristics), and data on field exploitation history (transient flow rate, enthalpy, chemical characteristics and reservoir pressure). In many cases the available data set is incomplete (or of poor quality), requiring sensitivity studies of the most important parameters.

Various types of exploitation models exist with different capabilities for answering long-term performance questions. These are the lumped-parameter and the distributed-parameter models; the latter ones can either simulate a lumped wellfield or individual wells. Well-by-well models are more detailed, and can address most questions related to future reservoir and well performance, and evaluate different production/injection scenarios. If the geothermal system is very complex, a three-dimensional model may be required. The development of such models, especially the calibration against all available well data, could represent significant costs in manpower and computational expenses (Bodvarsson et al., 1986).

Independent of the sophistication of the available methods, one should always start with the simplest possible model that can explain the field data. The final complexity of the modeling effort should be determined by the performance issues that need to be resolved and by the quantity and quality of the available data (Bodvarsson et al., 1986).

The basic methodology to compute the future behavior of geothermal systems is presently available; the requirements for carrying out these predictive calculations and the general approach to follow are given in Table 1 and Figure 1. What are generally missing are long-term production data that can be used to (1) confirm the conceptual, natural state and exploitation models developed for different fields, and (2) validate the methodology used to evaluate their long-term performance under production. It is clear that there is a need for field-case studies documenting the experience gained at different geothermal areas. However, one should remember that many geothermal fields have been under development for less than 10 years and the data are not generally in the public domain.

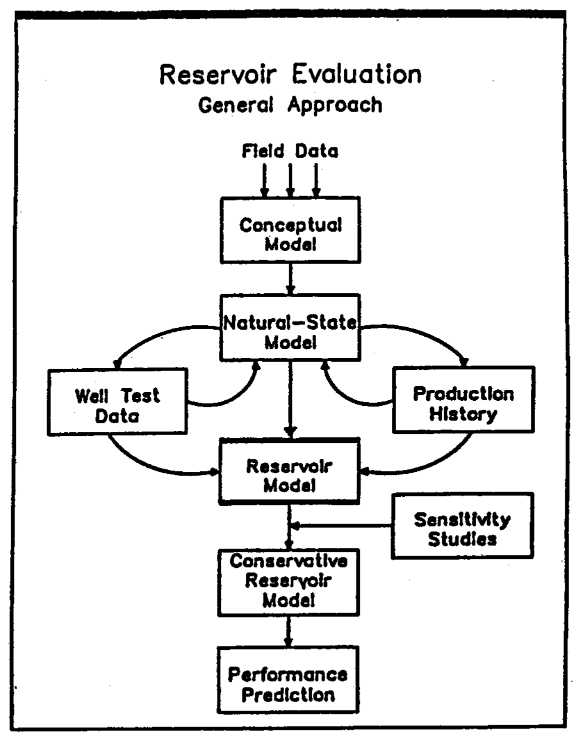

Figure 1. General approach to geothermal reservoir evaluation (from Bodvarsson, 1987)

TABLE 1

STEPS FOR PREDICTING THE LONG-TERM PERFORMANCE OF HYDROTHERMAL SYSTEMS

DATA COLLECTION

- Use available (or develop new/improved) tools, instrumentation and methodologies to collect geological, geophysical, geochemical and reservoir engineering data, before and after fluid production begins
- Carry out theoretical studies and laboratory experiments to identify fundamental reservoir processes and parameters

ANALYSIS AND INTERPRETATION OF AVAILABLE DATA

- Use available (or develop new/improved) methodologies to analyze and interpret field and laboratory data
- Determine rock and fluid properties
- Establish the distribution of pressure, temperature, chemical species and thermodynamic conditions in the system, and their changes with time
- Locate and characterize reservoir boundaries
- Evaluate well production/injection characteristics and their changes with time
- Identify the most important reservoir processes, before and after field exploitation began
- Develop a conceptual model of the system

MODELING RESERVOIR BEHAVIOR

- Apply available (or develop new/improved) modeling techniques to create a natural state model of the system
- Apply available (or develop new/improved) modeling techniques to create an exploitation model of the system
- Carry out sensitivity studies on important reservoir parameters
- Evaluate different reservoir management strategies to optimize long-term field performance.
- (Develop and document field case history to validate methodologies and models used to study and evaluate hydrothermal systems.)

THE DOE HYDROTHERMAL RESEARCH PROGRAM

Over the recent years, under DOE sponsorship, significant advances have been made in understanding reservoir processes/phenomena, and in the areas of well testing (methods, tools, and data analysis) and modeling techniques to simulate the flow of heat, fluids and chemical species in porous and/or fractured reservoirs. However, there is still a lack of quantitative information on important processes and parameters that control the flow of steam-water mixtures in fractured and porous reservoirs (e.g., relative permeability curves). Still to be clarified is the temporal relation between tracer (chemical) and thermal breakthroughs, taking into consideration the complexity of the fractured/porous network in the reservoir. Uncertainties exist in some important aspects of reservoir dynamics, especially with regard to chemically and mechanically coupled processes, and fluid and heat flow processes in the deeper zones of geothermal systems. There is also a need for field case studies documenting the validity of long-term reservoir performance predictions that may require the re-evaluation of the original assumptions made to reach these predictions.

The field, laboratory and theoretical activities (listed below) being carried out under the Hydrothermal Research Program are contributing to the reduction of uncertainties in establishing the long-term performance of geothermal systems. This research is intended to (1) increase the availability and quality of field data, (2) improve the data analysis and modeling techniques, and (3) add to our understanding of reservoir processes, important elements for predicting reservoir performance. A significant part of this work is sponsored by joint DOE/industry projects.

Recent and ongoing activities under the Hydrothermal Research Program

Based on the recognition of the importance of field case studies (see above), a significant effort of DOE's Hydrothermal Research Program has been directed towards field projects, a number of them in cooperation with industry.

Geologic and geochemical methods to analyze and interpret data from cuttings, cores and fluid samples have been developed and applied to a number of geothermal areas to establish the properties of these systems and prevailing conditions (e.g., Stallard et al., 1987; Moore and Adams, 1988; Nielson and Wright, 1988).

State-of-the-art geophysical techniques to determine geologic structures and the characteristics of fractures in the reservoir have been developed and applied to several geothermal areas (e.g., Salton Sea, East Mesa and The Geysers, California). They are discussed in detail by Zhou et al. (1987), Kasameyer (1988), Nielson and Wright (1988) and Goldstein (1988).

New well testing techniques, including tracer tests and tracer compounds, and their application to different geothermal areas (such as Los Azufres, Mexico), are discussed by Adams et al. (1986) and Horne (1988).

The development of a new interpretation method for injection test data has allowed determination of the increase in near-bore permeabilities in Los Azufres wells, which are completed in fractured volcanic rocks (Benson et al., 1987). Under the existing DOE/CFE agreement on geothermal energy, additional information is being obtained and analyzed to identify the process causing permeability enhancement that results from cold water injection (possibly thermal contraction and fracturing of the rock mass bounding the natural fractures).

The construction of an improved version of the LBL downhole sampler (Solbau et al., 1987) has been completed. The new tool can capture a 2-liter fluid sample at bottomhole temperatures of up to 350°C.

Models have been developed to (a) simulate the behavior of wells fed by more than one producing zone (Bjornsson and Bodvarsson, 1987; Ripperda and Bodvarsson, 1988); (b) analyze wellbore heat transmission in layered reservoirs (Wu and Pruess, 1988); (c) consider the effects of non-condensible gases and gravity on reservoir performance (Gaulke and Bodvarsson, 1987; Bodvarsson et al., 1988; McKibbin and Pruess, 1988); (d) study temperature regimes near the critical point of water (Cox et al., 1988); and (e) evaluate the response of fractured geothermal systems (Pruess and Wu, 1988; Renner, 1988). The new and existing modeling capabilities have allowed the study of the relative importance of given reservoir processes (e.g., boiling/condensation, compositional effects, deep recharge), the heat and mass transfer in wellbores, and the effects of fractures on reservoir performance.

Laboratory studies of heat and mass transfer in fractured hydrothermal reservoirs have been carried out at INEL (Renner, 1988), Stanford (Horne, 1988) and are underway at LBL. The purpose of LBL's studies is to determine the relative permeability curves for steam-liquid water mixtures in fractures with rough surfaces.

The multidisciplinary studies of the Cerro Prieto and Los Azufres fields in Mexico continues under the DOE/CFE agreement. The results of the 1986-1989 activities will be presented during a conference planned for April 1989. The Salton Sea Scientific Drilling Program is still active (DOE, 1988); a well test is being planned for the near future.

The study of the geology and geochemistry of the Valles caldera, New Mexico, continues. The DOE-sponsored work is focused toward the hydrothermal alteration and the fracture characteristics in the hydrothermal system (e.g. Hulen et al., 1987). DOE and Oxbow Geothermal are planning a tracer test in Dixie Valley, Nevada, to determine the characteristics of the subsurface fracture network.

The ongoing study of hydrothermal alteration and fluid inclusions in the Coso, California, system is part of a DOE/UURI/California Energy Co. project (Echols et al., 1986). GEO and DOE/LBL have recently completed a self-potential survey of East Mesa, California, in a repeat of a 1978 survey. Under a similar cooperative effort, preliminary plans for a series of well and tracer tests have been developed.

A long-term geochemical fluid sampling program is underway at Heber, California, as part of a DOE/UURI/Chevron project. At The Geysers, California, DOE/LBL, Unocal and Geysers Geothermal Co. have just began cooperating on high-frequency seismic monitoring of fluid injection; this became the first project funded by the recently-created Geothermal Technology Organization.

SUMMARY

The above-mentioned geothermal areas are just some in which data are being gathered to test and validate the instrumentation and methodology developed as part of DOE's Program. Independent of formal joint projects, the DOE-sponsored groups continue to collect and analyze information from different hydrothermal fields. The exchange of data is usually done on a personal basis between researchers having common research interests. Long term performance data have been gathered on several fields abroad, including Wairakei, New Zealand; Lardarello, Italy; Cerro Prieto and Los Azufres, Mexico; and Krafla and Svartsengi, Iceland. Additional, but shorter, open-file case histories are becoming available on many foreign and some U.S. fields.

The theoretical and laboratory work, as well as the experience gained in collecting and analyzing field case study data, are helping to determine the important processes active in hydrothermal systems, and to validate simulation models that can now be used with increasing confidence to predict long-term reservoir performances.

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Understanding Geothermal Reservoir Dynamics

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ABSTRACT

Tracer experiments and well testing in geothermal reservoirs emphasize the very great influence of fractures on variability of fluid movement through geothermal rocks. This variability extends from the ten meter to the kilometer length scale. Tracer returns have been observed at some locations within hours at distances of up to one kilometer from the injection point, while other much nearer locations in the same formation do not observe the tracer until much later. In addition, transport rates have sometimes been extremely fast (up to 100 m/hr) even over such distances.

This paper discusses the implications of observations from tracer tests and well tests in fractured reservoirs. It is evident in some cases that large scale geological features, such as faults, are responsible for the variations in response. Based on these results, there seems no reasonable way of forecasting transport rates in fractured systems without performing a tracer test.

The various Department of Energy programs in geothermal reservoir technology are addressing the analysis of the problem from several different directions. The Stanford Geothermal Program is focussing on the interpretation of tracer tests and well test analysis of fractured reservoirs. The University of Utah Research Institute is seeking more definitive tracers for this purpose. The Lawrence Berkeley Laboratory program approach to understanding reservoir dynamics includes careful consideration of non-isothermal effects in the wellbore during an injection test.

INTRODUCTION

That the porosity and permeability of geothermal reservoir rocks exist mainly in the fractures has been known for many years. Measurements of the permeabilities of cores recovered from geothermal wells are extremely low (of order 10^{-17} m^2), and are not characteristic of permeabilities inferred from well tests (which can be as large as 10^{-13} m^2). Porosities of cores are similarly low. Thus it has been concluded that, although fluid may be stored within the rock matrix, it is mobile primarily through the fractures only (at least within the time scale of interest to geothermal developers).

In spite of this knowledge, it was originally assumed that the degree of heterogeneity represented by the fractures was such that on the scale of an entire reservoir (which might cover tens of square kilometers) the flow would be as if through a porous medium. Calculations of heat and fluid recovery were traditionally made on this basis in the 1960's and early 1970's.

The recognition of the importance of the fractures coincided with the evolution of interest in reinjection. Until 1972, the waste hot water from geothermal power developments was disposed of to surface waters or ponds. Since the water was in very large quantities (thousands of tonnes per hour) and contained toxic substances (Axtmann, [1]), surface disposal presented environmental difficulties. In addition, the loss of fluid from the reservoirs resulted in substantial drawdown of pressures, and there was concern that fluid reserves would be depleted far in advance of the recovery of the usable heat still contained in the rock. For these two reasons, reinjection was suggested as means to prolong the useful life of the resource as well as a means to avoid the release of contaminants into the environment.

In early work involved in the design of a reinjection scheme for the Ahuachapan geothermal field in El Salvador, two significant new insights into geothermal development were obtained. A tracer test, using tritium, demonstrated that flow in the reservoir was highly heterogeneous (Einarsson et al., [2]). Tracer was recovered in a producing well 400m distant from the injection well within 48 hours, while two similar wells did not receive any tracer until several months later (one well was 500m distant from the injector, and the other was 1000m). Based on these observations, Bodvarsson [3] made calculations on the "safe distance" between injectors and producers such that there would be no premature breakthrough of unheated injection water back into the production wells. Bodvarsson [3] used a model of flow in a fracture to conclude that a "safe distance" could be anywhere from 700m to 4500m, depending on the degree of fracturing in that particular direction. Thus it had been determined that; (1) fractures caused heterogeneities in flow over scales as large as one kilometer, and (2) tracer tests were very useful in determining where these heterogeneities lie.

The work described by Einarsson et al [2] and Bodvarsson [3] involved only three wells at Ahuachapan, and since large scale reinjection into geothermal reservoirs only became widespread in the early 1980's, the full significance of their observations as to the fractured nature of geothermal reservoirs did become evident until several years later. Due to the channeling of reinjected water through relatively small volumes of rock, unheated water was being returned to production wells in several different geothermal fields. The resulting loss of productivity became a serious concern to geothermal developers, who began to take pains to overcome the problem and avoid it in subsequent developments (Horne, [4]).

Since the late 1970's, a large number of tracer tests have been reported for both existing and newly developed geothermal reservoirs. Collectively, these tracer tests confirm the original observations of Einarsson et al [2], and have shown that fractures in the volcanic rocks (and some cases sedimentary ones too) can be very major conduits for flow, and are different within reservoirs as well as between one reservoir and another. It has been seen that water can flow for distances as far as one kilometer at speeds of up to 100 m/hr. This has created significant uncertainty in the process of field development, and has given birth to major research efforts in several countries. This paper summarizes the implications of the geothermal experience and the research into forecasting that has resulted from it.

The first part of the paper describes the effects of individual fractures crossing a wellbore, while the second illustrates the effects of fieldwide heterogeneity on tracer returns. The consequence of the effects of the preferential flows are discussed in the third section.

Fractures Intersecting Wells

The spacing between fractures within a geothermal reservoir is highly variable. However since very large amounts of flow are required to develop a geothermal well economically, usually attention only focuses on the largest fractures. Large fractures intersecting the wellbore are commonly also known as "feed zones". When it comes to assessing feed zones, all (commercial) geothermal wells have at least one, and most have several more, over their productive length (which can vary from 300 m to 2000 m). Thus in terms of typical separations between major productive fractures, it is not an unreasonable generalization to say that they lie hundreds of meters apart, at least in the vertical sense.

It is another feature of active geothermal reservoirs (at least those of the liquid dominated type) that the fluids are in upward motion due to natural convection over the heat source. As a consequence of this, the pressure gradient in the reservoir as a function of depth is almost always greater than hydrostatic (typically by about 10%). This gives rise to an imbalance of pressures when the reservoir is penetrated by an open wellbore, which obviously can only support a hydrostatic pressure gradient if the fluid in the wellbore is stationary. It is therefore very common for geothermal wells to flow internally, usually upwards, from one feed zone to another, even when the well is closed at the surface.

These internal flows are a considerable nuisance when trying to make measurements of reservoir pressure and temperature, since they mean that the well pressure is not the same as the reservoir pressure (except if there is only one feed zone, and even then only at that one location). The temperature of the fluid in the well is also not the same as that in the formation, since over the flowing section of the well the temperature will be constant (over the interval between the inflow and outflow points) and equal to the temperature of the inflowing water from only one feed zone (see Figure 1). At best, the reservoir pressure and temperature can only be determined at a single depth, namely

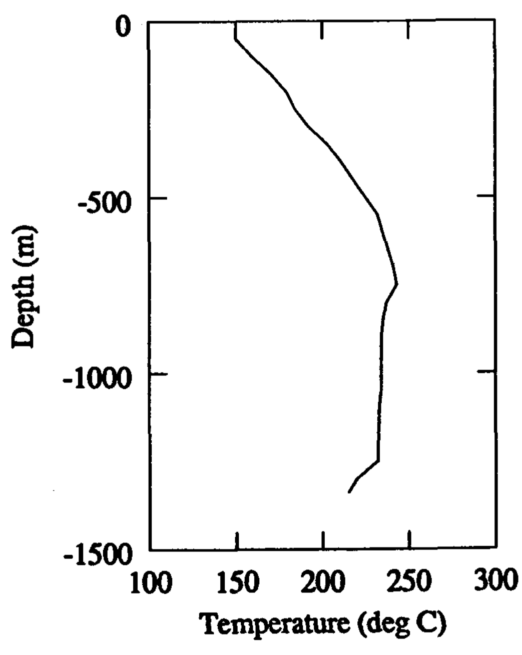

Figure 1. Temperature profile for well M-9, Cerro Prieto, Mexico

that of the principal feed zone.

In spite of the fact that fluids produce into the wellbore at only isolated points, many standard well testing interpretation techniques can be and are commonly applied to geothermal well tests. Many of these methods are based on a model of pressure transients in an isotropic, homogeneous porous medium. Although it is also common to see pressure transient responses characteristic of fractures (Ramey and Gringarten, [5]), and sometimes double porosity behavior (Deruyck et al, [6]), at least half of geothermal well tests show uniform porous medium, radial flow response. This may lure us into the belief that fractures are so multiply connected out in the reservoir that pressure is transmitted more or less radially beyond a certain distance. This belief is further strengthened by observations from interference tests from one well to another, in which standard radial flow solutions are validly applied even more commonly.

That major heterogeneities are not evident in pressure transient tests is due to the diffusive nature of pressure transmission through permeable rocks. Sageev and Horne [7] demonstrated that even a large impermeable body with a radius ten times its distance from a producing well will affect the pressure interference at a well a similar distance from the opposite side of the obstruction by only an imperceptible amount. Thus although pressure transient tests can be interpreted correctly to provide estimates of the permeability averaged over a large volume of the reservoir, the fracture permeability can be missed in a single interference test, even though the fractures may extend very large distances. It is only in the analysis of multiple interference tests that large scale fracture zones become evident. Even though the tests themselves may show classical radial flow responses, the permeabilities between well pairs can be radically different. Two examples of this have been published. The first was for the Beowawe geothermal reservoir in Nevada by Epperson [8], in which strong interference was observed along the Malpais fault but lesser effect perpendicular to it. The second example (Hoang et al, [9]) shows this more clearly for the Heber geothermal field in Southern California, in which a map of permeabilities inferred from well tests clearly shows high values along two fault zones. This second example is of additional interest since the Heber geothermal reservoir lies in a sequence of sandstones and shales, unlike most geothermal reservoirs which are in volcanic rocks. Until development began, it was assumed that the Imperial Valley reservoirs would behave much more uniformly than their counterparts in volcanic zones. More recently it has become evident that fractures and fracture zones play an important part in the performance of these sedimentary reservoirs too.

The paradoxical behavior of flow systems that seem relatively uniform in pressure transient tests but which experience rapid and major breakthrough of injected material through fractures is due to the fundamental difference between two mechanisms. Well tests monitor the transmission of pressure pulses through the reservoir, whereas fluid breakthrough arises due physical transport of the fluid mass. Pressure transients are a diffusive phenomenon and obey the diffusion equation (slightly compressible pressure transmission equation). Fluid flow, on the other hand, is a convective phenomenon, and obeys the convection equation. Thus we expect measurements of the mass flow to expose much more detailed effects of the transport process. This expectation has been borne out in the tracer test observations described in the next section.

Fractures Between Wells

The pressure transients measured in a well test are transmitted through all of the connected fluid in the reservoir, whether the fluid is moving or stationary. A tracer test, on the other hand, monitors only that portion of the fluid that is actually moving between the point at which the tracer is injected and the points at which it is being recovered. Fluid that is immobile, or which is moving towards a location which is not being monitored, is invisible to the tracer test. However from the point of view of reinjection design, it is most useful to determine where the the injected fluid is going with reference to the existing production wells. That portion of the traced fluid that does not return to the production wells is of lesser significance since it holds little concern of premature thermal breakthrough. For this reason, well-to-well tracer tests have been much more common than the injection-backflow kind of tracer test used in groundwater applications to estimate regional flows.

Discussed here are some typical responses of geothermal tracer tests in fractured geothermal reservoirs, based on results from El Salvador (Aumento et al, [10], Cuellar et al, [11], Einarsson et al, [2]), Japan (Horne, [12], Inoue and Shimada, [13], Ito et al, [14] and [15]), Iceland (Gudmunsson et al, [16]), the Philippines (Dobbie and Menzies, [17], Sarit, [18], PNOC, [19]), and New Zealand, (McCabe, Barry, and Manning, [20]). Extensive tracer testing has also been carried out in the vapor-dominated geothermal system at the Geysers, California (Gulati et al, [21]) although published details are not as complete as those from other fields.

In general, the results of these tracer tests emphasize the strongly heterogeneous flow paths created by fractures - usually coincident with faults. Figure 2 from McCabe, Barry and Manning [20] shows this particularly clearly for the set of tracer tests performed at Wairakei geothermal field in New Zealand. Figure 3 shows a tracer response characteristic of those at Wairakei (and most other geothermal fields). There is a single, sharply defined peak, suggesting only a single major flow path. Notice also the very rapid arrival time. Table 1 summarizes the responses of these various tests with respect to first tracer arrival, peak tracer arrival, peak tracer concentration, fraction of tracer recovered and horizontal and vertical separation between injection and production points. Lovekin and Horne [22] used these results to optimize the hypothetical reinjection scheme using these wells. It was found that the optimum combination of injectors and producers selected was almost the same based on any of the tracer return parameters. On the other hand, using horizontal separation alone

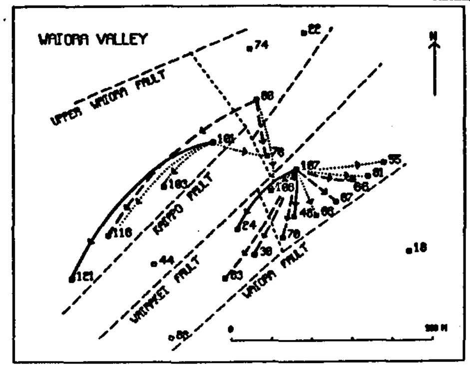

Figure 2. Wairakei tracer return map (from McCabe, Barry and Manning [20])

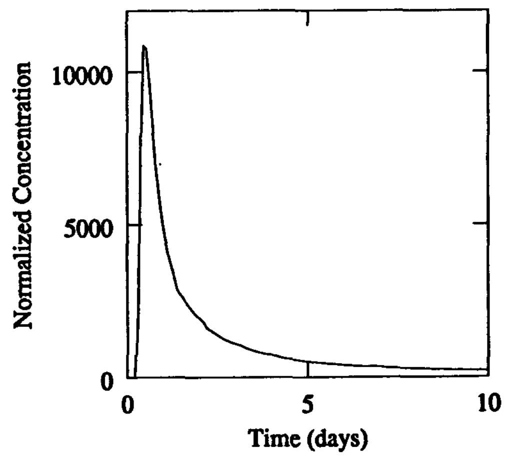

Figure 3. Typical tracer response at Wairakei (from McCabe, Barry and Manning [20])

	1st arrival	Peak arrival	Peak concentration	Fractional recovery	Horizontal distance	Vertical distance
WK80→76	4.0	8.7	88	0.0024	142	+119
80→108	5.5	10.0	16	0.0006	229	-33
80→116	3.3	7.6	230	0.0040	499	+97
WK101→76	2.5	7.0	10	0.0005	139	+114
101→103	2.0	5.0	30	0.0009	168	+140
101→116	2.5	7.5	23	0.0005	350	+92
101→121	1.2	2.5	10,500	0.0580	489	+585
WK107→24	0.2	0.4	10,000	0.0373	209	+389
107→30	4.5	9.0	55	0.0028	238	+236
107→48	0.3	0.7	2360	0.0133	117	+617
107→55	5.5	15.7	29	0.0018	216	+290
107→67	2.2	15.3	46	0.0032	126	+248
107→68	4.0	15.0	39	0.0007	124	+214
107→70	4.0	9.5	43	0.0025	174	+182
107→81	4.8	9.5	21	0.0009	178	+270
107→83	4.5	11.0	53	0.0034	326	+167
107→108	10.0	23.0	17	0.0001	84	-7

Table 1: Summary of Wairakei tracer results

(without including tracer test results) gave an entirely different design which failed to avoid combinations of wells in which breakthrough of injected water had been rapid. This simple observation emphasizes our appreciation of the fact that the reservoir is not areally homogeneous.

Interestingly, Lovekin and Horne [22] found that using the vertical separation between injection and production points *did* give rise to the same optimum selection of wells as did the use of the tracer test results. Table 2 shows why this was so; all of the tracer test parameters characteristic of strong and rapid tracer breakthrough (early arrival, high concentration, large fractional recovery, and early peak arrival) are well correlated with each other and with the vertical distance between wells. The correlations are negative for arrival times; this would imply that arrival time is small if the distance is large, which is counter-intuitive. However, since the correlation coefficients are not large, this means only that the first arrival and peak arrival are largely independent of vertical distance. On the other hand, there is a much stronger correlation between the fraction recovered and the vertical distance, suggesting that the fluid is generally moving downward, presumably due to negative buoyancy of the heavier, cooler water.

	First arrival	Peak arrival	Peak concentration	Fraction recovered	Horizontal distance	Vertical distance
1st arrival	1.0000	0.8533	-0.5272	-0.5156	-0.2336	-0.6546
Peak arrival		1.0000	-0.5753	-0.5573	-0.3448	-0.5746
Peak conc			1.0000	0.9760	0.3624	0.6686
Fraction recov				1.0000	0.4519	0.7117
Horiz dist					1.0000	0.1397
Vert dist						1.0000

Table 2: Correlation matrix for Wairakei tracer results

Notice in Table 2 that the horizontal separation is uncorrelated with any other parameter - the tracer return results are completely independent of areal separation of the wells. This result is even more significant than the correlation table shows, since the table only includes wells for which tracer actually broke through in measurable quantities. Thus there are several other monitored wells within similar distances for which there was no tracer recovered. Thus the tracer returns are even less dependent on separation than is evident in the table.

Even though the tracer returns are independent of distance, they are not independent of location. Figure 2 shows that there is a distinct correlation between the fault locations and the strong returns. The seemingly paradoxical behavior along the Kaiapo fault in which the largest return (indicated by the solid arrow line) is over the largest distance is explained by the fact that well 121 is the deepest. McCabe et al [20] explain the high recoveries in wells 24 and 48 (both of which are deep) as a flow down the Wairakei fault and back up the Waiora fault, postulating that the faults intersect at depth.

Another aspect of the fracture flow was evident in a series of tracer tests conducted in the Tongonan geothermal field in the Philippines (Figure 4). In June 1981, I^{131} injected into well 4R1 was recovered at wells 404, 401, 108. A total of 16.29% of the injected tracer was recovered (compared to a maximum of only 6% in any of the Wairakei tests described above) with 11.45% being recovered in well 404 alone. 2.84% was recovered in well 401, and about 2% in well 108 (PNOC, [19]). The arrival times indicate a minimum tracer speed of 57 m/hr for well 404, 30 m/hr for well 401 and 22/m/hr for well 108. The tracer responses at Tongonan differed from those at Wairakei in that each return was characterized by two or more peaks, whereas all but one of

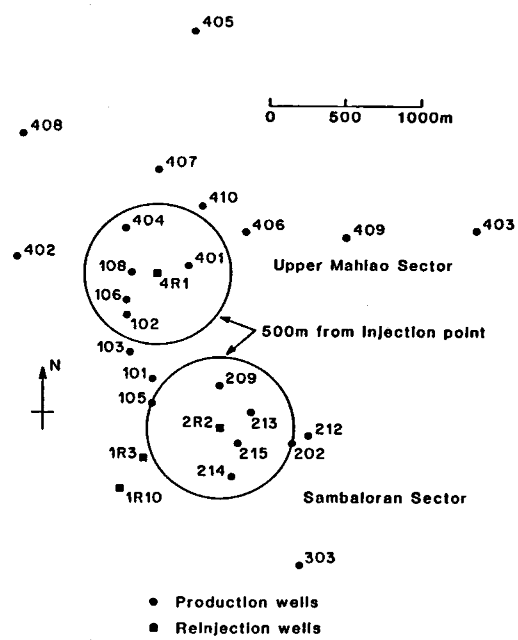

Figure 4. Well location map of Tongonan geothermal field, the Philippines

the Wairakei returns showed only one peak.

Tracer tests at another well at Tongonan, well 2R2, emphasize this two path effect. Unlike the Wairakei tests, in which the tracer was injected at a single point, the Tongonan tests were performed by releasing the tracer downhole using a wireline sampling bottle. In March 1981, I^{131} was released in well 2R2 at the depth of its upper feed zone (400m). In June 1981, a second test was conducted in which tracer was released into the lower feed zone at 1300m depth. In the March test (upper feed zone), positive returns were measured at well 213 with a peak arrival at 19 hours and a recovery of 0.34%. In the June test (lower feed zone), much more of the tracer was recovered (1.68%) at well 213, but the first concentration peak did not arrive until 4.4 days. These results emphasize the individual behavior of single fractures intersecting the wellbore, and demonstrate that the flow paths are not necessarily connected out in the reservoir (although the surface locations of wells 2R2 and 213 are only about 200m apart). The injection rate into well 2R2 was constant at 200 tonnes/hr (Sarit, [18]).

There are other examples of results similar to those described in these two geothermal fields. Many of these are available in the open literature, although many are still confined to proprietary company files and reports. The selection of these two examples is not intended to be comprehensive, but simply to point out some of the salient aspects of the problem.

TRACER INTERPRETATION WORK AT STANFORD UNIVERSITY

Based on the observations described in the two previous sections, we are able to formulate a conceptual model of the way in which injected fluid (and perhaps naturally occuring fluid, too) flows through fractured geothermal reservoirs. The fractures clearly provide the major conduits for flow, both at the scale of a single wellbore as well as that of the entire reservoir. Fluids move along planar fault zones, and are frequently constrained to flow in straight paths from one side of the reservoir to the other. Thus we can postulate that the tracer responses should be characteristic of linear flow in a planar fracture.

There are several different models available to describe the linear flow of a dissolved substance in a fracture. Horne and Rodriguez [23] demonstrated that Taylor Dispersion was likely to be the dominant dispersive mechanism in the fracture itself, and derived an extension of Taylor's dispersion coefficient (Taylor, [24]) to include the linear planar flow configuration. This model was then used to model the tracer return profiles from the Wairakei tests by Fossum and Horne [25]. Although the profiles could be matched, matching was possible only by considering two separate paths with their corresponding responses superimposed upon each other. This was an unsatisfying result since it did not correspond to the basic concept. The inclusion of a second path was required in order to match the characteristic long "tail" in the return profile (see Figure 3, for example). One of the possible explanations for this delay in arrival of the trailing edge of the tracer spike is diffusion (Neretnieks, [26]). Jensen and Horne [27] used the "matrix diffusion" model of Neretnieks et al [18] to provide a response with a longer tail than the pure convection-dispersion model, and were able to match most of the Wairakei returns with only a single path. Figure 5 and 6 compare the matches of Fossum and Horne [25] and Jensen and Horne [27] to one of the Wairakei tests.

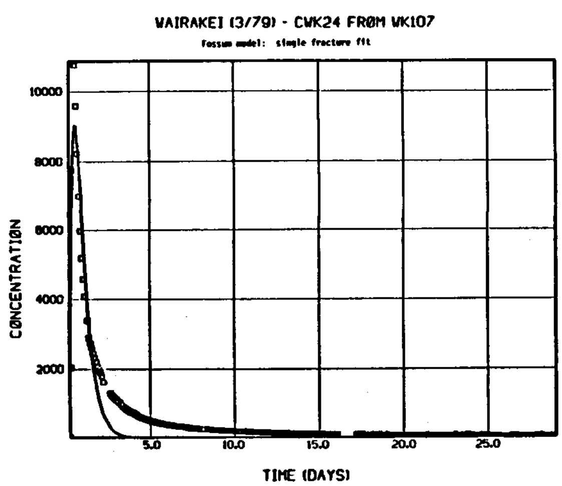

Figure 5. Single path match of convection-dispersion model to WK24 tracer response, from Fossum and Horne [25].

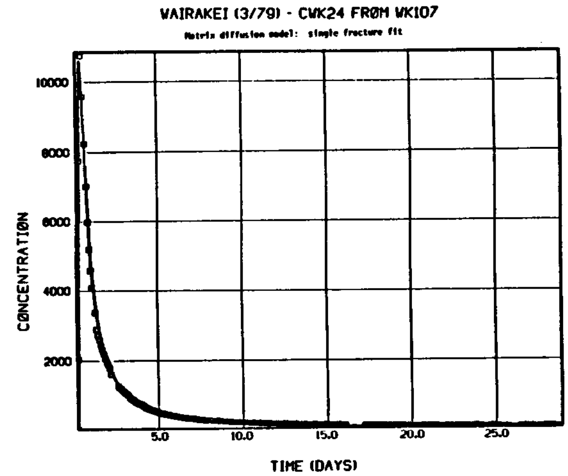

Figure 6. Single path match of matrix-diffusion model to WK24 tracer response, from Jensen and Horne [27].

Thus the high speed transport of geothermal water containing tracers appears to follow the same model as that of Neretnieks et al [28] which was derived for transport of radionuleides through fractured rocks at very much slower rates. This demonstrates that one of the principle mechanisms governing the transport of the tracer is physical loss of the tracer out of the fracture flow stream. The precise mechanism of this loss term is still unclear. It could be due to adsorption, chemical reaction, diffusion into the rock matrix around the fracture, diffusion into stationary fluid in other fractures, degradation of the tracer or ion exchange. All of these mechanisms are capable of giving rise to similar terms in the differential equations governing the model. Using a laboratory core with a fracture created along its axis, Johns [29] found that more tracer was retained in the core than flowed through. Research to pinpoint the site and mechanism of the holdup is ongoing.

TRACER DESIGN WORK AT UURI

As described above, siting injection wells is a crucial aspect of field development. Many injection wells are converted production wells that failed to produce enough fluids. Since such injection wells are located in or near production zones, they may provide inflow of cold fluids into producing wells. Chemical tracers can be used to detect breakthrough of injected fluids into production wells and thereby help predict thermal breakthrough in advance. For this reason, UURI has been working on development of new chemical tracers for the geothermal environment.

UURI has tested 40 derivatives of benzoic and sulfonic acid in autoclaves to simulate the geothermal environment. The derivatives tested were aromatic hydrocarbons with moieties of trifluoromethyls, sulfonates, methyls, fluorides, or carboxyls. They are potential liquid-phase tracers. The tests consisted of heating the compounds in distilled water or in geothermal water under nitrogen or oxygen atmospheres at temperatures ranging from 125 deg C to 300 deg C. At 200 deg C, 32 of the 39 tracers survived for one week; at 250 deg C, 15 survived; and at 300 deg C, 5 survived. The most stable compounds were the sulfonates, methylates, and carboxylates. These results show that some derivatized hydrocarbons are potentially suitable as tracers.

UURI has also tested the commonly used tracer dye fluorescein, and have obtained good kinetic data for its decay in distilled water and geothermal fluid. Our data predicts that fluorescein will have a half-life of about two years at 200 deg C, but will have a half-life of only 20 days at 250 deg C. Thus, tracer tests using fluorescein need to take these data into account. UURI has also developed a new method for analysis of fluorescein that increases the sensitivity by a factor of 100 over previously available methods.

UURI will shortly begin field tests of the tracers species identified as being potentially most useful for geothermal work. The sulfonates will be tested first in an injection- backflow test of a the Pleasant Bayou geopressured well in April. Later this year, probably in August, tests at the Dixie Valley site will be conducted in cooperation with Oxbow Geothermal.

INJECTION ANALYSIS WORK AT LAWRENCE BERKELEY LABORATORY

Injecting cold water is a common technique for estimating the permeability, productivity, and injectivity of geothermal wells. In addition to providing a measure of these parameters, there is some evidence that this practice stimulates the well (Bodvarsson et al. [30]). This is contrary to the predictions of physical and mathematical models that consider only the temperature dependent fluid properties (Benson, [31]; Benson and Bodvarsson, [32]).

This intriguing phenomena is particularly apparent in geothermal wells in the Los Azufres Geothermal Field in Mexico, where a large set of pressure transient data exhibit unusual characteristics. As shown by pressure buildup curves for three wells in Figure 7, it is not uncommon to observe that after an initial period during which the pressure increases as expected, the pressure stabilizes and then begins to drop, even though injection continues at a steady rate. This unusual behavior is attributed to progressive increases in the near-bore permeability. Several physical mechanisms can increase the near-bore permeability, including; hydraulic fracturing, pushing drilling mud and formation fines away from the well-bore and into the formation, thermal contraction and thermal stress cracking of the rock, and dissolution of fracture filling minerals. As these tests were conducted well below the fracture gradient, hydraulic fracturing has been eliminated as a possible cause for the permeability increase, leaving one or more of the other mechanisms to account for the observed behavior. The goal of this investigation is two-fold. First we attempt to quantify the magnitude of the permeability increase needed to explain the observed pressure behavior. Next, we investigate correlations between temperature and the permeability increase in an effort to provide insight into the physical mechanism governing this occurrence.

To circumvent the restrictive assumptions required for applying conventional analytical methods to this problem we haved developed an approximate solution for calculating the pressure buildup during injection. The solution is in the form

$$\Delta p(r_w,t) = \Delta p_{ss}(r_w,t) + \Delta p_t(r_f,t)$$

where $\Delta p(r_w,t)$ is the pressure change at the injection well, $\Delta p_{ss}(r_w,t)$ is the steady-state pressure change across the invaded region at time t, and $\Delta p_t(r_f,t)$ is the transient pressure response in the uninvaded formation. The mathematical advantages of this form of the solution are two-fold. First, all of the non-linear terms associated with the region behind the front are incorporated into the first term of the equation, which for a slightly-compressible single component fluid flowing through a radially symmetric system is calculated by

$$\Delta p_{ss}(t) = \frac{q}{2\pi h} \int_{r_w}^{r_f(t)} \frac{\mu(r,t)}{k(r,t)\,\rho(r,t)} \frac{dr}{r}$$

where q is the mass injection rate and the other terms are defined as before. Second, the term $\Delta p_t(r_f,t)$ can easily be evaluated from well established solutions such as the exponential integral solution, convolution of the instantaneous line source solution for variable flow rates, or any one of a number of relevant solutions that satisfy the desired outer boundary conditions.

The Los Azufres geothermal system occurs in fractured volcanic deposits, at a depth of 1000 to 2000 m. Reservoir temperatures range from 220 to 280 degC in the wells from which injection test data are available. Geothermal fluids are produced from fractured horizons within andesitic rocks. The injection tests consisted of injecting 20 degC water into the formation at a constant wellhead injection rate for 2 to 3 hours. During injection, the formation pressure was measured with an Amerada pressure gauge positioned adjacent to the production zone in the well.

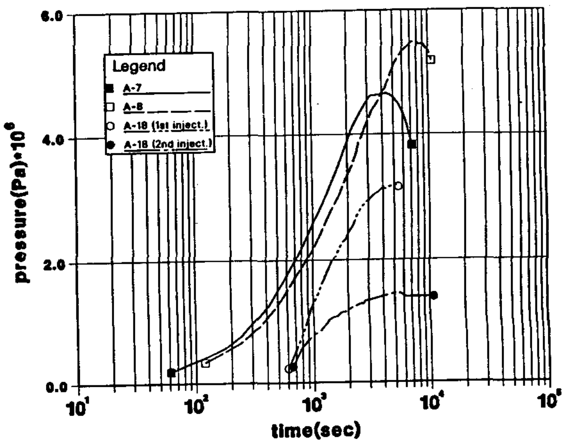

Figure 7. Pressure buildup curves from three wells at Los Azufres

Log(pressure) vs. log(time) graphs (not shown here) of the pressure buildup data shown in Figure 7 indicate that wellbore storage effects persist throughout the entire 2 to 3 hour test. Another factor that must be considered is that although the temperature of the injected water is constant at the wellhead, it is not constant at the formation face. The sandface temperature decreases throughout the test but by the end of the test, the temperature is still nearly 70 degC above the surface temperature. The time-varying injection temperature causes the fluid viscosity and density to vary throughout the test. This creates a non-uniform distribution of the fluid properties in the region behind the front. The computer program INJECT has been developed to interpret test data subject to all of the complexities.

The magnitude of the near-bore permeability enhancement in 3 wells from Los Azufres (A-7, A-8, and A-18 (two tests)) is plotted as a function of the sandface injection temperature in Figure 8. The calculated permeability increases for wells A-7, A-8, and the first test of A-18 are remarkably similar, suggesting that the correlation between the sandface injection temperature and the permeability increase is attributable to the thermal characteristics of the rock mass. On the other hand, the larger increase in the permeability calculated from the second test in well A-18 suggests that the effects of heating and cooling are cumulative.

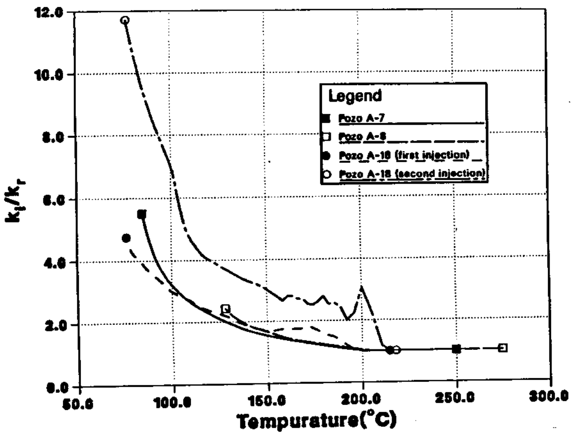

Figure 8. Permeability enhancement as a function of temperature for three wells at Los Azufres.

This suggests that stress changes occurring during injection also influence the permeability increase. The readjustments of the contact points between the opposing walls of the fractures that take place in response to pore pressure increases and thermal contraction of the rock may result in permanent increases in the near-bore permeability as the result of injecting cold water into a geothermal formation.

There are several possible explanations for the observed temperature versus permeability relationship, including; thermal stress cracking, dissolution of the formation, and thermal contraction of the rock matrix. In the absence of additional information, we can not decide which amongst these possibilities is the correct one, nor if a single mechanism is responsible for the observed behavior. Recent laboratory studies of thermal stress cracking indicate that both intragranular and grain-boundary stress cracks can develop in the thermal regime in which these tests are conducted (Fredrich and Wong, [33]). Analysis of field experiments at the hot-dry-rock site at Fenton Hill indicate that "reservoir growth" can be at least partially attributed to thermally induced stress cracks (Tester et al., [34]). It is likely that a similar mechanism is responsible for the permeability enhancement observed in the data described here.

The analysis presented here is just the beginning of a series of studies that must be conducted if we are to improve our understanding of the physical phenomena that accompany reinjection into geothermal reservoirs. To date, we do not have an adequate physical understanding of the physical mechanisms causing the unusual pressure transients responses nor the observations that well injectivity is often better than anticipated. The possibility that the observed permeability increases may be permanent or semi-permanent is also intriguing. If so, cold water injection may come to be considered as a bona fide stimulation treatment for geothermal wells.

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Geophysical Measurement of Geothermal Fluid Production and Injection

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ABSTRACT

Geothermal operators use complex reservoir engineering models to design their well fields and production/injection strategies and to predict the performance of their reservoirs. Collection of in-situ data for input and validation of these models in wells is expensive, and geophysical measurements from the surface or remotely at some distance from boreholes can be cost effective. The Hydrothermal Research Program of DOE is developing techniques to track injected fluid and to monitor the effects of production and injection geothermal fields using geophysical means.

INTRODUCTION

Reservoir engineering models are used to predict the future performance of geothermal fields in order to make decisions about well placement and production strategy. Information about the response of a geothermal field to production and injection is required in order to validate the applicability of these models to that field. For this purpose, information, typically temperature, pressure and fluid samples, is routinely collected in monitoring and production wells. Wells can provide very precise information from specific locations in the geothermal field, but they are expensive, and measurement and sampling problems due to high temperatures and flashing can reduce the value of the information obtained in them. Geophysical monitoring of changes in the geothermal field can be used to supplement traditional monitoring methods and provide additional constraints for validating geothermal model applications.

VALUE OF GEOPHYSICAL MONITORING

Changes in physical properties at depth can be measured using geophysical methods with sensors on the surface or in remote boreholes. Changes in physical properties may be associated with the movement of pressure, chemical and thermal fronts through the geothermal reservoir. These changes may be direct, such as an change in electrical resistivity caused by a change in pore fluid salinity or temperature. Alternatively, the detectable change might be related to a more complex phenomenon, such as increasing micro-seismicity as the pore pressure reaches a critical value. Geophysical monitoring has three advantages compared to using data from monitoring wells. First, a large volume of the reservoir can be studied from the surface or from a few wells, lowering monitoring costs. Second, geophysical measurements integrate properties over larger volumes, providing average values that can be appropriately compared to model results. Finally, geophysical instrumentation may not be exposed to the hot corrosive conditions in monitoring wells, making more types of measurement possible.

LIMITATIONS OF GEOPHYSICS

Geophysical monitoring has different limitations than monitoring wells. First, the usefulness of a specific geophysical method differs significantly from site to site, and with production/injection strategy. This variation comes both from the question of what physical property changes will occur within the reservoir, and the question of how well those changes can be detected in a given location. A second limitation comes from ambiguity in the interpretation of a geophysical anomaly once it is detected. There are two levels of ambiguity, uncertainty about where the changed physical properties actually occur, and uncertainty about how they should be translated into relevant reservoir information. The first level of ambiguity is reduced significantly in our application, where repeated measurements are used to eliminate geological variability. Because of these ambiguities, geophysical methods are best used to supplement and extrapolate accurate single point measurements from observation wells.

The DoE program is designed to increase the usefulness of geophysical monitoring by identifying methods that do or could work, and by reducing the importance of the limitations described above. The limitations are being dealt with by collecting case histories and improving measurement and interpretation methods for geophysical methods. Work relevant to geophysical monitoring is taking place at three organizations, Lawrence Berkeley Laboratory (LBL), University of Utah Research Institute (UURI), and Lawrence Livermore National Laboratory (LLNL). These efforts will make it possible to predict whether geophysical methods will be useful in specific cases, and to increase the number of times when the answer is yes.

GEOPHYSICAL METHODS ARE USEFUL

Some geothermal methods have been successfully used to monitor and understand changes in geothermal reservoirs. Density and resistivity changes within reservoirs can be predicted with confidence, and their measurement is routine and well understood. A very useful application of surface gravity measurements has recently been published by Atkinson and his colleagues at UNOCAL Geothermal. Over several years, they have used repeated surface gravity surveys over a geothermal field to measure the total mass loss in the field, and to determine which areas in the field are losing mass the fastest. They require the recharge parameters in their numerical simulations be adjusted to produce the observed values of mass loss, which are uniquely determined by the changes in the gravity field with time. This information has been incorporated into models for several years, and is obviously considered to be cost effective. This proven method could be applied effectively at many geothermal fields, and supplemented by repeated borehole gravity surveys, which work in cased holes, in order to constrain the depth where the mass loss is occurring. Repeated surface resistivity measurements have also been used by the LBL group to estimate the amount of fresh water recharge at Cerro Prieto. Like gravity, this routine method should be useful at those geothermal fields where there are large variations in fluid salinity, and can be routinely extended to borehole measurements. The DoE program will continue to publicize successes in order to promote the use of geophysical methods for monitoring.

DOE WORK DEVELOPING NEW METHODS TO PREDICT AND INTERPRET GEOPHYSICAL DATA

DoE is supporting a number of efforts to develop and improve techniques to allow us to predict the geophysical signature produced when reservoir properties change. These efforts concentrate on improving the prediction and interpretation of anomalies in those techniques known to be useful: gravity and resistivity. Two approaches are being taken. The first is to develop improved methods to interpret the signals caused by 3-dimensional anomalous bodies. UURI is developing codes for the 3-dimensional interpretation of DC and EM resistivity, and LBL is studying the application of 3-dimensional codes to gravity interpretation. The second approach, followed by both LBL and UURI, is to calculate the downhole and cross-borehole resistivity anomalies for a variety of geometries, in order to evaluate the best method for collecting this type of data. These studies are useful to the reservoir characterization and fracture detection efforts, as well as to the geophysical monitoring project.

DOE CASE STUDIES

There are several geophysical signals that would be useful for understanding processes if we could predict their occurrence or understand fully their causes. Examples include electrical self-potentials and micro-seismicity. Electrical self-potentials are natural DC electrical signals, that are caused by a combination of pressure gradients, fluid chemistry gradients, and thermal gradients. If we understood these signals, we could gain information about the pressure, fluid and thermal fronts in the reservoir. Unfortunately, we do not understand the characteristics of the reservoir rocks that give rise to these signals. We are collecting case studies of changes in SP signals as a reservoir is produced in order to determine if these anomalies are common, and to develop a database to stimulate theoretical and laboratory studies of electrical self-potential. These studies include surveys collected by LLNL before and after start-up of the Mammoth-Pacific Power Plant, in Mammoth Lakes, California, and a recent re-survey of the self-potential around the East Mesa power plant, conducted by LBL.

Micro-seismicity is known to occur when injection raises pore pressure above a critical level, and unexplained events have been seen at several sites. In addition, seismicity is detected around production wells at the Geysers. In order to better understand the many factors that produced induced seismic signals in geothermal fields, DoE is supporting a number of case studies where micro-seismicity is being collected in well-characterized reservoirs. LLNL is completing a study at the Mammoth-Pacific plant, and is planning to monitor seismic activity during the production/injection test of the Salton Sea Scientific Drilling Project well in June, 1988. With support from the Geothermal Technology Organization, LBL is starting a detailed monitoring program at the Geysers. These studies have the additional benefit of observing waves from natural earthquakes. These waves provide an additional source of energy used to characterize the reservoir and observe changes in the system.

DOE STUDIES DEVELOPING NEW GEOPHYSICAL METHODS

DoE is supporting a number of studies to develop advanced geophysical methods that will be useful for geophysical monitoring. LBL has developed a multiple-electrode resistivity system for rapidly collecting borehole-to-surface electrical data as a function of azimuth about an injection or production well, and has developed a shear-wave vertical seismic profiling system that could be used to look for changes in the ratio of compressional and shear wave velocities around a well. LLNL has produced seismic attenuation images of the Medicine Lake Volcano area, which, when combined with velocity data, are interpreted to indicate zones of dry and saturated rock. Each of these methods could be repeated to detect and understand the changes in a reservoir. In addition, LLNL is testing array processing method to locate continuous seismic noise generated by production and injection.

SUMMARY

The DoE program is designed to increase the amount of information available to validate reservoir models by developing and demonstrating geophysical methods for monitoring changes in geothermal fields. This program has three components: development of improved modeling and prediction capability for a number of techniques, the collection and dissemination of case studies to increase our understanding of the circumstances which make each technique useful, and the development of advanced techniques for geophysical monitoring. The value of the program will come as industry is encouraged to use geophysical monitoring methods, which can be a cost-effective means for gathering information about reservoir response.

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OPTIMIZING RESERVOIR MANAGEMENT THROUGH FRACTURE MODELING

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Abstract

Fracture flow will become increasingly important to optimal reservoir management as exploitation of geothermal reservoirs continues and as injection of spent fluid increases. The Department of Energy conducts research focused on locating and characterizing fractures, modeling the effects of fractures on movement of fluid, solutes, and heat throughout a reservoir, and determining the effects of injection on long-term reservoir production characteristics in order to increase the ability to predict with greater certainty the long-term performance of geothermal reservoirs. Improvements in interpreting and modeling geophysical techniques such as gravity, self potential, and aeromagnetics are yielding new information for the delineation of active major conduits for fluid flow. Vertical seismic profiling and cross-borehole electromagnetic techniques also show promise for delineating fracture zones. DOE funds several efforts for simulating geothermal reservoirs. Lawrence Berkeley Laboratory has adopted a continuum treatment for reservoirs with a fracture component. Idaho National Engineering Laboratory has developed simulation techniques which utilize discrete fractures and interchange of fluid between permeable matrix and fractures. Results of these research projects will be presented to industry through publications and appropriate public meetings.

Introduction

The geothermal industry has long been aware of the importance of fractures to the productive capacity of geothermal wells and of the role of fractures in controlling the movement of fluid in a reservoir. Much effort has been expended in the search for methods of delineating fracture zones in the subsurface prior to both exploration and production drilling. Fracture flow will become increasingly important as exploitation of the field continues and as injection of spent fluid increases for environmental protection and reservoir management. As an example, Malcolm Grant reported at the most recent Stanford Workshop on Geothermal Reservoir Engineering (1988) that production locations in the Wairakei field in New Zealand, may need to be significantly altered due to premature breakthrough of cooler groundwater into the geothermal reservoir along fracture zones. In addition to the empirical evidence that fractures have an important influence on reservoir management, sensitivity studies utilizing numerical codes have shown that the influence of fractures and the manner in which they are considered in reservoir models is an important factor in planning for the location and completion of production and injection wells, and establishing the productivity and injectivity.

To assist the geothermal industry with the development of reservoir management techniques, the Reservoir Technology Program of the Department of Energy's Geothermal Technology Division has conducted research into the fundamental transport processes in reservoirs since the inception of the geothermal research program. One set of outcomes of this program is the computer codes developed at Lawrence Berkeley Laboratory. Several related areas of investigation have been added to the program. These research efforts are centered on the need for locating and characterizing fractures in a geothermal system, modeling the effects of fractures on the movement of fluid, solutes, and heat throughout a reservoir, and determining the effects of injection on long-term reservoir production characteristics.

Since the Geothermal Technology Division has limited funding, it has attempted to limit its activities to those research areas where it can combine existing expertise with areas of greatest interest to the geothermal industry. Efforts to optimize management through reservoir fracture modeling have drawn on the experience at several national laboratories and universities. The five groups work together conducting complementary research aimed at developing a methodology that will assist industry in maximizing the return from reservoir development. As new technology is developed, DOE seeks the cooperation of industry to carry out field investigations to verify the laboratory findings.

R&D Objectives

The objective of the research program is to reduce the cost of hydrothermal electricity by increasing our ability to predict with greater certainty the long-term performance of the reservoir. This objective is being met, in part, through improved techniques for resource analysis and fluid production. More specifically, the research associated with fracture modeling seeks to better delineate fractures in order to increase the success in siting exploration wells and to obtain optimal energy recovery through improved knowledge of fluid flow and the thermal and chemical effects of injection.

Research

The Geothermal Technology Division's research program seeking to optimize management through fracture modeling includes studies conducted specifically for reservoir management in fractured reservoirs as well as research on fracture detection which is conducted primarily for increasing confidence in well siting and reservoir confirmation. Examples of these activities are discussed elsewhere in this volume in papers by Horne, Kasameyer, Lippmann, and Nielson, Moore, and Wright.

A great deal of the information on the location and orientation of fracture patterns needed for modeling reservoirs is gained during the exploration for geothermal reservoirs. Improvements in interpreting and modeling.

geophysical techniques such as gravity, self potential, and aeromagnetics are yielding new information for the delineation of active major conducts for fluid flow. Although seismic tomography utilizing teleseismic effects has not been applied by researchers at Lawrence Berkeley Laboratory to date in thermal areas, the technique shows some promise in delineating zones of increased fracturing.

The majority of research aimed at increasing our knowledge of the influence of fractures on fluid flow requires the use of measurements obtained from borehole data. Knowledge of flow paths and the history of geothermal systems is gained through studies of fluid inclusions and thermal alteration observed in cuttings and cores obtained from boreholes. Such information is of vital importance in deciphering the past and current influence of fracture zones on the circulation within a geothermal reservoir (Nielson, et al, this volume). Ongoing investigations of improved methods of well testing and advances in well test interpretation may further assist in the delineation of fractures (Horne, this volume).

Vertical seismic profiling and cross borehole electromagnetic techniques currently being developed show promise for delineating fracture zones and, in particular, near vertical fractures not intersected by a nearby well (Lippmann, 1987). If these techniques can be proven in the field, they may provide important data on which to base directional drilling.

Several other research projects are expected to produce geophysical techniques for monitoring fluid flow within a producing reservoir and delineating fracture zones. Microseismic techniques under development at Lawrence Berkeley Laboratory and at Lawrence Livermore Laboratory are currently being tested in the field at the Geysers and at the Salton Sea. The work at the Geysers is sponsored jointly by the Geothermal Technology Organization and DOE. Repeated self potential measurements have been made at East Mesa. Researchers have observed intriguing correlations between geophysical signals and production at this, and other, tests of geophysical methods.

Reservoir Modeling

More realistic predictions of reservoir performance and reduction of the adverse thermal and chemical effects of injection will decrease the uncertainties inherent in operating geothermal fields and lead to maximizing the energy recovery from geothermal reservoirs. DOE is funding several efforts to develop numerical codes for simulating geothermal reservoirs. The work at Lawrence Berkeley Laboratory and Idaho National Engineering Laboratory is described below, work at Stanford is summarized by Horne (this volume).

Fractures are significant features in most geothermal reservoirs (even those with primary matrix permeability) and represent high mobility channels for the migration of injected fluids through geothermal reservoirs. Horne (1982) has documented loss of production due to thermal interference in several geothermal fields and has demonstrated that fluids can move rapidly through fractures.

Modeling of fractured media has been based on two primary approaches, continuum and discrete. The continuum approach is based on a lumped parameter model of the fracture system. The scale of the model must be large enough so that the fractured rock can be treated as if it were homogeneous. The discrete approach represents the opposite end of the spectrum. All fractures which are considered relevant are modeled as individual entities. Presently, discrete fracture simulations are limited to reservoirs with few relevant fractures or to small portions of a fracture system.

Lawrence Berkeley Laboratory (LBL) follows a double-porosity approach for reservoir simulation and adopts a continuum treatment for both the fracture network and for the porous rock matrix. The discussion which follows is freely taken from Pruess and Narasimhan (1985). Global flow in the reservoir is assumed to occur only through the network of interconnected fractures, whereas fractures and rock matrix can exchange fluid and heat locally. The "MINC" (multiple interacting continua) method when used in conjunction with LBL's MULKOM simulator (Pruess, 1983) makes possible a fully transient representation of interporosity flow, which is applicable to problems with coupled fluid and heat flow, and to multiphase fluids with large and varying compressibility. For purposes of simulating a number of important reservoir processes it was necessary to improve code capabilities. Many of the modifications are discussed in the paper presented by Lippmann (1987) at the Sparks, Nevada meeting of the Geothermal Resources Council. Work is currently underway to extend the temperature range of the MULKOM code to supercritical conditions, to develop numerical techniques that permit realistic modeling of the heat sweep associated with injection in fractured reservoirs, and to assess differences between reservoir evaluations that are based on porous and fractured medium representations.

INEL has recently developed simulation techniques incorporating two significant features, dual-permeability and fluid front tracking, which have made simulation of complexly fractured reservoirs feasible (Stiger and Renner, 1987). The FRACSL simulation code can be used to simulate transient and steady-state flow in a fractured, permeable media. The smaller fractures and the permeable matrix are simulated as permeable matrix cells, while larger fractures are represented as discrete elements (Clemo and Hull, 1986). FRACSL allows advective interchange of fluid between fractures and the matrix. The code employs a particle tracking routine in which individual fluid particles are tracked through the reservoir. This enables explicit simulation of heat transfer and chemical interactions at the fluid/rock interface.

Work is continuing at INEL on an innovative approach to dealing with complex fractured reservoirs. A method employing representative elements has been developed which will allow simulation of reservoirs that are too large for discrete simulation, yet are dominated by a few major fractures, making the continuum representation impossible (Miller and Clemo, 1988).

An important milestone in the FY-88 INEL program is the publication of the FRACSL code for use by industry. Current efforts are aimed at streamlining the code so that effective reservoir-scale simulations can be made. The code is run on a Cyber 176 at INEL, but modifications in progress will enable the code to be run on a work-station type computer (4 megabyte capacity). The modified code will use sparse matrix numerics instead of the proprietary ACSL driver. Heat transfer simulation using a particle-based routine similar to the fluid particle tracking routine will simplify thermal simulations.

Significance of Fractures to and Heat Transfer

Heat transfer in a geothermal reservoir is a function, in part, of the thermal conductivity of the rock, the surface area contacted by the fluids, the temperature gradient and the fluid mass flux (Horne, et al, 1987), A few large fractures may be the primary controlling factors in fluid flow in a reservoir. However, secondary fractures and a permeable matrix can represent a much greater surface area for heat transfer and rock-water chemical interactions.

The dual-permeability code has been used to assess the sensitivity of fluid migration and thermal breakthrough forecasts to simplifying assumptions commonly used in simulations of geothermal reservoirs. The studies, in a test reservoir, demonstrated that simulating a few of the dominant fractures is all that is required to analyze the pressure response to production and injection (Hull and Clemo, 1987). However, simplifying the reservoir in order to run reservoir-scale simulations can yield significant error when assessing heat transfer and the potential for thermal breakthrough. An equivalent porous media simulation of the reservoir would have predicted that the cooling front would have moved only about 100 meters away from the injection well. On the other hand, a simulation based on a single fracture connection between the wells would have predicted that the cooling front would have reached the production well in less than 2000 days.

R&D Value

The impacts of research related to management of an operating field can not be quantified easily using IMGEO; therefore, only a qualitative assessment of the value of the reservoir management research has been made. The principal goal of reservoir management is the maximization of the return from a reservoir, whether that be maximization of income, recovery, or some other measure of return. The fracture modeling efforts of the DOE research program seek to provide tools to locate and characterize fracture systems, describe the effects of fractures on flow, and model flow in reservoirs where fractures play an important role in the transfer of fluids and heat so that optimal management will result. Successful development and utilization of these tools will reduce the uncertainties in predictions of reservoir performance and increase the confidence that cool fluids will not prematurely enter the production zone.

Transfer of Research Results to Industry

Research results have been, and continue to be disseminated to the industry through publications, talks at professional meetings, and DOE sponsored symposia. The Reservoir Technology Program also seeks to validate technology and transfer it to industry through joint field projects. The Lawrence Berkeley Laboratory Industry Review Panel anticipates holding a meeting in the near future at which the researchers in the Reservoir Technology program will present detailed status reports on their research. INEL plans to transfer the FRACSL code to industry through a number of small hands-on workshops in which the participants will be encouraged to utilize actual field data with the FRACSL model.

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DECREASING ENERGY CONVERSION COSTS WITH ADVANCED MATERIALS

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ABSTRACT

If the Geothermal Technology Division (GTD) is to meet its programmatic objectives in hydrothermal fluid production and energy conversion, it is essential that new materials of construction be available. Level III Program Objectives include 1) reducing the costs associated with lost circulation episodes by 30 percent by 1992, 2) reducing the costs of deep wells and directionally drilled wells by 10 percent by 1992, 3) reducing well-cementing problems for typical hydrothermal wells by 20 percent by 1991, and 4) the development of a corrosion-resistant and low-fouling heat exchanger tube material costing no more than three times the cost of carbon steel tubes by 1991.

The Brookhaven National Laboratory (BNL) materials program is focused on meeting these objectives. Currently, work is in progress on 1) high temperature chemical systems for lost circulation control, 2) advanced high temperature (300°C), lightweight (~1.1 g/cc), CO_2-resistant well cementing materials, 3) thermally conductive composites for heat exchanger tubing, and 4) ultra high temperature (600°C) cements for magma wells. In addition, high temperature elastomer technology developed earlier in the program is being transferred for use in the Geothermal Drilling Organization programs on drill pipe protectors, rotating head seals, and blow-out preventors. Recent accomplishments and the current status of work in each subtask are summerized in the paper.

INTRODUCTION

In order to meet GTD's Programmatic Objectives, attainment of which will greatly enhance development of the Nation's geothermal resources, advanced technology is required for industry to reduce costs caused by the severe geothermal environments encountered during drilling, well completion and test field development, heat extraction, power production, and reinjection of spent brine. Particular needs are for improved materials and methods to withstand 1) extremely high temperatures encountered in geothermal reservoirs and in energy conversion processes, and 2) severe corrosion and scaling by geothermal brines. Materials needs exist for specific components such as downhole drill motors, pumps, casing, packers, blow-out preventors, drill-pipe protectors, rotating head seals, and heat exchangers. In particular, improvements in lost-circulation control, lightweight well-completion materials, and downhole drill motors would significantly reduce well costs.(1)

The GTD initiated the Geothermal Materials Program in 1976, and since 1978, BNL has provided technical and managerial assistance in the implementation of this long-term high-risk effort.

To date, the most significant geothermal materials advance has been in high temperature elastomers. Developed under GTD sponsorship by L'Garde, Inc., the Y-267 EPDM (ethylene, propylene, diene, methylene) elastomer can be classified as a technology breakthrough.(2,3) Three major U.S. seal manufacturers acquired the technology from the Department of Energy (DOE) in 1982, and molded parts are now commercially available from these and other firms. The elastomers are widely used in well logging tools, packers, valves and other equipment. Recently, GTD-sponsored work has been performed to modify the Y-267 EPDM to enhance its performance in drill pipe protectors, rotating head seals, and blow-out preventors, and these results are being utilized in the Geothermal Drilling Organization's programs on these components.

Another successful materials advance was the development of high-temperature polymer concrete formulations. These materials are now available for use as corrosion resistant linings at temperatures up to 260°C.(4)

Cements represent another area where considerable progress has been made. The results from this effort currently serve as the basis for the selection of cements used for geothermal well completions throughout the world.(5) There is still, however, a major need for improved lightweight CO_2-resistant cements.(6,7)

Handbooks summarizing the performance of materials in above-ground and downhole geothermal environments are other widely used outputs from the materials program.(8,9)

Research and development (R&D) efforts aimed at further cost reductions, in accordance with GTD Programmatic Objectives, are currently in progress. Tasks include work on high temperature lightweight cements, chemical systems for lost circulation control, nonmetallic heat exchanger tubing, and ultra high temperature cements. R&D on elastomers for dynamic sealing applications and for liners on well casing was discontinued at the end of FY 1987, but technology transfer efforts on these materials are continuing. Major accomplishments during FY 1987 and the thrust of the current efforts are summerized below.

1. High Temperature Cements

- Surface treatment of sillimanite-based microspheres for strength and durability enhancement of lightweight cements.

- Oxidation of carbon fiber surfaces for bond enhancement in lightweight cements.

- Downhole characterization of lightweight cements at ∿300°C in low CO_2-containing brines.

2. Chemical Systems for Lost Circulation Control

- Optimization of previously identified systems.

- Microencapsulation of reactive components.

- Engineering-scale placement tests.

3. Materials for Nonmetallic Heat Exchangers

- Fabrication of prototype heat exchanger tubing.

- Laboratory durability tests.

- Field measurements of fouling coefficients and corrosion rate.

4. Ultra High Temperature Cements

- Identification of pumpable ceramic-type materials stable at >500°C.

5. High Temperature Elastomers for Dynamic Sealing Applications

- Completed modifications of Y-267 EPDM to optimize for dynamic seals.

- Identified high temperature chemical coupling system for bonding Y-267 EPDM to carbon steel.

- Liaison with Geothermal Drilling Organization on full-scale test of drill pipe protectors.

Detailed descriptions of each of these tasks are given below.

RESULTS

1. Advanced High Temperature Lightweight Cements

In order to meet the GTD Programmatic Objectives of reducing well cementing problems for typical hydrothermal wells by 20 percent by 1991, improved well cements must be developed. The R&D strategy seeks to improve the effectiveness of geothermal well completion procedures and to reduce the occurrence of lost circulation problems by the development of CO_2-resistant lightweight high temperature cements. These improvements will help to transfer well-life limitations from materials to reservoir constraints in a cost effective manner. The work is being performed as a cooperative research effort with the New Zealand Department of Scientific Research (DSIR). BNL develops the cement formulations and performs physical, chemical and mechanical evaluations. DSIR conducts the downhole tests in wells at their Mokai and Rotokawa geothermal fields.

Two very promising lightweight cements were developed, and they are currently being tested downhole by DSIR. This test is being conducted in a low CO_2-containing brine at ∿310°C. Tests in fluids containing higher CO_2 concentrations are planned for next year. One formulation consists of class H cement, silica flour, water, a sodium alpha olefin sulfate foam generator, and carbon fiber.(10) The material has a slurry density of 1.2 g/cc, a bulk density of ∿1.0 g/cc, and a 24 hr compressive strength of 1200 psi. Recent data indicate that oxidation of the carbon-fiber surfaces prior to mixing results in significant enhancement of the fiber-cement interfacial bond, thereby giving further improvements in strength and durability.(11)

The second promising cement formulation contains class H cement, silica flour, water, and calcium hydroxide [$Ca(OH)_2$]-treated ceramic microspheres. This formulation has a slurry density of 1.19 g/cc, a bulk density of 0.91 g/cc, and a 24 hr compressive strength of 1400 psi.(12) Pretreatment of the sillimanite [$Al(AlSiO_5)$]-containing microspheres with deionized water and $Ca(OH)_2$ at 200°C is essential for producing a high quality cement that will meet the American Petroleum Institute's (API) criteria for geothermal cements. Specimens prepared without the pretreated spheres exhibited a compressive strength of 610 psi and a water permeability of 7.9×10^{-4} darcy after curing for 24 hr in a 300°C hydrothermal environment. API criteria are >1000 psi and $<10^{-4}$ darcy, respectively. The advanced BNL cement yielded values of 1440 psi and 5.6×10^{-6} darcy. After a 180 day exposure to 300°C brine, the samples still met the API criteria.

Currently, work to develop lightweight CO_2-resistant cements is in progress. Emphasis is being placed on calcium aluminate-based materials. Laboratory evaluations are to be completed by the end of FY 1988, at which time downhole testing at DSIR will commence.

2. Chemical Systems for Lost Circulation Control

Currently, the cost of correcting lost circulation problems occurring during well drilling and completion operations constitutes 20 to 30 percent of the cost of a well. The GTD Objective is to reduce well drilling costs for typical hydrothermal wells by 10 percent by 1991. Therefore, our goal is to develop an advanced high temperature chemical system that can be introduced through the drill pipe into the lost circulation zones. Elimination of the need to remove the drill string will greatly reduce down time and aid in the location of the fractured zone, resulting in considerable cost savings.

During FY 1984 and 1985, BNL developed two promising chemical formulations, but due to budget constraints, the task was suspended.[13,14] Work was resumed in FY 1988.

One formulation is composed of bentonite, ammonium polyphosphate (AmPP), borax, magnesium oxide, and water. The appropriate combination of these ingredients results in the formation of slurries with viscosities and thickening times adequate to allow placement. After curing at elevated hydrothermal temperatures, the cement produced was characterized by a compressive strength >500 psi at 2 hr age, a permeability to water $<2.0 \times 10^{-4}$ darcy, and a linear expansion >15 percent. Consistometer tests performed at Sandia confirmed the pumpability of the materials at high temperature and pressure.

The second promising system consists of cement, borax, glass fiber, and bentonite. The system is pumpable at 250°C, and at 2 hr age has a compressive strength of 400 psi, a water permeability of 2×10^{-3} darcy, and a linear expansion of ∿2 percent.

In FY 1988 emphasis is being placed on the bentonite-AmPP-borax-magnesium oxide (MgO) system. Since the pumpability and curing times for the system can be closely controlled over a wide temperature range (150°-350°C) by varying the MgO concentration, methods for the microencapsulation of it in plastics are being investigated. As conceived, these MgO-containing capsules will be mixed with the other constituents and pumped down the drill pipe. Depending upon the thickness and thermal stability of the encapsulant, the combination of temperature and shear forces at the nozzle will be sufficient to rupture the capsule, thereby mixing the highly reactive MgO with the other materials. Curing will take place within seconds.

The laboratory phase of the task will be completed by December 1988, at which time plans will be made for a mud displacement test as a cooperative effort with Sandia National Laboratories and industry. Contingent upon these results, a well demonstration could be conducted early in 1990.

3. Materials for Nonmetallic Heat Exchangers

One of the objectives of GTD's Energy Conversion program is to improve the net geothermal fluid effectiveness of binary plants. Based upon the results from a recent Idaho National Engineering Laboratory study,[15] the development of a low cost corrosion and fouling resistant heat exchanger tube which could be used as a substitute for high alloy tubes, could reduce the generating cost of electricity up to 10 percent. Therefore, the goal of this task is to develop a corrosion-resistant and low-fouling heat exchanger tube material costing no more than three times the cost of carbon steel tubes by 1991.

potentially low-fouling liner material.[16] Autoclave exposure tests of lined tubes in brine at 150°C were initiated, and to date after 120 days, deterioration or scaling have not been detected. Centrifugal casting techniques for applying the liner onto tubes varying in size from 0.375 to 1.0 in. were also developed. Preliminary cost estimates indicated that the cost of the lined tubing will only be ∿50 percent greater than that of carbon steel, well below the GTD criterion.

Currently, work is in progress to field test a prototype 80-ft long single tube shell and tube countercurrent heat exchanger as a cooperative effort with INEL. The tube diameter will be 0.75 in. and water will be the shell-side fluid. This test is scheduled to start in October 1988. The test site is currently being selected. Contingent upon the results from this test, a prototype multi-tube brine/organic heat exchanger will be fabricated and tested.

4. Ultra High Temperature Cements

This is a new project initiated in FY 1988 with the goal of designing and developing ceramic-type cementitious materials systems that can be used for the completion of wells in magma environments. It is also expected that since all of the materials to be considered will not be vulnerable to carbonation, their use with the lightweight aggregates discussed in Task 1 should result in excellent lightweight CO_2-resistant cements for hydrothermal wells. For the magma application, the cement must be capable of withstanding corrosive fluids and gases in rhyolite magma environments at depths from 3 to 8 Km, pressures from 7,000 to 30,000 psi and temperatures up to 850°C. Specific criteria that the material must meet are as follows:

1. 24-hr compressive strength 10,000 psi.
2. Stability in volatile components (H_2O, CO_2, S, Cl and F) and in fusing rhyolite glasses at 850°C.
3. Cement/superalloy bond strength >10 psi.
4. Non-corrosive to superalloy casing.
5. Maintenance of pumpability at temperatures up to 300°C for 4 hr.

The scope of the work in FY 1988 is to select and evaluate various ceramic composites consisting of a matrix and a filler prepared at temperatures of up to 1000°C and atmospheric pressure. During the placement of material in the magma zone, the chemical structure of cements appears to transform from a hydrogen bond-based slurry to a hydraulic bond-based product, and then to a ceramic bond. Thus, it is important to note that possible strength retrogression during this phase transformation is an important factor to be considered in the evaluation of potential material systems.

gel (called solid-gel reaction), Al_2O_3-TiO_2-Amorphous Ti Hydroxide gel, Al_2O_3-TiO_2-Amosphous Zr Hydroxde gel, and MgO-Polyphosphate-$NaB_4O_7 \cdot 10H_2O$-H_2O. Tests to measure the mechanical and physical properties under dry and hydrothermal conditions at temperatures of up to 1000°C are currently being made.

5. High Temperature Elastomers for Dynamic Sealing Applications

This project which was completed in FY 1987, consisted of applied research to optimize the Y-267 EPDM elastomer formulation, developed earlier by GTD for static seal applications, for use in dynamic seal applications at temperatures up to 260°C. Elastomers for these conditions do not currently exist, and a successful development and subsequent utilization in downhole drill motors, drill pipe protectors, rotating head seals, and blow-out preventors could substantially reduce drilling and completion costs to meet GTD Objectives by 1992.

During FY 1987, a series of screening tests on 15 developmental compounds were completed and the results compared with those from the base case Y-267 EPDM. Based upon these results, one was selected for a final life expectancy test. The composition and properties of this formulation are compared with those of the Y-267 EPDM in Tables 1 and 2, respectively.

TABLE 1. DYNAMIC SEALS
MOST PROMISING FORMULATION

Constituent	Control Y-267	Formulation 485
Nordel 1660	100	100
Hypalon 20	5	5
Polybutadiene 6081	20	20
Thermoguard S	5	5
N110 Black	75	50
Cyanox 2246[a]	0.5	0.5
Dicup R[b]	3.5	3.5

a, antioxidant
b, peroxide curing agent

TABLE 2. DYNAMIC SEALS
PHYSICAL PROPERTIES

Property	Control Y-267	Formulation 485
Tensile, psi	1973	2190
Elongation, %	122	137
Die B, ppi	169	—
Die C, ppi	223	226
Set, %	5.3	—
Shore Hardness at 20°C	92	85
Life Test in DSST, hr	8	>49[a]

a, test voluntarily terminated before any sign of failure.

A life expectancy test was performed on Compound 485 and the Y-267. Test conditions were as follows: brine temperature 204°C, shaft speed 350 rpm, and pressure gradient 300 psi. After 8 hr in test, the Y-267 failed. In comparison, testing of Compound 485 was voluntarily terminated after 49 hr. Visual examination of the seal indicated some deterioration, but at shutdown it was still performing well. The cause of the Y-267 EPDM failure was not apparent. The post-test physical and mechanical properties of both sealing materials were measured, and they will be included in the final report which should be published by July.

BNL has initiated liaison responsibilities with Sandia National Laboratories and the GDO on their program on elastomers for drill pipe protectors, rotating head seals and blow-out preventors. A contract for the drill pipe protectors has been placed by Sandia with Regal International, Inc., and work started in December 1987. The specified design conditions for this application are as follows:

1. Brine containing 180,000 ppm TDS and 10 atm CO_2 at 288°C and 5000 psi.
2. Steam at 600 psi and 260°C.
3. In both environments, a side load of 3500 lb during rotation must be tolerated.

All of the GTD-sponsored data on high temperature elastomers for dynamic seals and chemical coupling systems for bonding them to metal substrates will be utilized in the GDO effort.

CONCLUSIONS

The DOE Geothermal Materials Program is addressing problems whose solutions have a short to moderate term impact on the operation of plants as well as conducting long-term R&D designed to have significant impacts on industrial viability and productivity in materials performance. Active technology transfer linkages are established and maintained. To date, the program has resulted in the development of the best known high temperature elastomer for geothermal service, and several other outputs from the program and are being used or tested by industry. Current efforts on dynamic seals and lightweight well cements may be used by industry in the very near future. Other efforts on CO_2-resistant cements, lost circulation control materials, and nonmetallic heat exchanger tubing will require longer development times, but should meet scheduled GTD Objectives.

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BIOLOGICAL SOLUTIONS TO WASTE MANAGEMENT

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ABSTRACT

The purpose of this program is to develop low-cost processes for the removal of toxic metals from geothermal residual brines. Processes and methodologies are also being developed for the utilization of detoxified residues. Laboratory work at Brookhaven National Laboratory (BNL) has shown that bioleaching is an efficient method for the removal of toxic metals from residual brine sludges. Samples of geothermal brine residues, supplied by the industry, containing elevated concentrations of heavy metals were treated with cultures of several strains of acidophilic bacteria Thiobacillus thiooxidans and Thiobacillus ferrooxidans, selected from the BNL collection. The effect of different experimental conditions on the rate of toxic metal removal has been investigated. Based on the experimental results obtained, a detoxification process for geothermal brine residues has been explored. A preliminary technical feasibility study indicates that for a typical 50 MW plant, a large-scale technically feasible process can be developed.

INTRODUCTION

Large-scale production of electricity from geothermal sources produces significant quantities of solid brine residues, a by-product containing concentrations of heavy metals, disposal of which will damage surface and ground water supply. These residues have to be either detoxified or shipped at a considerable cost to distant hazardous waste disposal sites. A typical output of a 50 MW power plant in southern California, Known Geothermal Resource Area (KGRA), is about 70,000 lb/day of residue. The solid residues thus generated are composed of salts, silica, and various amounts of heavy metals. Some of the heavy metal contents exceed California state regulation limits.[1] We have found that bioleaching is the most suitable method for detoxification of such brine residues. The efficiency of several strains of acidophilic bacteria belonging to the Thiobacillus thiooxidans and Thiobacillus ferrooxidans group of microorganisms has been investigated. These bacteria oxidize sulfur or metal sulfides to sulfuric acid and soluble metal sulfates. In addition, metals are solubilized by the action of sulfuric acid or by ferric iron into soluble metal sulfates. The bacterially mediated processes are highly efficient. For example, in continuous oxidation of ferrous sulfate, T. ferrooxidans oxidizes ferrous ions at a rate of $5x10^5$ faster than the oxidation rate in the absence of the microorganism. Residues obtained from proprietary sources in Southern California were used in the experiments. Various amounts of solid residues were suspended in culture media and inoculated with T. thiooxidans and T. ferrooxidans, as well as mixtures of both. Conditions which led to efficient solubilization rates were then applied to five different brine residues. The data base generated was used to evaluate the feasibility and cost efficiency of a detoxification process for a typical 50 MW KGRA power plant. This study showed that a ten-day cycle treatment is technically and economically feasible.

RESULTS

In this work, strains of Thiobacillus thiooxidans and Thiobacillus ferrooxidans obtained from the BNL collection were used. The variables studied were: sludge concentration, initial nutrient concentration, nonsterile conditions, agitation, and air supply through the medium. Experimental details, such as culture media, batch kinetic studies, and the effects of different sludges, have been described elsewhere[2-4] and will be mentioned here briefly. All the experiments were carried out at 22 ± 3°C and bioleaching of heavy metals was monitored by measuring the metals in leachates with atomic absorption spectroscopy (AA) or in solids with AA and proton induced X-ray emission (PIXE).[4] Concentration of solid residue in the bioreactor influences the residence time. Thus, relative to controls, in cultures with 2% and 4% brine residues, the growth of T. thiooxidans was delayed by 20 and 70 hr, respectively. However, after eight days of culture, the cell concentration in all cultures reached the same full exponential growth level. Variation in the design of the bioreactor and techniques of measurement of reaction rates have allowed the concentration of solid residues to increase to 60% (w/v) with an efficient removal of metals in a ten-day cycle. Typically, metal solubilzation varies in different residual brines, and higher efficiences can be attained by choosing strains and combinations of strains. Table 1 illustrates these characteristics for a single six-day cycle.

Kinetic studies in which growth rates and pH changes have been measured also show effects which are due to both chemical and biochemical processes. Best laboratory results were used to

Table 1: VARIATIONS IN THE METAL REMOVAL EFFICIENCY BY DIFFERENT STRAINS OF SINGLE AND MIXED CULTURES OF MICROORGANISMS

	T. thiooxidans (BNL-3-25) Residual brine			*T. ferrooxidans*		Mixed Culture BNL-3-25: BNL-2-44		
				BNL-2-44	BNL-2-47			
	P_1	C-5	G*	P_1	P_1	P_1	A4	B5
Metal	% Metal Removed			% Metal Removed		% Metal Removed		
Cu	50	65	27	91	31	90	90	55
Cr	2	6	8	32	48	65	20	25
Zn	77	73	41	85	89	85	62	74
Mn	30	34	4	41	57	80	78	87
As	37	48	10	18	44	40	90	25

* Central California, C-5, P_1, A4, B5, Imperial Valley.

design a biological solid-waste treatment plant, using as a basis a 50-MW double-flash plant located in the Salton Sea area of the Imperial Valley generating 70,000 lb/day of geothermal sludge.[3] The location was chosen because of a high concentration of TDS (up to 350,000 ppm) in its geothermal brines. The design is based on the fluid from a Salton Sea well, where the brine temperature is 500°F and the TDS is about 300,000 ppm, and assumes that the best laboratory results currently available serve as the model case. Other improvements, such as better strains of microorganisms, mixed cultures, and other parameters yet to be optimized, would further improve the process. As part of the ongoing program, these parameters are currently being explored.

It has been estimated[5] That a 50-MW plant produces about 115,000 lb/day of 65% solid filter cake. This represents about 74,000 lb/day of geothermal waste. The proposed bio-treatment waste facility is a continuous process running at ambient conditions (80°F) in the Imperial Valley. It is based on 80,000 lb/day of dry geothermal waste contained in a 65 wt% filter-press cake. Laboratory experiments have indicated that efficient bioleaching will occur at a 5% sludge-to-liquid ratio with residence times for both the sludge and leachate of 10 days. Processing 80,000 lb/day of solid waste will require about 470 lb/day of nutrients and 66,600 lb/day of irrigation water in order to provide a 10-day residence time in the bioreactor. The leachate from the bioreactor containing the dissolved metals is neutralized, filtered, and reinjected.

The process flow sheet for the proposed biological waste-treatment facility is given in Figure 1. The filter press cake (65 wt% solid) (Stream 1) is placed on a conveyor belt at an average rate of 5,130 lb/hr. This is an average rate because the filter press cake is removed as a batch operation. The filter cake is at a temperature of 230°F before it is removed and placed on the conveyor belt. While on the conveyor belt, it will partially cool before being added to the bioreactor. Nutrients (Stream 2) and water (Stream 3) at 80°F are also continuously added to the bioreactor. Bioleaching takes place in the bioreactor where the solid and liquid residence time is 10 days, and the sludge-to-liquid loading 5%. Since the reproduction rate of the bacteria is faster than the rate at which they are being removed (along with the liquid), the concentration of bacteria in the bioreactor should reach a steady state.

The bioreactor underflow (Stream 10) containin 15% precipitated solids is sent to a filter press where it is concentrated to a 65 wt% solid cake. The resulting filter press cake (Stream 11) leaves the process at a flowrate of 5,130 lb/hr. The liquid (Stream 5) is recycled back to the bioreactor. The solids contained in the filter press cake now contain regulated metals at permissible concentrations which makes the filter press cake a nonhazardous solid waste.

In order to protect the reinjection well from corrosion, the leachate from the bioreactor (Stream 4) is sent to a neutralization drum where the pH is raised to above 4 with soda ash (Stream 6). It is then pumped through a filter (Stream 7) in order to collect any precipitated solids. These solids can be recycled to the bioreactor or treated as regulated waste (Stream 9). However, their volume will be much smaller than the total volume of solid waste produced. The filtered leachate (Stream 8) is then pumped down a reinjection well drilled for leachate disposal. Due to solubility limitations, this reinjection well is not the same well used in the brine-solids separation process of the double-flash plant. Table 2 summarizes the stream properties.

A preliminary cost analysis suggests a potential saving of just over a million dollars a year, or approximately the 1986 regulated waste disposal cost. The total capital cost of the biological waste treatment plant was estimated at $3,309,000. This cost includes equipment, installation costs (100% of purchased equipment), land, a reinjection well, working capital, and a 20% contingency. The

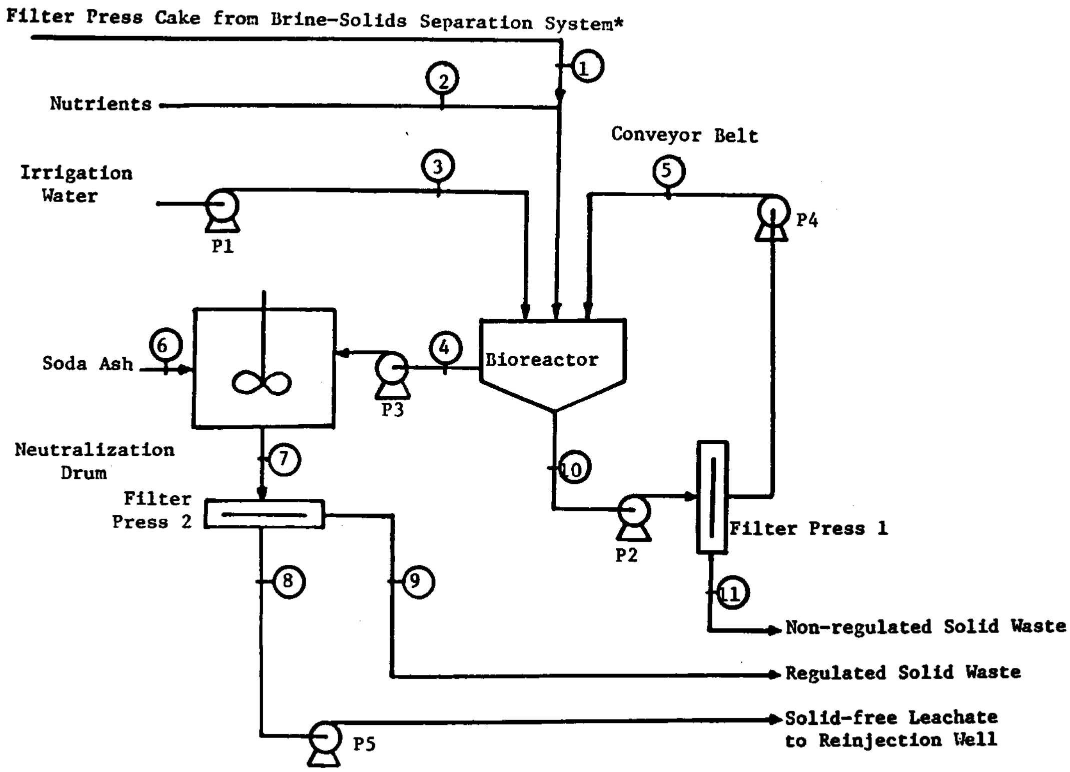

Figure 1. Proposed biological waste-treatment facility. (P_1-P_5: pumps)
*For details see Premuzic et al., 1988a.

Table 2: BIOLOGICAL WASTE-TREATMENT PLANT STREAM SUMMARY

Basis: 5% Solids
10-day residence time for liquids and solids

Stream Number	Description	Flow Rate (lb/hr)	Amt. of Solid (wt%)
1	Filter Press Cake From Brine-Solid Separation	5130	65
2	Nutrients	470	100
3	Irrigation Water	66,600	0
4	Thickener Overflow	67,100	0
5	Filter Press Recycle	17,100	0
6	Soda Ash	400	100
7	Exit from Neutralization Drum	67,500	0
8	Reinjection Liquid	67,400	0
9	Regulated Solids from Filter 2	Very Small (<100)	65
10	Thickener Underflow	22,200	15
11	Filter Press Cake (Non-Regulated Solids)	5100	65

thickener cost was based on stainless steel construction. The cost of the reinjection well was based on estimation methods of Tester (1982). The well depth was taken to be about 2,000 ft. The fluid being reinjected was less than 3% of the originally reinjected fluid and therefore needed a much smaller reinjection well diameter. The working capital of the plant was assumed to be 20% of the total capital cost.

The annual operating expenses were $687,000/yr and included nutrient costs for the bacteria (approximately $130/ton nutrients), disposal of non-regulated waste, insurance, irrigation water, and labor.

The total capital cost of the treatment plant was amortized over the 30-year plant life at an interest rate of 10%. The annual cost of the process (amortized capital and annual operating) corresponds to approximately $1,038,000, which is 0.23¢/kWh or about 5% of the current cost of producing electricity from geothermal energy. The 1986 estimated cost of electricity from geothermal energy is 4¢/kWh based on data obtained from a 1985 Meridian Corp. report prepared for the U.S. Department of Energy. Therefore, the cost of a biological waste-treatment plant is small relative to the total cost of geothermal power generation. The major gain from operating the treatment plant instead of disposing of solid waste as hazardous material is the protection from long-term liability associated with hazardous waste disposal and should be considered together with significant increases in cost of shipping, dumping and possibilities of the dump sites being closed.

Sensitivity analyses have also been carried out in which increased concentrations of sludge, liquid residence time, utilization of solid wastes, and the recovery of valuable metals from the leachate were considered. For example, by increasing the sludge concentration in the thickener to 10 wt%, the thickener volume an the capital costs are decreased, which results in the reduction of total cost. The liquid residence time can be increased to 50 days by decreasing the make-up water flowrate five-fold and by not changing the thickener volume. This significantly decreases pump sizes and nutrient costs and therefore further reduces the total cost. Alternatively, the non-regulated solid waste from the biological waste treatment facility, which is primarily silica, can potentially be used by the construction industry as a filler for concrete. If this non-regulated solid waste were given away, then the cost of its disposal would be saved. This would amount to further savings. Additional income, and therefore a decrease in operating costs, would be realized by sending the leachate from the bioreactor (Stream 4) of Figure 1 to a metal recovery plant. The stream leaving the metal recovery plant would then be recycled to the clarifier without the occurrence of precipitation.

CONCLUSIONS

1. Preliminary results indicate that it is technically and economically feasible to build and operate a biological geothermal waste-treatment plant. The total cost of such a facility would be approximately 0.2¢/kWh of electricity produced.

2. The bioleaching of toxic metals from geothermal solid waste by strains of microorganisms used in this program can be performed under non-sterile and minimum-nutrient requirements, making the process suitable for field applications.

3. Work with combined cultures of different BNL strains of T. ferrooxidans and T. thiooxidans indicates that higher metal solubilization rates are possible, and therefore shorter periods of residence time can be considered.

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THE PREDICTION OF CHEMICAL SCALING IN GEOTHERMAL POWER OPERATIONS

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ABSTRACT

The purpose of the DOE program at UCSD is to provide a highly reliable thermodynamic model of brine chemistry for use by the geothermal community. This model will be of sufficient accuracy to be used for the prediction of chemical problems in production, energy extraction, and brine reinjection. By replacing and extending costly laboratory simulations, the model will provide a cost effective design tool to enhance the efficiency of geothermal operations.

Recent emphasis has been placed on modeling the deposition of the scale-forming minerals, calcite ($CaCO_3$), calcium sulfate ($CaSO_4$), and amorphous silica (SiO_2). At present, the scaling model has the capability to calculate gypsum-anhydrite, amorphous silica and calcite solubility as a function of partial pressure of CO_2 and brine composition for a range of temperatures to 250°C. We also now have the capability of calculating breakout (onset of two phase flow) for a limited set of temperatures.

In the following article, we use the model to treat several examples of scaling and breakout in geothermal production systems. For example, we predict from well head concentration data for a Dixie Valley well that 2.328×10^4 kg of calcite scale will precipitate in the well bore in one year of operation. These results demonstrate that important information about the design and operation of a geothermal power production system can be obtained from model simulation.

1) Introduction

Interest in the utilization of geothermal energy continues to grow. However, with this growth there is an increasing awareness of the chemical problems which can hinder the efficient extraction of energy. While the chemistry of geothermal brines has received less attention than other aspects of geothermal operations, problems with the chemistry often limit or completely restrict the exploitation of the resource. Similar problems occur in the petroleum industry; however, they may be less damaging to the utilization of the resource. For example, well damage due to scale formation in oil wells necessitates some down-time to clean up well bores. This is inconvenient but endurable because of the potentially high amount of oil energy extractable per brine volume. On the other hand, scaling in geothermal operations can be of such magnitude as to render them infeasible. This is because of the relatively smaller amount of energy available per volume from geothermal brines and the much greater amounts of brine handled during the energy extraction process.

Chemical problems can be experienced in all phases of geothermal plant operation. Removing brine for energy extraction can cause porosity changes in the formation which result in sealing of the well, thus making it difficult to produce enough brine for continued operation. Chemical incompatibilities encountered during reinjection of waste brines which are out of equilibrium with the receiving formation and formation brine may lead to plugging of the formation. Significant mineral precipitation in power plant equipment is also common. As an example, figure (1) shows a section of pipe, taken from a geothermal power plant in the Imperial Valley, which is almost completely plugged with calcite scale. The costly effects of such pipe scalings have been well documented.

It is important to be able to evaluate the possible effects of brine chemistry on geothermal plant operation for a specified range of conditions in order to assess and enhance the economic value of the resource. Given this capability, proper choices can be made so that chemical problems such as the scale formation illustrated in figure (1) can be avoided or diminished. Such a capability would also allow design criteria to be established for the successful exploitation of a resource. Moreover, it would allow the potential of a possible resource to be evaluated under specified site conditions before substantial investment is made.

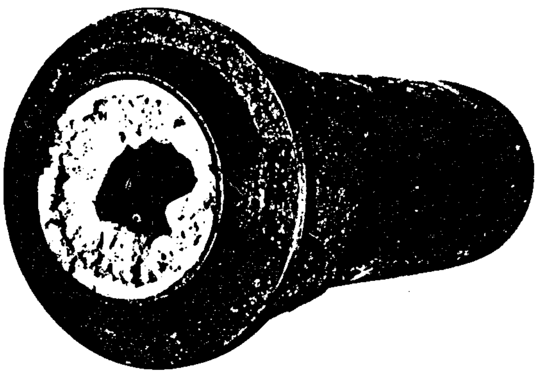

Fig. (1) Calcite scale in a pipe from a geothermal power plant.

In our program at UCSD, we are developing models of brine chemistry which will be used to predict the problems encountered when brines are utilized for the production of geothermal power. Traditionally such problems have been identified either from actual plant production experience or from laboratory simulations. The models we are developing greatly facilitate the identification of such problems, the development of strategies for their solution and the testing of these operational approaches. The models are easily and inexpensively applied to the wide variety of chemical problems that are encountered in geothermals operations. In addition to being a valuable and inexpensive aid to laboratory simulations, these models can provide information about the process chemistry under conditions which are difficult to simulate in the laboratory (e.g., high temperature and pressure environments). In table (1), we summarize some of the ways our chemical models of geothermal brines may be used to optimize geothermal operations.

In prior reports and publications we have given detailed descriptions of our model equations and parameterization procedures (see, for example, Weare, 1987). This article, after a brief description of the model in section (2), will emphasize the application of the model to scaling problems which are common to geothermal plant operation. These applications include discussions of the chemical controls governing the formation of the important scaling minerals, amorphous silica (section (3)) and calcite (sections (4) and (5)).

As is graphically illustrated in figure (1), calcite scale formation frequently plays a role limiting the economic value of geothermal power plant operations. Such chemical problems are particularly difficult to predict because of the relation of the gas phase composition and pressure to the solubility of the scale forming minerals. Because of this relationship, it is critical in plant design to identify conditions under which the working brine will become a two phase system (flash or breakout). In section (4) we discuss the prediction of breakout in geothermal brines from our model. Our results show excellent agreement between on site measurements and the brine breakout predicted by the models.

In designing power plants it is important to have an accurate estimate of the down hole composition of the geothermal fluid. Unfortunately, down hole samples are rarely available because of technical difficulties. Surface samples, on the other hand, may not accurately reflect the down hole composition because the scale forming minerals may have precipitated out of the brine when it was produced. In section (5) we discuss the application of the models to reconstructing down hole brine compositions from surface sample measurements. In the process of reconstructing this composition, potential problems due to brine scaling can be identified.

Table 1

USES OF A BRINE SIMULATION MODEL	
Exploration	
	• Scale Prediction • Formation Water Characterization • Simulation of Chemical Treatments
Plant Design and Operation	
	• Scale Formation • Energy Recovery Prediction • Prediction of Gas Breakout
Waste Treatment	
	• Simulation of Mineral Recovery • Prediction of Environmental Hazards • Simulation of Reinjection Strategies

2) Overview of the Model

In order to predict scale formation from the composition of the working fluid, it is necessary to build a highly accurate model of the thermochemical behavior of the geothermal brine. The solubility of a mineral which produces scale is determined by the interactions of the dissolved solutes composing the solid with the other principal solutes in the aqueous phase. For example, the solubility of the scale forming mineral, amorphous silica, in a concentrated NaCl brine is a function of the interaction between the dissolved SiO_2 species and the dissolved Na^+ and Cl^- ions. Our models focus on the accurate description of these interactions. Recently this work has been reviewed (Weare, 1987).

The model begins with the expression for the free energy, G, of the system:

$$G = \sum_i n_i \mu_i, \qquad (1)$$

Where the summation i is over all solution species and solid phases. This function, if minimized subject to mass balance constraints, gives the amounts of each aqueous species and of the solid phases. Generally, the chemical potentials, μ_i, in equation (1) are further defined in terms of the activity coefficients, γ_i, and concentration m_i of the individual species i in solution by the relation:

$$\mu_i = \mu_i^o + RT \ln m_i + RT \ln\gamma_i^{elec} + RT \ln \gamma_i^{exc}. \qquad (2)$$

The first term on the right hand side of equation (2) is the standard chemical potential. For a pure mineral, this term is the only term needed. For a solution phase species, the three additional terms are necessary. The second term, where m_i is the molality of species i, describes ideal mixing. The third term represents nonideal corrections for long range electrostatic forces and is usually given in terms of the Debye-Hückel activity formula, and the fourth term represents additional (excess) nonideal corrections for highly concentrated brines. As very little is known about concentrated brines, the fourth term must be given in terms of a phenomenological expression, which contains parameters evaluated from experimental data.

Two steps are required to define a model describing brine chemistry. First, the species in solution which appear in equation (1) must be specified. For most geothermal applications, the species in solution are well known (e.g., Na^+, Cl^-, HCO_3^-, etc.). And second, an expression must be given for the fourth term in equation (2). In the models we have been developing, this term is given by the expressions of Pitzer and coworkers (Pitzer, 1987). This approach appears to have the accuracy required while introducing a minimum number of parameters to be evaluated from experimental data. In this approach, the fourth term is represented in the virial expansion form:

$$RT \ln \gamma_i^{exc} = \sum_j B_{ij}(I) m_j + \sum_{jk} C_{ijk} m_j m_k \ldots\ldots \qquad (3)$$

In the first term on the right hand side of equation (3), the coefficient, B_{ij}, is a function of ionic strength (see Pitzer, 1987) containing parameters which must be established from experimental data. The constant coefficient, C_{ijk}, in the second term on the right hand side also is evaluated from experimental data. The procedure for evaluating the required parameters has been discussed in detail in Weare (1987). For most systems of interest to the geothermal community, all the required parameters may be obtained from binary (e.g., $NaCl-H_2O$) and ternary (e.g., $NaCl-CaCl_2-H_2O$) experimental data. The high accuracy of our models, parameterized by these relatively simple data, in applications to very complex systems has been documented in a number of published articles (see Harvie, Møller and Weare, 1984). In the remainder of this article, we will focus on the application of our models to investigate various problems encountered in the geothermal industry.

3) Control of Silica Scale Formation

Scale formation in plant equipment and porosity losses in injection well formations created by the precipitation of amorphous silica have been identified as important problems in the operation of geothermal power plants. The formation water in high temperature hydrothermal systems is usually in near equilibrium with the SiO_2 mineral, quartz. The solubility of quartz below the critical temperature of water is a monotonically increasing function of temperature. Therefore, when hydrothermal brine is produced from a formation and the energy extracted in the geothermal power plant, it would be expected that quartz would precipitate from the cooled brine. Fortunately, however, quartz rarely precipitates because of the slow kinetics involved in this reaction. The more common precipitation product is amorphous silica. At a given temperature, amorphous silica is considerably more soluble than quartz. Its solubility is also an increasing function of temperature. Therefore a brine initially saturated with respect to quartz would not be expected to precipitate any SiO_2 until it reaches saturation with respect to amorphous silica at a considerably lower temperature.

This effect provides a strategy for avoiding silica scaling problems. If a brine is extracted from a formation saturated with respect to quartz at temperature, T_{in}, and if the operating temperature of the power plant is not allowed to decrease below the temperature, T_o, at which amorphous silica will precipitate, then silica scale formation should not be a problem. The difference between the temperatures T_{in} and T_o represents the range of outlet temperatures at which the plant may be operated without scale formation. In the following, we show how the model may be used to calculate the temperature T_o.

The data of Chen and Marshall (1982) were used to evaluate the silica interaction parameters in the appropriate expression for term four in equation (2). The results of this data fitting are given in figure (2) for two of the required subsystems. When all the subsystems have been parameterized from experimental data over an appropriate temperature range, a variable temperature model of amorphous silica solubility for brines of general composition can be constructed. This model can then be used to calculate the solubility of amorphous SiO_2 for a given temperature in an arbitrary brine. Such calculations are illustrated for three different brine compositions in figure (3) (for concentrations, see table (2)). If the measured concentration of amorphous silica in the geothermal brine exceeds the equilibrium value calculated for that brine at a given temperature (solid lines, figure (3)), then precipitation may occur at this operating temperature. For example, consider the Heber brine. If the calculated solubility of amorphous silica exceeds .047 (the concentration of SiO_2 measured in the Heber brine), then we would not expect scale formation. From figure (3) we see that this condition is met for the Heber brine for all temperatures above 160°F.

Of course, the consequences of retaining a high outlet temperature can be expensive. In figure (3), we have also calculated the solubility of SiO_2 in more concentrated brines (Woolsey and Salton Sea) from the Imperial Valley (see table (2)). As can be seen from the figure, SiO_2 is less soluble as the concentration of the solution increases. To operate these wells without silica scale formation requires higher outlet temperatures assuming the same cocentration of SiO_2 in the formation brine. To illustrate the effect of this requirement on the power production of the system, we have calculated the ideal efficiency ($e = \frac{T_{in} - T_{out}}{T_{in}}$) of these brines and have compiled the results in table (3). For the most concentrated brine (Salton Sea) there is a 40% loss of efficiency. Such model calculations may provide valuable information when deciding whether or not to establish a geothermal power plant in a particular area.

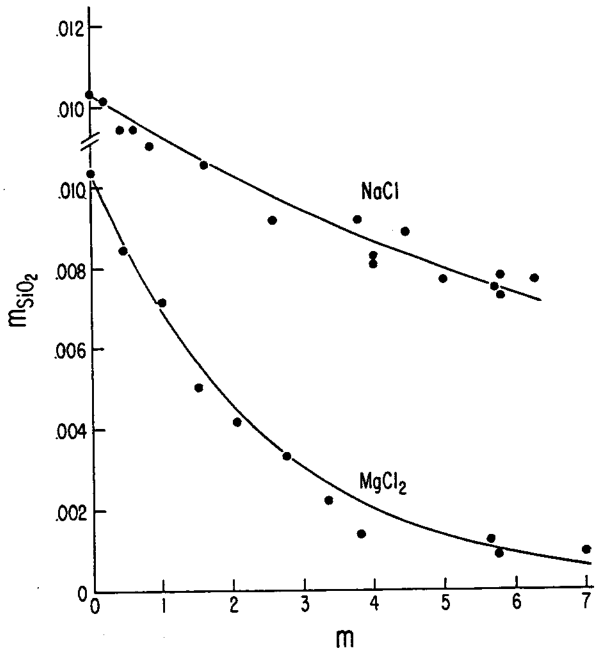

Fig. (2) Solubility of amorphous silica in concentrated brines at 150°C. The solid lines give the model predictions. The points are the data of Chen and Marshall (1982).

Table 2

COMPOSITIONS OF GEOTHERMAL WELL WATERS

Component	Heber	Woolsey	Salton Sea
Na	.1862	1.3801	2.969
K	.0065	.2015	.606
Mg	.00016	.01086	--
Ca	.0522	.50138	.946
Cl	.2222	3.1917	5.921
SO_4	.00086	--	--

4) Prediction of Breakout

Scale formation from the carbonate mineral, calcite, is a persistent problem in geothermal operations. An illustration of the disastrous effects on power plant equipment of such scale has been given in figure (1). The prediction of carbonate deposition is particularly difficult because of the strong dependence of the solubility of calcite on the concentration of dissolved CO_2. The problem is complicated further by the polyprotic acid/base equilibria in the carbonate system. This means that a complete model of the acid/base equilibria in the solution as well as a model of gas to solution equilibria must be available before meaningful predictions can be made. Our group has made considerable progress with such a model. The details of this work have been discussed elsewhere (see Harvie, MΦller and Weare, 1984). In this section and the following, we discuss the application of this work.

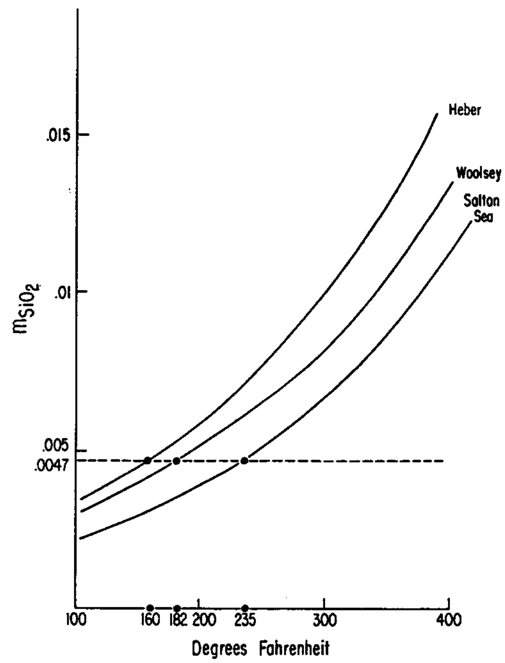

Fig. (3) The predicted solubility of amorphous silica in mixed brines (solid lines). The silica concentration is that of the Heber brine (dashed line).

Table 3

IDEAL EFFICIENCY CHANGES

	Temperature		% Change in Efficiency
	Inlet	Outlet	
Heber	340	162	---
Woolsey	340	180	-10%
Salton Sea	340	235	-41%

The solubility of calcite is a strong function of the solution concentration of CO_2. The solution concentration of CO_2 is in turn a function of the CO_2 pressure above the solution. When a brine forms a bubble (breaks out) and two phase flow begins, the CO_2 concentration in the solution phase drops precipitously. Since calcite is more soluble in high CO_2 solutions, this leads to precipitation of scale if the carbonate system is the principal acid/base system in the brine. For this reason, the onset of two phase behavior in a geothermal operation involving carbonate brines is important to control.

A brine will break out when the vapor pressure of the brine equals the overburden pressure. When a geothermal well is produced, the overburden pressure may be reduced. This can induce break out which may result in scale formation at some point in the well or power plant.

The vapor pressure of a brine is determined from the pure water vapor pressure corrected for the dissolved solute concentration plus the contribution of the confining pressures of the various dissolved gases in the brine. In a typical carbonate carrying brine, the contribution of the dissolved gases to the total vapor pressure of the brine is apt to be of the order of magnitude of the contribution of the water vapor. Typically, dissolved CO_2 is the most concentrated dissolved gas in a geothermal brine. However, other dissolved gases such as methane, which may appear in lesser concentration, may have a higher escaping tendency than CO_2 and therefore contribute considerably to the breakout pressure.

As an example and test of our model, consider the East Mesa brine, the composition of which is given in table (4). The breakout characteristics of this brine as a function of temperature were measured by Robertus (private communication) and are shown in figure (4). As is typical, these concentrations were measured after breakout and therefore the concentrations prior to breakout had to be reconstructed using the model. The calculated prebreakout concentrations are given in table (5). Using these concentrations, the various contributions to the vapor pressure of the brine as a function of temperature can be computed. The results are summarized in table (6) and are plotted as the Δ in figure (4). The agreement between the calculated breakout and the measured values is within experimental accuracy. Note that for this brine, the contribution to the vapor pressure from dissolved gasses is of the same magnitude as the contribution from water vapor.

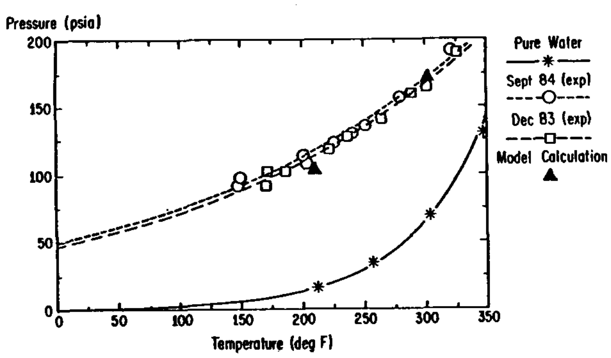

Fig. (4) CO_2 breakout conditions in the Magma plant inlet.

5) Prediction of Calcite Deposition in Well Bores

Our calcite solubility model may also be used to calculate the amount of calcite deposited when geothermal water is produced from a formation. In the following example, measured well head concentrations for a Dixie Valley well (table 7), supplied by Marshall Reed of DOE, were used to calculate the saturation index, SI, of the brine under various conditions. SI, which is defined as:

$$SI = \left\{ \frac{\prod_i a_i^{\nu_i}}{K_{sp}} \right\}, \qquad (4)$$

gives an estimate of the ability of the brine to precipitate or dissolve calcite. In equation (4), a_i is the activity of solution species i. ν_i is the stoichiometric coefficient of species i in the mineral. K_{sp} is the solubility product of the species composing the mineral of interest. (For example, for calcite, $S.I. = \left\{ \frac{a_{Ca^{++}} a_{CO_3^=}}{K_{sp}} \right\}$.) A value of S.I. greater than 1.0 indicates that the brine is supersaturated and can precipitate scale, while a value less than 1.0 indicates that the brine is undersaturated.

Table 4

ANALYTICAL DATA SUPPORTING CO_2 BREAKOUT TESTS

Gas/Liquid Ratio = 0.31 Liters/Kg at 39°C. Gas Volume also at 39°C.

	mg/l		mg/l
Al	0.0	Cl^-	3449.0
As	0.5	$SO_4^=$	70.0
B	6.75	HCO_3^-	492.0
Ba	0.80	Tot CO_2	1519 (1738 in Jan.85)
Ca	51.5	pH = 5.71	@43°C
Fe	15.5	15.1 psia	
K	210		
Li	6.60		
Mg	1.80		
Na	2035.0		
Si	103.0		
Sr	11.70		
Cu	1.10		
Mn	0.25		

Anion/Cation Analysis

Components	Moles
CO_2	72.9
Ar	0.16
O_2	1.13
N_2	9.20
CO	< 0.10
He	< 0.01
H_2	0.27
CH_4	16.3

Table 5

RECONSTRUCTED EAST MESA BRINE COMPOSITION

Component	Concentration (m.)
Na^+	.108
Ca^{+2}	.00135
Cl^-	.102
HCO_3^-	.00848
CO_2	.03169

Table 6

CONTRIBUTIONS TO BREAKOUT PRESSURE

Temperature (°C)	P_{CH_4} atm.	P_{CO_2} atm.	P_{H_2O} atm.
150.	26.	77.	69.
200.	16.	72.	225.

Table 7

COMPOSTION OF WELL HEAD WATER DIXIE VALLEY [a]

	I[b]	II[c]
Na	0.01143	0.01143
Ca	0.0000178	0.0000178
Cl	0.00777	0.00777
HCO_3	0.00329	0.00329
CO_3	0.000203	0.000203
CO_2	0.0	0.0516

[a] Brine compositions from Marshall Reed.

[b] Brine composition after flash.

[c] Brine composition with CO_2 reintroduced.

The calculated solution compositions using the water concentrations given in table (7) are summarized in table (8). The first row contains calculated values for the separated brine (flashed brine) calculated from the separated brine concentration (table (7), column I). As indicated in table (8), row 1, the SI for this brine is supersaturated with respect to calcite, indicating that some calcite precipitation may have occurred. Generally, complete equilibrium is not obtained in a flashing system. In the second row, the concentrations used were those calculated when the gas phase was incorporated in the separated brine (column II, table (7)). As expected, because of the increase in dissolved CO_2, the brine is now undersaturated with respect to calcite.

There are two explanations of the undersaturation (low value of Ca and CO_3 in the brine) of the well head water when brought back to formation conditions by theoretically incorporating the outgassed CO_2. Either calcite was not present in the formation and therefore the brine did not reach saturation, or calcite precipitated when the brine flashed. In the latter case, calcite has been deposited in the well bore. When the CO_2 and other gasses are reincorporated in the brine for purposes of calculation (column II, table (7)), this lost calcite is not included. We can estimate the amount of scale deposited by using the model to reequilibrate the reconstructed formation brine with calcite. The results of such a calculation are given as row 3, table (8). Subtracting the Ca concentration in row 2 of table (8) from the value in row 3 of the table gives the amount of Ca ($.97 \times 10^5$ mole) deposited per kilogram of water produced from this formation. According to Reed's measurements, 2.4×10^9 kg of brine would be produced from this well per year. Therefore 2.328×10^4 kg of scale would be deposited in the well bores.

Table 8

SATURATION CALCULATIONS FROM THE DATA OF REED

Case	CO_2	HCO_3	CO_3	Ca	P_{CO_2}	pH	SI
1[a].	.000902	.00256	.000036	.0000178	0.090	8.1	2.3
2[b].	.0514	.00365	.0000053	.0000178	5.1	6.5	0.65
3[c].	.0514	.00368	.0000078	.0000275	5.1	6.5	1.0

a Calculated using composition I, table 7.

b Calculated using composition II, table 7 calcite not allowed to dissolve.

c Calculated using composition II, table 7 calcite allowed to dissolve.

The accuracy of the model for calculations such as those in the last example could be tested if both downhole and well head samples were available. Unfortunately, such samples are difficult to find. An alternative is to test the model against laboratory simulations of down hole conditions as reported by Shaughnessy and Kline (1982). In these simulations, which were done to analyze oil well field damage from scale formations, surface brine samples were re-equilibrated with formation rocks in an autoclave at 100°C. Our model can be used to compute the amount of Ca under simulated formation conditions. The results of the model calculations are compared to the laboratory data in table (9). As can be seen from the table, the predictions of the model are in excellent agreement with the Shaughnessy and Kline (1982) laboratory simulation. These results support the calculations given in the prior paragraph suggesting that our calculations using the Dixie Valley data are correct.

Table 9

MODEL CALCULATION OF CALCITE SOLUBILITY IN HIGHLY PRESSURED FORMATION WATERS AT 100°C

	Equilibrium composition of surface brine	Composition of surface brine re-equilibrated to formation conditions (calcite present) $P_{CO_2} = 34$ atm. EXPERIMENT	Composition of surface brine re-equilibrated to formation conditions (calcite present) $P_{CO_2} = 34$ atm. MODEL CALCULATION
Na^+	.331 m.	.331 m.	.331 m.
Cl^-	.301	.301	.301
Ca^{+2}	.00042	.006	.00567
HCO_3^-	.030	.042	.043

It is a pleasure to acknowledge many discussions with Marshall Reed (DOE), Don Shannon (Battelle) and Bob Robertus (Battelle).

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MONITORING THE MATERIALS AND CHEMISTRY OF A GEOTHERMAL PLANT

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ABSTRACT

Geothermal energy has considerable potential to improve the energy independence of the United States and to reduce dependence on foreign sources of oil. However, only a few of the most economical geothermal sites are cost-competitive today because energy prices are affected by the current low price of oil. Most forecasts of future energy prices indicate prices for oil will probably increase, which will expand the future opportunities for geothermal development. However, rather than waiting for energy prices to increase, geothermal utilization can be increased right now by decreasing the costs of geothermal site development, plant operation, and maintenance.

One of the major ways to reduce geothermal costs is through control of corrosion and mineral scaling and plugging of injection wells, some of which are discussed below.

This paper will review the components of geothermal brines that cause corrosion and scaling problems, especially brine pH, CO_2, H_2S, oxygen (from air), silica, calcium, sulfides, and suspended particulates. Instrumental methods for on-line measurement will be discussed to show how to keep costs low by operating a geothermal plant from a position of knowledge of what is occurring to the plant materials. The U.S. Department of Energy (DOE) research and development (R&D) program in brine chemistry and on-line instrument development at Pacific Northwest Laboratory (PNL)[a] will be discussed along with the strategy for commercial availability of new instruments to the geothermal industry.

INTRODUCTION

Geothermal energy has considerable potential to improve the energy independence of the United States and to reduce dependence on foreign sources of oil. However, only a few of the most economical geothermal sites are cost-competitive today because energy prices are affected by the low current price of oil. Most forecasts of future energy prices indicate prices for oil will probably increase, which will expand the future opportunities for geothermal development. However, rather than waiting for energy prices to increase, geothermal utilization can be increased right now by decreasing the costs of geothermal site development, plant operation, and maintenance.

One of the major ways to reduce geothermal costs is through control of corrosion and mineral scaling, and plugging of injection wells. Corrosion and mineral scaling problems usually start as soon as drilling begins, and continue throughout the life of the geothermal plant. Geothermal fluids are not pure water, but rather are a "rock soup" created by stewing the minerals in the underground reservoir with water at high temperatures for years or even centuries. This "rock soup" is further spiced with the addition of noxious gases. If the chemistry of these geothermal fluids is measured and the plant materials and design are adjusted to account for the fluids, then operational costs can be controlled. However, if site development proceeds as if the only important problem is the most efficient conversion of the heat energy to electricity, then operational problems are guaranteed to occur. It should be emphasized that the cost of geothermal electricity as measured in mills/kWh becomes infinite if the plant is forced to shut down and the kWh in the denominator becomes zero.

Monitoring the Brine Chemistry

In conventional fossil-fired or nuclear steam boilers, it is the normal practice to control boiler water chemistry to strict standards. It is recognized that the plant life depends on careful boiler water treatment and chemical monitoring to ensure that the plant is operating within specifications.

In geothermal plants the geothermal fluids are taken largely as nature provides them, since any significant water treatment is uneconomical with the very large once-through fluid volumes needed. This means that the plant designers must understand the chemistry of the geothermal brines and gases being used, as well as the behavior of the plant materials in that environment. Problems arise when the chemical properties of geothermal fluids are not considered. Sometimes there is a surprise because of some minor component in the brine makeup that is very destructive to the plant materials, causes mineral scale deposits, or plugs injection wells.

It is usually not the major chemical components of a geothermal brine that cause plant problems. The two major factors controlling the corrosion of materials are the pH (acidity) and the presence of oxygen. Scale deposition is usually associated with the minor brine components silica, calcium, barium, strontium, and heavy metal sulfides such as lead, zinc, and arsenic. Dissolved gases are extremely important, especially carbon dioxide, hydrogen sulfide, and oxygen (if present).

(a) The Pacific Northwest Laboratory is operated for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 by Battelle Memorial Institute.

Fortunately, dissolved oxygen gas does not exist in a geothermal reservoir. However, once the fluids reach the surface, air in-leakage is an ever-present possibility. If air in-leakage occurs (such as during a maintenance outage), a normally benign environment may turn extremely aggressive to the plant components. In-line instruments are available to detect this environmental change and will be discussed below.

The pH of geothermal fluids is controlled by a complex chemistry involving the dissolved gases, rock minerals, and buffering anions such as bicarbonate and carbonate. The pH is the most important chemical parameter controlling both scaling and corrosion.

It has been noted many times that the high-saline Niland brines are highly corrosive, and there is a tendency to attribute the corrosiveness to the high salinity or high total dissolved solids. This is misleading. As the salinity of a brine increases, ion exchange with the reservoir minerals occurs where sodium, potassium, and calcium ions exchange with hydrogen atoms in the minerals, increasing the H^+ in solution. This process called hydrogen metasomatism leads to increasing acidity (lower pH) as salinity increases. Niland brines have acid pH values of 4 to 5, and it is this increased acidity (e.g., dilute hydrochloric acid), that causes the high corrosion rates--not the high salinity itself. This explanation is an example of the benefits of continuing basic research in brine chemistry.

The pH measurement of the brine is the most important item in the brine analysis. However, laboratory pH measurements on samples which are cooled, depressurized, and degassed are of little use. Much of the published data on brine analyses contain erroneous pH measurements. What is needed are on-line pH sensors operating at full system temperature and pressure. Down-hole logging tools are needed to measure the pH of the fluid in the reservoir. Commercial pH sensors are currently limited to about 220°F and with very limited pressure capability. The U.S. Department of Energy has sponsored research on new pH sensor concepts in the past, and progress has been made. However, work is currently stopped.

Monitoring Materials and Corrosion

One of the problems that the corrosion engineer faces is acceptance by plant operations personnel that corrosion problems may exist and need attention. If the plant is running the philosophy may be, "If it ain't broke, don't fix it." Unfortunately, by the time the plant "breaks", it may be too late to fix it. To use a medical analogy, do we consider a problem to exist when high blood pressure begins, or is there no problem until a stroke or heart attack occurs? By detecting and treating the high blood pressure early, a far more serious problem can be avoided. Materials performance can also be monitored, and operating conditions that are destroying the plant can be modified in time to make a difference. Techniques have been developed to insert coupons in sensitive regions of a plant for periodic inspection. On-line corrosion monitoring instruments are available which can sound an alarm when corrosive conditions exist. Experience with such monitoring methods has been documented.[1,2]

One of the reasons more materials monitoring is not done is a lack of experienced corrosion engineers available to the plant operating staff to operate and interpret the output of the instruments. A full-time corrosion engineer is not necessary, and the industry is not yet large enough to support an easily available service industry. One of the ways which Pacific Northwest Laboratory has proposed to help this training problem is through implementation of easy-to-use personal computer programs based on newly available Artificial Intelligence software. Such a computer program would help plant operating personnel diagnose their own problems and determine when it really is necessary to consult a "materials doctor." PNL has proposed preparation of such a knowledge base of the results of the past decade of research, and making this available to the industry as a diagnostic and training tool. If there is interest in such a "technology transfer" effort, the reader is urged to communicate this interest to DOE.

Particulate Monitoring

Economical operation of a geothermal plant requires disposal of large volumes of spent brine by injection back into the reservoir. If the injection wells plug, then the plant must either curtail power output, go to higher injection pressures with a larger parasitic power load, drill more injection wells, or conduct expensive well work-overs. The cause of injection well plugging is suspended particulates in the injected brine, or scale deposits in the well.

There are three main areas in a geothermal power plant where the ability to monitor particulates on-line would improve the technical and economical operation of the plant:

1. The Production Well: For example, injection of a calcite scale inhibitor; an on-line particulate monitor may be able to accurately determine the minimum dosage.

2. Solids Removal Process: For example, the reactor clarifier/filtration processes in the plant would be able to use an on-line monitor to perform final adjustments for flow rate, residence time, and additive dose.

3. Injection Well: The lifetime of the injection well is directly related to the quantity and size of injected particulates; and an on-line monitor would protect the well from transient particulate spikes by identifying when plant operations are causing increased particulate loadings.

PNL is developing and testing two units (one laser and one ultrasonic) for operation at temperatures in the 150° to 250°F range (injection side), 350°

to 450°F (production side), and pressures in the 200 to 700 psi range.[3,4]

Research and Development Needs

In 1987, the National Research Council convened a workshop of university and geothermal industry participants to focus on geothermal energy research and development and on related cooperative arrangements.[5] The workshop prepared a number of conclusions, two of which are relevant to this paper:

> "Many geothermal waters leached from reservoir rocks contain dissolved solids and gases that corrode materials. Materials fail relatively quickly unless preventive measures are taken and corrosion-resistant materials are used.
>
> "Control of corrosion is better understood today, but much remains to be learned about the complex chemistry of fluids and their behavior under variable operating conditions. Research on corrosion prevention techniques is needed, especially in the following areas:
>
> - Chemical corrosion inhibitors
> - Cathodic and anodic protection
> - Chemistry and kinetics
> - Sampling and analysis.
>
> "Alternative cost-effective materials are needed to limit corrosion, enhance system performance, and reduce maintenance requirements. Research is needed on high-temperature elastomer formulations for dynamic seals and on fabrication and field-testing of elastomer-lined well casings. High thermal conductivity nonmetallic composite materials for heat exchanger tubing and metallic cladding for well casings are also needed."
>
> "Fluid injection may result in precipitation of scale from the brine, blocking the flow paths and requiring either expensive workover or drilling a new well. Because dissolved solids from a given well vary, effective continuous monitoring instrumentation is needed, as are models to predict the degree of scaling under variable fluid conditions."

In conclusion, there remains a need for continued work on 1) the basic science of geothermal brines, 2) the kinetics of the interactions between the geothermal fluid environment and plant materials, 3) on-line monitoring methods to permit plant operators to operate from a position of knowledge of what is occurring to the plant, and 4) technology transfer such as easy-to-use computerized diagnostic knowledge bases.

The PNL program includes instrument subcontractors who will provide a commercial source of the instruments after development is complete.

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Improving the Efficiency of Binary Cycles

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ABSTRACT

The performance of binary geothermal power plants can be improved through the proper choice of a working fluid, and optimization of component designs and operating conditions. This paper summarizes the investigations at the Idaho National Engineering Laboratory (INEL) which are examining binary cycle performance improvements for moderate temperature (350 to 400 F) resources. These investigations examine performance improvements resulting from the supercritical vaporization and countercurrent integral condensation of mixed hydrocarbon working fluids, as well as the modification of the turbine inlet state points to achieve supersaturated turbine vapor expansions. For resources with the brine outlet temperature restricted, the use of turbine exhaust recuperators is examined. The reference plant used to determine improvements in plant performance in these studies operates at conditions similar to the 45 MW Heber binary plant. The brine effectiveness (watt-hours per pound of brine) is used as an indicator for improvements in performance. The performance of the binary cycle can be improved by 25 to 30% relative to the reference plant through the selection of the optimum working fluids and operating conditions, achieving countercurrent integral condensation, and allowing supersaturated vapor expansions in the turbine.

INTRODUCTION

The Heat Cycle Research Program is currently investigating the potential improvements to power cycles utilizing the moderate temperature geothermal resources. The technology being considered either improves the performance and reduces the cost of electricity, or it provides a means of utilizing a marginal resource (because of institutional or technical barriers). Although geothermal energy is provided by nature, it is generally expensive to produce, and compared to fossil fuel is a low grade energy source. Because of the low quality and high cost of the energy, optimized power cycles should utilize as much of the energy contained in a unit mass of the fluid as possible. The net brine effectiveness, or the net electrical power produced by the plant per unit mass of brine, is used as a primary indicator of the improvements in the cycle performance. This method of optimization was confirmed with both a "value analyses" study (1) and a "market penetration" study (2). These studies examined the impact of performance improvements on the cost of electricity and on the future utilization of geothermal energy to produce electrical power.

The current Heat Cycle Research Program investigations are specifically examining binary power cycles. This type of cycle was selected because of its high brine effectiveness relative to a flash steam cycle for the moderate temperature resources of interest. In these binary power cycle investigations, the program is examining those operating conditions, working fluids, and component designs which will provide the optimum cycle performance for the moderate temperature resource. At resource conditions similar to those at the Heber binary plant, Demuth (3,4) found that mixtures of saturated hydrocarbons (alkanes) gave improved performance over that obtained with the corresponding pure working fluids. Bliem (5) in subsequent studies showed that the same results were true if halocarbon mixtures (Freons) were used.

In order to evaluate the relative gain in performance from the concepts being considered, a baseline or reference plant was defined. As indicated previously, the reference plant used in the analyses is based on the predicted performance from a binary plant operating at conditions similar to those at the Heber 45 MW binary plant. The Heat Cycle Research Program investigations are concerned with the advances and performance improvements beyond those projected for the reference plant; these improvements are the topic of this paper. The analytical investigations of these improvements in performance are given in References (3-6).

With analytical projections of performance improvements, field investigations were initiated to further examine the potential performance gains with these concepts. These field studies verify the validity of the assumptions used in the predictions, and the adequacy of the "state-of-the-technology" design methods and fluid transport properties. The field investigations are being conducted at the Heat Cycle Research Facility currently located on the East Mesa of California's Imperial Valley.

Studies are also being conducted on alternative schemes for rejecting the heat loads in the binary cycles. Geothermal resources are typically found in regions lacking in either an adequate quantity or quality water supply for cooling water make-up. Preliminary scoping studies suggest make-up water requirements could be reduced by 20% without significant performance penalties. This area will be the next topic of investigation in the program.

This experimental program is being conducted at the Idaho National Engineering Laboratory. The work is supported by the U.S. Department of Energy, Assistant Secretary for Conservation and

Renewable Energy, Office of Renewable Technologies, under DOE contract No. DE-AC07-76ID01570. Mr. Raymond LaSala of the Geothermal Technology Division is the program manager.

APPROACH

The overall objectives of the Heat Cycle Research Program are 1) to improve the performance of binary geothermal power plants through the utilization of advanced plant concepts, and 2) to expand the base of resources that can be economically developed by removing institutional and technical barriers. The approach utilized by the Heat Cycle Research Program to achieve these objectives is summarized below:

- identify concept or innovative scheme
- conduct thermodynamic analyses of concepts and determine potential impact on utilization of the resource
- review concept and projected impact with others in industry
- confirm analyses of concept with experimental testing
- utilize experimental investigations to examine concepts where analytical scoping is not possible, or to examine innovative schemes with the potential to expand resource base.
- review analysis of investigations with industry and report results

As concepts are identified, analyses of the concept's impact on the cycle performance and costs (both capital and O&M) are conducted. Once these are defined, studies are made to determine the impact on the cost of power and the resource utilization. The "value analyses" and "market penetration" studies mentioned previously have provided the basis for determining the impact of the concepts on the economics of power generation. The recent development of the IMGEO code (7) provides an additional method for examining the impact of cost reductions and performance improvements on the cost of electricity.

As concepts are identified and determined to have benefit, they are discussed and reviewed with individuals involved in industry to evaluate concept acceptance by the industry and determine whether additional investigations are merited. The present program plan was reviewed by a informal panel of industry personnel familiar with concerns relating to the generation of electrical power from geothermal binary cycles. As detailed plans of investigation are formulated and results are obtained, the findings are reviewed with these individuals prior to reporting.

When it is determined that further investigation of a concept is warranted, field testing is conducted. In the Heat Cycle Research Program the field investigations are conducted utilizing the Heat Cycle Research Facility (HCRF). The HCRF is an experimental binary cycle facility used to conduct both concept and component investigations. Although the HCRF components have functions similar to those of typical binary power plant, they differ both in size (nominal power output of 50 kW) and in component design. The HCRF components are designed to take advantage of an advanced concept or to provide flexibility in testing.

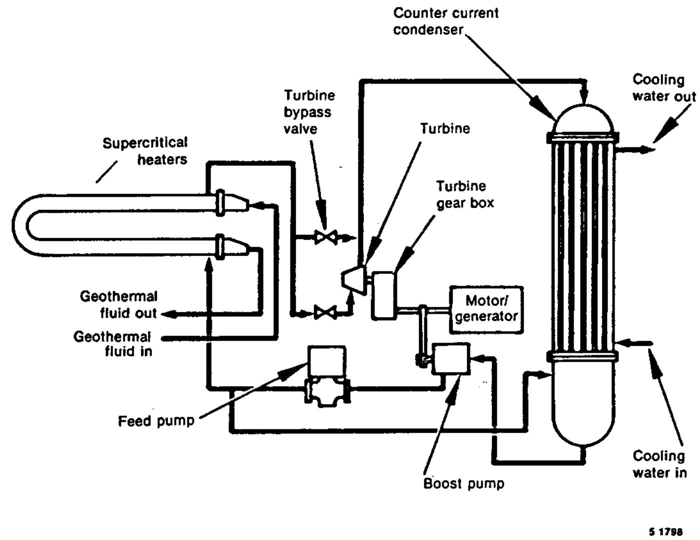

Figure 1. Flow Schematic for Heat Cycle Research Facility

The present configuration of the HCRF is shown schematically in Figure 1. In this configuration, the facility is operated as a supercritical cycle. The working fluid is circulated in a closed loop. It is first pumped to the supercritical heaters where it is preheated and vaporized at a pressure above the working fluid critical pressure. Geothermal fluid circulating through the tube side of the supercritical heaters, provides the heat required to vaporize the working fluid. The working fluid vapor leaving the supercritical heaters can be expanded either through a turbine or through an expansion valve to the condenser pressure. This low pressure vapor is condensed on the tube side of a countercurrent flow condenser. The heat rejected in condensing the working fluid is transferred to a cooling water circulating through the shell side of the unit. The working fluid condensate is then pumped back to the heater and the cycle repeated.

The field investigations conducted with the HCRF can focus on the component or the cycle performance with a particular working fluid. Investigations are conducted with working fluids ranging from a pure fluid to mixtures containing from 5% to 50% of the heavier component (by mass). Investigations to date have been conducted with fluids from the isobutane, hexane and the propane, isopentane working fluid families. Concurrent with the field investigations, the data is evaluated with existing "state-of-the-technology" design methods and fluid property codes to determine the adequacy of these design tools. As these design methods and property codes are used, results are discussed with those from whom the codes were obtained. Typically the analysis conducted by the program is beyond what the codes and methods were intended. For the advanced plant concept investigations, heat exchanger design codes from Heat Transfer Research Inc. (HTRI) and a National Bureau of Standards property code, EXCST (8), are utilized to evaluate component performance. Engineers from the INEL involved in the data analysis have worked with HTRI in the development of the methods for evaluating the data and the interpretation of the code predictions. As results of the data evaluation are completed, they are reported in formal report documents and in the proceedings of technical conferences.

ADVANCED CONCEPTS

For a geothermal power cycle utilizing a given resource temperature and rejecting heat to a given sink temperature, there is a theoretical maximum amount of work that can be produced per unit mass of brine. This is the change in the thermodynamic availability of the brine between its initial state and the state corresponding to the sink temperature. The actual work is less the amount of thermodynamic irreversibilities generated during each of the real processes in the cycle. The following concepts were identified which could decrease these irreversibilities and thus improve the cycle performance.

- the use of working fluid mixtures of non-adjacent hydrocarbon with integral mixing during phase changes
- countercurrent flow in all heat exchangers
- turbine exhaust recuperation to preheat the working fluid if minimum brine temperature is limited
- supersaturated turbine expansions (through two phase region)

To illustrate the principle behind the use of the mixtures in counterflow, the general thermodynamics of two simple binary cycles are shown in Figure 2. The solid lines illustrate a cycle using a pure fluid and the dashed lines a similar cycle using a mixed working fluid. The irreversibility generated in a heat exchanger process is directly related to the entropy production in the process. It can be shown therefore that the average difference in the temperature between the two fluids in the heat exchange process is a measure of the irreversibility introduced. In comparing both the heat addition process and the heat rejection process for each cycle shown in Figure 2, the temperature differences between the streams is substantially lower for the mixtures. These lower temperature differences correspond to a lower entropy production and lower cycle irreversibilities when the mixtures are used. To achieve this performance improvement with the mixtures, the countercurrent flow paths in both the heat addition and heat rejection processes must be maintained. It is also necessary to maintain the thermal equilibrium between the liquid and vapor phases during a working fluid phase change This is referred to as integral boiling or condensation. Uncertainties in designing heat exchangers to achieve integral boiling is one reason for selecting supercritical cycle operation where there is no discrete phase change and integral boiling of mixtures is not a concern.

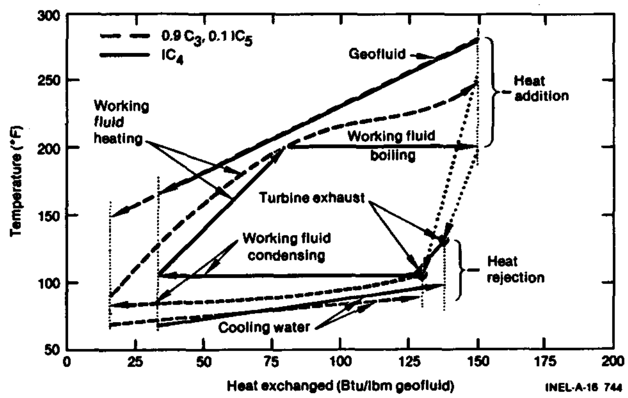

Figure 2. Temperature Heat-Load Diagrams for Binary Cycles

With certain brines a minimum outlet temperature is maintained to prevent the precipitation of amorphous silica (if temperature drops below limit, precipitation will form). It has been shown analytically (6) that the use of a turbine exhaust recuperator to preheat the working fluid, recovers the decrease in the net brine effectiveness that results when the lower brine temperature limit is imposed.

The final advanced concept considered is the use of supersaturated turbine expansions in the supercritical cycle operation. The improvements possible is applicable to those working fluids which have a tendency to dry on expansion (move further from the saturation line). Figure 3 illustrates the power cycle for such a fluid. Typical turbine expansions occur outside the two phase region (represent by the expansion from 3 to 4). Supersaturated expansions are represented by the isentropic expansion between 3' and 5. The previous work by Demuth (9) indicated that during the supersaturated expansions, no condensation would occur (depending upon the turbine inlet state point). The impact of allowing these types of expansions in the cycle is illustrated in Figure 4. For a given minimum temperature difference between the brine and working fluid, the cycle whose turbine expansion passes through

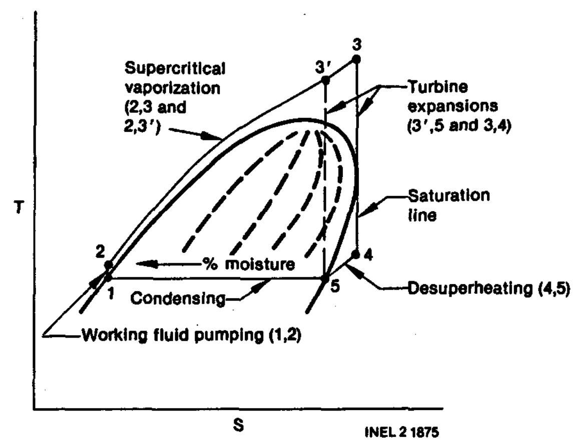

Figure 3. Binary Cycle Showing Two Types of Turbine Expansions

the two phase region, requires less heat addition and allows the brine to be exhausted at a lower temperature. Less brine is required, and given no adverse impact on turbine efficiency, the net brine effectiveness increases.

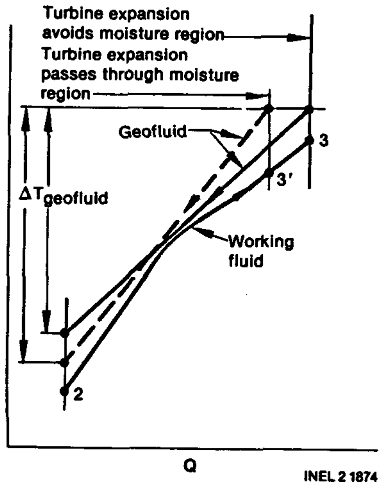

Figure 4. Temperature Heat-Load Diagrams During Working Fluid Heating for Two Types of Turbine Expansions

PERFORMANCE IMPROVEMENTS

To quantify the performance gains, cycle parameters were established to provide for comparison on an equivalent basis with the reference plant.

- The brine resource delivered fluid at 360 F to the plant. The brine pumping requirements (per lb of fluid) were considered the same for all cases, and not included in calculations.
- An ambient wet bulb temperature of 60 F was used. Cooling water was delivered to the plant at 70 F. Cooling tower parasitic losses were calculated using methods described in Reference 4.
- Pinch points of 10 F were assumed. Pump and turbine efficiencies were assumed at 80% and 85%. Motor and generator efficiencies were assumed to be 100%. Frictional losses in piping and components were assumed the same in all cases, and not included in calculations.

With these assumptions, the reference plant performance was determined to be 7.73 w-hr/lb of brine. This plant operated with a turbine inlet pressure of 580 psia and utilized a 90 % isobutane, 10% isopentane (mole fraction) working fluid. The reference plant utilized a horizontal condenser with the working fluid condensation on the shell side; for this configuration differential condensation was assumed.

If the same working fluid and turbine inlet conditions are used and countercurrent integral condensation is achieved, the net brine effectiveness is increased to 8.17 w-hr/lb of brine. This is an increase of 6% in the brine effectiveness relative to the reference plant. (Note to achieve integral condensation, the liquid and vapor phases of the mixture must remain intimately mixed throughout the condensation process. If achieved, total condensation will occur at the mixture bubble point temperature.)

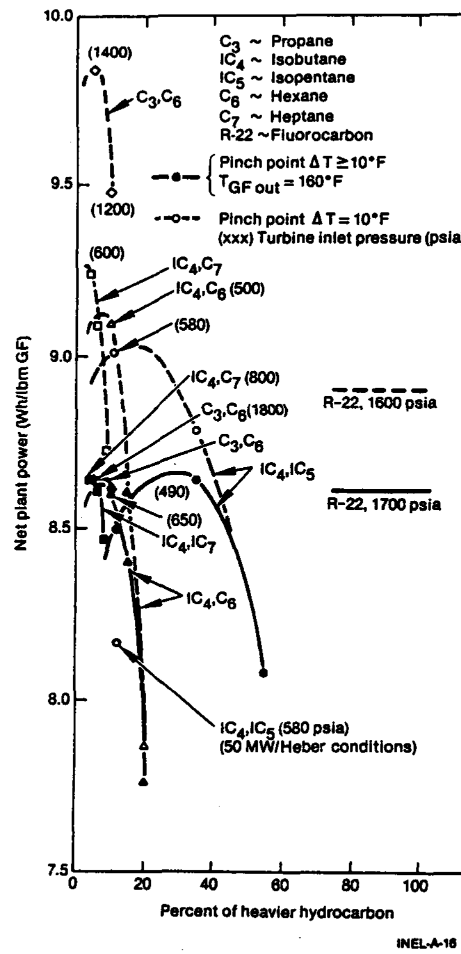

Figure 5. Maximum Brine Effectiveness for Binary Cycles (Brine Inlet Temperature of 360 F)

Previous studies by Demuth (4) indicated that for a 360 F resource temperature, other working fluids and operating points provided superior performance (see Figure 5) to those used in the baseline, or reference plant. Using a 96% isobutane, 4% heptane working fluid and a 600 psia turbine inlet pressure, increased the net brine effectiveness to 9.25 w-hr/lb of brine. This performance improvement reflects achieving countercurrent integral condensation with the mixture, and assumes no constraint on the brine outlet temperature. This is a 20% increase over the reference plant performance.

If the brine outlet temperature is constrained (for these studies, a 160 F minimum constraint imposed) to prevent silica precipitation, the improved plant performance would be 8.64 w-hr/lb of brine. This is an increase of 12 % relative to the reference plant. Demuth and Kochan (6) showed that with the brine exhaust temperature constrained, the addition of a turbine exhaust recuperator to preheat the working fluid increased the brine effectiveness to 9.25 w-hr/lb of brine. This returned performance to the level of the improved plant without the temperature limit and represents a 20% improvement relative to the reference plant.

The final improvement investigated is achieved when the vapor expansion through the turbine is allowed to pass through the two phase region (termed supersaturated expansions). When a supersaturated turbine expansion is permitted in the improved cycle, the net brine effectiveness is increased to 10.0 w-hr/lb of brine (assuming no loss in turbine efficiency). The resulting cycle with the improvements previously described, provides a performance improvement of 29% over the reference plant.

IMPACT ON COST OF POWER

The Heat Cycle Research Program developed and approach called the "value analysis" (1) to evaluate the impact of performance improvements on the cost of electrical power. This approach is based on relative changes to costs and performance, and provides a means of estimating the relative effect on power costs without performing a facility cost estimate. For the optimized plant which achieves the 20% improvement in the net brine effectiveness, the cost of electricity is estimated to be reduced 13%. When supersaturated turbine vapor expansions are allowed, resulting in a total performance improvement of 29%, an additional estimated reduction of 5% to 6% in power costs is achieved for a total reduction of approximately 18%. The impact on the cost of power from these projected binary plant performance improvements can also be evaluated using the IMGEO model. This model utilizes a different approach to determine the impact on cost of power. Where the value analysis utilizes and projects relative impacts on the cost and performance, IMGEO predicts the actual cost of electricity that result from an improvement in performance or costs. Utilizing the IMGEO model (base case prediction for the Imperial Valley), a 20% improvement in the net brine effectiveness provided a 10% reduction in power costs. A 29% improvement in plant performance was projected to reduce the power cost by 12%. Although slightly different (reflecting the different assumptions and approaches used), the models do predict reasonably consistent impacts on the power. If one incorporates these concepts, one could expect reductions in cost of power ranging from 12% to 18%.

EXPERIMENTAL VERIFICATION

After the identification of concepts improving performance and reducing power costs, experimental investigations were initiated to verify the gains in performance. The major activity in the Heat Cycle Research Program is currently this experimental verification. The investigations are conducted with the Heat Cycle Research Facility components configured to provide performance data for verification of the different concepts. The heaters are designed to vaporize working fluid mixtures at supercritical pressures and temperatures. The units include instrumentation necessary to produce the data for evaluating the ability of "state-of-the-technology" design methods to predict size and performance.

Results of testing suggest design methods and property codes available are adequate for specifying a supercritical heater for operation with the hydrocarbon working fluid mixtures. No operational problems attributable to the supercritical operation have been noted with these heat exchangers.

The condenser is designed to provide countercurrent integral condensation to achieve the projected performance gains with the mixed working fluids. The condenser is fabricated to provide in-tube condensation of the working fluid, with internal fins to augment the heat transfer area. The condenser was originally installed in the vertical orientation to provide the optimum opportunity to achieve integral condensation. The condenser position can also be varied to provide data at non-vertical inclinations (user desired orientations). The condenser position has been varied and data collected at two additional orientations. As with the heaters, the condenser is instrumented to provide data for evaluating the most current design codes. The evaluation of the data collected also provides information relative to the adequacy of the available fluid thermophysical property codes.

Results of the adequacy of the "state-of-the-technology" design codes for the condenser are currently inconclusive; particularly for the non-vertical operation. In the analysis of data collected to date, no deviation has been noted from the assumption of integral condensation, including testing designed to magnify the deviation.

Some preliminary investigation of the supersaturated turbine expansions has also been attempted. This testing examined the impact of these expansions on the efficiency of an existing impulse turbine. Preliminary results indicate there was no adverse effect on the turbine efficiency for those expansions considered. This effort will be expanded to include investigations with a two-dimensional expansion nozzle to identify those conditions which produce condensation droplets during expansion. A radial inflow reaction turbine will be tested to 1) determine the impact of the supersaturated expansions; 2) identify effect on efficiency when working fluid mixtures are used; and 3) evaluate the predicted higher performance of these types of expanders.

CONCLUSIONS

From the analytical studies and experimental investigations conducted in the Heat Cycle

Research Program, the following conclusions have been reached.

- Analytical studies indicate that performance improvements in binary power cycles of up to 29% can be reached relative to a current technology plant (approximated by the Heber binary plant). Performance improvements can be achieved through supercritical cycle operation with the proper working fluid mixture, achieving countercurrent integral condensation, and allowing supersaturated vapor expansions through the turbine.

- These performance improvements are projected to reduce the cost of electrical power by an estimated 12% to 18%.

- Experimental investigations have indicated that current "state-of-the-technology" methods are adequate for the design and fabrication of supercritical vaporizers with working fluid mixtures. Available property codes have been adequate for predicting thermophysical fluid properties for the mixtures.

- No deviation from the assumption of integral condensation has been noted in performance data obtained indicating the use of in-tube condensation design will achieve the desired equilibrium between the liquid and vapor phases during condensation. The adequacy of existing methods for the design of a condenser to achieve the countercurrent integral condensation has not been validated. Predicted performance at non-vertical condenser orientations has not matched observed performance. Evaluation of data from these condenser positions has been limited.

TRANSFER OF RESEARCH RESULTS

The thermodynamic analyses conducted indicate binary cycle performance gains can be achieved; the adequacy of the design methods will determine whether the performance gains can be realized. For the projected performance gains discussed, it will be necessary to be able to design and operate heat exchangers which provide countercurrent flow paths and achieve integral mixing during phase changes. Program personnel have worked closely with HTRI in defining both how to utilize HTRI heat exchanger design codes, determining the adequacy of the codes for predicting performance, and identifying and resolving areas where code predictions do not match observed performance. These discussions with HTRI are typically held on a semiannual basis. The knowledge exchanged is in turn transferred through HTRI to the code users; the designers and manufactures of heat exchange equipment. The results of the investigations conducted to date have been reported at technical conferences and published in formal reports, technical journals and conference proceedings.

FUTURE ACTIVITIES

The Heat Cycle Research Facility is currently in the process of being relocated at the East Mesa to a higher temperature resource; the higher temperature is necessary to conduct the investigations of the condensation behavior of the supersaturated turbine expansions. After the completion of these investigations, the facility will be modified to examine alternative heat rejection schemes (improve heat rejection system performance and/or reduce cooling water make-up requirements). The field investigations for these studies are tentatively scheduled to be completed in 1991.

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REDUCING DRILLING AND COMPLETION COSTS -- HARD ROCK PENETRATION RESEARCH

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ABSTRACT

Hard Rock Penetration research is directed at reducing the costs associated with drilling and completing geothermal wells. The goal is to reduce these costs by about 20% by 1992. The program is divided into three major elements: borehole mechanics, rock penetration mechanics, and industry cost shared research. Current research topics include lost circulation control, high temperature drilling, coring technology development, drill string dynamics, fracture mapping using downhole radar, and acoustical data telemetry through drill pipe.

This work was performed at Sandia National Laboratories, supported by the U. S. Department of Energy under contract DE-AC04-76DP00789.

BASIS FOR GEOTHERMAL WELL COMPLETION R&D

GEOTHERMAL RESOURCE IS SIGNIFICANT

WELL COSTS ARE 30 - 50% OF TOTAL ENERGY COSTS

DRILLING IS NEEDED FOR EXPLORATION, RESERVOIR ANALYSIS, PRODUCTION AND REINJECTION

OIL & GAS TECHNOLOGIES INADEQUATE FOR GEOTHERMAL TEMPERATURES, HARD & FRACTURED ROCK, UNDER-PRESSURE AND CORROSIVE RESERVOIRS

TECHNOLOGY DEVELOPMENTS ALSO APPLICABLE TO AREAS OTHER THAN GEOTHERMAL

DRILLING TECHNOLOGY PROJECTS

<u>Identification</u>
- Sandia (system studies)
- GTD
- Industry

<u>Review</u>
- Industry review panel

Larry Diamond Dyna-Drill	Del Pyle Consultant	Gene Polk NL Baroid
Ed Martin Superior Oil	Ben Bradford Dowell	Ed Bingman Shell Oil Company
Dwight Smith Halliburton	Larry Watson Stratabit	Tom Warren Amoco Production Co
Mel Friedman Texas A & M	Tom Turner Phillips Petroleum Co.	James Langford Dresser Industries
John C. Rowley Los Alamos National Lab	Jim Combs Geothermal Resources Int'l.	Steve Pye Unocal

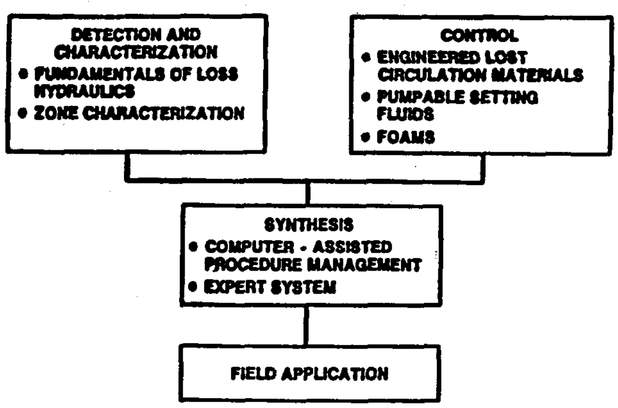
LOST CIRCULATION

<u>Rationale</u>
- #1 problem in geothermal drilling (review panel)
- Environmental concerns

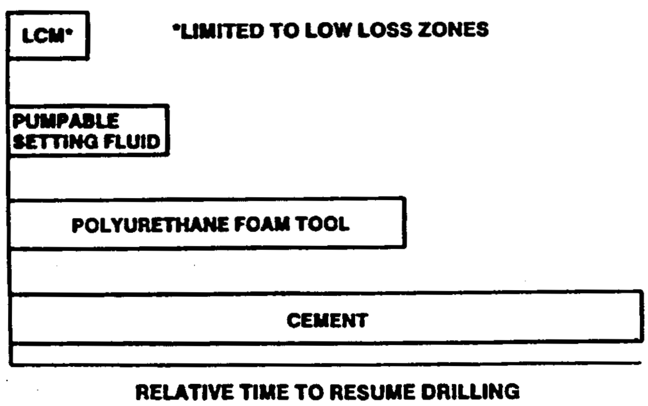
<u>Status</u>
- Developed high temperature LCM
- Developed improved testing methods
- Identified plugging mechanisms
- Evaluated polyurethane foam

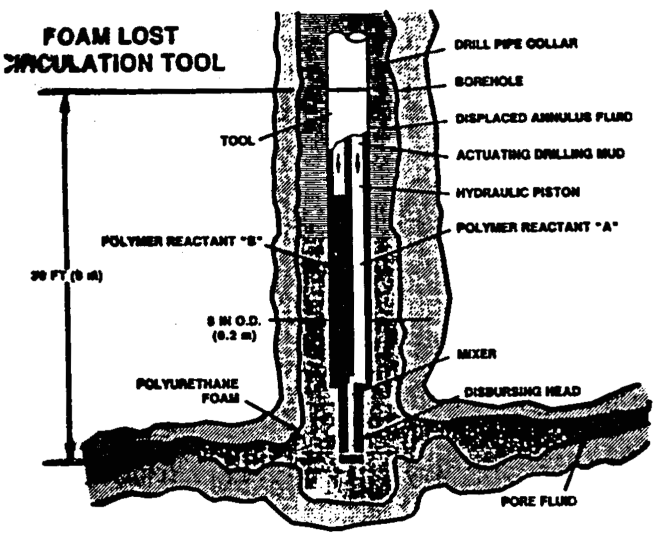
<u>Future</u>
- Characterize field LC zones
- Test pumpable setting fluids
- Emplacment dynamics

LOST CIRCULATION PROGRAM ELEMENTS



APPROACHES TO LOSS CONTROL IN FRACTURED, VUGULAR ZONES





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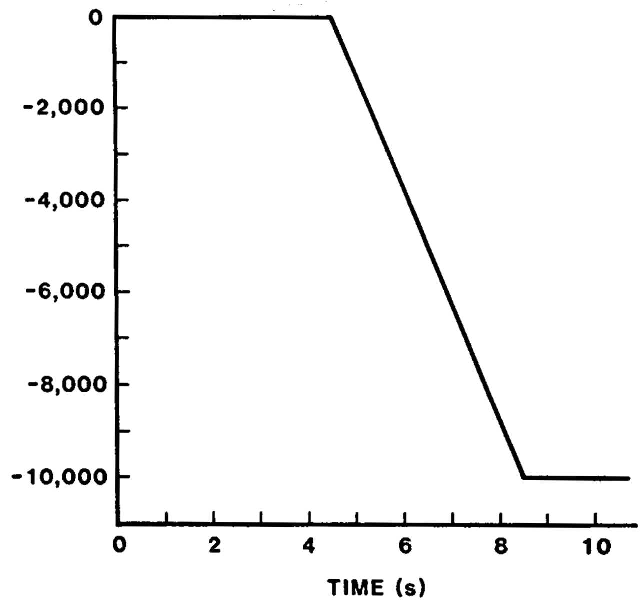

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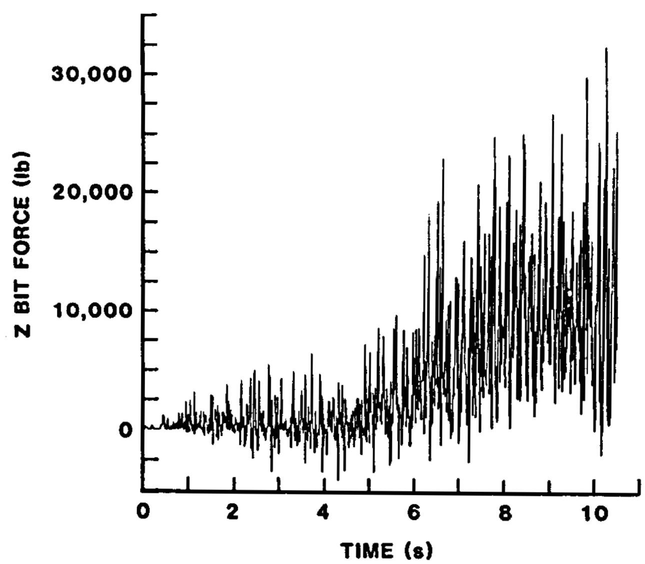


DRILL STRING DYNAMICS

Rationale
- Optimize drilling performance
- Determine drilling environment

Status
- Cost shared with ARCO, Conoco, Mobil, BP-America
- GEODYN2 computer code complete
- Industry adapting code

Future
- User group

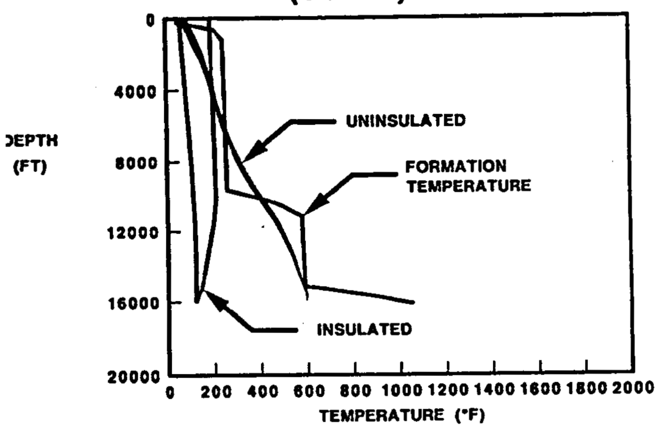
INSULATED DRILL PIPE

Rationale
- Required in high temperature formations

Status
- Thermal analysis completed
- Two detailed designs completed by industry

Future
- Purchase prototype drill pipe
- Test thermal/mechanical performance
- Evaluate in magma exploratory well

WELL TO 16,000 FT (500°C)



ACOUSTICAL TELEMETRY

Rationale

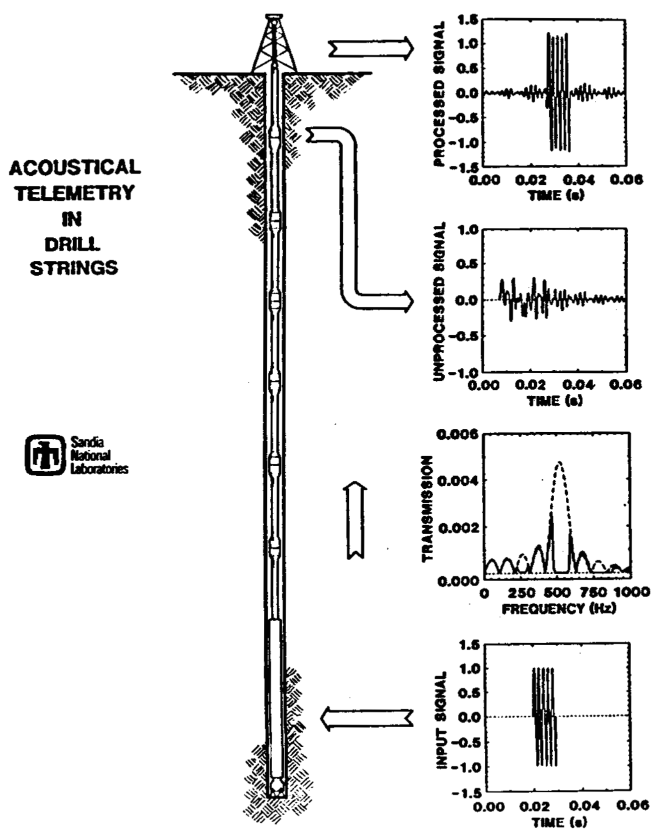
- Increased data rates (compared to mud pulse)
- Can be used with air drilling
- Potential annual market $200M

Status

- Analysis complete
- Sperry Sun field data evaluated
- Laboratory experiments completed

Future

- Transducer design and test
- Field experiments



SLICKLINE INSTRUMENTS

Rationale

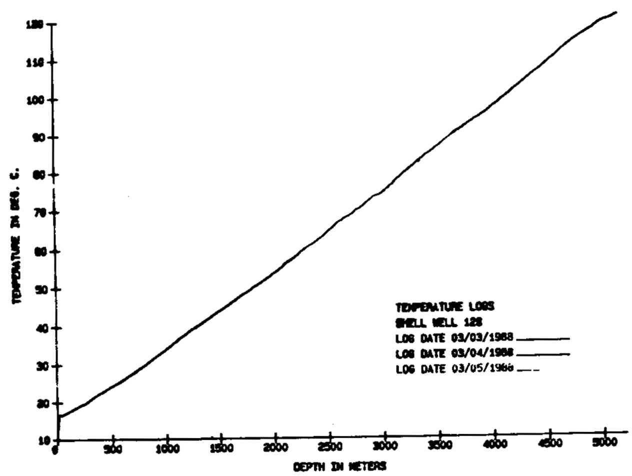
- Designed for SSSDP
- Needed for measurements above 300 C

Status

- Temperatures logged in SSSDP
- Heat flow in deep gas well

Future

- Modular design
- New flow measurement



RADAR FRACTURE MAPPING

Rationale

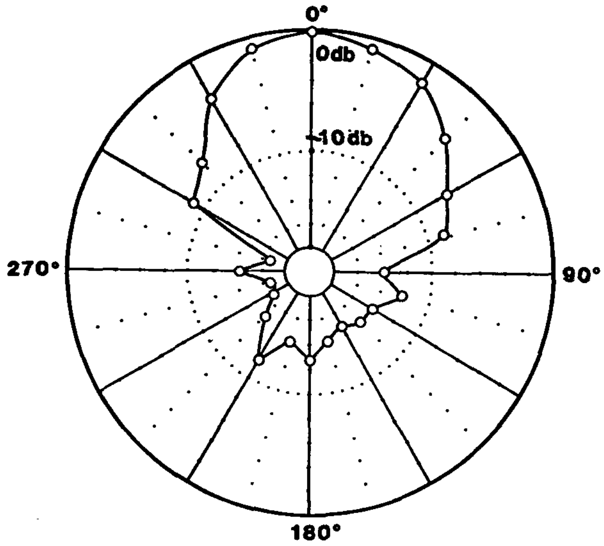
- Fracture detection will lead to improved production

Status

- Prototype directional radar tool constructed
- Prototype tested in homogeneous medium (water)
- Prototype being evaluated in fractured rock quarry

Future

- Measurements in granite planned
- Construct second prototype



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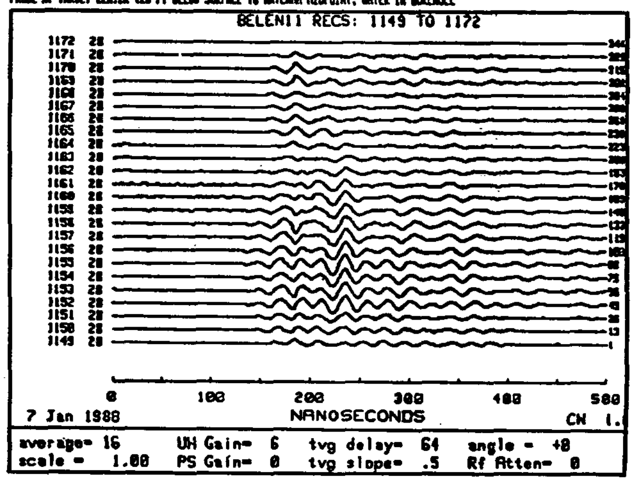
PROBE AT TARGET CENTER (20 FT BELOW SURFACE TO ANTENNA MIDPOINT; WATER IN BOREHOLE



SESSION III

GEOPRESSURED-GEOTHERMAL RESEARCH
PROGRAM OBJECTIVES

CHAIRPERSON: SUSAN PRESTWICH
GEOTHERMAL PROGRAM MANAGER
IDAHO OPERATIONS OFFICE
U.S. DEPARTMENT OF ENERGY

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RESEARCH TO UNDERSTAND AND PREDICT GEOPRESSURED RESERVOIR CHARACTERISTICS WITH CONFIDENCE

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ABSTRACT

The Department of Energy's Geopressured Geothermal Program has sponsored a series of geoscience studies to resolve key uncertainties in the performance of geopressured reservoirs. The priority areas for research include improving the ability to predict reservoir size and flow capabilities, understanding the role of oil and gas in reservoir depletion and evaluating mechanisms for reservoir pressure maintenance. Long-term production from the Gladys McCall well has provided the basis for most of the current research efforts. The well was shut-in on October 29, 1987, for pressure recovery after producing over 27 million barrels of brine with associated gas. Geologic investigations are evaluating various mechanisms for pressure maintenance in this reservoir, including recharge from adjacent reservoirs or along growth faults, shale dewatering, and laterally overlapping and connected sandstone layers. Compaction studies using shale and sandstone core samples have provided data on the relationship between rock compression and reservoir pressure decline and the correlation to changes in porosity and permeability. The studies support the use of a porosity-coupled reservoir simulation model which has provided an excellent match to the well's production history.

Related studies have evaluated the production of aromatic hydrocarbons and their correlation to the onset of oil production from the well. Studies of the electrical properties of formation rocks have been used to revise accepted methods of log interpretation and to determine the impact of trace elements on log analyses. Post-mortem studies planned for the Gladys McCall reservoir will provide unique data on reservoir mechanics in a large stressed reservoir. These studies will also confirm the geochemical mechanisms controlling the success of carbonate scale inhibitor injection which has enabled long-term production from the geopressured reservoir.

INTRODUCTION

A goal of the energy research programs sponsored by the U.S. Department of Energy (DOE) is to develop a balanced domestic energy resource base that will provide a range of competitive options for future energy markets. During the mid-1970's, the National Science Foundation and the predecessor of DOE initiated a comprehensive geopressured geothermal research program to investigate the nature and development potential for high-pressured thermal fluids encountered principally in the Gulf Coast Basin.

Geopressured reservoirs are unique, producing fluids at temperatures of 300 to 450 F which contain natural gas dissolved at levels averaging 25 to 40 scf/bbl. Pressure gradients in these zones approach lithostatic, nearly 1 psi/ft. Early program efforts used wells of opportunity to evaluate flow rates and fluid composition. Subsequently, four wells were drilled at geologically optimum locations to assess long-term reservoir performance and to enable studies of environmental effects. Data from the wells of opportunity demonstrated that natural gas was present at levels near or exceeding saturation in all reservoirs. Field tests of the four design wells have indicated larger than expected recoveries from produced reservoirs (National Research Council, 1987). The field tests have also enabled resolution of the major engineering problems related to production, brine handling and fluid disposal.

The current emphasis of DOE's geopressured research efforts is on understanding the behavior of geopressured reservoirs under long-term production with the goal of decreasing the uncertainty in predictions of reservoir size, longevity and chemistry. It is evident that the mechanisms which control flow in geopressured reservoirs are different from those of conventional oil and gas reservoirs and conventional analytical techniques are not necessarily applicable without modification.

Specific reservoir research tasks in the current DOE program include developing reliable methods to locate and evaluate geopressured zones, developing an understanding of the mechanisms which drive the production of fluids from the reservoir, and developing test procedures which enable accurate prediction of the reservoir capability under production.

The geopressured geothermal reservoir research effort is being conducted by a consortium of universities and industrial participants, including Louisiana State University/Louisiana Geological Survey, the University of Texas at Austin, the University of Southwestern Louisiana, Rice University, S-Cubed, the Eaton Operating Company and EG&G Idaho. The progress and most recent results of these research efforts are summarized in the following sections.

GLADYS MCCALL WELL

The most recent geopressured reservoir tests were conducted using the Gladys McCall well, which produces from a sandstone interval between 15,160 and 15,470 feet in a reservoir which consists of relatively thick sand zones and thin shale interbeds. Measured temperature and static pressure at the top of the producing sand zone are 289 F and 12,784 psi, respectively. The total dissolved solids content of the fluids is about 98,000 mg/l and the natural gas content averages 30 scf/bbl.

The Gladys McCall well produced nearly 27 million barrels of brine with gas during a series of tests between October, 1983, and October, 1987. The well was shut-in on October 29, 1987, for a pressure buildup test after 1460 days of production testing. During early production, severe scaling was encountered in the 5-inch production tubing, which hampered operations and complicated reservoir analyses. In June, 1985, and in February, 1986, a phosphonate scale inhibitor was injected into the producing interval. This treatment enabled sustained production from the well--about 13 million barrels were produced since the last inhibitor squeeze with no scaling apparent in the high-pressure production equipment (Eaton, et al., 1988). The cost of the inhibitor treatment was about $0.0038/bbl.

Initial testing of the sandstone zone in which Gladys McCall is completed indicated a porosity of 22% and a permeability of 160 md. During the long-term tests, the well was produced at rates ranging from 5000 to 36,500 bbl/day (70,000 to 530,000 lb/hr), with the longest stable production at about 20,000 bbl/day (290,000 lb/hr). During this production period, no substantial decrease in bottomhole pressure was observed and it is believed that production could be continued at rates of about 19,000 bbl/day for an indefinite period of time (John, 1988).

Various mechanisms have been postulated to explain the behavior of the Gladys McCall reservoir, which has sustained production at higher pressures and for a period much longer than originally expected. The mechanisms under investigation include dewatering of adjacent shales, stress-dependent formation compressibility, long-term formation creep, cross-flow from adjacent sands and leakage across boundary faults (Dorfman, 1988).

CONCEPTUAL GEOLOGIC MODEL

A critical factor in evaluating the Gladys McCall reservoir and in determining reservoir production and recharge mechanisms is correlating the reservoir analyses to the geologic model of the reservoir. An extensive review and reinterpretation of existing data is being conducted by personnel from the Louisiana Geological Survey at Louisiana State University The northern Gulf of Mexico region was the repository for large volumes of sediments with a cumulative thickness of over 32,000 feet. This rapid sedimentation caused subsidence accompanied by growth faulting.

Wells in the vicinity of Gladys McCall have penetrated some of the thickest geopressured sands in Louisiana or Texas, which is contrary to the predominance of shale indicated by regional geologic studies (John, 1988). The stratigraphic section consists of alternating sandstones and shales, with about 1150 feet of net sand thickness between 14,400 and 16,300 feet. Seismic studies and lithologic correlations (specifically paleontologic analyses) with nearby wells have shown that the producing reservoir is bounded on the north and south by faults. The east-west extent of the reservoir is poorly defined due to lack of deep well control.

A conceptual model of the depositional environment in the region of the Gladys McCall well was developed as an aid to resolving reservoir uncertainties. It is theorized by John (1988) that the sandstone section penetrated by Gladys McCall represents a genetic unit generated within the same river channel system, consisting of interconnected channel and point bar sands. At times when the sand supply was interrupted, local deposits of shale could have accumulated. While in one well, the sandstone sections may appear to be separate, it is possible that these layers behave as a single unit, allowing fluid communication between sections. Thus, it is considered important to model genetic units of sandstones rather than single layers to more accurately estimate reservoir production potential (John, 1988).

RESERVOIR MODELING

The conceptual model of the Gladys McCall reservoir that has evolved based on geologic information and analyses of well tests is shown in Figure 1. This model depends on crossflow from sands overlying or underlying the producing sand interval. Simulations which have been conducted based on this conceptual model (see Figure 2) produced an excellent match to the original reservoir limits tests, to the intervening production history and to the pressure buildup since the well was shut-in last October (Figure 3). The best match of production data from the well assumes a fluid recharge remote from the well, in the sense that the fluid flow path from the adjacent sandstone layers around the shale interbeds can be tortuous. The most recent simulations are based on a near-well permeability of 120 md, which is 25% lower than that determined from early tests of the well. It is apparent that the reduction in formation permeability extends through a significant portion of the reservoir and Riney (1988b) hypothesizes that the decrease results from the increasing effective stress caused by the reduction in fluid pressure.

Since the formation in the immediate vicinity of the wellbore experienced the greatest pressure drawdown, the permeability reduction may be most severe near the wellbore and may be reflected as an increase in the apparent skin factor. The test data from Gladys McCall have also indicated that even the successful scale inhibitor injections have resulted in increases in the apparent skin factor (Riney, 1988a). Subsequent to the inhibitor injections, the wellhead pressure increased at a constant flow rate, indicating that flow through the formation flushed out some of the precipitates formed during the inhibitor injection. The latest modelling is based on using a skin factor of 17, compared to an initial value of $s = 4.3$ (Riney, 1987). Correlations of permeability and skin factor to production rates and formation pressure have shown that nonlinear processes are operating, possibly due to matrix compressibility. Parametric studies are in progress to further delineate possible mechanisms and will be correlated with results of rock mechanics tests.

MECHANICAL PROPERTIES OF ROCKS

Studies of the mechanical properties of shale and sandstone core samples are continuing at the Center for Earth Sciences and Engineering at the University of Texas at Austin. Triaxial compaction and uniaxial compaction tests have been conducted to evaluate the significance of rock compaction on reservoir performance. The uniaxial tests have shown that the mean reservoir compressibility is approximately constant with drawdown when the initial residual stress difference is on the order of 500 to 1500 psi. However, with a residual stress difference of 2500 psi, the sandstone samples exhibit a more pronounced compressibility variation (Fahrenthold and Gray, 1988).

Data from the tests were used to estimate the significance of fluid-solid coupling in reservoir models. Classic reservoir models do not specifically incorporate rock deformation due to drawdown, but include compaction effects using a pore volume compressibility parameter with a pore pressure-dependent formation permeability. Fahrenthold and Gray (1988) conclude that in regions of sharp pressure gradients, particularly near the wellbore, reservoir analyses will be particularly sensitive to formation deformation characteristics.

RELATED STUDIES

Studies by the Departments of Chemistry and Physics at the University of Southwestern Louisiana have been investigating the hydrocarbon content and composition in geopressured brines. The brines contain small amounts of C6+ hydrocarbons which are primarily aromatic, in addition to a variety of light aliphatic hydrocarbons termed cryocondensates. The cryocondensates contain at least 95 compounds and appear to be of terrestrial plant origin (Keeley and Meriwether, 1988). In all wells studied, the concentration of cryocondensates increased prior to the onset of oil production from the wells. It is postulated by Keeley and Meriwether that the increase results from a partitioning of the aromatic components from oil migrating into the production zone from adjacent shale layers.

Subsidence and seismic monitoring by Louisiana State University in the vicinity of producing geopressured wells is continuing. The monitoring efforts were instituted due to the concern that fluid withdrawal and reservoir pressure declines could lead to significant subsidence and may induce additional seismic activity along growth faults. The design wells were completed with radioactive tracer bullets to measure formation compaction. Periodic surveys of the extensive ground elevation networks have been conducted since production from the wells was initiated. Although natural subsidence of about 2 mm per year occurs in southern Louisiana, there has been no evidence of subsidence related to geopressured production (NRC, 1987). Seismic monitoring in the vicinity of the Gladys McCall well detected two small (M less than 0.0) events which were located at depths and in areas probably influenced by fluid withdrawal. With only two events, it is not possible to determine if these events were related to inferred growth faults at depth (Van Sickle, et al., 1988).

A series of log interpretation studies are being conducted by the University of Texas at Austin, partly sponsored by an industry consortium. One of the specific objectives of these studies is to develop more reliable techniques to identify productive geopressured zones during drilling, but the results of the studies have more general application to log interpretation in hydrocarbon environments. Current tasks include evaluating the effect of wettability and stress on sandstone resistivity, theoretical modelling of wettability and pore geometry effects, the effect of oil-based muds on rock wettability, resistivity behavior in shaly sands and the influence of boron and other trace elements on thermal neutron logs. Recent results have shown, for instance, that the wettability characteristic of consolidated sandstones has a significant effect on electrical resistivity. Such influences as drilling mud invasion can change wettability near the wellbore and could result in incorrect calculations of fluid saturation in hydrocarbon-bearing formations which are based on resistivity logs.

POST-MORTEM RESERVOIR STUDIES

A series of tests of the Gladys McCall reservoir are planned following the completion of the pressure build-up tests. The objective of these studies is to provide additional data to help confirm postulated reservoir mechanics in a large stressed reservoir. Spectral gamma, pulsed neutron, and neutron density logs will be run in selected intervals between 5000 feet and bottomhole to evaluate hydrocarbon contents of sandstone intervals and for comparison to the original pre-production logs. Sand and shale zones adjacent to the production interval will be perforated and isolated for measurements of pressure and to enable collection of fluid samples. This information will provide evidence on the potential for shale dewatering and pressure communication between sand zones.

The final planned tests will be related to a series of sidetrack cores taken in the production interval. Prior to coring, a scale inhibitor will be injected into the formation and cores will be analyzed to study the effect of the inhibitor on the formation. The last core is planned to be run through the producing sand and into the adjacent shale interbeds. Logging and core analyses will provide evidence of compaction and alteration.

It is anticipated that these tests will be conducted in mid-FY-89, depending on funding availability. Initial results of the Gladys McCall reservoir analyses will also be used to refine reservoir tests of the Pleasant Bayou well which is scheduled to begin long-term production in May, 1988. These tests will provide more definitive information regarding reservoir drive mechanisms and the production capability of geopressured reservoirs. The extensive operating experience and scientific data base will improve the understanding of how geopressured reservoirs behave over extended periods of time and will decrease the uncertainty in the prediction of reservoir characteristics and reservoir performance.

ACKNOWLEDGMENTS

This paper presents a compilation of recent results of research efforts conducted by Louisiana State University, the University of Texas at Austin, the University of Southwestern Louisiana and S-Cubed. Also included is information on well production histories and operation provided by Eaton Operating Company. The authors acknowledge the excellent research being conducted for the Geopressured Geothermal Program and the support that was provided for preparation of this paper.

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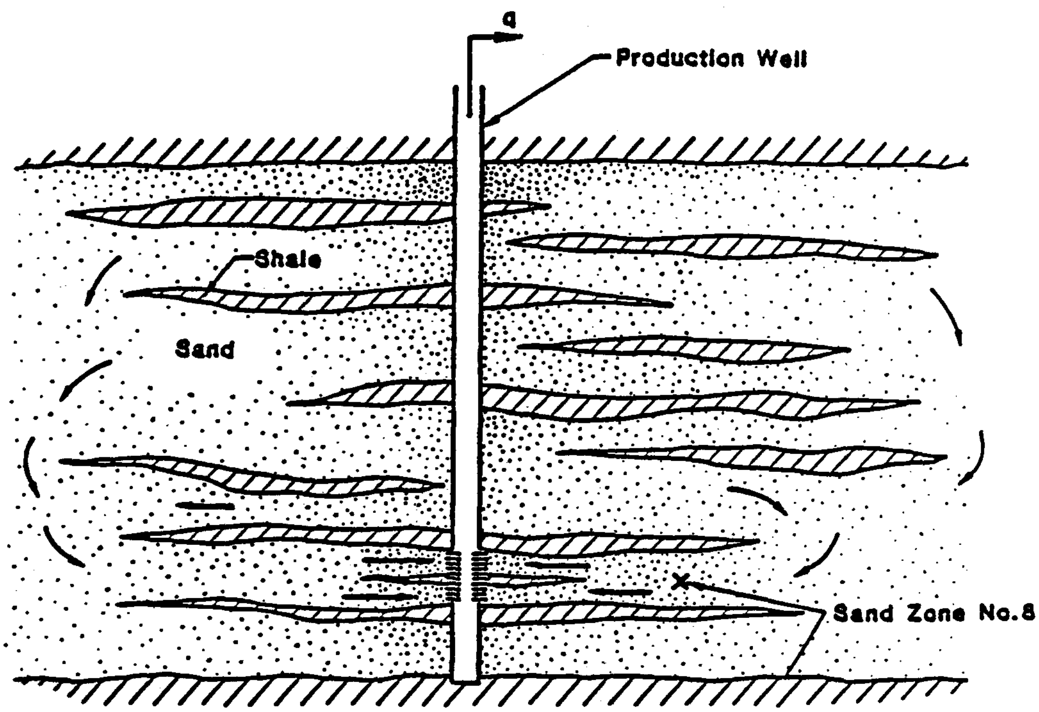

FIGURE 1. Conceptual model of Gladys McCall reservoir, Sand Zone No. 8 producing interval (Riney, 1987).

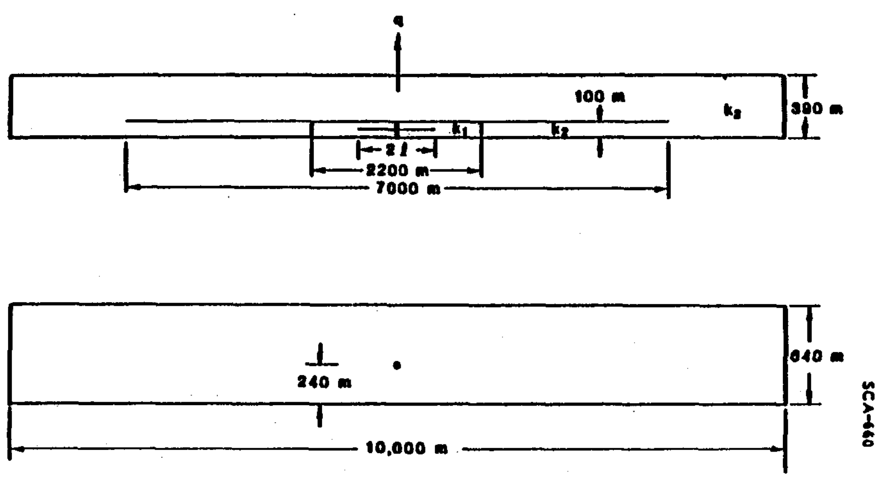

FIGURE 2. Model for Gladys McCall reservoir based on the assumption that pressure maintenance is due to crossflow from overlying/underlying sands (k_1=160 md, k_2=20 md, l=200 m) (Riney, 1987).

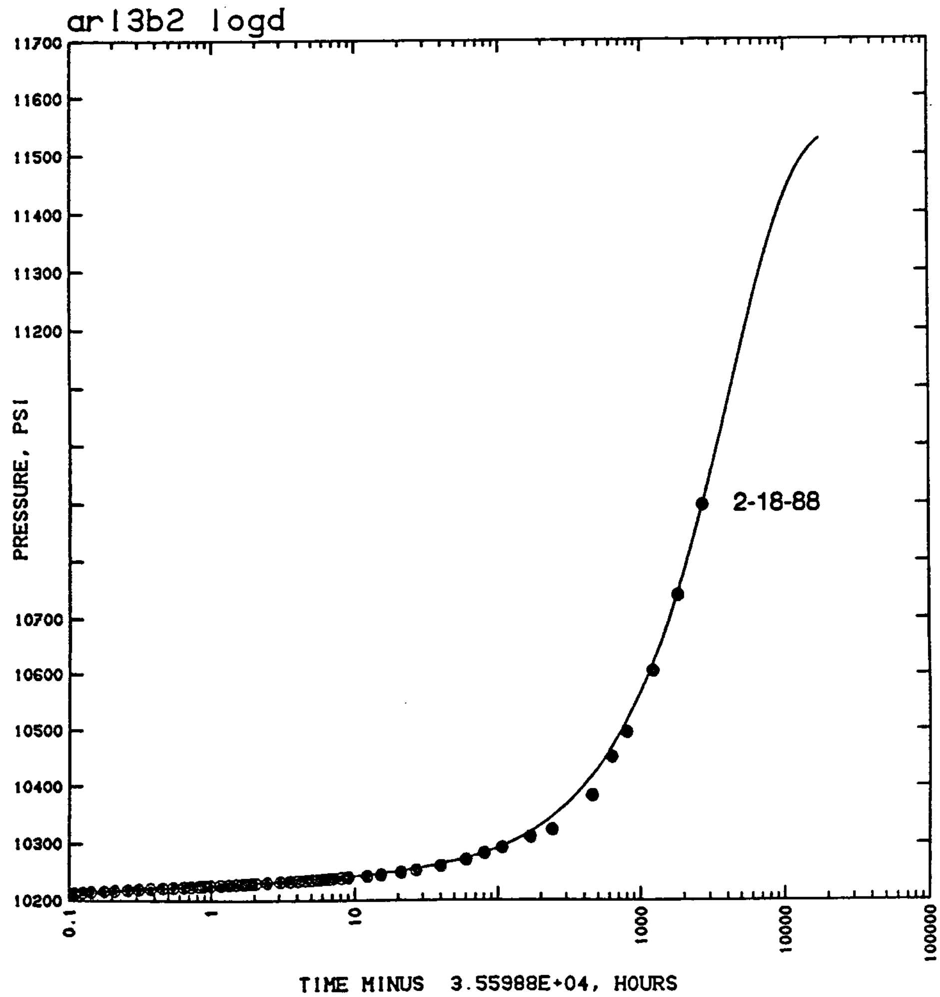

FIGURE 3. History match simulation compared with bottomhole pressure data during Gladys McCall pressure buildup tests (provided by S-Cubed).

"POTENTIAL FOR UTILIZING THE GEOPRESSURED-GEOTHERMAL RESOURCE"

C. R. Featherston
Eaton Operating Company, Inc.
Houston, Texas

ABSTRACT

Eaton Operating Company, Inc. (Eaton) is presently operating the field operations sites for the DOE U. S. Gulf Coast Geopressured-Geothermal Energy Program in Texas and Louisiana.

Large reservoirs of geopressured-geothermal fluids have been identified in the U. S. Gulf Coast. The operations of these field sites are being conducted to prove that these reservoirs are indeed the potential energy sources they have been projected to be. As part of this program, the Gladys McCall well in Louisiana has been produced in excess of twenty-seven (27) million barrels. Valuable research in potential gas production and scale control has been accomplished. These reservoirs are potentially much larger than original estimates. Testing of the Pleasant Bayou site in Texas is being initiated to obtain data on Texas reservoirs and to test a binary electrical energy conversion system.

The two present test wells are completed at depths of 15-16,000 feet. The third field site, the Hulin well in Louisiana, has reservoirs from 20-21,000 feet. Testing of this site will provide many opportunities that will have much appeal to industry.

1. The reservoirs have much higher temperatures and will provide greater potential for generation of electricity.

2. A much larger volume of gas will be in solution due to the increased temperature and pressure, providing more gas sales income.

3. Present studies conducted at The University of Texas, in cooperation with Schlumberger, Ltd., indicate that zones appearing to be only water bearing formations, by current petroleum industry log interpretation methods, may contain significant amounts of free gas. Thus, one by-product of the DOE investigations in this well could be confirmation of a new approach to well log interpretation, one of great interest to the oil and gas exploration industry.

4. In addition to providing essential research, this project may be sold to industry for continued testing after completion of the basic program, if successful.

Other uses have been proposed for this geopressured-geothermal energy. Mr. Tom Meahl (Eaton) has proposed utilization of the hot geothermal brine, from deep reservoirs, for enhanced recovery in thermal waterfloods of shallower oil productive zones. This also has great potential for industry interest and possible joint venture operations.

DISCUSSION

Geopressured-Geothermal reservoirs have been identified through oil and gas operations in Texas and Louisiana. These have been investigated by the DOE through the "Wells of Opportunity Program" in 1981-82 and the subsequent "Design Well Program", as shown in Figures 1 and 2. Two of the design wells are still active: the Gladys McCall well in Cameron Parish, Louisiana, and the Pleasant Bayou well in Brazoria County, Texas.

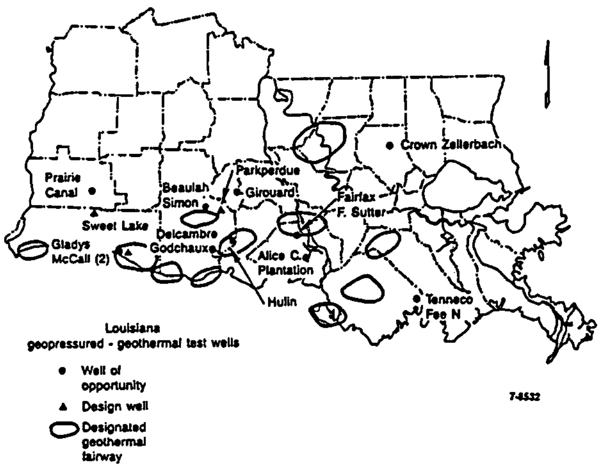

Figure 1. Louisiana geopressure-geothermal test wells.

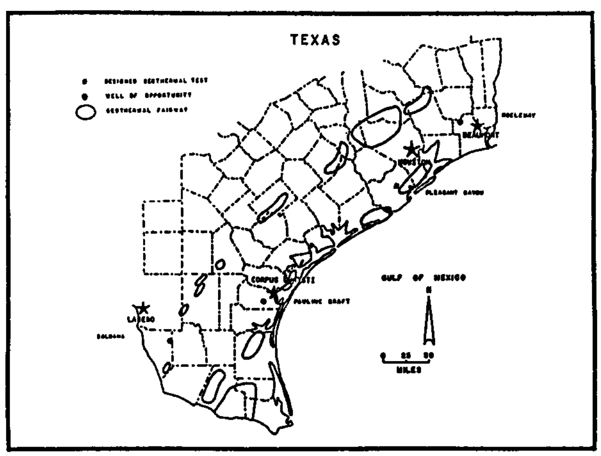

Figure 2. Texas Geopressured-geothermal Fairways and Test Wells.

A. The Gladys McCall Well (Cameron Parish, LA)

This well (Figure 3) was completed in the interval 15,160 feet (4,620 m) to 15,470 feet (4,715 m). This well produced 27,318,414 Bbl (43,433,073 m^3) of salt water brine (Figure 4), with associated gas of 676,782,900 SCF (19,166,492 m^3) (Figure 5) prior to being shut in for one year of pressure build-up tests in October 1987, proving that very large geopressured-geothermal reservoirs are present and that they can be produced successfully for several years. This well is still yielding valuable reservoir data (the reservoirs are much larger than originally estimated), and has provided a unique, large production volume history of brine and gas production versus pressure decline, successful scale inhibition results, brine chemistry analysis, aromatic hydrocarbon and cryocondensate production, and disposal well performance. This well is in a wind-down phase. Upon completion of the pressure build-up tests in October 1988, sidetrack operations for coring will be made to investigate what precipitates and residual chemicals remain in the producing sand formation immediately after a phosphonate scaling inhibitor squeeze. Also, cores will be taken and compared to original cores (taken when the well was drilled) to determine what formation alterations have resulted from production, such as compaction and possible shale alteration.

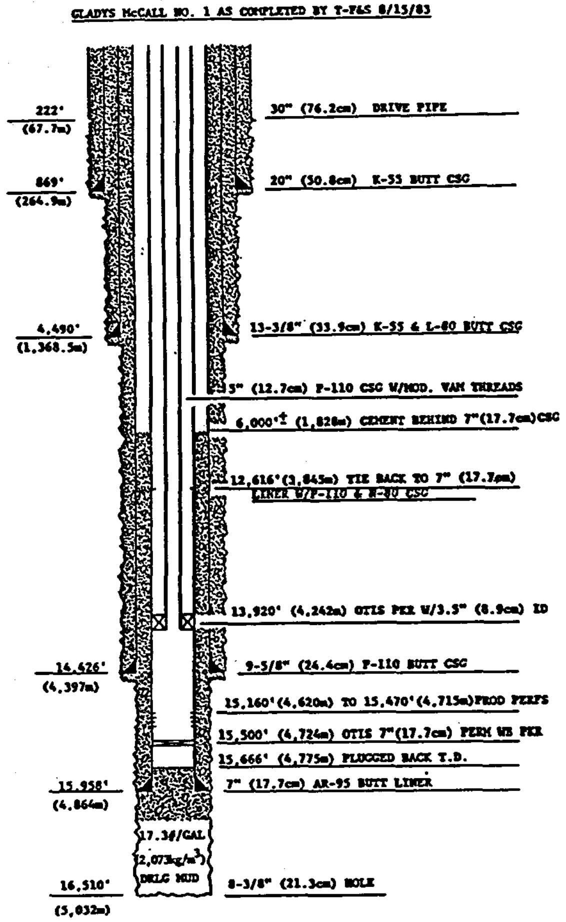

FIGURE 3

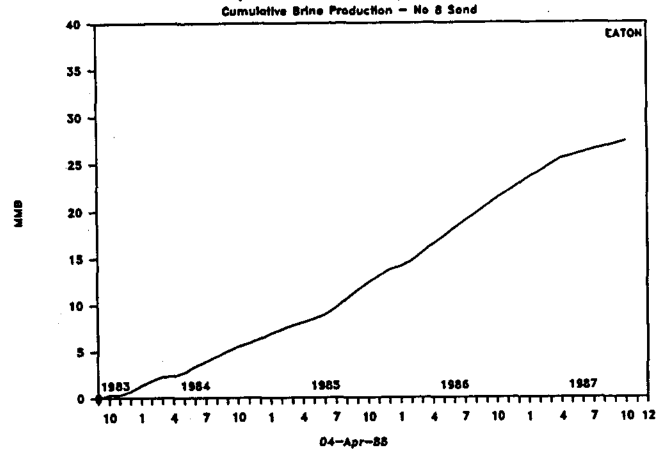

FIGURE 4

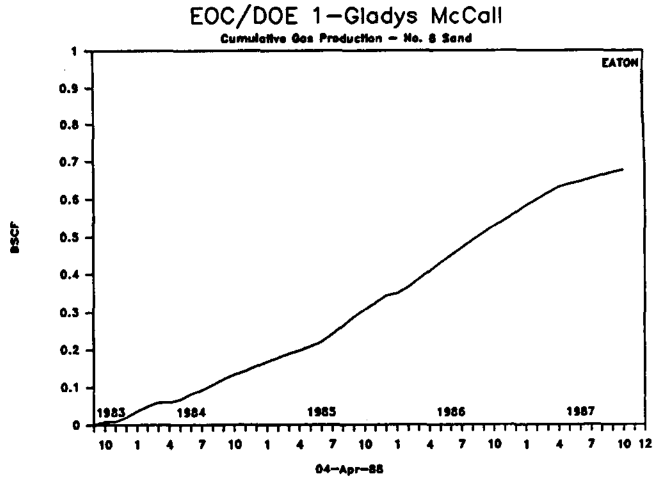

FIGURE 5

B. <u>The Pleasant Bayou Well (Brazoria County, TX)</u>

This well was tested initially and experienced severe scaling and tubing failure (May 1983). The well has now been successfully restored to operating condition. The production facilities have been redesigned, utilizing the materials and equipment performance experience obtained from the Gladys McCall well, refurbished, and rebuilt. The well is scheduled to resume flow testing shortly. This well has production perforations from 14,644 feet (4,464 m) to 14,704 feet (4,482 m) (Figure 6). The well will be squeezed with a phosphonate scale inhibiting chemical treatment developed by Dr. Mason Tomson of Rice University and placed back on production at rates up to 20,000$^+$ BPD. Construction of a binary energy conversion system (Figure 7) will be started on this well in fiscal year 1988 for generation of electricity, utilizing the heat from the produced brine and exhaust gas from a gas engine driven generator.

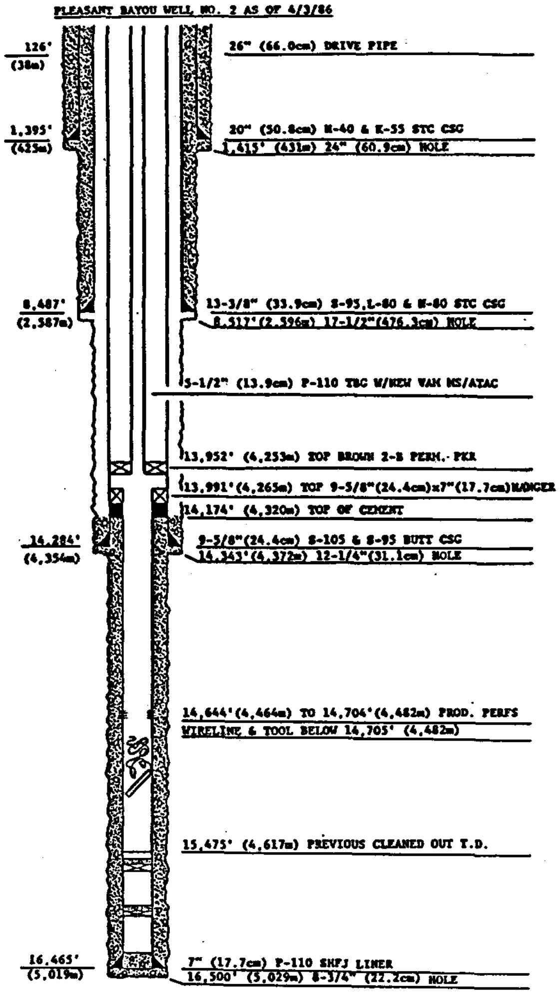

FIGURE 6

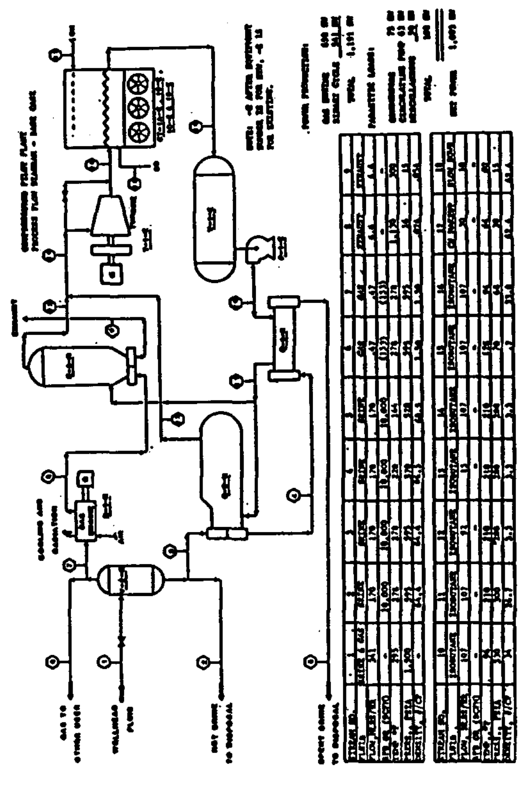

FIGURE 7

C. The Hulin Well (Vermilion Parish, LA)

The well with the most potential of any well tested to date is the Hulin well in Vermilion Parish, Louisiana. This third well is essentially a "Well of Opportunity", obtained from Superior Oil Company after it was drilled to 21,546 feet (6,567 m) and tested as a gas well in the interval 21,059 -21,094 feet (6,418.8 -6,429.5 m). The well developed mechanical problems (apparent packer failure), and Superior offered the well to DOE rather than attempt remedial operations. (The present well configuration is shown on Figure 8.) As discussed in the paper, "Future for Geopressured-Geothermal Resources" by J. Ramsthaler (EG&G) and Martin Plum (EG&G) (January 1988), "This well represents a well having the potential to produce a commercial quantity of energy from a geopressured-geothermal reservoir." As such, this test will be monitored quite closely by industry, as they have expressed a strong interest in the testing of this well. The two present producing wells are completed at depths of 15,000-16,000 feet (4,572-4,877 m) and have bottom hole temperatures of 301 to 313°F (149 to 156°C) and bottom hole pressures of 11,200 to 12,500 psia (77.2-86.2 KN/M^2). The Hulin well will have bottom hole temperatures in the range of 350 to 375°F (176 to 190°C) and bottom hole pressures of ± 18,850 psi (130 KN/M^2). The increased amount of heat produced will provide a greater efficiency of energy conversion to electricity. With a newer type EEC System, now available, a significant increase in the amount of electricity produced could result. The increased heat and pressure in the reservoir will result in a large increase in the amount of gas in solution, increasing from about 22 to 27 SCF/Bbl in the present wells to ± 50 SCF/Bbl in the Hulin well. At a production rate of 20,000 BPD, this could result in 1.0 MMCF/D of gas production.

The annular pressures of the Hulin well are being monitored. As shown on Figure 9, the pressures are increasing. For safety reasons, it is very important that operations begin on this well soon, before these pressures increase to unsafe levels. One of the program research objectives has been to increase the amount of automation of operations, thereby reducing personnel requirements. Initial design efforts have been implemented at the Pleasant Bayou site and will be further developed at the Hulin site.

One by-product of the DOE research investigations in this well could be confirmation of a new approach to well log interpretation, which will be of great interest to the oil and gas exploration industry.

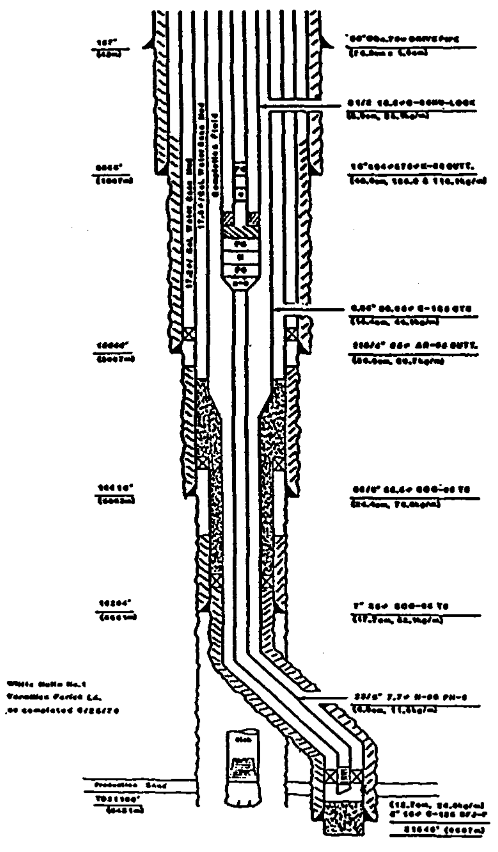

FIGURE 8

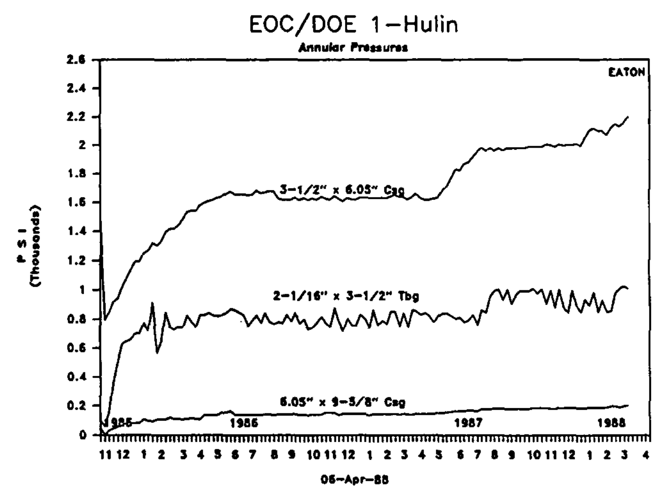

FIGURE 9

Studies being made at The University of Texas, in cooperation with Schlumberger, Ltd., indicate that zones in the Hulin well, that have been interpreted to be only water-bearing formations by current log interpretations, may actually contain significant amounts of free gas. The confirmation of these new log interpretations by testing of the Hulin well is of great interest to the oil and gas industry. If proven, large reserves of by-passed gas may be identified for future recovery. This is a function of log interpretation and the fact that, under the pressures present in this well, the gas may be in a liquid form in the formation so that it does not read as "gas" on the logs. This by-product research is very exciting in that it should act as a stimulant to increased industry participation. Improvement of conventional log analysis by development of improved techniques from study of the effect of rock stresses, temperature and wetability on rock resistivity, and determination of the effect of trace elements on neutron logs is also an important research area. Post-production logging is an important phase of this research.

Another by-product area of interest to industry, outlined by Mr. Tom Meahl (Eaton) in his January 1988 paper, "Utilization of Geopressured-Geothermal Energy for Enhancement of Secondary Oil Recovery", described how hot-pressured water from a geopressured-geothermal production well could be used to increase recovery from a waterflood in a shallower oil producing zone (even after the water had been used for electrical energy conversion).

The DOE Geopressured-Geothermal Program has shown that long-term, high volume production of hot brines is possible and that high volume injection of salt water in shallow sands, utilizing the flowing pressure of the producing well, is effective. Limited oil industry research, utilizing heated water injection, has shown significant recovery improvements in secondary water flooding operations.

It is proposed to combine these two proven technologies for enhanced secondary oil recovery. A deep, geopressured-geothermal well could be produced, the gas extracted (and sold), and the well flowing pressure utilized for water injection in a shallower oil zone. This would reduce field operating costs by minimizing the need for injection pumps. The hot, geothermal brine would heat the oil in the reservoir, reducing its viscosity, resulting in less resistance to flow (i.e., lower pressure), and increasing oil recovery.

This research has immediate industry application and should generate joint DOE/industry venture interest to produce otherwise uneconomical or abandoned oil for our country's needs.

The production of these wells is demonstrating that large geopressured-geothermal reservoirs are present in the Louisiana-Texas Gulf Coast and that the fluids can be produced in large volumes for long periods of time. Scale formation, one of the biggest production restrictions in the past, is being overcome by scale inhibition treatments that are still being improved.

The determination of reservoir size and production capabilities, through log interpretation and production history, is still being investigated, as completely reliable techniques for this can only be developed by continued production and analysis of pressure-production-logging histories. Industry is very interested in this reservoir research, as oil and gas operations in the Gulf Coast do not operate at these high levels of individual well production. The goal is to be able to predict reservoir size and longevity, hydrocarbon content, salinity, etc. with 90% confidence over a ten year operating period, by 1992. The same is true of the injection well performance.

The testing of the electrical energy conversion systems, in conjunction with the reservoir studies, is aimed at the objective of improving the technology to the point where electricity could be produced commercially from a substantial number of geopressured resource sites via Wells of Opportunity.

The involvement of the many support groups, such as:

1. The University of Texas - Austin,
2. Texas Bureau of Economic Geology,
3. S-Cubed,
4. Louisiana State University,
5. University of Southwestern Louisiana,
6. Institute of Gas Technology,
7. Rice University, and
8. EG&G (Idaho)

has been very important (and will continue to be) in the establishment of goals and development of the test plans for all sites.

CONCLUSIONS

Large volume, geopressured-geothermal reservoirs have been identified. Long-term, high rate production, with scale inhibition, has been proven to be practical. Reservoir analysis still requires much additional research for adequate identification and production prediction. Electrical energy conversion experiments are being started, and this research area must be continued to establish its feasibility and long-term application potential.

The Hulin well offers many new and exciting research opportunities in reservoir analysis, higher pressures and temperatures, and verification of new log interpretation techniques that can identify new gas reserve additions.

Several areas of industry interest have been identified, and efforts will be continued to generate joint industry/DOE involvement and possible joint venture operations in conducting these research activities.

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2) Meahl, T. E. (Eaton Operating Company, Inc. - Houston, Texas), "Utilization of Geopressured-Geothermal Energy for Enhancement of Secondary Oil Recovery", presented at the Eleventh Annual ASME/GRC Energy-Source Technology Conference, New Orleans, Louisiana, January 10-13, 1988.

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DOE/EPRI HYBRID POWER SYSTEM

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ABSTRACT

One of the primary objectives of the DOE Geopressured Geothermal Program is to improve methods for optimum energy extraction from geopressured reservoirs. Hybrid power systems which take advantage of the chemical and thermal energy content of geopressured fluids could improve conversion efficiency by 15 to 20% over the same amount of fuel and geothermal fluid processed separately. In a joint DOE/EPRI effort, equipment from the Direct Contact Heat Exchange test facility at East Mesa is being modified for use in a unique geopressured hybrid power plant located at the Pleasant Bayou wellsite in Brazoria County, TX. Natural gas separated at the wellhead will fuel a gas turbine, and exhaust heat from the engine will be used with the geothermal brine to vaporize isobutane in a binary power cycle. The hybrid power system is designed for 10,000 bbl/day brine flow, with estimated power production of 980 kW (net). In addition to evaluating the enhanced performance resulting from the combined power generation cycles, operation of the hybrid unit will provide a demonstration of fuel flexibility in an individual plant. This approach would allow a resource developer to reduce costs and risks by optimizing production for various economic climates and would improve the mix in a utility's generating system.

INTRODUCTION

A goal of the energy research programs sponsored by the U.S. Department of Energy (DOE) is to develop a balanced domestic energy resource base that will provide a range of competitive options for future energy markets (Lombard, 1985). During the mid-1970's, the National Science Foundation initiated a comprehensive geopressured geothermal research program to investigate the nature and development potential for high-pressured thermal fluids encountered principally in the Gulf Coast Basin. The research program was subsequently transferred to what is now the Department of Energy.

To date, the DOE Geopressured Geothermal Program has demonstrated that geopressured reservoirs can sustain long-term production of brine saturated with methane. The major engineering problems related to production, brine handling and fluid disposal have been solved. Detailed monitoring has shown that subsidence and induced seismicity, once considered major deterrents to the development of geopressured reservoirs, may be much less of a concern.

The current emphasis of DOE's geopressured research efforts is on understanding reservoir production mechanisms and on developing methods for total energy recovery from the produced fluids. Geopressured reservoirs contain brine at moderate to high temperatures and at nearly lithostatic pressure gradients. The brines are frequently saturated with gas which is principally methane. Thus, these resources provide a unique opportunity to recover thermal, chemical and mechanical energies.

Analyses by the Ben Holt Company for the Electric Power Research Institute (EPRI) demonstrated the advantages of converting the thermal and chemical energy of a representative geopressured brine to electricity using a hybrid power system. Their analyses showed that a gas/geothermal hybrid cycle could improve conversion efficiency by at least 15 to 20%. This improvement is relative to the same amount of fuel and geothermal fluid processed separately (Biljetina and Campbell, 1988).

The hybrid concept has been discussed in the technical literature since the early years of the federal government's geothermal research and development program (City of Burbank, 1977; DiPippo, 1979; Khalifa, 1981). However, the concept has not been demonstrated in actual practice. In a joint effort, DOE and EPRI are funding a test of the hybrid power cycle concept to establish its potential benefits. Operating experience and field test data will enable geothermal resource developers to design and build hybrid power systems when the advantages of such a system make it the best option for a particular development.

During the hybrid tests, EPRI will be evaluating the enhanced power output from the hybrid system, as well as assessing several other potential benefits, including:

Risk Reduction - As a first unit in a new geothermal field, a hybrid power plant offers the plant owner a form of insurance against the risk that the geothermal reservoir will not be capable of producing enough heat for the full capacity of the plant. The insurance would be in the form of back-up capability provided by the gas engine. This concept would also make it possible to build a project in phases that are appropriate for different economic and market conditions (i.e., cost of natural gas).

Fuel and Resource Flexibility - For utilities, the hybrid concept can be used to increase the resource mix in their generating systems. On an individual plant basis, the concept offers some measure of fuel flexibility, the extent depending on the turndown and turnup capability built into the combustion and geothermal parts of the plant.

Peaking Capability - When a utility's need for new capacity is a need for peaking or other load following capabilities, the gas engine offers the chance to increase the hybrid plant's output at high-demand periods while keeping the geothermal production at constant level. This would improve project economics, especially when there is a premium price for delivery of on-peak electricity.

ENERGY CONVERSION SYSTEM DESIGN

The DOE/EPRI hybrid power system will be tested at the Pleasant Bayou geopressured wellsite in Brazoria County, Texas. Much of the equipment for the binary system was obtained from the DOE Direct Contact Heat Exchange (DCHX) test facility and refurbished for this project. New equipment provided for the Pleasant Bayou installation includes heat exchangers, an evaporative cooler, firewater pump, gas-freeing condenser and electrical switchgear. The operating conditions will approximate those of the DCHX system to minimize design and equipment modifications (Biljetina and Campbell, 1988).

Brine production from the Pleasant Bayou well will be controlled at 20,000 bbl/day (290,000 lb/hr), which is the capacity of the two separators in the brine handling system (Figure 1). Nominal flowing wellhead conditions are expected to be 295 F and 3000 to 4000 psi. At the primary choke, pressure will be reduced to 1500 psi. The brine flow will then be run through two flow-splitting chokes where the pressure will be further reduced to 800 psig. At that point, the brine will enter one of two gas/brine separators which will be operated in parallel.

The operating pressure for the gas/brine separators is determined by the gas sales pressure, which is nominally 600 psig. The gas produced from the Pleasant Bayou well consists of approximately 83% methane, 11% carbon dioxide and 6% ethane and higher components. After separation, cooling and dehydration, the gas can be either sold or run to the gas engine included in the energy conversion system. The gas engine will produce 650 kW under normal operating conditions. The exhaust from the gas engine will be used to vaporize a portion of the isobutane in the binary cycle.

Brine from the gas/brine separators will be split into two nominal 10,000 bbl/day (150,000 lb/hr) flow streams. One brine stream will be filtered and injected. The other brine stream will be run through a binary heat exchanger and then through an isobutane preheater prior to disposal. Condensed isobutane will be pumped through the preheater, where the temperature will be raised from 96 F to 210 F. Approximately 86% of the isobutane will then be vaporized in the primary heat exchanger. The remaining 14% of the isobutane will be vaporized in a secondary evaporator using heat from the 1130 F gas engine exhaust. The combined isobutane vapor streams will then be run through an isobutane turbine-generator with 540 kW design output. Parasitic power loads are estimated to total 210 kW, for a net power production for the combined cycles of 980 kW.

Some design changes have been made in the brine system based on operating experience at the Gladys McCall wellsite. At Gladys McCall, erosion and corrosion of pipe was high in areas of high brine velocity and where tortuous piping paths or gas entrapment existed. The highest piping failure rates at Gladys McCall were located just downstream of the chokes and the separator level control valves. At Pleasant Bayou, most of the brine piping remains carbon steel. Piping immediately downstream of the chokes and control valves has been upgraded to 316 stainless steel. In addition, pipe velocities will be maintained below 10 fps under normal operating conditions. Tighter specifications for material and welding have also been instituted (Biljetina and Campbell, 1988).

TEST PLAN

The primary objective of operating the energy conversion system is to demonstrate for the first time the generation of electricity from a geothermal hybrid power cycle. The system will be operated over a range of conditions to obtain data for system optimization and as a base for future commercial installations. Following initial startup and shakedown, the facility will be operated under a variety of operating conditions. Following this will be a period of operation at maximum power output under conditions as close as possible to that of a commercial facility. Performance data will be used to evaluate the reliability of the hybrid cycle and to develop and document those design, operation and maintenance features that are important for achieving high reliability. The duration of the test program will range from 12 to 24 months, depending on the operating experience and on funding availability.

During the test period, data will be collected on system performance under the adverse conditions of saline geothermal brine (total dissolved solids content of about 130,000 mg/l) and methane containing contaminants. Of particular interest will be heat exchanger fouling, scale formation, corrosion, erosion and long-term reliability of the geopressured fluid supply. Also important will be changes in the rotating equipment efficiency over time, which would indicate potential problems such as wear of the rotor or impeller, changes in clearance, vibration or mechanical failure.

To ensure that an operational data set is provided that can be verified and reanalyzed, an extensive instrumentation and data acquisition system will be installed. Instrument readings for key parameters will be recorded using a data logging computer and chart recorders. Many of the critical process streams will have backup instrumentation which will be read and recorded manually to confirm the automatically-recorded values. Data for calculation of equipment performance will be gathered at regular intervals, with the frequency of gathering depending on the test being run.

Key calculations for the hybrid system are rotating equipment efficiency and heat exchanger performance. While most of the required calculations are straightforward, the turbine efficiency calculations will require an estimate of the thermodynamic properties of isobutane. An equation of state, such as the Benedict-Webb-Rubin equation will be used to estimate these properties. Even at the turbine inlet, the isobutane will be substantially below the critical point in a region where the properties are known and the equations are considered accurate.

Long-term production from the Pleasant Bayou well is scheduled to begin in May, 1988. Final construction of the energy conversion system is expected to begin in late 1988, with operation of the system to begin in early 1989.

ACKNOWLEDGMENT

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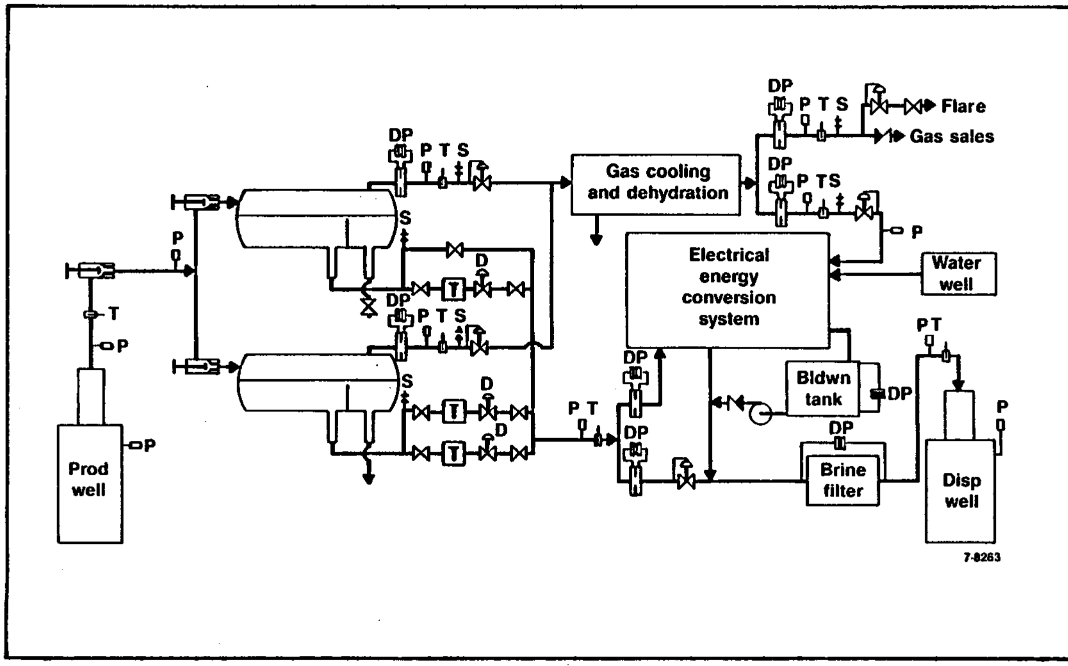

FIGURE 1. Pleasant Bayou Process Flow Diagram.

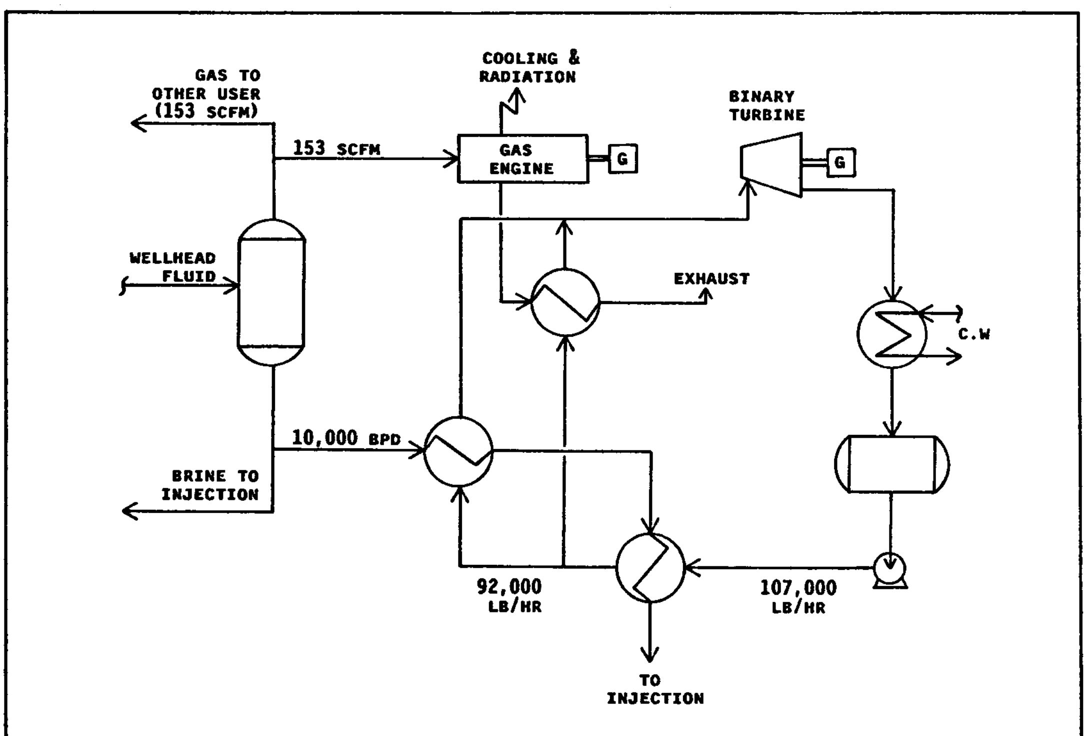

FIGURE 2. Process flow diagram for hybrid energy conversion system at Pleasant Bayou.

SESSION IV

HOT DRY ROCK RESEARCH PROGRAM OBJECTIVES

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HOT DRY ROCK RESEARCH PROGRAM OBJECTIVES SESSION: INTRODUCTION

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Albuquerque Operations Office
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The objectives of the Geothermal Technology Program research are to provide the required scientific and engineering knowledge, through technology tranfer to domestic industries, for the commercially cost effective utilization of the vast and virtually inexhaustible geothermal resources of our nation. Hot Dry Rock is a technology on the brink of availability for such usage. The completion of the work requires the measurement of the energy available from the reservoir. The Long Term Flow Test (LTFT) is planned to provide the draw-down data on which model calculations can be based. With such modelling available, the industrial and financial communities will have the assurance of sufficient accuracy of predictions and estimates that substantial commitments can be made with confidence.

The resource, at least fifteen times greater than all U. S. coal, guarantees the worthwhileness of the research. The technique for establishing the reservoirs by means of hydraulic fracturing is established. Proof of concept and protypical efforts at energy production techniques have been successful. Many instruments and techniques for providing the required measurements of the reservoir characteristics and increasingly precise measurements of the fractured reservoir location in the heat source have been developed. There remains the task of improving the accuracies and lowering the costs to within ranges of commercial acceptability in a few remaining critical areas. As these efforts proceed, (and they will, whether in this nation or in others) the beneficiaries of this research will achieve increasing energy independence using an environmentally benign technique whose commercial appeal and economically available areas of application will increase as costs of implementation are lowered. That is the aim of HDR research; technology transfer is the means of its early implementation.

The primary programmatic objective is to complete the LTFT, so that industry can use the data for economic forecasts to show the viability in open market competition of their proposed projects. Second, the program aims at improving the accuracies of measurements and analyses to reduce the error band of those forecasts and to permit cost reductions in the establishment and operations of the reservoirs. Third, the research is aimed at reductions in costs of drilling, fracturing, and operating reservoirs.

The research and development to be conducted is outlined to the depth necessary to provide a match with these objectives. The Los Alamos technical experts will provide detailed data.

As stated above, the primary program objective is to complete the LTFT. The remainder of the fiscal year, we will be preparing for that effort as we put the seven-inch casing down the redrilled EE-2 well and plan the surface system for the test. The massive pumps required for the test will enter the procurement cycle and the detail system planning will be well underway. Installation of the equipment and pre-LTFT testing will begin during FY 1989. The actual date for beginning the LTFT is budget dependent.

Beyond the LTFT, as much of the proposed advanced research and development program will be conducted as can be accommodated within the budget. An immediate need is the development of triaxial seismic methods for determining the locations of hydraulic fractures. The triaxial method differs from conventional seismic methods of locating fractures in that only one well is needed, because a triaxial seismometer detects not just the distance to a fracture, but the complete location. Conventional methods employ triangulation to determine a fracture location and require multiple wells, which are, of course, expensive to drill. An item of primary importance to industrial concerns is a means of predicting the useful lifetime of an HDR reservoir as early in its development as possible. A promising method is the use of reactive chemical tracers, which allow estimation of internal reservoir temperatures. Normally temperatures can be measured only in the injection or production well.

Beyond these reservoir tools, it must be recognized that about fifty per cent of the cost of HDR electricity is accounted for by drilling expenses. Consequently, the proposed research and development aim at improved drilling methods and such cost reduction techniques as cementless casings. Other work aims at reducing operating expenses by reducing flow impedance and pumping power required. Thus the objectives all aim at achieving cost competitive, cost effective HDR power.

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HOT DRY ROCK FRACTURE PROPAGATION AND RESERVOIR CHARACTERIZATION

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I. ABSTRACT

North America's largest hydraulic fracturing operations have been conducted at Fenton Hill, New Mexico to create hot dry rock geothermal reservoirs. Microearthquakes induced by these fracturing operations were measured with geophones. The large volume of rock over which the microearthquakes were distributed indicates a mechanism of hydraulic stimulation which is at odds with conventional fracturing theory, which predicts failure along a plane which is perpendicular to the least compressive earth stress. Shear slippage along pre-existing joints in the rock is more easily induced than conventional tensile failure, particularly when the difference between minimum and maximum earth stresses is large and the pre-existing joints are oriented at angles between 30 and 60° to the principal earth stresses, and a low viscosity fluid like water is injected. Shear slippage results in local redistribution of stresses, which allows a branching, or dendritic, stimulation pattern to evolve, in agreement with the patterns of microearthquake locations. Field testing of HDR reservoirs at the Fenton Hill site shows that significant reservoir growth occurred as energy was extracted. Tracer, microseismic, and geochemical measurements provided the primary quantitative evidence for the increases in accessible reservoir volume and fractured rock surface area. These temporal increases indicate that augmentation of reservoir heat production capacity in hot dry rock system occurred. For future reservoir testing, Los Alamos is developing tracer techniques using reactive chemicals to track thermal fronts. Recent studies have focused on the kinetics of hydrolysis of derivatives of bromobenzene, which can be used in reservoirs as hot as 275°C.

II. INTRODUCTION

The primary objective of the US Hot Dry Rock (HDR) Project is to develop and demonstrate an economical, commercially usable technology for recovering thermal energy from naturally heated rock at accessible depths in the earth's crust. While other methods are possible in different geologic environments, the Program has so far concentrated on hot crystalline rock of low initial permeability; the use of fluid pressure (hydraulic fracturing) to create flow passages and heat-transfer surface in that rock; and operation of a closed, recirculating, pressurized-water loop to extract heat from the rock and transport it to the earth's surface.

III. FRACTURE PROPAGATION

Most rock masses, particularly crystalline ones, contain pre-existing fractures called joints. When fluid is injected into joints during hydraulic fracturing, several types of joint deformation can take place. At first the pressure rise in the joint is small enough that the joint does not actually open. Nevertheless, the effective closure stress, that is, the difference between the total earth stress acting normal to the joint plane and the fluid pressure, is reduced. If injection continues, the pressure can attain a value high enough that the effective closure stress no longer provides sufficient friction to resist shearing stresses acting parallel to the joint surface, and the joint will slip in a shear mode. If the slippage is sufficient, one rough surface asperity can ride over, or atop another, so that even if the pressure is suddenly reduced the joint opening and permeability are irreversibly increased. This is termed "shear stimulation." If fluid viscosity or injection rates are modest shear stimulation may result in sufficient permeability that no further increase in pressure is attainable. If, however, the formation of void space by shearing is insufficient to accommodate the fluid volume injected into the rock joints, the pressure will continue to rise, and eventually attain a value equal to the earth stress acting normal to the joint. Then the opposing surfaces of the rock that meet at the joint will part. If proppants, either purposely injected with the fluid, or rock chips broken off the joint surfaces, are trapped in a joint following shut-in, the joint opening will again be irreversibly increased, and the joint thus "stimulated."

The kinematic argument for shear stimulation is shown in the Mohr diagram, Fig. 1. A two-dimensional stress state is depicted, in which the principal maximum and minimum compressive stresses are labeled σ_{min} and σ_{max} and the stresses on any other plane can be represented by the Mohr circle connecting the two principal stresses (Jaeger and Cook, 1979). In Fig. 1 a fairly typical stress state is assumed, in which σ_{max} is about twice σ_{min}. The effective closure stresses on a joint are reduced by the pressure, P, within the joint. Consequently, joint separation occurs when the effective closure stress is zero, or $P = \sigma_{min}$. As shown in Fig. 1, separation thus requires that the Mohr circle be moved so completely to the left that by pressurization its left side is coincident with the origin. On the other hand, shearing requires only that the Mohr circle move left sufficiently to encounter the Coulomb-Mohr failure envelope. A mere touching is sufficient if a joint has the optimum orientation, but even if not optimally oriented most joints will shear long before they separate.

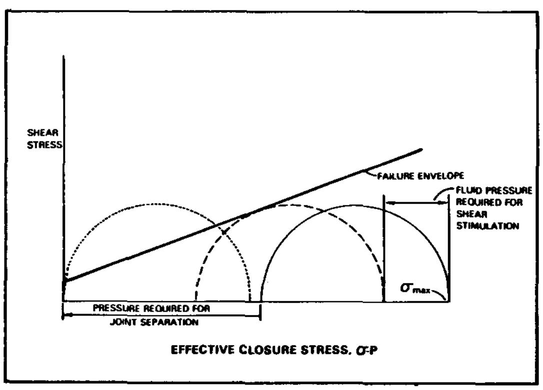

Figure 1. Mohr stress diagram illustrating that lower fluid pressure is required for shear stimulation compared to joint separation.

Shear stimulation is rarely discussed in hydraulic fracturing theory. Lockner and Byerlee (1977), who demonstrated in experiments that slow pressurization could result in shear fracturing of intact, not just jointed, rock specimens, were moved to state that: "in the literature on hydraulic fracture the possibility of producing shear rather than tension fractures is surprisingly disregarded." Subsequently, several other papers (Hast, 1979, and Solberg, Lockner and Byerlee, 1980) have appeared which support the possibility of shear stimulation.

While it thus appears that joints will shear at fluid pressures less than that required for separation, the joint opening, or dilation behavior for slippage and separation is quite different. As pressure increases the dilation is small at first, simply resulting from the decrease of effective closure stress, but then shear slippage ensues. As the joint surfaces continue to slip, they attain a state in which one large roughness asperity lies atop another, and further slippage would allow the largest asperity to slide over and down the other. Thus one expects a natural limit to the shear dilation. This maximum shear dilation is typically of the order of a fraction of a millimeter (Barton et al., 1985). If the joint pressure can be increased so that separation occurs, then the results of conventional hydraulic fracture theory (but taking the tensile strength of the jointed rock to be zero) indicate that the dilation is typically tens of millimeters (Perkins and Kern, 1961; and Daneshy, 1973), many times that of shear dilation. Thus as Lockner and Byerlee correctly foresaw, the key to understanding stimulation is not just rock mechanics, but also fluid dynamics. If a low viscosity fluid is injected into a joint at a low enough flow rate, the fluid volume can be accommodated within the small dilation created by shear slippage. Even though the joint opening and permeability are not increased as much as if by separation, the permeability increase could be sufficient to sustain low flow rates for low viscosity fluids without large pressure gradients, and the pressure need not build up to separation requirements.

In an actual hydraulic fracturing operation the entire spectrum of joint deformation can occur: near the injection well the flow passage area is limited, hence fluid velocities and pressure gradients are large and separation occurs (Bame and Fehler, 1986). But near the tips of joints, far from the injection well, velocities and pressures are much reduced, and shear stimulation occurs. In the most common application of hydraulic fracturing, in petroleum reservoirs, very viscous fluids are normally used and injection rates are high. Consequently, joint separation is dominant, and if few joints are present, as is often the case in petroleum formations, actual fracturing of intact rock occurs. However, in the geothermal reservoir fracturing described below, joints occur frequently, and high downhole temperatures render most viscosifying agents useless, so water is used as the fracturing fluid. Hence, shear stimulation dominates.

1. Reservoir Stimulation Experiments. Hydraulic stimulation experiments were conducted in two Hot Dry Rock (HDR) geothermal energy reservoirs. The first of these is located at Fenton Hill, on the west flank of the Valles Caldera, a dormant volcanic complex in the Jemez Mountains of New Mexico, USA. The second site is at Rosemanowes Quarry, in Cornwall, England. At both sites the reservoirs are jointed, granitic rock.

Early successes with the small Phase I reservoir at Fenton Hill led to the decision to create a deeper, hotter, and larger Phase II reservoir at the Fenton Hill site. Figure 2 shows a perspective view of the two new wells drilled for the deeper reservoir. The upper well, EE-3, which was the intended production well, lies 300 m above the lower injection well, EE-2, in the slanted interval. Temperatures varied from 200°C at 3 km to 325°C at 4.4 km. Also shown in Fig. 2 is a well drilled for the older reservoir which contains a geophone sonde. This geophone and others placed in other nearby boreholes detect and locate the microearthquakes triggered during hydraulic stimulation (House, 1987).

In December 1983 a massive hydraulic fracturing operation was conducted in which 21,000 m^3 (5,600,000 gal) of water were injected at 3.5 km in the lower well at a downhole pressure of 83 MPa and an average flow rate of 0.1 m^3/s (40 bbls/min). Details are provided by Dreesen and Nicholson (1985). Figure 3 shows the locations of the largest induced microearthquakes. The downhole geophones are extraordinarily sensitive, which enabled detection of events with extrapolated Richter body wave magnitudes as low as -5, but Fig. 3 shows only the 850 high-quality events with magnitudes from -3 to 0. The microearthquake locations indicate a zone of stimulation distributed throughout a rock volume that is about 0.8 km high, 0.8 km wide in the N-S direction, and about 0.25 km thick in the E-W direction. The precision of microearthquake locations is 20 m, so the width of the seismic volume, 250 m, is not an artifact of measurement uncertainty. The volume of the stimulated zone is 4000 times greater than the volume of water injected. House, 1987) concluded that the first motions of the microearthquakes and fault plane solutions determined from a surface array of seismometers indicated a

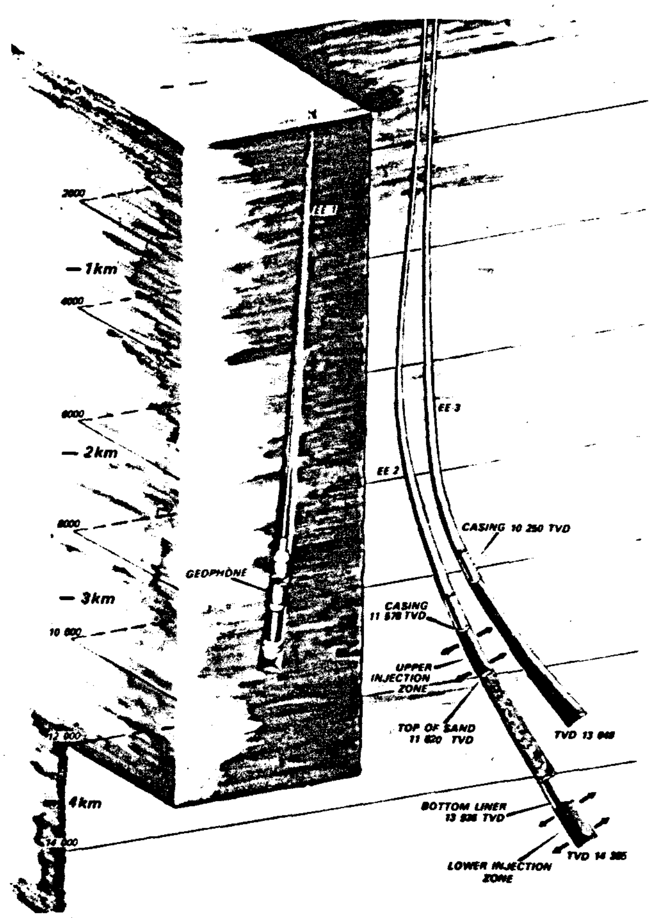

Figure 2. Perspective view of wells and geophone tool placed for microearthquake monitoring during hydraulic stimulation.

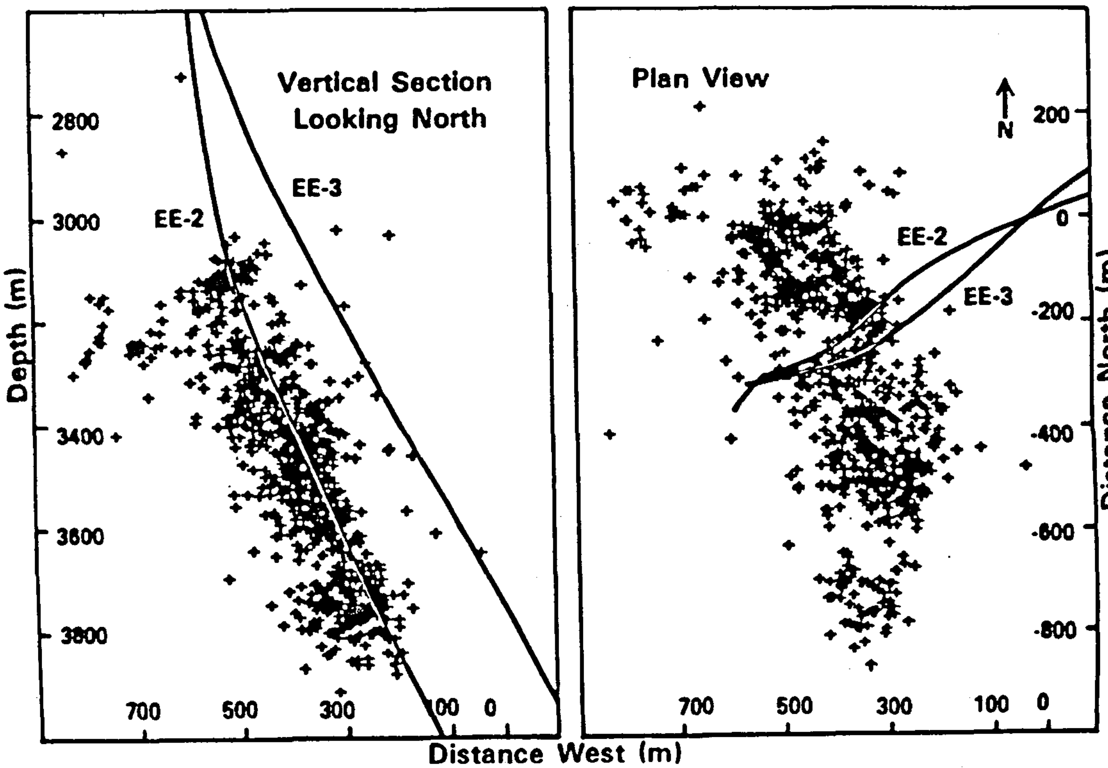

Figure 3. Single joint stimulation induced by shear slippage when frictional resistance to shear slippage is low or the ability to open the joint in shear is high.

shear-slip motion, probably along pre-existing rock joints. This suggests that tensile fracturing, if it occurred at all, generated only very weak seismic signals that could not be detected by the surface seismic array.

These results indicate a fracturing mechanism which is inconsistent with conventional theories of hydraulic fracturing which predict the propagation of a single fracture caused by tensile failure of the rock. However, our results are consistent with Lockner and Byerlee's observation of shear failure in rock specimens at low injection rate. Furthermore, our observations were confirmed at the British Hot Dry Rock reservoir in Cornwall where it was observed (Pine and Batchelor, 1984) that fracturing occurred as a zone of multiple fractures, and that shear slippage along existing joints was the dominant cause of seismicity.

More recenty, we have developed a method, called the three point method, which allows us to identify the most intensively stimulated joints. We applied the method to microearthquakes occurring during many injection experiments, and successfully identified numerous planes along which we believe that fluid flows (Fehler, et al., 1987; Fehler, 1988). The locations of these planes have been correlated with well log anomalies, which provide independent confirmation of the existence of fractures and the correlation is quite good (Dreesen, et al., 1987). Knowledge of the location of these shear slip planes has been used by Dreesen et al. (1987) to develop a three dimensional deterministic model of the larger flow paths through the reservoir.

2. Modeling Shear Stimulation in Jointed Rock. The unexpected stimulation results presented above suggested further study, using a model incorporating detailed fluid dynamics and rock mechanics within jointed rock masses. The Fluid Rock Interaction Program, based upon the calculation method developed by Cundall and Marti (1978), was adapted for this use. Pre-existing rock joints are deployed on a regular rectangular grid and the code permits interactive coupling of fluid dynamics with rock stresses and deformations. For example, an excess of pressure on a block during one

computational cycle will result in compression of the block, and opening (dilation) of the joints next to it, resulting in additional permeability and a changed pressure distribution.

When a computation in which joints were aligned parallel to the principal earth stresses was studied, a process equivalent to classical hydraulic fracturing (but without the necessity of accounting for rock strength) was predicted: a single joint opened at a pressure equal to the minimum earth stress, and the aperture and shape of the opened joint agreed well with conventional hydraulic fracturing theory (Daneshy, 1973). However, when the orientation of the pre-existing joints were rotated 30° from the principal stress directions, and a low viscosity fluid like water was used for fracturing, two types of stimulation patterns occurred. In the first type, typified in Fig. 4, which occurs when frictional resistance to shear slippage is low or when the maximum dilatancy due to shear is large, only a single joint is stimulated. The resolved stresses shown in Fig. 4 result from a principal earth stress of 2σ applied at an angle of 30° to the joints. For simplicity the subscript min has been deleted so σ is the minimum principal earth stress and it acts perpendicular to the maximum stress, 2σ.

In the second type of shear stimulation, corresponding to high shear resistance or small dilatancy, multiple joint stimulation occurs as shown in Fig. 5. Shear slippage along the joints is accompanied by shear-stress drops, and the interaction of these stress drops with the acting earth stresses result in opening of joints more perpendicular to the maximum stress, so that a dendritic, or branched joint pattern occurs. This pattern of stimulated joints and the computed shear-stress drops offer an explanation as to why the previous microearthquake maps are not planar, but are elliptical in shape, and why the observed first motions of microearthquakes indicate a shear mechanism.

The multiple joint stimulation pattern depicted in Fig. 5 has important implications for other energy reservoirs. As suggested in Fig. 6, volume drainage, whether it be of hydrocarbons or geothermal fluids, is more efficient than areal drainage.

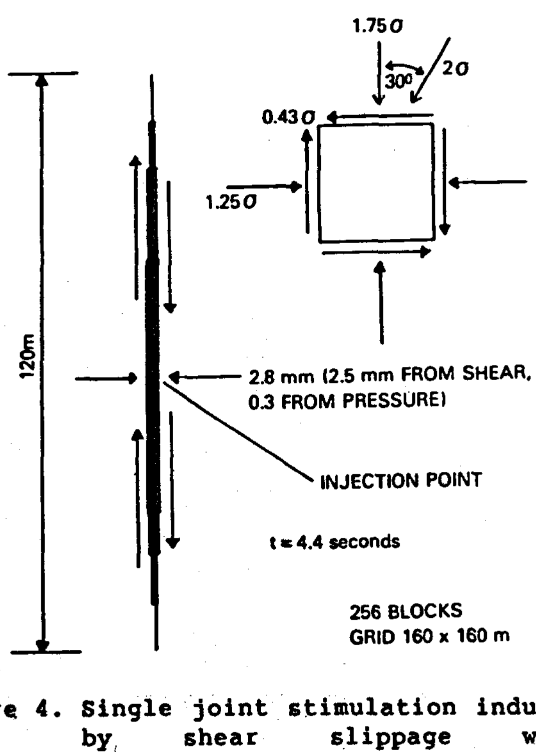

Figure 4. Single joint stimulation induced by shear slippage when frictional resistance to shear slippage is low or the ability to open the joint in shear is high.

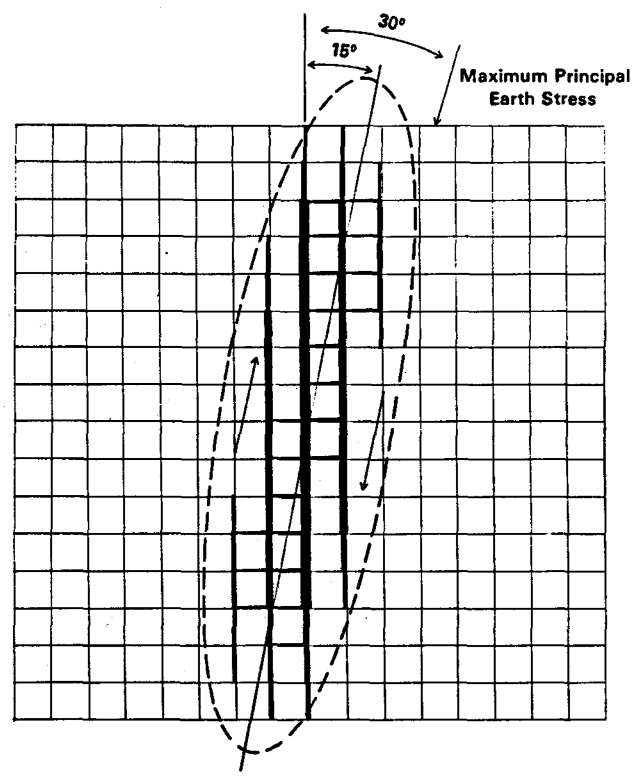

Figure 5. Multiple joint shear stimulation which occurs when shear resistance is high or shear dilatancy is low.

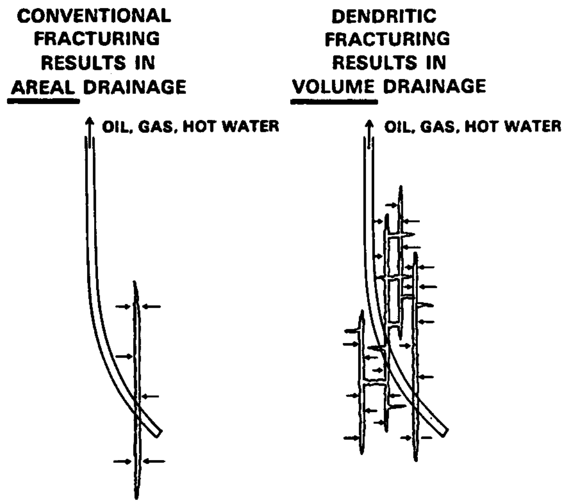

Figure 6. Volume drainage of fluids is more effective than areal drainage.

IV. RESERVOIR CHARACTERIZATION

Briefly discussed here are diagnostic techniques used during early testing of the Phase I reservoir at Fenton Hill. The Phase I reservoir was a small one, created and operated to establish the scientific feasibility of HDR. Following this discussion we present a new technique, chemically reactive tracers, for early diagnosis of the thermal capacity and lifetime of the larger, Phase II reservoir.

1. Thermal-Hydraulic Techniques and Models. During all testing, surface and downhole temperature and flow measurements were made. A spinner/temperature logging tool was used for all downhole measurements. During extended production periods, the spinner/temperature tool was positioned in the production well inside the casing above all production zones. Periodically, logging was accomplished during production using a pressurized cable packoff system mounted in the wellhead.

One model used to estimate the effective heat transfer area assumes 1-D or 2-D steady flow in a planar fracture coupled to 1-D conduction in the rock perpendicular to the flow field. Thus, the rate of production temperature decline or thermal drawdown will be controlled by the areal rather than volumetric features of the rock exposed to the circulating fluid. Although simplistic, this areal sweep model conveniently describes the thermal behavior of a fractured reservoir by matching the observed thermal drawdown with a single adjustable parameter, the fracture area. This fitted area should be regarded as an effective heat transfer area, most useful for modeling purposes.

Large-scale heterogeneities, such as the superposition of flows in multiple joints, undoubtedly exert great influence on heat transfer behavior, since the spatial positioning of these low impedance conduits effectively defines the accessible volume of rock. In the two early HDR reservoirs studied to date, the onset and subsequent rate of thermal drawdown seems to be controlled by that portion of the reservoir surface area of the flow paths directly connecting the wells.

Other heat transfer models have been proposed for fractured HDR systems to account for these complexities. One such model, developed by Robinson and Jones (1987), treats the reservoir as a composite of several zones of highly-fractured rock which behave as a porous continuum. The tracer response, or concentration-time behavior in the produced fluid caused by injecting a slug of tracer in the injection fluid, is used to set the flow rates and fluid volumes of each zone. The principal adjustable parameter is the total rock volume bathed by the circulating fluid.

In summary, computer models have been developed which span the spectrum of fractured reservoir geometries: from single, discrete fractures to situations with such intense fracturing that the rock can be considered a porous continuum. As discussed earlier in FRACTURE PROPAGATION, a single fracture is an unlikely result if jointed rock is stimulated. On the other hand, while many joints are simultaneously stimulated throughout a vast rock region, the 3 point seismic method shows that some joints are preferentially opened, either because they were more permeable to begin with, or their orientations are aligned with the existing earth stresses such that they open more readily. When heat is extracted from the reservoir these preferentially opened joints transmit most of the water flow, so a highly heterogeneous model, using several discrete fractures, usually matches the data best.

2. Tracer Techniques. Throughout the testing periods, pulses of tracers were injected into the reservoir and

monitored in the produced fluid. Both sodium fluorescein dye and neutron-activated ammonium bromide ($NH_4Br[Br^{82}]$) tracers were used to map the flow and mixing patterns in the reservoirs. As described by Tester (et al., 1982), tracer tests provide a direct measure of accessible volume and dispersion levels within the active reservoir. The tracer concentration history in the production well describes a breakthrough curve giving the distribution of fluid residence times within the reservoir. Changes in reservoir mean or modal volume can be obtained easily from a pulse tracer test. The modal volume is simply the volume of fluid produced between the time the tracer pulse was injected into the reservoir and the time the peak tracer concentration appears in the production well. Since the flow channels directly connecting the two wells are apt to have the shortest residence times, the modal volume is most closely related to the fluid volume of the high-permeability paths. The physical significance of the mean tracer volume is that it represents the total volume of all flow paths conducting fluid, regardless of flow velocity.

3. Chemically Reactive Tracers. Figure 7 illustrates the progress of a thermal front in an HDR reservoir. Heat is transmitted from the rock to the fluid by conduction, and the rock gradually cools near the injection well. As time progresses, this cooled region moves closer to the production well. When it finally reaches the production well, the produced fluid temperature starts declining, and then estimates of reservoir size can be deduced from heat transfer considerations. For large reservoirs several years of operation are required to achieve discernible produced fluid temperature decline. Clearly, some other method of sizing an HDR reservoir is required. Chemically reactive tracers are one possible technique.

The kinetics of most chemical reactions are extremely temperature dependent. For first order reactions carried out in a batch reactor, the following rate equation is applicable:

$$\frac{dC}{dt} = -kC$$

where C is reactant concentration and t is time. The rate constant k can normally be described by the following expression:

$$k = A_r \exp(-E_a/RT)$$

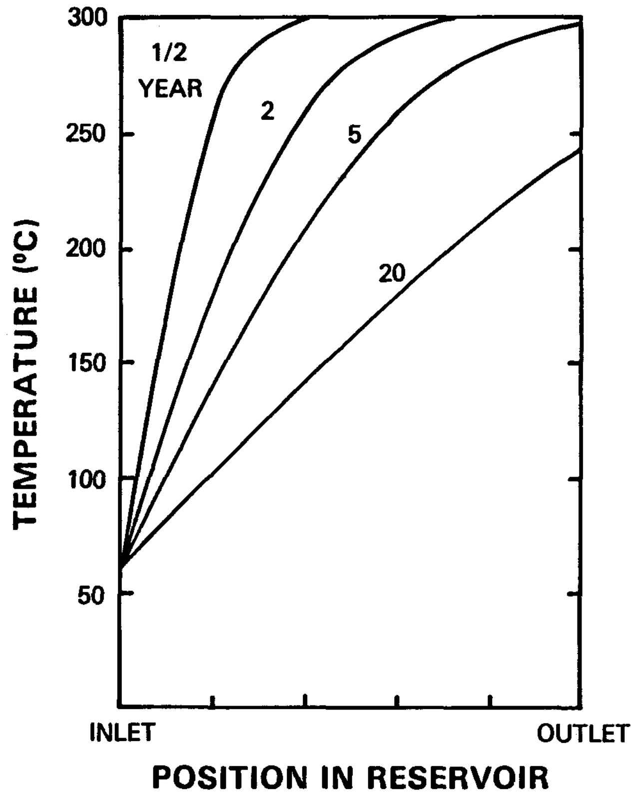

Figure 7. Progress of a Thermal Front Through a Fractured HDR Reservoir Undergoing Energy Extraction.

where A_r is the pre-exponential factor, E_a is the activation energy, R is the universal gas constant, and T is absolute temperature. For typical reactions in solution, k will vary over many orders or magnitude over the range of temperatures encountered in an HDR reservoir undergoing energy extraction.

Figure 8 shows the results of a series of simulations of reactive tracer experiments at different times during a long-term reservoir operation for the temperature patterns in Fig. 7. In each tracer experiment, a step change in tracer concentration is imparted at t = 0, and the extent of reaction is governed by the residence time and temperature field encountered. As the thermal front moves closer to the production well, the tracer experiences less time in hot rock, and the extent of reaction decreases. Thus more unreacted tracer reaches the outlet in each successive tracer experiment. By simulating this behavior using a combined heat transfer and fluid flow model, we should be able to estimate reservoir lifetime early in the production history, well before the thermal front actually reaches the production well.

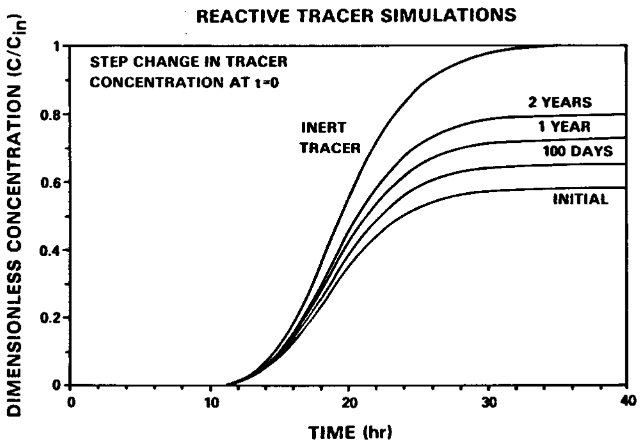

Figure 8. Reactive Tracer Step Response Simulations for the Temperature

Work so far has shown that ester and amide hydrolysis reactions are suitable for low temperature (75 to 150°C) reservoirs. For higher temperatures (up to 275°C), hydrolysis of bromobenzene derivatives is more appropriate. Additional details are provided by Robinson and Birdsell (1987).

Future reactive tracer studies will focus more closely on the bromobenzene compounds, since these have kinetics more appropriate for the Fenton Hill Phase II conditions. The two areas we will address most carefully are adsorption and analytical sensitivity. The reactive tracers we are proposing are designed to react homogeneously in the liquid phase rather than with the rock minerals. Adsorption should ideally be negligible, and preliminary laboratory results indicate that the extent of adsorption is small for these tracers. To perform a field test, extremely sensitive analytical techniques must be used to measure tracer accurately at very low concentrations. Otherwise, the enormous dilution ratios encountered in most field tracer experiments will require large quantities of tracer to be injected. We are developing high-pressure liquid chromatography techniques to detect tracer reactants and products at low levels. Initial investigations suggest that with the proper enhancement techniques, the parts per billion range can be achieved. Finally, the reactive tracer concept needs to be proven in the field to be considered a reliable diagnostic technique. During the upcoming long term flow test of the Fenton Hill Phase II reservoir, we will attempt to demonstrate the utility of reactive tracers to map thermal fronts in HDR reservoirs.

ACKNOWLEDGEMENTS

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PROSPECTS FOR HOT DRY ROCK IN THE FUTURE

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ABSTRACT

The Hot Dry Rock (HDR) geothermal energy program is a renewable energy program that can contribute significantly to the nation's balanced and diversified energy mix. The program was reviewed five times in the past three years. Three of these reviews were done by the U.S. Department of Energy (DOE) and a fourth was conducted by the National Research Council at the request of DOE. In addition, HDR was evaluated in the Energy Research Advisory Board's Solid Earth Sciences Report. Recent economic studies for HDR have been performed by Bechtel National, Inc., the Electric Power Research Institute, and the United Kingdom. These studies are reviewed in light of recent progress at Fenton Hill in reducing drilling costs, and mapping and in identifying drilling targets. All of the attention focused on HDR has resulted in evaluating the way in which HDR fits within the nation's energy mix and in estimating when HDR will contribute to energy security. To establish a framework for evaluating the future of HDR, the status and progress of HDR are reviewed and the remaining Fenton Hill program is outlined. Recommendations are also made for follow-on activities that will lead to achieving full development of HDR technologies in the appropriate time frame.

INTRODUCTION

The Hot Dry Rock (HDR) geothermal energy program is a renewable energy program that can and will contribute to the nation's balanced and diversified energy mix. The Department of Energy sponsors the HDR Program and Los Alamos National Laboratory, operated by the University of California, has primary responsibility for the program. HDR geothermal reservoirs differ profoundly from conventional geothermal reservoirs. The latter, usually referred to as hydrothermal reservoirs, are only in a few geologically favored regions in the western United States. In these regions, nature provides not only the hot rock, but also hot water or steam that is easily tapped for electricity generation. In contrast, HDR energy reservoirs are manmade and, thus, any convenient source of hot rock can serve as the host reservoir. Consequently, hot rock can be found at attractive depths throughout the U.S., a fact that accounts for the huge HDR resource base (hundreds of times greater than U.S. coal).

The widespread availability of HDR lends itself to the small-is-better plant strategy espoused more and more by electrical utilities. To quote Secretary of Energy Herrington's report to the President, entitled Energy Security,[1] HDR, like most renewable energy technologies, can be "assembled in relatively small building blocks or modules (which) will permit additions to energy supply in smaller units than is common for conventional technologies. This could be a distinct advantage when energy demand projections are uncertain, and when growing financial risks are associated with the construction of large supply units such as more conventional generating plants." Although geothermal energy is often considered a "western" U.S. resource, research by Los Alamos and others shows that HDR is a national resource. HDR potential exists in the Northeast, Mid-Atlantic, West, as well as the Mid-West.

The HDR method for recovering heat from the earth's crust involves drilling two wells and connecting them through a series of cracks or fractures produced by pressurizing one of them. As shown in Fig. 1, water pumped down one well is heated as it circulates through the fractures; it returns to the surface through the other well. Heat exchangers extract the useful heat, and the

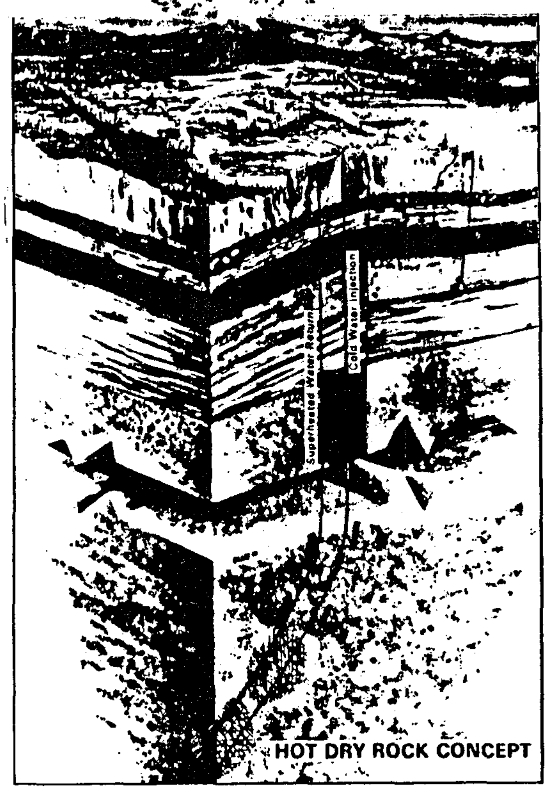

FIG. 1.
Artist's conception of a hot dry rock system.

water recirculates and recovers more heat. The removed heat can be used directly or can be converted to electricity. Because this is a closed-circulation loop, with little release to the biosphere, the system is environmentally safe.

An evaluation of the potentially useful heat in HDR at accessible depths beneath the United States indicates that HDR energy content is several thousand times the total energy used in this nation in one year. Figure 2 provides a comparison of HDR with other U.S. energy resources. HDR has the potential of adding enormous energy to our nation's resource base: 90 million megawatt-centuries. The high-grade HDR resources are those in which the temperature increases with depth so rapidly that HDR reservoirs can be created at shallower, more economically attractive depths. These resources alone contain the heat equivalent of 15 times the nation's coal reserves. The HDR resources are comparable to fission or fusion in overall energy potential.

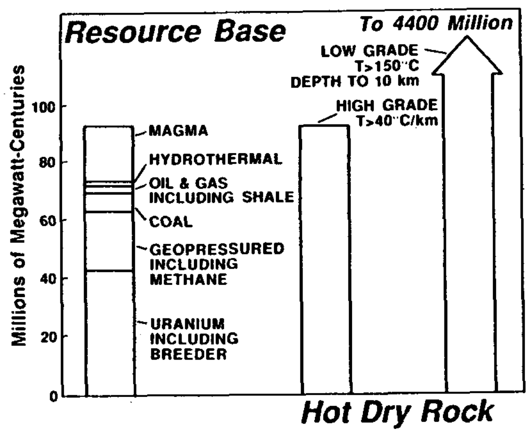

FIG. 2.
Comparison of Hot Dry Rock with other U.S. energy resources.

Several years ago, Los Alamos completed the world's first hot dry rock system at Fenton Hill in the mountains of northern New Mexico. The year-long operation brought hot water at a temperature of about 140°C (280°F) to the surface. Los Alamos has since undertaken development of a larger, deeper, and hotter system. Two wells were drilled at Fenton Hill to depths of about 4.3 km (14,000 ft). After initial fracturing experiments near the bottom of the holes, the wells were hydraulically connected at 3.6 km (11,800 ft) by pressurizing one of them. In the largest experiment, nearly 22,000 m^3 (6,000,000 gal) of water were pumped out into the rock at a pressure of about 48 MPa (7000 lb/in^2).

In May and June of 1986, Los Alamos conducted the 30-day-long Initial Closed-Loop Flow Test. The goal of this initial reservoir test was to provide preliminary technical information so a longer and final test of the system could be properly designed. This final test is called the Long-Term Flow Test (LTFT). The 30-day-long test met all objectives. At test conclusion, hot water was brought to the surface at a temperature of 192°C (375°F). Energy was extracted at rates as high as 10 MW-thermal, at a production flow rate of 16 l/s (260 gal/min). At the end of the test, all parameters that govern successful and efficient energy extraction were improving.

RECENT HDR ACTIVITIES AT FENTON HILL

During the last year, the Los Alamos staff successfully completed the redrilling of a damaged well, EE-2, thereby improving the potential power production rates. We drilled out of the damaged well at 3.2 km (9700 ft) and reached our goal of 4.1 km (12,360 ft) on November 11, 1987, just one day later than planned. It required just 30 days to drill 860 m (2600 ft) of additional hole. This was at an average drilling rate of 29 m (87 ft) per day, an excellent rate in hard rock. This drilling rate is nearly 2.5 times faster than that achieved during the original drilling a few years ago. Due to new technology, if the wells were drilled today, they would cost 60% less than their original cost. Not only does the cost savings brighten the future of HDR and other geothermal programs, but this advance will also benefit the oil and gas industry and the Continental Scientific Drilling Program. The 60% savings of drilling costs correspond to a 30% reduction of overall costs to generate electricity.

In addition to the repair and redrilling of the damaged well, EE-2, planning for the LTFT continued. With the operating data from the interim 30-day flow test in hand, Los Alamos continued to design the equipment for the Long Term Flow Test needed to demonstrate the maximum heat capability of the reservoir to provide the design basis for commercial HDR development.

HOT DRY ROCK AND THE NATION'S ENERGY MIX

Despite the accelerated spending on energy research in the seventies, 96% of the world's energy needs are still derived from fossil fuels, and 70% of the fuels now used are in the form of oil or natural gas. At present, the United States imports about a third of its oil, but that fraction is expected to rise to 50% by the mid-nineties. Oil and gas are less expensive these days, but they are a limited resource. New reserves are becoming more difficult to find, especially in North America. In 1986, American oil companies found new domestic reserves that amounted to only 41% of the oil they pumped out during the year. The replacement rate of 48% for gas is not much better. A recent summary of a United States Geological Survey (USGS) study reports that total gas reserves may be 40% less than previously assumed.[2] Furthermore, an April 1988 report by the United States Energy Association notes that the level of proved reserves in the lower 48 states has dropped 36% during the last 15 years, and even the high rate of drilling from 1982 to 1985 did not result in net additions to the reserves.[3] The report also stated that large investments and many years are required to develop gas supplies and to construct gas pipelines. Therefore, considerable time and money would be required to respond to a large increase in demand for natural gas.

In the 1985 "National Energy Policy Plan V"[4] (NEPP V), the Department of Energy (DOE) reiterated the nation's policy that "...Americans should have an adequate supply of energy, available at a reasonable cost. The basic strategies for holding to this goal are to ... promote a balanced and mixed energy resource system." The report further explained that a balanced and diversified energy mix includes renewable energy, for which research should "...address key, high-risk technical issues that will provide a scientific and engineering knowledge for industry..."

To quote from Secretary Herrington's report, Energy Security,[1] "...the United States and the world will, in time, come to rely largely on energy sources that are essentially inexhaustible, possibly including advanced nuclear fission reactors, fusion, and many diverse sources that are commonly lumped under the term 'renewable energy.' ... The combination of solar, wind, geothermal, water, and biomass energy represents an extremely large resource base that, over the long term, could become a major new source of energy supply. Perhaps the greatest advantage of these 'new' renewables is simply that they are based on technology -- rather than on insecure resources. The resources that underlie them (including innovative ideas) are indigenous. They are not subject to politically induced disruptions. The cost of the renewables is likely to drop, rather than to rise. By its very definition, renewable energy can significantly reduce energy security problems -- but only whenever and wherever renewable energy is available at a reasonable cost, in sufficient quantities, and in the desired applications. The very presence of additional energy options in the marketplace will tend to moderate the size and frequency of swings in conventional fuel prices. Renewable energy technologies have excellent export potential in the developing countries. Penetrating these markets and holding domestic markets in the face of rising foreign competition depends on continuing technical progress driven by advanced research. The development of a technology base upon which industry can build will involve a sustained research commitment well in advance of potential payoffs. The federal research program will continue to emphasize collaboration with industry in long-term, high-risk areas of technology base development. Continued research progress in key areas will speed the day when private sector initiatives make more renewable energy technologies competitive."

The <u>Energy Security</u> report also noted that, in 1985, almost two-thirds of US oil consumption went for transportation. The electric utility industry used only 0.48 million barrels of oil per day (MMBD), or about 3%. Oil and gas combined accounted for about 2 MMBD equivalent, about 12%. However, the oil used for generating electricity has quadrupled since 1955, and projections indicate further increases. One of the report's conclusions, using projections that assumed a 2% electricity demand growth, was that oil and gas consumption by electric utilities may increase beyond economic levels after 1995. The report made the point that many energy analysts have believed for years: since 1900, there has been a close correlation between electricity consumption and real gross national product. Projections of U.S. economic and electricity demand growth rates from thirteen authoritative sources, shown in Fig. 3, indicate an average rate of 2.3%. Figure 4 shows that, at this rate of growth, electricity demand will outstrip supply by 1995, and the shortfall will reach 100 GWe by 2000.

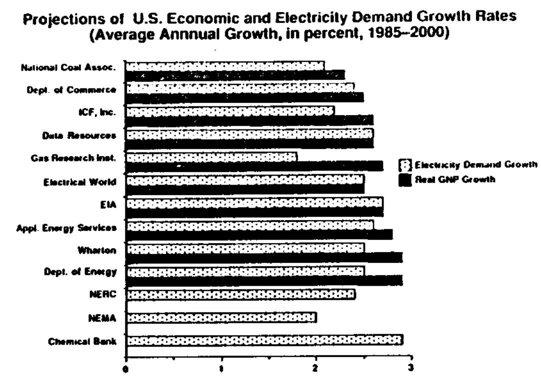

FIG. 3.
Projection of U.S. economic and electricity growth rates.

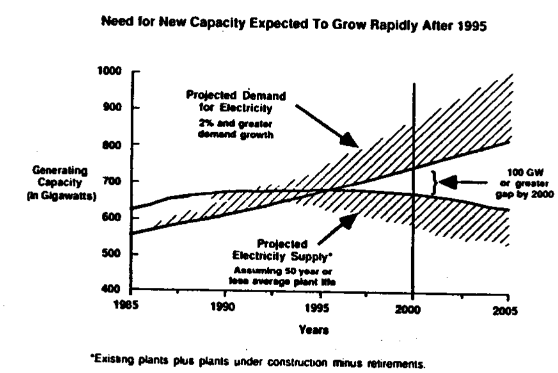

FIG. 4.
Projected electricity supply and demand.

Thus, a strong case exists for federal support of renewable energy technologies, including HDR, as candidates for relieving the projected post-1995 electricity shortfall and for reducing the rate of increase of oil and gas consumption for electricity generation.

Data presented in the Energy Security report on the aging of today's electric generating capacity makes an even stronger case for continued federal support that is consistent with federal policy. As shown in Fig. 5, a significant portion of the generating capacity, greater than 10,000 megawatts (MW), is older than 20 years. Hence, a need exists for the nation to have available, by 1995, the capability to deploy small, modular electric generating plants that can be brought on line quickly and with minimal environmental impact. Geothermal energy, and hot dry rock in particular, is a technology that meets these requirements.

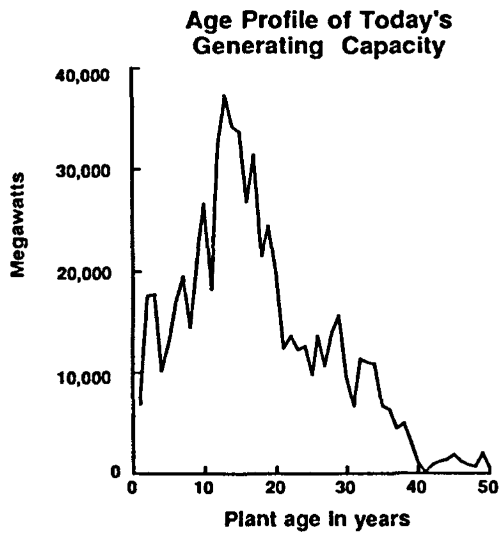

FIG. 5.
Aging of U.S. electricity power plants.

ASSESSMENT OF THE PRESENT STATE OF GEOTHERMAL TECHNOLOGY

In 1986, the National Research Council formed the Committee on Geothermal Energy Technology. The committee's study, sponsored by the Department of Energy's Geothermal Technology Division, addressed major issues in geothermal energy technology and made recommendations for research and development.[5] Although not part of its brief from DOE, the funding levels for geothermal research activities were also outlined by the committee. To paraphrase the committee's suggestion, it noted that funding for the DOE's Geothermal Technology Program has decreased from a high of about $158 million in FY 1979 to $21 million in FY 1987. In addition, current low petroleum prices have led to stagnation of the U.S. geothermal industry. The committee suggested that the current low price of hydrocarbon fuels, especially of petroleum, is a short-term phenomenon within a long-term trend toward rising prices. Given this scenario, it is necessary for the United States to maintain some energy supply options over the coming decades. Many of these options are now only marginally economic. Because of the large U.S. geothermal energy base (Fig. 6) and the possibility of converting even a small part of this resource into economically useful energy, the study concluded that the development of U.S. geothermal resources at competitive prices could be an important contribution to U.S. energy self-sufficiency.

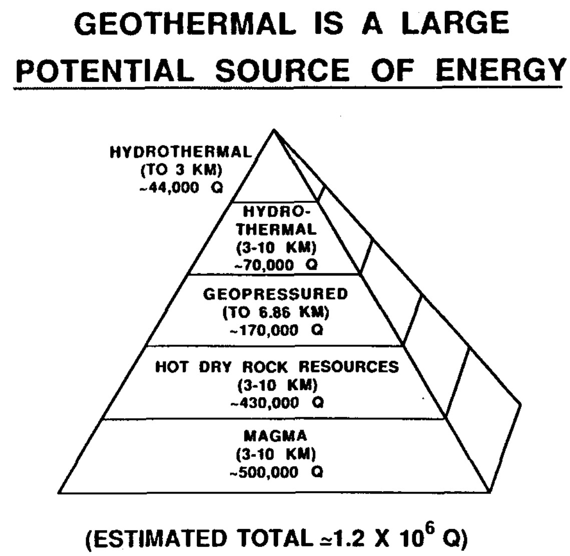

FIG. 6.
Estimates of total geothermal resource base.

The study noted that hydrothermal systems are the only geothermal type that are now competitive commercially. The economics are more uncertain for the longer-term technologies for extracting energy from geopressured, hot dry rock, and magma systems. For some sites, the cost of energy derived from geopressured and hot dry rock systems is projected to be within a commercially competitive range. The study concluded that the use of magma energy is too far in the future to make reasonable economic calculations. Figures 7 and 8 show the Department of Energy's assessment of the development status of geothermal technologies. The figures also show comparative economics, which are consistent with the conclusion of the NRC report. Recent studies, discussed in the next section, suggest economics for HDR.

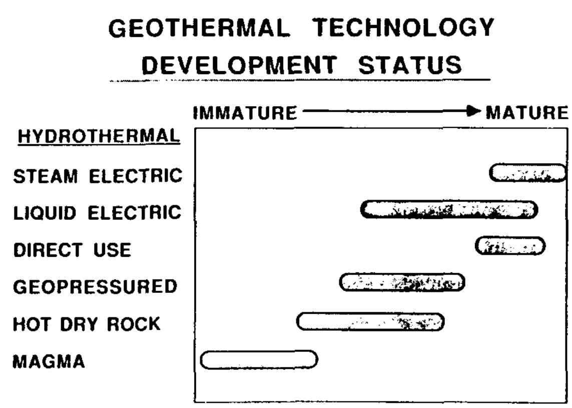

FIG. 7.
Geothermal energy technology development status.

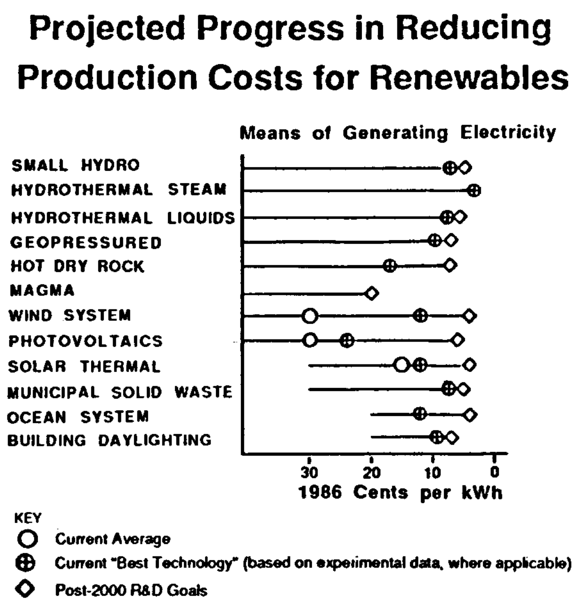

FIG. 8.
Projected electricity production costs for renewable energy sources.

The study agrees with the DOE's overall Geothermal Technology Program goal: to determine and improve the scientific, engineering, and economic feasibility of using energy from hydrothermal, geopressured, hot dry rock, and magma geothermal resources. Developing hydrothermal resources should receive near-term emphasis by both government and private industry. Development of the longer-term resources of geopressured, hot dry rock, and magma systems requires federal leadership and support. Budget decreases over the last few years in the Geothermal Technology Program have delayed many R&D projects. The study suggested that a higher and much more stable level of funding is required to accomplish further commercialization of many hydrothermal resources in the near term and to maintain a viable research program for the longer-term resources.

The committee estimated the following DOE budget need forgeothermal resources research and development (in millions of dollars):[5]

The HDR program has shown that practical means now exist to recover and to use this thermal energy. It has concentrated on the key, high-risk technical issues, consistent with federal policy, that will provide scientific and engineering knowledge for the geothermal and utility industries. Ten years of continued environmental surveillance at the Fenton Hill site has shown no adverse environmental effects. Environmental safety is a benefit that can give HDR-generated electricity the edge when compared with electricity from coal- and gas-fired generating plants. Furthermore, a study by Bechtel National, Inc., concludes that, with sufficient support, HDR technology will be positioned to impact the anticipated post-1995 electricity shortage.[6] The recommended program plan required to develop HDR technology for the future is outlined later.

RECOMMENDATIONS OF ADVISORY PANELS

In 1984, the Department of Energy's Office of Program Analysis conducted an assessment of geothermal research. The reviewers selected nine projects from within the HDR program and rated three of them as "outstanding," five as "strong projects deserving of continuing priority support," and the final one as "good."[7]

In 1985, the DOE's Office of Conservation and Renewable Energy determined that its priorities for HDR should be elevated.[8] It was recommended that HDR should increase from 20% in 1985 to 32% of total federal geothermal effort within five years. This would make HDR second only to hydrothermal research, which was to increase only 2%, from the current 40% to 42%.

On October 15-16, 1986, the major DOE geothermal programs were reviewed again by technical experts from private industry, national laboratories, and universities. After a two-day review of the advanced research activities, these experts recommended the Hot Dry Rock Program as its number one priority. This top priority for Hot Dry Rock was based largely on its enormous resource base, applicability to the production of either electricity or direct heat, recent technical successes, promising economic estimates, increased international interest in the technology, and attainment of the later phase of engineering development, which calls for a LTFT and final assessment before program completion.

TABLE I
COMMITTEE OF GEOTHERMAL ENERGY TECHNOLOGY RECOMMENDED FEDERAL FUNDING FOR GEOTHERMAL RESEARCH AND DEVELOPMENT

Program Area	Fiscal Year 1988	1989	1990	1991	1992
Hydrothermal	16.7	16.7	16.7	13.2	14.0
Geopressured	7.0	7.0	7.0	7.0	7.0
Hot Dry Rock(research)	10.0	10.0	9.0	5.0	0.0
Second Site	2.0	15.0	15.0	25.0	15.0
Magma Energy	1.3	5.0	3.0	7.0	5.0
Total (without HDR second site)	35.0	38.7	35.7	32.2	26.0
Total (with HDR	37.0	53.7	50.7	57.7	41.0
Total HDR Funding	12.0	15.0	24.0	30.0	15.0

The panel also felt that, after a total investment of $155 million, the Hot Dry Rock Program should be completed on schedule; the engineering data from the long-term flow test should be made available to private industry; and that a joint industry, university, and laboratory assessment should be conducted on final test results.

As previously noted, the Committee on Geothermal Energy Technology reviewed the Department of Energy's geothermal programs. The Committee reported that the HDR program is well managed with reasonable and important technical goals directly addressing the program's objectives.[5] The panel also recommended $57 million in additional funds for HDR development at a second site.

Yet another review, but an unfavorable one, was conducted by the Solid Earth Sciences Panel (SESP) of the Energy Research Advisory Board.[9] We do not agree with its suggestions that 1) geothermal energy will be limited to only a minor role in future energy use; and 2) the HDR and Magma research projects should be terminated. On the contrary, the HDR resource is extremely large: 90,000,000 megawatt centuries of thermal power. This huge resource base was evidently overlooked by the SESP. The HDR project has been a successful pioneering effort that has been brought to the threshold of economic viability. Furthermore, the Fenton Hill experiment is not a demonstration, as the SESP report implies. Considerable scientific and engineering assessments of the reservoir need to be completed before transferring the technology to industry. Further advances in technology and in advanced drilling techniques have the potential to reduce substantially the costs of this technology. With such advances, HDR technology has the potential to be a major energy source.

TECHNOLOGY TRANSFER

The HDR program is becoming a model for technology transfer. Much of HDR technology is directly useful in the oil and gas industry as well as in the conventional geothermal industry. Industry has been involved, through a variety of formal and informal partnerships, from the very beginning of the program. Plans for drilling and conducting the 30-day-long initial closed-loop flow test were reviewed by several representatives from industry. An advisory committee of industry and state government personnel was established. This committee includes representatives of Geothermal Resources International, Bechtel National, Inc., Stone and Webster, Plains Electric of New Mexico, San Diego Gas and Electric, private consultants, and representatives from the state energy departments of California and New York. It is the consensus of the committee that the completion of the final, major milestone in the Fenton Hill program, the Long-Term Flow Test, will provide the necessary information so that industry can undertake the development of a project on a commercial scale.

Over 40% of the $155 million funding for HDR has been contracted to industry. Most of this has been spent with contractors in the oil and gas industry, which also supports drilling, logging, and other services for the geothermal industry. Spin-off technologies from HDR already benefit both oil and gas and geothermal companies. Examples are new drilling and coring bits, high-temperature packers, high-temperature logging tools, new high-temperature drilling muds and cements, and advanced microseismic techniques. In addition, we plan to solicit a contractor to assist in the operation of the LTFT as another means of transferring HDR technology and of providing the private sector with hands-on experience in operating a hot dry rock system.

As a result of this type of participation, and with the financial support of the DOE, Bechtel National, Inc., formed a partnership with the state of Utah and with International Geothermal Company, a wholly-owned subsidiary of Chevron Resources Company, to participate in a feasibility study of HDR development at Roosevelt Hot Springs in Utah. There have been close interactions between the partnership and Los Alamos. The relationship works because each participant has a well-defined role. Los Alamos carries out the basic research and technology development with strong participation and advice from industry. Industry, on the other hand, is using its strengths in understanding the market and engineering to design and develop a second HDR site based on Los Alamos research. The Bechtel National, Inc., report endorsed the technical feasibility of HDR and encouraged an experiment by industry at a second site.[6]

ECONOMICS OF HOT DRY ROCK

Several independent studies have concluded that HDR-generated electricity will be economically competitive with other methods of electricity generation. An early analysis completed for the Electric Power Research Institute indicated that HDR electricity could be produced for a break-even busbar cost of 4.3 cents per kWh.[10] In 1985, a Los Alamos study revised this figure to 4.2 cents.[11] Figure 9 shows a comparison of this cost with other electrical generation costs.

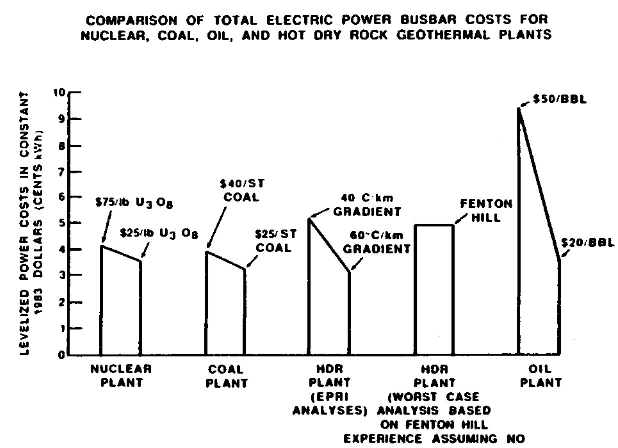

FIG. 9.

The Bechtel National, Inc., report, previously mentioned, concluded that HDR could produce electricity for 5 cents per kWh at Roosevelt Hot Springs.[6] British HDR economics have been reviewed by independent analysts of the Energy Technology Support Unit of the United Kingdom Department of Energy. These analysyts concluded that the busbar cost would be 3 pence, or roughly 5 cents, per kWh.[12] In summary, there exists a wide uniformity of views that indicate that HDR will not only provide an alternative to conventionally generated electricity and should provide this electricity just as inexpensively.

The successes and improved economics of the U.S. HDR program have lead to similar programs being initiated in other countries. Programs in Japan, the United Kingdom, and the USSR actually employ more personnel than does the U.S. program. Smaller programs are also under way in Sweden and, as a joint effort, in France and West Germany.

REMAINING GOALS AND PROGRAM PLANS

During the past 14 years, the U.S. Government has invested $123 million to develop the technology required to make hot dry rock geothermal energy commercially useful. Japan and the Federal Republic of Germany have contributed an additional $32 million to the U.S. program.

The initial objective of that program was met by the successful development and long-term operation of a heat-extraction loop in hydraulically fractured hot dry rock. The operation produced pressurized hot water at temperatures and flow rates suitable for many commercial uses, such as space heating and food processing. It operated for more than a year with no major problems or detectable environmental effect.

With this program goal accomplished and with the technical feasibility of HDR energy systems demonstrated, the program undertook the more difficult task of developing a larger, deeper, hotter reservoir capable of supporting operation of a commercial electricity generating power plant. Such a system was created and operated successfully in a preliminary 30-day flow test.

To justify capital investment in the new geothermal technology, industry requires assurance that the reservoir can be operated for many years without major problems or a significant decrease in the rate and quality of energy production. Industrial advisors to the HDR Program have concluded that, although a longer testing period would certainly be desirable, a successful and well-documented flow test of this high-temperature system lasting one year should convince industry that HDR geothermal energy merits investment in commercial development.

In one funding option, shown in Fig. 10, the assumption is that the funding drops to $3.6 million in FY 1989, but then rises to $4.8 million in FY 1990 and FY 1991 for the LTFT.

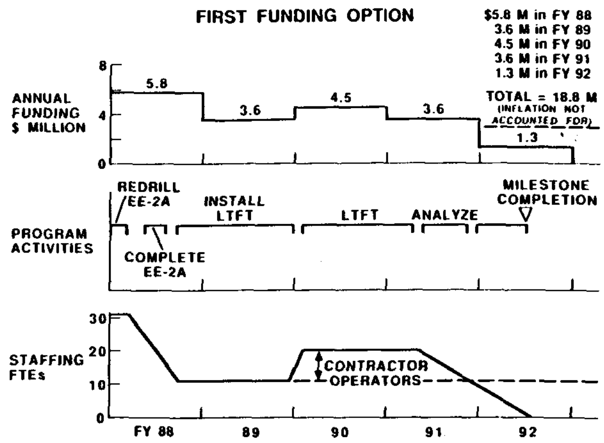

FIG. 10.
First funding option for continued HDR program.

Funding then drops to $3.3 million in FY 1992 to support data analysis, shutdown operations, and the securing of wells and equipment. The total is $16.5 million. A small advanced R&D program, costing an additional 10-15 people is recommended to provide technology base support.

In another funding option (Fig. 11), the assumption is again that FY 1989 funding is $3.6 million.

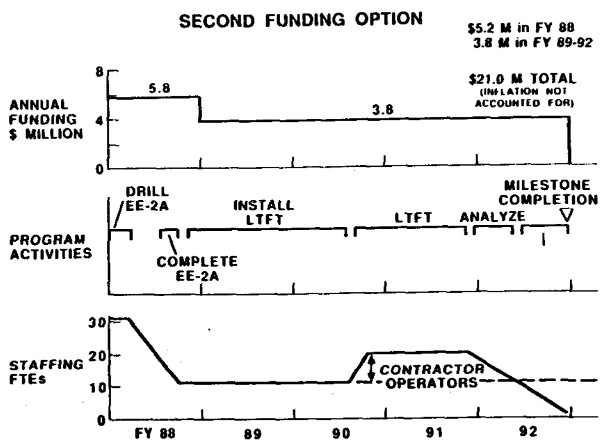

FIG. 11.
Second funding option for continued HDR program.

This option assumes that funding remains nearly flat, with just small inflationary increases. Consequently, it takes so long to acquire the funds to purchase the expensive pumps and other equipment that the LTFT cannot start until FY 1992. Total funding for this very stretched out program is $22 million. Once again, the advanced R&D program requires an additional $2.5 million.

To this point, the HDR Program has focused on engineering development; the final major objective of the program is the successful completion of the long-term flow test. Supporting R&D has been restricted to that essential for creating and operating a new energy system in the challenging underground environment at Fenton Hill.

TABLE II

SUMMARY OF FUNDING OPTIONS
(Millions)

Option	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	Start LTFT	Total Cost
1	5.8	3.6	4.8	4.8	3.3	0	0	FY 90 3rd Q	16.5
2	5.8	3.6	3.8	4.0	4.2	4.4	2.0	FY 92 3rd Q	22.0

Therefore, many questions that will be important to HDR development in other locations and geologic environment remain unanswered.

The Los Alamos HDR Program has pioneered in development of well-logging, sampling, and downhole monitoring instruments resistant to the temperatures, pressures, and corrosive environments of geothermal wells and in the collecting and interpreting of information from them. This information has been essential to HDR development at Fenton Hill and useful for measurements in steam, hot water, and hot oil and gas wells. However, much remains to be done in continued improvement of the instruments themselves, in techniques for using them, in transmitting the information to the surface, and in analyzing and interpreting that information. An immediate need is improvement of downhole geophones, particularly with regard to their acoustic coupling to the borehole wall. Improvement of the hodogram technique for determining the source locations of those signals will be important. The hodogram method differs from conventional seismic methods of locating fractures in that only one well is needed. Conventional methods use multiple wells, which are expensively drilled. There is an urgent need for development of a downhole stress-measuring device, and for further improvement of the borehole televiewer. An item of primary importance to industrial concerns is some means of predicting the useful lifetime of an HDR reservoir as early in its development as possible. A promising method is use of reactive chemical tracers, this requires further development.

A basic understanding of the thermal, hydraulic, and mechanical behavior of fractured HDR reservoirs will significantly contribute to the successful development of geothermal energy systems in a wide variety of geologic environments. This will involve a combination of theoretical, laboratory, and field studies with improved computer modeling to analyze, correlate, and interpret the results. To improve the economics of HDR systems by reducing pumping costs and increasing energy production rates, further development of techniques to reduce flow impedance through the fracture system by hydraulic or chemical stimulation is needed. The ability to control the chemistry of the circulating geothermal fluid makes possible important experiments in rock-water interactions, chemical mining, scaling and plugging by mineral deposition, and the incidence, nature, and control of corrosion in geothermal systems. The huff-puff operating mode (alternate injection of cool water and production of hot water or steam) requires investigation in large-scale field experiments.

Additional knowledge will be gained from results collected and experiments run during the LTFT. If, as expected, the test is successful and creates strong industrial interest in further HDR development and application, continued long-range R&D in such areas as those listed above will be important and justified. Los Alamos' laboratories, first-hand expertise, and field experience will contribute to this advanced R&D program.

CONCLUSION

Hot dry rock is a renewable energy technology that, with proper support can impact the anticipated electricity shortages beginning in the mid-1990s. Projected economics show that it should be able to compete with fossil fuels, and with no oxide or particulate emmisions. Ten years of environmental surveillence at Fenton Hill has indicated no adverse environmental impact. HDR power systems can be implemented in small, modular plants and in a relatively short time. Thus, new supply will be available to be brought on-line quickly and at competitive cost. However, much remains to be done for this to happen. The LTFT should be started soon in order to avoid the possibility of losing the reservoir. The LTFT will also provide the necessary data on total heat extraction and reservoir lifetime that industry requires to make sound investment decisions about HDR technology. In addition, industry has shown an interest in developing HDR power systems. However, industry also needs state and federal partnerships for the development of a second HDR site before accepting total risk for future HDR power plants. We therefore strongly encourage the funding given in funding Option 1, followed by an HDR technology base research and development program targeted towards an industry-led second site. Furthermore, we support the concept of an industry-state-federal partnership in the development of a second hot dry rock site.

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DRILLING AND COMPLETION AT FENTON HILL

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I. ABSTRACT

Fenton Hill Hot Dry Rock (HDR) Well EE-2 was successfully sidetracked and redrilled into the HDR Phase II reservoir after two attempts to repair damage in the lower wellbore were not successful. Before sidetracking was begun, four cementing procedures were planned to plug the abandoned lower wellbore and to support the production casing during drilling.

The directional redrilling, from 2965 to 3768 m in Precambrian crystalline rock at temperatures up to 250°C was a combination of motor and rotary drilling with a lightweight circulating fluid. The redrilling was accomplished on schedule within budget, and reestablished connections to the previously tested reservoir. This demonstrates that HDR drilling need not be the high risk, difficult venture experienced during the original drilling of these wells.

The cementing and the redrilling of EE-2A was completed in November 1987 and we are now preparing to complete the well for production service with an open-hole liner and tie-back casing.

II. INTRODUCTION

Well EE-2 was drilled to a total depth (TD) of 4660 m in 1981 as the intended reservoir stimulation (reservoir creation) and injection well for the Phase II HDR experiment. The well design was based on the rather benign Phase I experience, which did not include a realistic worst case prediction of well conditions. Damage which occurred to the 13-3/8-in. (340-mm) intermediate casing during and following its installation required a premature installation of 9-5/8-in. (244-mm) casing. The 40 lb/ft relatively thin wall casing, with 320 m (1000 ft) of cement above the shoe, was severely worn in several places by the time the well was drilled to total depth.

Fracturing deep in the well through a cemented-in liner failed to establish a reservoir connection to the production well, EE-3, and most of the open hole below the casing was abandoned with the placement of sand plugs up to 3550 m. Fracturing below the casing shoe at 3530 m was conducted through casing packers and tubing to protect the casing from the fracturing pressure which was 2 to 3 times higher than had been predicted. Following the injection of 20,000 m^3 of water in 1983, a wellhead failure occurred. A series of control and downhole failures followed which resulted in connection of the reservoir to subhydrostatic aquifers just above the basement rocks at 730 m and collapsed the 9-5/8-in. (244-mm) casing below 3250 m.

The first attempt to repair the well in 1984 isolated the aquifer but left the well connected to a low pressure reservoir at 3000-m depth. The collapsed casing was still in use when a reservoir connection to EE-2 was achieved during the 1985 redrilling of well EE-3A. Continued deterioration of well EE-2 during its first production service prevented wireline logging of the Phase II reservoir. A 30-day flow test was conducted in 1986 using EE-3A for high-pressure injection and EE-2 for low-pressure production service.

A second repair attempt in November 1986 found EE-2 in much worse condition than had been predicted and the repair was quickly terminated. The condition of EE-2 was reevaluated following a cement bond log and a 64-arm caliper log of the casing. The condition of EE-2 above the collapse at 3200 m was found to be reasonably good.

III. PLANNING

A detailed plan to plug back, cement the 9-5/8-in. casing annulus, sidetrack EE-2, redrill and complete EE-2A for production service was prepared by Los Alamos and reviewed by a Department of Energy (DOE) panel. The DOE panel suggested a much more conservative and expensive well repair and completion than was proposed but was in basic agreement with the drilling plan. Cementing through perforations would be necessary for deep operations as well as for the big annular placement from 6500 ft to surface. Sidetracking would utilize a packer set whipstock set in the lower casing stub after milling a section of the 9-5/8-in. casing above the collapse. A 7-in. (177-mm) liner will be installed and cemented from the top of producing region to surface.

IV. DRILL RIG

Big Chief Drilling Company Rig No. 47 was on-site and available having been used for the redrill of EE-3A and the 1986 EE-2 repair attempt. The rig provided a single ram, a double ram and annular blowout preventers. A rotating head was installed to provide maximum crew safety against occasional short but prolific kicks of carbon dioxide gas with up to 150 ppm concentration of hydrogen sulfide. A mud mixing and mud storage plant was installed adjacent to the rig's mud tanks to minimize the amount of rig time expended mixing and conditioning mud. A mud cooling apparatus was also installed.

V. WELL OPERATIONS

1. Cementing and Plug Back. The complexity of cementing operations to be conducted before EE-2 was sidetracked required that excellent communication between the cementing service company, Dowell Schlumberger (DS), and Los Alamos staff and consultants be maintained throughout the planning, cementing testing and operations. Detailed procedures were completed, cooling and thermal recovery projections were made by Los Alamos; cement testing was conduction by DS based on the temperature projections and procedures.

The drill string and Baker Service Tools tubing-set cement retainers and hurricane plug packer were used for plug back and squeeze operations. Both the packer and retainer were dressed with a proprietary ethylene propylene diene monomer (EPDM) elastomer packer element and O-ring.

Perforations were made by Oil Well Perforators using conventional 34 g, 425°F (218°C) jet charges in a hollow steel carrier perforating gun. All charges fired. Special effort was made to correct wireline depth measurements to drill pipe measurements. Wireline depths varied from 6 to 12 m deeper than pipe measurements.

Batch mixing was prescribed for all cementing. However, for the large 76 m^3 emplacement from 1980 m (6500 ft) to surface, 16 m^3 was premixed and the remaining slurry mixed and blended in a batch mixer while pumping downhole from the same batch mixer.

Cementing operations were controlled to keep dilution and contamination of the cement to a minimum. Redundant pumping equipment and piping were rigged up to assure that cement placement would be completed in the planned time. Displacement volumes were corrected for thermal expansion and shutdowns were specified to prevent over-displacement of the cement.

2. Sidetracking. A-Z International section mills were used to cut an 18-m section at 2955 m. The casing had not been centralized at this depth and it is believed that contact with the formation contributed to intermittent, rapid wear of the tungsten carbide cutting knives. Difficulty in retracting the knives added several days to the milling operations. A sand plug was placed in and over the lower 9-5/8-in. casing (stub) below the window. A very hard cement plug was placed over the rest of the window to keep debris out of the window while cementing operations uphole were completed. The cement in and above the window was drilled out and a "dummy" packer locator assembly was run to assure good condition of the lower casing stub for setting the packer/whipstock. The entire packer/whipstock was then run on drill pipe, located on the casing stub and oriented with Scientific Drilling, Inc.'s (SDI) high-temperature service steering tool. Sidetracking was accomplished with two very limber drilling assemblies using tricone bits.

VI. DRILLING

The drilling plan was based on the very successful redrilling of EE-3A in 1985. The major features of the plan were: (1) elimination of drill pipe twistoffs with large diameter moderate-strength drill pipe, (2) accurate directional drilling and longer bit runs with carefully-designed bottomhole assemblies (BHA) and bit selection, and (3) higher penetration with good hole cleaning using a sepiolite base drilling fluid.

1. Drill String. A 5-in. (127-mm) drill string including 29 Kg/m Grade E, 38.1 Kg/m Grade X-95 and 74.6 Kg/m Grade E heavy-weight drill pipe, all with NC 50 tool joints was used in the drill string. Stronger, light weight pipe was not used because of its susceptibility to stress corrosion cracking. The large diameter pipe also minimized bending stresses and fatigue failures in areas of high wellbore curvature.

Rough, hard-banded pipe was used for open-hole service and smooth, hard-banded pipe was used in casing to minimize wear on the already worn 9-5/8-in. casing. The drill string weight was kept as low as possible to help keep the wear rate on the 9-5/8-in. casing low. The drill pipe sequence was shifted three stands (triples) within each pipe grade on every trip to prevent concentration of wear and fatigue over a short part of the drill string.

2. Bottomhole Assemblies and Direction Drilling. EE-2A was drilled using 22 drilling assemblies, including 14 rotary, 2 junk milling and 6 drilling motor assemblies. The well trajectory, about 25 m (75 ft) from and parallel to the original hole, to reach the selected drilling target, required: (1) a slight left turn and angle building assemblies to separate the wellbores, followed by (2) angle holding assemblies in the middle region, followed by (3) dropping assemblies. It was hoped that only one motor run would be required but the rotary assemblies produced a strong left hand walk in the upper part of the well, followed by a shift to right hand walk once the required right hand turn had been completed.

The rotary assemblies used 3-point and 6-point roller reamers to (1) minimize the amount of reaming to bottom, (2) provide the required directional characteristics (in lieu of integral blade stabilizers, which wear rapidly), and (3) reduce the BHA wear and hole drop by providing stand off for the drill collars.

Drilex motors, (6-3/4-in. [171.5-mm]), and 1-1/2 or 2° bent subs were used for all motor drilling. The drilling plan called for a maximum wellbore curvature of 2°/30 m so motor and rotary drilling were alternated. Turn rate increased with penetration when motor drilling and careful analysis of the steering tool readout was required to assure that the motors were removed before the 2° curvature was exceeded. Even so, on two motor runs the curvature reached 4°/30 m when motors were run 10 to 20 m too far.

Magnetic compass single-shot surveys were run every 10 m near the whipstock and then every 20 to 30 m to the target. A multishot gyro survey was run after drilling 140 m to assure that the azimuth readings from the single shot were accurate. The multishot location was within 3.5 m of the single-shot bottomhole location. A magnetic multishot survey was run at TD and showed a bottomhole location within 7 m of the single-shot location. EE-2A deviated from its planned trajectory no more than 15 m.

3. Bits. Two primary bits used for the drilling were the Hughes Tool Company and Smith Tool Company (IADC bit classification 7-3-2 or 7-3-9, Type 3) insert bits for hard abrasive formations, with roller bearings for air drilling. The air ports through the bearings were plugged and jets were installed to optimize the drilling hydraulics.

Four journal bearing insert bits were run for comparison purposes. These bits were IADC Class 7-3-7 with special gage protection on one of the bits and were 1.5 to 2 times more expensive than the air bits. While the bearings showed little wear, the cone and insert structures were worn out with less penetration than was obtained with the air bits.

4. Drilling Fluids and Hydraulics. A lightweight, low solids, fresh water sepiolite and bentonite mud treated with lignite, caustic and Torq-Eze was used for section milling and drilling. Experience on EE-3A had shown that a high viscosity, good hole-cleaning fluid improved total penetration and drill rate, and reduced BHA and drill string wear. Hydraulics did not seem to be nearly as important to drilling performance as these factors. Bit jets were sized to maintain an annular velocity in excess of 46 m/min (150 ft/min) and resulting bit hydraulic power was usually near the optimum.

Maintenance of the simple drilling fluid system became more complicated as the new wellbore penetrated the Phase II reservoir. In-flow from the reservoir was encouraged to protect the reservoir from plugging with drill cuttings and dehydrated mud. The first fractures penetrated near the top of the reservoir caused more dilution of the mud than had been expected. The high CO_2 concentration in the reservoir fluids required very large caustic treatments, which caused high gel strengths and difficulty in degassing the mud.

5. Drilling Results. Figure 1 shows the penetration rate achieved during the 30 days actually spent drilling. Although minor problems with directional drilling and drilling fluids occurred, the drilling was completed within time estimates and budget predictions. The rotary drilling was more expensive than predicted because the trajectory problems required that directional services remain mobilized much longer than was planned; this cost increase was fortunately balanced by lower than predicted nondrilling costs.

VII. RESERVOIR EVALUATION

The reservoir evaluation and protection plan called for EE-3A to be pressurized and the reservoir to be inflated to a pressure 15 MPa above the hydrostatic pressure as EE-2 penetrated the reservoir. Flow detected by the mud logging and flow monitoring equipment indicated the top of the reservoir had been intersected at about 3300 m. As additional major flowing fractures were penetrated the mud log, monitored flow,

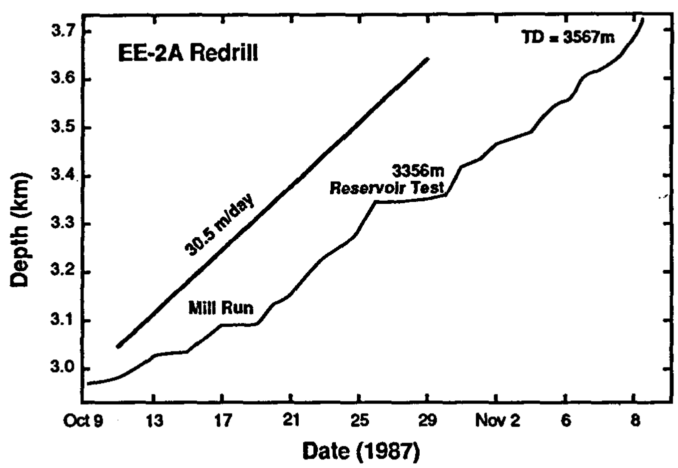

Figure 1. EE-2A redrill time line. Average drilling rate was 27.5 m (88 ft) per day.

pH, CO_2 and other cation and anion concentration changes, provided their location. A logging and flow testing operation was conducted after the top 60 m of the reservoir had been penetrated. The drilling mud was displaced with water and the drill pipe removed. Temperature logs, a bottomhole fluid sampler and flow tests were run over a 2-day period.

EE-3A injection pressure was reduced several times as more fractures were intercepted. A balance between protection of the reservoir and high-drilling fluid and drilling costs was the objective. By the end of redrilling the EE-3A pressure had been reduced to less than 3 MPa. More than 90 m of "rat hole" was drilled below the lowest indication of reservoir flow.

After reaching total depth at 3768 m, a final 2-day logging and flow testing operation was conducted including: (1) cement bond log of the 9-5/8-in. (244.5-mm) casing; (2) 64-arm maximum ID log (wear measurement log of the casing); (3) the multishot magnetic directional survey; and (4) a short flow test of the entire producing interval. The cement bond log showed that most of the intervals to be cemented were covered but some gaps occurred between the new and old cement. Over 32 m3 of cement was placed in the subhydrostatic aquifer at the top of the Precambrian rock and the cement top was found at 730 m as expected (from the damaged 13-3/8-in. [340-mm] casing). The casing ID caliper log showed moderate wear of the casing over the entire length but the effort to protect the previous high-wear areas with the use of smooth, hard-banded pipe appeared to have been successful.

An evaluation of the resulting well-reservoir condition was conducted in December 1987 which included: (1) temperature/gamma ray logs, (2) 3-arm caliper/gamma-ray log; and (3) an 8-day flow test of the entire penetrated reservoir with a 6.6 l/s, 23-MPa injection into EE-3A. Two RA bromine tracer injections in EE-3A were conducted. Temperature and RA logs showed the same production interval that was predicted by mud logging. A well completion is being designed based on that producing interval and the basic plan mentioned above.

VIII. WELL COMPLETION DESIGN

A 7-in.- (178.8-mm-) o.d. casing will be installed in May 1988 and cemented in two sections: a 35 lb/ft (52.08 Kg/m) C-

90 VAM open-hole liner, and a 32 lb/ft (47.62 Kg/m) C-95 Nippon NS-CC (premium connection) tie-back casing. Both the liner and tie-back string have been designed for high-pressure fracturing and injection service even though the present plans call for the well to be used for production service. The design is based on the successful liner installation deep in EE-2 in 1982. The liner will be cemented with a high-density, high-strength cement. The tie-back casing will be cemented to 730 m with a medium density, moderate strength, very low-free-water perlite cement. Figure 2 shows the final bottomhole well completion. After cementing, the 7-in.-o.d. tie-back casing will be pretensioned to the optimum axial load to equalize the thermal stress load during both high-temperature production and low-temperature/high-pressure stimulation. An Aflas elastomer primary seal, and an omega style, spring-energized metallic seal in a secondary packoff will be installed in the bottom of a tubing spool. A 7-1/16-in. (179.5-mm) API 10,000-psi working pressure master valve will be installed over the 7-in. (177.8-m) casing.

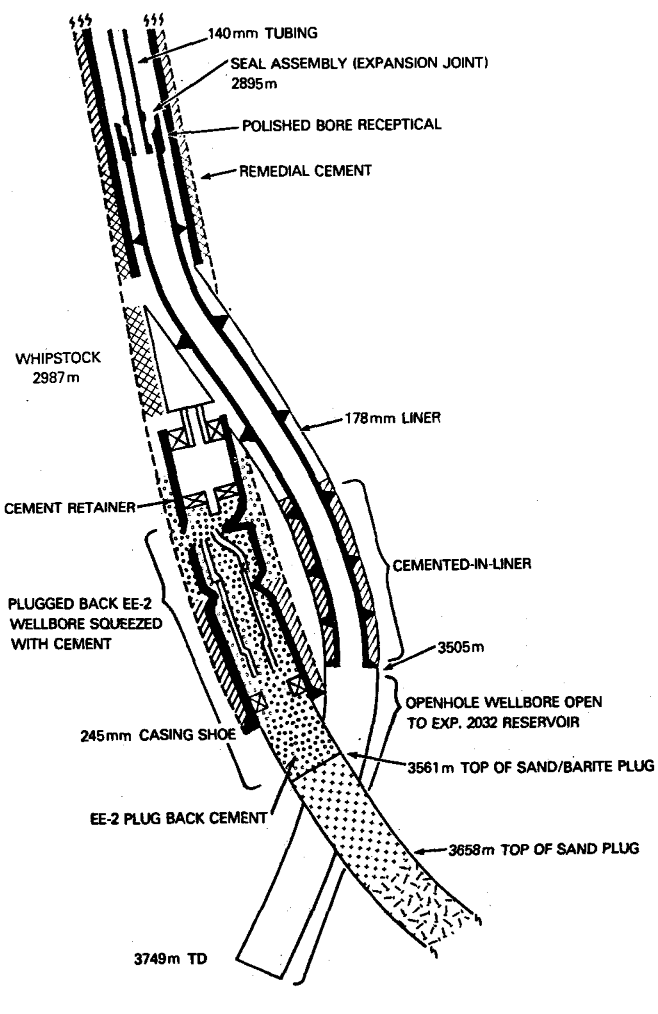

Figure 2. EE-2A well completion bottomhole configuration.

IX. CONCLUSIONS

The EE-2 plugback and repair and the EE-2A drilling were completed on schedule and within the cost estimate. This was accomplished using available equipment and services of the petroleum and geothermal drilling industry. This operation and the earlier results of the EE-3A drilling show that HDR drilling need no longer be the high risk, difficult venture experienced during the original drilling of these wells. With adequate planning, complete preparation, and careful operation, a drilling project in a difficult drilling environment similar to Fenton Hill can be undertaken with moderate risk and completed with reasonable cost.

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HOT DRY ROCK VENTURE RISKS ASSESSMENT

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ABSTRACT

This study assesses the Roosevelt Hot Springs resource in central Utah as the potential site of a commercial hot dry rock (HDR) facility for generating electricity. The results indicate that, if the HDR reservoir productivity equals expectations based on preliminary results from research projects to date, a 50 MWe HDR power facility using the Roosevelt Hot Springs resource could generate power at a cost competitive with new coal-fired plants. However, the HDR generic information presently available leaves considerable uncertainty about expected reservoir performance. These uncertainties must be resolved to attract venture investment. Testing that develops solid data concerning productivity and depletion rate is needed to design and adequately evaluate the economic potential of a commercial HDR project.

INTRODUCTION

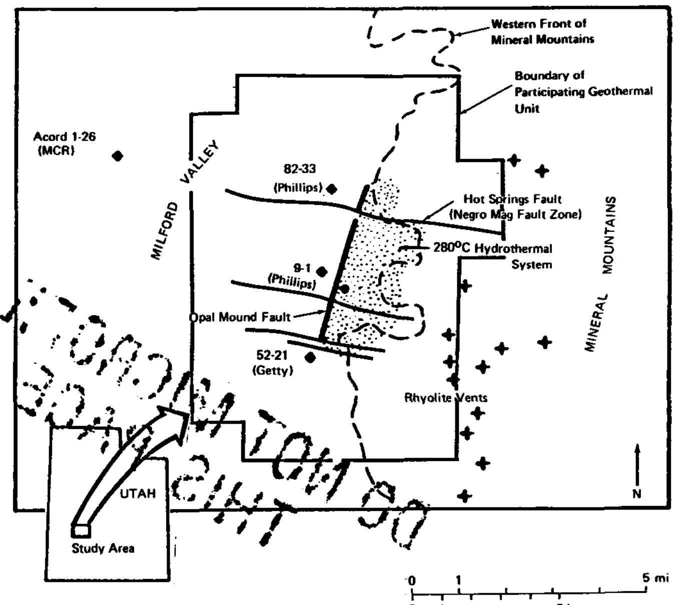
In mid-1986, the U. S. Department of Energy (DOE) issued a request for proposals to investigate a specific site for HDR commercial venture potential. In response to this request, Bechtel proposed to evaluate the Roosevelt Hot Springs, Utah resource as the location for a potential 50 MWe power generating facility, and DOE awarded a contract to Bechtel for this investigation.

Access to the HDR site and data was granted by Intermountain Geothermal Company, a wholly owned subsidiary of Chevron Resources Company which is the operator of the Roosevelt Hot Springs Unit.

An Industrial Advisory Group met twice during the study to review study planning and results. Members of this group were representatives from the Electric Power Research Institute, Los Alamos National Laboratory, Utah Department of Natural Resources, Utah Power and Light Company, and Utah Associated Municipal Power Systems.

Figure 1 shows the location and some of the prominent features of the Roosevelt Hot Springs resource area in south central Utah.

This investigation adhered to the following ground rules concerning the technology: First, currently available geotechnical data were used; no additional geotechnical field work was performed. Second, current technology or reasonable extensions were used for well and reservoir design and in the design concepts for the surface facilities. These ground rules limited the technology base to the current state of the art so that commercial development could proceed if the project economics were favorable and the technical risks were acceptable. Use of these ground rules during the



Modified from Ref. 2

Figure 1 Location of Roosevelt Hot Springs

investigation highlighted important technology risks and identified the need for additional HDR generic data before expected project performance and economics can be evaluated for investment purposes.

This paper summarizes the results of the investigation[1] and makes recommendations for the next step toward implementing a commercial HDR facility.

GEOTECHNICAL EVALUATION

The geotechnical evaluation was an assessment of the available site-specific information to estimate the HDR potential, to define the input parameters for the design of the subsurface reservoir, and to identify technical risks associated with development of a commercial HDR reservoir. The results of this evaluation may be summarized as follows:

- Heat source associated with Pleistocene plutonic emplacement.[3,4,5]
- Four generations of faults transect area. Published structural cross sections only to 7,000 ft (2,100 m)[4]
- Two distinct regimes of structure, lithology, and alteration are separated by a gently westward-dipping major fault zone.[4,7] Above fault zone: lithology is complex, alteration is moderate to intense, and structural disruption is abundant.

Below fault zone: rock is relatively unbroken, alteration is weak. Granitic rock is known to exist to 6,885 ft (2,100 m).

- Information on magnitude of principal stresses, fracturing pressure, and deep subsurface jointing patterns not presently available. Therefore, conceptual well design and a drill-fracture-drill sequence for injection and production wells were developed to accommodate a wide range of orientation and length of hydraulic fractures.
- Shear displacement of existing joint faces may create self-propping fractures (based on hydraulic fracture operations at Fenton Hill and Rosemanowes.[8,9,10,11,12])
- Probability of significant induced seismicity is remote. Thermal stress cracking is slow and continuous, preventing unrelieved stress. Water leakage into surrounding rock is minimized with HDR reservoir installed in impermeable rock away from major natural faults. Induced microseismic activity at Fenton Hill and Rosemanowes has been typically 4 to 7 orders of magnitude (extrapolated Richter scale) below the level of human sensitivity[8,13]
- Depth to HDR reservoir temperature (300°C or 572°F). Shallowest is near the Opal Mound Fault. Average about is 12,000 ft (3,660 m).
- HDR resource potential for several hundred MWe at Roosevelt Hot Springs
- Water for 50 MWe HDR plant (3,900 gpm or 6,300 acre-ft/yr) could come from a shallow aquifer if rights can be acquired. This pumping is not expected to affect the water supply near town of Milford due to distance and low transmissivity.[14,15]

Overall, the Roosevelt Hot Springs area appears to be well suited for installation and operation of an HDR power facility.

Although a wealth of surface and near–surface data were available for this study, major issues that are important to technical risk mitigation and cost estimates remain unanswered. These concern the subsurface faults, relative magnitudes of the principal stresses, hydraulic fracturing pressures, temperatures at depth, and pressures needed to drive the HDR reservoir.

SUBSURFACE SYSTEM DESIGN

Results obtained early in the study emphasized the economic importance of creating large heat transfer area (fracture surface) per well pair and maximizing the target temperature consistent with technical constraints and cost considerations. This led to a concept for installing multiple, discretely created fractures illustrated in Figure 2 using the following sequence:

- Drill an injection well to the depth corresponding to the target temperature. Deviate the bore 20 to 25 degrees below 2,590 m (8,500 ft).

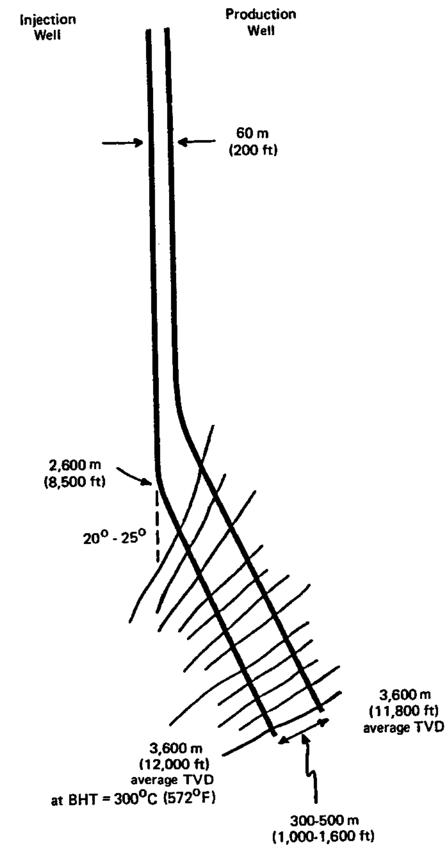


Figure 2 Injection–Production Well Pair

- Case to the bottom of the injection well.
- Extend the depth of the injection well by 20 to 60 m (66 to 200 ft).
- Run 7 in. tubing from the surface to the top of the 7 in. liner that cases the deviated portion. Hydraulically fracture the open-hole interval. The water used for hydraulic fracturing cools the wellbore for subsequent logging and perforating. During the hydraulic fracturing operation, use microseismic monitors to map the subsurface fractures.
- Allow the wellhead pressure to decay to 3,000 psi (20 MPa), from about 7,000 psi (48 MPa). Do not flow back the fracture fluid.
- Set a cast iron, casing cement retainer ring as a casing packer near the bottom of the 7 in. liner.
- Perforate 10 to 25 m (30 to 80 ft) of the wellbore for the second fracture interval.
- Hydraulically fracture the second interval while using microseismic monitors to map the fractures.
- Repeat the four steps above until 12 fracture intervals have been created in the injection well.

- Drill a production well approximately parallel to the injection well targeting the fracture zones with the deviated portion 250 to 500 m (820 to 1,640 ft) above the deviated section of the injection well.

Although this is an aggressive hydraulic fracturing program, present-day equipment and techniques are used throughout. Installing a high quality cement job is a key requirement. Also, the casing throughout the fracture length is designed to withstand fracturing pressures from both the inside and the outside. Major advantages of this approach compared to that used at Fenton Hill and Rosemanowes are:

- Damage to the wellbore from thermal cycling is minimized by using a single episode of wellbore cooling.

- More reliable casing packers (retainer rings) are used instead of open-hole packers.

- Hydraulic horsepower and surface safety hazard are minimized by low friction loss through relatively large-diameter fracture tubing.

- Time-consuming flow back of the fracture fluid is not required.

- The production well is targeted through the fractured zones using the microseismic locations of the fractures.

Maximizing the amount of heat transfer area exposed by each fracture is crucial to HDR well productivity and longevity. Based on preliminary information from Fenton Hill and Rosemanowes,[13,16,17] the following estimates of the initial heat transfer area and growth after beginning production appear reasonable and conservative:

- 100,000 m^2 (1,080,000 ft^2) effective heat transfer area per fracture interval initially

- Doubling of the effective heat transfer area within the first year of plant operation

Because multiple fractures in one fracture interval were observed at both Fenton Hill and Rosemanowes, effective heat transfer areas significantly larger than 100,000 m^2 (1,080,000 ft^2) with greater productivity may be feasible with proper targeting of the production well. However, the maximum feasible size of the effective heat transfer area that can be accessed in each fracture interval has not been demonstrated. The initial size of the heat transfer area and the rate and magnitude of its growth after beginning operation are crucial to reservoir performance and project economics. These must be satisfactorily demonstrated by generic HDR tests before commitment to build a first-of-a-kind commercial facility.

The proposed approach for coping with well-pair depletion is the addition of new well pairs. Restimulation by fracturing additional intervals in existing wells may not be feasible due to lower temperatures in the remaining upper wellbore intervals. However, as the size and location of the fractures become better understood and more reliably located, other restimulation methods, such as drilling additional production wells, may be identified as cost-effective ways to maintain production.

Two important site-specific operating characteristics were assumed because data specific to Roosevelt Hot Springs are not available at present: First, the steady-state reservoir leakage was assumed to be 10 percent of the circulation rate; this was experienced during one of the longest test runs at Fenton Hill and approached by the longest test at Rosemanowes. Second, the operating pressure at the injection wellhead was assumed to be 1,500 psi (10 MPa); this pressure was used for much of the testing at Fenton Hill and Rosemanowes.

The following characteristics were used as the average values for a base case injection/production well pair for the economic analysis:

- 300°C (572°F) target bottomhole temperature

- 12 fracture intervals

- 100,000 m^2 (1,080,000 ft^2) effective heat transfer area per fracture interval

- Doubling of the heat transfer area within the first year of well-pair production

- 10 l/s (160 gpm) production flow rate per fracture interval

- 12 MWe initial salable power per well pair declining to 2 MWe after 30 years

- For 50 MWe of salable power

  - 4 injection/production well pairs initially

  - 8 additional well pairs over 30-year plant life

Table 1 summarizes the estimated costs for an HDR injection/production well pair drilled to 12,000 ft (3,660 m) at Roosevelt Hot Springs. For comparison, average costs for oil and gas wells drilled to 12,000 ft (3,660 m) in Utah are about $1 million and $2 million, respectively, in 1987 dollars.

Consulting work by Dr. Robert Nicholson was extremely beneficial in the process of refining the concept and cost estimates for the subsurface system.

SURFACE FACILITIES

The wellfield surface facilities include the injection, gathering, and flash systems plus the make-up water supply as shown in Figure 3.

The injection system distributes water to the injection wellheads with enough pressure to produce the needed flow rate through the fractured reservoir. It consists of an injection water storage tank, a set of

Table 1

Average Cost Per HDR Injection/Production Well Pair

($ million, 1987)

Item	Cost
Pumping services	2.2
Wireline services	0.2
Subtotal	2.4
15% contingency	0.4
Subtotal	2.8
Drilling and casing (two wells)	6.7
Microseismic mapping	0.1
Subtotal	9.6
Management fee	0.5
Total	10.1

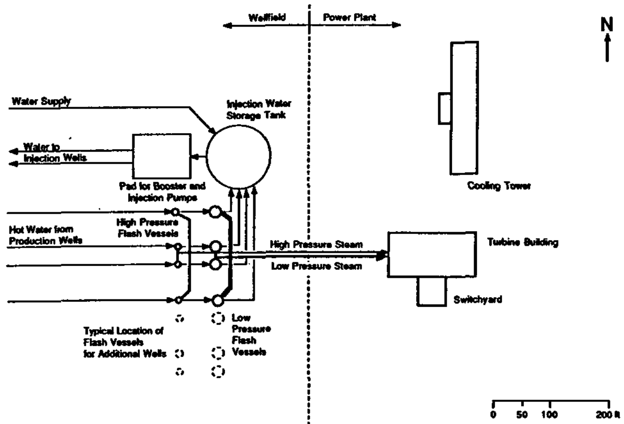


Figure 3 HDR Facility Plot Plan

centrally located booster and injection pumps, and distribution piping to deliver the water to the injection wellheads.

The gathering system transports the hot water from the production wellheads through carbon steel, aboveground piping to the centrally located flash system.

The flash system converts part of the hot water to steam in two stages (225 and 31 psia or 1,550 and 214 kPa) and transports it to the power plant.

The make–up water supply furnishes water needed for operating the facility. Up to 3,900 gpm (6,300 acre–ft/yr) of water from 13 wells is pumped about 2 miles (3.2 km) to the injection water storage tank where it is mixed with warm water from the low pressure flash vessels.

The two-stage flash process was selected for the power plant because of its proven commercial service, its high energy conversion efficiency for the relatively high water temperatures expected, and its relatively low cost. In this process, steam is admitted to the turbine at two different pressures with the combined stream exhausting to a surface condenser. Condensate from the condenser is used as cooling tower make-up. Excess condensate is returned to the wellfield injection water storage tank.

The electrical systems, turbine building, and auxiliary systems of the power plant are similar to those for an equal capacity power plant for other geothermal resources.

PROJECT COST ESTIMATE

Estimates of capital and O&M costs for the four initial well pairs, the wellfield surface facilities, and the power plant are summarized in Table 2. In addition, wellfield costs of $2.7 million for wellfield surface facilities and tangible well costs plus $8.9 million intangible drilling costs will be required at 3– or 4–year intervals as new well pairs are installed to make up for reservoir temperature decline.

Table 2

Summary of Estimated Project Costs

WELLFIELD - Four Initial Well Pairs				
Wellfield Capital Costs (1987 $ millions)				
Surface Facilities	9.3			
Tangible Well Costs	4.3(a)			
Capitalized Interest	2.7			
Total Wellfield Initial Investment		16.3		
Preproduction Costs		1.1		
Total Initial Wellfield Capital Costs			17.4	
Intangible Drilling Costs			35.2(a)	
Total Initial Wellfield Costs				52.6
Wellfield O&M Costs				
Fixed O&M Costs (1987 $ millions per year)			1.35	
Variable O&M Costs				
Make-up water purchases (mills/kWh)			0.45	
Geothermal resource royalties - 10 % of wellfield gross receipts				
Electrical power (range in 1987 $) - 1.4 million/year to 4.4 million/year				
POWER PLANT				
Power Plant Capital Costs (1987 $ millions)				
Power Plant and Transmission Line			56.5	
Allowance for Funds Used During Construction (AFDC)			10.5	
Preproduction Costs			1.9	
Total Power Plant Capital Costs				68.9
Power Plant O&M Costs (1987 $ millions per year)			2.3	

(a) The total of tangible and intangible drilling costs is $39.5 million. This is $600,000 less than four times the $10.1 million cost of a typical well pair given in Table 1. The difference results from adjustments to the mobilization costs and to repeated use of a single frac pond.

ENVIRONMENTAL AND SOCIOECONOMIC ISSUES

There are no apparent environmental or permitting constraints to developing a 50 MWe power plant at Roosevelt Hot Springs, or to conducting an industrial HDR experiment to demonstrate that HDR technology is ready for commercial development.

The most important environmental consideration for development is obtaining the water needed to operate the facility. Although all available groundwater in the Milford Valley area is appropriated, but about 11,000 acre-ft/yr is currently unused. The unused amount is more than sufficient for a 50 MWe HDR power plant. If the water rights can be acquired, water wells drilled nearby could supply the operating requirements.

DEVELOPMENT PLAN

Figure 4 shows the major activities and a schedule for developing a commercial HDR facility at Roosevelt Hot Springs.

The first activity is an industrial HDR experiment to verify both the drilling/completion concept and the reservoir performance (e.g., heat transfer area per well pair, growth of heat transfer area, and thermal drawdown). Such a test would involve drilling and casing a full-depth full-bore injection well, fracturing four to six intervals, drilling a full-depth full-bore production well, and test flowing the well pair for about 2 years at a rate somewhat greater than commercial optimum to project long-term thermal performance.

The schedule in Figure 4 indicates that about 10 years would be required. This schedule is a deliberate one; it may be possible to accelerate the schedule 1 to 2 years. if necessary.

ECONOMIC AND RISK ASSESSMENT

The economic and risk assessment concentrated on the comparative cost of electricity, commercial viability, and sensitivity to cost components and technical risks. The first full year of power production was assumed to be 1997 for purposes of economic projections.

Levelized revenue requirements were estimated assuming that the HDR resource is developed and operated by a non-utility resource developer and that the power plant is owned and operated by a privately-owned utility company. Two of the more prominent economic assumptions are the return on common stock for the resource developer (18 percent) and the power plant owner (15 percent).

The results in Figure 5 show that an HDR project could produce electricity at costs competitive with new coal-fired plants using Utah coal. On the other hand, a hydrothermal plant at Roosevelt Hot Springs could produce electricity at a significantly lower cost due to lower drilling and well completion costs. With this economic advantage, the hydrothermal resource at Roosevelt Hot Springs is likely to be fully committed by the time HDR testing can be completed and a commercial HDR plant can be built.

Year	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Industrial HDR Experiment										
Drill and test a pair of test injection and production wells	x	xxxx	xxxx	xxxx	xxxx	xxx				
Secure water rights for 50 MWe HDR power facility		x	xxxx	xxx						
Drill and test two water wells				x	xxx					
Develop a numerical model to simulate, evaluate, and predict reservoir performance		x	xxxx	xxxx	xxxx	xxx				
Perform additional geology and geophysical evaluation		x	xxxx	x						
Drill exploration and observation wells		x	xxxx	xxxx	xxx					
Secure permits		xx								
Project Preliminary Design						xx				
Venture Formation						xx	xxx			
Negotiate power sales agreement						xx	xxx			
Prepare permitting plan and submit initial applications						xx	xxx			
Financing							xx x			
Final Design and Construction										
Wellfield										
Design and drill HDR injection and production wells								xx	xxxx	xx
Design and construct injection, gathering, and flash systems								xx	xxxx	xxx
Drill water wells and install pumps								xxxx	xxxx	
Construct make-up water pipeline								xx	xx	
Secure permits							x	xx		
Power Plant										
Develop detail design for power plant							xx	xxxx	xxxx	xx
Construct power plant								xxxx	xxxx	xxx
Perform power plant startup										xx
Secure permits							xxxx			

——— Critical Path

Figure 4 HDR Project Schedule

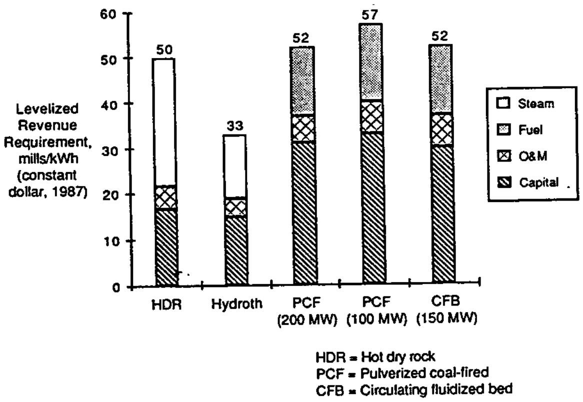


Figure 5 Cost of Electricity Production

Figure 6 summarizes the results of a number of sensitivity analyses that were performed to determine the impact of variations in cost and performance estimates. For these analyses, variations of ±25 percent were selected arbitrarily to test sensitivity; they are not estimates of uncertainty. In general, these results suggest that steam and electricity costs are not highly sensitive to variation in any single cost component.

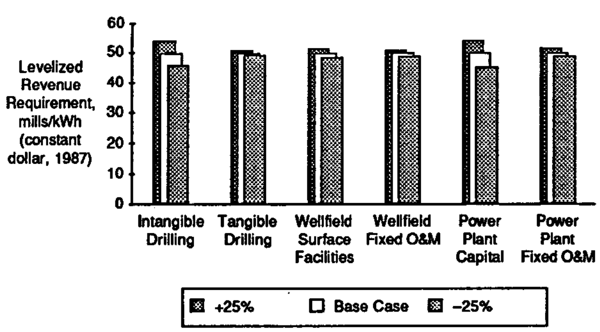
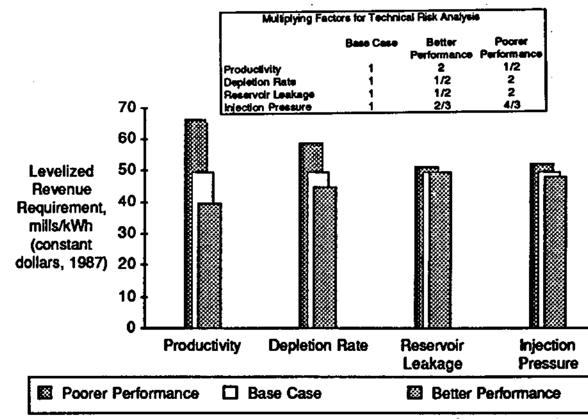


Figure 6 Sensitivity of Revenue Requirements to Cost Components

To analyze the economic consequences of technical risks, potential cost impacts were investigated for the performance characteristics that cannot be confidently predicted with the HDR data currently available. Figure 7 summarizes these results and shows that well-pair productivity and depletion rate are key performance variables that have pronounced effects on project economics. Testing that provides performance data on productivity and depletion rate is imperative for commercial project development.

Reservoir leakage and injection pressure could significantly affect project economics, but they are lower order effects compared to well-pair productivity and depletion rate. Site-specific testing to determine the values of these two variables and to mitigate the associated risks is also needed.



Multiplying Factors for Technical Risk Analysis

	Base Case	Better Performance	Poorer Performance
Productivity	1	2	1/2
Depletion Rate	1	1/2	2
Reservoir Leakage	1	1/2	2
Injection Pressure	1	2/3	4/3

Figure 7 Sensitivity of Revenue Requirements to Technical Risks

CONCLUSIONS AND RECOMMENDATIONS

The economic results are so promising that a site–specific industrial HDR experiment at Roosevelt Hot Springs is highly recommended.

The technical uncertainties of HDR technology and moderate earnings expectation currently prevent industry–funded HDR resource development even though installation of an HDR facility appears to require straight–forward but aggressive application of existing drilling, fracturing, and seismic monitoring technology. Furthermore, the electric energy market for the foreseeable future does not provide enough economic incentive for a private developer to invest in HDR energy technology development. Therefore, federal support for funding the industrial HDR experiment is recommended. Cost sharing by others, including industry participants and the state of Utah, is also recommended; however, these sources can be expected to provide only a small fraction of the funding required.

Further, a commercial–size first–of–a–kind HDR power plant project is recommended if the industrial HDR experiment verifies the technical and economic projections.

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SESSION V

MAGMA ENERGY RESEARCH PROGRAM OBJECTIVES

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MAGMA ENERGY RESEARCH PROGRAM OBJECTIVES SESSION: INTRODUCTION

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U. S. Department of Energy

As was stated at the beginning of the previous session, the objectives of the Geothermal Technology Program research are to provide the required scientific and engineering knowledge, through technology tranfer to domestic industries, for the commercially cost effective utilization of the vast and virtually inexhaustible geothermal resources of our nation. In contrast to Hot Dry Rock, however, magma energy extraction is a technology for which feasibility demonstrations are still ahead of us. In this case, the accessiblity of the virtually infinite resource, pinpointing the locations to achieve that access, the drilling techniques to access the magma, the techniques of extracting power from the magma body, and even the parameters for determining the economics of the energy source all remain to be determined, except in the most general terms. We are seeing the dawn of an energy age whose time will come.

Even if the accessability is limited to the upper 10 km of the Earth's crust, in the U. S., the useful energy contained in molten and partially molten magma has been estimated at 50,000 to 500,000 quads. The DOE/OBES funded Magma Energy Research Project concluded that the magma energy concept was scientifically feasible. The long range objective of this program is to conduct an energy extraction experiment directly in a molten, crustal magma body. Engineering feasibility is, at any point in time, a different thing than scientific feasibility. Critical to determining engineering feasibility are several key technology tasks. In geophysics, detailed definition of potential magma targets must be obtained. For geochemistry as related to materials, the magma environment must be characterized and suitable criteria developed for the selection of engineering materials. For drilling, drilling and completion techniques must be developed for entry into a magma body. And heat extraction technology must be developed. Finally, while accomplishing all these things will be a major achievement, eventually it must be known what the life of the reservoir will be as a heat source, or what its replenishment rate will be.

The caldera at Long Valley, California has been selected to be drilled at the southern portion of the resurgent dome. This recently reaffirmed decision will be implemented by drilling an exploratory well in a staged, drilling/scientific measurements program that will span several years, depending on the budget.

The objectives of the magma energy extraction program will be achieved in a number of steps, integrating the data obtained from the drilling and experiments at Long Valley. The technology needs will be identified through a series of internal studies. These priorities will be confirmed through interaction with industry, government and university representatives. Laboratory tests and analyses will be conducted to initiate solutions to the problems identified. Prototype equipment and techniques will be developed aimed at implementing the solutions postulated above. These prototypes will be tested under realistic conditions to evaluate their operational characteristics. Then full scale hardware will be built where necessary and used to conduct field tests.

Once the engineering technology is developed, it will be tested by drilling a well into a magma body and conducting an energy extraction experiment for perhaps six months. Since the concept of magma energy extraction is new, this last phase is extremely important. The physical nature of magma bodies and the adequacy of developed drilling and energy extraction technology must be verified.

The Sandia scientists will present their more detailed descriptions and discussions of these activities as steps on the way to implementation of magma as an energy source for mankind.

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RESEARCH TO TAP THE CRUSTAL MAGMA SOURCE

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ABSTRACT

Thermal energy contained in magmatic systems represents a huge potential resource. In the United States, useful energy contained in molten and partially-molten magma within the upper 10 km of the crust has been estimated at 50,000 to 500,000 Quads. The goal of the Magma Energy Extraction Program is to determine the engineering feasibility of locating, accessing, and utilizing magma as a viable energy resource. The stated Level I objective is to develop technology that would enable magma generated power to be produced in the cost range of 10 to 20 cents/kWh by the year 2000. Realization of this objective will require progress in four critical areas. (1) Magma location and definition - crustal magma bodies must be located and defined in enough detail to locate the drill. (2) Drilling - high temperature drilling and completion technology require development for entry into magma. (3) Materials - engineering materials need to be selected and tested for compatibility with the magmatic environment. (4) Energy extraction - heat extraction technology needs to be developed to produce energy extraction rates sufficient to justify the cost of drilling magma wells.

This work was performed at Sandia National Laboratories, supported by the U. S. Department of Energy under contract DE-AC04-76DP00789.

MAGMA ENERGY EXTRACTION

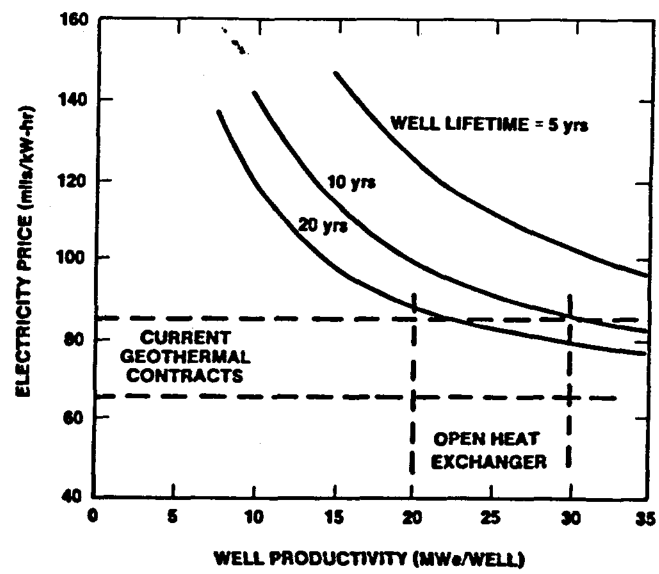
- **PURPOSE**
  - EXTRACT HIGH QUALITY THERMAL ENERGY DIRECTLY FROM MOLTEN CRUSTAL MAGMA BODIES
- **RESOURSE**
  - 50,000 QUADS IN THE U.S. AT DEPTHS LESS THAN 10 KM
- **R&D STATUS**
  - SCIENTIFIC FEASIBILITY CONCLUDED BY 7-YEAR OBES STUDY
  - ENERGY EXTRACTION DEMONSTRATED IN LAVA LAKE 1150°C
  - CURRENT PROGRAM INVESTIGATING ENGINEERING FEASIBILITY (PROVIDE FUNDAMENTALS FOR INDUSTRIAL CONSIDERATION OF COMMERCIALIZATION)

MAGMA ENERGY OBJECTIVES

Level I - **Demonstrate magma-generated power by the year 2000 (engineering feasibility)**

Level II

- **Resource Analysis:**
  - **Target location and characterization**
- **Fluid Production:**
  - **Drilling and completion**
  - **Energy extraction technology**
  - **Long term test**
- **Energy Conversion:**
  - **Surface plant design for magma wellhead conditions**
- **Other Operation:**
  - **Hazards**
  - **Environmental Concern**

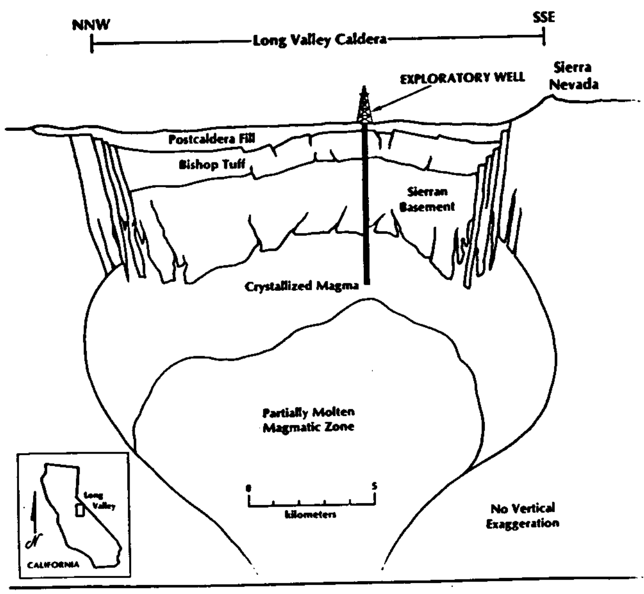


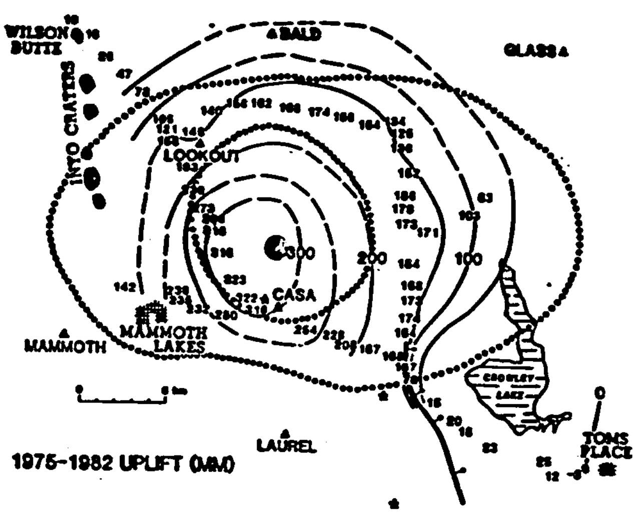
TARGET LOCATION/CHRACTERIZATION

Status
- Long Valley selected as primary site
- Geophysical data evaluated
- Exploratory well site chosen

Future
- Determine nature of geophysical anomalies
- Evaluate state of magma underlying Long Valley

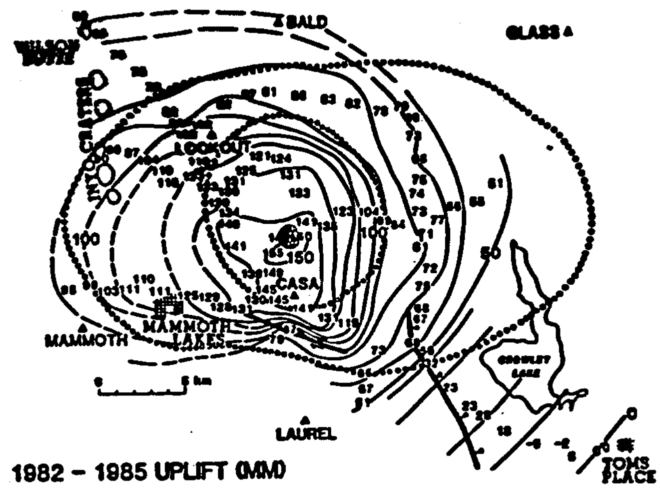
MAGMA ENERGY PROGRAM
LONG VALLEY EXPLORATORY WELL





1975-1982 UPLIFT (MM)

LONG VALLEY



1982 - 1985 UPLIFT (MM)

DRILLING

Objective: Develop technology to drill and complete wells in magma bodies

Status
- Magma drilling analyzed
- Insulated drill pipe designed

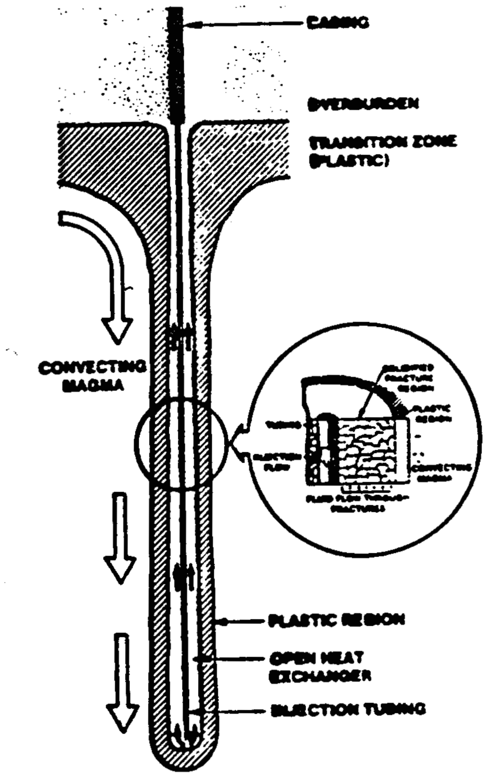
Future
- High temperature completion
- Experimental well

ENERGY EXTRACTION

Objective: Develop magma energy extraction technology to produce 25 to 50 MWe per well.

Status
- Energy extraction process analyzed
- Thermal stress fracturing characterized
- Heat transfer experiments are near completion (U. of Utah)
- Magma convection experiments underway

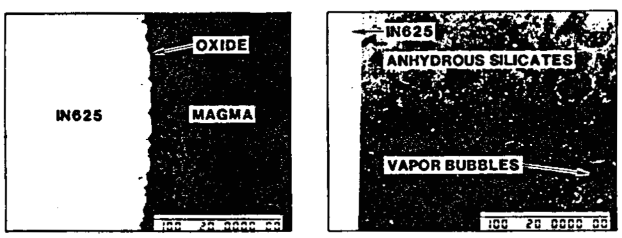
Future
- Large scale experiment



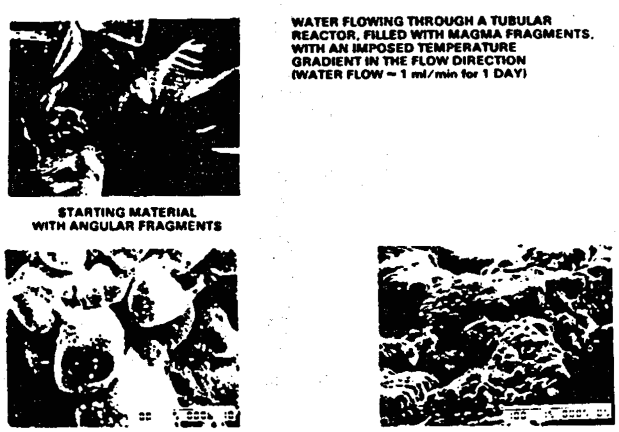
INCONEL 625 COMPATIBILITY

MAGMA - METAL TEST
850° C, 2000 bars, 7 days

GLASS - METAL TEST
500° C, 500 bars, 42 days



WATER FLOWING THROUGH A TUBULAR REACTOR, FILLED WITH MAGMA FRAGMENTS, WITH AN IMPOSED TEMPERATURE GRADIENT IN THE FLOW DIRECTION (WATER FLOW ~ 1 ml/min for 1 DAY)



STARTING MATERIAL WITH ANGULAR FRAGMENTS

600°C — Mass Transport/Recrystallization — 450°C

FRAGMENTS WITH ROUNDED EDGES DUE TO DISOLUTION

FRAGMENTS WITH PRECIPITATES

ENERGY CONVERSION

Objective: Develop preliminary surface plant design for magma well

Status
- **Ideal and Rankine cycles analyzed**
- **One preliminary design completed**

Future
- **Complete generic design for magma conditions**

OTHER OPERATIONS

Objective: Develop plans to address possible hazards and environmental concerns associated with drilling into magma.

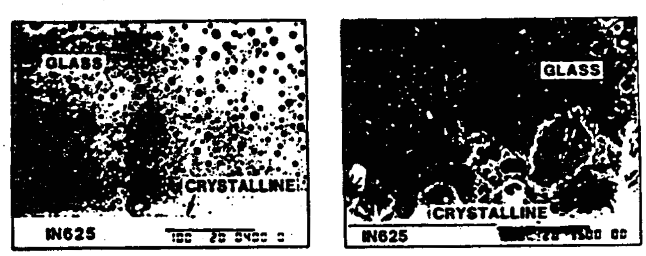
Status
- **Hazards evaluations are underway**

Future
- **Document hazards/environmental investigations**

VESICULATION PROCESSES

ISOTHERMAL DECOMPRESSION

ISOBARIC CRYSTALLIZATION



500° C, 500 bars, 4 days

500° C, 500 bars, 15 days

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RECENT ADVANCES IN MAGMA ENERGY EXTRACTION

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ABSTRACT

Recent advances in magma energy extraction are summarized in four research areas: (1) thermal stress fracturing during solidification, (2) laboratory demonstration of drilling into a molten body, (3) experimental and numerical simulation of convection in magma, (4) thermo- dynamic system analysis of energy conversion in a magma power plant. Of particular interest is the successful demonstration of the "solidifying while drilling" technique for establishing a direct contact heat exchanger in a molten magma body.

INTRODUCTION

Research in Magma Energy Extraction is aimed at developing engineering capability to extract energy directly from crustal magma bodies. It is envisioned that energy will be extracted by direct-contact heat transfer where a working fluid is circulated through a mass of solidified and fractured magma (Figure 1), first established during drilling (Figure 2), surrounded by a convecting magma body. The paper presents results of recent research in four areas: (1) thermal stress fracturing during solidification, (2) laboratory demonstration of drilling into a molten body, (3) experimental and numerical simulation of convection in magma, and (4) thermodynamic system analysis of energy conversion in a magma power plant. Experiments using a low temperature simulant showed that a magma-like material will produce a regular three-dimensional network of interconnecting fractures during solidification. We have also demonstrated experimentally, in the laboratory, for the first time the "solidifying while drilling" technique proposed for drilling into molten magma.

THERMAL STRESS FRACTURING

In order for the direct contact heat exchanger to work effectively, the solidified magma surrounding the injection tube must be sufficiently fractured to provide a large heat transfer area. By using a low temperature simulant in glass test vessels, we were able to make direct observations of thermal stress fracturing during solidification which were impossible to do in earlier experiments using aluminosilicate glass as a magma simulant[1,2]. The material used is a terpene phenolic resin. It has a softening point at approximately 125°C. Its viscosity is highly dependent on temperature at temperatures in the vicinity of the softening point; and it exhibits qualitatively similar fracturing behaviors as glass when cooled from an elevated temperature.

Dynamic solidification experiments were carried out with a cylindrical heat exchanger immersed in the molten simulant at 160°C. As solidification takes place, the solidified material fractures under thermal stress, forming an essentially regular cellular fracture pattern normal to the direction of solidification, Figure 3. Typically the cells are polygons with four to six sides, quite similar to the fracture patterns of frozen lava [3]. The fractures continue to grow as solidification progresses. The fracture growth is, however, not continuous; rather, by bursts over large patches on a surface, suggesting that the strain energy is only released when a threshold is exceeded. A fracture face with several generations of growth is shown in Figure 4. While the interval between bursts of growth increases with time, the amount of growth appears to be fairly constant. At each stage of growth, only selected fractures grow, several (typically 5 or 6) cells would form a cluster, the fractures outlining the outer boundary of the cluster would grow thus resulting in a new cell with increased dimension. Shown in Figure 5 are three successive generations of fracture growth on a cooled flat surface. It is interesting to note that the basic pattern is unchanged although the dimension of the cells increases with each generation of growth. A close examination of Figure 6 reveals at least four generations of essentially similar patterns.

LABORATORY DEMONSTRATION OF DRILLING IN A MOLTEN BODY

Laboratory demonstrations of the "solidifying while drilling" technique for drilling into molten magma were successfully carried out. This is the first time all the required processes for forming a borehole in a molten body have been demonstrated in a single laboratory experiment.

These experiments made use of the same simulant materials as the fracturing experiments. A three-liter melt at 160°C in a four-liter glass test vessel was prepared in a furnace. At the start of the experiment, the test vessel was placed on the table of a drill press and a water mist was sprayed onto the surface of the melt forming a thin solid crust. With the thin crust as a barrier, approximately one liter of water was poured over the the melt. Within twenty minutes, a 3mm-thick frozen crust formed and separated the melt and the water on top. A 10-mm and a 13 mm standard machining drill were used in the experiment. As the drill bit advanced, water followed into the hole and chilled and solidified the molten material in front of and around the drill bit. The solidified material appeared as a halo in front of the drill bit and a fracture front was observed in the halo region ahead of the advancing drill bit. The drill was in contact with solid at all times and the material removed was in the form of machining chips. At times when the rate of drilling became too fast, a small break would occur near the tip on the sidewall of the borehole, and a stream of water droplets would leak out into the melt. As the droplets of water rose, they followed along the outline of the solidified region around the borehole. Shown in Figure 7 is the outline of the solidified zone, in the shape of an inverted frustrum, formed by the water droplets. It is also interesting to note the highly fractured region surrounding the borehole. The total drilling depth in the experiments was about 10cm. A sequence of three photographs showing the drilling process is shown in Figure 8.

Following one of the drilling experiments, the test vessel was returned to the furnace and a water injection tube was placed into the borehole to continue to cool the borehole as would be the case during energy extraction. The borehole remained stable and fractures continued to grow around the borehole.

While these experiments are by no means detailed and direct simulations of the actual drilling process, they do provide the first overall proof-of-concept demonstration of the "solidifying while drilling" technique for forming the direct contact heat exchanger for magma energy extraction.

CONVECTION IN MAGMA

This study is undertaken to gain an understanding of convective transport in a magma chamber[4]. The approach taken in our studies is to first characterize the convection in the magma chamber and then to examine the convective heat transfer to an energy extraction device inserted into the magma chamber. Typically, a magma chamber is periodically replenished at a discrete location. Hence, we elect to represent the magma chamber as an enclosure with localized heating from below. The present study involves both laboratory experiments and computer modeling.

The experimental apparatus consists of a Lexan enclosure with a square planform measuring 56 cm on a side. A heated strip measuring 13.6 cm by 56 cm centered on the lower inside surface of the enclosure. The depth of the fluid layer is set equal to the width of the heated strip. The enclosure, therefore, has essentially a four to one width to depth ratio. The top of the layer is maintained at a constant temperature by a water cooled plate. The large viscosity variation characteristic of molten magma is simulated with a commercial 42/43 corn syrup. The experiments top covered to bottom viscosity ratios ranging from 3 to 1400. In addition to the measurement of overall heat transfer between the heated strip and the top surface, velocity and temperature distributions were obtained. The velocity field was mapped by taking time exposure photographs of light scattered from seeded particles illuminated by a sheet of light from a He-Ne laser. The temperature field was mapped using a thermocouple probe.

The experiment is numerically simulated through the use of a state-of-the-art finite element computer program[5]. Shown in Figure 8 is a typical isotherm pattern and a comparison between numerically and experimentally obtained streamline patterns. The flow is laminar and steady; it is characterized by two counter rotating vortices driven by a plume rising from the heated strip. Very good agreement is demonstrated between predictions and measurements.

Temperature and velocity distributions from the experiments and numerical simulation both show that the effect of large viscosity variation is mainly confined to a stagnant conduction layer next to the cold surface; the rest of the flow field is quite similar to an iso-viscous flow. As a result, the heat transfer form the heated strip is found to be well correlated by a conventional iso-visocity power law formulation with a power law viscosity ratio correction, Figure 10. In this correlation, the largest effect of viscosity variation is accommodated by evaluating properties at the mean temperature of the top surface and the heated strip. The additional power law correction based on the viscosity contrast is relatively small. The result is quite remarkable because it indicates, at least in laminar flow, iso-viscous heat transfer correlations can give reasonable results to flows with extremely large viscosity variations. While the configuration is different for an energy extraction device in a magma chamber, we feel the heat transfer and flow field will still exhibit the same general behavior.

THERMODYNAMIC SYSTEM ANALYSIS

A numerical code MAGMAXT[1] developed at Sandia is used to determine the downhole heat transfer and the thermodynamic states of the return water for specific injection rates into the magma well. Thermodynamic system analysis is then performed to evaluate the amount of useful work to be harvested from the well. As discussed in References 1 and 2, the heat transfer to the working fluid in the direct contact heat exchanger is modeled as a fully developed flow in a porous medium and it is essentially proportional to the effective thermal conductivity of the fractured matrix constituting the direct contact heat exchanger. A best estimate value of the thermal conductivity is 3 w/m-K. However, because the enhancement of heat transfer due to entrance effects the amount of heat transfer can be substantially higher than the fully developed case. To account for the enhancement, calculations were also performed for effective thermal conductivities of 15 and 30 w/m-K. Our analysis of entrance flow effects indicates that 15 w/m-K is the most realistic case; it is designated as the base case.

Three power plant designs were evaluated. An open Rankine cycle where water from the magma well is introduced directly into the turbine, Figure 11; a closed Rankine cycle where a heat exchanger is used between the water returning from the well and the power plant water, Figure 12, and a flashed Rankine cycle, Figure 13, for cases where the energy of the return water is too low to be utilized directly. The closed Rankine cycle is likely to be more practical from corrosion and plant design/operation considerations.

Typical results of system analysis for the open Rankine cycle are shown in Figure 14. The isentropic expansion efficiency and the pump efficiency were both assumed to be 80% in these calculations. For the base (K_{eff} = 15 w/m-k) case with a flow rate of 50 kg/s a power output of about 70 MWe can be achieved. If a closed cycle is used, the output would drop by about 10%. For the base case, there is a fairly broad maximum for the power output as a function flow rate. It is advantageous to operate with the lower flow rates in order to keep the turbine exit quality at reasonable values.

SUMMARY

Experiments using a low temperature simulant showed that a magma-like material during solidification will produce a three-dimensional network of interconnected fractures. We have also demonstrated experimentally, in the laboratory, for the first time the "solidifying while drilling" technique proposed for drilling into molten magma. The magma convection study provided significant insights to the understanding and modeling of magmatic convection and produced useful guidelines for calculating energy extraction from magma. Thermodynamic system analysis showed that power output of 50 MWe or more can be obtained with flow rates in the range of 40-50 kg/s.

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2) Boehm, R. F., Berg, Jr., D. L., and Ortega, A., "Modelling of a Magma Energy Geothermal Power Plant," ASME Winter Meeting, Boston, MASS, 1987.

3) Aydin, A., and DeGraff, J. M., "Evolution of Polygonal Fracture Patterns in Lava Flow," Science, Vol. 239, 1988, pp 471.

4) Chu, T. Y. and Hickox, C. E., "Thermal convection with Large Viscosity Variation in an Enclosure with Localized Heating," submitted for Publication ASME Winter Annual Meeting, Chicago, IL, 1988.

5) FIDAP Users' Manual, Vols. 1-3, Fluid Dynamics Internal Orrington Ave., Evanston, IL, 1987.

This work was performed at Sandia National Laboratories, supported by the U. S. Department of Energy under contract DE-AC04-76DP00789.

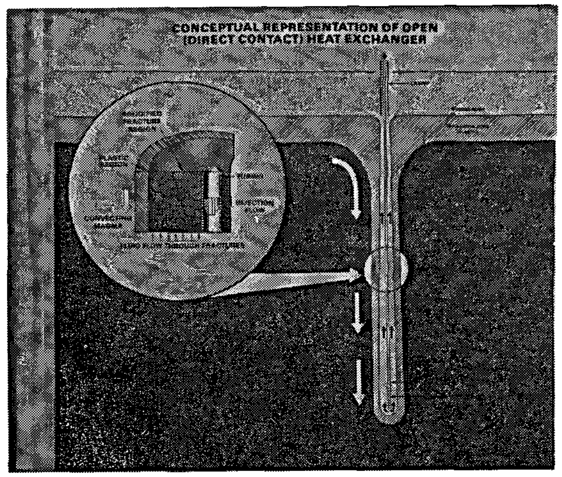

Figure 1 Conceptual representation of direct contact heat exchanger

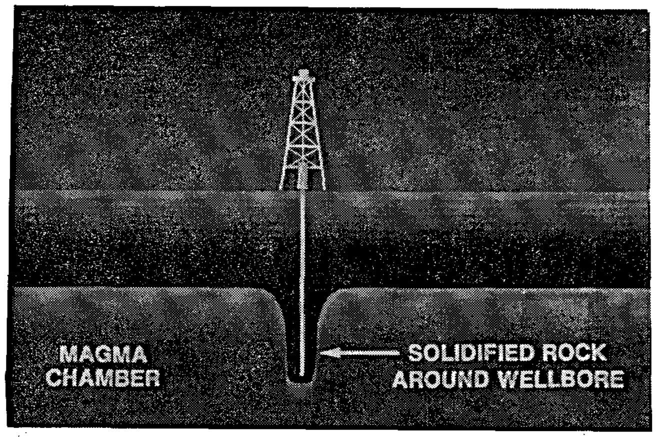

Figure 2 Conceptual representation of drilling into magma

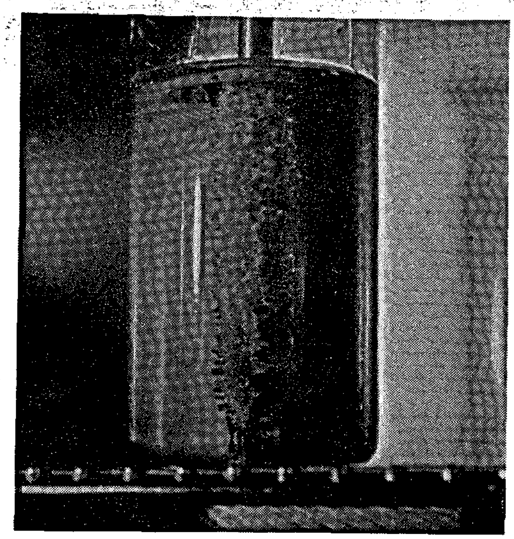

Figure 3 Thermal stress fracturing of material solidified around a cylindrical heat exchanger

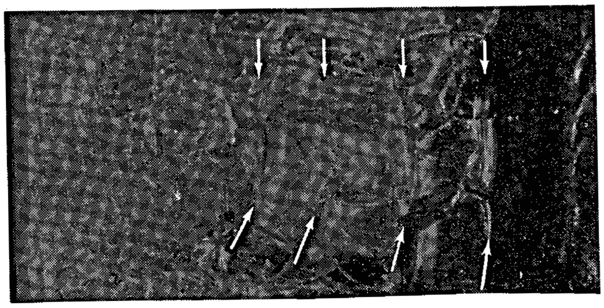

Figure 4 Fracture face showing stepwise growth of fractures

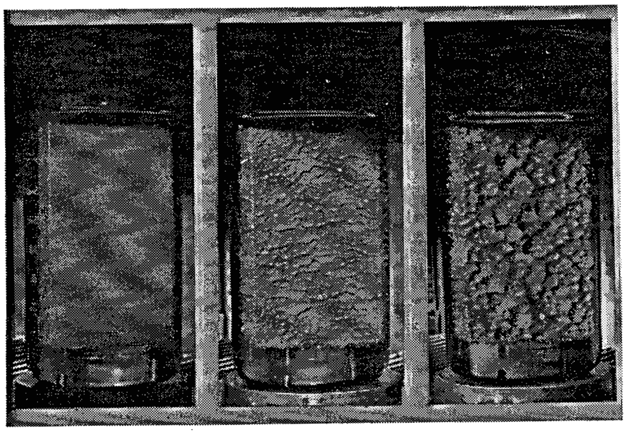

Figure 5 Fracture growth in material solidified on a cooled flat plate

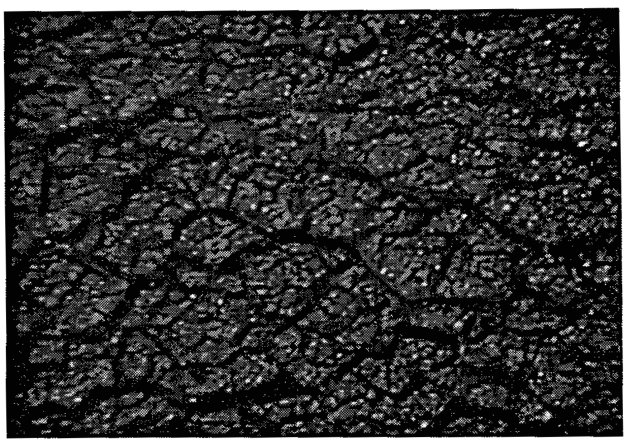

Figure 6 Details of fracture pattern on a flat plate

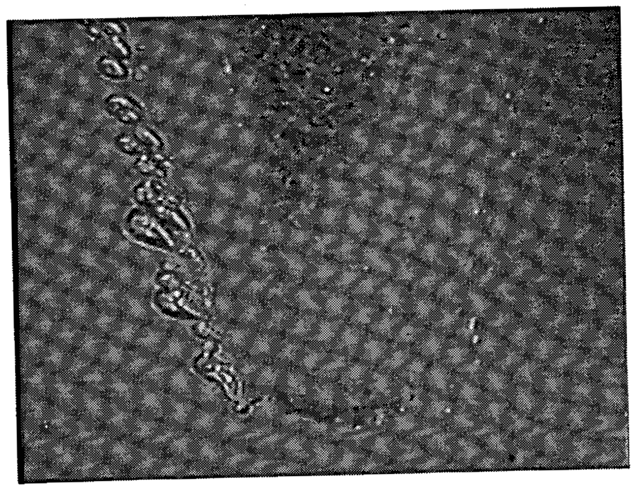

Figure 7 Solidified region around a borehole Drilled into a molten body as outlined by water droplets

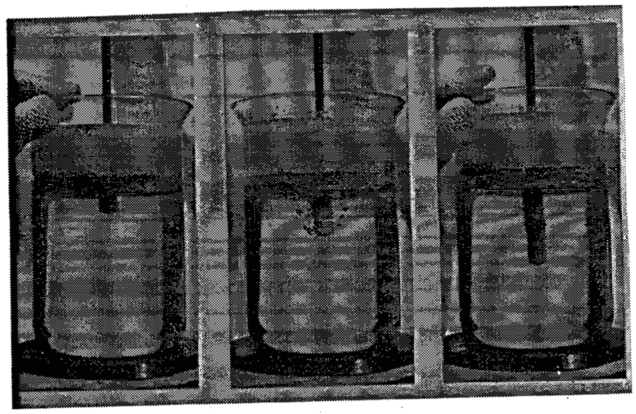

Figure 8 Drilling into a molten body

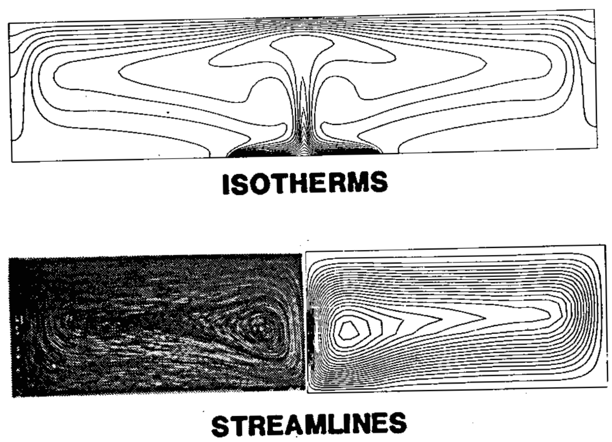

Figure 9 Isotherms and streamlines of magma convection experiment

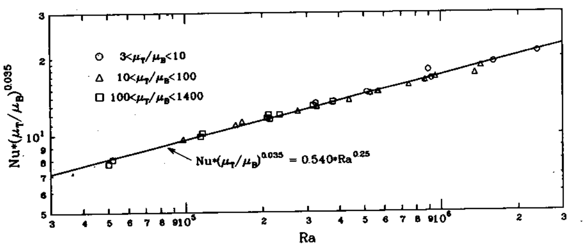

Figure 10 Heat transfer correlation for convection in an enclosure with localized heating from below

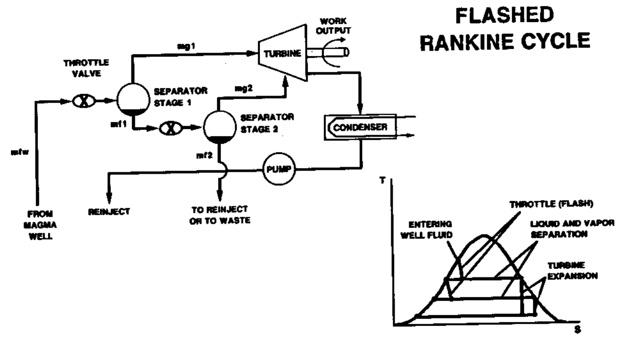

Figure 13 Schematic of a flashed Rankine cycle

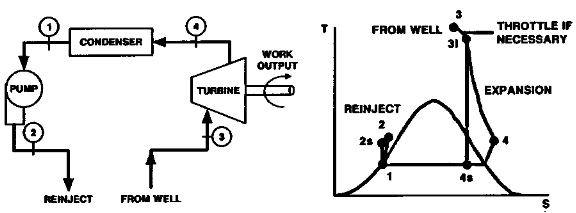

Figure 11 Schematic of an open Rankine cycle

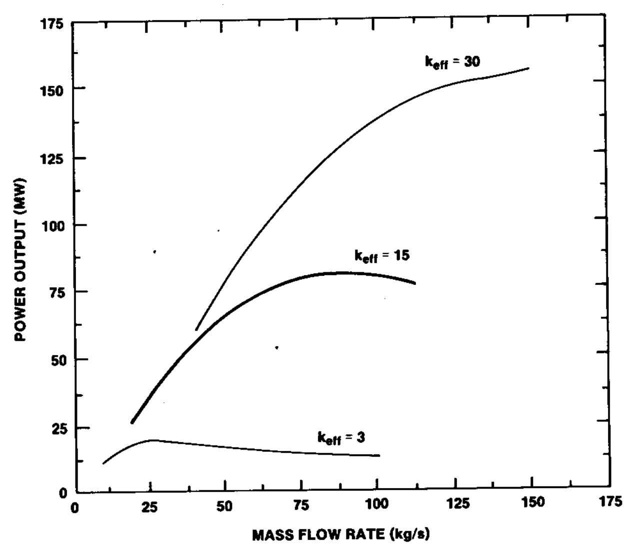

Figure 14 Power output as a function of flow rate for open Rankine cycle

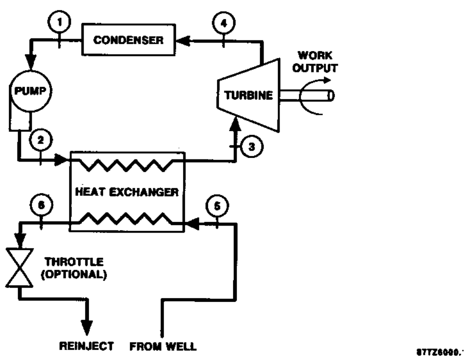

Figure 12 Schematic of a closed Rankine cycle

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DRILLING PROGRAM FOR LONG VALLEY CALDERA

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ABSTRACT

In September of this year, we will begin the first of four drilling phases in the Magma Energy Exploratory Well that is planned to reach a depth near 20,000 feet. This well will be used to verify the configuration of the magma body and to calibrate surface geophysical techniques against downhole data. It will also provide information of several kinds that is of interest to several groups: (1) We will resolve geologic uncertainties -- such as the location of fractured and abnormally pressured zones, chemistry of rocks and produced fluids, and magnitude of creep in the deep basement -- that affect the drilling of any subsequent well, (2) We will test drilling technology -- e.g., high temperature drilling fluid, bits, coring, logging tools and tubulars -- in a realistic environment, and (3) We will gain insight on the history of collapse, resurgence, and intrusion in a major young caldera.

INTRODUCTION

The fundamental objective of Sandia's Magma Energy Program is to answer the question, "Can we locate magma bodies and produce power from them at a reasonable cost?" If analysis and laboratory work indicate that the answer to this question is "yes," we would demonstrate that feasibility by finding a magma body, drilling into it, emplacing an energy extraction system, and producing useful amounts of power in long-term experiments.

Drilling the well for this ultimate experiment is a profound technical challenge. The hole will be large, hot, deep, and expensive, but we can slash its risks and costs by learning from the experience of drilling a deep exploration well nearby. Our aim for this exploration well is to make it cheap, deep, and informative -- compared to the energy extraction well, it will have lesser requirements on diameter, depth, and service life, but we will learn a great deal from it.

DRILLING PLAN

The exploratory well will be near the center of Long Valley Caldera's resurgent dome (Figure 1). Extensive geophysical evidence indicates that there is a magma body beneath the caldera and that its shallowest point lies approximately beneath the drill site. In the exploratory well, our goal is to drill near enough the magma for our technical objectives and we have tentatively set that criterion as being a bottom-hole temperature of 500°C, or a depth of 20,000 feet, whichever comes first.

Well design, shown in Figure 2, is based primarily on the pressure limitations of the casing and on the known stratigraphy of shallower wells drilled in the area. Because of budget constraints, and to give opportunities for scientific experiments between drilling operations, the well will be drilled in four phases at approximately yearly intervals. Figure 2 also shows completion dates for the phases and the corresponding depths. We believe that the temperature profile in the rock is very non-linear (Figure 3) because of groundwater convection, so the drilling temperatures may not become challenging until depths below 9,000 feet. The relative youth of near-surface intrusions, however, means that once we approach the magma closely, the rock temperatures may rise sharply. If these assumptions are correct, and there is sound geophysical reason to believe that they are, then the drilling in the first two phases should be nearly conventional. By the same argument, the temperatures in the lower reaches of this hole and the even more extreme conditions of the energy extraction well will dictate new technology to drill them successfully.

BENEFITS OF THE EXPLORATORY WELL

There are several specific and important aspects of drilling for energy extraction that can be clarified by an exploration hole:

(a) Location confirmation -- It will allow us to make downhole seismic and heat flow measurements that confirm our magma location capability. Although an enormous amount of geophysical data supporting the existence of a magma chamber under Long Valley caldera has been collected, there is a chance that we could be surprised by a "dry hole" at the target location. If that happens, an exploration well will have been a cheaper experiment -- and it will signal our need to think carefully about the validity of geophysical interpretation if we cannot positively identify a magma body in a place as thoroughly studied as Long Valley.

(b) Depth definition -- After assuring ourselves that a magma chamber is truly there, it is still important to have an accurate measure of the depth to its upper boundary. This measure is now uncertain within a 2 kilometer range. Downhole seismic and heat flow measurements can refine this estimate and give a definite target depth. Since the casing program and drilling plan, and thus the cost, for any well are highly dependent on the depth, accurate knowledge of the target will allow the cheapest design for the energy extraction experiment.

(c) Prediction of drilling problems -- Historically, much of the cost on big wells is a result of unexpected events; trouble not foreseen in the drilling plan. Lost circulation, unstable formations, sudden changes in lithology that require a different bit, or zones of unusually high or low pressure are conditions that, at best, will increase time and cost and, at worst, can endanger the hole and the crew. The exploration well will be near enough to experience the same formations, conditions, and problems as the experiment well, but finding and solving these problems will be much cheaper in the smaller well.

(d) Materials compatibility -- The high temperature and likelihood of corrosive gases or liquids in the formation make the tubular materials selection a crucial part of the well design. This becomes even more important in the experiment well, since it must be planned for data collection that might last years. Uncertainty about the local geochemistry would force the experiment hardware to be capable of resisting a range of corrosives, but rock and fluid samples from the exploration well would narrow that range and would identify specific corrosion hazards. This would lead to significant savings in buying drillpipe and casing.

(e) Test insulated drillpipe -- Drilling fluid temperatures affect so many other aspects of the well plan (tubular selection, choice of drilling fluid and additives, corrosion rates, bit cooling, wellbore stability) that controlling these temperatures appears to be a crucial part of a successful project. Our approach to this problem is the use of insulated drillpipe, which can make a dramatic difference in the fluid temperatures when drilling an energy extraction well (Figure 4.) If we are not able to keep these temperatures relatively low, then we must face the prospect of solving all the problems associated with drilling a long, large diameter interval in rigorous, little known conditions. To prove a valid solution, we must test prototype insulated drillpipe in a realistic, hot well.

(f) Opportunities for science -- Because the drilling operations schedule will be driven by the budget and will be divided into phases approximately one year apart, the times between active drilling periods will give windows in which scientists will have access to an open hole deeper than any ever available in this unique location. A science program for this well is not yet completely defined, but we expect that most of the effort will concentrate on geochemistry, seismic experiments, and studies of caldera evolution. Downhole seismic data, free from interference of the shallow fractures and clutter, can be correlated with surface measurements and will be especially useful in clarifying the geological evolution of the caldera and the configuration of the magma chamber.

CONCLUSION

The act of drilling this well will focus our research. We have tried to preserve as much generality as possible in looking at the questions of energy extraction, drilling technology, and geophysical interpretation, but it is valuable and necessary to design for a specific, unique site. Planning for an experiment here at the best available location will demonstrate the process that we must practice and extend for the Magma Energy Program to be a success.

This work was performed at Sandia National Laboratories, supported by the U. S. Department of Energy under contract DE-AC04-76DP00789.

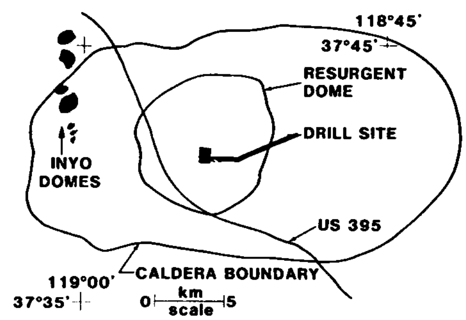

Figure 1 Drill Site Location

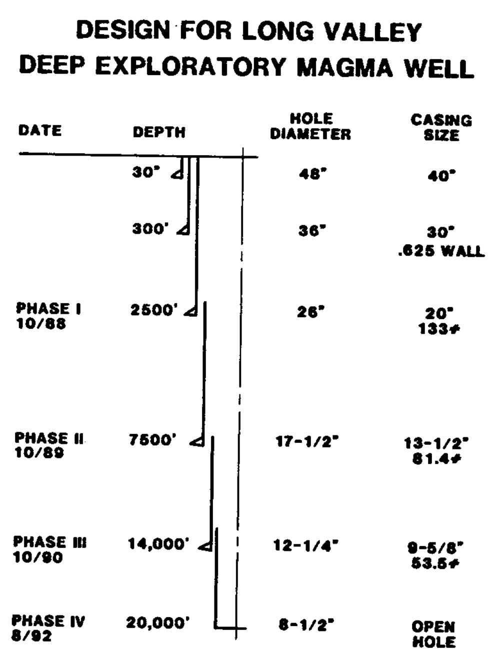

Figure 2

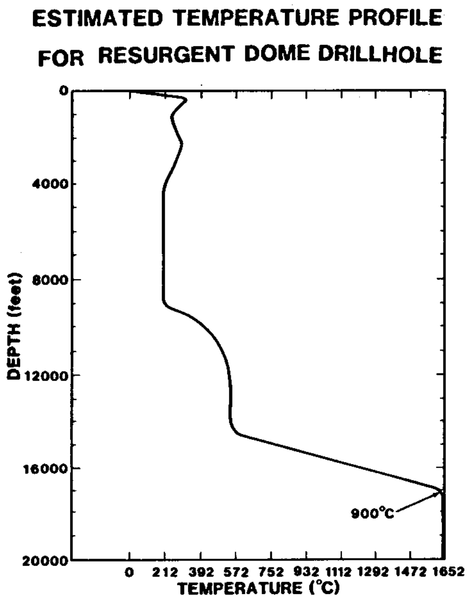

Figure 3

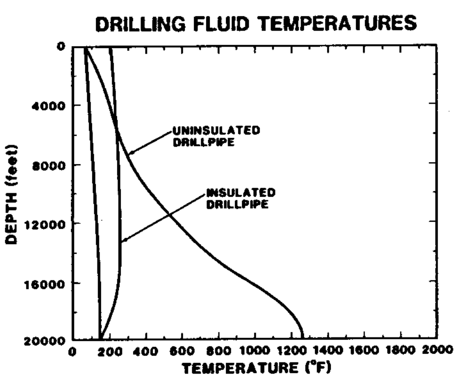

Figure 4

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SESSION VI

SPECIAL ISSUES

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QUANTIFYING THE COST-OF-POWER IMPACTS OF FEDERAL GEOTHERMAL R&D

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ABSTRACT

The Geothermal Technology Division, DOE, has sponsored the development of a computer model, "IM-GEO", to assist its research and development (R&D) program managers in quantifying geothermal R&D objectives and to quantify the impacts that meeting the objectives are likely have on the cost of electricity. The model is based on assessments of the performance and cost of 1986 hydrothermal technology. It works from a database of eight reservoirs which represent U.S. regions being studied and/or developed by industry.

An important innovative feature of the model is that it calculates effects of reservoir uncertainties upon power-project financial risks. This feature supports entry points for cost-impact analyses of geoscience R&D that seeks to reduce technical uncertainties about the long-term performance of reservoirs.

The paper describes the structure of the model and how it is being used to estimate cost impacts of the Geothermal Technology Division's hydrothermal R&D objectives. Anticipated extensions of the model and analysis to R&D related to geopressured, hot dry rock, and magma technologies are also described.

INTRODUCTION

Estimating the value of specific Federal research projects and programs is important because supporting resources need to be allocated to relatively high-value efforts. Many factors must be included in the assessment of the value of R&D efforts, including technical, economic, environmental, and political considerations. This report describes two portions of a system that the Geothermal Technology Division (GTD) is using to improve the quantification of the economic value of its research efforts.

The first part of the system is a computer-based "Cost of Power" model that simulates the performance and cost of a number of geothermal electric projects of the types that U.S. industry is pursuing. The second part is a process whereby technology improvements expected to result from research (GTD's "research objectives") are estimated by R&D program managers. The technology improvements are then analyzed, using the model, to estimate geothermal electricity cost savings that are expected to result from the R&D.

The purpose of the "Research Objectives" exercise and the "Cost of Power" model are to:

- Achieve better quantitative descriptions of the technology improvements expected to result from GTD's research
- Be able to make reasonable estimates of the future effects of those technology improvements on the cost of power from geothermal energy systems.

The purpose of this report is to document some of the technical bases of Dr. John E. Mock's description of GTD's research objectives at this Geothermal Program Review (1). It also is intended to solicit comments on the process for setting objectives, the cost-of-power model, and how the model is used to analyze the objectives.

The modeling and analysis effort have been focused on hydrothermal power systems because these are fairly well understood due to the existence of feasibility studies, costed conceptual designs, and recent U.S. industry experience in construction and operation. Geopressured, hot dry rock, and magma geothermal energy systems will be analyzed in later efforts.

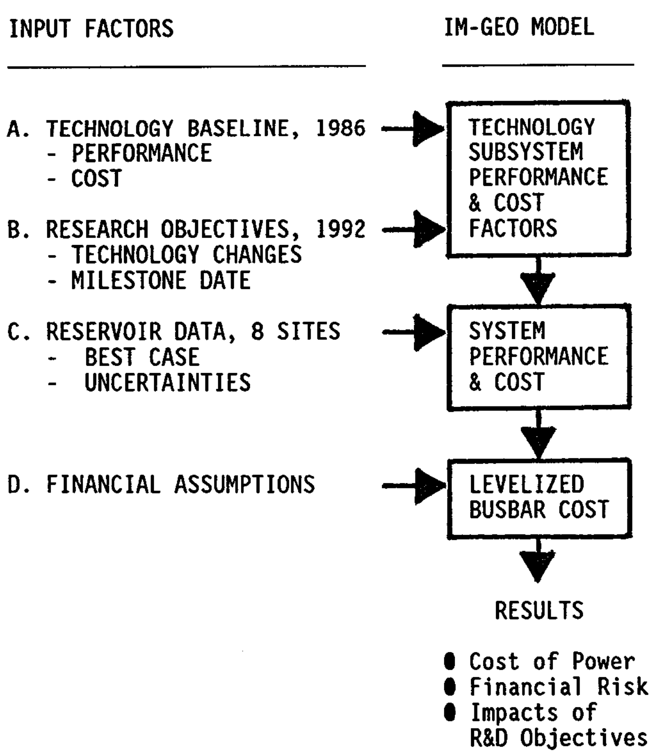
The authors of this paper are the model-development team, led by Richard Traeger. The GTD hydrothermal R&D program managers, Gladys Hooper, Ray Lasala, Lew Pratsch, and Marshall Reed played equally important roles in describing and quantifying the R&D objectives. They were ably guided in that task by Allan Jelacic, the GTD geoscience team leader. Dr. John E. Mock, Director of GTD, designed and managed the overall process for formulating and analyzing the objectives. The analysis of the objectives using the model was performed by D. Entingh.

GENERAL APPROACH

The general approach and underlying technical rationale fall into the mainstream tradition of previous hydrothermal performance and cost models used for geothermal research policy analysis: GEOCOST by PNL (2), GELCOM by MITRE (3), and the "electric market model" by EER/TECHNECON (4). The new model, "IM-GEO", for "Impacts of Geothermal R&D", is different from earlier models principally because it had more data on industry experience at liquid-dominated projects to draw from, and because it has added features to estimate the economic value of research on aspects of geothermal resource and reservoir analysis.

The main elements of the information used to ascribe economic value to R&D objectives are shown in Figure 1, and described here.

FIGURE 1. PROCESS FOR ESTIMATING ECONOMIC IMPACTS OF GEOTHERMAL RESEARCH OBJECTIVES



A. Baseline technology (reflecting industry practice as of early 1986) for liquid-dominated hydrothermal electric systems was analyzed and its major engineering performance and cost factors were embodied in computer code. Technology change entry points for about 40 possible improvements in technology were embodied in the code, and made accessible through user-friendly menus.

B. In parallel, the GTD R&D managers, with assistance from National Laboratory researchers and some inputs from industry sources, estimated the degree of improvement of technology that is expected to result from GTD's current research projects, and the date at which such improvements would be available for industry use. These "research objectives", when entered to the model via the technology change entry points, define improved technology for some future date.

All of the current GTD hydrothermal R&D objectives are estimated to be met by 1992, and some earlier than that. Therefore the total set of the expected technology improvements is described here as "1992 Technology".

C. A data base of resource characteristics was established for eight site-case simulated reservoirs. Resource characteristics are defined in terms of fluid-flow properties, not geophysical properties. The data include estimates of uncertainties associated with major reservoir characteristics.

When the model is run, the technology code produces system performance and cost estimates for each site-case. "Best case" and "uncertainty" data for each reservoir are used to estimate financial risk, as described more fully below. 1986 technology produces "base-case" costs, while 1992 technology produces "improved technology" costs.

D. Financial assumptions and technology costs are combined through a final set of equations to give the levelized busbar cost (required price) of electricity from each site-case. The specific financial assumptions are for an electric utility-financing case currently being used by the DOE Office of Renewable Energy to make comparisons across a range of renewable energy technologies.

Results are available in a number of formats, including research-induced percentage changes in the cost of power across the eight sites, weighted by resource availability or other factors; the cost of power and changes therein, either averaged or individually for each site-case; and details of the estimated performance and component costs for each site-case.

The number of site-case reservoirs was kept small (eight) because of the effort needed to estimate reservoir characteristics and the uncertainties associated therewith. Each site-case represents a composite of characteristics encountered at real U.S. reservoirs in a particular region, as drawn from references 5 and 6 and interviews of industry sources. The range of characteristics and associated uncertainties is believed to be a reasonable representation of the U.S. reservoirs that industry is and will be working at in the 1986 - 1995 decade.

RESERVOIR UNCERTAINTIES AND FINANCIAL RISK

A novel capability has been included in the IM-GEO model in order to estimate cost impacts of GTD geoscience research activities that seek to reduce uncertainties about reservoir performance. The approach used for this is similar to that used by investment bankers in evaluating the degree of financial risk associated with a specific geothermal power development project.

Estimates of uncertainties in reservoir characteristics are contained in the IM-GEO sites data base. These are represented by numerical offsets from the expected or "best case" conditions. IM-GEO calculates a "Base Case" cost for each site from the best case conditions and calculates a "Risked", worst-case, cost using the offsets. The overall cost difference between those prices is the "financial risk". All electricity prices shown in the IM-GEO reports include the financial risk, and thus are "worst case" estimates.

Effects of GTD research that seeks reduce uncertainties about reservoir performance, e.g., through better testing and interpretation methods, are modeled in IM-GEO by reducing the reservoir uncertainty estimates. The analysis uses estimates from the R&D managers of the degree to which new technology will aid industry in estimating reservoir properties and related uncertainties.

Another purpose for including this capability was to attain a better overall understanding of the implications of current hydrothermal reservoir uncertainties on the financial risk associated with hydrothermal electric projects. To our knowledge, this has not been studied systematically.

Such risks and perceptions thereof affect the cost of loans to geothermal developers. Reducing reservoir uncertainties and financial risks could reduce both the direct costs and financing costs of geothermal development.

FEATURES OF THE COST OF POWER MODEL

The model is relatively complex to capture a significant degree of information about how geothermal reservoirs and plants behave, and how industry develops geothermal power systems. IM-GEO is written in MicroSoft QuickBasic 2.0 (TM), (6,7). About 1500 lines of source code are hydrothermal system performance or costing data and algorithms. Another 2000 lines support user-friendly data manipulation and reporting functions.

Figure 2 displays some of the main components of the model. Performance and cost factors are aggregated separately for four project phases: Exploration, Confirmation, Construction (of power plant plus additional production and injection wells), and Operation (of plant and field). Each block in Figure 2 shows some of the project items that are modeled for each phase. Table 1 lists many of the major features of project performance and cost that are considered in the model.

The greatest portion of the modeling effort has concentrated on:

- Estimating reservoir characteristics and associated uncertainties.
- Clarifying how reservoir geology affects trouble-free and trouble-related costs (e.g., lost circulation) drilling costs.

FIGURE 2. COST AND PERFORMANCE FACTORS IN THE IM-GEO MODEL

Cost or Performance Factor	PROJECT PHASE			
	EXPLORATION	CONFIRMATION	CONSTRUCTION	OPERATION
LIKELIHOOD OF SUCCESS	P(Success) = 0.20 per attempt	P(Success) = 0.60 per attempt	P(Success) = 1.0	P(Failure) = 0.05 (Reservoir Insurance)
WELLS AND FIELD PIPING	1 Wildcat well per attempt	6 Wells per attempt	Producers Injectors Piping (Per plant flow need)	O&M, initial wells Capital, O&M for make-up wells
TESTS AND ANALYSES	Surveys Flow Tests	Flow Tests Reservoir Modeling	Flow Tests	
POWER PLANT		Design of Plant	Plant Core Auxiliary equipment	O&M for all components

TABLE 1. MAJOR PERFORMANCE AND COST FACTORS ACCOUNTED FOR IN THE IM-GEO HYDROTHERMAL COST OF POWER MODEL

EXPLORATION AND RESERVOIR CONFIMATION

- Exploration Unit:
  - Geological surveys
  - One wild-cat well and flow test
  - Probability of success = 0.20
  - Success = Invest in Confirmation attempt
  - Costs are spread across 4 to 8 power plants

- Confirmation Unit:
  - Six production-capable wells attempted
  - Flow tests, reservoir modeling
  - Probability of success = 0.60
  - Results in 4 good producers, 1.5 injectors
  - Success = Lender makes project loan
  - Cost is repeated for each power plant

FLUID PRODUCTION FIELD

- Point estimates for well costs
  - Trouble-free base well cost
  - Lost circulation trouble cost
  - Cementing trouble cost
  - Cost to extend well 500 feet
  - Cost to side-track lower third of well
  - Production and injection tests
  - Likelihoods for extension and side-track

- Number of production and injection wells
  - Point estimates of flow per well
  - Fluid inlet and outlet requirements of the plant.
  - Piping costs, based on the number of wells and layout

- O&M costs
  - Explicit well workover costs and frequencies
  - Other O&M costs, based on rules of thumb

- Pressure and flow make-up wells
  - From exponential decline curve based on the "Decline Coefficient" datum for each site.

INTERACTIONS BETWEEN PLANT AND FIELD

- Physical properties of brine affect the components, net brine effectiveness, and cost of the plant:
  - Reservoir temperature or wellhead enthalpy
  - Total dissolved solids (TDS)
  - Noncondensible gases (NCG)
  - Hydrogen sulfide (H2S)

- Net brine effectiveness of the power plant determines:
  - Mass flow required from producer wells and to injection wells
  - Number of wells required based on the estimated flow per well for producers and injectors
  - Pumping power load if producers are pumped

POWER PLANT CALCULATIONS

- Input parameters
  - Well-head enthalpy, based on reservoir saturated temperature, or explicit well-head enthalpy of super-heated brine
  - Effects of dissolved solids upon enthalpy and/or available work
  - Effects of noncondensible gases on flash performance
  - Summer ambient dry bulb temperature

- Core plant performance calculations
  - Net brine effectiveness(Wh/pound of brine)
  - Flash: from First Law enthalpy and mass balances
  - Binary: from Second Law ("exergy") calculations, using cycle data from Khalifa and Rhodes, 1985, (9)
  - Net brine effectiveness is adjusted for "auxiliary" cycle effects and power use

- Power plant costs
  - Based on regression of plant total costs on resource characteristics, from a 1987 analysis of plant cost estimates and reports that covered 1973-1987 period.
  - Closed-form equations estimate the cost for a pure-water plant.
  - "Pure-water" costs are adjusted for equipment costs and losses due to TDS, NCG, and auxiliary power consumption

- Power Plant Auxilliary Factors
  - TDS: Thermodynamic effects, modeled as sodium chloride
  - TDS: Effects on scaling, in field pipes and plant
  - TDS: Effects on corrosion, estimated as additional capital expense for more corrosion-resistant materials
  - TDS: Poor brine stability (at moderate to high TDS) accounted for by addition of crystalizer-clarifier, filtration equipment, and costs of sludge disposal
  - Non-Condensible-Gases: Cycle effects and gas ejector costs at flash plants
  - Hydrogen Sulfide: H2S treatment equipment costs, chemical costs, sludge-disposal costs
  - Injection Boost Pumps: Costs and power requirements
  - Production Downhole Pumps: Auxiliary power requirements accounted for at binary plants

- Establishing power-plant performance and cost estimates that are appropriately sensitive to a wide range of reservoir characteristics.

We also began a process to better understand how U.S. industry's practices during the reservoir confirmation phase affect the uncertainties about long-term reservoir performance.

A technology baseline of early 1986 was chosen because a reasonable amount of data was available on real U.S. liquid-dominated geothermal power projects. Also, short-term declines in well drilling costs had roughly stabilized. Costs are reported in January 1986 dollars. Electricity prices are levelized in constant (real) dollars.

Exploration and reservoir confirmation costs are based on U.S. hydrothermal experience, 1975-1986. Well costs are based on details of site-case geology, and 1985-1986 drilling technology, practices, and costs. Power plant performance and cost estimates are based on an extensive review of available theory, conceptual designs, and data from real plants. Power plant output is set at 50 MWe net, with an annual capacity factor of 0.80. Long-term reservoir enthalpy decline is not accounted for explicitly in the model.

The eight regional site-cases in the model are identified in Table 2. Table 3 shows the major reservoir characteristics that define each site-case. There you can see the degree to which problematic hydrothermal brine conditions are covered by the eight-site scenario. Values labeled "UNCERT" indicate the degree to which the nominal (best-case) values are offset to reflect reservoir uncertainty.

An overview of the financial assumptions is shown in Table 4. These assumptions reflect a

TABLE 2. IDENTIFICATION OF ANALYZED REGIONS

IV-FL.	Imperial Valley - Flash
IV-BI.	Imperial Valley - Binary
BR-FL.	Basin & Range - Flash
BR-BI.	Basin & Range - Binary
CS-FL.	Cascades - Flash
CS-BI.	Cascades - Binary
YV-F1.	Young Volcanics - Flash Case 1
YV-F2.	Young Volcanics - Flash Case 2

"BI" denotes a binary plant design.
"FL", "F1", and "F2" all denote double-flash designs.

TABLE 4. FINANCIAL FACTORS USED IN ANALYSIS

FACTOR	VALUE
- Years to construct power plant	2.5
- Cost Basis: AFDC not included in modeled costs; Adjustment for AFDC	1.081
- General inflation rate	0.06
- Discount rate; Cost of capital	0.1249
- Book life of project, years	30
- Annual Capital Charge Rate (Includes Amortization, Income Taxes, Tax Incentives, Property Tax and Insurance)	0.1683
- Cost Levelization Factor	1.748
- Royalty Rate	0.10
- Severance Tax	0.04
- Percent Depletion Allowance	0.15
- Intangible Fraction of Well Cost	0.75

TABLE 3. SITE-CASE DATA: PLANT TYPE AND RESERVOIR PROPERTIES

SITE CASE:	IV-FL	IV-BI	BR-FL	BR-BI	CS-FL	CS-BI	YV-F1	YV-F2
1. Plant Type: 1=Binary 2=Flash								
BASE:	2	1	2	1	2	1	2	2
2. Reservoir Saturated Temperature, Deg. F.								
BASE:	525	360	450	300	425	280	600(a)	550
UNCERT:	-25	-20	-50	-20	-50	-10	-25	-75
3. Non-Condensible Gases, Percent								
BASE:	0.5	0.1	0.1	0.2	0.1	0.1	0.2	0.1
UNCERT:	1.5	0.5	0.5	0.8	0.1	0.1	0.07	0.02
4. Hydrogen Sulfide, Parts per million								
BASE:	50	0	10	0	0	0	1500	50
UNCERT:	50	50	50	200	25	25	500	75
5. Total Dissolved Solids, Parts per thousand								
BASE:	250	5	1.5	1.2	1.0	0.5	15	10
UNCERT:	125	1	1.0	1.3	1.5	0.5	20	5
6. Well Depth, 1000 Feet								
BASE:	6	9	8	3	10	3	6	5
7. Producer Well Redrill (Side-Track) Fraction								
BASE:	.15	.10	.33	.20	.35	.20	.35	.20
UNCERT:	.05	.05	.07	.05	.10	.05	.10	.05
8. Dry Holes per Producer								
BASE:	.17	.17	.25	.17	.17	.17	.20	.14
UNCERT:	.03	.03	.08	.03	.33	.08	.13	.06
9. Yrs Between Workover, Producer								
BASE:	2.0	10.	15.	3.	10.	10.	7.	10.
UNCERT:	-1.5	-2.	-5.	-2.	-2.	-1.	-2.	-3.
10. Yrs Between Workover, Injector								
BASE:	2.0	10.	15.	3.	10.	10.	7.	10.
UNCERT:	-1.5	-2.	-5.	-2.	-2.	-1.	-2.	-3.
11. Producer Well Flow, Klb/hr								
BASE:	450	580	750	400	350	500	70	550
UNCERT:	-100	-130	-250	-50	-100	-50	-5	-100
12. Producer Flow Decline Coefficient, 1/Years								
BASE:	.002	.024	.020	.027	.020	.010	.036	.020
UNCERT:	.008	.006	.015	.011	.025	.010	.064	.010
13. Injector Well Flow, Klb/hr								
BASE:	1350	1160	2250	1200	700	1500	210	2200
UNCERT:	-450	-580	-750	-800	-175	-500	-70	-550

NOTE: (a) Modeled as wellhead enthalpy of 900 BTU/lb.

utility financing case being used in early 1988 by the Office of Renewable Energy, D.O.E., to compare technologies. The electricity cost, in cents/kWh levelized in constant dollars, is given approximately by:

$$\text{COST} = \frac{\text{CAPCOST X 1.081 X 0.1683/1.748 + O\&MCOST}}{\text{50,000 kW X 8750 hr/yr X 0.80 / 100}}$$

CAPCOST is entered as $, and O&MCOST as $/year. 1.081 is the AFDC adjustment factor. 0.1683 is the fixed charge rate. 1.748 is the price levelization factor. 0.80 is the plant capacity factor. (This equation omits adjustments related to intangible drilling costs and other field-related revenue adjustments.)

Some of the results, for the 1986 base case technology, are shown in Table 5. There you can see some aspects of the degree to which the reservoir characteristics (in Table 3) affect the cost of power from site to site. The estimated cost of power ranges from 3.9 to 17.9 cents/kWh, reflecting both commercially feasible site-cases and cases where extensive technology improvements are needed to make case economical.

Also from the data in Table 5, the estimated financial risk accounts for between 15 to 50 percent of the projects' fully-risked cost of power. The risk ranges between 25 and 35 percent for five of these eight projects. This presents a substantial opportunity for improvement through R&D.

Examples of the sensitivity of the resulting cost of power scenario (i.e., the interactions of this specific combination of modeled 1986 technology and the eight site-cases) are shown in Table 6.

TABLE 6. EXAMPLES OF SENSITIVITIES OF WEIGHTED AVERAGE COST OF POWER

	% Change in Cost of Power
A. <u>For 20 % change in Variable</u>: (a)	
1. P(Success), Exploration	- 0.3
2. P(Success), Confirmation	- 0.6
3. Base Well Cost	- 7.3
4. Lost Circulation Problems	- 0.4
5. Cementing Problems	- 0.6
6. Flow per Production Well	- 9.9
7. Binary Plant Efficiency	- 5.6
8. Binary Plant O&M Cost	- 0.5
9. Flash Plant O&M Cost	- 0.5
10. Sludge Disposal Cost	- 0.6
B. <u>For 20 % reduction in Uncertainty</u>:	
1. Reservoir Temperature	- 2.7
2. Flow Decline Coefficient	- 1.4
3. Total Dissolved Solids	- 0.3
4. Hydrogen Sulfide	- 0.0004
5. Noncondensible Gases	- 0.2
6. All five of above	- 5.6
C. <u>Example of Combined Impacts</u>:	
1. Effects A-3, A-7, B-6 entered simultaneously:	- 17.3
2. Simple sum of the impacts of effects A-3, A-7, B-6 entered individually:	- 18.5

NOTE: (a) All changes werre made in the direction of reducing the cost of power.

TABLE 5. ELECTRICITY COST ESTIMATES, 1986 TECHNOLOGY, BY REGION

SITE-CASE:	IV-FL	IV-BI	BR-FL	BR-BI	CS-FL	CS-BI	YV-F1	YV-F2
<u>Capital, $ Million</u>:								
Discovery	24.	24.	27.	15.	39.	16.	44.	21.
Field, Initial	73.	88.	52.	226.	224.	168.	143.	27.
Plant, Core	45.	105.	60.	207.	68.	204.	40.	51.
Plant, Auxil.(a)	24.	1.	4.	1.	4.	0.	10.	3.
Total, Capital	166.	218.	143.	449.	335.	388.	237.	102.
<u>O&M, $ Million/Year</u>:								
Field, Initial	3.8	1.3	0.6	6.6	0.9	2.6	0.8	0.6
Field, Makeup	0.0	0.5	0.5	3.1	3.9	0.2	8.2	0.2
Plant, Core	2.2	4.0	2.7	7.0	2.9	6.9	2.0	2.2
Plant, Auxil.(a)	4.8	0.0	0.2	0.0	0.2	0.0	1.0	0.6
Total, O&M	10.8	5.8	4.0	16.7	7.9	9.7	12.0	3.6
<u>Cost of Power, Cent/kWH</u>:								
Cost	7.8	7.9	5.2	17.9	11.2	14.0	9.9	3.9
Risk Portion	2.7	2.0	1.6	8.1	5.5	3.6	3.0	0.6

Note:

(a) Major equipment or O&M related to brine total dissolved solids handling, scaling, corrosion, hydrogen sulfide, other noncondensible gases.

Those indicate the degree of overall cost saving that could be achieved if 20 percent improvements could be attained in the listed technology factors.

Table 6 indicates two expected interactions among effects of the technology change variables. Interactions among reductions in reservoir uncertainty (Section B.) are synergistic. Combined effects (B.6.) are larger than than the simple sum of the independent effects. Interactions among most of the major technology variables are usually antagonistic (Line C.). For example, if power plant efficiency improves, there will be fewer wells for any reduction in unit well cost to impact upon.

ANALYSIS OF R&D OBJECTIVES

Note that Table 6 implies nothing about the degree to which research might be able to improve any particular aspect of technology. For that, expert opinion is needed. That opinion has been drawn from the GTD R&D program managers and their research associates in the National Laboratories, universities, and industry.

The process began in February 1987, with the R&D program managers defining general technical objectives and describing the objectives in terms of expected quantified improvements in technology. The objectives were collected, and transmitted to field researchers for review, comment, and additional quantification in April of 1987.

Comments from researchers and industry were received by August 1987. These were reviewed for substance, and extensive revisions to the March 1987 version 2.09 of IM-GEO (7) were begun. The revisions added a few technology improvement factor entry points, calibrated the power plant performance and costing codes to new data on real plants, and added more explicit algorithms for certain plant-related auxiliary equipment. In some instances, research objectives were reworded and requantified to conform to IM-GEO technology factor entry points.

The current definitive version of the research objectives is being reviewed by the geothermal R&D community (10).

A summary view of the detailed research objectives is shown in Table 7. This view shows the total set of technology improvements expected to result by 1992 from all GTD hydrothermal R&D activities. The improvements are expressed in terms of percent changes in technology performance relative to 1986 values.

The categorization scheme in Table 7 was adopted solely to compress the presentation. It differs from the "Cost Tree" scheme used to develop the objectives and to help review the breadth of research coverage of opportunities for technology improvement (1). Unexpectedly however, the scheme illuminated for the first time a previously under-emphasized aspect of technology improvements expected to result from the hydrothermal R&D: an improved capability in siting boreholes with re-

TABLE 7. TECHNOLOGY IMPROVEMENTS EXPECTED FROM HYDROTHERMAL RESEARCH OBJECTIVES FOR 1992

(Percent of 1986 Value)

1. EXPLORATION:		
- Wildcat Success Ratio		127
- Testing Costs, Exploration	(a)	110
2. RESERVOIR ANALYSIS: (b)		
- Confirmation Success Ratio		135
- UNCERT: Reservoir Temperature	(c)	62
- UNCERT: Non-Condensible Gases		70
- UNCERT: Hydrogen Sulfide Content		70
- UNCERT: Total Dissolved Solids		70
- UNCERT: Production Well Flow		66
- UNCERT: Flow Decline Coefficient		70
- UNCERT: Injection Well Flow		66
3. BOREHOLE LOCATION:		
- Dry Holes per Production Well		60
- Flow Rate, Production Well		108
- Producer Redrill Fraction	(d)	40
- UNCERT: Well Cost, Extension	(d)	40
- UNCERT: Producer Redrill Fraction		60
- UNCERT: Dry Holes per Producer		60
4. DRILLING AND COMPLETION:		
- Well Problems, Lost Circulation		70
- Well Problems, Cementing		60
- Total Cost, Average Well		86
5. POWER PLANT DESIGN:		
- Binary Plant - Efficiency		128
- Binary Plant - Capital Cost	(a)	102
- Heat Exchanger - Capital Cost	(a)	200
- Heat Exchanger - O&M Cost		50
- Cooling Water - Use Cost		80
6. BRINE CHEMISTRY AND MATERIALS:		
- O&M Cost, Gathering System		50
- Cost per Workover, Production Well		90
- Binary Plant Availability		102
- TDS-Sludge Disposal Cost		75
- TDS-Scaling, O&M Cost		80

NOTES:
(a) Increased cost required to achieve improved performance
(b) "UNCERT" = Predictive uncertainty
(c) With some contribution from Bore-Hole Location improvements
(d) With some contribution from Reservoir Analysis improvements

spect to productive zones of reservoirs.

Detailed reviews of the model and the research objectives were begun in February. Reviews in progress as of mid-April include:

- DOE, Albuquerque Ops Office — General
- DOE, Idaho Ops Office — General
- Electric Power Research Inst. — Power Plants
- Idaho Nat'l Engineering Lab. — Reservoirs & Power Plants
- Lawrence Berkeley Laboratory — Reservoirs
- Stanford University — Reservoirs
- Univ. of Utah Research Inst. — Discovery & Reservoirs

Reviews with industry are being conducted by the authors of this paper.

SOME RESULTS

Some of the economic impacts of the hydrothermal research objectives estimated by the model are described here. Other results can be found in Dr. Mock's report (1).

Table 8 shows the "highest-level" results of the analysis of hydrothermal technology, resources, and research objectives. Those results reflect weighted averages of base-case (1986 technology) costs and R&D impacts of the 1992 technology (defined in Table 7), across the five flash and three binary plants in the scenario data base. These results are the basis for the "Level I" objectives of hydrothermal R&D.

Some interpretive comments are presented here. The underlined letters correspond to annotations in Table 8.

1. The overall effect is a 32 percent reduction (a) in the levelized cost of power across the eight sites, comparing the expected 1992 "new" hydrothermal technology to the 1986 technology assumed in the base case. Based on additional interpretation (10), this objective is expressed as a 25 to 35 percent reduction in the cost of power from liquid-dominated hydrothermal systems.

2. Project financial risk would be reduced by about two thirds, from about 35 percent of overall project costs (cost of electricity) in the base case (1986 technology) to about 20 percent of overall costs in the new-technology (1992 technology) case (b). This impact should contribute to long-range improvements in investors' and lender's confidence in such projects, and therefore eventually lead to slight decreases in the cost of capital funding.

3. Exploration costs are reduced by about half (c), and Confirmation costs by about one quarter (d).

4. Production field development (construction and operation phases of projects) life-cycle costs are reduced to roughly half of current levels (e), compounded from joint effects of (1) less costly wells and (2) fewer wells being required due to improvements in power plant efficiency (especially for binary cycle cases).

5. Power plant life-cycle costs are reduced by about 12 percent (f), across the eight-site scenario.

TABLE 8. OVERALL COST IMPACTS OF ENTIRE HYDROTHERMAL R&D PROGRAM

(IMPACTS AVERAGED ACROSS EIGHT SITE-CASES)

GEOTHERMAL COST OF POWER ESTIMATE — RUN: 03-21-1987 - 03:19:18
Multi-Region Weighted Averaged Data — WEIGHTS = Regional Capacity

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ********* % OF COST	***** 1992 TECHNOLOGY SYSTEM ****** % OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL:	100.0	67.5	- 32.5 (a)	100.0
RISK FRACTION:	34.0 (b)	12.7	- 62.6 (b)	18.8 (b)
1. Identify Reservoir	1.8	0.8	- 55.0 (c)	1.2
2. Confirm Reservoir	4.7	3.4	- 28.0 (d)	5.0
3. Prod./Inject. Wells	31.7	15.1	- 52.3 (e)	22.4
4. Downhole Pumps	1.7	0.9	- 46.2 (e)	1.3
5. Gathering Equip.	5.7	3.1	- 45.7 (e)	4.6
6. Draw-Down Wells	6.4	2.7	- 57.2 (e)	4.0
7. Power Plant (Core)	37.1	33.3	- 10.2 (f)	49.3
8. Brine TDS Effects	5.8	4.4	- 25.1 (f)	6.5
9. Gas Handling	1.8	1.6	- 10.1 (f)	2.4
10. Reservoir Insurance	3.4	2.2	- 34.1 (g)	3.3

6. Because of the way that the reservoir insurance is estimated in the model, the result in Row 10 allows the following inference: The expected technology improvements would lead to an average 34 percent (g) reduction in the capital expenditures (summed for field and plant) during the construction phase of such projects.

Figure 3 shows some of the results on a site-by-site basis. The two horizontal lines depict an estimate of the range of the cost of power from competing base-load technologies (coal, nuclear, gas) in the mid-1990s (1). Both reductions in the cost of power, and in project financial risk are notable in that figure.

IM-GEO is also being used to estimate impacts of the R&D objectives across parametric ranges of certain reservoir characteristics. An example is shown in Figure 4. Cases A and B there were drawn from the assumptions of the IV-BI site-case in the IM-GEO data base (see Table 3 for details), with appropriate variation in reservoir temperature and plant cycle design. Case C was formulated from the IV-FL site-case. The lower thick lines show the cost of power using "1992 technology" expected to result from the current GTD R&D objectives. If the objectives are met, the reservoir conditions under which hydrothermal technology is economic will be extended considerably.

EXTENSION TO OTHER GEOTHERMAL RESOURCE TYPES

Quantitative objectives have been formulated for GTD's research on geopressured, hot dry rock, and magma geothermal resource and technology systems (1,10). IM-GEO will be extended in the future to analyze those objectives with respect to their impacts on the cost of electricity or other forms of energy.

Considerable attention will have to be devoted to the conceptual designs, estimates of performance, and estimates costs for the energy extraction portions of the systems, for less is known about these matters for geopressured, hot dry rock, and magma systems, compared to hydrothermal systems. The costs and rates of success of exploration and reservoir confirmation will be key elements.

It seems likely that the concepts used in IM-GEO for translating reservoir uncertainties into financial risks could be especially useful in quantifying the degree to which research on those matters are likely to foster economic benefits.

FIGURE 3. COST IMPACTS OF HYDROTHERMAL OBJECTIVES, BY REGION

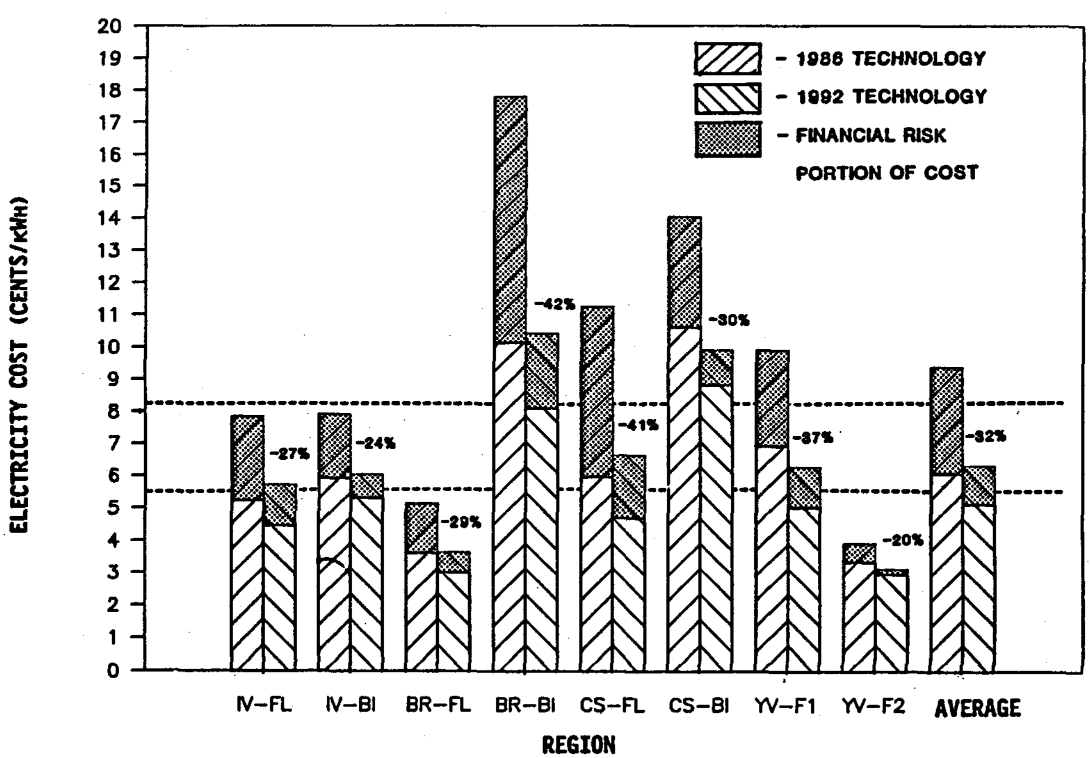
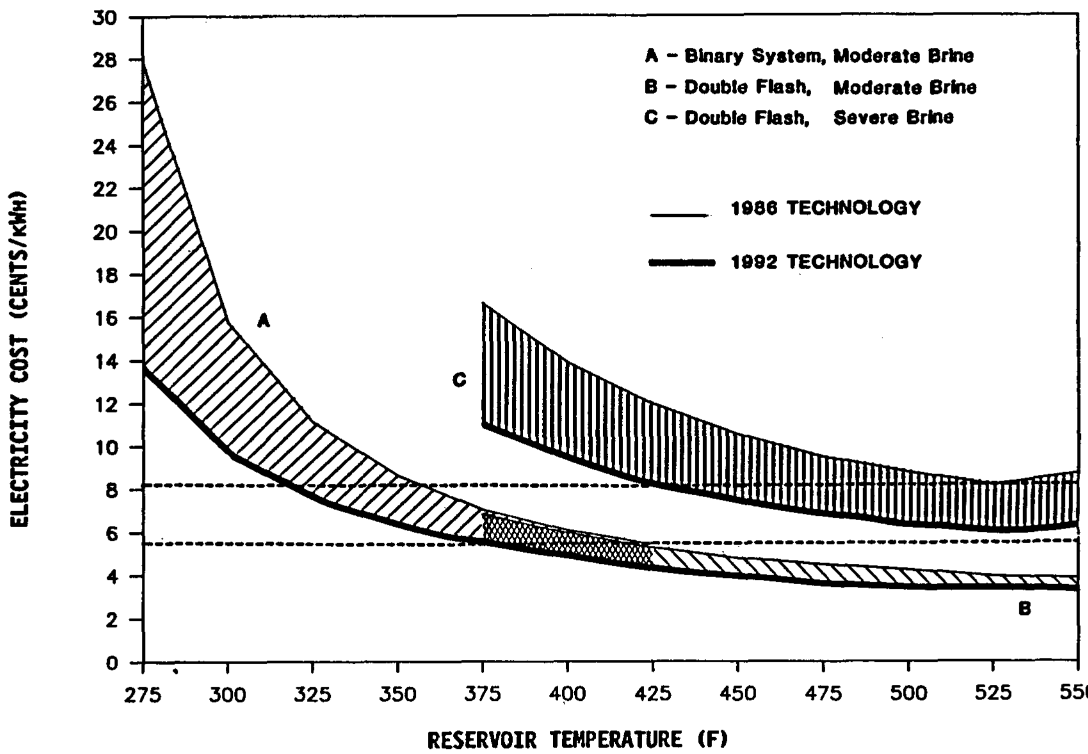


FIGURE 4. COST IMPACTS OF HYDROTHERMAL OBJECTIVES, BY RESERVOIR TEMPERATURE



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GOVERNMENT/INDUSTRY COOPERATIVE ARRANGEMENTS -- NATIONAL ACADEMY OF SCIENCES RECOMMENDATIONS

John E. Mock, Director
Geothermal Technology Division
U.S. Department of Energy

It is especially appropriate to discuss government/industry cooperative arrangements at this Special Issues Session of Program Review VI. This is true because the Office of Management and Budget (OMB) has made R&D cost-sharing a major issue at the Department of Energy (DOE) by its challenge to the Department to maximize its utility of federal R&D dollars by obtaining matching funds from industry.

The response of the Geothermal Technology Division (GTD) to this challenge was a decision to seek more effective mechanisms to supplement the existing cooperative arrangements, some of which have been in place for a number of years. We turned to the National Academy of Sciences (NAS) for recommendations because of its mandate to advise the government on scientific and technical matters.

The Statement of Work of our contract with NAS called for two major activities:

Task 1 - a review of geothermal energy goals and the DOE geothermal program and identification of major technical issues.

Task 2 - a recommendation for cost-effective cooperative arrangements to optimize limited research funding.

In order to carry out these assignments, the Academy appointed a Committee on Geothermal Energy Technology composed of representatives of both the geothermal industry and non-geothermal members. The Committee membership was as follows:

Norman Hackerman, Chairman
The Robert A. Welch Foundation
Houston, Texas

James B. Combs
GEO Operator Inc.
San Mateo, California

Myron H. Dorfman
Dept. of Petroleum Engineering
University of Texas, Austin

Wilfred A. Elders
Institute of Geophysics and Planetary Physics
University of California, Riverside

Stephen J. Gage
Midwest Technology Development Institute
St. Paul, Minnesota

Robert G. Lacy
San Diego Gas & Electric Co.
San Diego, California

Carel Otte
Unocal Corp.
Los Angeles, California

Martin Robbins
Colorado School of Mines
Golden, Colorado

Jefferson W. Tester
Massachusetts Institute of Technology
Cambridge, Massachusetts

Eric A. Walker
The Pennsylvania State University
University Park, Pennsylvania (Retired)

Mr. William R. Gould of the Southern California Edison Co. served as liaison with the Energy Engineering Board, and the following members comprised the formal Advisory Group:

Daniel Cubicciotti
EPI

Lansing Felker
Department of Commerce

Herbert Fusfield
Rennsselaer Polytechnic University

Robert Hirsch
ARCO

Tom Hogan
National Science Foundation

Harold Hubbard
Solar Energy Research Institute

Richard Nelson
Columbia University

Tom O'Hare
Brookhaven National Laboratory

Manik Talwani
Houston Area Research Center

The Committee based its deliberations on three general considerations: current worldwide oversupply of hydrocarbon fuels is a short-term phenomenon; U.S. oil production will decline from 11 million barrels per day in 1985 to 8 million in 1995; and the result will be a sharp rise in imports. In this context, the value of the geothermal resource and the contributions it can make to the nation's long-term energy security were recognized.

Results of Task 1

While I am here today to discuss primarily the results of Task 2, recommendations for cost-effective cooperative mechanisms, you may be interested in the major conclusions of Task 1 since they express very strong support of our program. After considering in detail the current technology status of all four forms of geothermal energy--hydrothermal, geopressured, hot dry rock, and magma -- the size of the resource base, economic issues and projected costs, environmental concerns, and other issues, the Committee made the following recommendations:

- For a successful hydrothermal R&D program, significant and stable funding over a number of years should be committed. Such funding is required for an orderly and systematic research program and for attracting the most qualified people to R&D activities.

- Sufficient funding should be provided to continue testing the Gladys McCall geopressured well, to conduct the Electric Power Research Institute power demonstration at the Pleasant Bayou well, to put the Hulin well into production, and to conduct research on geopressured reservoirs. After sustained funding at this level for five years, it would be anticipated that the DOE program might be phased out.

- The second phase hot dry rock program at Fenton Hill should be completed with up to two years for reservoir testing and two years for analysis and modeling, documentation of results, and technology transfer. DOE commitment should end by 1990, and the site turned over to industry for second phase power plant development.

- For magma experimental and analytical investigations and a trial borehole, the budget should range between $3 and $7 million per year through 1992.

While Task 1 did not solicit budget recommendations, the Committee concluded that GTD should be funded over a five-year period at a somewhat higher and stable level, and presented budgets typified by the following:

	Million $
Hydrothermal	$16.7
Geopressured	7.0
Hot Dry Rock	9.5
Magma	5.0
	$38.2

It was also noted that industry could be expected to contribute $3.5 million per year for five years to the hydrothermal reservoir and drilling technology program elements.

Performance of Task 2

The Committee found that there is currently a strong interest in promoting cooperative government-industry-university relationships. This interest appears to be driven by several factors: tightened or reduced federal and industrial R&D budgets; aggressive foreign competition strengthened by increased government-industry cooperation; a need to share expensive facilities and equipment; changes in the antitrust laws and their interpretation that facilitate cooperation among private companies; and a belief prevalent in many circles that the results of university research often languish in the laboratory too long without application.

The major benefits of cooperation, the Committee felt, is that participants can share the costs and financial risks. Other advantages discussed include:

- Government agencies and private companies can generally leverage their investments and participate in efforts of broader scope than they can afford individually.

- With increasing national concern about U.S. competitiveness, the belief is increasing that more commercial advantages should flow to U.S. companies from public and private investments in research.

- Collaboration seems to have improved communication among managers and professionals involved in the joint efforts.

Despite the advantages, however, tradeoffs may arise from participating in cooperative organizations. Participants must share control and ownership of intellectual properties, where applicable. A potential problem is that cooperative efforts may unduly expose a company's proprietary information to its competitors. In addition, a cooperative organization may simply create another layer of bureaucracy between the sponsoring and performing parties, often adding unnecessary overhead.

The Committee considered several types of cooperative relationships. These included:

- Industry-industry
  - Microelectronics and Computer Corp.
  - Electric Power Research Institute
  - Gas Research Institute

- Industry-university
  - Industry affiliates programs pioneered by Massachusetts Institute of Technology
  - A single company contract with or grant to a university for research of a specified scope
  - Group of companies supporting university research in a well-defined area (e.g., Semiconductor Research Corp.)

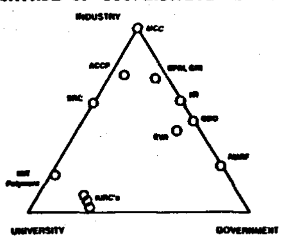
- Government-university
  - Large laboratories serving major government agencies
  - Small contracts for specific studies
  - National Science Foundation support of laboratories or scientific projects directed by a consortium of universities (e.g., University Corp. Atmospheric Research)

- Government-industry
  - Government contracts with single companies
  - Arrangements between government agencies and a consortium of companies (e.g., Geothermal Drilling Organization)

- Government-industry-university
  - Engineering Research Centers and cooperative R&D centers sponsored by National Science Foundation

Among the criteria for success in cooperative relationships the Committee considered was the question: Where should program direction and control reside? To help understand the broad range of approaches that can be taken, the Committee reviewed the examples shown in Exhibit 1. Other criteria for success included sufficiently long-term commitment by the partners, availability of adequate resources to achieve the objectives, and good communication based on basic trust and experience.

EXHIBIT 1
PROGRAM CONTROL OF COOPERATIVE R&D ORGANIZATIONS



ACCP - ADVANCED CERAMICS AND COMPOSITION PARTNERSHIP, MIDWEST TECHNOLOGY DEVELOPMENT INSTITUTE
AMRF - ADVANCED MANUFACTURING RESEARCH FACILITY (NBS)
EWI - EDISON WELDING INSTITUTE (OHIO)
EPRI - ELECTRIC POWER RESEARCH INSTITUTE
GDO - GEOTHERMAL DRILLING ORGANIZATION
GRI - GAS RESEARCH INSTITUTE
ITI - INDUSTRIAL TECHNOLOGY INSTITUTE (MICHIGAN)
IURCs - INDUSTRY UNIVERSITY RESEARCH CENTERS (NSF)
MCC - MICROELECTRONICS AND COMPUTER CORPORATION
MIT/POLYMERS - MASSACHUSETTS INSTITUTE OF TECHNOLOGY, IURC
SRC - SEMICONDUCTOR RESEARCH CORPORATION

Task 2 Conclusions and Recommendations

The Committee concluded that because of current economic conditions and the state of development in the geothermal industry, it is unrealistic to expect that private industry can or will fund most of the R&D needed in this area. The short- to mid-term profit potential is not sufficiently high, and the industry is not mature enough to generate the profits needed to support significant R&D. Thus, industry-university cooperation such as an industry affiliates program or the SRC are unlikely in geothermal R&D. Nor could an organization like MCC or EPRI be supported; limited partnerships do not offer enough profit potential to serve as a new source of R&D funding. Consequently, the Committee agreed, the government must continue to sponsor R&D if substantial progress is to be made.

After its review of the various mechanisms for near-term geothermal resource R&D, the Committee concluded that one model stood out above all others -- the existing cooperative agreement between the Geothermal Drilling Organization and the Department of Energy. Although the objective of the agreement is presently limited to developing technology for reducing the cost of drilling, completing, and logging geothermal wells in the short-term, and the organization is not without shortcomings, the Committee said that the GDO is an apparently successful operation that responds to most issues raised and generally meets the criteria for success.

GDO membership is open to all (business, universities, individuals, and others). It has 18 members, each of whom paid an initial $500 membership fee. The organization sets priorities for short-term R&D projects and seeks funds from its members as well as matching funds from DOE. Each project is funded by individual firms and DOE. The funders have priority use of the equipment developed for one year and royalty-free licenses thereafter. Anyone may use the equipment after the first year.

Sandia National Laboratories, acting as project administrator for GDO and DOE, contracts with outside performers project by project. The principal elements of this arrangement are the following:

- Projects have well-defined, short-term objectives.

- GDO members select the projects, if any, they wish to support.

- DOE reserves the right to select which GDO-proposed projects it wishes to support.

- DOE support for projects can be approved through a prior legal agreement ("Project Letter Agreement") without having to renegotiate each time. This agreement is the heart of the GDO-DOE model.

- All funds (both industry and DOE) flow into Sandia National Laboratories, which serves as the contracting agent for the agreement.

- The projects are performed by outside parties under contract to Sandia.

The Committee concluded that this arrangement is a successful and effective model that should be modified through changes in its charter to cover the wide range of short- through mid-term cooperative geothermal development activities. Correspondingly, the organization's name should be changed from the Geothermal Drilling Organization to the Geothermal Development Organization. The Committee recommended consideration of other changes in structuring the new GDO:

- Organizing as an independent membership corporation capable of owning assets.

- Developing a board of directors and officers that does not include DOE or DOE contractors (as Sandia does)

- Adding a small permanent staff, including an executive director, to serve as a secretariat and fiduciary agent.

The Committee did not state its reasons for recommending these administrative changes.

In considering alternative cooperative mechanisms for research on long-term geothermal resources, the committee concluded that several facts must be confronted. Industry will probably continue to invest in near-term hydrothermal resource development, but it will probably invest little, if any, for research on geopressured, hot dry rock, and magma geothermal resources. However, because of the critical importance of ensuring various future energy supply options, a minimal long-term research program on advanced systems must be pursued.

Formation of a Geothermal Research Organization (GRO) was recommended to be composed of researchers interested in the scientific and technological issues relating to the advanced geothermal resources. This organization would serve as an excellent means of coordinating the relatively small number of academic researchers working on these long-term resources and the large number of scientists working in allied fields. It would advise government agencies and formalize communication among academic researchers, and, in cooperation with government funding agencies, develop a research agenda. Within its framework, researchers, individually, or in collaboration, would submit research proposals. DOE would allocate part of its long-term research budget to these efforts on a sustaining basis.

The Committee concluded that any entity--national laboratory or DOE operational organization -- serving as contract administrator should not compete with universities and other eligible performers for funds under this mechanism. Both DOE and GRO would work together to identify other funding sources, primarily federal agencies with program interests compatible with such research.

A "geothermal coordination group," composed of an equal number of representatives from the GDO and GRO, could be formed to keep the two organizations aware of each other's activities, share information, provide a bridge between government-industry and government-university cooperative efforts, and speak for the broader interests of those involved in geothermal R&D.

The report of the National Research Council, principal operating agency of NAS, published the Committee's findings in a report entitled Geothermal Energy Technology -- Issues, R&D Needs, and Cooperative Arrangements dated 1987. Copies are available from:

Energy Engineering Board
Commission on Engineering and Technical Systems
National Research Council
2101 Constitution Ave., NW
Washington, D.C. 20418

GOVERNMENT-INDUSTRY COOPERATION AT WORK:
EXAMPLE OF THE GEOTHERMAL DRILLING ORGANIZATION

James C. Dunn

Geothermal Research Division
Sandia National Laboratories
Albuquerque, New Mexico

ASTRACT

The Geothermal Drilling Organization (GDO) is a joint DOE/ Industry group that acts to identify and fund technology development that will have near-term impact on costs of geothermal wells. The emphasis is on products or services that can be commercialized after project completion. Each project is jointly funded by DOE and participating industry partners with industry providing at least 50% of the total cost. Currently, the GDO has 23 members with both geothermal operators and service companies represented. Four separate projects with different participating groups are underway. A high temperature borehole acoustic televiewer is being commercialized for fracture detection and casing inspection in the Geysers. A downhole pneumatic turbine has been developed and will be tested in the Geysers. A tool that emplaces two-part urethane foam in lost circulation zones has been designed and fabricated and will be tested in actual lost circulation zones. Drill pipe protectors are being constructed using new high temperature elastomers; compatibility tests in geothermal wells will be conducted. After two years of operation, at least two major benefits of this DOE-industry association can be identified. (1) Industry has direct access to the DOE technology base through the GDO projects, thus enhancing technology transfer. (2) Researchers carrying out geothermal technology development have the opportunity to observe first-hand the real problems facing the geothermal industry today and this leads to relevant ideas for future research.

This work was performed at Sandia National Laboratories, supported by the U. S. Department of Energy under contract DE-AC04-76DP00789.

GOVERNMENT-INDUSTRY COOPERATION at WORK

EXAMPLE OF THE GEOTHERMAL DRILLING ORGANIZATION

GEOTHERMAL DRILLING ORGANIZATION

OBJECTIVE

TO FOSTER THE DEVELOPMENT OF TECHNOLOGY AIMED AT REDUCING THE COST OF DRILLING AND MAINTAINING GEOTHERMAL WELLS.

APPROACH

TO ESTABLISH NON-PROFIT COOPERATIVE FUNDING ARRANGEMENTS AMONG INDUSTRY PARTNERS AND WITH THE U.S. DEPARTMENT OF ENERGY TO FUND SPECIFIC PROJECTS OF VALUE TO THE GEOTHERMAL OPERATORS.

MEMBERSHIP

ARCO
CALIFORNIA ENERGY CO.
CHEVRON GEOTHERMAL
DAILEY DIRECTIONAL
DRESSER INDUSTRIES
EASTMAN CHRISTENSEN
EXLOG-SMITH
FOAMAIR PRODUCTS
GEOTHERMAL RESOURCES INTERNATIONAL
GEYSERS GEOTHERMAL
GRACE DRILLING
H & H OIL TOOL CO.
MCR GEOTHERMAL
MONO POWER CO.
NL INDUSTRIES
PAJARITO ENTERPRISES
REPUBLIC GEOTHERMAL
RIFT ENGINEERING
SANDIA NATIONAL LABORATORIES
SMITH INTERNATIONAL
STEAM RESERVE CORP.
UNOCAL GEOTHERMAL
TERRA TEK

OFFICERS

CHAIRMAN
Jim Combs, Geothermal Resources International

VICE CHAIRMAN
Steve Pye, Unocal Geothermal

SECRETARY
Jim Dunn, Sandia National Laboratories

TREASURER
John Rowley, Pajarito Enterprises

LIAISON
Lew Pratsch, DOE/GHTD

HIGH TEMPERATURE BOREHOLE TELEVIEWER

Total Project Cost	$948K
Industry Contribution (cash)	$474K

Participating Members

- Unocal
- Geo Operator

Status

- Contractor Squire Whitehouse declared bankruptcy
- Sandia completed hardware assembly and testing
- Follow on contractor will complete field logging phase

PNEUMATIC TURBINE

Total Project Funding	$418K
Industry Contribution (in kind)	$294K

Participating Members

- Rift Engineering
- Geo Operator
- Geysers Geothermal
- Unocal
- Eastman Christensen
- Grace Drilling
- H & H Tool

Status

- First prototype turbine drilled 400 feet of sand and shale sequences at penetration rates up to 180 ft/hr
- Second prototype drilled 80 feet in Unocal well at the Geysers
- Bearing/Seal problem requires minor modification

FOAM FOR LOST CIRCULATION

Total Project Cost	$400K
Industry Contribution (in kind)	$250K

Participating Members

- NL Industries
- Geo Operator
- Unocal
- Grace Drilling
- H & H Tool

Status

- Two downhole tools have been assembled
- First field test in the Geysers did not produce expected foam volume
- Foam test facility constructed at Sandia and testing is underway

HIGH TEMPERATURE DRILL PIPE PROTECTORS

Total Funding	$80K
Industry Contribution (cash)	$40K

Participating Members

- California Energy Co.
- Geo Operator
- Unocal

Status

- Thirty-five materials have been screened
- Laboratory testing is underway
- Full scale protectors will be tested at the Geysers during drilling

MAJOR BENEFITS OF GDO

- COMMERCIALIZATION OF NEW TECHNOLOGY DEVELOPED BY DOE SPONSORED RESEARCH
- NATIONAL LAB RESEARCHERS OBSERVE FIRST-HAND THE REAL PROBLEMS FACING THE GEOTHERMAL DRILLING INDUSTRY

INTERNATIONAL MARKET OPPORTUNITIES FOR GEOTHERMAL COMPANIES

Linda Joy DeBoard and Tim Olson*

Energy Technologies Export Program,
California Energy Commission
Sacramento, California

ABSTRACT

Several developing countries including the Philippines, Thailand, and Indonesia have recently revised their government policies to encourage foreign investment and ownership of energy development projects. These marked changes in policy appear to offer many California-based energy companies with an advantage suited to their strengths in competing against Japanese and European firms heavily supported by their governments. Firms or consortiums with experience in offering a turnkey approach and providing their own financing may find more opportunities to "build-own-operate" or "build-own-transfer" projects in these countries.

The California Energy Commission (CEC) is offering to assist government officials in these countries to implement their new policies and act as a "marriage broker" to enhance opportunities for California firms. Current activities include a schedule to meet a goal of $1.2 billion of new international export sales by California firms in 1990.

INTRODUCTION

Thank you for inviting me to participate in this NGA/GRC Roundtable at DOE's Program Review on California's world trade activities.

In my comments today, I would like to emphasize a few points to address the California Energy Commission's role in international trade.

A. We have designed a low-cost program which responds to a growing worldwide demand for energy technologies to stimulate economic expansion. It is not uncommon to see electricity demand in developing nations increasing at rates two to three times greater than the annual demand in the U.S. and California.

B. Governor Deukmejian has deemed it important to enhance international trade opportunities for two significant sectors of California's economy: agriculture and energy. In 1986 California's energy firms generated $69 billion, the highest revenue-producing sector in the state.

C. In most nations, energy development is controlled by government agencies. This differs from the U.S. which appears to be the exception, rather than the rule. In these other nations, when energy technologies and project development services are needed through imports, business is typically conducted or enhanced by government-to-government relations.

D. The California Energy Commission played an instrumental role in implementing the Public Utility Regulatory Policies Act of 1978 (PURPA), a federal law designed to encourage the use of indigenous energy sources and reduce our reliance on petroleum. The CEC provided assistance programs to stimulate the sale of electricity from private power producers to utilities. This led to standardized contracts between these parties and a profitable business climate for private investors.

E. The CEC has a highly trained and experienced staff of over 400 engineers, economists, and scientists. The staff has conducted a variety of programs including joint venture funding of energy projects, technical assistance, technology field tests, consumer protection, information and marketing, and energy policy development. For the past 13 years, staff activities have covered a multitude of technologies and energy resources and led to practical experience in the following areas:

- o Resource assessment
- o Energy project audits
- o Project design and planning
- o Technology development
- o Project construction, operation, and maintenance
- o Project financing
- o Power sales contracts

For these reasons, the Governor has directed the Energy Commission to conduct a specialized export program to supplement the efforts of the California World Trade Commission and Department of Commerce.

THE CEC'S ENERGY TECHNOLOGY EXPORT PROGRAM

Authority for the Energy Commission's Energy Technology Export Program is based on broad mandates to accelerate the development of the state's energy technologies (Public Resources Code 25601 and 25602) and evaluate energy development trends which impact the state (Public Resources Code 25604). In addition, year-to-year funding is appropriated through the budget act.

The CEC acts as a facilitator or "marriage broker" to match international buyers with

* References are at the end of the text.

California energy firms which supply technologies and energy project development experience. As a result, the CEC must be aware of the needs of each party and sensitive to a variety of business methods.

The Energy Commission's domestic programs continue to achieve international recognition for success in promoting the use of new energy technologies and are rich in staff experience. Many of the ingredients for success and pitfalls to avoid can be learned from our previous efforts and transferred to developing nations.

We were astounded that over 400 California-based firms expressed interest in the CEC's support to help export their energy technologies and energy-related services. This demand was greater than expected. An estimated 90 percent of these firms are small businesses.

Over the last two and a half years, the CEC has received delegations from 48 foreign countries who have expressed interest in energy technologies from California. The following is a list of international delegations the CEC has received since 1985:

Antigua	Italy
Argentina	Jamaica
Australia	Japan
Barbados	Jordan
Bolivia	Mali
Brazil	Malaysia
Canada	Mexico
Chile	Morocco
China	New Zealand
Costa Rica	Nigeria
Cyprus	Panama
Denmark	Philippines
Djibouti	St. Lucia
Dominican Republic	Spain
Ecuador	South Korea
England	Sweden
El Salvador	Sudan
Egypt	Taiwan
France	Tanzania
Greece	Thailand
Guatemala	Turkey
Hungary	Venezuela
India	West Germany
Indonesia	Yugoslavia

It is our observation that many of these nations do not have sophisticated electricity grid systems found in the U.S. Instead, power, if available, is delivered in a decentralized manner requiring special remote applications. Therefore, the CEC's original focus on solar photovoltaics, solar thermal, wind, geothermal, small hydroelectric, cogeneration, biomass, and conservation, has expanded to accommodate needs such as industrial uses, lighting, telecommunications, water pumping, refrigeration, and village or rural electrification.

CEC TRADE DEVELOPMENT PROGRAM ACTIVITIES

The CEC program has four main activities and is in the process of establishing a fifth. Each activity is designed to enhance trade between California energy companies and foreign partners. Program success is measured by export sales and improving the competitive position of California firms in the international marketplace. The CEC's facilitator or "marriage broker" role includes the following activities:

1. Government-to-Government Contacts

   As mentioned previously, the CEC has received delegations from over 50 countries. The CEC also hosted an international roundtable comprised of representatives from 25 nations in 1985. This type of activity has been effective in starting dialogue leading to serious interest by other nations in exploring options for energy projects. Many of these countries see the CEC as an objective source of information to obtain reliable data and as a point of contact to meet California firms.

2. Buyer/Seller Forums

   The CEC has completed market studies of international energy project opportunities for eight technologies: geothermal, wind, cogeneration, biomass, small hydropower, solar thermal, photovoltaics, and energy conservation. Additional work will be completed in 1988 on coal technologies, methanol, and synthetic fuels. As a result of these studies and information gathered from overseas trips, the CEC has developed plans for 15 target market countries including the People's Republic of China, the Philippines, Thailand, Indonesia, Pakistan, and India. An implementation strategy involves setting up a number of forums and events for California energy companies to meet selected government and industry officials from these countries. These buyer/ seller forums can be defined as trade missions, reverse trade missions, and technical exchange missions.

   A. Trade Missions

      The CEC is sponsoring trade missions to the Philippines, Indonesia, Thailand, the People's Republic of China, and Latin America in 1988. These are now in the planning stage and will involve about 20 private companies on each. The technology areas determined to be most promising in terms of near-term specific projects are conservation, cogeneration, geothermal, and mini-hydro.

      The CEC will conduct advance trips to identify project opportunities, arrange the trade missions, set up appointments for California companies, and conduct seminar/workshops as part of the missions. The purpose of these activities is to (1) acquaint the foreign government and private sector of the host nation with the technology, financing, and success of the California CEC/private sector cooperation and (2) most importantly, introduce California suppliers, developers, and engineering firms to the host nation's potential private sector clients and government projects. California firms are willing to provide turnkey projects through various ventures such as "Build-Operate-Transfer" and "Build-Own-Operate". The CEC will also identify and help seek appropriate financing for major conventional power plant projects.

B. Multi-Nation Reverse Trade Missions

The CEC co-sponsored a reverse trade mission in October 1987 by bringing geothermal technology experts from 18 nations for a two-week tour of geothermal projects throughout the state and meetings with over 60 California-based equipment vendors. Purchase orders for approximately $500,000 were placed during the trip or within three months thereafter. The CEC is helping additional firms to complete negotiations for small-scale geothermal power plant purchases valued at $13 million. The CEC is planning to duplicate this type of activity with a specific focus on single technologies (i.e., wind and cogeneration) or to cover several technology needs of a delegation from a regional area (i.e., Southeast Asia, Central America, the Middle East).

The planning steps were taken by the CEC to conduct the Geothermal Tour/Reverse Trade Mission in October 1987:

1) Met with representatives of the geothermal industry trade group to discuss the trade mission concept and determine industry commitment. (February 1987)

2) Identified sources of funding and propose a co-sponsored effort with the U.S. Department of Energy, the World Bank, the U.S. Agency for International Development, Los Alamos National Laboratory, and the California Energy Commission. (February 1987-April 1987)

3) Conferred with representatives of geothermal companies to select country invitees by considering their geothermal resource conditions (temperature and flow rates), status of project development, and level of technical expertise and influence over decision-making. (March 1987)

4) Sent invitations to foreign government representatives and inquire about specific geothermal energy needs and prospects. Gather information on foreigner's requests about technology applications, equipment specifications, reservoir drilling, and resource assessment. (April 1987-June 1987)

5) Conducted pre-tour meetings with equipment vendors, power plant operators, and operation and maintenance specialists to express foreign visitors' needs and conduct "dry runs" of tour events and presentations. (June 1987-August 1987)

6) Confirmed final tour logistics, develop briefing materials and technology fact sheets, and organize content and speakers for post-tour workshops. (August 1987)

7) Distributed tour advertisements, press releases, and organize social receptions. (September 1987)

8) Conducted tour, business meetings, and workshops involving representatives from 18 countries and 60 California equipment vendors. (October 1987).

9) Organized follow-up activities, correspondence, questionnaires, and complete post-tour report. (November 1987)

10) Completed three-month follow-up and discovered that: six U.S. firms were being considered for $1.1 million purchase of well completion equipment; $100,000 sale was completed during the tour; $100,000 was ordered and was working on $250,000 to $300,000 for delivery within one year; and, one delegate's government is currently negotiating a $13 million purchase.

11) Produced a 35-minute commemorative videotape of the mission which will be shown today during the Honorable Barbara Crowley's luncheon presentation. This video is presented for your review and comments. The CEC expects to deliver the videotapes to the tour participants in mid-June.

In answer to this morning's Special Issues Session question on whether we will do this again, probably yes, providing that the industry supports another proposal. The CEC will organize the California participants, provide a lead role in identifying specific international invitees, seek co-sponsors, plan project site visits and technology yard demonstrations, arrange travel and lodging logistics, escort the international delegations, set up workshops, and present information briefings. Anticipated co-sponsors include individual firms, industry trade organizations, utilities, federal agencies (i.e., USDOE, USAID), and international organizations such as the World Bank and Asian Development.

C. Technical Exchange Missions

The CEC has conducted two technical exchange missions, which are similar to a reverse trade mission, but focused on the needs of a single country.

In February 1988 the CEC met with the Executive Secretary and senior managers of Costa Rica's national utility, Instituto Costarricense de Electricidad (ICE). A joint agreement between the CEC and ICE was approved to help the Costa Rican's develop hydropower, geothermal, biomass, and wind projects, with initial work valued at $15.9 million.

In February 1987, the CEC initiated a technical exchange with the Royal Hashemite Kingdom of Jordan by organizing project site tours and in-depth business discussions with several California energy companies. This activity led to a prototype "friendship agreement" between the CEC and two Jordanian organizations, the government's Energy Ministry, and the Royal Scientific Society. The agreement states intentions on information sharing and joint activities to help Jordan develop windfarms, photovoltaic projects, and tar sand development estimated to cost $7.5 million.

The CEC will arrange the technical exchange mission logistics, organize project tours and technology briefings, and set up meetings with California firms. The CEC anticipates near-term technical exchange missions will occur with organizations in the Philippines, the People's Republic of China, Morocco, and Mexico.

This has been a very successful trade technique because foreign visitors can get a firsthand look at the diverse range of technologies and technical skills available. This method is also effective in determining the potential value and interest of conducting California industry trade mission back to the visiting nation.

3. Business Assistance to California Industry

The CEC provides advisory services to specific companies which have requested help for their export ventures. Seventy California-based firms have responded to this CEC project. The assistance is tailored to the needs of each specific firm and is provided by CEC staff and contract consultants. In appropriate instances, the CEC will seek the counsel of federal agencies such as the U.S. Department of Commerce and U.S. State Department.

Assistance is offered to identify project opportunities, develop international marketing plans, evaluate financing options and arrange financing, address trade laws and regulations, and provide advice for product shipping and transport.

The CEC will offer guidance to evaluate financing options offered by U.S. commercial banks, international donor organizations, foreign banks, federal agencies, California government programs, and other sources. Several financing methods will be considered such as direct export contracts, joint ventures, countertrade, equity financing, in-country sales offices, licensing agreements, and tax-advantaged sales.

Advice on suitable methods to complete the mechanics of transactions will be provided to the energy firms. Procedures such as packing, documentation, purchase orders, shipping, quotas, port charges, insurance, tariffs, and payment collection will be addressed to guide California businesses.

4. Information Transfer

The CEC offers a wide variety of information services to enhance mutually beneficial trade opportunities for California's energy technology exporters and foreign partners. Information transfer includes:

A. Energy Technology Publications

The CEC has published a series of documents highlighting international market prospects for the use of eight energy technologies, as previously mentioned. This series also focuses on specific energy project opportunities in 15 nations. Additional publications provide California exporters with energy-related information on sources of government assistance, overseas competitors, and case studies of successful U.S. export ventures. The CEC also publishes a directory of California-based energy companies for international distribution.
The CEC also has in stock current information on technology status and energy policy trends in California.

B. Surveys of California's Energy Industry

The CEC has conducted two industry surveys to identify over 400 energy technology firms interested in exports to the international marketplace, and obtain projections for the sales potential in these markets. An annual industry survey is planned as an ongoing program activity.

The CEC has developed company profiles and gathered information on equipment performance, technology and service offered, and cost and price data. This type of information is valuable to international buyers. As of March 1988, Governor Deukmejian's overseas trade offices in London and Tokyo have a complete file for in-country inquiries.

C. Project Financing Sources

As information becomes known about project financing techniques used, the CEC will document the steps taken and results. The CEC plans to develop a financial primer and pass this information to interested parties.

D. Trade Lead System

The CEC has established a computer database to help introduce California-based energy firms to international partners. This will also provide a business and consultant referral system when the system is fully operable. The CEC anticipates linking this network initially to California's overseas offices in London, Tokyo, and Mexico City and possibly U.S. Embassies.

E. Trade Events Calendar

The CEC has produced a calendar of international trade events focused primarily on energy technology sales or energy-related issues. This calendar will be updated regularly and distributed to California's energy industry.

F. Promotional Materials

The CEC has developed several items in conjunction with California's energy industry to promote the technologies and services offered. This includes full-color brochures, photo displays, and exhibits featuring equipment in operation to depict the actual applications of lighting, water pumping, cooking, and refrigeration. In addition, the CEC has documented its geothermal reverse trade mission through a videotape. The CEC anticipates developing more materials, including a videotape featuring California's energy industry.

G. International Conferences and Workshops

The CEC organized an international roundtable in 1985 to give representatives from 25 nations a forum to discuss energy issues. The CEC has also continually co-sponsored an international energy conference (RETSIE/IPEC) held every year in California. The CEC has conducted several workshops to give information on export opportunities and hear about the successes and pitfalls experienced by California's energy technology exporters. The CEC will continue these activities frequently for the near future.

5. <u>Training</u>

The CEC is just beginning to establish the foundation for this newest element of the export program. The CEC will soon complete a plan to organize an information and technical training center for international visitors. In addition, the CEC will develop a training curriculum to cover energy planning, equipment performance testing and monitoring, energy project evaluation and audits and financing options. Specific training will also be offered to address specific countries' needs but focused on project operation and maintenance. The CEC will set up a pilot project to test this training package with organizations from three countries, not yet selected. The CEC is well-suited to conduct this activity with over 400 technology and economic specialists. The CEC staff recognizes the advantages of exposing foreign energy planners and technicians to the planning, policy, and technical operations of California companies and CEC projects.

The more understanding of the California experience in "privitization" (private sector power development), the sooner it will be implemented in Asia. The more exposure to the technology and operation of commercial projects, the more likely that technology will be used in a widespread manner. Cross-training will occur as well and the CEC and California companies will learn from their foreign visitors.

Besides providing its own training, the CEC will seek to coordinate training activities with private firms, universities and federal agencies such as the U.S. Agency for International Development (USAID). The CEC can act as a liaison for the combined efforts.

CEC ACCOMPLISHMENTS TO DATE

The CEC has established a firm program foundation to address the export needs for over 400 California energy companies covering a wide array of technologies. In addition, the CEC has completed target market activities to focus efforts on 13 developing nations. Since December 1987, 72 California-based firms have received some form of assistance or have requested help from the CEC. A reverse trade mission was conducted in October 1987 to introduce representatives of 18 countries to 60 geothermal companies. Equipment sales of $500,000 occurred within three months after the tour and an additional $13 million in powerplant sales is under negotiation. Technical exchange missions with Jordan and Costa Rica occurred in 1986 and 1987 which are expected to result in $24 million in potential export transactions for California firms. The CEC's overseas advance work indicates that energy projects valued at over $2 billion in sales is suited to the capabilities of California-based companies.

CEC PROGRAM FUNDING

The CEC program is in its third year of authorization. The contract funding is at a baseline level of approximately $250,000 per year and in-kind staff services valued at about the same amount. The contract funding history includes:

- FY 1985-86 $190,000
- FY 1986-87 $425,000
- FY 1987-88 $225,000
- FY 1988-89 $250,000 (Proposed)

The CEC effort in FY 1985-86 included information gathering on California companies and international market prospects for several energy technologies. The subsequent funding has been aimed at activities to stimulate export sales. The current focus of overseas activities is on the Philippines, Thailand, Indonesia, the People's Republic of China, Costa Rica, Mexico, and Jordan.

The CEC will also address the need for project financing by exploring a combination of private and government sources of funds for loans up to $500,000,000 per year.

REFERENCES

Tim Olson is the initiator and director of the California Energy Commission's (CEC) Energy Technologies Export Program, designed to assist California firms to export their energy technologies and services to the international marketplace. Under his direction, the CEC has organized trade missions, business assistance activities, technical exchange and training programs, and technology transfer for over 400 California-based firms to 13 nations. He has worked at the CEC for 10 years with experience managing project development, financing activities, and energy project marketing for a wide array of technologies.

Linda Joy DeBoard is an International Trade Specialist at the CEC.

Excerpts from testimony by Barbara Crowley, Vice Chair, California Energy Commission, presented to the Assembly Committee on International Trade and Intergovernmental Relations, Interim Hearing, November 4, 1987, Los Angeles, California. Commissioner Crowley developed the trade proposal which was adopted by Governor Deukmejian in the 1985-86 State Budget.

CLOSING REMARKS

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CLOSING REMARKS

Ronald R. Loose, Director
Office of Renewable Energy Technologies
U.S. Department of Energy

We came to Program Review VI to consider geothermal research and development objectives -- specific, time-marked, quantitative targets for geothermal technology improvement that will permit industry to reduce the cost of geothermal power. As Dr. Mock described Program Review VI in his opening remarks, these sessions were designed as a coordinated programmatic and management review of ongoing and planned research within the context of the Geothermal Technology Division's (GTD) programmatic objectives. In order to facilitate these discussions, each person making a presentation was asked to address the following points:

- the specific stated R&D objectives in his/her topic area
- the probabilities of meeting the stated objectives
- the link between successful completion of these objectives and the overall GTD objectives
- the potential value of R&D results to industry needs
- the explicit strategy for transfer of research results to industry.

I hope the discussions on these topics -- both here in the meeting room and elsewhere -- will give us a new sense of purpose in geothermal research and development. We have recognized the importance of these discussions in light of shifting national priorities and changing Federal budgets. We have confronted the need to use the objectives, once they are finalized, as the driving force of the GTD program.

Since management by objectives is not a new programmatic mode at GTD, some of you may be asking what is different now. The major difference is that we have the ability to quantify the estimated impact of our objectives on the cost to industry to produce geothermal power. Until recently, our analysis of technology performance, a critical step in determining objectives, was largely an "order of magnitude" exercise, necessitating some degree of subjective judgment on the part of decision-makers. Our approach could have been characterized as reactive, in which we based our objectives more on reducing or responding to the negative impact of deterrents to increased geothermal power development. From the perspective of the achievements that have resulted from this approach, I will say that it has worked very well due to the efforts of DOE geothermal managers, industry, the national laboratories, operations offices, and others that provided the knowledgeable input. But such an approach is not sufficient in today's environment.

Now, it is time for us to take advantage of more sophisticated planning tools and to look ahead to accomplishments that can accrue from objectives based on positive estimates of their impact on the cost of power down to the cents per kilowatt hour level. With this calculated data available, we can maximize the relative potential impacts through adopting appropriate objectives, wise resource management, and strict monitoring of R&D activities with little or no room for discretionary practices that do not demonstrably support one or more objectives.

The Division's ability to quantify the effects of its performance should enhance industry's ability to judge the usefulness of achieving the objectives as they are presently proposed. Quantified objectives offer targets to which industry can address its views reflecting the "real world" as industry experiences it. We strongly urge industry representatives to communicate with us in the coming weeks and help us make the objectives as realistic and viable as possible.

We also want to hear the extended views of those of you in the audience from the operations offices, national laboratories, and participating universities once you have had the opportunity to reflect on the discussions here and interchange with your colleagues at home. Once the objectives are finalized, DOE intends to make them available to all interested parties.

This does not mean, however, that the objectives that express a consensus now will remain forever static, or static even until the designated target date, in come cases. Some areas of research may have to be abandoned if they prove unsuccessful; others may take their place if they have a better chance of reducing the cost of power. It is incumbent on all of us to be more vigilant than perhaps we have been in the past to recognize when change in direction is indicated -- to monitor and evaluate research results in the context of their impact on objective accomplishment. Simplistically put, you might say, now that milestones "X" and "Y" have been achieved, do their results assure the achievement of milestone "Z?" Or, do they indicate that milestone "Z" is no longer a viable milestone, or, even if it can be accomplished, will it result in achievement of the relevant objective? If the indications are that it will not, that is when we need to hear your proposals for research modification.

We have proved that we can meet ambitious objectives. For example, the economic use today of the "worst case" brines at the Salton Sea for power generation derives from the cooperative effort at the Geothermal Loop Experimental Facility at Niland, the site of which is occupied by a commercial plant today. All sectors of the geothermal community -- many of you in this room-- participated in that effort. Another major example of objective achievement is the result of the Industry-Coupled Cost-Shared Reservoir Exploration Program. The objective was to accelerate geothermal development by stimulating industry efforts through cost-sharing, and thereby, risk-sharing. Today, 8 of the 14 fields initially investigated are under development by industry.

I trust that by the mid-1990's we will be looking back with pride at the successful achievements of the objectives we are setting for ourselves now -- more economic use of the reservoirs currently under development; the potential to extend economic hydrothermal development to additional reservoirs; and geopressured and hot dry rock performance that competes in cost with other fuels.

To make these things happen, only those programs that are consistent with the finalized objectives can be continued under the funding levels of today -- and expected tomorrow. That is the message of Program Review VI.

It was a pleasure as always to spend time with this group of both old and new associates in the geothermal field. I thank you all for your interest and participation, and look forward to your continued help and support.

FINAL AGENDA

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U.S. Department of Energy
Geothermal Program Review VI

"Beyond Goals and Objectives"

April 19-21, 1988

Travelodge at the Wharf
San Francisco, CA

AGENDA

April 19, Tuesday

SESSION I

Overview:

8:00	Registration	
9:00	Greeting	John E. "Ted" Mock, Director, Geothermal Technology Division, U.S. Department of Energy, Washington, D.C.
9:05	Welcome	Thomas Heenan, Assistant Manager, Energy Programs, San Francisco Operations Office, U.S. Department of Energy
9:15	Opening Remarks - Renewable Energy Contribution to the National Energy Future	Robert San Martin, Deputy Assistant Secretary, Renewable Energy, U.S. Department of Energy, Washington, D.C.
9:30	Keynote Address - Industry Perspective on the Federal Geothermal R&D Program	James B. Combs, President, Geothermal Resources International, Inc.
10:00	Coffee Break	
10:30	Introduction to Theme - **Beyond Goals and Objectives**	John E. "Ted" Mock, Director, Geothermal Technology Division, U.S. Department of Energy
11:00	Regional Aspects of Geothermal Energy Development	Martha Dixon, Director, Conservation and Renewable Energy Division, San Francisco Operations Office, U.S. Department of Energy
11:30	Lunch (no host)	

April 19, Tuesday

SESSION II

Hydrothermal Research Program Objectives:

Chairperson: Susan Prestwich, Geothermal Program Manager, Idaho Operations Office, U.S. Department of Energy

1:10	Increasing Reservoir Confirmation and Well Siting Confidence through Hydrothermal Earth Science Research	Dennis L. Nielson and Phillip M. Wright, University of Utah Research Institute
1:40	Reducing Long-Term Reservoir Performance Uncertainty	Marcelo Lippmann, Lawrence Berkeley Laboratory
2:10	Understanding Geothermal Reservoir Dynamics	Roland Horne, Stanford University
2:40	Geophysical Measurement of Geothermal Fluid Production and Injection	Paul Kasameyer, Lawrence Livermore National Laboratory
3:10	Coffee Break	
3:30	Optimizing Reservoir Management through Fracture Modeling	Joel Renner, Idaho National Engineering Laboratory
4:00	Decreasing Energy Conversion Costs with Advanced Materials	Lawrence Kukacka, Brookhaven National Laboratory
4:30	Biological Solutions to Waste Management	Eugene Premuzic, Brookhaven National Laboratory
5:00	The Prediction of Chemical Sealing in Geothermal Power Operations	John Weare, University of California at San Diego
5:30	Adjourn	

April 20, Wednesday

SESSION II (Continued)

Hydrothermal Research Program Objectives:

Chairperson: Susan Prestwich, Geothermal Program Manager, Idaho Operations Office, U.S. Department of Energy

8:30	Monitoring the Materials and Chemistry of a Geothermal Plant	Donald Shannon, Pacific Northwest Laboratory
9:00	Improving the Efficiency of Binary Cycles	Gregory Mines, Idaho National Engineering Laboratory
9:30	Reducing Drilling and Completion Costs -- Hard Rock Penetration Research	James Dunn, Sandia National Laboratories
10:00	Coffee Break	

April 20, Wednesday

SESSION III

Geopressured-Geothermal Research Program Objectives:

Chairperson: Susan Prestwich, Geothermal Program Manager, Idaho Operations Office, U.S. Department of Energy

10:20	Research to Understand and Predict Geopressured Reservoir Characteristics with Confidence	Susan Stiger, Idaho National Engineering Laboratory
10:50	Potential for Utilizing the Geopressured-Geothermal Resource	C.R. Featherston, Eaton Operating Co., Inc.
11:20	DOE/EPRI Hybrid Power System	Susan Stiger, Idaho National Engineering Laboratory
11:50	Lunch (no host)	

SESSION IV

Hot Dry Rock Research Program Objectives:

Chairperson: George P. Tennyson, Jr., Program Manager, Geothermal, Wind Energy and Superconductivity Programs, Albuquerque Operations Office, U.S. Department of Energy

1:10	Hot Dry Rock Fracture Propagation and Reservoir Characterization	Hugh Murphy, Los Alamos National Laboratory
1:40	Prospects for Hot Dry Rock in the Future	Michael Berger, Los Alamos National Laboratory
2:10	Drilling and Completion at Fenton Hill	Hugh Murphy, Los Alamos National Laboratory
2:40	Hot Dry Rock Venture Risks Assessment	Frank Cockrane, Bechtel National, Inc.
3:10	Coffee Break	

SESSION V

Magma Energy Research Program Objectives:

Chairperson: George P. Tennyson, Jr., Program Manager, Geothermal, Wind Energy and Superconductivity Programs, Albuquerque Operations Office, U.S. Department of Energy

3:30	Research to Tap the Crustal Magma Source	James Dunn, Sandia National Laboratories
4:00	Recent Advances in Magma Energy Extraction	T.Y. Chu, Sandia National Laboratories
4:30	Drilling Program for Long Valley Caldera	John Finger, Sandia National Laboratories
5:00	Adjourn	
5:00	DOE/GTD Management Review (Executive Session)	

NGA-Sponsored Industry Round Table

(The National Geothermal Association will hold an Industry Round Table Discussion in the same hotel. Program Review VI registrants are invited to attend and participate.)

April 21, Thursday

8:30	National Geothermal Association Program Lanier Lohn, President
8:45	Round Table Discussion on Government/Industry Partnership: Perspectives and Cooperation
	Coffee Break (as time permits)
12:00	NGA-Sponsored Luncheon: Commissioner Barbara Crowley, California Energy Commission

SESSION VI

Special Issues:

Moderator: Ralph Burr, Geothermal Technology Division, U.S. Department of Energy, Washington, D.C.

2:00	Quantifying the Cost-of-Power Impacts of Federal Geothermal R&D	Richard Traeger, Sandia National Laboratories, and Daniel Entingh, Meridian Corporation, Alexandria, Virginia
2:20	Government/Industry Cooperative Agreements -- National Academy of Sciences Recommendations	John E. Mock, Director, Geothermal Technology Division, U.S. Department of Energy, Washington, D.C.
2:40	Government-Industry Cooperation at Work: Example of the Geothermal Drilling Organization	James Dunn, Sandia National Laboratories
3:00	International Market Opportunities for Geothermal Companies	Linda Joy DeBoard, Energy Technology Export Program, California Energy Commission
3:20	Question and Answer Period	
4:00	Closing Remarks	Ronald Loose, Director, Office of Renewable Energy Technologies, U.S. Department of Energy, Washington, D.C.
4:15	Adjournment	

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April 19-21, 1988

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