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U.S. Department of Energy

GEOTHERMAL PROGRAM REVIEW XII

Geothermal Energy and the President's Climate Change Action Plan

April 25-28, 1994
San Francisco, California

Sponsored by:
U.S. Department of Energy
Assistant Secretary,
Energy Efficiency and Renewable Energy
Geothermal Division

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Preface

Geothermal Program Review XII, sponsored by the Geothermal Division of U.S. Department of Energy, was held April 25-28, 1994, in San Francisco, California. This annual conference is designed to promote effective technology transfer by bringing together DOE-sponsored researchers; utility representatives; geothermal energy developers; suppliers of geothermal goods and services; representatives from federal, state, and local agencies; and others with an interest in geothermal energy. In-depth reviews of the latest technological advancements and research results are presented during the conference with emphasis on those topics considered to have the greatest potential to impact the near-term commercial development of geothermal energy.

The geothermal industry in 1994 is facing a number of challenges which are affecting the rate of growth of geothermal energy projects throughout the world, including the low cost of conventional sources of energy; the rapidly changing nature of the utility sector, particularly in the United States, but also in other developed and developing countries; and concerns about global climate change. Many of these issues were addressed by the speakers in the **Overview** session and discussed informally among the conference participants.

The relationship between the geothermal community and the government has continued to strengthen. We have established common goals and work cooperatively on problems which heretofore limited the development of geothermal resources. During the planning phase of Geothermal Program Review XII, we invited representatives from the geothermal industry to chair each of the technical sessions: **The Geysers, Exploration, Energy Conversion and Materials, Drilling,** and **Geothermal Heat Pumps**. The willingness of industry representatives to invest their time and play a role in this conference is further evidence of the strong industry interest in the DOE Geothermal Energy R&D Program.

This year's program included two special sessions, **Technology Transfer** and **Geothermal Opportunities**. The **Technology Transfer** session featured presentations of technologies that have been successfully demonstrated, but are not yet fully commercialized. New joint ventures and potential opportunities for industry were described in the **Geothermal Opportunities** session.

The conference concluded with an "**Industry Critique**" organized and conducted by the Geothermal Energy Association. This session offered the geothermal community an opportunity to comment on the DOE Geothermal Energy R&D Program and provided an excellent forum for in-depth discussions among all conference participants. The Geothermal Division regards these annual sessions as a vital part of the annual Geothermal Program Review and uses the input to develop outyear plans.

I wish to express my thanks to everyone who participated in and contributed to this year's successful Geothermal Program Review. Your continued involvement is vital for the future of the DOE Geothermal Energy R&D program and for furthering the growth of the geothermal industry. I also wish to convey my appreciation to Perle Dorr and others at Princeton Economic Research, Inc. and Meridian Corporation whose assistance and support in planning and implementing Geothermal Program Review XII helped ensure its success.

Ted Mock

John E. Mock, Director
Geothermal Division
Energy Efficiency and Renewable Energy

Session 1: Overview

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

The Role of Geothermal Energy in the Evolving Electric Utility Sector

Presented by:
Dr. Robert L. San Martin, Deputy Assistant Secretary
Office of Utility Technologies
U.S. Department of Energy

The operating environment of electric utilities has been evolving from generation-driven planning to an end-use focus. As a result, demand-side management (DSM) measures, consumer needs and wants, and the distributed utility concept are playing increasingly important roles. Geothermal energy, with its size flexibly in electricity generation units, along with geothermal heat pumps and direct use applications, has an opportunity to play a significant role in the utility markets of the future.

U.S. Energy Use

Electric and gas utilities currently account for almost 60 percent (47 out of 82.3 Quads) of U.S. primary energy flows. They deliver 64 percent of the energy used in industry and over 90 percent of the energy used in buildings. The utility sector is key to the Nation's economic future, environmental health, and national security.

Electricity and electrotechnologies can provide the keys to future environmental improvement and economic competitiveness in each of the three major end-use sectors: industry, buildings, and transportation. Industry's demand for electricity continues to grow as combustion-driven manufacturing processes are converted to more efficient electricity-based processes. In the buildings sector, the utility service industry will be markedly influenced by advances in electric and gas appliances, innovations such as smart-houses, modular environmental controls, advanced energy management systems, electrochromic glazings, and advanced information services based on fiber optics and satellite communications. In the transportation sector, electricity, electrotechnologies, and natural gas are promising options for reducing U.S. dependence on imported oil, and for mitigating transportation emissions -- one of our most intransigent environmental problems.

Managing the Nation's Electricity Needs

As electrification of the U.S. economy increases, it will become increasingly important for the utility industry to make the best use of its assets to deliver the greatest value to stakeholders. Enhanced energy efficiency and strategic conservation must be encouraged through DSM measures and by increasing utility asset utilization.

Various estimates of DSM's potential to meet projected new loads range from 24 percent to 75 percent of future demand growth. Without conservation and DSM, the demand for electricity could rise from approximately 10 quads to roughly 15 quads by the year 2010. With new policy options, DSM and conservation are projected to reduce this demand to about 13.7

quads. One of the most optimistic views of the role of DSM comes from the Rocky Mountain Institute which estimates that nearly 75 percent of demand could be met through efficiency improvements, while the Electric Power Research Institute (EPRI) estimates that the substitution of new efficient technologies could reduce total U.S. electricity demand by 24 percent to 44 percent by the year 2000.

The uncertainty in the performance of DSM is a key issue identified by the Office of Utility Technologies' (OUT's) Integrated Resource Planning program. However, there is no doubt that DSM will play a major role. As noted by the Pacific Gas and Electric Corporation (PG&E), DSM programs can contribute to deferring or avoiding substation upgrades and transmission line additions. In addition, advances in transmission and distribution control systems have already made direct management of many DSM measures possible, giving utilities the ability to dispatch DSM savings in the same way they dispatch generation.

Improving Asset Utilization Via the Distributed Utility System

The concept of the distributed utility system has evolved from the growing perception among electric and natural gas utilities that "smaller might be better." The idea is that applications of energy production, primarily electricity, which are closer to the end-use application might be more efficient from an overall energy and environmental perspective than central station plants with long-distance transmission and distribution requirements. The Distributed Utility Valuation Project, a cooperative effort of PG&E, EPRI, and the National Renewable Energy Laboratory (NREL), is a new initiative working to quantify the benefits of distributed applications and to define the market. The project is also evaluating the role of rapidly developing solar, wind, fuel cell, storage, and battery technologies in (i) enhancing the delivery of load management and efficiency programs, (ii) maximizing the use of the existing transmission and distribution infrastructure, and (iii) supplying a portion of a utility's power requirements. For example, PV applications in dispersed end-use applications can reduce utility demand and displace the need for transmission and distribution (T&D) system extensions in remote areas. During the past year, the Department of Energy has joined in cooperative efforts with seven U.S. manufacturers with a high potential for bringing photovoltaics into competitive markets. Dispersed applications of wind energy for voltage support and to displace T&D system extensions in remote areas is becoming a higher priority for utilities interested in the distributed utility approach to integrating all stages of production, delivery, and end-use options. As opportunities for dispersed generation and end-use applications of geothermal energy increase in the utility market, near-term commercial opportunities for modular binary power systems, geothermal heat pumps and direct-use applications such as combination generation/process heat systems will increase.

Geothermal Energy Technologies are Well-Suited for Distributed Applications

Most geothermal power plants, especially those installed during the last 10 years, fit well within the definition of a distributed utility application. As the trend continues toward smaller generating units, geothermal technologies will already have the systems designed, tested, and ready for installation in areas of the country where geothermal resources are adequate for electricity generation. Newer generation binary power systems are modular and come in increments as small a 0.5 MW. They can use geothermal fluids with temperatures as low as 100°C to generate electricity, creating the possibility of accessing lower temperature resources in areas of the country outside traditional geothermal areas on the U.S. west coast.

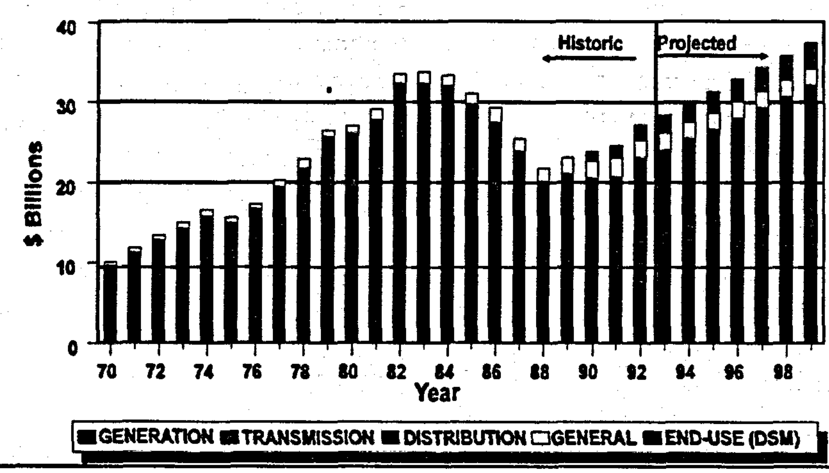
The distributed utility concept would also include many direct-use applications whose resources are also much more geographically dispersed than those of currently used resource areas. Geothermal direct-use has many diverse applications, from industrial heat processing, to agricultural and aquaculture, to space-heating. These applications are often economical and can result in noticeable energy savings. Two such examples are the San Bernardino district heating system in California which saves the municipality over $200,000 per year while creating 50 jobs, and the Susanville, California, district heating system which results in $90,000 savings per year. From an end-use perspective, geothermal heat pumps as a DSM option could result in residential energy savings of 35,000 MW annually and even greater commercial savings.

Electric Utilities Operating in a Changing Environment

Prior to the 1970s, the electric utility industry was characterized by low energy prices and increasing electrification of the nation -- improved economies of scale in generation was a major driver in how electric systems were planned and operated. In the 1970s, national energy security became a major emphasis as a result of the OPEC oil embargoes and substantial energy price increases. The nation began restructuring its energy sector under this new thrust. During the 1980s, the utility industry began complying with newly enacted major environmental legislation. Declining rates of demand growth and excess capacity drove up the price of electricity while PURPA opened the door to alternative generation sources. Now, in the 1990s, each of these factors is coming into play to increase competitiveness in energy markets. It is becoming clear that the energy picture will be framed by a multitude of factors that will affect these markets. Economic, environmental, and emerging energy issues will each have a role in this new model for the energy industry.

Electric utilities have responded to these new challenges by altering their planning strategies, resulting in a shift in utility capital expenditures. As shown in Figure 1, investor owned utilities' past capital expenditures were primarily directed towards production plant (generating facilities), while only about 25 percent of total capital was expended on transmission and distribution plant. This was primarily a result of completing power plant construction programs that were initiated in the 1970s and the high cost of nuclear plants which entered service during the 1980s. By 1992, investor owned electric utilities spent approximately $27 billion on capital equipment; however, over half was invested in transmission and distribution, general plant and DSM, rather than new generating facilities. It should be noted that since 1990, the amount of capacity built by non-utility companies just about equals that built by utilities. Thus, it is clear that investor owned utilities are going to have a high level of interest in T&D technologies as they continue to upgrade and expand their T&D systems to better serve their customers' needs. The utility industry will probably react to this development by intensifying efforts to maximize the use of existing transmission and distribution assets. The industry may also consider novel methods in which to serve customers more efficiently in providing new types of energy services since capital expenditures are projected to increase by over 40 percent to roughly $38 billion in 1998.

Figure 1
Capital Expenditures by Investor-Owned Electric Utilities



The environment in which the utility industry will operate in the future will be much different from the past. The old paradigm of planning generation, then determining transmission and distribution needs, is falling by the wayside. The utility of the future will have to turn its attention first to what the customer needs and wants. This new focus will increase interest in the technologies and planning perspectives related to distributed applications. Geothermal energy power plants are well suited for distributed applications by virtue of their dispersed, small, and modular plant designs. From an end-use perspective, direct use geothermal energy currently offers diverse and economic applications, while geothermal heat pumps offer the potential to offset generation requirements.

The opportunity for renewable energy technologies lies in an industry that thrives on providing the customer with energy services that span the range of end-use, distribution, transmission, and generation applications available today and in the future. To ensure that the services provided are relevant to the customer's needs, one must look beyond the utility's side of the meter.

Federal Energy Policy Issues

As the utility sector has evolved and responded to these various influences, OUT's programs, including the Geothermal Program, have also evolved. Additional factors that are helping to shape OUT's programs include the Energy Policy Act of 1992 (EPAct) and the Administration's Climate Change Action Plan (CCAP).

EPAct defines the energy aspects of U.S. international, commercial, regulatory and technology policies. It supports diversification of U.S. sources of energy and promotes more efficient energy use and transformation. Four major areas where EPAct will affect the utility sector are:

- Renewable energy R&D and demonstration, tax, and production incentives
- Energy efficiency standards and incentives
- Increased competition in power generation and transmission (exempt wholesale generators and transmission access)
- Integrated resource planning

The Climate Change Action Plan (CCAP) was released in October 1993. It represents a comprehensive plan to reduce greenhouse gas emissions in all major sectors of the economy to 1990 levels by the year 2000. In energy supply, CCAP actions affect four major areas:

- Renewable energy - including DOE/industry consortia for technology commercialization
- Electricity transmission and distribution - promulgation of efficiency standards for electric transformers/equipment
- Utility industry - *Climate Challenge* to reduce utility greenhouse gases and expand IRP assistance
- Natural gas - encourages use of natural gas and commercialization of efficient gas equipment.

Geothermal Program Activities

As depicted in Figure 2, DOE's existing Geothermal Program activities are being built upon and accentuated by the various initiatives contained in EPAct and the CCAP. The Geothermal Division's proposed FY95 programmatic activities can be divided into "Base Program" and "FY95 Budget Initiative" elements. These activities span the range of stages related to advanced technology development and can be divided into the five technology areas described below and shown in Figure 3:

- **Exploration** activities to discover new geothermal resources, characterize and confirm their potential for producing electricity or for direct-use applications.

  Objective by year 2005: discover 25 new resource areas, focusing especially in the Pacific Northwest

- **Drilling** activities related to those that occur during the exploration phase as well as during development of a power plant or direct-use application. Drilling also involves installation of GHPs and affects the life of geothermal power plants by ensuring availability of geothermal fluids.

  Objective by year 2005: reduce geothermal well drilling cost by 50 percent

Figure 2
Geothermal Program Activities
FY95 Utility Sector Proposed Budget $37.2M

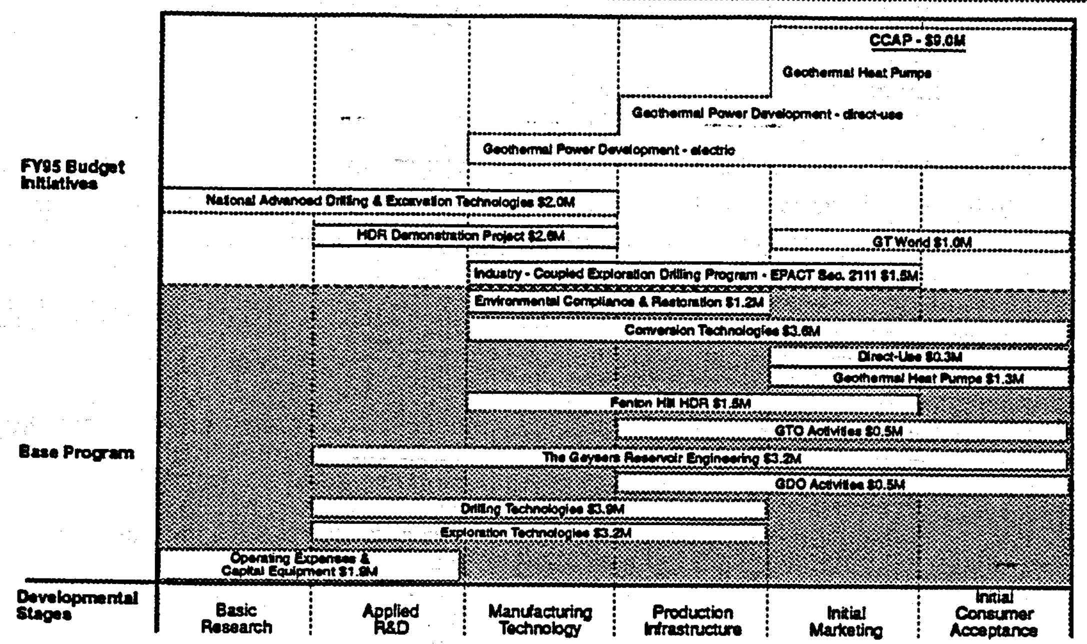
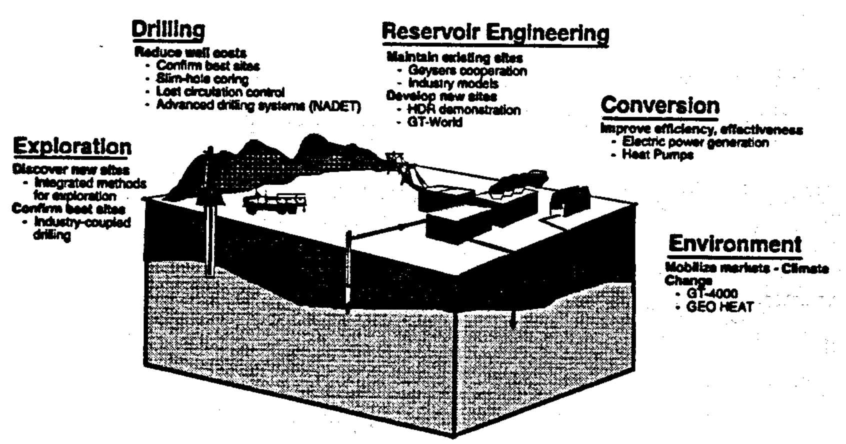


Figure 3
OUT's Geothermal Program Areas



- **Reservoir Engineering** involving the monitoring, evaluating and management of geothermal reservoirs to maximize production and minimize depletion of the geothermal fluids.

  Objective by year 2005: develop eight new reservoirs

- **Conversion** activities related to technologies dealing with conversion of geothermal energy to electricity and direct-uses (i.e., space conditioning or industrial processes and geothermal heat pumps.).

  Objective by year 2005: have 5,000 MWe on-line

- **Environment-related** activities associated with issues such as environmental compliance and national/international environmental goals such as those outlined in EPAct and CCAP.

  Objective by year 2005: reduce CO_2 emissions by 35 MMT

In moving towards accomplishing these objectives, OUT's Geothermal Program budget request, as shown in Figure 4, reflects a 55 percent increase in funding above FY94 levels. The bulk of the increase is in the exploration, drilling and environmental areas. The purpose of the additional funding is to respond to the most pressing issues for the geothermal industry through the turn of the century -- increasing reserves to meet projected increases in demand for geothermal power; reducing the costs associated with developing geothermal energy; and maintaining the high environmental standards that have characterized geothermal energy use when compared to other current sources of electricity generation.

Figure 4
Geothermal Program
Proposed FY95 Budget

($ in 1,000s)

Program Activity	FY 1994 Estimate	FY 1995 Request
Exploration	2,700	4,700
Drilling	3,400	6,400
Reservoir Technology	7,972	8,800
Conversion	7,000	5,200
Environment	1,000	10,177
Other	1,900	1,900
TOTAL	23,972	37,177

A 74 percent increase is requested in the exploration technology area to support increased cost-shared activities with industry, partly in response to EPAct section 2111. An important new activity will be an industry-coupled exploration program to discover new geothermal resources. An 88 percent increase in funding for the drilling technology area will be used to conduct cost-shared activities for developing, testing/evaluating drilling hardware and instrumentation, slim-hole drilling research, and seed money for the National Advanced Drilling and Excavation Technologies (NADET) initiative. An increase of funding from $1 million to $10 million in the environmental technology area will be used to fund two CCAP actions -- Geothermal Power Development and Geothermal Heat Pumps. The Geothermal Power Development action plan is designed to bring additional geothermal electric power generation and direct-use applications on-line within the next three years and to have a strong continuing effect in stimulating new power development into the next century. The Geothermal Heat Pump action plan is designed to reduce the barriers to wide-scale customer acceptance via an Edison Electric Institute/DOE consortium.

OUT's Geothermal Program Highlights

OUT's Geothermal Program activities focus on meeting the needs of the geothermal industry's stakeholders. Toward this end, the Geothermal Program has a number of proposed and ongoing collaborations with industry stakeholders in geothermal power generation.

- The Geothermal Drilling Organization (GDO), an industry-sponsored DOE program focused on improving drilling technology and accelerating the deployment of new drilling instrumentation and materials.

- The Geothermal Technology Organization (GTO), an industry-DOE collaboration focused on commercialization of non-drilling related technologies.

- OUT's Geothermal Division participates in numerous joint projects with industry to develop, test, and transfer technologies to increase the amount of currently available and accessible geothermal resources. These cost-shared activities make up over half of the program's current budget ($12.6M of $24M in FY94).

- A new industry-coupled exploration drilling program to confirm geothermal fields for commercial development as part of EPAct section 2111.

- A project proposed under CCAP to assist the construction of first power plants at new geothermal fields and to increase the efficiency of existing geothermal power plants.

A recent area of concentrated activities involves geothermal heat pumps (GHPs) which offer an attractive DSM alternative in space-heating. The Geothermal Division increased its commitment to GHPs by sponsoring a series of teleconferences last year, conducting research to improve drilling related to GHPs, and by planning additional GHP program activities. FY95 base program activities include a requested funding increase which more than triples FY94 levels. These funds will be used to develop a low-cost portable drilling system for GHP installation, complete a grouting materials study and design manual, and begin data acquisition and analysis for comparing GHPs to other utility DSM options. GHPs are included in the Geothermal Program's CCAP. The objectives are to improve cost competitiveness by developing innovative financing options, increase awareness of the GHP benefits and build consumer confidence, and strengthen the infrastructure through activities such as design assistance, training, marketing and regulatory actions.

Geothermal direct-use applications are found worldwide and provide a clean, low-cost option for reducing electricity demand. Currently, funding exists for providing technical assistance and technology transfer for geothermal direct-use projects in the United States. Because these applications are environmentally benign and offer demand reductions, the program's CCAP includes plans to reduce developers' risk in acquiring geothermal wells for direct-use projects and to start an outreach program to accelerate geothermal energy development.

Conclusion

Geothermal energy has a definite and unique role in the changing operating environment of the present and future electric utility sector. The Department of Energy's Geothermal Program aims to encourage the use of geothermal energy in all its forms -- in power generation especially with the environmentally benign modular binary systems, as a DSM measure with geothermal heat pumps, and in all types of direct-use applications. Federal policies and requested FY95 funding are designed to address and assist the geothermal industry's major concerns of increasing reserves, reducing costs, and maintaining its high environmental standards.

4000 BY 2000
DESIGNED GROWTH IN A COMPETITIVE MARKET

David W. Cox
California Energy Company

Thank you Ted, for both the introduction and the opportunity to speak with the industry this morning. My plan for this morning's discussion is really threefold. First is to quantify what we are all painfully aware of in terms of recent statistics. Second, I will give you my version of the crystal ball. And third, I will discuss how we as an industry can have some effect on the outcome of the future. All this in the next 25 minutes.

As many of you know, I spent most of my career in the banking and telecommunications business, just as deregulation was beginning to take hold and give birth to new industry structures. There are many similarities in telecommunications, banking, and energy although I will be the first to admit, they are far from identical. But we cannot ignore the process and learning curve they went through. I believe many geothermal and energy industry people have been too inwardly focused, and need to look at the larger picture that surrounds us.

I will begin with the quantification of 1993 numbers to lay a foundation for the rest of my discussion. Unfortunately, our industry has been caught in the middle of a much larger issue of deregulation of the energy industry. Last year, IPP results were pretty dismal by anyone's standards in terms of new power online, regardless of the technology and fuel source.

As you can see in Figure 1, it was not a banner year for IPP developers. Installed new capacity from independents in 1993 totaled approximately 2,800 MW. As is apparent, the trend has been downward for several years. Unfortunately, this trend gets worse for the next few years, not better.

Equally disturbing was the reversal in the percentage of the market share that IPP's had enjoyed in the last couple of years. As you can see in Figure 2, independents not only received far less megawatts in 1993, but also lost market share. Only 46% of new projects were built by independents in 1993. And of course, these numbers do not include repowerings, retrofits, etc., that the utilities accomplished on their own. Unfortunately, while we are a threat, in the big picture, the 51,000 MW of online IPP power generation is still a small blip on the total installed domestic capacity of over 2.5 trillion kWh. And also not surprising is the mix of the new capacity (Figure 3).

Natural gas was the predominant fuel of choice again in 1993, gathering 78% of the new online capacity. This trend has been relatively constant during the last few years. And as discussed later, despite the sharp decline of projects in total, natural gas accounts for over 70% of projected new capacity through the end of the decade. Speaking of projected capacity, 1993 also went into the record books with another disheartening historical first.

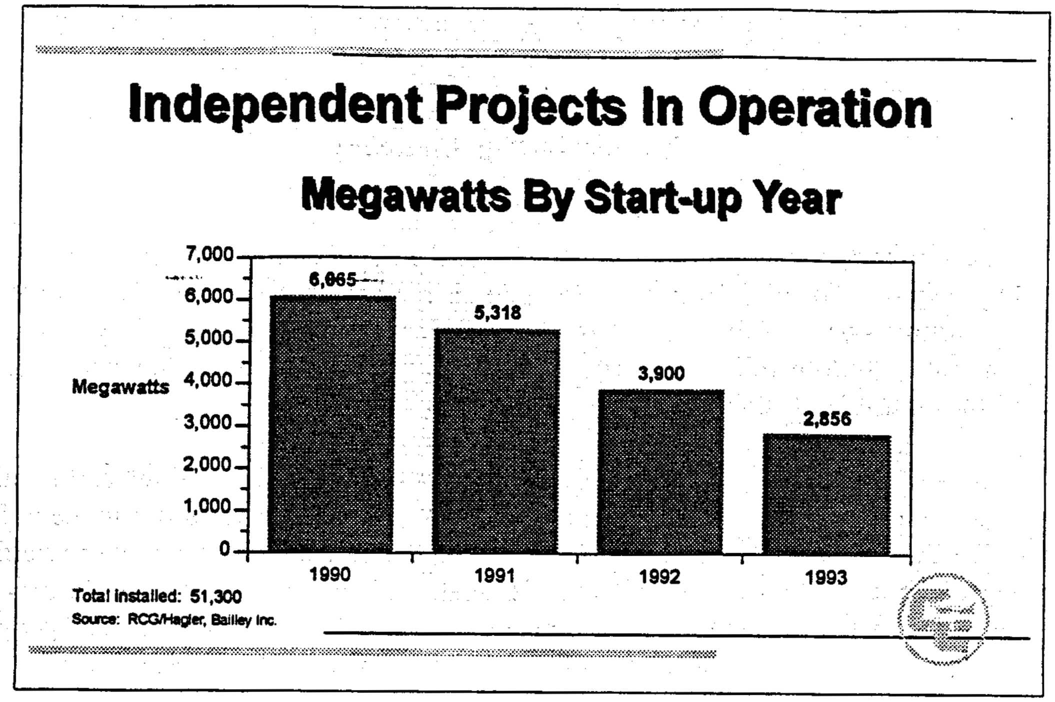


Figure 1

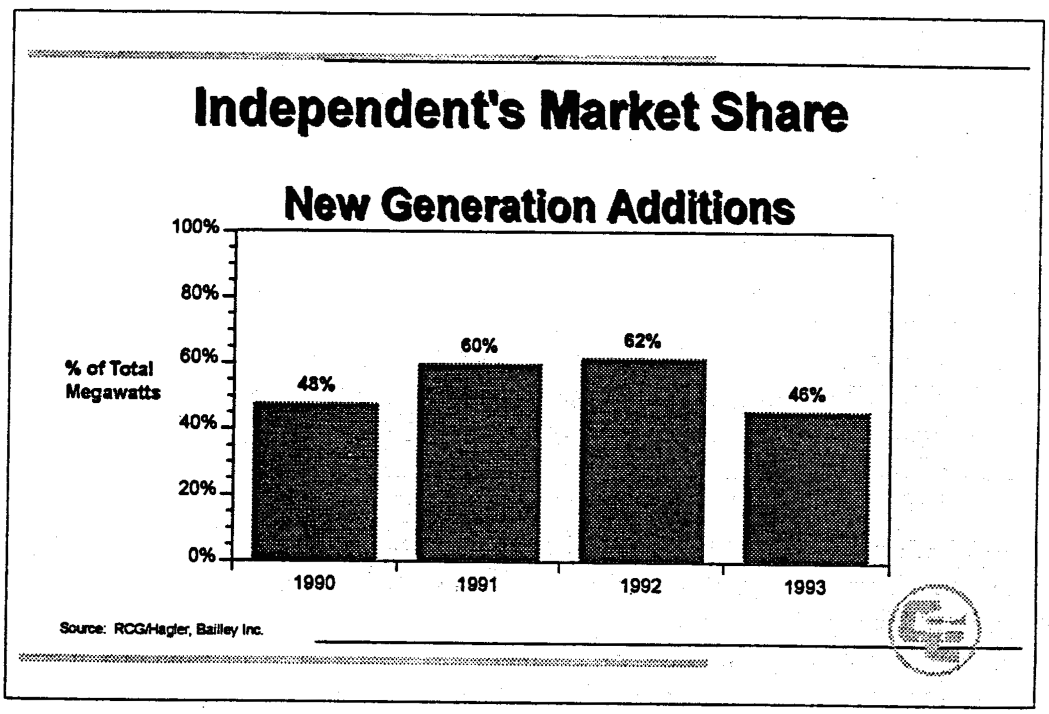


Figure 2

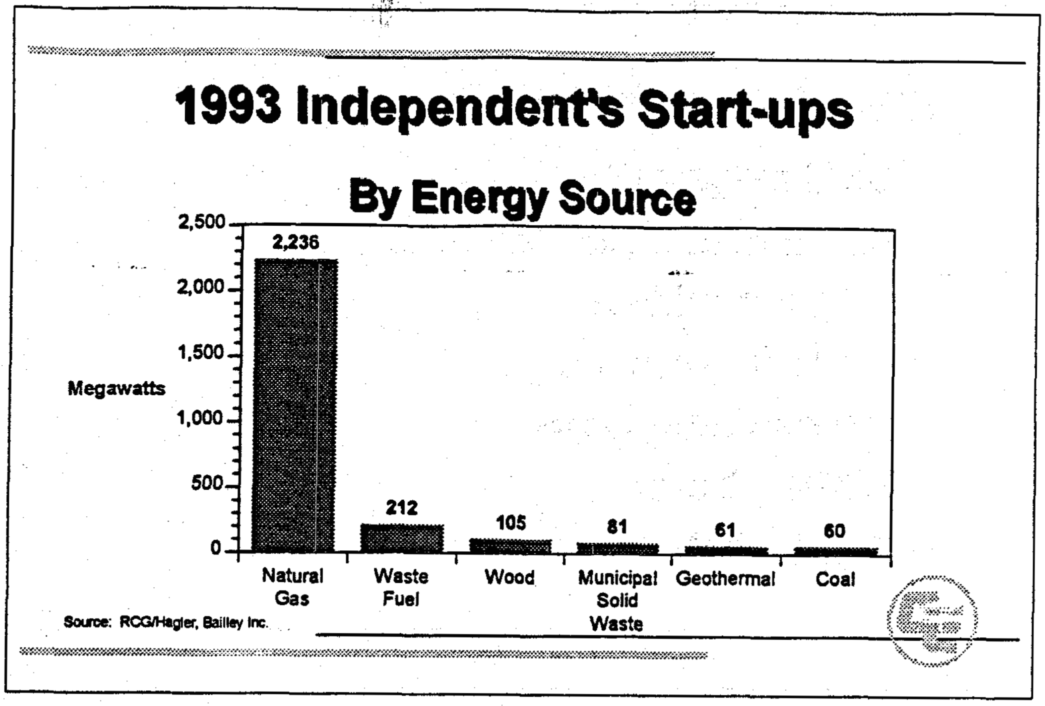


Figure 3

The real fact is that the utilities cancelled or bought out more contracts in 1993 than they awarded. Although the numbers vary according to which study you utilize, the overall percentages hold relatively constant. In fact, the ratio of cancellation to award was nearly 2:1, which has the effect of significantly reducing future projects coming online in the next few years. One analysis had tallied 44,000 MW of contracts cancelled in 1993. As expected, even the most optimistic energy pundits have scaled back their forecast of potential new demand through the end of the decade. The more recent studies I have seen include new numbers which show that, through the year 2000, estimates which used to be 100,000 to 200,000 MW have gone down to 40,000 to 80,000 MW. This does not paint a pretty picture. Again, this excludes projects such as repowering or sales of facilities by utilities, which in fact may be one of the larger markets in the next few years. There were several other miscellaneous trends that occurred in 1993 (Figure 4) that I thought might be of value in mentioning.

Although I view DSM as an opportunity later in my presentation, here I note it more as an obstacle. Last year, utilities spent over $3.2 billion on DSM. According to Integrated Resource Planning documents collected by one investment analyst, DSM equates for over one third of all utility demand through the end of the decade. Personally, I believe the DSM goals are highly political and unrealistic. Despite this, they have been accepted as credible, allowing many of the utilities the ability to cancel or postpone new bidding solicitations. This is not insignificant since each "negawatt" replaces new, potentially geothermal, generation.

1993 Domestic Trends

- DSM megawatts
- Demand in South Atlantic
- Larger facilities
- APP crossbreeding
- International focus
- FERC - State
- Dispatchability

Figure 4.

Also, despite our wishes in the geothermal world, through 1996 most of the forecasted new demand is located in the South Atlantic states, as has been the case for the last two years.

The plants last year were generally larger than in the recent past. Projects over 100 MW took 54% of the market in 1993, with those over 50 MW taking nearly 90%. This trend continues through 1996, then begins to grow exponentially as massive EWG's begin to come online.

The cross breeding by utilities of their unregulated subsidiaries, better known by the APP acronym, also accelerated during the year. The APP's began winning contracts outside their parents' service territory, but of course, in some cases they were barely outside the territory.

And 1993 was also the second year of phenomenal international growth, although by the end of the year, countries were maturing quickly and becoming smarter and more selective. They have found the competition so intense that it has not been difficult in many countries to turn what was a seller's market into a buyer's market.

Of course, no discussion would be complete without mentioning the face-off, or lack thereof, between federal and state efforts. Although the FERC has made a valid attempt to provide guidance with several issues such as RTG's, network services, etc., they are still well behind the market and technology curve. But, they are currently moving in the right direction. As James Hoecker has said, "they are embracing the competitive model." Most state commissions are currently so confused that they will avoid a decision with the electrical markets at any cost. Utilities, as prudent business people of course, have leveraged the uncertainty and fear to create one of the purest forms of gridlock I have ever seen.

The final aspect to discuss for last year was the switch to more dispatchable plants. In fact, as discussed in a few minutes, less than 25% of new generation needs for the next ten years are forecasted to be baseload. It is peak and intermediate that the utilities will be focusing on.

But enough of last year's statistics, let me discuss the crystal-ball aspect of what may happen in the next several years and then discuss how the industry should react.

My thoughts must be broken into two different phases or timeframes. As you can see in Figure 5, the first phase will probably last for the next two to three years and continue the stagnation we saw in 1993. The second phase begins around 1996 as "real" deregulatory impacts begin to take hold and the international market begins to slow down. Let's first discuss Phase I (Figure 6).

Having managed a large telecommunication division during the deregulation years in the 1980 timeframe, I can easily say that although the technologies are different, the long painful deregulatory processes have been almost identical. Unfortunately, the energy industry is only in the initial stage of the dismal effort which I call utility retrenching. After getting their first taste of competition, many utilities no longer like the idea and have found they are not adequately prepared. They now are fighting to eliminate a process they supported only a few years ago. Although they know it is inevitable, denial and chaos can buy them precious additional time to prepare and leverage the deregulatory process. The longer it is deferred, the longer they have for lobbying, reinvesting, etc. This is not bad. In fact, if I were working for an IOU, you'd better believe I would be doing the same thing. My guess is that this will continue for several more years.

Regulatory uncertainty is a key problem. Although FERC has recently moved quickly in terms of perhaps geologic time, the market is moving much faster. I suspect FERC will firm up some of the issues this year, but it will take a couple of additional years before they wind their way into actually being implemented, challenged in court, and finalized. There is also a lot of areas such as transmission issues that need to be resolved between the state PUC's and FERC. As you may know, although the Energy Policy Act of 1992 gave FERC greater powers, it also shifted immense responsibility to the state level, most of which can barely find their way home, let alone feel competent enough to understand and comprehend the complicated issues.

The second bullet of retail or wholesale wheeling is also a chic topic these days. Although utilities and some environmental groups have certainly tried to use this subject to advance their own causes, the reality is that it is already here, just using different names such as industrial incentive programs, economic incentives, etc. This focus on short-term spot markets is not positive for the geothermal industry, but we would be foolish indeed to follow our environmental brothers by ignoring the facts and simply chanting over and over that retail wheeling is a myth and will not happen.

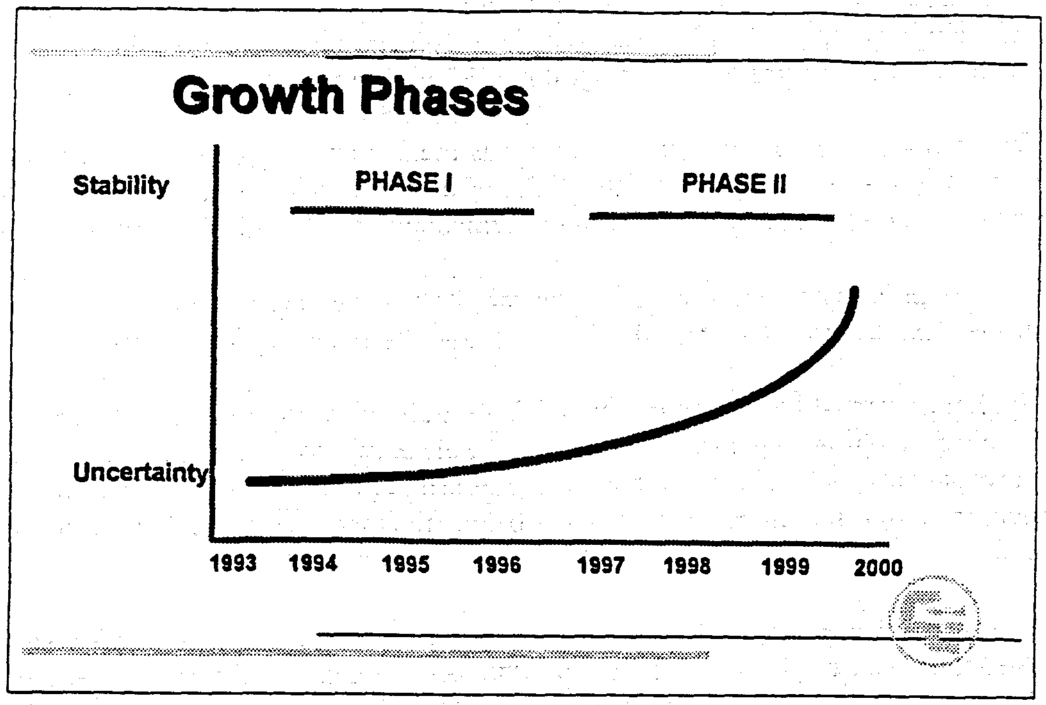


Figure 5

Phase 1 Issues

- Regulatory uncertainty
- Retail wheeling
- Financial markets
- Generation
- Demand

Figure 6

One good indication of retail competition occurring is the potential financial derivative products that are slated to open this fall and next year. These include a formal swap market, electricity futures market, and a spot market. While certainly old concepts, they are new for the electrical industry. Any and all of these are very similar to products offered in other deregulated markets and will likely accelerate the pace of change and confusion.

The generation market will, of course, be dominated by gas, and as mentioned previously, although demand for electricity went up approximately 5% in 1993, the demand for new generation did not. Most forecasts of demand in Phase I are around 1-3% per year.

The results of Phase I (Figure 7) vary depending upon the strategy and capability of the individual company. The results will be nothing new. Firms that have the strength will focus on the international markets where the industry has phenomenal growth. Many companies like California Energy, Magma, Unocal, etc., have already begun this effort and are now leveraging into other forms of energy production.

In the next couple of years, the domestic consolidations will continue and, in fact, may even accelerate given the weak market. In 1993, existing project sales for IPP's, more commonly called the secondary market, grew to over 10,000 MW and 70 facilities. That is, nearly one fifth of all IPP projects changed hands last year.

Partnering is a requirement, not an option. The key is to pick the partner for the right reasons. I am talking about long term partners or strategic partners, not project by project partners. Twenty to thirty years is a long time to suffer.

As previously mentioned, demand will be weak at best, and non-existent for all practical purposes. Gas will be the primary fuel and APP's will gather larger market share. I should also note that I do not believe gas will increase in the short-term, and feel this last winter proved that point. The only hope for a quick hit on gas may be the Canadian debate currently in process.

Phase II (Figure 8) is gradually more optimistic. Many aspects of the deregulatory process will have been worked out, and the gridlock hopefully will be breaking up. Of course, not all of the changes will have been beneficial for our industry.

Within the next three years, the gridlock and uncertainty should begin to diminish. A good example of this is last week's announcement by the CPUC. Although we may not agree with their plan, the end result is that it will add stabilization to the market. The key, however, is that we must begin positioning ourselves to lobby for what it is that we want in these types of forums. As I mentioned earlier, FERC, even if they issued a decision today on pricing, would take another year or two to wind through the civil court systems. In Phase II, the FERC versus State PUC's should be resolved and new FERC orders on transmission and pricing should be well defined.

Phase I Outcome

- Further domestic consolidation
- International focus
- Partnering
- Super NUGs
- No market demand
- Gas domination

Figure 7

Phase II 1997 - 2004

- Initial regulatory framework completed
- Demand strengthens
- Environmentals quantified
- Open competitive market
- Fossil fuel price escalation
- Super NUGs
- Technology integration

Figure 8

Demand should also pick up. Although, as utilities begin to abandon the generation business, their current 20% reserves will eat some new demand. Due to the slow down of new plants being built from 1993 to 1996, hopefully the current glut of supply will diminish. Another positive during this time period will be the realization that DSM and the billions of vaporwatts will, in fact, not disappear as promised.

Environmental externalities, if we as a renewable industry do a better job, hopefully will have quantified and proven the value of environmental benefits. Today, all the renewables are saying different things and, to the best of my knowledge, no one has done a good, theoretically accurate, agreed upon, quantitative study of environmental externalities. While several labs have published results, there is no uniform standard yet. As an industry that currently survives on our environmental benefits, I would believe this to be one of our highest priorities.

Originally I had planned to devote a large portion of my discussion today to the market place, but as of last week, the CPUC has already stolen most of the publicity. As I hope each of you are aware, the CPUC last week unveiled their plans for an open market by 1996, in which many retail and industrial users will be able to chose their power provider. The CPUC plan is long on rhetoric and short on substance, and the announcement is more for political gain in an election year than for any substantial progress. I think it is on target.

Hopefully, between the substantial increase in usage, and the greed factor, natural gas should begin to rise in the next several years. Although I do not believe, as many of my colleagues, that it will rise sufficiently to make geothermal cost competitive in a short-term environment.

Super NUG's. The firms with the resources and foresight to work overseas the next several years will certainly be positioned to return to the domestic market in the late 90's. CECI is a good example. As domestic utilities and IPP's continue to be inwardly focused on defending their own turf in the U.S., their growth will be limited. Financially, they will stagnate and their resources will turn from engineering to legal assistants working on deregulation. Firms like CECI, however, that can wrap contracts overseas will continue to build technical organizations, may surpass domestic firms in terms of construction and development experience, continue to build exceptionally strong balance sheets, learn the intricacies of project based financing, diversify their portfolio, expand into other technologies, etc. CECI, as an example, now has assets of over one billion and is as strong financially as many large domestic utilities.

Technology will also play a role. Currently, there is no technology on the horizon. Solar is still decades away, at least commercially, and fuel cells still have a long development road. The other aspect of technology that does not impact us directly is the integration of the retail business by the cable companies. As more and more interactive services are added to the cable system, it is clear that energy, similar to telecommunications, will be a service that could be provided through that medium. I am talking about the buying and selling of the kilowatts, not the production. At least one utility has seen the proverbial handwriting on the wall recently and is now asking for permission to diversify into the telecommunications field. As a consumer, I can't wait to buy or change my provider of electrical services, similar to the way I regularly change long distance companies, and to be able to do it while watching a 49er game.

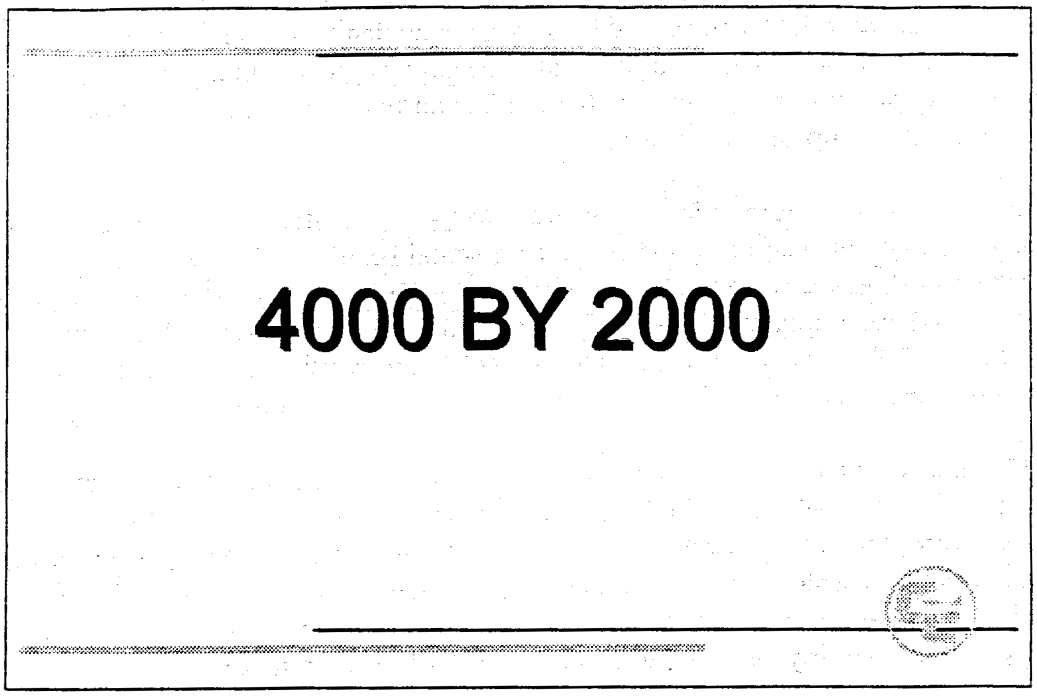


Figure 9

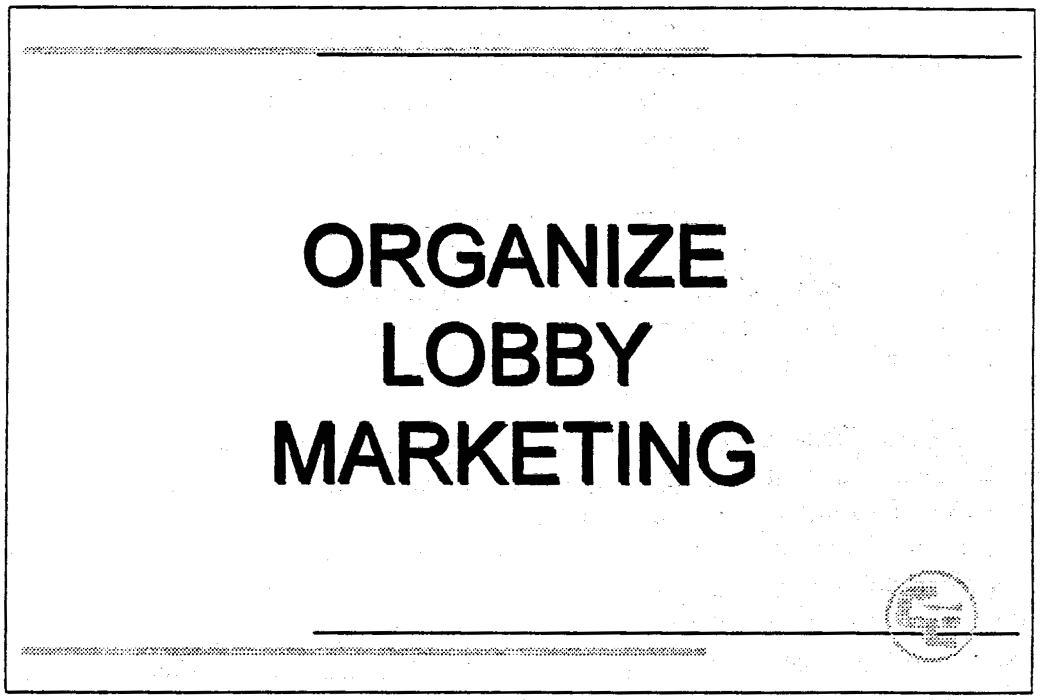


Figure 10

Now, let's talk about how our industry can survive and even flourish in the next 10 years: 4000 by 2000 (Figure 9). After what I have reviewed so far, is there hope? Well, obviously, I think there is. But we must be focused, realistic, and unrelenting in our quest for the elusive megawatts.

What can we do? Actually, during the next several years, it will be more of a task of setting a foundation than anything else. There are three key aspects (Figure 10) which we need to focus on in the next several years: organize, lobby, and market. While there are certainly more than these three, these are what I believe to be the keys for the next couple of years. Very simple concepts, but very difficult to implement.

The ability to act quickly and with one voice is extremely important (Figure 11). In the past, developers' goals differed from those of the labs, and those differed from many of the smaller suppliers. Each company or individual chased their own goals and said whatever they felt was necessary. Unfortunately, in today's environment, that strategy is worst than ineffective, it is deadly. We as an industry must decide whether we care to survive in the face of strong competition or simply to rest on our successful 2800 MW and hope the market comes begging us on their hands and knees for more.

Even a cursory look at the amazing success of either the solar or wind industry in promoting themselves and their products should motivate us to put aside the differences and reach a common goal. The industry may have had the power to be everything to everyone, but in today's environment, it simply isn't possible. As is apparent from the turnout today, the industry has consolidated. Our support groups must as well. The recent progress of the GEA in Washington is a good example. Exceptional progress and visibility have been made and now geothermal is usually part of the team, although we still sit the bench regularly.

Organize

- **One entity - one voice (GEA/GRC)**
- **Better coordination**
- **Broader membership**
- **Secure funding**
- **Develop goals**
- **Develop plans**
- **Lay foundation**

Figure 11

While this is good, we are a long way from getting set-asides, tax credits, funding, and the other benefits solar, wind, and gas receive. Hopefully, soon we will have a full time person and office in Washington dedicated only to promoting geothermal causes and visibility. But we must decide to work together in a united fashion with focused goals. When you go to Washington, or lobby in Nevada/California, attempt to communicate what it is you are doing. You may be surprised to discover that you have a lot of allies.

The third bullet of broader membership is a must. To be successful at being a renewable bully, we need allies. Bankers, lawyers, financiers, construction companies, engineers, etc., must all be a vital and vocal part of the industry. Look at other successful industries and you will find that they are vertically integrated in their efforts.

The funding effort has already gotten off to a good start thanks to the DOE support. But it will be incumbent upon us to continue and expand that effort.

Developing plans and goals, which are very different by the way, is imperative if we are to succeed. Hopefully, the GEA will have a set of draft goals in the next 30 days to review. Please make an effort to comment and help us.

Although probably no one in this room dislikes marketing and lobbying (Figure 12) more than I, it is not an option. For a clean, cost effective renewable product, we have a disgusting reputation. I am not saying it is deserved, but simply that it needs to be fixed. We must rectify The Geysers perceptions, the Hawaii blowout, the Crater Lake nightmare, among others. We have a wonderful product, and need to ensure others understand and fully appreciate it. Look at how little solar has commercially progressed in the last ten years, yet they have more funding and support in a week than we gather in a year.

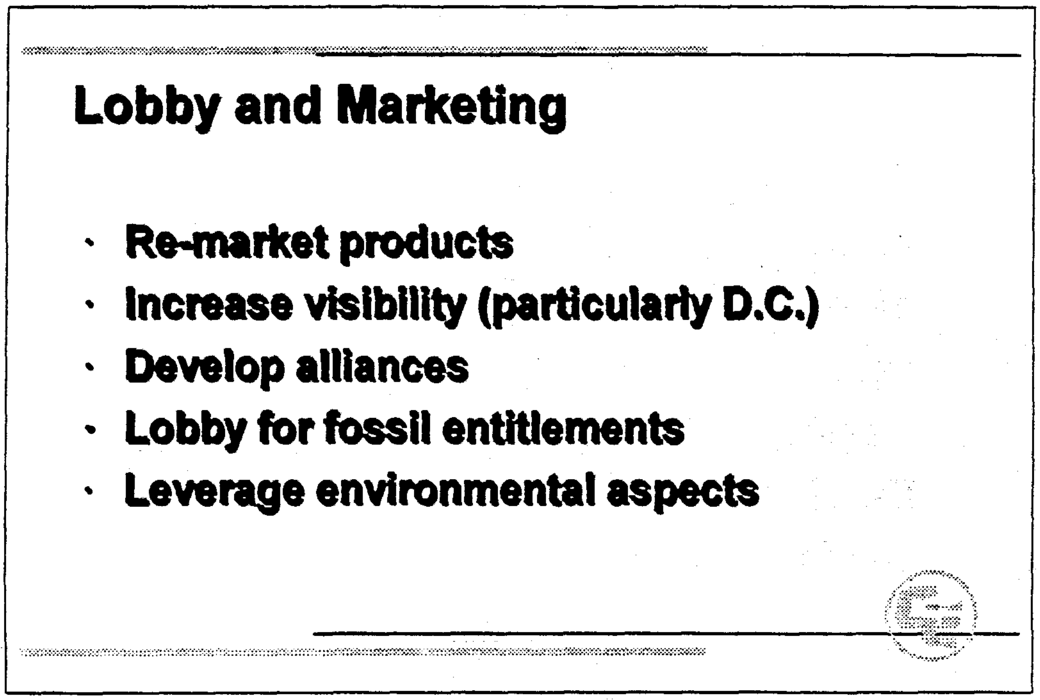


Figure 12

As I mentioned earlier, the GRA office in Washington has made good progress in the last 12 months, but now is the time to raise the hurdle another notch. We have begun to get the attention, now we need to expand and leverage that initial effort.

As a renewable in today's environment, we can not survive alone. Alliances with various factions must be repaired and strengthened. This includes the solar lobby, wind, other renewables, and particularly people within our own industry. Yes, Magma is my competitor, but when they win, the industry wins as well. It sure beats having a wind farm take the bid. Other allies we have not leveraged include entities such as the American Public Power Association, NARUC, EPRI, environmentalists, municipalities, etc.

And as to the last bullet, we have missed the boat on several beneficial issues of the past. The Global Climate issue is one of those that nearly passed us by that has tremendous political and financial gains for the industry. We, in essence, are the only technology prepared to help the government and utilities attain their CO_2 goals by the year 2000 (wind could help, but is not baseload). Thanks to the DOE and our Washington consultants, we have been quite involved in this effort lately, and hope to turn the issue to our advantage. The Global Climate issue could be a major hope in positioning us for new business for the rest of the decade.

To conclude, I would just like to reiterate that our industry does have a great deal of potential. We are not the only energy industry facing uncertain times, although we may be somewhat behind the marketing curve. We have what many of the other technologies can only dream about, now we need to leverage them and promote ourselves.

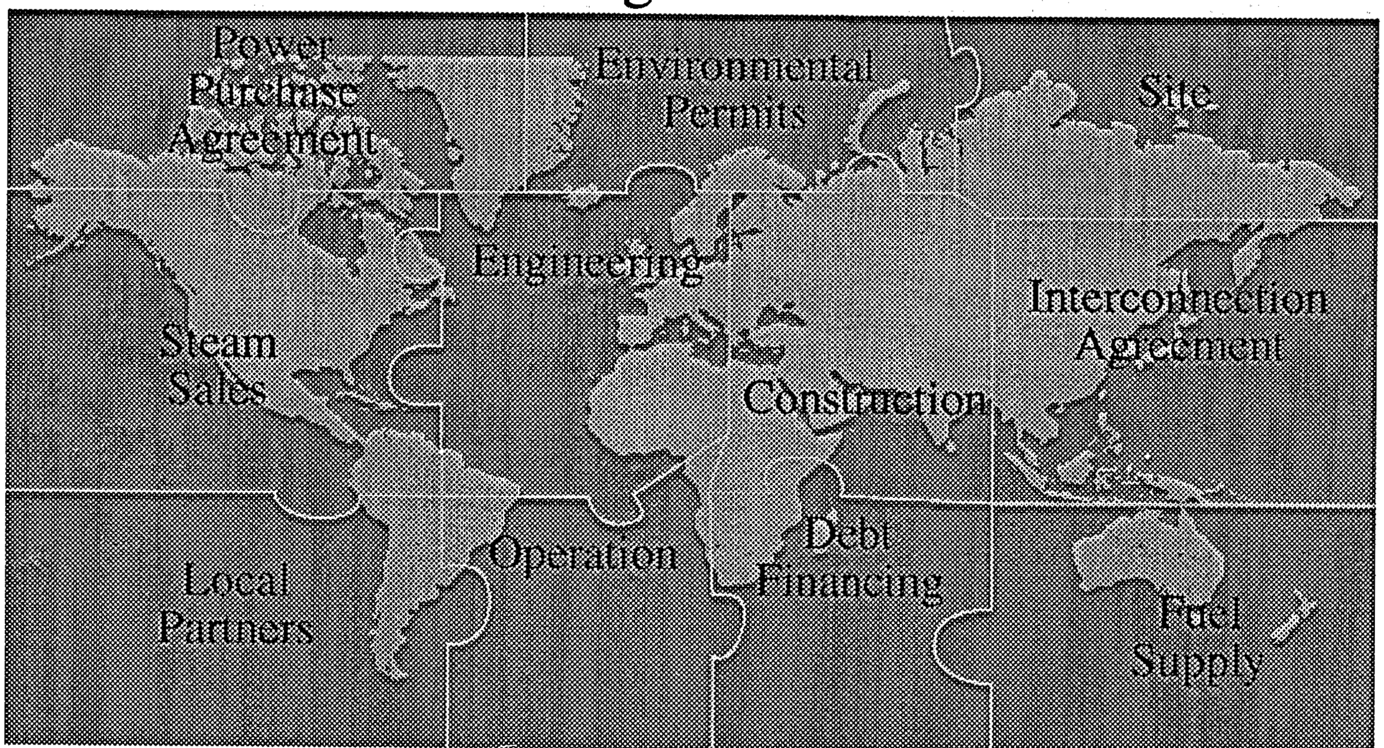
We at California Energy believe that developing new projects is a puzzle in which all the pieces not only have to fit together, but also must be done in a logical and planned fashion (Figure 13). If one piece of the puzzle is missing, it must be reworked until that piece fits into place. Although each puzzle is unique, all the pieces will still be there in the end and must conform, or the entire puzzle is of no value. Only after the last piece is in place is the entire puzzle complete, and you have what you want.

Our industry is very similar. We are missing a significant number of the pieces, and our framework is somewhat non-existent. For those few pieces we have completed, we do not know where they fit into the overall picture. But, at least we can realize our deficiencies and can begin to correct them. Given what the industry has accomplished in the past, I have no doubt that we are up to the challenge, but now is the time for our second wind. Thank you for your time and attention, and don't forget to call me if you can get involved in the GEA.

Thank you.

The Development Puzzle

Regulation



Legislation

Figure 13

Energy Resource Development: A Citizen Involvement Perspective

Randy Berggren, General Manager
Eugene Water & Electric Board

The Eugene Water & Electric Board is a municipally owned utility in Eugene, Oregon. EWEB and California Energy Company are working together to develop the Newberry Geothermal Pilot project in Central Oregon as part of a Bonneville Power Administration pilot program. Today I hope to provide you with our perspective on renewable resource development -- with particular focus on our work on the Newberry project. I want to:

- briefly give you some background on our utility including our interest and involvement in renewable energy resource development and our interest in the development of geothermal at Newberry; and

- talk with you about the public information and outreach work we have been doing in Central Oregon and why we think public involvement is so important.

Background on EWEB and Our Resource History

EWEB is a municipally owned utility that has been in business for more than 80 years. We have approximately 70,000 electric customers. We also operate a water utility and a district heating system.

We currently purchase about 65% of our power from Bonneville and we obtain the remainder from 5 hydro projects and a cogeneration facility we own, hydro purchases from long term contracts with non-BPA sources, and conservation.

Our utility has a history and a philosophy of developing and owning energy resources and we believe, in doing that, we enhance our community's control over the type and cost of our energy supplies.

We know that as our long term contracts expire, we will become increasingly dependent on BPA -- and less able to control our costs -- if we don't take steps to acquire and develop additional resources.

EWEB Resource Development Program -- Our Citizens Group on Resources

A few years ago, our Board assembled a group of local citizens for the purpose of advising the Board on future directions of energy development for our community.

That group learned about the energy picture for the Northwest and also about the various energy resource technologies. They were chartered by our Board of Commissioners to provide policy recommendations for the Board on the future strategies EWEB should use to manage its energy supply future. They concluded that although conservation could play a significant role in our resource future, we should acquire additional resources, diversify our portfolio of resource supplies, and put a priority on conservation and renewable resources.

Their recommendations were incorporated into EWEB's first comprehensive Energy Resource Plan calling for conservation as our number one priority followed by geothermal, thermally-matched cogeneration, retrofits of existing hydro facilities, solar, and wind. They also concluded that we should utilize partnerships with both public and private sector entities to share both risk and benefits.

I would emphasize here that the strong consensus of the citizen's group was that the best approach for our community was a focus on conservation and renewables, and the least acceptable resources were coal and nuclear. This consensus on direction and priorities for resource development reflects a strongly held value within our community. In our view, our work with the group allowed us to align our Resource Plan with the values of our community.

In May of last year, the voters of the City of Eugene passed a measure granting EWEB with $150 million in bonding authority to begin the initial five-year phase of that resource development program. That measure passed by a 3-to-1 margin -- a significant show of support for our plans that we attribute in large part to our citizen involvement in the development of the plan.

Our Geothermal History

EWEB has been interested in the geothermal resource for a number of years. We began acquiring geothermal lease holds in the Cascades in the early 1970's and by the late 1970's, we had about 30,000 acres under lease. We participated in a DOE-sponsored drilling project in the Cascades in 1979.

We currently have about 10,000 acres on lease in the Santiam area in Central Oregon.

The Pilot Project

Our involvement in the Newberry pilot project can be traced to a couple of events.

In 1991, the Northwest Power Planning Council -- a regional planning body -- recommended that Bonneville and the region's utilities initiate, on a pilot basis, the development of several renewable resources, including geothermal. The purpose of the pilot projects, in part, was to determine the cost and availability of these resources.

In July of 1991, BPA solicited proposals for geothermal pilot projects. BPA asked for proposals from developer-utility partnerships. In response, California Energy and EWEB submitted a proposal to BPA in September of 1991 for a geothermal project west of the Newberry crater, about 30 miles southeast of Bend, Oregon. That proposal was accepted in December of 1991 and by December of 1992, BPA, California Energy, and EWEB signed a Memorandum of Understanding defining their relationship and the project.

Under the terms of the agreement, California Energy will finance, construct, own, and maintain a 30 MW plant. BPA will purchase 20 MW directly and EWEB will purchase 10 MW under a power supply credit arrangement with Bonneville (a "billing credit"). In addition, EWEB is participating with California Energy in the permitting and development phase of the project.

The EIS process, which is being led by the U.S. Forest Service and involves BPA and the BLM, is nearly complete and we expect a final EIS this summer. If the necessary permits are acquired and if the resource can be proven, construction is scheduled to start in the summer of 1995 and the plant would come on line in late 1996.

Our Public Involvement Effort in Central Oregon

One of our primary efforts from the beginning of our development work on the project has been to involve the public.

After we submitted our proposal to BPA in the fall of 1991, EWEB staff spent a considerable amount of time in the Bend and La Pine area talking to community leaders, government officials, and representatives of various public interest groups. We identified what we thought were the major areas of interest including education, environmental, commerce, energy, local governments, and so on.

We identified a variety of groups and agencies representing these interests and solicited from them the names of people who might be interested in serving in a public involvement group. Out of that process, we assembled a group of people that represented a cross section of the Central Oregon community and we asked them to work with us through the development phase of the project.

The purpose for the group was to learn about the northwest energy resource picture, learn about the geothermal technology in particular, and provide us with insight as to the issues, concerns, and questions that the Central Oregon community would have regarding the project.

We met with the group for two years, from March 1992 to March of 1994. We heard from energy planners in the Northwest; visited the proposed project site; visited some facilities in The Geysers area; and learned about volcanoes, drilling technology, and the environmental impact statement process.

We told them early on that we were not looking for them to advocate the project for us, but rather to learn about the resource and provide us with their views and perspectives on the project. We also included agency representatives from BPA, BLM, Oregon Department of Energy, and the Forest Service, who provide technical support and information. The group developed their own list of project issues that was used by the Forest Service in the scoping of the EIS and when the draft EIS was issued in January of this year, the group submitted their own comments to the Forest Service.

It is our belief, based on the comments on the draft EIS that we have seen, that the process is proceeding smoothly. There are not, at this point, significant voices of opposition to the project. The major environmental groups that have chosen to comment are essentially telling California Energy and EWEB to proceed with caution.

Citizen Involvement Philosophy

I believe, in a substantial way, this is a result of the public involvement and public outreach process that we implemented in Central Oregon and I want to share with you some observations about citizen involvement in our business, an involvement process that we believe is critical to our success as an electric utility operating in the 1990's.

In addition to using this process to work with California Energy in the public education process related to the Newberry project and to develop the Energy Resource Plan I described earlier, we have also used citizen groups successfully in relicensing two hydro projects east of Eugene and in the development of our first long term Water Resource Plan for the water utility.

Within the last few months, we have started a new citizen's involvement process to address questions related to the issue of EMF, an issue, as most of you know, with the potential for profound impacts on electric utility operation and business.

The process of involving affected customers and stakeholders in critical review of our proposed projects, if done in a genuine and open market, if done with the intent to educate and not to bias, can create a relationship between the people making the decision and those who will be affected by the decision that is based on respect and trust. Such a relationship gives those affected a realistic sense of being a constructive and influential participant in the process. By providing those who are critically interested in our work with clear information in an open environment, we give them permission to educate us and we enable them to educate us about the issues we must address in order to be successful.

This relationship -- if you can create it -- is very powerful and, somewhat paradoxically, is very fragile. It becomes important to demonstrate that you are willing to "walk your talk" and to demonstrate, as you proceed with development and implementation, that you really did listen.

It is not enough to talk with environmentalists or others who may be critical of resource development plans; you need to develop a predictable relationship of trust and you need to understand that you can't do projects that do not provide environmentally acceptable solutions to issues. We believe as a utility that we have to care about our environment.

Our Belief in Renewables

In closing, I want to briefly talk about renewables. As I said earlier, our utility believes it is important to develop renewable sources of energy and that belief is a reflection of the values of the community that owns our utility. In the face of low cost gas supplies, all of us -- utilities, industry, and government -- need to find ways to put these renewable projects in today and trust that they will be viable in 10 years or even 20 years.

Development of renewables needs the support of institutions like Bonneville and the Department of Energy. We all need to work to preserve the ability of these agencies to continue support of renewable development. In the Northwest, Bonneville has the ability to regionalize resource development costs in the short term. No one else has that ability. Absent Bonneville, it would be difficult for us to proceed.

There seems to be a characteristic in our culture to value everything in terms of the "market". This is an approach that probably makes eminent sense for the many questions of "value" we are confronted with in our lives, but in the case of renewable sources of energy, which most people will agree are more environmentally acceptable, if one relies only on the market, we may not develop these resources in an appropriate and timely manner, and we may pay much higher costs in the future.

We need to find a way to temper the values of the market with human values. Today's market must be guided by a human vision for tomorrow, a vision that can intuit that which is not today internalized in the market, and through our institutions of education, government, and service, provide for a sustainable and renewable energy future.

Electric Power - The New Era

Thomas R. Sparks
Unocal Corporation

This morning I intend to discuss the evolution going on in the electric power business and tell you how the geothermal industry might be affected by these changes.

It all began in 1978 with the enactment of the Public Utilities Regulatory and Policy Act, or PURPA legislation. For the first time, power from certain fuel sources could be produced and sold into the market by non-utility producers.

But, there were some conditions imposed on this new market structure:

First, the non-utility producer must be a Qualifying Facility (QF); that is, the power source must be geothermal, wind, biomass, solar, co-generation or waste fuel, along with size limits on some technologies.

Second, the price for the power must be what the utility would have paid for "alternative power". That is the price the utility would have paid for the same increment of power from the next available source.

Third, the utilities must buy the power or wheel it to an adjacent utility.

By 1985, PURPA had nurtured a rapidly growing business in most areas of the United States, and particularly California where over 10,000 Megawatts of power was either in development or on-line. The implementation of PURPA in California was the major impetus for geothermal development in the 80's with more than 700 MW of power contracts signed by major investor-owned utilities.

Ten years later, the "QF Industry" or independent power business had matured. It represented a diversified, highly competitive and efficient industry well-positioned for rapid growth into the next century. In California and Nevada the geothermal industry has been a major contributor to the success of independent power.

In 1988, the Federal Energy Regulatory Commission, the official administrator of PURPA, conducted a nationwide evaluation of the effects of PURPA and concluded that the QF industry was a major success. The FERC recommended that legislators consider expansion of the independent power business to allow other non-utility generators to compete with electric utilities for supply of new capacity needs.

In 1992, the Energy Policy Act became law. The Act included two provisions to clear the way for more independent power development:

First, it created a class of non-utility generator, the Electric Wholesale Generator or EWG. EWG's differ from QF's in three ways: utilities are not obligated to buy power from EWG's; utilities do not have to pay EWG's their avoided cost; and they are not restricted to certain types or sizes of generation.

Second, the EPA provided for access to transmission systems under very broad rules. Those rules are being tested today at both Federal and State levels. Under FERC regulations, transmission systems are being grouped geographically with volunteer Regional Transmission Groups. These RTG's are expected to administer the allocation of transmission capacity and attendant costs.

Last week, the Public Utilities Commission proposed the most dramatic overhaul ever of how Californians will get electric power. The Commission laid out a two-pronged plan. First, beginning in 1996, large industrial and commercial customers would be allowed to buy electricity from any source of their choosing, rather than simply from the utility company holding a monopoly in their service territory. That option would gradually, by 2002, be extended to all business and residential customers. Second, the state would shift away from traditional formulas that have tied electric rates to utility costs for power plants and other expenses. The proposed method, known as performance-based-ratemaking, would reward utilities for more efficient operation, management and investments. To the extent that a utility could reduce costs below an established target, it could divide any savings between ratepayers and shareholders.

Today, we stand at the threshold of a new era. It is not as dramatic as the information super highway, but the implications for the geothermal industry are very exciting.

The business of generating electricity is no longer a monopoly. While the transition to competitive power is still evolving, evidence from recent bid solicitations suggests that independent power producers can out-bid utility projects and accept greater risks than utility-owned projects can tolerate. The trend has swung toward the traditional utility buying power from other sources rather than producing it. A very probable future trend may be for traditional utilities to get out of the generation business and focus on the transmission and distribution business.

Some utilities, such as Pacific Gas & Electric, have announced that they do not plan to build new generation facilities. Other utilities, such as Southern California Edison, are searching for ways to compete in this new environment with projects of their own.

In any event, the era of strong competition is upon us; even international projects are encouraging privately-owned power plants with Build-Operate-Transfer or Build-Own-Operate contracts.

With this clear path of opportunity lying before us, what can we in the geothermal industry do to participate? Our goal should be to successfully develop and supply geothermal power to a world-wide market.

In order to prepare for this endeavor, we should assess our strengths and our weaknesses.

First, let's look at what we've got going for us:

We are an environmentally-preferred technology.

I won't go through the statistics here, but geothermal has great advantages in emissions, safety and land use. These advantages grow in importance as our planet's population grows and resources shrink.

We are a proven, reliable generation resource.

The 1993 production statistics for QF geothermal plants in California are impressive. Once again geothermal QF power plants have achieved capacity factors exceeding 90 percent. This compares with base-loaded utility plants that occasionally produce capacity factors near 80 percent.

Our product occurs in world wide regions with tremendous growth potential. Electric demand in these areas is projected to double in the next fifteen years. Geothermal is a natural fit in these regions.

We have the best, most sophisticated technical and business skills of any nation in the world for utilizing geothermal energy. We have the experience and the knowledge to be successful. The technologies developed by the U.S. geothermal industry in cooperation with the Department of Energy have given us the worldwide leadership position. With a few cost-saving breakthroughs, geothermal energy could become the fuel of choice for power generation.

Now let's look at areas for improvement:

We must become more cost effective.

First, we must reduce the cost of finding and developing geothermal energy. That, ladies and gentlemen, is the primary reason we're all here today. We can't expect to compete with $15 per barrel oil or $2 per mcf gas, but we must continue to improve our methods for exploring, drilling and producing geothermal resources. Remember, we're not looking for a breakthrough technology like solar cells or electric batteries; we just need to improve on what we have.

Second, we must improve our productivity. We need more MW-hrs per dollar of input. This can be achieved through improved conversion efficiency and more effective use of our most valuable resource, people.

We must become more active in marketing geothermal energy.

We must redouble our efforts to sell our industry and our product in the utility, regulatory and political arenas. History is replete with stories of institutions who waited for the market to come to them... and waited, and waited, and waited. Let me assure you that lessor technologies with more aggressive marketing techniques can and will pass us by if we don't get out there and "sell" geothermal at all levels of government and power industry.

If we do these things successfully, we cannot fail. Geothermal Energy has a great role to play in the world's energy future. A door has been opened; a clear path lies ahead. This is no time to turn back.

Thank you.

TRANSFER OF GEOTHERMAL TECHNOLOGY AS A MEANS TO MEET THE NATION'S ENVIRONMENTAL GOALS

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

Gene V. Beeland
Dyncorp•Meridian

INTRODUCTION

The geothermal research and development program, in partnership with industry, has developed a number of technologies that are reported to be in use by industry or are manufactured and available for use. In use, these technologies improve geothermal performance in the marketplace through direct cost reductions or indirect cost reductions through increased efficiency and/or reliability. They therefore increase the economic feasibility of greater geothermal use and, in turn, enhance the nation's ability to meet its environmental goals through substitution of this clean source of energy for less environmentally acceptable fuels.

Many different methods of technology transfer have been employed, and are employed today, to ensure that industry is aware of the range of technologies available, their functions, benefits, and limitations. However, questions arise from time to time that indicate that this awareness has not permeated throughout industry and suggest a need to establish and catalogue the commercial availability of DOE-funded and DOE/industry-funded products.

It is understood that the various companies within the industry often modify and refine these technologies for their own specific applications and generally hold these applications in strict confidence. This practice is borne out by correspondence from industry to DOE expressing general appreciation for the Department's long-term support, but declining more specificity due to confidentiality requirements.

Thus, in order to identify products that have been successfully transferred, we have relied primarily on the best knowledge of the national laboratories involved in technology R&D. Specific company names are used only when a company has acknowledged publicly that its operations incorporate a given technology. Our preliminary list will be introduced below. Let me emphasize, however, that this list is open to addition, deletion, or correction from those with more current information.

TECHNOLOGY TRANSFER -- A BUILT-IN FEATURE OF GEOTHERMAL PROGRAM MANAGEMENT

All recent legislative and administrative statements of U.S. energy policy have placed greatest emphasis in technology transfer on the use of joint industry-government efforts in

R&D and in the commercialization of new technologies. This concept of industry participation as the optimum means of technology transfer emerged very early at the decision-making level of the federal geothermal research program.

While the record shows that the Atomic Energy Commission -- where Congress first placed responsibility for federal geothermal research -- developed its program "largely through activities of its staff and the national laboratories," early realization that formal integration with industry was needed led to the Geothermal Power Development Conference at Stanford University in June 1974. (1) The AEC described its strategy as an effort to stimulate voluntary industry construction of commercial utilization facilities with R&D work "particularly in areas where industry lacks near-term profit motivation or appropriate staff and facilities to perform such work."

By the time of the next major geothermal conference in September 1974, the role of the lead geothermal agency had been shifted to the National Science Foundation which sponsored the Conference on Research for the Development of Geothermal Energy Resources. (2) An NSF spokesman, Richard J. Green, discussed the policy alternatives available to the federal geothermal program and identified the strategy adopted that was to guide the program from that time to the present:

> "There are several strategies which could be adopted to foster the growth of geothermal energy utilization in the United States. One is to give the government exclusive control over all phases from resource exploration to commercial power generation. This is clearly unacceptable. Another strategy would be no government involvement at all. This is undesirable in view of the high-risk nature of exploration, the need for more advanced technology for the more marginal types of resources, and the urgency of our energy supply situation."
>
> "The strategy that makes most sense -- and the one we have adopted -- is based upon a short-term government involvement with the geothermal industry. The private sector is expected to assume an increasing role, and a greater share of the risk, as the national research program begins to pay off."

The technology transfer function inherent in program management in accord with this concept was acknowledged with Dr. Green's announcement that: "Industrial organizations and consortia thereof will be awarded contracts to design, construct, manage, and operate experimental research facilities. In these instances, *a major benefit will be the flow of information and results directly to the private sector.*" Cost-sharing arrangements were also initiated with his statement that "industrial partners will be sought for the dual purposes of: (1) promoting early participation by the private sector on a partnership basis, and (2) reducing the government's cost."

MOVING TECHNOLOGY TO THE MARKETPLACE

Industry's role in the development of geothermal technologies begins up front -- that is, decisions of the DOE program to pursue research on specific technologies, and to seek budget funding to support such research, derive directly from industry's own expressions of its technical priorities. For example, a number of research projects -- both past and present -- respond to industry's critical need to reduce the high costs of finding and confirming economically exploitable reservoirs. These technologies range from evaluation of the reliability of reservoir knowledge obtainable from slimholes as a substitute for costly production-size wells, to continued development and refinement of reservoir performance simulation tools, to the demonstration of tracers and thermodynamic models of brine chemistry as cost-effective means of predicting fluid behavior. Successful results of previous R&D are in current industry use in characterizing reservoirs -- as well as in making day-to-day field management decisions -- and the success of one or more of the related ongoing projects will assist industry in reducing the cost of finding the as yet undiscovered reservoirs so badly needed for continued development.

Industry's role in DOE's R&D program continues, frequently, throughout the development and testing phases of new or improved technologies. For example, of those enumerated above, industry is cost-sharing the drilling and testing of slimholes at several locations where reservoir parameters are well known from large hole flow tests and comparisons of data can be made. And, industry has cooperated in the performance and costs of several highly successful tracer tests that demonstrated the commercial viability of several compounds as geothermal tracers.

In both instances, national laboratories provided, or are providing, the expertise for the government's share of the cooperative effort. In the case of the brine chemistry models, spin-offs to the potash and oil and gas industries have occurred, and this project receives financial support from both industries.

The next step in moving the resulting geothermal technology to the marketplace is wide dissemination of information on its application to industry. Some of the mechanisms used "to spread the word" are identified in Exhibit 1.

Other technology transfer mechanisms may be grouped under the broad term "technical assistance." Government at all levels has provided technical assistance to the geothermal industry for more than 20 years, first to support its early efforts to gain a foothold in the nation's energy mix, and, more recently, to sustain its growth into a mature industry. Current efforts and earlier ones are enumerated in Exhibit 2.

It is to be noted that in one mechanism listed in Exhibit 2 -- Geothermal Drilling Organization/Geothermal Technology Organization projects, industry shares the cost of the final research push needed to bring a technology to the marketplace. Thus, in some instances, industry's role may begin in the upfront planning process, continue through development and testing, and extend all the way through to commercialization.

The steps involved in moving geothermal technology to the marketplace are summarized graphically in Exhibit 3.

THE RESULTS OF TECHNOLOGY TRANSFER

The transfer of new or improved technologies sponsored by DOE's geothermal R&D program has produced two major results:

- Geothermal industry commercialization
- Spin-offs to other industries

As to commercial geothermal use, a recent informal survey of participating laboratories identified those shown in Exhibit 4. We prefer to think of this as a preliminary list, as suggested earlier, and any informed corrections, additions, or deletions are welcomed. We are undertaking to develop uniform information on these technologies by preparing data sheets as illustrated in Exhibits 5, 6, and 7.

Information on spinoffs to other industries is found on the data sheets. Further information on this or other points of interest is available from the participating laboratory and from the printed proceedings of the annual DOE geothermal program reviews.

TECHNOLOGY TRANSFER VIS-A-VIS ENVIRONMENTAL GOALS

It can be readily seen from the sample data sheets presented here, and from others in preparation, that the commonalities among the uses and benefits of new and improved technologies are:

- reduced cost
- increased efficiency/reliability
- environmental benefits

However, closer analysis of the data sheets shows that environmental advantages are not only a benefit separate from reduced cost and better performance, but are inherent in those characteristics as well.

When geothermal energy is used knowledgeably and responsibly, it is a virtually pollution-free resource. Thus, technologies that permit more cost-effective evaluation of the likely behavior of a reservoir under production conditions not only improve the economics of the operation, but contribute to the planning and execution of safe geothermal performance, greatly reducing the opportunity for accidents with the potential to pollute the surface or subsurface environment. Similarly, improvements in material performance also enhance accident-free operation -- e.g., while protecting the developer's investment in a well, more reliable cements provide protection for the subsurface formation and obviate the need for drilling a new well with attendant temporary surface disturbance and noise.

Thus, collectively, the economic and environmental benefits of new or improved technologies may enhance geothermal's posture in the marketplace, both in direct and indirect competition among fuels. The documented performance of this resource has demonstrated, over and over again, that it is an environmentally preferred fuel over oil, coal, or, even, natural gas. Thus, to the extent that more widespread industry knowledge of the benefits of new or improved technologies translate into greater growth in geothermal use, technology transfer offers the nation an important tool in meeting its environmental goals.

1. *Proceedings of the Geothermal Power Development Conference*, Atomic Energy Commission/University of California, Berkeley (June 18, 1974).

2. *Proceedings on Research for the Development of Geothermal Resources*, National Science Foundation/Jet Propulsion Laboratory, Pasadena (Sept. 23-25, 1974).

EXHIBIT 1

DISSEMINATION OF INFORMATION/TECHNOLOGY

- Joint DOE/Industry Program Reviews
- Annual Geothermal Resources Council meetings; printed transactions
- Annual Stanford University reservoir engineering workshops
- Industry/academic advisory committees
- Researcher participation in relevant technical conferences; journal papers
- Wide distribution of geothermal models by U.S. software/information centers
- Annual laboratory reports
- Open-door policy at DOE Geothermal Division

EXHIBIT 2
TECHNICAL ASSISTANCE

- Cooperative experimental ventures -- e.g., the earlier Geothermal Loop Experimental Facility and today's Geysers Research Program
- Cost-and risk-shared exploratory drilling programs, past and present
- Cooperative, cost-shared projects sponsored by the Geothermal Drilling Organization, Geothermal Technology Organization, and Geothermal Power Organization
- Tests of materials/equipment at industry facilities
- Cooperative, cost-shared tracer tests
- Transfer of patents to commercial manufacturers
- In-house laboratory workshops on specific technology applications
- USGS reservoir assessments and exploratory drilling
- State agency low-temperature resource assessments

Exhibit 3
Moving Technology to the Market place

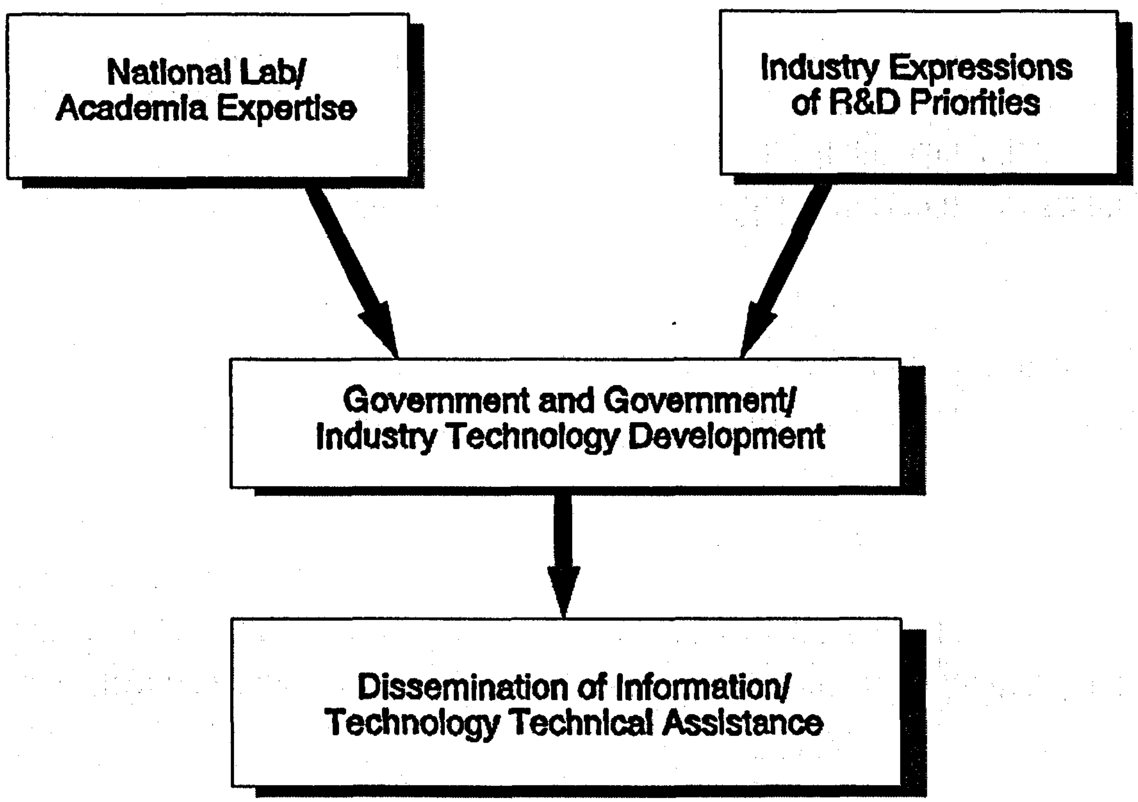


EXHIBIT 4

RESULTS OF INFORMAL SURVEY TO IDENTIFY GEOTHERMAL R&D PRODUCTS IN COMMERCIAL USE OR COMMERCIALLY AVAILABLE

- Crystallizer-clarifier
- Reservoir simulation codes
- Automated seismic processor
- GEOTHERM (brine chemistry models)
- Stable tracer compounds
- Procedure for optimizing allocations of injectate among wells
- Dispersion coefficient for species transport in fractures
- Fluid inclusion studies
- Borehole breakout studies
- High-temperature elastomers
- PDC drill bits
- Borehole acoustic televiewer
- Pneumatic turbine
- GEODYNE2
- Rolling float meter
- Polymer cement composites for lining steel pipes
- Electronic logging tool
- High-temperature drilling muds
- Other lost circulation control
- materials and techniques

EXHIBIT 5

COMMERCIAL PRODUCTS OF DOE GEOTHERMAL R&D

- **TECHNOLOGY:** GEOTHERM (brine chemistry models)
- **R&D PARTICIPANTS:** Researchers at the University of California, San Diego, Chemistry Department
- **METHOD OF TECHNOLOGY TRANSFER:** Annual workshop on specific applications, workbook to facilitate use, technical papers/presentations at national and international level
- **USE OF TECHNOLOGY:** To predict scale formation and other brine behavior characteristics in exploration, plant design and operation, and injection of waste brine
- **BENEFITS OF TECHNOLOGY:** Replace and extend costly laboratory simulation and provide a cost-effective design tool to enhance efficiency of geothermal operations; protection of underground drinking water
- **GEOTHERMAL INDUSTRY USERS:** Caithness Power, The Ben Holt Co., Unocal, others
- **USERS IN OTHER INDUSTRIES:** Potash Corp. of Saskatchewan, Unocal (Oil & Gas), Exxon Production Research Co.

EXHIBIT 6

COMMERCIAL PRODUCTS OF DOE GEOTHERMAL R&D

- **TECHNOLOGY:** SHAFT79, MULKOM, TOUGH, TOUGH2 (reservoir simulation codes)
- **R&D PARTICIPANTS:** LBL
- **METHOD OF TECHNOLOGY TRANSFER:** Distribution through software/information centers; in-house workshops; technical support and hosting of visiting scientists; use as a university teaching tool; reports, conference presentations, publications
- **USE OF TECHNOLOGY:** Simulating reservoir characteristics and understanding complex reservoirs; design and analysis of well tests and laboratory experiments; performance assessments of nuclear waste repositories
- **BENEFITS OF TECHNOLOGY:** Supplement costly drilling with more cost-effective exploration tools; optimize field development and operation; facilitate day-to-day field working decisions; protection of underground drinking water
- **GEOTHERMAL INDUSTRY USERS:** Geothermex Inc., Philippine National Oil Co. (geothermal division), others
- **USERS IN OTHER INDUSTRIES:** Bechtel, Westinghouse, nuclear energy agencies in this country and abroad

EXHIBIT 7

COMMERCIAL PRODUCTS OF DOE GEOTHERMAL R&D

- **TECHNOLOGY:** High-temperature cements
- **R&D PARTICIPANTS:** BNL, API, Chevron, CFE, Unocal, Halliburton, Dowell, Philips Petroleum, NIST
- **METHOD OF TECHNOLOGY TRANSFER:** Field demonstration of BNL-developed materials under API Committee on Standardization of Oil Well Cements; publication of results by API
- **USE OF TECHNOLOGY:** To increase the integrity of well completions by reducing potential for well casing failures
- **BENEFITS OF TECHNOLOGY:** Protect multimillion dollar wells from being rendered useless
- **GEOTHERMAL INDUSTRY USERS:** Well service companies; well owners
- **USERS IN OTHER INDUSTRIES:** Norwegian oil firms drilling in North Sea; LNG firms for storage facilities; gas distribution systems for use on condensing heat exchangers; a utility for vaults in a steam district heating system

Session 2:
The Geysers

Chairperson:
W. Thomas Box,
Calpine Corporation

The Geysers Session
Introduction

W. Thomas Box
Calpine Corporation

The depletion experienced in The Geysers field between 1987 and 1993 has had a profound effect on the perception of geothermal development projects by the financial and business communities. At the request of the utilities and steam producers with investments in The Geysers, the Department of Energy initiated a research program to address the major problems affecting the production from and operation of this large, dry steam field. These major problems are: (1) the higher than anticipated productivity and reservoir pressure decline; (2) production of highly corrosive HCl; and (3) an increase in noncondensible gases. The development of a successful injection strategy to combat these problems has been a major focus of the industry in recent years. Since 1990, the Department of Energy has spent more than $8.5 million on this joint industry/government effort involving reservoir modeling, geophysical studies, tracer development and cost-shared field experiments. The presentations which follow summarize progress to date in some aspects of this research.

In May of 1992, four Working Groups were established to improve and strengthen the cooperative R&D program. The Working Groups have met to discuss technical problems at The Geysers, propose research to help solve the problems, and prioritize research projects to be conducted. P. Michael Wright of the University of Utah Research Institute was designated as the facilitator for these Working Groups by the Geothermal Division. He will provide a status report on these high priority joint projects.

Karsten Pruess of Lawrence Berkeley Laboratory will review the recent work being conducted on injection modeling in the Southeast Geysers. This research is focused primarily on gaining a better understanding of the physical processes and mechanisms which result from injection into a vapor-dominated reservoir and on improving the description of two-phase flow in heterogeneous media.

A study of the effects of an adsorbing phase on water injection into The Geysers was performed by John Hornbrook and Roland Horne of Stanford University. They compared the magnitude of delay caused by adsorption, diffusion partitioning, preferential partitioning, and permeability variation with tracer production data to determine the probable delay mechanism for injected tracer at The Geysers. Roland Horne will present the results of this work.

The last presentation, by John Zucca of Lawrence Livermore National Laboratory, will address the use of seismic images from microearthquakes for reservoir management. Using data from two high-frequency, high-resolution microearthquake networks installed at The Geysers, the research team is computing seismic velocity and attenuation images and attempting to monitor the effects of steam production and the migration of injected fluids from these images.

SUMMARY OF WORKING-GROUP ACTIVITIES
AT THE GEYSERS GEOTHERMAL FIELD, CALIFORNIA

by
Phillip Michael Wright
University of Utah Research Institute

ABSTRACT

After several productive meetings, the four Geysers working groups have recommended three projects to be carried out jointly by DOE and the industry. They are (1) continuous coring in reservoir rocks to obtain samples for subsequent analyses, (2) a three-year injection test at Unit 18, and (3) construction of a suite of field-wide maps showing such things as superheat and deuterium distribution to supplement similar maps on top of reservoir and isobars.

INTRODUCTION

The Geysers field reached peak output of 2,000 MWe in 1988 and has been in decline since then. The current production is about 1,250 MWe. After 33 years of electrical power generation, more than 95% of the heat still remains in the rock. The infrastructure investment at The Geysers is about $3.5 billion. At this point, it appears that improvements in the power plants to increase efficiency and improvements in injection technology, along with obtaining more water for injection, are the most profitable lines of pursuit. The Department of Energy initiated a program to help the industry mitigate the effects of the decline. This presentation reviews the progress made by four working groups formed to bring industry and DOE-funded researchers into closer contact and to help determine the best way to utilize the DOE funding and R&D support.

BACKGROUND

For some months in 1991, Carel Otte (a private consultant) was on a special assignment to Ted Mock (DOE) to help evaluate the effectiveness of the DOE research program at The Geysers. Although he found that there were many favorable comments, Carel identified three areas where improvement was needed: (1) communications between DOE-funded researchers and their industry colleagues; (2) a better method for determining priorities for R&D projects; and (3) imparting a sense of urgency in the R&D.

In response to these needs for program improvement, DOE established a number of working groups comprised of research personnel and industry personnel working in the same topical areas. By providing a working-group forum, it was hoped that we could generate a synergistic effect to propel the research forward at a faster pace and instill a renewed sense of importance while encouraging better communication among researchers and other parties who have a need to know.

Each working group is comprised of 6 to 12 members intimately involved through actual performance of research and related work at The Geysers. The chair of each group is an industry person.

The charter of each of the working groups is to: (1) discuss technical problems at The Geysers, propose potential ways to solve these problems (research approaches), and help place the proposed research in an order of importance; (2) review the progress reported by each principal investigator and incorporate results into their own projects as appropriate; and, (3) communicate research results in technical reports. In general, the working groups are to help steer the R&D projects and bring them to an early and successful conclusion while helping to avoid pitfalls and blind alleys. Phillip Michael (Mike) Wright (UURI) was assigned by DOE as special program facilitator to work closely with Marshall Reed (DOE) and the industry in getting the working groups going and their recommendations implemented.

The four working groups that have been established are as follows:

Working Group 1. Field Geological and Geochemical Models

Problems.

1. Quantitative and qualitative parameters from conceptual models are required as input to reservoir-engineering simulation models for field-wide predictions as well as predictions of the effects of injection.

2. Unacceptably high levels of HCl have been found in steam from the northern portion of The Geysers reservoir, causing corrosion problems in surface and subsurface equipment. The mechanisms for generation of HCl in the reservoir are poorly understood.

3. The level of non-condensible gases has been increasing in steam produced from some portions of The Geysers, causing degradation in power-plant performance.

Goals.

1. To develop conceptual geological, geochemical, geophysical and hydrological models of the steam field and immediate environs that account for and quantify (a) the geometry of the steam reservoir, (b) the geologic structure of the reservoir, especially the development and occurrence of porosity and permeability, (c) the production of HCl and anomalous levels of non-condensible gases, and (d) other pertinent reservoir processes.

2. To develop means of predicting future changes in these quantities.

3. To transfer this information to other working groups and to operators and utilities.

Participants.

Bill Smith (NCPA), Mark Walters (RREC), Joe Beale (Calpine), Ken Williamson (Unocal), Al Truesdell (LBL), Colin Williams (USGS), Joe Moore (UURI), Jeff Hulen (UURI), Jay Zucca (LLNL), Ernie Majer (LBL), Bob Fournier (USGS). Bill Smith is the Chair of this group.

Working Group 2. Injection Techniques

Problem.

1. Many people believe that injection will prove to be a major component in programs to stabilize the rate of decline in production from The Geysers steam field. Local effects, as well as field-wide effects, of injection need to be determined, and injection strategies need to be developed.

Goals.

1. To model injection performance, develop means to predict the effects of water injection into the reservoir, and develop injection strategies.

2. To transfer this knowledge to other working groups, and to operators and utilities.

Participants.

Keshev Goyal (Calpine), Steve Enedy (NCPA), Mark Walters (RREC), Kathy Enedy (PG&E), Ben Barker (Unocal), Mike Adams (UURI), Karsten Pruess (LBL), Dave Faulder (INEL), Roland Horne (Stanford). Kathy Enedy was the Chair of this group, but resigned because of reassignment within PG&E. Her replacement has not been named yet.

Working Group 3. Reservoir Performance Prediction

Problem.

1. Additional investment at The Geysers to help regain power production capability and

stabilize reservoir pressure decline will require economic justification over a 30-year time period. Reliable, calibrated reservoir simulation techniques are needed to instill confidence in predictions of future reservoir performance.

Goals.

1. To develop means to model the reservoir on field-wide and subregional scales.

2. To transfer this knowledge and make computational models available to operators, utilities and governmental agencies.

Participants.

Keshev Goyal (Calpine), Kip Bloomfield (PG&E), Ben Barker (Unocal), Steve Enedy (NCPA), Robert Emslie (RREC), Bo Bordvarsson (LBL), Hank Ramey (Stanford), Mike Shook (INEL), Al Truesdell (LBL). Ben Barker is the Chair of this group.

Working Group 4. Power Generation, Pipelines, Injection Water and Corrosion Control

Problems.

1. Many of the power plants are old and will need replacement or upgrading some time in the next 30 years. Significant improvements in power plants have been made in the last 12 years.

2. Some plants and other equipment are subjected to corrosive, HCl-containing steam and to higher than normal levels of non-condensible gases.

3. Supplies of additional injection water need to be identified.

Goals.

1. To determine methods for improvement in efficiency of power plants, both in the short term and in the long term.

2. To examine the effects of load following.

3. To develop ways to optimize steam and injection-water pipelines.

4. To develop ways to protect power plants, gathering pipelines and wells against corrosion.

5. To identify additional supplies of injection water.

Participants.

Dan Ballantine (PG&E), Shawn Brady (PG&E), Vincent Fesmeyer (Stone & Webster), Murray Grande (NCPA), Calpine rep, Unocal rep, Steve Ponder (RREC), Larry Kukacka (BNL), Joel Renner (INEL). Dan Ballantine is the chair of this group.

RESULTS OF WORKING-GROUP MEETINGS

Two meetings have been held of all of the working-group participants together, and several meetings and telephonic conferences have been conducted by the individual groups. As a result of this effort, three projects have been proposed as being of the highest priority. They are discussed in this section. While they do address some of the goals of the working groups, the limited money available precludes working on all of the problems that are important at this time.

In the descriptions of these projects, I have drawn heavily on written input from the working group chairs and their supporters. I would like specifically to acknowledge their efforts, reported here.

Project 1. Deep Well Continuously Cored Through the Reservoir.

Background

In order to improve the ability to predict future reservoir performance at The Geysers, and the further changes that will occur in steam quality, far more complete determinations need to be made of specific reservoir parameters for the full vertical extent of the *typical* dry steam reservoir. And to the extent practical, these determinations need to be extended deeper into that reservoir section than present development exists, in order to determine if the underlying high temperature-high chloride-high NCG reservoir of the Northwest Geysers is also beneath the main part of the field.

Throughout The Geysers, the dry steam reservoir typically begins at depths from 3,000 to 5,000 ft, with production wells commonly extending downward through an interval thickness of 5,000 ft to an average total depth of about 9,000 ft. The produced steam comes from both fluid-filled fractures and from reservoir rock matrix, but their relative storage capacities still remain very much uncertain. Typical fracture investigative tools, such as down-hole televiewers, are inoperative in these wells because the wells can not be filled with water. Furthermore, the samples of reservoir rock normally obtained during drilling are completely disaggregated by the air-drilling process. Some core samples have been obtained from within The Geysers reservoir section, but to date they collectively total only between 150 and 200 ft. These cores represent about 20 discontinuous intervals from as many scattered wells. Consequently, less than 4% of the reservoir interval has ever been core sampled, and little of that material now remains for examination.

Proposed Project

A deep investigative well needs to be drilled in the Central Geysers region to acquire the information necessary to achieve improved forecasts of future reservoir performance. This well should be rotary drilled to the top of the cap rock, which occurs at a depth of about 4,500 ft, and then continuously cored through the cap rock and through the typical reservoir section to a depth of at least 9,000 ft. Such a program will provide a continuous sampling of the total lithologic section present, from cap rock, through both the normal metagreywackes and the units that are progressively more hornfelsed, and then into the upper portions of the felsite intrusive. Continuing to a depth of 12,000 ft will characterize the reservoir section to the present limits of resource development, and deepening the well to 15,000 ft will reach the maximum suspected reservoir depth (based on seismicity data), while testing for the presence of a high-temperature reservoir (HTR) in the area.

The wide range of specific scientific studies that can subsequently result only after having undertaken this proposed drilling program include a vertically continuous description of the following:

1. Reservoir physical properties: porosity, permeability, water saturation, density, velocity, and thermal conductivity.

2. Reservoir chemical properties: bulk, isotopic, fluid-inclusion and pyrolysis-derived gas compositions of core materials, and compositions of the various fluids recovered.

3. Mineralogical/hydrothermal variations, internal fluid saturations, leaching and solution history, and a description and dating of the felsite intrusion(s) that furnish the heat that sustains The Geysers.

4. Particular attention will focus on the distribution, orientation, relative age and hydrothermal histories of the reservoir fractures encountered.

5. In addition to simultaneously logging down-hole pressure/temperature/flow rate (spinner) measurements, other logging tools can be utilized to the extent that their size and temperature limits permit.

The estimated cost for a 12,000-foot corehole is nearly $2 million.

Project 2. Field Test of Water Injection and Tracers in Unit 18

Background

The Geysers field is most intensely developed in its southeastern portion, with consequent rapid depletion. An industry cooperative injection test program in 1989-90 showed the reservoir in the northern part of the NCPA leases and the southern part of the PG&E Unit 13 area (Calpine) to be highly responsive to shallow water injection. These tests demonstrated the high potential of the area around NCPA well C-11 to accept water with sustained productivity gains.

The Geothermal Technology Organization (GTO) sponsored tests of two gas-phase tracers in this area during the initial injection period. The results of the tracer tests were encouraging, and they showed the practicality of using multiple tracers in an area simultaneously. The tracer responses could not be directly correlated with earlier tracer work elsewhere in the field, however. This removes one of the few tools available for extrapolation of the southeast Geysers experience to other areas. An understanding of the relationship between tracer results obtained in different areas with different materials at different phases of depletion has great potential for reducing the risks associated with injection without prohibitively expensive pilot tests.

Motivated in part by the positive experience of the C-11 tests, several major capital projects have been proposed which would bring additional water to the southeast Geysers area for injection. One of these, the Lake County Wastewater Pipeline, involves a long-term requirement for disposal of treated effluent, with no economical backup in the event of reservoir production problems. The C-11 test results raised questions about why the area west of Unit 13, especially the southern Unit 18 area, showed relatively less response to C-11 injection than equally distant wells in the eastern quadrants. Some have suggested that there may be a zone of diminished lateral reservoir permeability which reduces fluid mixing between the Units 13 and 18 area. If such a barrier exists, it could substantially increase the risk to operations from prolonged large-scale water injection in this part of the field.

Proposed Project

An injection test in the southern section of Unit 18 will involve:

1. Construction of a 150-foot long pipeline from Unit 18 to Unocal well D&V-6;

2. Remedial work on D&V-6 if "barefoot" injection is not practical;

3. Injection of two tracers, one of which is tritium, in a program designed to yield comparative interpretation with older tritium test results;

4. Sampling of steam produced and analytical determination of tracer concentrations over a three-year period from the Unocal, NCPA and Calpine wells which may be affected;

5. Seismic monitoring of the area in a near real-time mode to guide steam sampling and operations during the test.

6. Evaluation of steam production and pressure response in the Unocal-NCPA-Calpine area over the same three-year period as tracer recovery is determined.

Estimated Costs and Schedule

Total cost of the three-year project, to be cofunded by industry and DOE through the GTO, is estimated to be $1.08 million.

Project 3. Field-Wide Physical- and Chemical-Property Maps

Background

The objective of this project is to develop field-wide maps of injection-related reservoir parameters. Industry will provide the basic reservoir data and cooperate with DOE principal investigators to develop both historic and current field-wide maps. These maps could include information such as isobaric contours, downhole to surface enthalpy and superheat, permeability, isotopes, non-condensible gases, micro-seismic occurrences, reservoir fractures and injection-derived steam. The primary use of these maps would be to determine both problems related to injection and areas that have or could benefit from injection.

Proposed Project

Industry representatives would first prioritize which field map or maps should be developed, the time frame to be covered as well as compilation units, scale, etc. The first field-wide maps to be developed from this project would probably be parameters that have already been mapped by individual companies, such as superheat or deuterium distribution. Field-wide maps for top of steam, top of felsite and isobaric data have already been developed jointly by industry. DOE principal investigators would coordinate, compile and combine the individual industry maps, digitize the final map and format it using a CAD system. Although this project would provide useful results on a short-term basis, it would be difficult for industry to complete without DOE support because of industry manpower constraints. The project could span over several years as currently-mapped parameters are first compiled, followed later by parameters that are not routinely mapped by industry. Each year, the type and number of maps would be decided and become the goal to attain.

Estimated Cost and Schedule

The estimated cost of this project is $40,000. DOE would bear all of this cost, and industry would contribute in kind through time spent by technical personnel in helping the DOE principal investigator copy and evaluate data from company files.

PRESENT STATUS OF PROJECTS

The Geysers Coring Project (GCP).

The GCP is a joint venture involving the Department of Energy's Geothermal Division; Unocal Corporation and other Geysers steam-field operators; and a team of 28 collaborating investigators from national laboratories, universities, and various government agencies. The GCP's governing objective, as determined by a designated Coring and Science Advisory Panel, is acquisition of critical new data on steam-reservoir porosity, permeability, and fluid saturation -- information essential for forecasting steam supply and quality during the field's long, remaining, productive life.

As a first step in achieving this objective, the GCP centers upon retrieval of 300-500 m of continuous core from the so-called "normal" Geysers reservoir (about 3.3 Mpa and 235°C pre-exploitation), with coring to commence at the bottom of an existing, 1260 m-deep, Unocal steam-production well, SB-15. The core will be carefully logged on site, with special attention to fractures, breccias, dissolution cavities, and other voids which potentially could store, or serve as conduits for, indigenous reservoir fluids or injectates. An ambitious program of subsequent, detailed core studies are planned by the GCP science team. For example, entire core runs sealed on site to minimize reservoir-fluid escape will be scanned through their encasements utilizing short-range remote-sensing methods (such as MRI) to determine these fluids' quantities and distributions. Attempts will also be made to collect and directly analyze the reservoir fluids from the deep interiors of the retrieved cores. Detailed studies of hydrothermal alteration, vein-mineral paragenesis, and fluid-inclusion systematics have great potential to advance understanding of the means by which large vapor-dominated geothermal systems like The Geysers form and evolve. The SB-15 core will be archived at the University of Utah Research Institute. Here, the entire length of the core will be imaged, with the images and a broad range of accompanying information to be made available in digital form to interested researchers.

At this writing, only details of the prime contract governing the GCP remain to be resolved, and the actual coring phase of the project is scheduled to get underway in mid- to late August. Initial results of the GCP will be presented at the 1994 GRC annual meeting in Salt Lake City in early October. Collaborating investigators' research projects will span 1-3 years.

Injection Test in Unit 18.

The Unit 18 cooperative injection test began in September of 1993 with injection into Unocal well DV-11. The industry participants are Unocal, PG&E, Calpine, and NCPA. The goals of the project are to monitor and define reservoir response to steam-production interval water injection, and to evaluate some vapor-phase tracers with respect to the performance of the two-phase tracer, tritium.

Pressure, temperature, flow rate, and steam chemistry have been monitored on a regular basis since the test began. Baseline samples were taken prior to the test. A tracer test was performed on April 18, 1994. The vapor-phase tracers sulfur hexafluoride and R-13 and the two-phase tracer tritium were injected over an eight-hour period. The tracers were detected in steam from production wells within one day.

Injection into well DV-11 was stopped during the summer months due to low availability of injection fluid, which results from the increased evaporation rate at the cooling towers when the ambient temperature is high. DV-11 requires at least 400 gpm to kill the well. Injection will resume when the ambient temperature drops.

The results of the DV-11 test will be summarized in a paper (Voge et al., 1994) to be given at the 1994 Geothermal Resources Council annual meeting, which will be held in Salt Lake City, Utah.

ACKNOWLEDGEMENT

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GEYSERS INJECTION MODELING

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ABSTRACT

Our research is concerned with mathematical modeling techniques for engineering design and optimization of water injection in vapor-dominated systems. The emphasis in the project has been on the understanding of physical processes and mechanisms during injection, applications to field problems, and on transfer of numerical simulation capabilities to the geothermal community.

This overview summarizes recent work on modeling injection interference in the Southeast Geysers, and on improving the description of two-phase flow processes in heterogeneous media.

INTRODUCTION

Vapor-dominated geothermal reservoirs are naturally water-short systems. Fluid reserves tend to get depleted during exploitation much more quickly than heat reserves. Injection of water is the primary means by which dwindling fluid reserves can be replenished, and field life and energy recovery be enhanced. Effects of water injection are not always beneficial, however, because thermal degradation or water breakthrough may occur at neighboring production wells.

The design and optimization of injection operations require reliable numerical modeling techniques. This is not an easy proposition. Water injection into vapor-dominated zones is a very complex process of immiscible displacement, which is further complicated by gravitational instability of water over steam, and by strong coupling between fluid flow and heat transfer with phase change (boiling and condensation). Viscous instabilities at the water-vapor interface may also come into play (Fitzgerald et al., 1994).

We have developed a general-purpose geothermal reservoir simulation tool, TOUGH2 (Pruess, 1991a). This simulator is capable of modeling most of the reservoir processes during injection, including appearance and disappearance of liquid and vapor phases, boiling and condensation, multiphase flow due to pressure, gravity, and capillary forces, and vapor adsorption with vapor pressure lowering. It is applicable to flow systems of arbitrary geometry from one to three dimensions, and has special provisions for flow in fractured-porous media. The code is available to the public through the U.S. Department of Energy's software distribution center.† TOUGH2 has recently been enhanced with a package of pre-conditioned conjugate gradient solvers, making possible the simulation of problems with 10,000 grid blocks or more on PCs (Antunez et al., 1994).

The present report summarizes recent attempts to model injection effects at The Geysers, and to improve modeling capabilities for heterogeneous media. Accompanying laboratory efforts directed at fracture relative permeability measurements have been reported elsewhere (Persoff et al., 1991; Persoff and Pruess, 1994).

INJECTION AT THE GEYSERS

Since the mid-eighties, reservoir pressures and well production rates at The Geysers have entered a period of accelerated decline (Goyal and Box, 1990; Enedy, 1992). Steam shortfalls have curtailed power production and have emphasized the need to view injection not just as a means for condensate disposal, but as a reservoir management tool for replenishing dwindling fluid reserves and enhancing energy recovery.

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In an effort to replace mass withdrawals at The Geysers, Unocal has injected condensate since 1969 (Barker et al., 1992). Beginning in 1980 this was augmented with fresh water from Big Sulphur Creek. Water injection and reinjection is now standard operating practice throughout The Geysers field. Through careful decline curve analysis, Goyal and Box (1992) and Enedy et al. (1991) have been able to quantify in detail the substantial production gains from injection. However, in some cases detrimental effects from injection have been reported, such as breakthrough of water at production wells (Barker et al., 1992).

Recent injection experiments performed by Northern California Power Agency (NCPA) in the Southeast Geysers have shown dramatic patterns of interference with production (Enedy et al., 1991; Pruess and Enedy, 1993). During 1990 water was injected into a well called Q-2 for periods of from one to several weeks at rates of 200-600 gpm (approximately 12-36 kg/s). A nearby production well, Q-6, responded to injection with rapid strong rate declines. When injection was stopped production not only recovered but over-recovered. As shown in Fig. 1,† the interference pattern could be repeated over many injection cycles, and (over-)recovery of production was stronger for longer periods of injection shut-in.

The NCPA test has yielded unique field data on injection-production interference. Replicating these effects would be a severe test on the capabilities of numerical simulation models. We have developed a model that attempts to capture in detail the reservoir conditions and processes deemed responsible for the peculiar observed behavior (Pruess and Enedy, 1993). The strength and rapidity of interference between Q-2 and Q-6 suggest that both wells intersect the same fractures or fracture zones. Accordingly, our simulation model contains a vertical fracture and a large background reservoir (Fig. 2). Numerical simulation of the process was made with LBL's general-purpose TOUGH2 reservoir simulator. Heat transfer from the wall rock to the fracture was included, as were effects of finite wall rock permeability. An "effective continuum" treatment was employed for the fractured-porous background reservoir. Full details are given in (Pruess and Enedy, 1993).

Typical results are shown in Fig. 3. Prior to start of injection the production well is placed on deliverability. Production is simulated for a five-year period to obtain reasonably stabilized rates. When subsequently injection is started, production rate is seen to decline through a combination of temperature, pressure and relative permeability effects. When injection is terminated production rates not only recover but over-recover. This behavior agrees with the field observations, although no attempt was made to match them in quantitative detail.

The main results from this study can be summarized as follows (for a more detailed discussion see Pruess and Enedy, 1993). (i) Current numerical modeling techniques are capable of simulating the highly non-linear fluid flow and heat transfer processes during injection in considerable detail, even including the complications of flow in highly permeable fractures. (ii) The most significant reservoir processes during injection include gravity-driven downward migration of injected water, local heat exchange between the injection plume and reservoir rock, capillary imbibition of injected water into matrix rock, vapor condensation in cooler portions of the plume, and boiling in the hotter portions. (iii) Injection is subject to heat transfer limitations. Cooler portions of injection plumes consume large amounts of reservoir steam, while hotter portions contribute additional steam. (iv) From the standpoint of reservoir management, injection should not be concentrated in a few wells operating at large rates. Better pressure support is achieved by distributing injection among many wells with modest rates, well below their capacity for accepting fluids.

PHASE DISPERSION

Numerical simulation of injection is subject to grid orientation effects, i.e., simulation results depend not only on grid spacing but also on the orientation of the grid relative to the vertical (Pruess, 1991b). This is demonstrated by modeling injection into the system shown in Fig. 4, which represents a vertical section through a depleted vapor zone. Using "parallel" and "diagonal" grids (Fig. 5) results in dramatically different predictions

† *Figures at end of paper.*

for injection plumes (Fig. 6). More consistent (less grid-dependent) results are obtained when a higher order ("9-point") differencing method is used (Fig. 7). The grid orientation effect arises from an interplay between the hydrodynamic (gravitational) instability and anisotropic numerical dispersion. A more careful analysis suggests that the 9-point results are not necessarily "better;" they avoid obvious inconsistencies simply because the numerical dispersion effects are more nearly isotropic.

In order to attain a physically realistic description of the behavior of injection plumes, it is necessary to explicitly represent the physical dispersion of liquid plumes from medium heterogeneities.

Water injection in fractured vapor-dominated reservoirs is dominated by gravity effects, which tend to pull the injection plume downwards. However, "straight" downward flow is only possible when appropriate permeability is available in the vertical direction. Water flowing downward in sub-vertical fractures is likely to encounter low-permeability obstacles, such as asperity contacts between fracture walls, or fracture terminations. Water will pond atop the obstacles and be diverted sideways, until other predominantly vertical pathways are reached (Fig. 8). By accounting for this process of heterogeneity-derived dispersion, artifacts from numerical dispersion become less significant, and more realistic simulation of injection into vapor-dominated systems can be achieved.

We have developed an approach that seeks to account for heterogeneity-derived phase dispersion by a suitable extension of conventional multiphase flow theory (Pruess, 1994). Liquid and vapor fluxes are usually expressed with a multiphase version of Darcy's law, as follows.

$$F_\beta = -k\frac{k_{r\beta}}{\mu_\beta}\rho_\beta\left(\nabla P_\beta - \rho_\beta g\right) \qquad (1)$$

The index β denotes liquid or vapor phase, k is the absolute permeability, $k_{r\beta}$ is relative permeability for phase β, μ is viscosity, ρ is density, P_β is pressure in phase β, and g is acceleration of gravity. We propose to model phase dispersion in analogy to Fickian diffusion by adding a dispersive flux term for liquid phase to Eq. (1), which is written as

$$\mathbf{F}_{l,dis} = -\rho_l\, \phi\, \mathbf{D}_{dis}\, \nabla S_l \qquad (2).$$

Here, ϕ is porosity, and **D** is the dispersion tensor. Dispersive flux is presumed to be proportional to the gradient of liquid saturation, S_l. The validity of the proposed Fickian dispersion model was examined by means of high-resolution numerical simulation experiments in heterogeneous media. TOUGH2 simulations with of the order of 10,000 grid blocks showed that the mean square size of descending liquid plumes tends to grow linearly with time, indicating that plume spreading indeed tends to be diffusive, and substantiating the flux model Eq. (2).

Subsequently the proposed flux term Eq. (2) was coded into TOUGH2, and calculations were made to explore phase dispersion effects during injection. A two-dimensional radially-symmetric problem was considered (Fig. 9). An injection well penetrates the top 500 m of a 1000 m thick reservoir. Problem parameters were chosen representative of depleted vapor zones at The Geysers. Liquid water is injected at a rate of 25 kg/s. The shape of injection plumes without and with phase dispersion is compared in Figs. 10 and 11. As expected, phase dispersion enhances the lateral and diminishes the vertical migration of injected fluid. An obvious implication is that neglect of phase-dispersive effects may underestimate the potential for water breakthrough at neighboring production wells. Reservoir pressure distributions may also be strongly affected. A more detailed discussion is given in (Pruess, 1994).

SUMMARY AND CONCLUSIONS

The complex interplay between fluid and heat flow, and the presence of gravitational instabilities and reservoir heterogeneities make mathematical modeling of water injection into vapor-dominated systems extremely challenging. Currently available simulation techniques are capable of dealing with the complexity of "real" field problems as they arise at The Geysers. New developments attempt to better represent reservoir heterogeneities, to increase the size of problems that can be handled, and to make simulation capabilities available on "small" computers, such as PCs (Antunez et al., 1994).

ACKNOWLEDGEMENT

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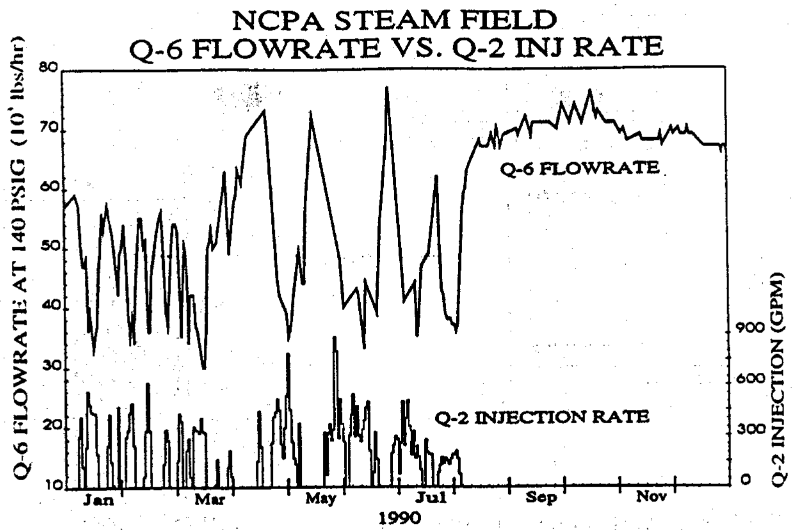

Figure 1. Injection and production data from wells Q-2 and Q-6, southeast Geysers (from Pruess and Enedy, 1993).

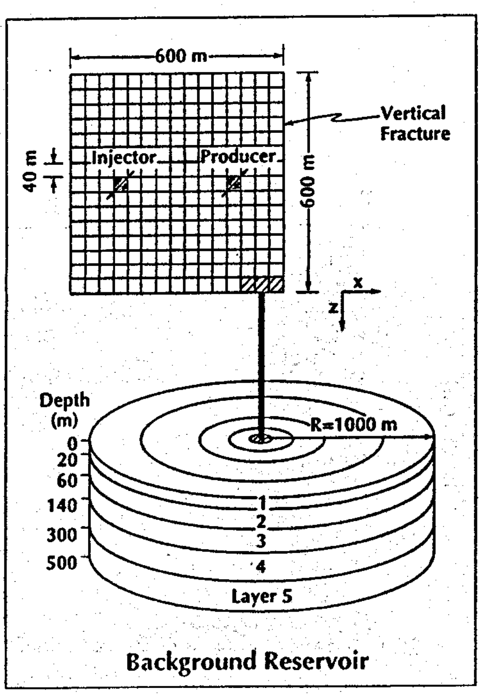

Figure 2. Schematic diagram of fractured reservoir model used in numerical simulations (Pruess and Enedy, 1993).

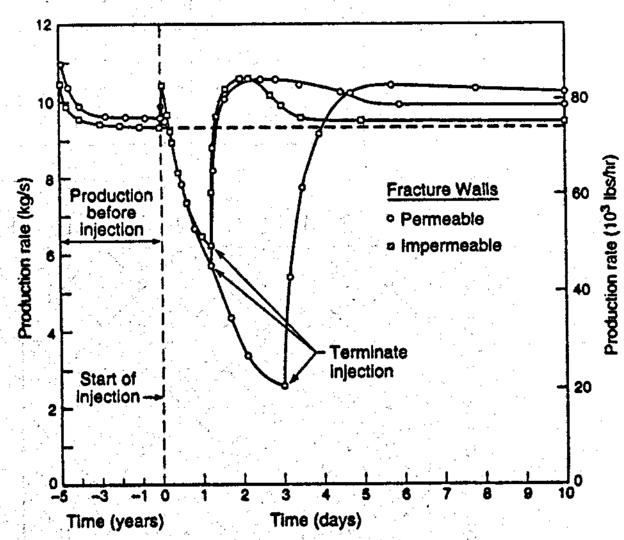

Figure 3. Simulated production before, during, and after injection (Pruess and Enedy, 1993).

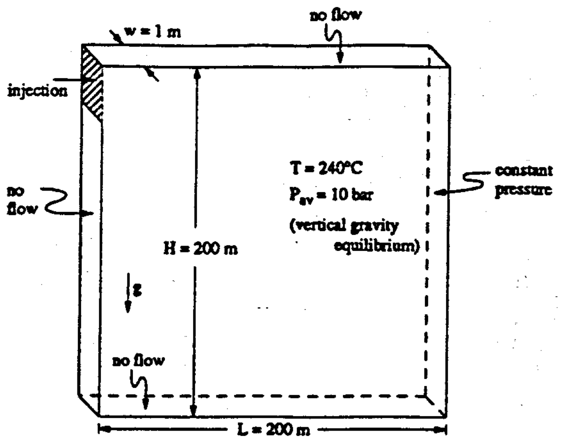

Figure 4. Vertical section model for study of grid orientation effects (from Pruess, 1991b).

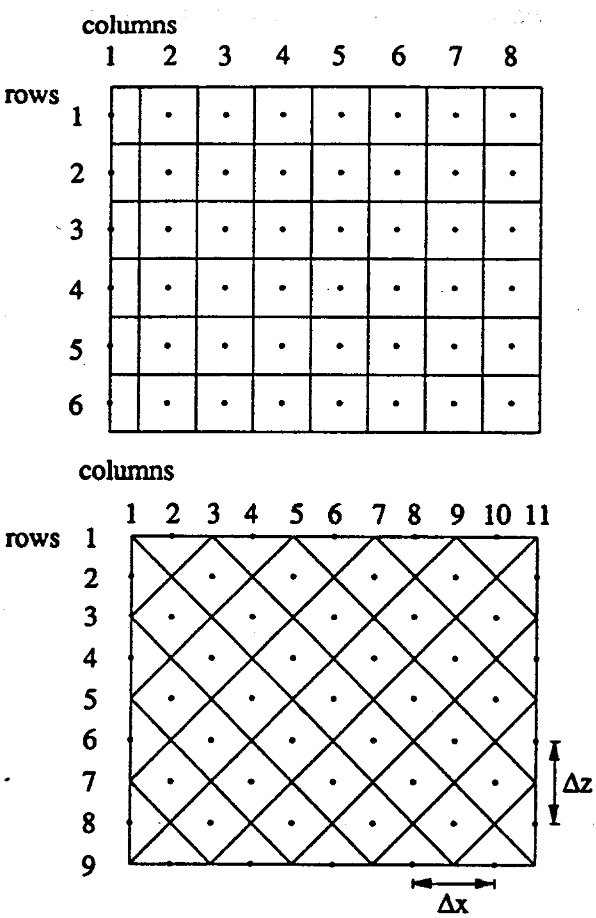

Figure 5. Schematic of "parallel" and "diagonal" grids used for modeling injection in 2-D vertical section (Pruess, 1991b).

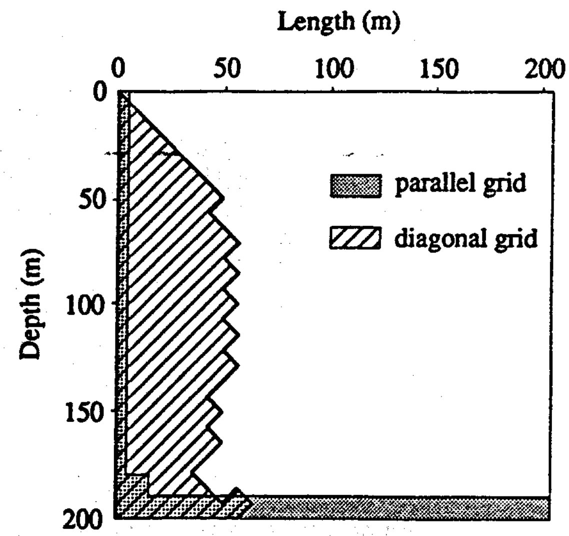

Figure 6. Simulated plumes after 717 days of injection in parallel and diagonal 5-point grids (Pruess, 1991b).

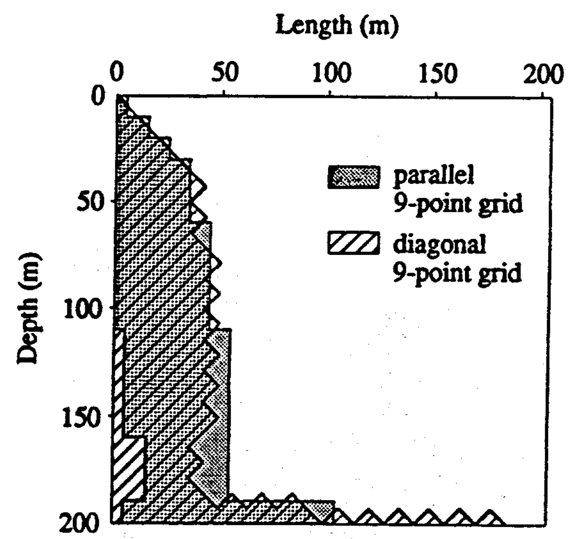

Figure 7. Simulated injection plumes after 717 days for 9-point differencing (Pruess, 1991b).

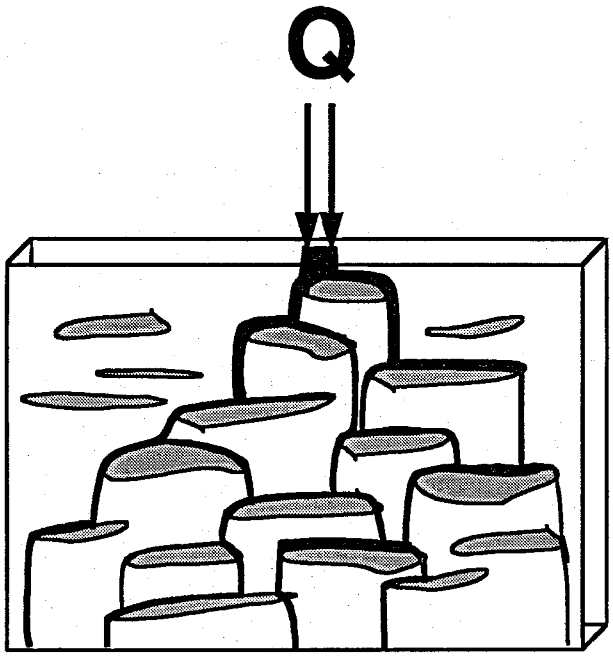

Figure 8. Schematic of liquid plume descent in a heterogeneous medium. Impermeable obstacles are shown by dark shading (from Pruess, 1994)

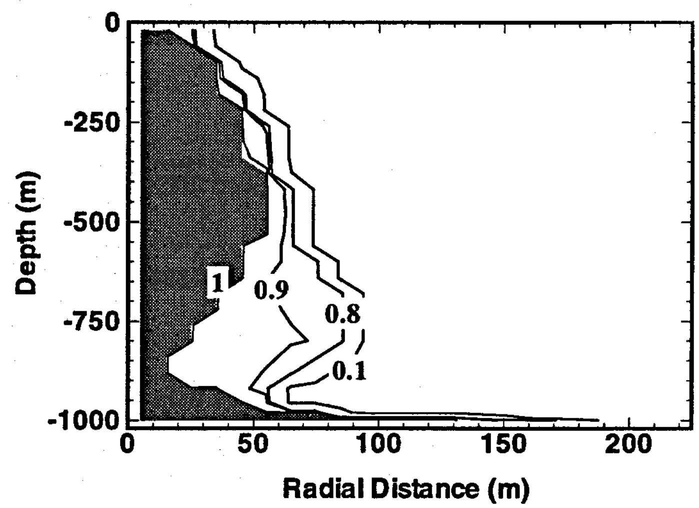

Figure 10. Injection plume (liquid saturation contours) after 692 days, no phase dispersion (Pruess, 1994).

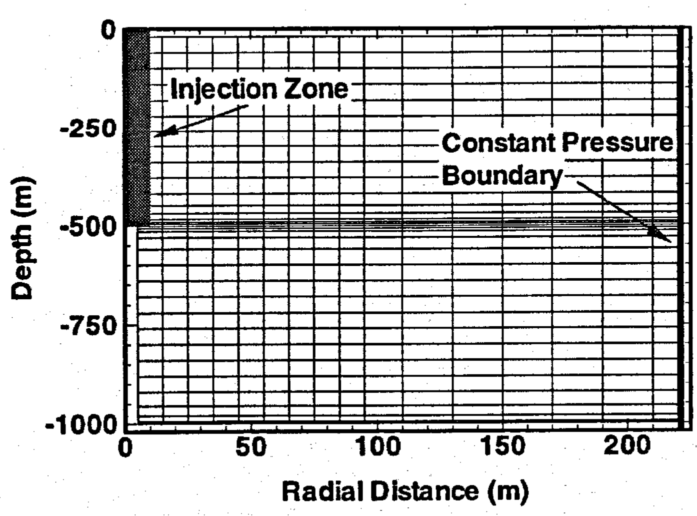

Figure 9. Gridding for 2-D R-Z injection problem (Pruess, 1994).

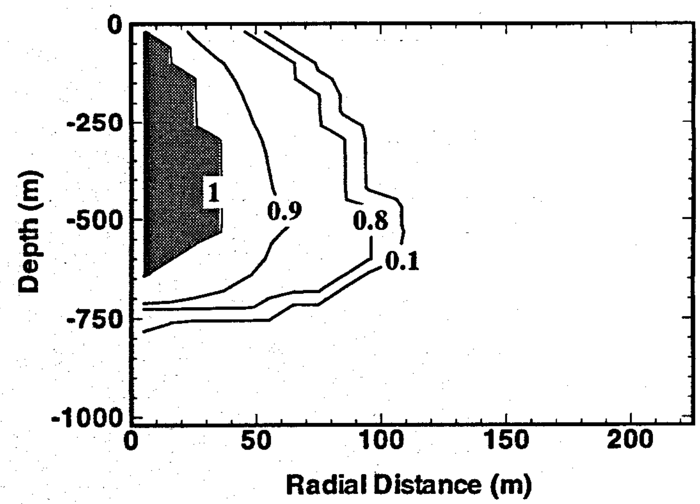

Figure 11. As Fig. 10, but transverse phase dispersivity of 10 m (Pruess, 1994).

THE EFFECTS OF ADSORPTION ON INJECTION INTO GEOTHERMAL RESERVOIRS

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ABSTRACT

The effects of an adsorbing phase on the injection of liquid and eventual production of vapor from a low-porosity, vapor dominated geothermal reservoir was studied. The magnitude of delay caused by adsorption, diffusion partitioning, preferential partitioning, and permeability variation were compared. Results were then compared to measured tracer production data at the Geysers to determine the most likely delay mechanism for injected tracer at the Geysers.

A one-dimensional numerical model describing vapor flow in a porous medium in the presence of a sorbing phase was used to investigate the delay of injected tracer caused solely by the sorbing phase. An analytical model was used to describe delay effects due to diffusion partitioning of tracer from the vapor phase into the liquid phase. Properties of steam and tracer used in Geysers tracer studies were compared to determine the effects of preferential partitioning. Finally, a streamline model of a tracer study was used to determine the magnitude of permeability delays possible using permeability values measured at the Geysers.

It was concluded that adsorption alone has very little effect on the delay of injected tracer indicating that little recharge of the adsorbed mass occurs for a typical injection program at the Geysers. Diffusion partitioning was shown to have a larger effect on tracer delay than adsorption while preferential partition was shown to have no effect. Permeability variation was shown to have the largest effect on tracer delay. Tracer delay was shown to be approximated closely by known permeability variations even when adsorption and diffusion effects are ignored.

INTRODUCTION

Adsorbed liquid has long been known to significantly contribute to the mass stored in geothermal reservoirs. Measurements of adsorption isotherms in a range of porous solids and with a variety of fluids (Hsieh and Ramey, 1981) showed that adsorption can be significant in many geothermal and natural gas reservoirs. Application of measured adsorption data to volumetric analysis of the Geysers led to the conclusion that most of the initial mass in the reservoir was probably stored as an adsorbed liquid (Economides and Miller, 1985). Recent measurements of adsorption in Geysers core material indicate that at high pressures, the low porosity portions of the Geysers reservoir may be almost completely saturated by an adsorbed phase (Shang, et. al., 1993). These same measurements have also provided increasingly accurate descriptions of adsorption isotherms in the Geysers allowing increasingly accurate estimates of the effects of an adsorbed phase on reservoir performance for a wide range of pressures.

Due to pressure decline in the Geysers, injection programs have been undertaken in a number of areas in the reservoir. The purpose of these injection programs is to increase reservoir pressure, replace produced liquid mass, and ultimately increase production rate and the productive life of the reservoir. In order to assess the effectiveness of injection programs it is necessary to closely monitor the propagation of injected liquid in the reservoir. Monitoring of injected fluid may be accomplished either by monitoring production and pressure response in the reservoir or by introducing tracer along with the injected liquid and studying the production of the tracer. Production of the tracer provides information on the propagation of injected liquid in the reservoir.

In the Geysers, several tracer tests have been carried out and tracer production has been used to infer characteristics of the fluid propagation through the reservoir. In general, production of tracer at the Geysers has been characterized by long production times indicating some delay mechanism which significantly spreads the tracer concentration in the reservoir. It is the purpose of this paper to investigate the possible tracer delay mechanisms at the Geysers and to determine the size of delay of each. Specifically, the effects of adsorption on tracer delay are investigated to determine the influence of adsorption on injection programs at the Geysers.

INJECTION AT THE GEYSERS

Injection of cooling tower condensate began at the Geysers in 1969 with an injection to production ratio of 5 %. At initiation of the injection program, all injectate was cooling tower condensate. In 1980, fresh water injection, extracted from Big Sulfur Creek, was initiated into the Units 1-6 area. A second fresh water facility began providing water for injection in 1983. Fresh water injection hit a peak of 7 % of production in 1983 while total injection has stayed fairly constant at 20 - 25 % since the early 70's.

In general, two strategies have been used at the Geysers -- deep injection and shallow injection. In deep injection, outlying wells with deep steam entries are used as injectors in order to minimize downward channeling of liquid water to nearby wells. Effects of deep injection are often difficult to quantify and while short term benefits have been observed, it has been assumed that most of the benefits are long term (UNOCAL, 1992). The shallow injection strategy uses injection wells with steam entries higher than surrounding wells and relies on the vaporization of injected water as it channels toward surrounding production wells. Since breakthrough of shallow injectate is usually fairly rapid, benefits of shallow injection are generally short term. A number of injection programs have been undertaken at the Geysers. Some successful programs are outlined below.

Unit 14 injection, begun in 1983, and Unit 17 injection, begun in 1988 were both deep injection projects. The programs met with limited success, but both projects had some short term benefits.

Units 9-10 injection, initiated in 1992, was a shallow injection project, UNOCAL's first, and was expected to provide short-term benefits. Increased production was almost immediate, but problems with watering out of producers limited the program's success.

In September 20, 1989, the LPA injection program was initiated with injection into C-11 (Enedy, et. al., 1992). The LPA injection program was very successful and resulted in both recharge of liquid mass and increases in production. It demonstrated that injection can be used as a means to increase production from the Geysers reservoir and increase the efficiency of heat extraction from the reservoir.

Planning of future successful injection programs must rely on an understanding of the mechanisms which affect the flow of injected fluids. In this paper, the mechanisms which can delay the production of injected tracer are studied. By understanding the magnitude of tracer delay caused by several reservoir mechanisms, conclusions can be drawn about which characteristics of the reservoir must be studied to increase the efficiency of injection programs.

TRACER DELAY MECHANISMS

Mechanisms which may delay the propagation of tracer initially in the vapor phase are adsorption, diffusion partitioning, preferential partitioning, and permeability and flow length variations within the reservoir. Adsorption delays injected tracer when reservoir pressure is increased by injection and some of the injected mass is adsorbed and becomes immobile. Since tracer which resides in the vapor phase is also immobilized by adsorption, the rate of propagation of the tracer can be reduced. Another way in which the adsorption process reduces the propagation of tracer is by decreasing the rate of pressure decline in the reservoir. Since pressure drawdown is reduced by desorption of adsorbed liquid, pressure gradients in the reservoir are decreased and the flow velocity of vapor is also decreased.

Diffusion partitioning refers to the diffusion of tracer from the flowing vapor phase into the immobile adsorbed phase due to a concentration gradient. Diffusion partitioning occurs even in the absence of net mass transfer between the vapor and adsorbed phases. If diffusion is large with respect to convection of the vapor phase, concentration equilibrium between the two phases may be assumed instantaneous and the delay in tracer propagation due to diffusion can be calculated.

Due to the heterogeneous nature of Geysers reservoir material, permeability variations and differences in the flow path lengths between an injector and producer can also cause delays in the propagation of injected tracer. Estimates of flow path lengths for a given well pair and use of measured permeabilities in the Geysers can be used to calculate the probable spread in the production concentration of tracer due to these effects.

NUMERICAL MODEL

A numerical model was constructed to study the effects of adsorption on the propagation of injected tracer. A one-dimensional, linear flow model with constant cross section and rock properties was used to model adsorption effects. An implicit pressure, explicit saturation and temperature solution scheme was used. It was assumed that the adsorbed phase is immobile and that the only flowing phase is vapor. The numerical model was validated against known analytical solutions describing the flow of constant compressibility liquids and against analytical solutions for the flow of highly compressible liquids in the presence of a sorbing phase (Hornbrook, 1994). The numerical model was shown to match all analytical solutions exactly. Adsorbed phase properties were assumed to be identical to saturated liquid water which has been shown to be valid for the Geysers geothermal reservoir (Hornbrook, 1994).

EFFECTS OF ADSORPTION ON TRACER PROPAGATION

The purpose of this section is to delineate the effects of adsorption on tracer propagation in a porous media. In order to isolate the effects of adsorption, the effects of diffusion, preferential partitioning, and permeability variations were ignored.

Since the tracer considered in this report is tritiated water which behaves very much like water, the propagation of tracer was modeled as the propagation of a water component:

$$(1)\quad y_i^{n+1}T_{i+1/2}(p_{i+1}-p_i)^{n+1} - y_{i-1}^{n+1}T_{i-1/2}(p_i-p_{i-1})^{n+1} - \frac{\Delta x}{\Delta t}\left[(y_{vi}\phi_i\rho_{vi}S_{vi})^{n+1}-(y_{vi}\phi_i\rho_{vi}S_{vi})^{n}\right] - \frac{\Delta x}{\Delta t}\left[(y_{ai}\phi_i\rho_{ai}S_{ai})^{n+1}-(y_{ai}\phi_i\rho_{ai}S_{ai})^{n}\right] + y_{inj}Q_{inj} - y_{prod}Q_{prod} = 0$$

where, the subscripts *a* and *v* refer to the adsorbed and vapor phases, respectively, the subscripts *i* refer to block numbering, and the superscripts refer to time steps in the numerical computation.

Adsorbed phase saturation is related to an adsorption isotherm by:

$$(2)\quad S_a = \frac{1-\phi}{\phi}\frac{\rho_r}{\rho_a}X(p/p_s)$$

where, X denotes the mass adsorbed per mass of rock at a given relative pressure (p/p_S).

In Eqn. 1, the pressures, saturations, and fluid properties determined at the end of each time step in the computation of mass transport of vapor are used to compute the mass fraction of injected mass in the vapor phase, y_V, in each block. In order to calculate the mass fraction in the vapor phase explicitly, a relation between the mass fraction in the adsorbed phase and in the vapor phase is needed. Since the goal in this section is to isolate adsorption effects, it was assumed that the mass fraction of injected tracer in the adsorbed phase is a weighted average of the fraction adsorbed at the old time step and the change in adsorbed mass over the time step:

$$(3)\quad y_a^{n+1} = \frac{y_v^{n+1}\Delta_t S_a + y_a^n S_a^n}{S_a^{n+1}}$$

By making the assumption that concentrations are a function of the adsorptive process and are not affected by diffusion, the effects of adsorption are isolated.

By varying initial and boundary conditions in numerical simulation of tracer flow, the range of adsorption effects on tracer propagation may be determined.

In the numerical simulations described below, the following form of the langmuir equation was used to describe adsorption isotherms:

$$(4)\quad X\left(\frac{p}{p_s}\right) = d\left[\frac{c(p/p_s)}{1+(c-1)(p/p_s)}\right]$$

where, c is the shape factor which determines the rate at which sorption occurs, and d is the magnitude factor which determines the maximum amount adsorbed at a relative pressure of 1.0.

Figure 1 shows a range of isotherms with d=1 and with c varying over the entire range of shapes considered in this research.

Figure 2 shows tracer profiles in a 4 m long simulated core for injection when steady state conditions have been reached in the core. Injection and production rates in the core were held constant for these experiments and steady-state conditions were allowed to develop. When steady state conditions had developed, the injection block pressure was approximately 7 MPa while the production block pressure was about 0.5 MPa. Clearly, when steady-state is reached, the presence of an adsorbed phase increases the propagation rate of tracer. This is due to the fact that the amount adsorbed at a given point in the reservoir is constant and, therefore, the area open for flow is reduced. This causes an increase in the tracer flow rate which is initially in the vapor phase.

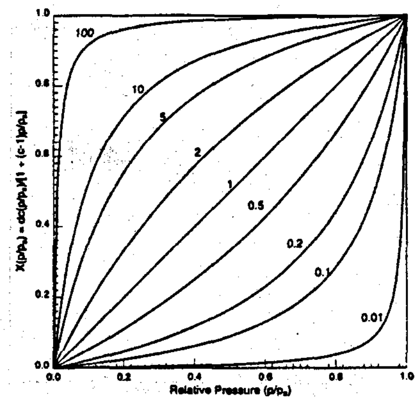

Fig. 1: Langmuir isotherms

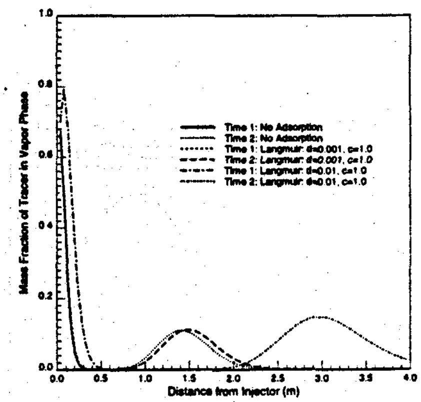

Fig. 2: Steady state flow

Figure 3 shows the tracer propagation in a core for conditions similar to those described above except that steady state conditions were not allowed to develop. In this case, the tracer begins moving faster due to a reduced flow area but eventually decreases in velocity due to adsorption of the vapor in which the tracer resides. The concentration of tracer when adsorption is occurring is also reduced due to loss of mass of the tracer to the adsorbed phase. Results shown in Figure 3 represent extreme conditions for the isotherm selected because the range between injection and production pressures is still large. Despite such large pressure differences, the tracer delay is shown to be only about 30%.

Figure 4 shows the rate of production of tracer injected into a 4 m long core. In this simulation, conditions approximating those at the Geysers were chosen to determine the likely effects of adsorption on tracer delay at the Geysers. Core temperature was set at a constant 300 C and injection was initiated at a relative pressure of 0.5. While the temperature is higher than that at the Geysers, the relative pressure is analogous. Tracer production is shown for injection with no adsorption, and for injection with adsorption for two controlling langmuir isotherms. In both cases, the magnitude factor is 0.01 which corresponds to an initial adsorbed phase saturation of 75%. This is an

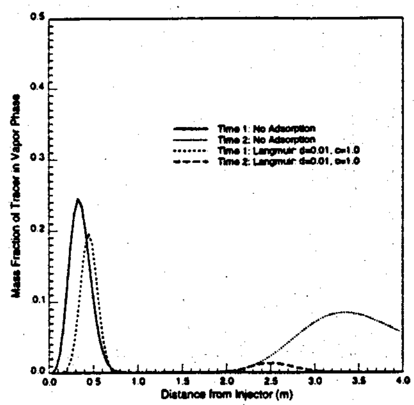

Fig. 3: Transient flow

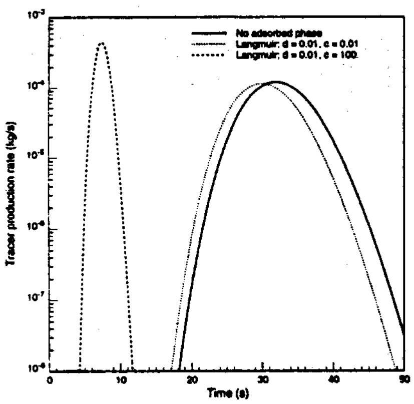

Fig. 4: Approximate Geysers tracer response

extreme case but is used to highlight adsorption effects. The shape factors used are 0.01 which is a concave up isotherm similar in shape to isotherms measured at the Geysers and 100 which represents a concave down isotherm for which desorption only occurs at low pressures.

It is shown in Figure 4 that the presence of an adsorbed phase increases the propagation of injected tracer. The reason for this increase in propagation is that the isotherms are nearly flat for relative pressure corresponding to initial injection into the core. Therefore, very little adsorption occurs to reduce the concentration of tracer in the vapor phase and very little pressure support is received by the production well to reduce the flow rate of vapor.

Based on these numerical experiments and others (Hornbrook, 1994), it was concluded that adsorption plays a very minor role in the transport of injected tracer in geothermal reservoirs. In the Geysers reservoir, tracer transport is probably increased slightly by the presence of an adsorbed phase.

EFFECTS OF DIFFUSION PARTITIONING ON TRACER PROPAGATION

Diffusion of tritiated water into the immobile adsorbed water phase was considered as a possible mechanism for delay of injected tracer. In order to understand the likelihood of diffusion partitioning, the relative sizes of the convective and diffusive fluxes must be computed and compared. The porosity in the Geysers and in other geothermal reservoirs is often very complicated (Fig. 5) with flow taking place mainly in the fractures and adsorbed phase storage occurring in the interparticle porosity (Gunderson, 1993). By comparing the convective flux computed using measured Geysers permeability and an estimated diffusive flux of tracer, it is possible to determine the range of permeabilities for which instantaneous diffusive equilibrium is likely.

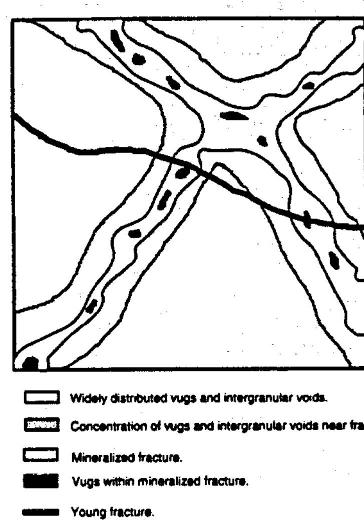

Fig. 5: Pore structure at Geysers (after Gunderson)

The diffusive flux of tracer is described by Fick's Law:

$$(5)\quad v_{diff} = -D_{mol}\frac{\partial C}{\partial x}$$

where, D_{mol} represents the molecular diffusivity into a bulk phase. The diffusivity of tritium has been reported as 2.3×10^{-5} cm^2/s (Leap, 1992). In porous material, however, the diffusivity of a substance is decreased due to the tortuosity of porous matrix (Aris, 1975).

$$(6)\quad D_{pore} = D_{bulk}\left[\frac{\phi}{a^2}\right]$$

where, a is the actual pore length per distance in the direction of diffusion. Assuming that the interparticle porosity is about 1% (Gunderson, 1993) and that the measure or tortuosity, a, is 2, the maximum diffusivity of tritiated water out of the vapor phase and into the adsorbed liquid phase was estimated to be 5.8×10^{-10} m/s. Assuming Darcy's law is a valid model for convective flux, the range of flow rates likely in the Geysers was found to be 2.9×10^{-5} to 2.9×10^{-9} m/s. Thus, except in the extremely low permeability regions of the reservoir, convective flux is significantly greater than the diffusive flux. Since is was demonstrated that, for at least some regions of the Geysers reservoir, diffusive partitioning is important, computations of delay caused solely by diffusion were made. An analytical solution for convection and diffusion of a tracer in the presence of an immobile phase has been constructed (Antunez, 1984). In the derivation, instantaneous concentration equilibrium between the phases was assumed. The expression for concentration as a function of location and time for constant injection of tracer into a porous media initially free of tracer is:

$$(7) \quad \frac{C(x,t)}{C_0} =$$

$$\frac{1}{2}\exp\left[\frac{xu_v}{K}\right]\operatorname{erfc}\left[\frac{x\sqrt{\dfrac{S_v\rho_v + S_a\rho_a}{KS_v\rho_v}}}{2\sqrt{t}} - \frac{\dfrac{u_v}{K}\sqrt{t}}{2\sqrt{\dfrac{S_v\rho_v + S_a\rho_a}{KS_v\rho_v}}}\right]$$

$$+\frac{1}{2}\exp\left[\frac{xu_v}{K}\right]\operatorname{erfc}\left[\frac{x\sqrt{\dfrac{S_v\rho_v + S_a\rho_a}{KS_v\rho_v}}}{2\sqrt{t}} + \frac{\dfrac{u_v}{K}\sqrt{t}}{2\sqrt{\dfrac{S_v\rho_v + S_a\rho_a}{KS_v\rho_v}}}\right]$$

In order to isolate the effects of diffusive partitioning, steady state flow conditions were assumed. When steady state flow conditions prevail, pressure at a given point in the reservoir is constant and, therefore, adsorption does not occur as vapor flows. This allows the study of diffusion into the immobile adsorbed liquid phase. In Eqn. 3, the vapor velocity, u_v is given by:

$$(8) \quad u_v = \frac{q_{sc}}{\phi S_v}$$

From Geysers data, the velocity of vapor was computed as about 8×10^{-6} m/s in the very low permeability regions of the reservoir where diffusion effects are large. From adsorption isotherm measurements (Shang, et. al, 1993) the saturation of adsorbed liquid was found to be about 3%. Saturated vapor and liquid properties were used in computations. The effects of diffusion partitioning on tracer propagation are shown in Figure 6. Tracer profiles with no adsorbed phase present and with an adsorbed phase saturation approximating conditions at the Geysers are shown. The effective velocity of injected tracer is shown to be reduced by about a factor of two due to diffusion into the adsorbed phase.

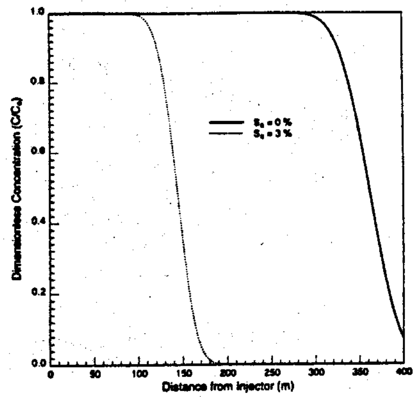

Fig. 6: Diffusion tracer delay

EFFECTS OF RESERVOIR HETEROGENEITY ON TRACER PROPAGATION

In order to investigate the effects of reservoir heterogeneity on the propagation of injected tracer, a model of the reservoir must be constructed which captures the flow characteristics of the reservoir. In this research, a stream tube model was constructed because it allows application of the linear flow model to complicated flow patterns. The DX-8 tracer injection test was modeled by assuming steady state flow between the injector and surrounding producers. Excess production was made up by introduction of surrounding imaginary injection wells. The reservoir was assumed to be homogeneous. Based on reported flow rates, and including the producers accounting for about 90% of recovered tracer, streamlines were generated for the DX-8 tracer study. Figure 7 shows developed streamlines for all wells included in the study.

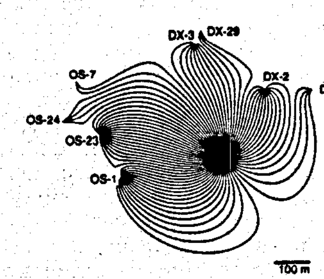

Fig. 7: Total DX-8 Streamlines

A single well pair was chosen to perform experiments on reservoir heterogeneity. The DX-8/OS-23 well pair was chosen because OS-23 accounted for approximately 34% of all produced tritium. The streamlines for the DX-8/OS-23 well pair are shown in Figure 8, and the tracer concentration in the produced vapor is shown in Figure 9. Concentration data are calculated from reported tritium production rate data (UNOCAL, 1991).

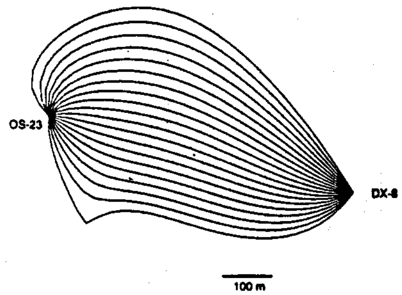

Fig. 8: OS-23/DX-8 Streamlines

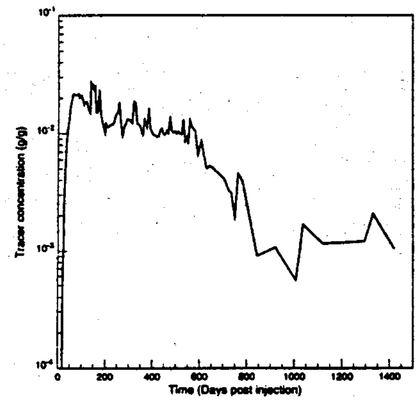

Fig. 9: Measured tracer concentration

Using the length of each stream tube shown in Figure 8 and the average cross-sectional area of each tube, a linear model of each tube was constructed. The permeability was varied in these stream tubes based on reported Geysers permeability. Slug injection of tracer was simulated and tracer concentration in the production block was monitored for each linear stream tube. By normalizing the initial breakthrough concentration of tracer to the measured value, and computing production tracer concentrations for all stream tubes, the effects of permeability and well separation on tracer propagation can be studied. Figure 10 shows a comparison of measured and computed concentrations. Production block concentrations for two of the stream tubes are shown to illustrate the range in tracer response possible for known Geysers permeabilities and well separations. The figure shows that even without adsorption or diffusion partitioning effects, the permeability and geometric variations present in the Geysers are sufficient to cause measured production delays in injected tracer.

Therefore, in designing injection programs, the communication between injection and production wells is the most important constraint with both diffusive partitioning and adsorption effects insignificant in comparison.

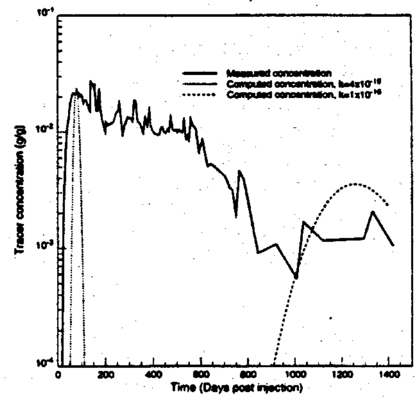

Fig. 10: Computed tracer concentration

CONCLUSIONS

Based on the results described above, the following conclusions about the effects of adsorption and other delay mechanisms on the propagation of injected tracer are:

1. The effects of adsorption on tracer propagation are small for adsorption saturations likely in geothermal reservoirs. For conditions likely at the Geysers, the presence of an adsorbed mass probably slightly increases the rate of propagation of injected tracer.

2. The effects of diffusive partitioning of tracer are large than those due to adsorption alone. In the Geysers, instantaneous concentration equilibrium does not occur in high permeability portions of the reservoir, but in low permeability regions diffusive partitioning may reduce tracer flux by as much as 50%.

3. Preferential partitioning due to differences in the boiling characteristics of the tracer and the carrying liquid does not occur to any measurable degree in the Geysers. The saturation curve for tritium is nearly identical to that of water.

4. Permeability and geometric variations, without any adsorbing or diffusive partitioning effects, is sufficient to explain tracer production characteristics at the Geysers. Thus, by far the largest factors in the design of injection programs are the reservoir permeability in the region of the injector and the separation between injector and producer pairs.

NOMENCLATURE

Variables

C	Mass Concentration	Dimensionless
D	Diffusivity	m^2/s
k	Permeability	m^2
p	Pressure	Pa
Q	Mass flow rate	kg/s
q	Volumetric flux	m^3/s

S	Saturation	Dimensionless
T	Transmissibility	kg/(m^2 Pa s)
t	Time	s
u	Velocity	m/s
X	Adsorbed amount	g-ads./g-rock
x	Distance	m
y	Mass fraction	Dimensionless
μ	Viscosity	Pa s
ϕ	Porosity	Dimensionless
ρ	Density	kg/m^3

Subscripts and Superscripts

a	Adsorbed phase.
bulk	Bulk phase.
diff	Diffusive quantity.
i	Counter for a block in numerical model.
mol	Molar quantity.
n	Time step counter in numerical model.
pore	Residing in a pore.
r	Rock.
s	Saturation conditions.
t	Denotes time operator.
v	Vapor phase.
0	Initial condition.

ACKNOWLEDGMENTS

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Microearthquake Monitoring and Seismic Imaging at The Geysers

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Lawrence Livermore National Laboratory
Ernest L. Majer, John Peterson, Art Romero, Ann Kirkpatrick
Lawrence Berkeley Laboratory

Abstract

We are monitoring two high-frequency, high-resolution microearthquake networks at The Geysers. The first network consists of 16 stations and is located in the northwest portion of the Geysers. This array is in an area that is representative of a high-temperature, deep, reservoir environment. The second network consists of 13 stations located in the southeast Geysers around the location of the cooperative injection experiment. We are using the data from the networks to compute seismic velocity and attenuation images and earthquake parameters such as precise location and rate and manner of energy release. Our goal is to evaluate the use of this information to manage steam release from geothermal reservoirs. We are supporting this effort with laboratory measurements of velocity and attenuation on Geysers core samples under varying degrees of saturation to help us better interpret our seismic images. To date we find that microearthquake activity follows injection activity, and the dry, low-pressure portions of the reservoir are characterized by low velocity and high attenuation.

Introduction

Seismicity is known to reflect injection activity at The Geysers (Stark, 1992). In other geothermal regions, seismic velocity and attenuation information can be used to infer saturation conditions in the reservoir (Evans and Zucca, 1988; Zucca and Evans, 1992). We are applying these techniques using higher-frequency seismic data than was available in these earlier studies in an attempt to improve resolution enough to be able to monitor the effects of steam production and the migration of injected fluids at the Geysers on a local scale. We currently operate two networks at the Geysers (Figure 1). The northwest network consists of 16, three-component borehole stations that digitally telemeter their data to a central site. The southeast network consists of 13 three-component surface stations that also digitally telemeter their data to another central site. Both networks use sample rates of 500 Hz per channel, which provides usable data over 100 Hz. The completed central Geysers study was done using data donated by the UNOCAL Corporation.

Inference of the reservoir parameters from seismic information depends on knowing the behavior of reservoir rocks under in situ temperature and pressure conditions.

Geysers Geothermal Field

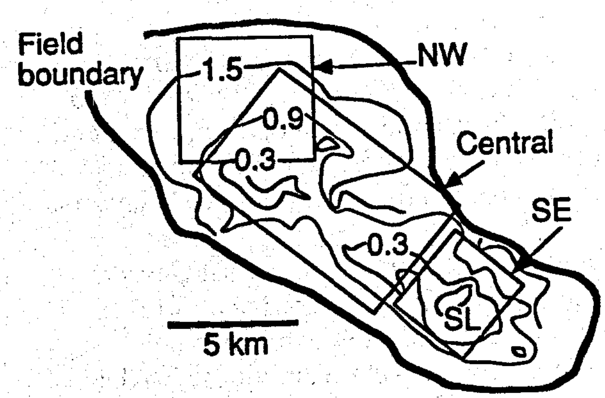

Figure 1. Geysers geothermal field showing the locations of our study areas. The contours are the depth to the dry steam reservoir below sea level (after the data from Field Operators, 1992).

These kinds of laboratory measurements are not commonly made and have not been made on rocks that are even a close analog to Geysers rocks. Therefore, we have undertaken a laboratory measurement program to characterize actual Geyser reservoir graywacke. We are calculating the basic properties, including dry and saturated densities, and the propagation velocity and attenuation for compressional and shear waves.

Seismicity

In March 1990, in conjunction with the Coldwater Creek Operator Company (CCOC, now CCPA), we began to collect, analyze, process, and interpret the microearthquake (MEQ) data in the northwest Geysers geothermal field in two phases. First, we monitored the initial time period from just before production and injection activities began in the Northwest Geysers (late 1987) to approximately one year later. The second monitoring period began in late 1993 and is continuing. In the initial data collection period we made detailed analyses, processing approximately 6000 events. Processing the data revealed a strong correlation between injection and seismicity. However, we also found that the injection seismicity is superimposed on a more general pattern of seismicity related to such factors as "natural" seismicity and effects of fluid withdrawal. In essence, the seismicity patterns in this area are related to various reservoir parameters (Figure 2). We plan to continue the second phase of monitoring and compare the results to the initial phase as well as to results from the Southeast Geysers.

Several operators in the Southeast Geysers region undertook a cooperative task to understand more fully the mechanisms associated with injection activities. To date, MEQ rates and location show a good correlation with these activities (M. Stark, UNOCAL, personal communication). UNOCAL presently operates an analog array of MEQ stations in the injection region.

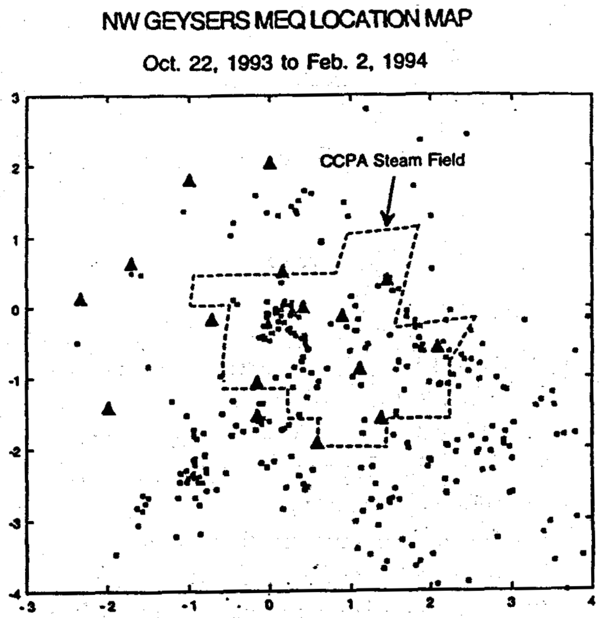

Figure 2. Seismicity in the northwest Geysers calculated using our network. Triangles = locations of seismic stations. Squares = locations of microearthquakes.

Although this array is very useful, precisely locating events requires digital acquisition at higher frequency contents using three-component data. The work in the Northwest Geysers demonstrates the utility of multi-component, high-frequency, digital data.

During the last year we upgraded the 13-station array in the Southeast Geysers to the latest version of the Nanometrics equipment, which streamlined the data collection and processing. It also eliminated many issues about data precision and accuracy because of operating an array with incompatible equipment. Examples of 1993 data are shown in Figures 3 and 4. Initial results indicate that we will be able to detect and locate three to four times the number of events detected by the UNOCAL array.

Seismic Imaging

Liquid water is injected into the reservoir to slow the decline of steam production. Understanding the movement of the water after it leaves the injection well is important

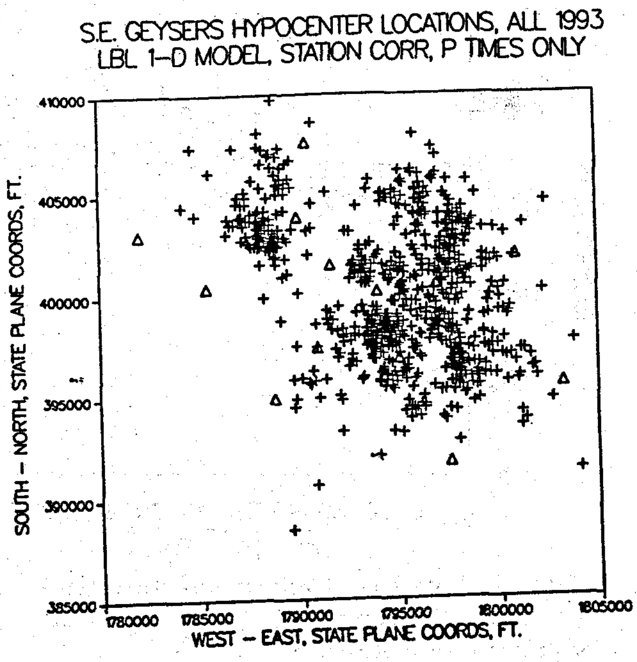

Figure 3. Map view of seismicity in the southeast Geysers calculated using our network. Triangles = seismic stations. Pluses = locations of microearthquakes.

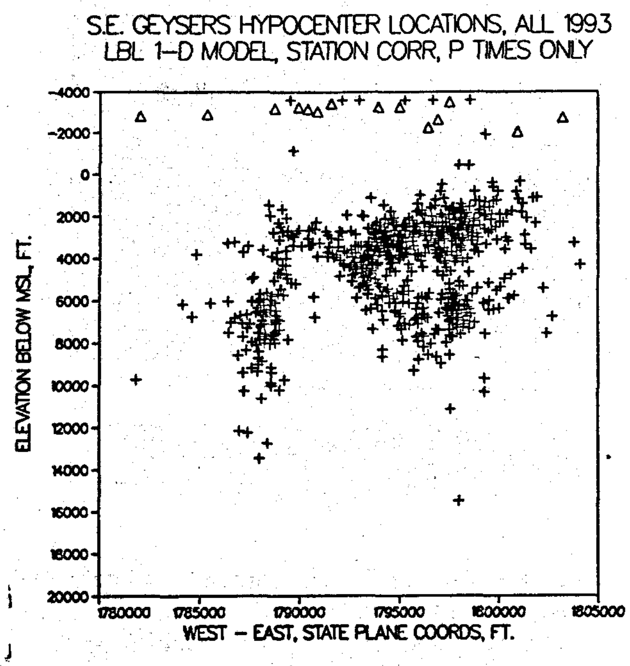

Figure 4. WestEast cross section of the seismicity in the southeast Geysers. Triangles = seismic stations. Pluses = locations of microearthquakes.

so that the injection process can be optimized. In past studies (Zucca and Evans, 1992) we used seismic attenuation and velocity images to map saturation conditions in other geothermal reservoirs. Our goal is to map the movement of liquid water away from the injection well in the southeast Geysers. Both P-wave velocity and attenuation are sensitive to changes in saturation, but have different responses. We use variations in the patterns of arrival time and frequency content of the P- and S-waves to calculate velocity and attenuation structure, respectively. Our seismic images are calculated from recordings of earthquake-generated seismic waves that pass through the region of interest, in this case, the geothermal field. To date, we have used mostly P-waves in our analyses. However, we are beginning to include S-waves, which should increase the reliability of our saturation estimates because S-waves are not as sensitive to changes in saturation as are the P-waves. Therefore, including shear wave information should make it easier to determine whether a given change in velocity is due to saturation variations or a change in lithology. Figure 5 shows an example of a seismic image from our completed work in the central Geysers. Note that the low-velocity (darker) parts of the image follow quite closely the regions of known low pressure (i.e., the 1.7 MPa contour) in the central Geysers.

Laboratory Measurements

Previous laboratory work with sandstone and granite at ultrasonic frequencies demonstrated that wave velocity and attenuation are sensitive to fluid saturation for reservoir conditions simulated in the laboratory. Although this result can be applied to the field in a qualitative way, the measurements were made for rocks very different than the graywackes and felsites at The Geysers. The previous studies also ignored the potential effects of velocity dispersion on extrapolating laboratory results to lower frequencies.

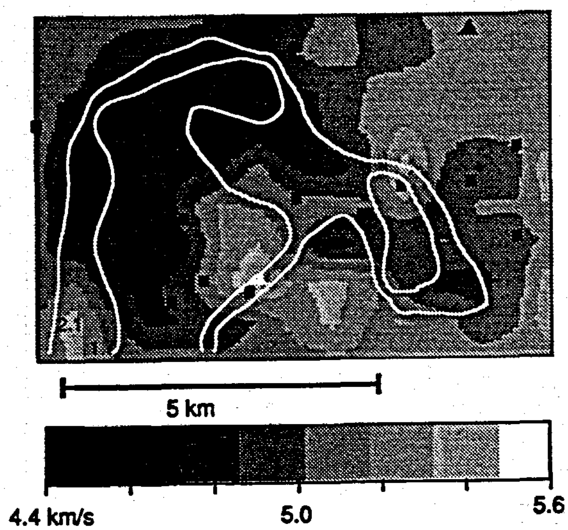

Figure 5. P-wave velocity image for a horizontal slice at a depth of 0.9 km below sea level in the central Geysers. Solid squares = locations of power producing units. Pressure contours are in megapascals and are adapted from Williamson (1992).

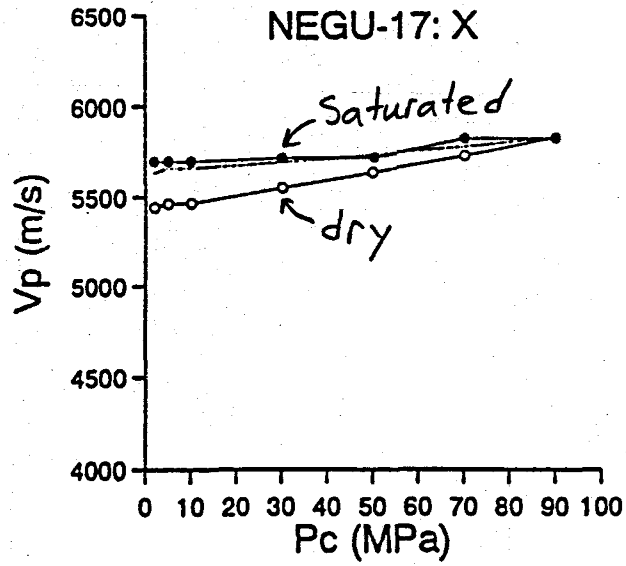

Figure 6. P-wave (Vp) velocity measurements for wet and dry Geysers reservoir graywacke with increasing pressure.

We measured fluid distribution within a half core of Franciscan graywacke recovered from reservoir depth (2599 m) from well NEGU-17. The entire sample, scanned with 150-kV x rays, produced a series of tomograms that clearly show filled and partially filled veins in the graywacke. Experiments are now underway at 150 kV and 4 MV to determine whether the density resolution is sufficient to distinguish pore fluid and open porosity in nominally saturated samples.

The NEGU-17 core was then divided to produce appropriate samples for ultrasonic and low-frequency measurements (Boitnott and Bonner, 1994). A difference in velocity with respect to pressure would imply fractures had occurred in the graywacke. In this case, ultrasonic compressional and shear velocities show a weak pressure dependence to 90 MPa for both the dry and saturated cases (Figure 6), which indicates that the drilling and recovery process did little damage to the matrix. Our P-wave velocity results for Geysers rocks show only a small change (3%) with liquid saturation (Figure 6), while we observe in the field a much larger difference (20%; Figure 5). This apparent discrepancy is probably due to our sample being quite small and only including matrix porosity. Partially healed veins and fractures are also significant contributors to porosity in Geysers rocks. In our future work, we plan to include the effects of these features. We also plan to measure attenuation under varying conditions.

Conclusions

We continue to monitor the northwest and southeast Geysers arrays for changes in seismicity from steam production and liquid injection. Our previous seismic imaging results suggest that it is feasible to map changes in liquid saturation around injector wells—particularly with the high-resolution seismic stations that are now deployed. We expect our laboratory studies of The Geysers reservoir graywacke to enable us to make a more quantitative interpretation of our images for reservoir saturation conditions.

Acknowledgments

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Energy and was performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract No. W-7405-Eng-48. Ultrasonic velocities were measured by G. N. Boitnott of New England Research.

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Session 3: Exploration

Chairperson:
Tsvi Meidav,
Trans-Pacific Geothermal
Corporation

Exploration Session
-- Introductory Remarks --

Tsvi Meidav
Trans-Pacific Geothermal Corporation

Marshall Reed, the Geothermal Division Program Manager for Exploration and Reservoir Engineering, opened the session with an overview of ongoing research in geothermal exploration sponsored by the Department of Energy. The development of better exploration methods and interpretation techniques are important to the geothermal industry because the costs associated with the exploration phase are substantial and have a great impact on the overall economics of the project.

Dr. Meidav introduced Dr. Michael Wilt, a geophysicist at Lawrence Livermore National Laboratory who has devoted a substantial amount of effort to the quantification of self-potential data. Self-potential appears to be a promising adjunct to reservoir engineering in providing an insight into the rate of convection of geothermal fluids. To the extent that this quantification proves reliable, it would be a valuable tool for preliminary assessment of geothermal reservoirs. Dr. Wilt has shown that numerical models that were developed by him and others provide indications of the location of the most active convection taking place and of the magnitude of the natural convection rate.

Dr. Dennis Nielson of the University of Utah Research Institute spoke of the correlation between geothermal system size and reservoir temperature. It is important to provide preliminary assessment of the magnitude (or volume) of a geothermal reservoir. That volume will determine the scope and expenditure in subsequent exploration. Hence, any correlations which can be made between reservoir temperature and reservoir volume will be of value to the geothermal industry. Dr. Nielson showed that such a correlation exists.

OVERVIEW OF GEOTHERMAL EXPLORATION RESEARCH

Marshall J. Reed
Geothermal Division, U.S. Department of Energy

The term *Exploration* is used here to refer to the process, from early geologic investigations through exploration drilling, that is needed to confirm the economic potential of a project. Exploration is the first and crucial step in any geothermal energy development, and the costs incurred in exploration are of special importance because there is the longest delay between exploration and an income stream from the sales of energy. Cost savings that can be realized in exploration will have more impact on the economics of a project than will equal savings later in the development.

The Geothermal Exploration Research Program of the U.S. Department of Energy has as its goal the development and testing of more reliable and more economical methods to locate and characterize the geothermal reservoir. A combination of surveys is used to gather information on the geology, geochemistry, geophysics, and hydrology to evaluate a potential area and locate drilling targets. Several wells are needed to confirm the economic viability of the development. By increasing the amount of information recovered and the confidence in the accuracy of the information from the surface surveys, exploration wells can be better located to confirm the resource and the number of necessary wells can be reduced.

To accomplish this goal, the program is investigating the integration of often disparate surface surveys. By using the results of one survey to constrain the interpretation of each other survey, the ambiguities inherent in each method are mostly eliminated. This replaces the former method of exploration where wells were located based on overlapping "bulls eyes" of geophysical anomalies. Often the anomalous area was misinterpreted in several surveys, and the alternative interpretations of the data were ignored. In order to develop the methodology for integration of exploration data, there are several exploration case studies underway. These studies are correlating the reservoir characteristics determined from several years of geothermal production with the exploration data sets gathered before the areas were drilled to evaluate the possible interpretations.

In the discussions for the Exploration session, two promising methods of approach were discussed. These exploration tools may prove to be widely applicable in constraining the interpretations of other exploration surveys. In the study of these methods, they will be evaluated as to cost effectiveness in comparison to existing, commonly used methods. Each type of geologic terrain may require a different set of exploration tools, but it should be possible to identify the minimum set of tools needed to identify potential geothermal reservoirs.

Exploration research includes the development of new subsurface tools and methods of interpretation for reservoir evaluation from exploration wells. This work is coordinated with the research on slim-hole drilling reported in another session of this review. The prime focus of the exploration research is the development of better computer codes to interpret well logging surveys, and the verification of these codes in producing fields. If successful, this work will greatly increase the reliability of exploration well evaluation and concurrently reduce the risk of development.

Advances in the Application of the Self-Potential Method for Geothermal Exploration

Michael Wilt and Paul Kasameyer
Lawrence Livermore National Laboratory

Abstract

The object of this work is to develop new techniques to overcome persistent problems in data collection and interpretation when using the self-potential (SP) method in geothermal exploration. In particular, we examine means to reduce external and geological noise in SP surveys. We are also seeking to improve the interpretation of SP data through added knowledge of SP cross-coupling coefficients and direct SP modeling from a fluid–flow simulator.

Two problems affecting SP data collection and interpretation in geothermal areas are drift and scatter in data collection and the effect of near surface geology. To evaluate several possible causes of SP scatter and drift, we devised an automatic data collection system whereby an entire profile of data is collected simultaneously. This allows us to evaluate common-mode SP drift and the effects of external noise. However, field trials with our system showed that the automatically collected data is no quieter than data collected manually. Although our system reduces the effects of common-mode thermal drift and external noise, this gain is balanced by noise caused by the individual electrodes, with different thermal and electrochemical characteristics, that are used at each location.

To investigate the relationship between observed short- and long-wavelength SP anomalies, we collected SP data on a 20 m by 40 m grid covering a 0.5-km^2 area in Long Canyon near Mammoth Lakes, California. We also used this data set to determine the effectiveness of applying standard data processing techniques, such as filtering and continuation, to remove short wavelength anomalies resulting from random measurement error or geological noise.

SP data is modeled using techniques that relate the observed voltages to subsurface flow processes through electrokinetic (streaming potential) or thermoelectric effects. Numerical codes are used to model the subsurface flow sources, assuming both simple and more complex flow systems. The simple technique has been used successfully for several years to model SP data; we show several examples in this report. The more complex technique was recently tested using data at the Susanville geothermal field.

Introduction

Self-potential is the only known geophysical technique in which the anomalies are a direct result of subsurface heat- and fluid-flow processes. Potentially a powerful tool in exploring for geothermal resources, it can also be useful in developing a heat- and fluid-flow models of a geothermal field and for monitoring a field during exploitation.

Collecting SP data for geothermal exploration has typically been a frustrating exercise. Although some field data show an encouraging and almost unmistakable correlation with deep-seated geothermal activity (i.e., Corwin and Hoover, 1979), other data sets show poor correlation and a great deal of noise and scatter. Interpretation of data has had a similarly limited success, due in part to the lack of tools in interpreting SP and the uncertainty about the underlying causes of the observed anomalies (Fitterman and Corwin, 1982).

To illustrate the problems associated with data collection, we show, in Figure 1, two SP profiles collected along the same line over Leach Hot Springs, in north-central Nevada (after Corwin and Hoover, 1979). These profiles (which under ideal circumstances should be identical) are similar in appearance but substantially different in detail. They each have a long wavelength anomaly, which is associated with the geothermal system, and many shorter wavelength features. Notice that there is a 5–10-mV random difference between the profiles.

These profiles illustrate two problems of SP data collection and interpretation in geothermal areas (a) drift and scatter in data collection and (b) the effect of near surface geology. The 5–10-

mV random measurement error, which may result from a variety of causes, is typical of carefully collected SP data. Data collected by inexperienced operators can be much noisier than this, and it is often not reproducible. The collection of good SP data are somewhat of an art form, requiring careful attention to detail and meticulous field procedure (Corwin, 1990). In our research, we evaluate several possible causes of the scatter and drift by using arrays to collect SP profiles. Our goal is to make SP data collection more repeatable and less dependent on field procedure.

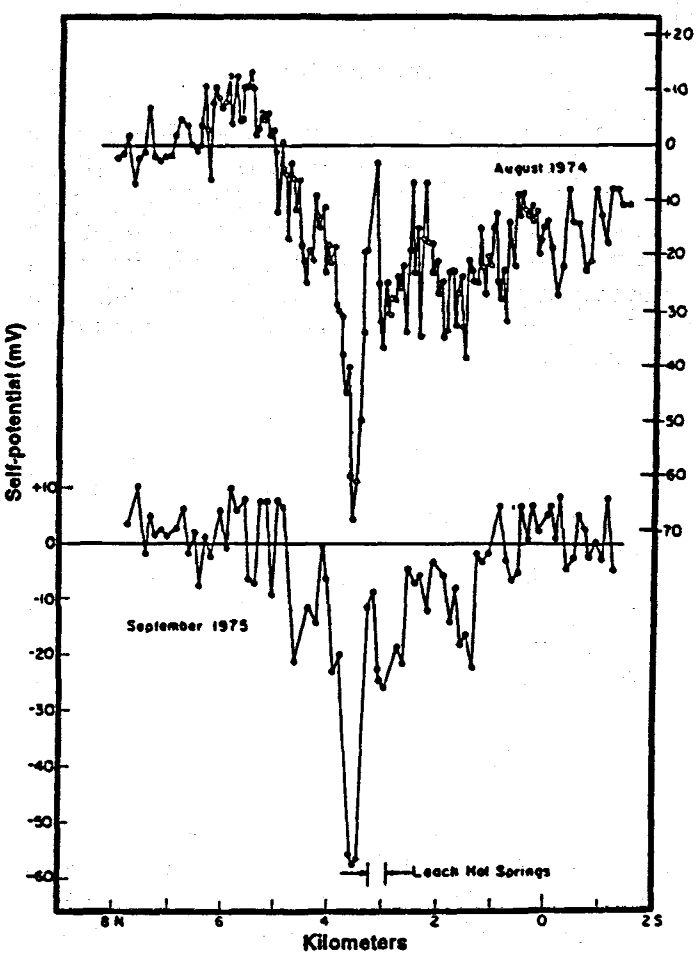

Figure 1. Repeated SP surveys collected near Leach Hot Springs, Nevada (after Corwin and Hoover, 1979).

The superposition of near-surface (short wavelength) anomalies over deeper (longer wavelength) anomalies of greater interest is another important problem. Near-surface anomalies can often obscure the deeper features of interest. For example, the 50-mV anomaly directly over Leach Hot Springs (shown later in Figure 4) is not of great interest in modeling the deeper geothermal system, but it does present a problem if we wish to separate it from longer wavelength features. We would like to apply some two-dimensional data collection concepts so that shorter and longer wavelength anomalies can be separated using standard data processing techniques.

Modeling SP data sets has typically been unsatisfying even when there is an obvious association with geothermal activity. Existing codes either assume the source is a large polarizable object, such as a sphere or plate (Fitterman and Corwin, 1984), or that it is associated with a discrete subsurface region generating high temperatures or pressures (Sill, 1983). Neither of these provides a satisfying link between the causative fluid- or heat-flow process and the SP voltages.

Following a different treatment by Sill (1982), we are coupling the SP voltages to the fluid flow velocity, rather than a "source." We therefore make no assumption about the source and use the simulator simply to supply temperatures and heat and fluid velocities. With such an approach, we have a more realistic possibility of using a geothermal simulator to model our data sets.

Data Collection: Evaluation of Temporal SP Scatter and Drift

To evaluate several possible causes of SP scatter and drift, we devised an automatic data collection system whereby an entire profile of data can be collected simultaneously. This allows us to evaluate many common-mode SP drift problems and the effects of external noise.

The data-collection system features an 18-channel seismic cable attached to an Hewlett Packard digital voltmeter and scanner, both controlled by a desktop computer (Figure 2). The electrodes are connected through the switch box to the scanner, and the voltages between electrode pairs are read one-at-a-time by switching between the scanner channels. The computer originates a data collection run, collects and stores the data, and does signal averaging, statistical analysis, or other calculations. The data collection rate is controlled by a clock (signal generator) and is limited by the scanner to a maximum rate of 3 ms per channel. The number of data channels is presently limited by the number of cable take-outs. With the appropriate cabling this system is capable of collecting up to one hundred channels of data per scanner and we can attach up to 10 scanners per computer.

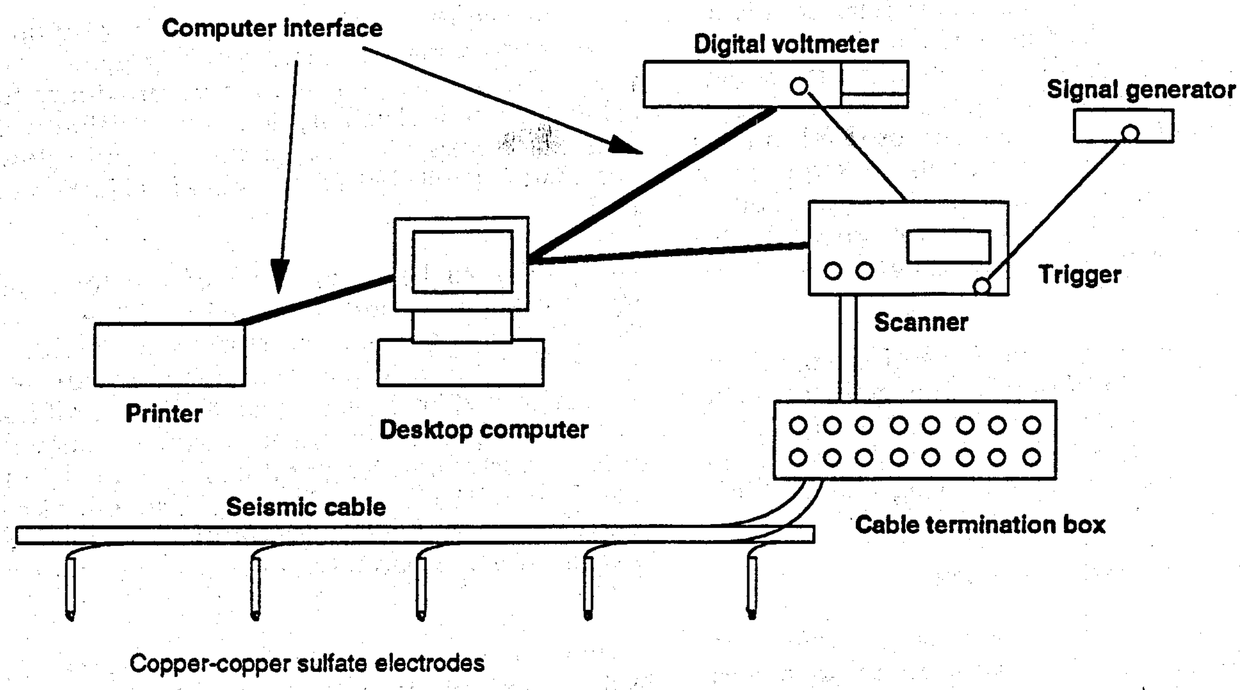

Figure 2. Schematic diagram of the SP data collection system.

Figure 3 shows results of using the system to measure variations of SP voltages for periods up to two hours after the emplacement of electrodes along an SP profile near Mammoth Lakes, California. Each plotted point represents the average of twenty measured voltages; standard deviations (not shown) were typically 0.1 mV or less. The three profiles show the same basic character but adjacent points typically differ by 5–10 mV, which greatly exceeds the calculated standard deviations for each profile. We summarize other findings below.

The automatically collected data seem to be no quieter than data collected manually. Although our system reduces the effects of common-mode thermal drift and external noise, this gain is balanced by variations because electrodes with different thermal and electrochemical characteristics (and therefore different self-voltages) are used at each location. When data are collected manually the same electrode pair is used at each station thereby canceling this effect.

The observed 5-mV/km telluric noise level was barely detectable for most of SP data, so we did not need the "smart-stacking" capabilities of our system. In high resistivity areas or in northern latitudes, telluric noise can be more than 100 times higher, and temporal filtering and smart stacking could be valuable.

Short-term stacking (signal averaging) did not seem to significantly improve the data quality. We postulate that electrochemical effects and local thermal cycles, which probably cause the drift, are much longer than the averaging times.

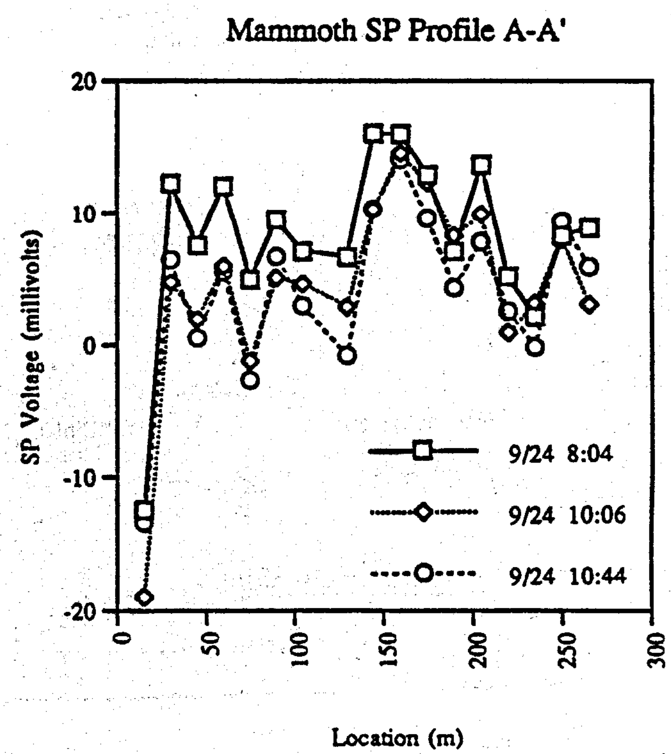

Figure 3. Repeated SP profiles collected with the automatic system.

The automatic system data offers no advantage in routine collection of SP data in a relatively quiet area such as Long Canyon. It is, in fact, much slower and more cumbersome to deploy. The observed 5–10-mV scatter observed in most surveys may be an unavoidable consequence of the burial of nonpolarizable electrodes in shallow holes. Corwin (1990) states that when electrodes are buried, removed, and reburied they can change by 5–10 mV.

The automatic system does offer significant advantages in monitoring SP voltages because up to 1000 stations can be measured from a single system. This suggests that SP could be used as a low-cost method for monitoring changes in a geothermal field during exploitation.

Long Canyon High-Density Survey

To investigate the relationship between observed short- and long-wavelength SP anomalies, we collected SP data on a 20 m by 40-m grid covering a 0.5-km^2 area in Long Canyon near Mammoth Lakes, California in September, 1992 (Figure 4). This data set is used to determine the effectiveness of applying standard data processing techniques, such as filtering and continuation, to remove short wavelength anomalies resulting from random measurement error or geological noise. The site was chosen for its proximity to known geothermal activity, and the availability of subsurface resistivity and heat- and fluid-flow information (Wilt, 1991; Stanley et al., 1976; Sorey, 1985).

The field area lies 6 km east of the town of Mammoth Lakes and 1 km east of the Casa Diablo geothermal power plant. Data were collected in 17 profiles spaced 40 m apart with stations spaced 20 m on each profile. These profiles cross several hot springs, and the area is known to have fairly high temperatures at depths less than 20 m (C. Farrar, 1992, personal communication). The field area consists partially of a large cow pasture and partially of undeveloped desert terrain.

In total, more than 1000 data points were collected over 6 days. These data were collected manually on individual profiles using the two-point method described in Corwin (1990). The profiles were tied using three cross lines on the last day of the survey. A two-person crew could typically survey the line (using compass and

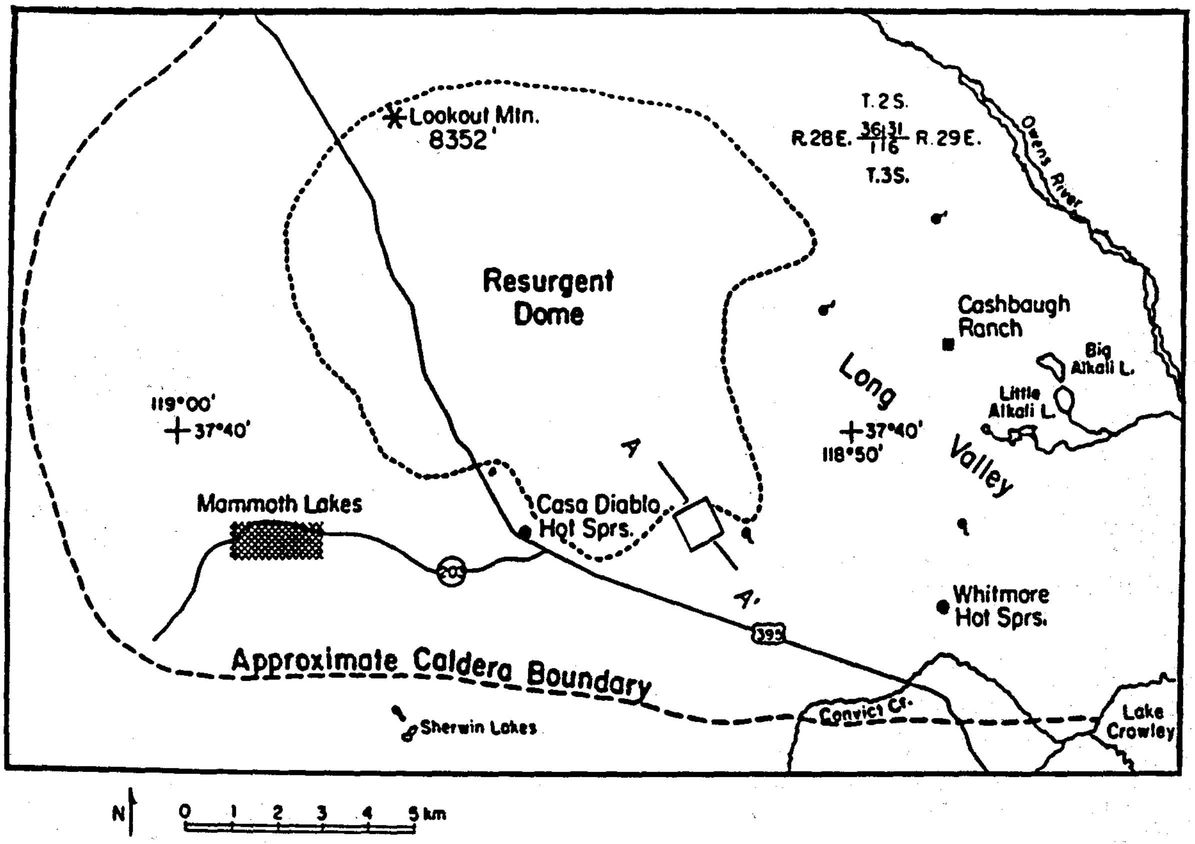

Figure 4. Location map for the Long Canyon high-density SP field survey.

tape) and make 100 or more measurements in a 10-hr day. The profiles were oriented NW–SE to correspond to the long axis of the valley; this made data collection easier and reduced location errors.

We show unfiltered and filtered contour plots of the collected data in Figure 5(a,b). The filtered map, which is made by applying a five-point smoothing operator to the data, considerably reduces the noise and jitter and emphasizes longer wavelength features. A prominent feature of the map is the arcuate-shaped high-voltage anomaly shaped suspiciously like the existing Mammoth Creek drainage system, visible on the topographic map, to the southeast of the anomaly. Perhaps this SP anomaly marks an older drainage system. Although the causes of many individual features is not yet understood, several prominent features can be modeled using simple programs. We are at an early stage of analyzing this data set and plan to apply our geothermal flow simulator to model the salient features of the contour map.

In addition to the two-dimensional grid, we collected a 3-km-long NW–SE-oriented line that crosses the array (A–A' in Figure 4); these data are plotted in Figure 6. The profile is notable for a sharp 100-mV positive anomaly located near station 1500 m and a 50–70-mV, 2-km wavelength positive anomaly that encompasses the known thermal area. We suspect that the short wavelength anomaly, which was also observed on several of our high-density lines, is due to some leakage of thermal waters into the shallow subsurface. The longer wavelength positive anomaly is likely due to deeper-seated thermal waters since the wavelength corresponds to a source depth of approximately 300 m. This is similar to the depth of production wells in the nearby geothermal power facility at Casa Diablo Hot Springs.

Modeling of SP Data

Self-potential field data can be modeled in several ways. The simplest method is to assume that the source is a charged or polarized object in the subsurface. This technique, although physically unsatisfying, is very simple to implement and is effective for determining source locations and depths (Fitterman and Corwin, 1982). The

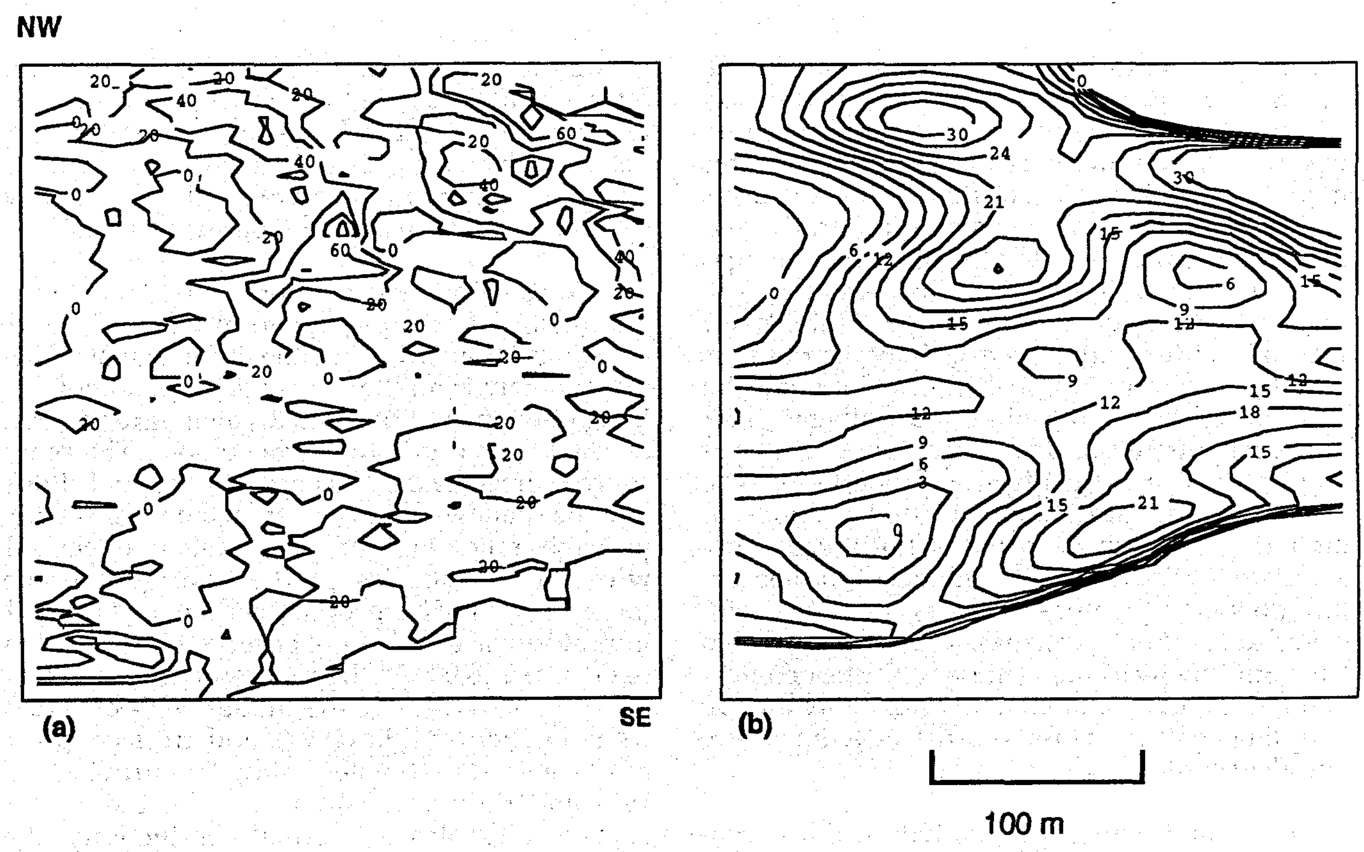

Figure 5. (a) Raw SP voltages collected over a two-dimensional grid and (b) filtered SP data.

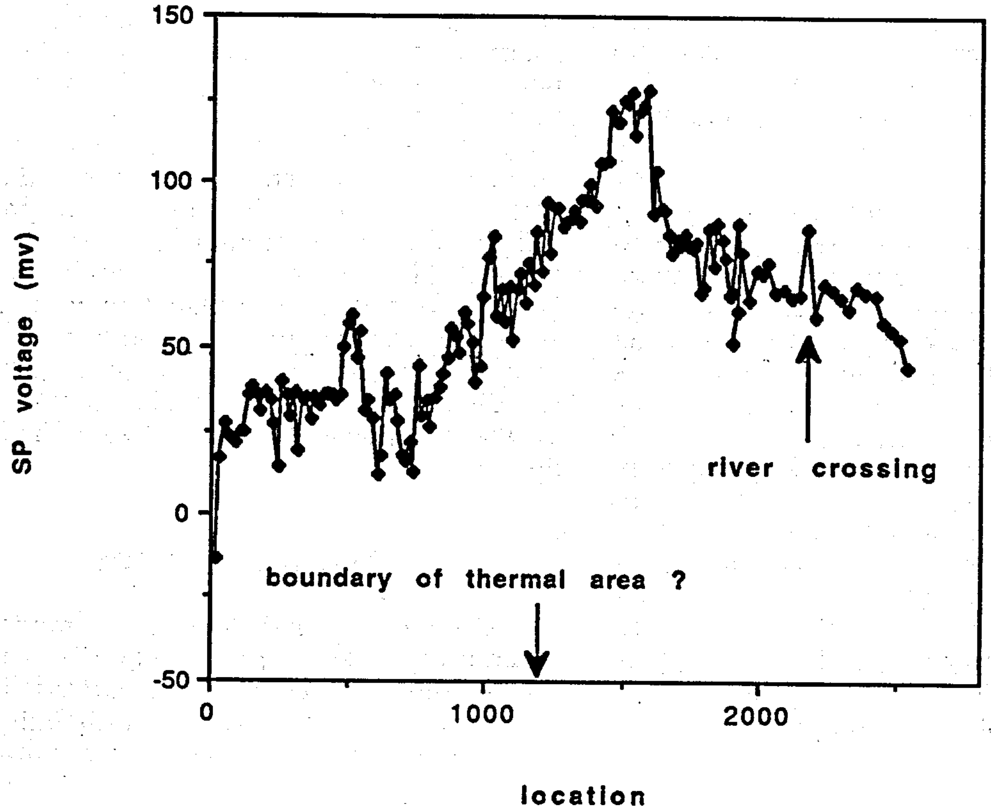

Figure 6. SP anomaly from profile A–A' (Figure 4). Distances are in meters from the NW end of the edge of the thermal anomaly, as inferred from the data.

second (Sill's) technique assumes that the SP voltages are due to electrokinetic or thermoelectric effects, whereby the voltages are caused by the subsurface flow processes (Sill, 1983). In this model, we assign discrete fluid or heat sources and a distribution of physical properties, and then we attempt to match the observed voltages with a greatly simplified flow model. The physical properties include the permeability (or thermal conductivity), the resistivity distribution, and the cross-coupling coefficients that relate the flow processes to the observed voltages. This approach often provides acceptable results if good estimates of the physical properties can be obtained. The most sophisticated manner of modeling SP data is to use a fluid/heat flow simulator to provide a good model of the subsurface flow, and then use the cross-coupling coefficients to obtain the voltages. This method differs from Sill's by including a more sophisticated flow simulator and by adjusting the resistivity and SP coupling coefficients for subsurface temperature and flow conditions.

For many exploration activities, Sill's technique is preferred because the numerical code SPPC (Sill, 1983; Wilt and Butler, 1990) is simple enough to operate on a personal computer and often insufficient detail is known about the field to utilize a complete fluid-flow simulator. For fields in which more detail is available from wells and good quality SP data are available, the flow simulator approach can provide superior detail.

We illustrate our simple SP modeling program with an example shown in Figure 7. Here, we show observed SP voltages for a sharp 100-mV anomaly from the survey described above in Long Canyon, and calculated voltages for a point thermal source in a two-layer model. The point source corresponds to leakage of thermal fluids into the shallow subsurface from a deeper source, probably following a fracture system associated with the boundaries of the resurgent dome (Sorey, 1985). The profiles shown in Figure 7 indicate a reasonable fit of observed to calculated data from a 80,000-W thermal source at a depth of 25 m. Resistivities for the model were obtained from a paper by Wilt (1991), and cross-coupling coefficients are estimates using data provided in Wilt and Butler (1990) as a guide. Using reasonable estimates of thermal conductivity, the model predicts subsurface temperatures near the source between 50 and 95°C. This is in good

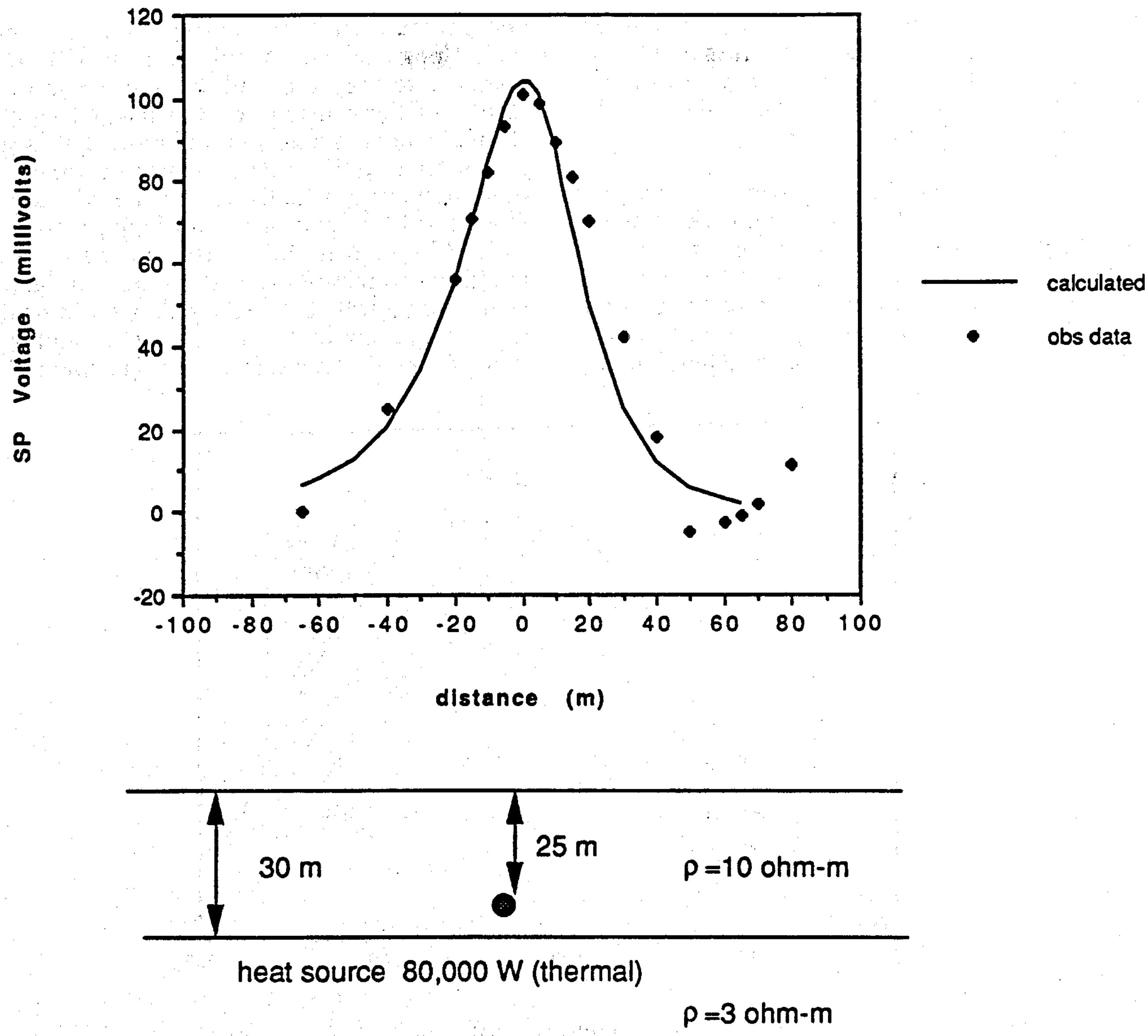

Figure 7. Model of short wavelength anomaly from Figures 5 and 6.

agreement with temperature data from a nearby monitoring well (C. Farrar, 1992, personal communication).

Modeling SP data with a Fluid/Heat Flow Simulator

An important part of this research involves the inclusion of SP voltage calculations in a geothermal fluid-flow simulator. We calculate the SP voltages from the velocity of fluid- and heat-flow processes and the subsurface resistivity and cross-coupling coefficient distribution. Used as a forward program, this approach should help us correlate SP anomalies with fluid- and heat-flow processes. Used as part of an inversion, the code could, in principle, constrain the flow model to fit temperature, pressure, and SP data.

This research is a joint effort between LLNL and Lawrence Berkeley Laboratory. The geothermal simulator was developed by Bodvarsson (1982) and the SP calculations are being done by K. Yasukawa (UC Berkeley graduate student) and M. Wilt (LLNL), using codes adapted from Sill (1982) and Wilt and Butler, (1990).

Yasukawa combined a geothermal fluid flow simulator PT (Bodvarsson, 1981) and a self-potential code SPVEL (Sill, 1982) to calculate the SP response to geothermal fluid flow systems. The new code (PTSP) first simulates the fluid and heat flow of the geothermal system, and then from the calculated temperatures and fluid flow velocities, it calculates the SP response within and on the surface on the model (Yasukawa, 1993). In her thesis, Yasukawa used two examples to demonstrate the code: (1) a fluid-flow simulation for the Susanville system, using SP to monitor exploitation, and (2) a fluid-flow model of the Amedee field, using SP and some well data.

For the Susanville geothermal system, the code was used to develop a fluid-flow model consistent with existing temperature and logging data from numerous wells. Using this model, a long-term simulation was done that corresponded to the exploitation strategy presently used by the city of Susanville. In addition to temperature and pressures, the model included SP calculations along a surface profile to determine the SP response to the fluid withdrawal; we show the results of these in Figure 8. This plot shows a strong SP anomaly developing immediately after exploitation and increasing over the first year; this anomaly gradually diminishes during the following 10 years as a result of the pressure decline. Although no SP measurements were collected to compare with these numerical data, the results suggest that the SP method could be used in combination with well data to monitor the state of a geothermal system during exploitation.

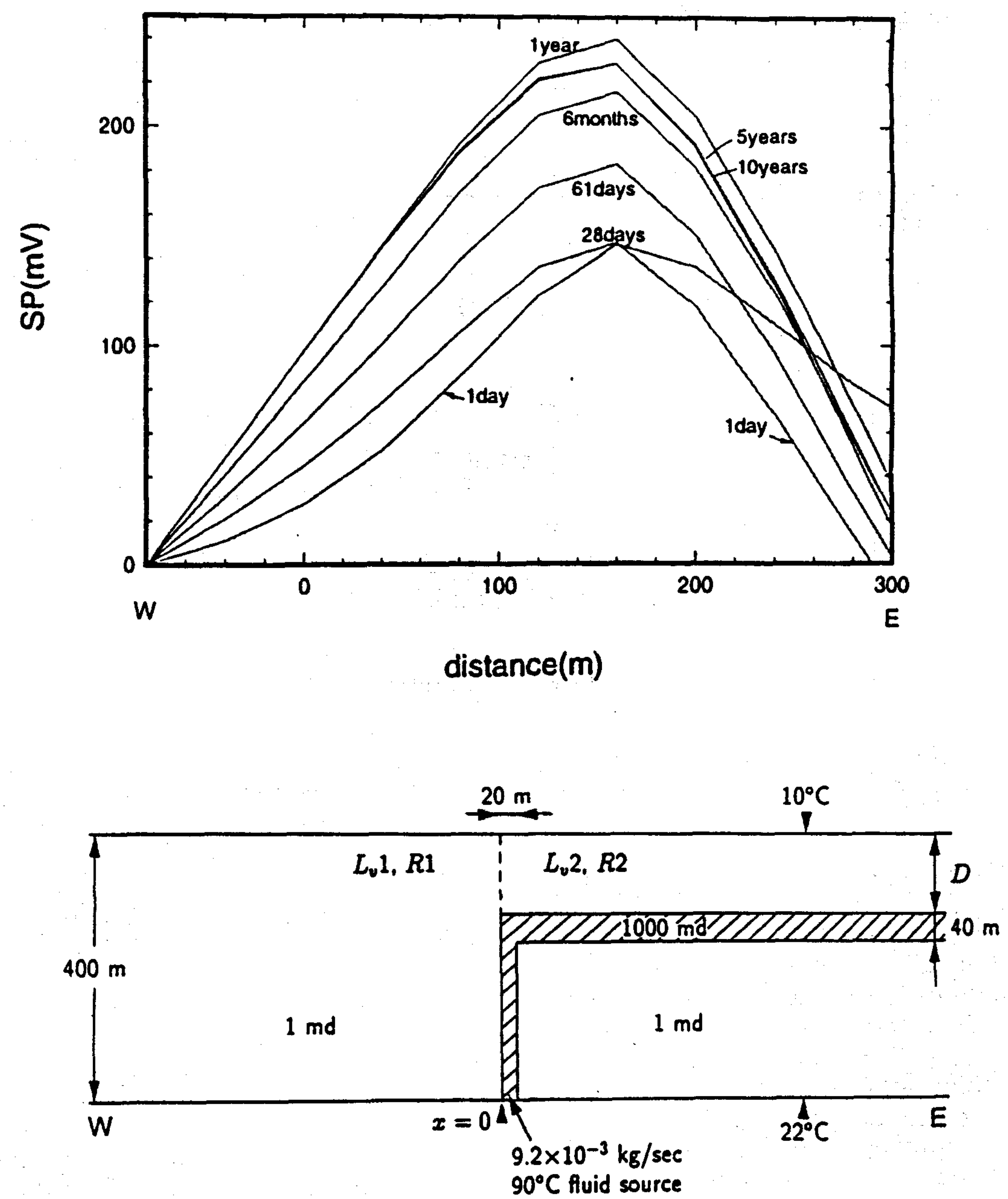

Figure 8. Self-potential calculations on a surface profile over the Susanville geothermal system. The SP data show a high sensitivity to the subsurface fluid-flow system during exploitation.

Evaluating SP Surveys in Geothermal Areas

Among our most important tasks is evaluating SP data collected over geothermal systems to understand the causes of the observed anomalies. Although some surveys indicate a clear coincidence with the SP anomaly and the deeper producing horizons, for much of the collected data, the observed anomalies are due to near-surface features such as hydrothermal alteration or shallow hot spring flow. It is important to be able to distinguish these anomalies from the deeper ones of interest. To do this, we are evaluating several data sets collected in geothermal areas by private and government surveys.

The first of these evaluations was done with data set collected by Transpacific Geothermal Inc. (TGI) over the Amedee field in Northeastern California. SP data collected by TGI showed a strong dipolar anomaly aligned along the Amedee fault. This fault is widely considered to be the controlling structure for the existing hot springs at Amedee and is a good target for deep hot-water sources. Using a structural model developed from ground magnetic data and published resistivity data, we applied SPPC to several of the SP profiles at Amedee to identify the source depths and upflow zones.

The model shown in Figure 9 gives the two-dimensional subsurface resistivity and source locations across the Amedee fault zone. The source depths are consistent with known producing horizons at Amedee, but the point source and

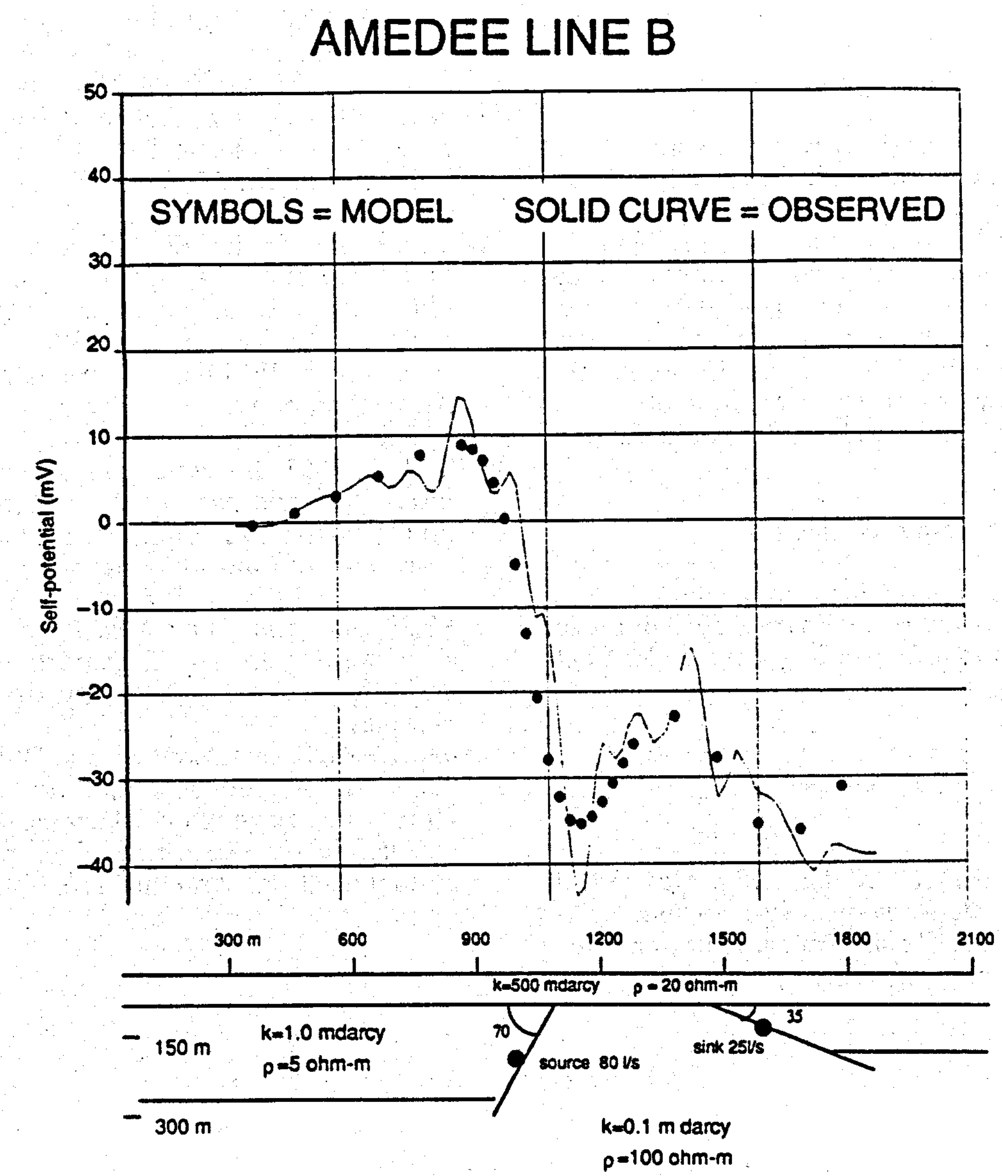

Figure 9. SP model over the Amedee geothermal system using code SPPC.

sink models are an unrealistic representation of the fluid flow. The coincidence of the source depths and producting horizons at Amedee suggests that the SP method is an excellent technique for locating upflow zones in moderately deep geothermal systems.

In spite of some unrealistic assumptions, we found that the code SPPC is useful in evaluating SP data sets in geothermal areas. It is a simple code accessible from a personal computer yet still sufficiently powerful to provide general two-dimensional modeling of SP anomalies. This code can help separate anomalies resulting from deep and shallow sources, provide a structural model consistent with field data, and is a good first step before applying more powerful codes such as PTSP.

Conclusions

This paper is a brief overview of some of the promise and a few of the problems in applying SP to geothermal exploration and development. At LLNL, we are attempting to address problems in data collection and to make some improvements in data interpretation. Although our early results appear promising, it will take some time to develop an effective modeling capability so that SP data can be more routinely used in geothermal exploration and fluid- and heat-flow modeling.

Acknowledgments

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GEOTHERMAL SYSTEM SIZE AND STRUCTURE

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ABSTRACT

There is a direct relationship between the size of a geothermal system and its temperature. This is principally a function of the system area; the depth limit of circulation decreases with increasing temperature. Within the recirculation volume of a geothermal system, structural heterogeneities often determine fluid flow paths both laterally and with depth. The depth limit for free circulation is defined by the transition from brittle to ductile deformation which takes place at a temperature of about 400°C. The natural cooling of a system will result in the downward migration of the brittle-ductile transition.

TEMPERATURE-VOLUME RELATIONSHIP

An understanding of the size of geothermal systems is important for their exploration and development. In the assessment of moderate- and high-temperature convective systems in the United States, Brook et al. (1979) noted a relationship between the <u>characteristic</u> temperature of a hydrothermal convective system and the volume of the system. Since few systems had been completely drilled at the time of their study, most of the information was estimated. Even so, a relationship did emerge showing higher system volume with higher temperatures.

Brook et al. considered the estimate of reservoir area to be the least certain parameter. Where the only system manifestation was one well or one hot spring, a likely area of 2 km^2 was assumed. For thickness, a uniform value over the reservoir was assumed. Also, since the assessment only included those resources above 3 km, this depth was used as a cutoff. When no information was available, a reservoir top at 1.5 km was assumed. Temperature estimates by Brook et al. were largely based on chemical geothermometers. We have yet to drill through an active geothermal system, although there is documentation of stacked systems vertically separated by partial or complete permeability barriers.

Since 1979, drilling has defined the size and temperature for a number of hydrothermal systems. I selected several for which there was sufficient drilling, seismic, numerical simulation and other data to derive reasonable estimates of their volume. The information used is principally from the United States, consequently fields associated with andesitic volcanism, which are more abundant world-wide, are under represented.

The results of this analysis are shown in Figure 1 and described in greater detail in Nielson (1993). This confirms the general conclusion of Brook et al. that hotter geothermal systems have larger volumes than cooler systems. I also concluded that systems controlled by a single fault are lower in temperature and have a different temperature-volume regression line.

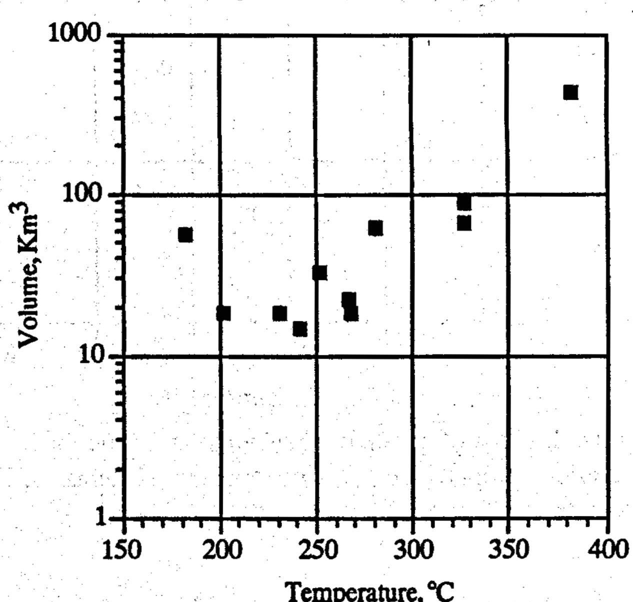

Figure 1. Volume vs. average temperature for active geothermal systems.

CIRCULATION AREA

The area of a circulation system that has been explored by drilling can often be determined with greater accuracy than the depth to which active fluid flow takes place. Figure 2 plots geothermal system area as a function of estimated average temperature for systems evaluated in Figure 1 plus additional data from the literature. Note that this figure excludes those hydrothermal systems that circulate along a single fault. The implications here are twofold; first, it is the area rather than the depth (see discussion below) that is directly related to temperature, and second, this relationship determines the target size for exploration.

The increase in area with temperature coupled with a decrease in circulation depth with temperature (see below) focuses attention on the heat source; the larger the surface area of a heat source, the larger and hotter the hydrothermal system developed above it. Above a temperature of 150°C, there is a systematic relationship for systems that both have associated young volcanic rocks and those that would be considered "non-volcanic".

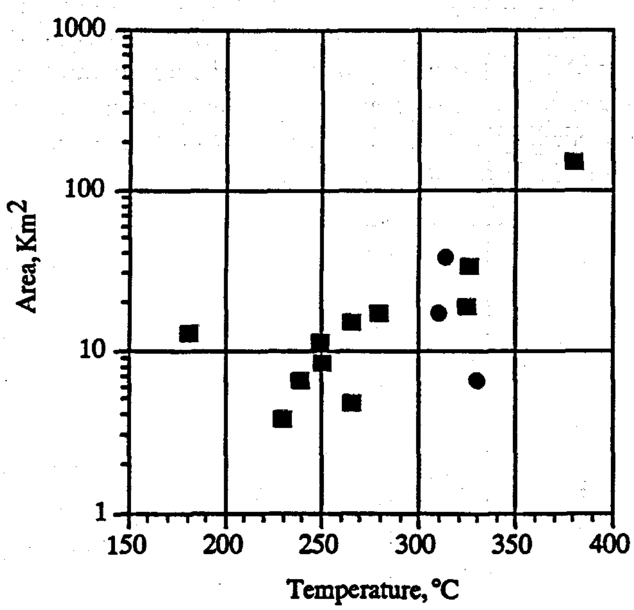

Figure 2. Area of geothermal systems as a function of average temperature. Circles represent systems associated with andesitic volcanoes.

Another very practical aspect of Figure 2 is that it defines the general target size of geothermal systems of different temperatures. For instance, a hydrothermal system with an average temperature of 250°C will present a target area of about 9 km^2. Note that an outflow plume may or may not be present producing a geochemical or geophysical signature that could effectively double the target size.

DEPTH OF CIRCULATION

Mechanical limits of open fractures are controlled by lithology, temperature, pressure and fluid content. Although the bottom of an active system has yet to be drilled in the U. S., there are several good examples of changes of permeability or structural control as a function of depth that serve to illustrate examples of lithologic influences on depth extent.

One of the unique aspects of the Valles caldera geothermal system is that it consists of two circulation systems separated by a relatively impermeable zone. A temperature profile of well Baca-12, the deepest well drilled in the Valles caldera (Hulen and Nielson, 1986), shows that the hydrothermal system in Redondo Creek circulates in fractured densely welded ash flow tuff to a depth of approximately 2500 m. At this point, fluid circulation is apparently terminated in shales of the Permian Abo Formation that deform in a ductile manner and are not able to sustain open fractures. However, below 3 km there is lost circulation in Precambrian granite basement to the bottom of the well at about 3200 m (T = 340°C). Core shows that the granite at this temperature deforms in a brittle manner and is able to maintain open fractures. Similar relationships were documented at Sulphur Springs (Hulen et al., 1989) where an upper hydrothermal system, confined to volcanic rocks of the Valles caldera, is separated from a hydrothermal system in Precambrian granite by a sequence of Permian and Pennsylvanian sedimentary rocks (Fig.1). The efficiency of separation of the reservoirs is shown by the absence of hydrothermal alteration within the Paleozoic sequence. In another example of lithologic controls of brittle-ductile behavior, Sternfeld (1989) documented the increased fracture permeability in brittle graywacke reservoir rocks as contrasted with ductile argillite in The Geysers reservoir.

In other explored geothermal systems, changes in structural style have been indicated both as a function of depth and laterally within the system. Thompson and Gunderson (1989) analyzed drilling results at The Geysers that showed different fracture orientations between the "felsite" and the overlying graywacke reservoir. The graywacke was dominated by low-angle fractures that they speculate represent re-opened Franciscan structures. The underlying intrusive rocks are dominated by high-angle fractures that are interpreted to result from recent strike-slip tectonics.

Lateral changes in fracture and stress orientation have also been documented in explored geothermal systems. Allison and Nielson (1988) investigated borehole breakouts from the Cove Fort-Sulphurdale geothermal system and proposed that the stress orientation changed with location within the field. At Roosevelt Hot Springs geothermal system, it appears that the zone of geothermal fluid flow is structurally decoupled from the regional stress environment (Nielson, 1989). Active seismicity, breakout analysis and the orientation of mapped faults show that the least principal stress is oriented approximately north-south within the geothermal area while its regional orientation is approximately east-west.

While structural and lithologic heterogeneities will influence how wells are drilled and completed and individual fields are developed, the brittle-ductile transition determines the depth to which fluids freely circulate, and it may influence the maximum energy recovery from the field. It has long been known that earthquakes terminate at a shallower depth in zones of higher heat flow. For instance, Gilpin and Lee (1978) show a maximum depth of earthquake foci of 3 Km under the Salton Sea field deepening to 9 km east of the field. Smith and Bruhn (1978) show a shallower termination of earthquakes beneath the Basin and Range province as contrasted with the adjacent Sierras and the Colorado Plateau. Sibson (1982, see also Fournier, 1991) has shown that the depth of the transition is related to the stress environment, strain rate, and rock properties as well as temperature. His model shows that shear resistance increases with depth, reaching a maximum at the brittle-ductile transition where resistance, and hence earthquake frequency, decreases. The actual transition is probably gradational. Within individual geothermal areas, the transition probably results largely from changes in rheologic behavior of rocks at higher temperature. Laboratory experiments suggest that quartz is the first major mineral to deform ductilly at about 300°C while feldspars will not undergo ductile flow until the temperature exceeds 450°C (Sibson, 1984). This is perhaps the reason that "granitic" rocks make such good high-temperature reservoirs, they remain brittle at high temperatures.

Fournier (1991) has discussed the change from brittle to ductile behavior in the context of a transition from hydrostatic to greater than hydrostatic pressure conditions. He points out the potential importance of vein sealing by hydrothermal quartz in allowing high-pressure conditions to develop. He concluded that the brittle-ductile transition may occur at temperatures as high as 370-400°C.

Recent investigations at Larderello and Monte Amiata in Italy suggest a similar model for the depth limits of circulation in active geothermal systems (Gianelli, 1994). A regional seismic reflector, the K horizon, is interpreted to represent the brittle-ductile transformation zone. A well drilled to just above this zone encountered fluids at >420°C and pressures above hydrostatic (see also Fournier, 1991). In this example, the brittle-ductile transition is located above the main mass of the intrusive heat source, in a position similar to the hornfels zone at The Geysers.

Stark (1990) investigated the depth of the reservoir floor at The Geysers from seismic data. Figure 3 is modified from Stark and shows seismicity induced by injection of water into the wells shown. Superimposed on this diagram are the top of the "felsite" and the top of the reservoir taken from company publications. Stark interpreted this data as showing that injected fluid descended to a reservoir floor at a depth of nearly 4 km. It is inferred that, at this depth, plastic flow is inhibiting the rock's ability to sustain open fractures. As The Geysers has matured, the brittle-ductile zone, which originally must have been located at or above the felsite-wall rock contact, has migrated downward into the intrusive heat source. This is consistent with models of porphyry copper system evolution (Beane, 1983).

Figure 4 plots the depth limit of circulation against average reservoir temperature and was constructed from the few active systems for which there is some evidence of the limits to which fluids circulate. The author cautions that this data is not well constrained. This diagram shows that the depth of circulation generally decreases with increasing temperature.

An interesting aside concerns the relationship shown by The Geysers, which is the largest volume system shown on Figure 1. There it is plotted at a reservoir temperature of 380°C, that represents the maximum fluid inclusion homogenization temperatures associated with the early high-salinity liquid-

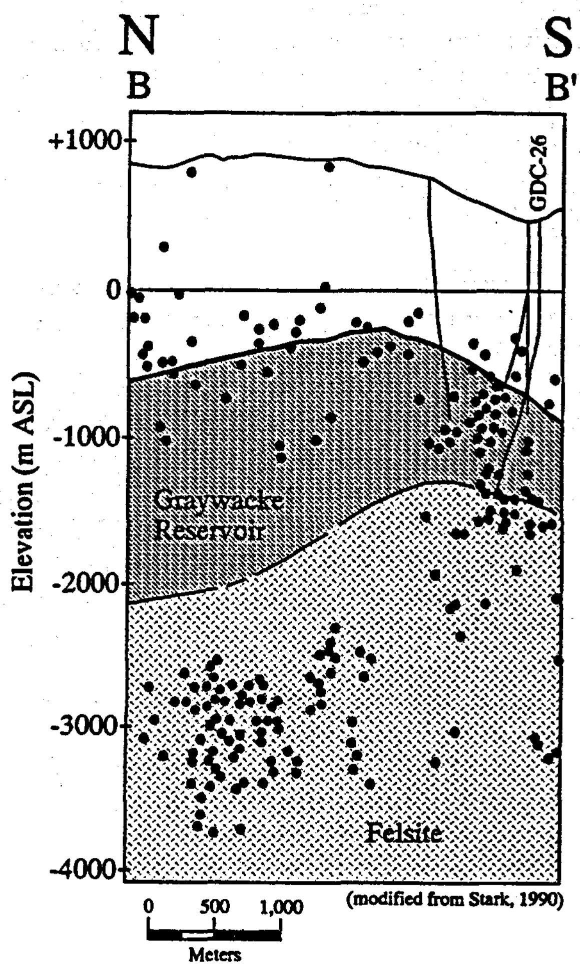

Figure 3. Microearthquakes at The Geysers measured during injection (Stark, 1990).

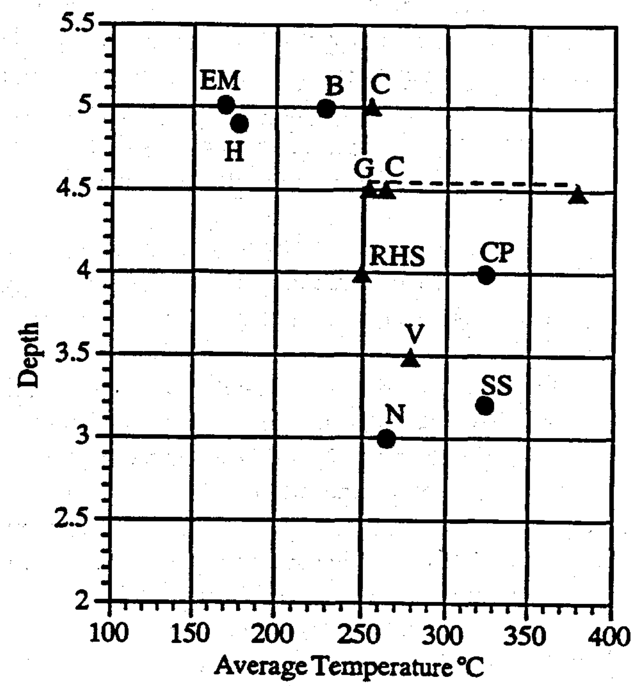

Figure 4. Estimated depth of circulation as function of average temperature. EM - East Mesa, H - Heber, B - Beowawe, C - Coso, G - Geysers (see text), RHS - Roosevelt Hot Springs, CP - Cerro Prieto, V - Valles, N - Newberry, SS - Salton Sea.

dominated system (Moore, 1992). This is more consistent with the general trend than a pre-production average temperature of 260°C. Similarly, the area of The Geysers is also more consistent with this higher temperature (Fig. 2). The point labeled "G" on Figure 4 is again the Geysers, and shows that, in contrast, the depth of circulation is more consistent with a present average temperature of 260°C. This result suggests that as the system naturally evolves and cools, the brittle-ductile transition retreats to deeper levels.

SYSTEM MODEL

The present evaluation, although admittedly limited in scope and prone to errors in estimates of system dimensions, suggests a generalized model for active hydrothermal systems, which will be illustrated using data from the Coso system. Seismic monitoring at Coso (Walter and Weaver, 1980) shows a pre-production distribution of events with depth that is similar to that which would be predicted by Sibson's model (Fig. 5; where Sibson uses the term quasi-plastic rather than ductile). I suggest that beneath an approximate 1 km cap, the freely convecting system is present to a depth of 5 km. Here there is an increase in the number of earthquakes that may result from a decrease in fluid along cracks and a resulting increase in friction. Below this, there is perhaps a 2 km thick transition zone separating brittle and ductile behavior. The estimated temperature as a function of depth is also shown, and suggests 400°C at the depth limit of circulation. At this point, the temperature gradient will increase due to restricted fluid circulation resulting from closure of microcracks due to increase in pressure (Morrow and Byerlee, 1992) and sealing by hydrothermal phases (Fournier, 1991).

Another component of Figure 5 is the estimate of pressure as a function of depth. S_V represents the overburden pressure taken from measurements in the Cahon Pass well, drilled to a depth of 3.5 Km in rocks similar to those found at Coso (Zoback and Healy,

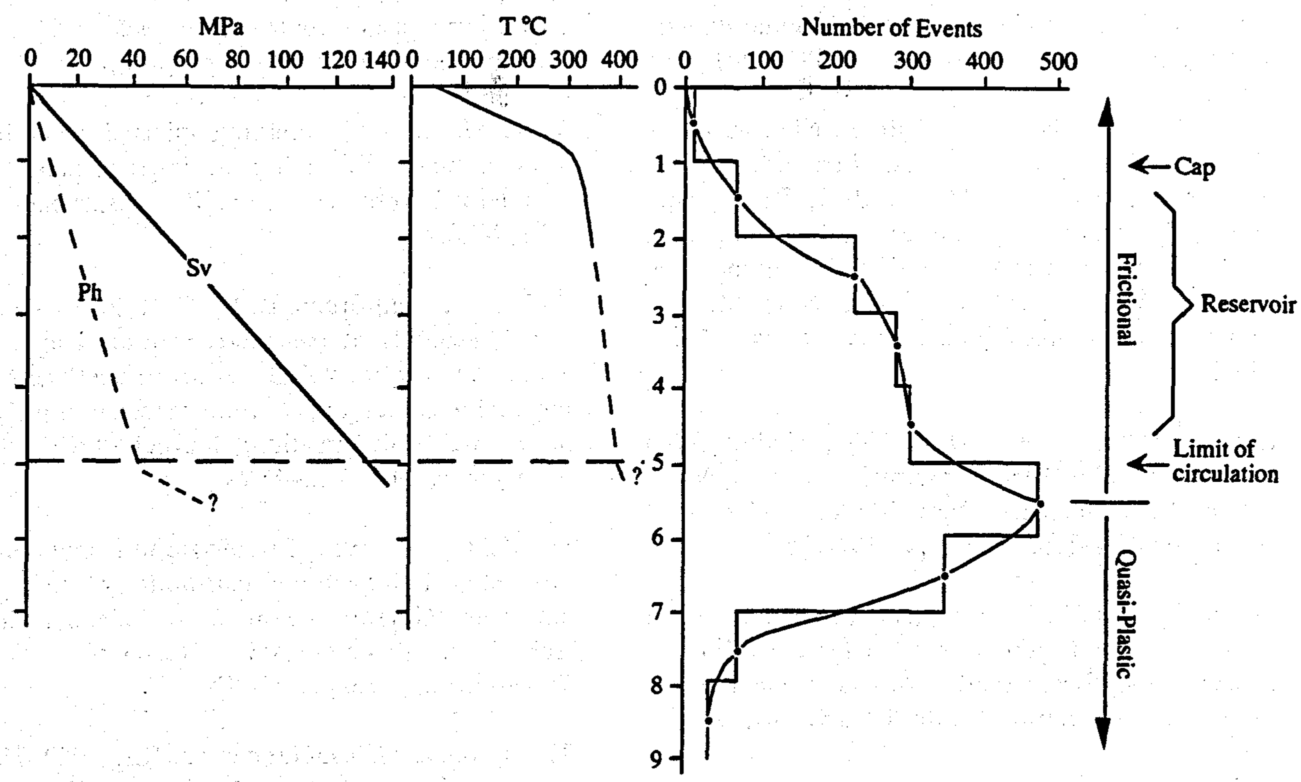

Figure 5. Model for active hydrothermal circulation systems using data from the Coso field. See text for sources of information.

1992). P_h is hydrostatic pressure measured in the field. If the limits of fluid circulation are as I have proposed, it can be expected that pressures will exceed hydrostatic at the limits of circulation and reach lithostatic in the zone of ductile behavior (Fournier, 1991).

In conclusion, there is a direct relationship between the volume of a hydrothermal system and its temperature. Although not precise and perhaps related to rock type, there is a general decrease in the depth limits of circulation as the system temperature increases. The volume increase, therefore, is largely a function of the area of the system, suggesting it is related to the area of an underlying heat source. Natural evolution will result in decent of the brittle-ductile transition, which can be regarded as an approximate 400°C isotherm.

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Session 4:
Energy Conversion and Materials

Chairperson:
Michael Forsha,
Barber-Nichols, Inc.

Energy Conversion and Materials Session
Introductory Comments

Michael Forsha
Barber-Nichols, Inc.

The recently reorganized Geothermal Power Organization (GPO) is the industry advisory group that provides DOE with feedback about their geothermal energy conversion programs. One of the missions of the GPO is to insure that the R&D requirements of the energy conversion industry are identified for the DOE program managers. In order to insure that the needs of industry are properly identified and prioritized, it is critical that the industry is well represented at GPO meetings. If your firm is involved with geothermal energy conversion technology, your participation is encouraged.

Overview of Energy Conversion and Materials Programs

Raymond LaSala
Geothermal Division, U.S. Department of Energy

Thank you, Mike. I really didn't prepare a formal overview because I felt it was more important to use the time available to tell you as much as possible about all the energy conversion R&D we have under way. Because of the limited time, we've selected just three projects for the detailed presentations that will follow mine. With that in mind, I'd like to take this opportunity to fill you in on all the rest of the energy conversion program.

The Golden Field Office of DOE has selected two proposals for award of three-year Cooperative Agreements to demonstrate the economic benefits of improved electric generation systems in geothermal applications. One of these has already been signed with Douglas Energy Co. of Placentia, California, to install a 1-MW Biphase rotary separator turbine (RST) at the California Energy Company's Coso Geothermal Project. Douglas is currently testing a 12-inch prototype device and expects to replace it with a 54-inch RST by the end of this year. This device will be tested at Coso for two years to demonstrate the feasibility of retrofitting existing flashed-steam power plants with Biphase turbines. We expect that this could increase the efficiency of flashed steam power plants by up to 30% both at home and abroad.

The other Cooperative Agreement is expected to be awarded within the next few months to Exergy, Inc. of Hayward, California, for demonstration of the world's first commercial Kalina cycle power plant, a 12-MW unit to be located at Steamboat, Nevada. This will be a highly recuperated binary cycle plant using a mixture of ammonia and water as the working fluid operating on a 335°F geothermal fluid supply; it will not, however, feature the distillation/condensation subsystem that is typically included in Kalina cycle designs for higher temperature heat sources. We hope to see power on line from this project in early 1997. Exergy projects up to a 40% improvement in efficiency over more conventional binary cycle designs by using this technology. Representatives from both Exergy and Biphase are here at the Program Review; I encourage you to look them up if you wish further information.

Our R&D on linings for heat exchangers is a good example of cooperation among several national laboratories and private companies. This project began with Brookhaven National Laboratory's identifying a formulation for a corrosion resistant, thermally conductive polymer concrete that could be made into heat exchanger tubes. Idaho National Engineering Laboratory constructed a heat exchanger test skid employing tubes lined with this material. They operated it first at the DOE Geothermal Test Facility and subsequently at the Red Hill geothermal power plant in the Salton Sea KGRA in collaboration with Magma Power Co., the plant owner. National Renewable Energy Laboratory has since taken over from INEL and has made important contributions to the project such as a methodology for inspecting the tubes and analyses of tube performance. Since this project is now covered by a Cooperative Research and Development Agreement, I can't say too much about the results at this time; but we currently have a field test underway, and the thermally conductive polymer concrete seems to be performing as well as the stainless steel reference material also being tested.

I'd like to say just a few words about the work sponsored by DOE that the National Institute of Standards and Technology is performing on characterization of the thermophysical properties of the ammonia-water system. In this, the second and final year of this project, NIST will conduct comprehensive measurements for pressure/volume/temperature relationships, heat capacity, and thermal conductivity of aqua-ammonia mixed working fluids. They will complete a final version of a state-of-the-art corresponding states model for calculation of thermodynamic and transport properties and will publish the results so that the engineering and scientific community will have full access to them.

Finally, I'd like to invite those of you with an interest in our geothermal energy conversion R&D program to attend this afternoon's meeting of the Geothermal Power Organization, which will be held in the adjacent meeting room shortly after the last presentation today. I hope to see many of you there.

Thank you.

FIELD INVESTIGATIONS EXAMINING THE IMPACT OF SUPERSATURATED VAPOR EXPANSIONS ON TURBINE PERFORMANCE

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Idaho National Engineering Laboratory
Idaho Falls, Idaho

ABSTRACT

Investigators in the Heat Cycle Research project are developing a technology base which will permit the increased utilization of the moderate-temperature, liquid-dominated geothermal resource for the production of electrical power. The project investigations have focused upon power cycles which have the potential for the increased utilization (power produced per unit quantity of fluid) of the hydrothermal resource. The investigations to date have confirmed the viability of technology required to incorporate concepts which will allow the binary power cycle to have a performance approaching practical thermodynamic maximums. Investigations in progress are examining the potential improvements that result from allowing supersaturated turbine expansions. During these metastable expansions, the working fluid is maintained as a supersaturated vapor during the turbine expansion process; if at equilibrium conditions, liquid condensate would be present. If it can be shown that these expansions proceed without a degradation in turbine performance or damage to the turbine internals by any condensate which forms, a projected 8% improvement in the performance of the advanced cycle could be realized. Investigators are presently examining the condensation behavior of these expansions, as well as determining the impact of these expansions on turbine performance. This work is supported by the U.S. Department of Energy, Assistant Secretary for Energy Efficiency and Renewable Energy, under DOE Idaho Operations Office contract DE-AC07-76ID01570.

BACKGROUND

The primary objective in the Heat Cycle Research project is to develop the technologies which will result in the increased utilization of the moderate-temperature, geothermal resource for the production of electrical power. Program studies[1-4] have shown that significant performance improvements could be achieved with supercritical binary cycles utilizing mixed hydrocarbon working fluids, where the turbine inlet conditions and working fluid composition are optimized for site specific conditions (brine temperature, heat rejection scheme, etc.). It was subsequently shown[5] that these supercritical cycles would operate near the thermodynamic maximums established by practical constraints, or operating limits. Project investigations have validated the assumptions made in projecting these performance improvements, and confirmed the viability of the technology required to design and build the components necessary to achieve these performance improvements in a commercial facility.

The project is currently examining the improvements in the brine utilization, or effectiveness, that are possible when metastable, supersaturated turbine expansions are allowed. For the resource temperature range of interest, the hydrocarbon working fluid which provides the highest cycle performance is isobutane, or a mixture of isobutane and a non-adjacent heavier hydrocarbon (with isobutane being the major component). Isobutane as well as the mixtures, have a retrograde dew point, or saturation, line when plotted on a T-s diagram; these fluid vapors tend to superheat, or become drier, when expanded. A supercritical binary cycle utilizing a pure working fluid is shown schematically in Figure 1. In this cycle, the working fluid is preheated and vaporized at a constant supercritical pressure. In a conventional power cycle sufficient heat is added to the working fluid to assure that an isentropic turbine expansion (represented by the process from points 3 to 4) occurs outside of the two-phase region. Demuth[1] suggested that a modified cycle where the ideal turbine expansion process passes through the two phase region (represented as the process from points 3' to 5) could proceed without adversely impacting turbine performance. If confirmed, it was projected that an additional 8% improvement in the brine effectiveness might be achieved.

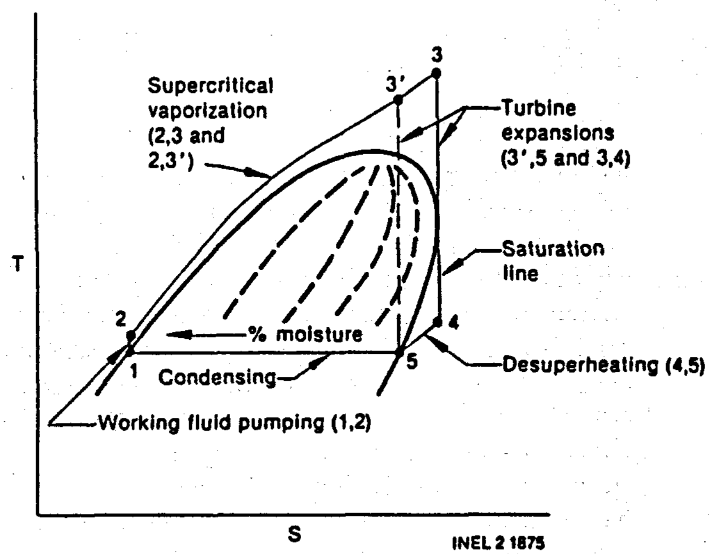

Figure 1. Binary Cycle Showing Two Types of Turbine Expansions

This expansion of a vapor into the equilibrium state, two-phase region in a turbine is not unusual; it typically occurs in steam turbines where the "Wilson Line" is frequently used for estimating the extent to which a supersaturated water vapor can be maintained without condensation. Even though some steam turbines take advantage of the phenomena that the steam can be expanded into the two-phase region without condensate forming (supersaturated expansions), these types expansions are not utilized in binary geothermal power cycles. In designing these cycles, the working fluid entering the turbine has been superheated sufficiently to assure that the turbine expansion completely avoids the two-phase region. This conservatism assures that no condensate forms during the turbine expansion which could adversely impact performance and potentially damage the turbine.

The condensation behavior of the hydrocarbon working fluids of interest are not expected the same as that of steam. Demuth[6] theoretically examined the condensation behavior of the hydrocarbon working fluids during these expansions and concluded that a supersaturated vapor state could be maintained. He postulated that if drops did form, they would initially be very small and tend to re-evaporate as the expansion proceeded.

The objective of the project investigations of these expansions is to define the limits to which the expansions can proceed without condensate forming, and determine the impact of these metastable expansions on turbine performance.

PERFORMANCE IMPROVEMENT

The improvement in cycle performance achieved by utilizing the supersaturated expansions results from a decrease in the amount of energy required to vaporize the working fluid. Because the working fluid does not have to be heated to as high a temperature, less brine is required. A shift also occurs in the location where the minimum temperature difference occurs between the working fluid heating curve and the brine cooling curve. This provides an additional reduction in the amount of brine required to vaporize a given quantity of working fluid. The net increase in the working fluid to brine flow ratio offsets the decrease in the isentropic enthalpy change through the turbine that occurs when the turbine inlet temperature is lowered. (The isentropic enthalpy change represents the ideal turbine work.) The result is an increase in the amount of power produced per unit mass of brine.

These effects are shown in Figure 2, which shows the impact of allowing these supersaturated expansions on a supercritical cycle operating with an isobutane working fluid. The cycle depicted is operating with an inlet pressure of 550 psia, an inlet brine temperature of 335°F, and a 10°F approach temperature between the working fluid and brine. The base condition contains sufficient superheat to assure an isentropic turbine expansion would occur completely outside the two-phase region. If the turbine inlet temperature is reduced to the point where an isentropic turbine expansion would exit the turbine at the exhaust pressure dew point conditions (~281°F), the mass flow ratio increases by ~30% while the isentropic enthalpy change across the turbine decreases by ~12%; the net impact is an ~15% increase in the brine effectiveness. These projections show that if the turbine inlet temperature is decreased even further, the brine effectiveness will continue to rise, and then begin to fall when the decrease in the isentropic enthalpy change offsets the increases in the mass flow ratio.

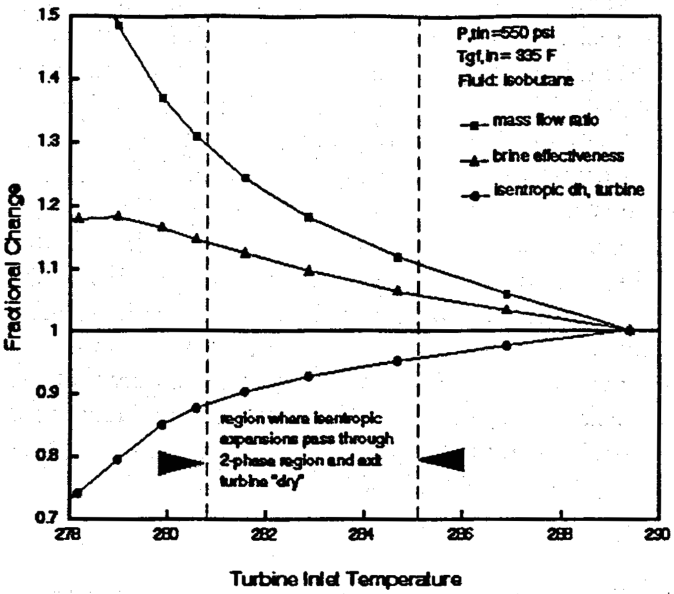

Figure 2. Potential Impact of Supersaturated Expansions on Cycle Performance

These types of expansions are applicable to supercritical power cycles, or boiling cycles where the boiler pressure is above the pressure at which the maximum dew point entropy occurs (the "nose" of the dew point curve in Figure 1), and the working fluid has a retrograde dew point curve similar to that depicted in Figure 1. The degree to which a power cycle performance can be increased will depend upon the inlet brine temperature, the initial turbine inlet conditions (pressure and temperature), and working fluid selected. The point at which brine effectiveness peaks is also dependent upon these factors. In general, the further the conditions are from the optimum cycle for a given resource temperature, the larger the impact on performance and the further the turbine inlet temperature can be decreased until the brine effectiveness peaks.

FIELD INVESTIGATIONS

The project field investigations with the metastable, supersaturated expansions have been conducted in two separate stages. In the first stage, investigators examined the condensation behavior of these expansions. In the second stage the impact of these expansions on turbine performance were investigated.

Condensation Behavior: Theoretical studies suggested that the supersaturated expansions would initially proceed without condensate formation. As the point where the expansion path crosses the dew point curve into the two phase region approaches the critical point, droplets would be more likely to form; initially these droplets would be small and have a tendency to re-evaporate.

Field investigations initiated by the project were to provide verification that the expansions behaved as theoretically predicted. These investigations were conducted at the Heat Cycle Research Facility (HCRF) located adjacent to the B.C. McCabe power plant in California's Imperial Valley. For this test program, a two-dimensional, converging-diverging nozzle was used to simulate an isentropic turbine process over the range of turbine inlet conditions of interest. The nozzle contained a window allowing the expansion process to be monitored. A laser-based droplet detection systems was used to identify the onset of condensate formation, as well as the location along the expansion path where the condensate was forming. Testing was conducted with an isobutane working fluid over a range of inlet pressures from 550 psi to 650 psi. Limited testing was also conducted with a 95% isobutane, 5% hexane mixture.

Impact on Turbine Performance: Following the testing to define the conditions which resulted in condensate formation in the nozzle, an axial-flow impulse turbine was installed at the HCRF. The turbine, generator, controls, and energy dissipation unit (heater load bank) were obtained from Barber-Nichols, Inc.. This equipment had been previously utilized by Barber-Nichols for testing with both isobutane and ammonia working fluids. Barber-Nichols modified the turbine to operate at the following conditions:

fluid: isobutane
inlet conditions: 600 psia and 300°F
exhaust conditions: 84 psia
flow rate: 5,000 lb./hr
power output: 40 to 45 hp

At a generator speed of 3600 rpm, the turbine operates at a speed of 21,780 rpm. The control governor provided allows the generator speed to be established and maintained at the desired set point. A bank of air cooled electrical heaters rejects the power generated as heat to the ambient. Torque meter and tachometer measurements from the shaft between the turbine gearbox and generator allowed for precise measurements of the turbine power. (Prior to installing the turbine, the gearbox losses were established over a range of speeds and lubricating oil conditions.)

In conducting the testing with the impulse turbine, the investigators first established the turbine performance at inlet conditions which resulted in a "dry" expansion. This provided the baseline condition for determining the impact of the supersaturated expansions on performance. For a given test sequence, the turbine inlet and exhaust pressures were established and maintained. A desired turbine inlet temperature (or entropy) was established, and a series of tests conducted where the turbine speed was varied by changing the generator speed in controlled steps over the range of 3000 to 4200 rpm, with the baseline condition being 3600 rpm. At each speed, data was collected which would allow the turbine performance to be evaluated. For each set of controlled inlet and exhaust conditions, investigators were able to generate an efficiency curve as a function of the turbine speed and define the peak performance. Once the "dry" expansion performance was established, the turbine inlet temperature (entropy) was sequentially reduced while maintaining the inlet and exhaust pressure, and a set of data collected over the range of turbine/generator speeds. This process was repeated until a degradation in efficiency was observed.

Testing was primarily conducted with an isobutane working fluid at the inlet design pressure of 600 psi. Limited testing was also conducted at an inlet pressure of 550 psi; for this testing, the exhaust pressure was reduced so that similar pressure ratios were maintained across the turbine. In addition to the investigations with the isobutane working fluid, tests were also conducted with a 95% isobutane, 5% hexane mixture. The limited testing with this mixture was accomplished at inlet pressures of both 600 psi and 550 psi.

RESULTS

Condensation Behavior: The tests conducted with the two-dimensional expansion nozzle confirmed that a supersaturated vapor was attained during the expansions of interest. The nozzle inlet conditions which resulted in the condensate formation were identified, and it was found that the condensate which initially formed did re-evaporate. Figure 3 shows the conditions producing the onset of condensation for both the pure fluid and the mixture at a nozzle inlet pressure of 600 psi. The nozzle inlet temperature is plotted as a function of entropy, where the entropy is referenced from the maximum dew point entropy for each fluid. The observed onset of condensation with isobutane occurred at an inlet entropy approximately half the distance between the point where an ideal isentropic expansion process first begins to pass through the two-phase region (s=0), and where it

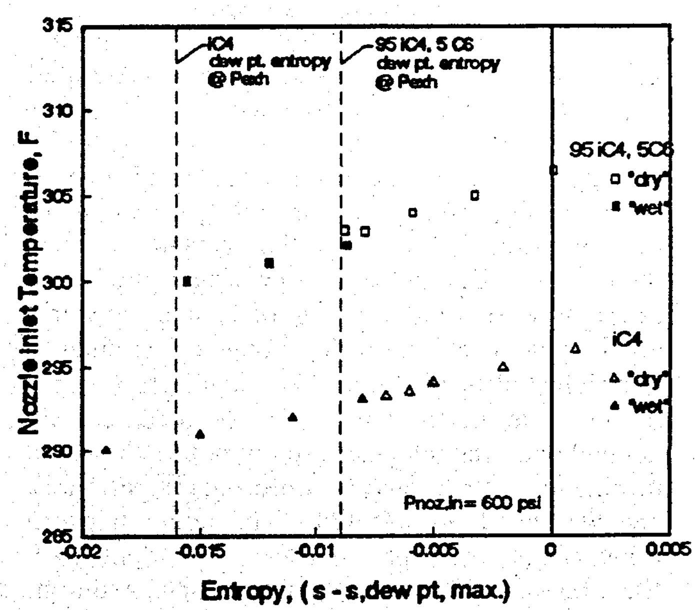

Figure 3. Onset of Condensate Formation in Two-Dimensional, Converging-Diverging Nozzle

would not exit the two-phase region (dew point entropy at the exhaust pressure). The onset of nozzle condensation with the mixture occurred at an entropy slightly higher than the dew point entropy at the exhaust pressure. This does not necessarily mean these expansions with a pure fluid are more likely to produce condensate. The onset of condensation for both the pure and mixed working fluid occurred at approximately the same entropy condition relative to where the expansions first begin to pass through the two-phase region (s=0). This suggests that perhaps a limit similar to the Wilson Line could be defined; this will be examined as all of the data is evaluated.

Impact on Turbine Performance: Investigators first established the performance of the turbine for inlet conditions which produced a completely "dry" turbine expansion. The efficiency curve at this dry condition is shown in Figure 4 as a function of the velocity ratio. The velocity ratio is the blade tip speed (varies directly with turbine/generator speed) divided by the theoretical spouting velocity (proportional to $[dh,isent]^{1/2}$). The open circles and triangles in Figure 4 represent the performance for the "dry" turbine performance with either the isobutane

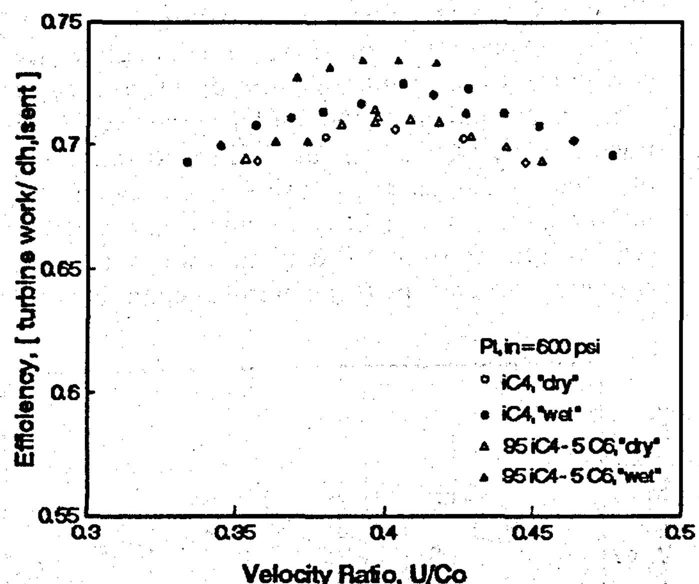

Figure 4. Turbine Efficiency Curves for "Wet" and "Dry" Expansions

working fluid, or the 95% isobutane, 5% hexane mixture. For the "dry" expansion, the turbine performance for both fluids were similar with peak efficiencies of slightly over 70% at close to the design velocity ratio of ~0.40. The closed circles and triangles represent the turbine performance when the isentropic expansion of the pure and mixed working fluids entered the two-phase region, but did not exit it at the exhaust conditions. Testing of both fluids in the nozzle indicated condensation would be forming in simulated expansions starting from the same inlet conditions.

In testing with both the pure and mixed working fluids at the "wet" expansion conditions, the data suggests the efficiency slightly increased and the point where the efficiency peaked shifted to a slightly higher velocity ratio. There is no known reason for the performance to increase. It is suspected that this increase in performance is more likely the result of a small deviation in the predicted properties used to determine the isentropic enthalpy change which is in the denominator of both the efficiency and velocity ratio terms. If this enthalpy change is under-predicted the apparent turbine efficiency would increase and that the peak efficiency would occur at a higher velocity ratio. In evaluating the data, two National Institute of Standards and Technology (NIST) property codes were used; NIST Database 12 was used for the pure fluids, and NIST Database 14 was used for the mixtures. The National Bureau of Standards EXCST code used previously by the project for data evaluation was also used, however investigators for much larger shifts (increases) in the turbine performance in going from "dry" to "wet" expansions. The NIST codes provided much more consistent results.

The initial testing with the isobutane working fluid did not indicate any degradation in performance at inlet conditions which nozzle testing indicated condensate, and which the properties indicated an ideal isentropic expansion to the exhaust pressure would exit the turbine inside the two-phase region. In December of 1993, engineers from Barber-Nichols assisted HCRF personnel during a series of tests where the turbine inlet temperature was reduced until a degradation in performance could be measured. The extent to which the inlet conditions were varied is shown in Figure 5. The open triangles in this figure represent the inlet conditions for which investigators did not note any degradation in performance; the open squares are the test conditions from the December testing. The lowest turbine inlet temperature tested was ~267°F, below the critical temperature of isobutane (~275°F).

The results of the turbine testing with isobutane at an inlet pressure of 600 psi is shown in Figure 6.

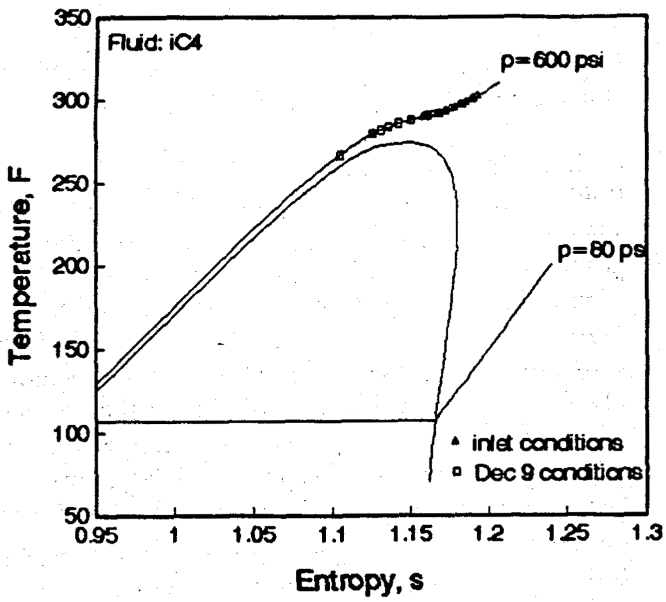

Figure 5. Summary of Turbine Inlet Conditions Tested with Isobutane at 600 psia Inlet Pressure

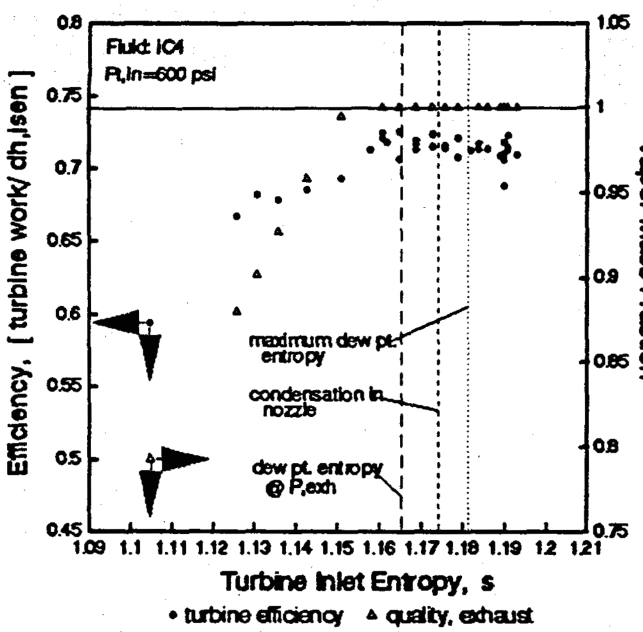

Figure 6. Turbine Performance with Isobutane at 600 psia Inlet Pressure

The observed turbine efficiency, as well as the vapor mass fraction (quality) of the fluid leaving the turbine are plotted as a function of the inlet entropy. The entropy points where an isentropic expansion first begins passing through the two-phase region and where an isentropic expansion never leaves the two phase region are identified, along with the point where condensation was observed in the two-dimensional nozzle. The turbine efficiency was relatively constant through this range of entropy conditions; there is no trend indicating a degradation in efficiency. The points shown between s=1.10 and s=1.15 are from the data collected during the December test sequence identified in Figure 5. It was during this test sequence that a decrease in turbine efficiency was noted. The degradation in efficiency was observed once the vapor fraction of the fluid leaving the turbine began to decrease.

Testing was also conducted with a 95% isobutane, 5% hexane mixture. The performance of the impulse turbine with this fluid is shown in Figure 7 as a function of entropy over the range of inlet conditions of interest. The turbine efficiency with the isobutane working fluid is also shown over the same range of inlet conditions. (The turbine inlet pressure was 600 psia for both fluids.) As with isobutane, there was no apparent degradation in turbine performance with the mixture as an ideal turbine expansion went from a completely dry condition, to a condition where an isentropic expansion would enter and not leave the two-phase region at the turbine exhaust. Through the range of inlet conditions shown, the efficiency of the turbine indicates a slight increasing trend, particularly with the mixture. The mixture was not tested at lower inlet entropy (temperature) conditions

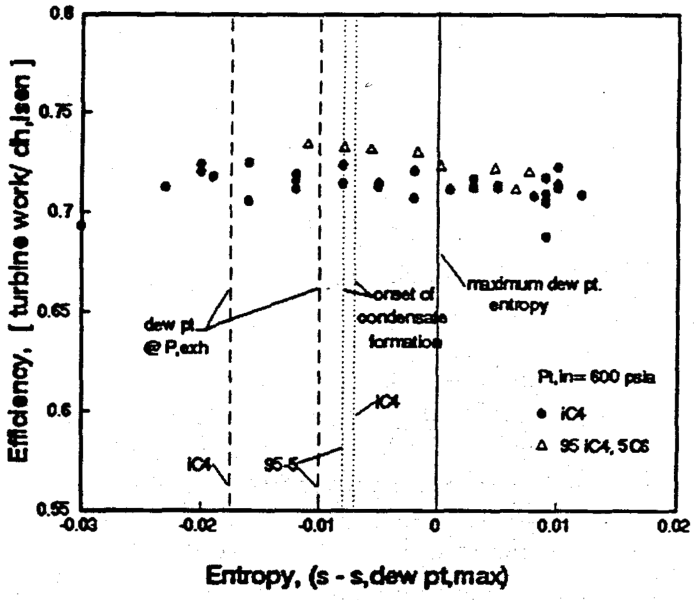

Figure 7. Comparison of Turbine Performance with Mixtures and Pure Working Fluids

because of the limited time available. In addition, the nozzle testing indicated condensation was forming at these lower entropy points. When the condensate forms, it preferentially contains more of the heavier component (hexane), while the vapor contains more of the lighter component. If this condensate does not re-evaporate, the composition of the fluid in the working fluid system begins to vary (cycle) and can not be accurately determined.

Examples of the effect of the metastable expansions on the brine effectiveness during the testing of the impulse turbine is shown in Figure 8. The brine effectiveness (turbine work divided by the brine flow rate) is plotted in this figure as a function of the turbine inlet entropy (temperature) at a fixed inlet pressure of 600 psi. The brine effectiveness is shown for two brine inlet temperatures, 308°F and 322°F. The region between the two entropy conditions identified represents the range of inlet conditions over which an ideal isentropic expansion through the turbine would pass through the two-phase region, exiting the turbine as a superheated vapor. At entropies below the dew point entropy at the exhaust pressure, the ideal expansion would not exit the two-phase region at the exhaust pressure. The brine effectiveness increased for both brine inlet conditions over this range of inlet conditions, with the lower temperature brine having higher increase (~20%). This

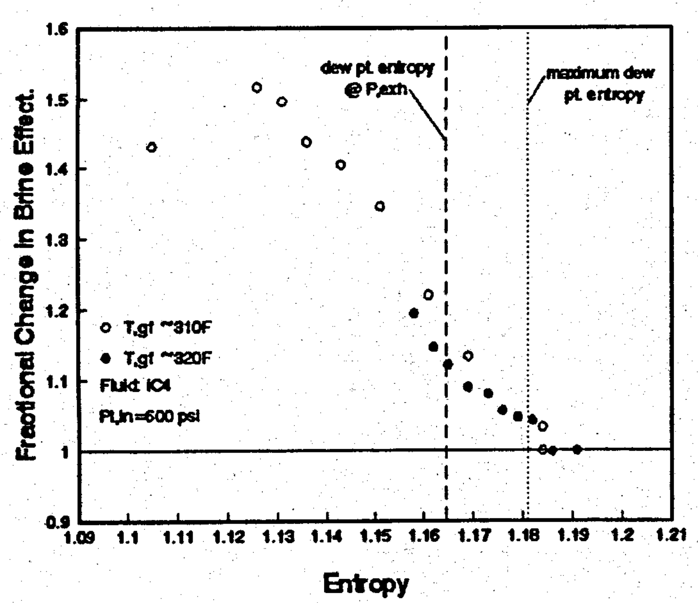

Figure 8. Measured Impact of Metastable Expansions on Cycle Brine Effectiveness

would be expected, the initial inlet conditions are not the optimum for the lower temperature resource. The data for the lower temperature fluid is from the December test sequence shown in Figure 5. During this sequence the brine effectiveness continued to increase, even though the turbine efficiency began to degrade at the lower inlet entropy conditions. The brine effectiveness peaked at a turbine inlet temperature of 280°F (s=1.125), and started decreasing as the turbine inlet temperature (or entropy) was further reduced. At the peak the brine effectiveness was approximately 50% higher than at the baseline turbine inlet conditions of 297°F and 600 psi.

SUMMARY

The project investigations into the condensation behavior of the metastable, supersaturated expansions and their impact on the performance of an impulse turbine have confirmed that the initial projections of cycle performance improvements are possible. The condensation behavior of the isobutane working fluid and an isobutane, hexane mixture have been mapped utilizing the two-dimensional nozzle over the range of inlet conditions of interest. The data collected suggests that with both fluids the condensate begins forming at similar points relative to where the expansions begin passing through the two-phase region.

The subsequent testing conducted with an axial-flow, impulse turbine did not indicate any degradation in performance until the actual conditions at the turbine exhaust was within the two-phase region, i.e., the fluid leaving the turbine contained liquid. The turbine performance with a 95% isobutane, 5% hexane mixture was similar to that with the pure isobutane working fluid over the range of inlet conditions tested. In analyzing the data collected, investigators found the NIST property codes Database 12 and Database 14 provided more consistent results for conditions approaching the critical point, than the NBS EXCST code utilized earlier in the program in analyzing the data from the supercritical cycle testing. The brine effectiveness was observed to increase over the range of inlet conditions of interest. During an extreme series of tests conducted to evaluate the onset of the turbine efficiency degradation, the brine effectiveness did not peak until turbine inlet conditions of 280°F and 600 psia, even though the turbine efficiency began decreasing once the inlet temperature was lowered under 288°F.

The project is currently preparing the HCRF for the next phase of turbine testing. During this phase of investigations, a radial-inflow, reaction turbine will be tested over a range of conditions similar to those in the initial turbine tests. These investigations are expected to be completed in late June 1994, after which the site closure activities will begin.

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LIGHTWEIGHT CO_2-RESISTANT CEMENTS FOR GEOTHERMAL WELL COMPLETIONS

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ABSTRACT

Alkali metal catalyzed reactions between CO_2-containing brines and portland cement-based well cements can result in rapid strength reductions, increased permeability and casing corrosion. These lead to reduced well life, increased costs and environmental concerns.

Work at Brookhaven National Laboratory (BNL) has indicated that materials formed by acid-base reactions between calcium aluminate compounds and phosphate-containing solutions yield high strength, low permeability and CO_2-resistant cements when cured in hydrothermal environments. The cementing formulations are pumpable for several hours at temperatures up to 150°C, thereby making their use for well completions technically feasible. When this cementing matrix was exposed in an autoclave containing Na_2CO_3-saturated brine for 120 days, <0.4 wt% $CaCO_3$ was produced. A conventional portland cement-based well completion material will form ~10 wt% $CaCO_3$ after only 7 days exposure. The addition of hollow aluminosilicate microspheres to the uncured matrix constituents yields slurries with densities as low as ~1.2 g/cc which cure to produce materials with properties meeting the criteria for well cementing. Laboratory characterization is nearing completion, engineering scale-up is underway, and plans for field testing in a variety of geothermal fluids are being made.

INTRODUCTION

The quality of the cementing phase of a geothermal well completion often establishes the life expectancy of the well. Poor cements can result in blow-outs and casing corrosion or collapse. In addition to the need for cements which, upon curing, yield the necessary physical, mechanical and chemical characteristics, their slurry precursors must have reheological properties that permit placement. Low slurry densities (~1.2 g/cc) are desirable to minimize the frequency of lost circulation episodes when attempts are made to cement in weak unconsolidated rock zones with very fragile gradients.

As drilling environments become more hostile, the need for lightweight, carbon dioxide (CO_2)-resistant cements becomes more critical. It is well known that alkali metal catalyzed reactions between CO_2-containing brines and the calcium silicate hydrate (CSH) compounds and calcium hydroxide in conventional well cements result in rapid deterioration at pressures, temperatures and CO_2 concentrations typical of geothermal wells.[1] In these cases, reactions between Na and K in the brines with CSH phases produce substituted CSH compounds such as pectolite and reyerite, both of which are susceptible to carbonation. Leaching of the resultant $CaCO_3$ and $Ca(HCO_3)_2$ increases porosity and permeability, and causes strength retrogression. Cement failures attributed to CO_2 are occurring in less than 5 yr, and in one case, resulted in a collapsed well casing within 90 days.

As a result of this rapidly expanding problem which if unsolved could seriously constrain the development of the World's geothermal resources, Brookhaven National Laboratory (BNL) under the sponsorship of the U.S. Department of Energy, initiated work in 1989 to develop non-portland based cementing materials. The following performance criteria were established: 1) slurry density, <1.3 g/cc, 2) pumpability, 4 hr at 150°C, 3) compressive strength, >5 MPa at 24 hr age, 4) bond strength to steel, >0.07 MPa, 5) carbonation rate, <5% $CaCO_3$ after 1 yr in brine at 300°C containing 500 ppm CO_2, and 6) water permeability, <0.1 m Darcy.

The work focused on the identification of pathways leading to the formation of chemically bonded cements (CBC) by acid-base reactions. The CBCs were prepared from two chemical components, the basicity (a proton accepting cationleachable powder), and the acidity (a proton-donating liquid). The powder may be either a metal oxide (MO) as a single component system, or an acid-decomposable binary or ternary system such as $MO \cdot xAl_2O_3$, $MO \cdot xSiO_2$ or $MO \cdot xAl_2O_3 \cdot ySiO_2$. The cementitious products formed are salt complexes which bind the partially reacted powder particles into a coherent mass. Such cement forming reactions may be represented by the generic equations given below.

Metal oxide-acid reaction, (1)

$$\underset{\text{base}}{MO} + \underset{\text{acid}}{H_2A} \rightarrow \underset{\text{salt matrix}}{MA} + H_2O,$$

Metal aluminate or silicate-acid reaction, (2)

$$\underset{\text{base}}{MO \cdot xSiO_2} + \underset{\text{acid}}{H_2A} \rightarrow MA + \underset{\text{silica gel}}{xSiO_2} + H_2O,$$

$$\underset{\text{base}}{MO \cdot xAl_2O_3} + \underset{\text{acid}}{H_2A} \rightarrow MA + \underset{\text{alumina gel}}{xAl_2O_3} + H_2O,$$

where M represents the cations and A is the acid anion. Both M and A are taken as being nominally divalent for convenience of representation.

The ongoing work is organized into five phases: 1) fundamental cement research, 2) mix design, 3) property characterization, 4) placement technology, and 5) downhole testing. The results to date indicate that the properties needed for a superior well cement can be attained. In this paper, the results from Phase 1-4 laboratory evaluations on CBCs produced by reactions between several calcium aluminate cements, polyphosphate compounds and lightweight fillers are summarized. A successful development will decrease the cost of well completions due to reductions in lost circulation control episodes, increase the life expectancy of wells, and reduce environmental concerns regarding blow-outs. It will also permit development of higher temperature, higher CO_2 content brine resources which are not currently exploitable due to cement deterioration concerns.

EXPERIMENTAL PROCEDURES

Materials

Four commercially available calcium aluminate cements (CAC); Refcon (RE), Luminite (LU), Secar 80 (#80), and Secar 41 (#41) were used as the base solid reactants. The first two were supplied by the Lehigh Portland Cement Company, the others by the Lafarge Calcium Aluminates Company. An ammonium polyphosphate fertilizer solution, known commercially as Poly-N (fertilizer grade: 11-37-0, Arcadian Corporation) was generally employed as the acid liquid reactant. Sodium hexametaphosphate $[NaPO_3]_n$, supplied by Albright and Wilson Americas, was utilized in later tests for comparative purposes.

Five commercial inorganic and organic microspheres were evaluated as lightweight fillers for CBCs. These were Q-Cel 650 (Q-C), and Extendospheres (EX), both supplied by the PQ Corporation; Macrolite (MA) and glass bubbles (GL) from the 3M Corporation; and Dualite M6017AE (DU), supplied by Pierce and Stevens Corporation. All except the MA are categorized as hollow microspheres. Physical and chemical property data for each of these fillers are given in Table 1.

Sample Preparation

Neat CPC pastes were prepared by thoroughly hand-mixing 60 wt% CAC powders and 40 wt% Poly-N solution at room temperature for ~3 min. The slurries were then cast in 30 mm-diam x 70 mm-long cylindrical molds and cured for 20 hr in an autoclave at 250°C.

Lightweight specimens (LCPC) were made by first dry mixing the CAC powder with the filler. Either Poly-N or $(NaPO_3)_n$ was added. After casting and curing at room temperature for 2 hr, autoclave curing was accomplished for 20 hr at 200° or 300°C. Compared to the CPC slurry which had a density of 1.98 g/cc, the LCPC slurries ranged from 1.18 to 1.55 g/cc.

Measurements

Differential scanning calorimetry (DSC) was used to determine the extent and onset temperature of the exothermal acid-base reaction between the

CAC and the Poly-N. The phase compositions and transformations of CPC after exposures to hot 0.05 M Na_2CO_3 solutions were explored by X-ray powder diffraction (XRD). Quantitative data on the amount of $CaCO_3$ formed in the CPC bodies were obtained from thermogravimetric analysis (TGA), by the weight loss at which thermal decomposition of $CaCO_3$ occurs over the range 600° to 770°C. Compressive strength tests were performed on neat CPC specimens having a diameter of 30 mm and a length of 60 mm; the result given is the average value of three specimens.

The characteristics of the microspheres used to produce LCPCs, namely bulk density, particle size and chemical composition, were measured using helium comparison pycnometry, scanning electron microscopy (SEM) and X-ray photoelectron spectroscopy (XPS), respectively. XRD and Fourier transform infrared (FT-IR) spectroscopy were used to determine the phase compositions and transformations of the LCPCs after hydrothermal exposure. Image analyses using SEM coupled with energy dispersion X-ray spectrometry (EDX) were made of the LCPC fracture surfaces to determine their microstructure and the chemical components in the matrix and at the critical contact zones between the CPC and the microspheres.

RESULTS

Calcium Phosphate Cement Pastes

Four commercially available calcium aluminate cements (CAC) were selected for use as the basicity component in the CBC formulation. These materials and their sources were identified in the Materials Section of this paper. Prior to use, chemical characterizations of the CACs were performed using XRD analysis over the range 0.444 to 0.249 nm. These data which have been published,[2] indicated that the #41 CAC powder contained two major components; monocalcium aluminate (CA) and gehlenite (C_2AS). The LU and RE-type reactants contained these compounds plus monocalcium dialuminate (CA_2), while the #80 had CA and CA_2 as major components and C_2AS as a minor one.

Differential scanning calorimetry (DSC) was then used to estimate the reactivity of the CAC reactants with Poly-N. Heating at a constant rate of 10°C/min in a N_2 environment was used in these tests. The data showed that the magnitude of reactivity of CAC with Poly-N depends mainly on the proportion of CA_2 to CA + C_2AS. Powders containing a high ratio retard setting, while those with a low ratio accelerate it. Based upon these results the reactivities of the four CAC powders is as follows: #41 > LU > RE > #80.

Compressive strength results for each of the CAC formulations after exposure to a 0.05M Na_2CO_3 solution at 250°C are given in Figure 1. The data for unexposed RE-, LU-, and #80-induced specimens show that strength increases during the first 7 days of exposure, and then decreases with time to 28 day; beyond this time, strength seems to level off. In contrast, there was no improvement in strength after 7 days exposure of the #41 specimens (which showed the highest strength in the series of unexposure specimens). The retrogression of strength for this specimen occurred for 28 days, and thereafter, showed no significant change in strength. The ultimate development of strength in CPC specimens was due to the combined structure of crystalline HOAp and γ-A100H phases, together with the amorphous $NH_4CaPO_4 \cdot xH_2O$ and Al_2O_3 gel phases which bind the partially reacted and non-reactive CAC particles into a coherent mass. The excessive in-situ growth of crystalline phases in the amorphous bodies led to the decrease in strength. Thus, we believe that the increased strength for 7 day-exposed RE, LU, and #80 specimens is related directly to the growth of crystalline phases. Assuming that the reductions in strength result from the formation of crystalline phases in the amorphous bodies, the absence of significant changes in strength for the specimens after exposure for 28 days is due to the ending of the hydrothermal phase conversion and transformation at 250°C. In other words, the $NH_4CaPO_4 \cdot xH_2O \rightarrow$ HOAp and Al_2O_3 gel $\rightarrow$ γ-A1OOH phase transitions were completed at the exposure age of 28 days. The strengths of the 120 day-exposed CPC specimens fell into the following order; RE > #41 > LU > #80. The exposed RE specimens had an excellent strength of > 80 MPa.[3] All of the strengths greatly exceeded the API criterion of 5 MPa.

In conjunction with the compressive strength determinations, analyses were performed to measure the rate of carbonation and the phases formed. TGA was used for the former, XRD for the latter. Carbonation data are summarized in Figure 2. As noted, a small amount of $CaCO_3$, 0.1 to 0.2 wt%, was already present in the unexposed control specimens. The data indicate that the rate of carbonation for CPC specimens depends primarily on the species of the CAC reactants. The rates for LU and #41 specimens tended to increase monotonously with increased exposure time; after 120 days these specimens contained only 0.2 wt% $CaCO_3$, while 0.5 wt% $CaCO_3$ was detected in the RE samples. By comparison, a higher rate of carbonation occurred in the #80 specimens. The rate of carbonation for this specimen increased with exposure time; after 28, 91, and 120 days the amount of $CaCO_3$ was 0.9, 1.3, and 1.7 wt%, respectively. However, the concentration at 120 days was considerably lower than that for 200°C-autoclaved neat calcium aluminate cement pastes exposed for 7 days to the Na_2CO_3 solution at 250°C (1.7 wt% vs. 6.2 wt%). These results, and data from earlier exothermal reactions suggested that the carbonation rate for CPC specimens probably is associated with the magnitude in reactivity of CAC with Poly-N. The specimens made with the #41 and LU reactants with a high reactivity had a low rate of carbonation, while the RE reactants with a moderate reactivity, had a moderate rate of carbonation. In contrast, #80 reactant with the lowest reactivity showed the highest rate of carbonation in this test series.

For comparative purposes, a conventional class G cement paste was also exposed to the hot Na_2CO_3 environment. In this case, the $CaCO_3$ concentration was 9.5 wt% after 7 days.

In addition to strength, low permeability and CO_2 resistance, well cementing materials must exhibit good adherence to the casing string and the borehole rock formation. If so, the cement not only serves to mechanically support the casing and resist blow-outs, but also protects the casing from external corrosion sources. In order to evaluate the ability of CPCs to meet this design criterion, their bonding characteristics at 200°C with cold-rolled steel (CRS) and stainless steel substrates were measured. For comparison purposes, similar measurements were performed for a conventional class G cement (CGC) which is generally used for well completions.

Evaluations of the shear bond strength and the interfacial phase compositions were made. For the latter, analyses of both the interfacial-failed cement and metal sides were performed after completion of the shear bond tests. The results from these examinations, given in Table 2, indicate that the bond strength is dependent upon the cement type and the metal composition. The CGC exhibited better bonding than the CPC. Both cements had higher bond strengths to CRS than with SS. Studies of the phase compositions at the interfaces indicated that the high shear strengths at the CGC/metal joints were due to strong mechanical bonding between the rough Fe_2O_3 layer formed as a corrosion product and the xonotlite phase formed by hydrothermal reactions with the CGC pastes. In contrast, no significant amount of Fe_2O_3 was found at the CPC/metal interfaces.

The interfacial contact layer between the CPC and the metals consisted of δ-A100H (Boehmite) and Na-zeorite phases separated from the major phase hydroxyapatite (HOAP) component of the matrix. Therefore, this phase segregation at the interface probably is the reason for the lower bond strength with CPC/metal systems. However, it should also be noted that the lowest bond strength measured was 0.47 MPa, almost 7 times the API criterion of 0.07 MPa.

Lightweight CPC Composites

The compatibility of CPCs with a variety of commercial inorganic and organic microspheres was then studied.[4] These hollow fillers were evaluated mainly on the relationship between the densities of the slurries and the compressive strengths of hydrothermally cured specimens. The mechanical behavior of the lightweight specimens (LCPC) was then correlated with the phase compositions, transformations, and morphological features of the composite cement matrices, and with the chemical elements and microstructural developments at the contact zones near the microsphere particles. The latter analyses provided us with information on the possible interaction mechanism between the CPC and the microspheres.

Compressive strength data for LCPC specimens as a function of slurry density, are shown in Figure 3. The specimens were autoclaved for 20 hr at 200° or 300°C prior to test. Specimens containing the aluminosilicate microsphere (EX) exhibited the highest strengths for both curing temperatures. Specimens with a slurry density of 1.2 g/cc had a strength of 8.5 MPa. At 300°C, this decreased to

~4.5 MPa. The strengths increased with slurry density. For the middle-range density of ~ 1.35 g/cc, LCPC strengths were in this order: EX > Q-C = GL > DU > MA. The poor performance of the MA filler was attributed to physical incompatibility; the spheres mixed poorly with the cement and separated quickly, floating to the top. This created non-uniform, weak specimens that performed poorly at both temperatures. In comparison with specimens autoclaved at 200°C, the hydrothermal treatment at 300°C resulted in a loss of strength, with the rates of reduction in strength for DU- and MA-filled CPC specimens being lower than those for the other microsphere-filled specimens. The mechanical strengths of the specimens made with the borosilicate-based glass fillers such as Q-C and GL was especially poor, exhibiting values between ~1.0 and ~3.0 MPa.

SEM coupled with EDX, XRD, FT-IR analyses were used to investigate the causes for the strength changes, and to identify phase compositions and transformations. These results which have been published,[4] indicated that the factors governing the development and loss of strength were 1) phase composition and transformation of the matrix itself and the interfacial reaction products formed by interactions between the microspheres and the CPC, 2) changes in microstructure developed at the microsphere-CPC interfaces and in the matrix phase, and 3) the susceptibility of the microspheres to hydrothermal and thermal decomposition. SEM images of EX-containing LCPCs revealed that failure occurred through two different modes, one of which was an adhesive mode in which separation occurred at the critical boundary regions between the CPC and the microsphere, leaving either matrix craters or smooth microspheres without any CPC coverage on the fractured matrix surface. The other mode of failure was a cohesive one, occurring through the microsphere shell. Based upon these analyses, we propose that the strength reduction with temperature results from the strong chemical affinity between the EX microsphere's surfaces and the CPC matrix. This not only leads to the formation of intermediate layers, which improve the interfacial bond strength between them, but also decreases the effective thickness of the hollow microsphere shell. The latter effect might cause the distribution of mechanically weak microspheres in the matrix phase. Since cohesive failure of the microsphere was observed on all four fracture surfaces, the retrogression of strength may be related to the high extent of microsphere-CPC interaction, rather than to the development of a porous microstructure brought about by the in-situ conversion of amorphous AmCOP and $Al_2O_3 \cdot xH_2O$ into crystalline HOAp and Boehmite, respectively.

CONCLUSIONS

Materials that yield a cementing matrix produced by acid-base reactions between calcium aluminate cements and phosphate-containing compounds can be mixed with lightweight fillers to produce pumpable slurries with densities as low as ~1.1 g/cc. Upon curing for 20 hr in hydrothermal environments up to 300°C, high strength, durable and CO_2-resistant cement pastes are produced. Four different commercially available calcium aluminate cements were used as base reactants, and it was determined that the reactivity and resistance to carbonation were dependent upon the chemical composition of the base ingredient. The presence of monocalcium aluminate (CA) and gehlenite (C_2AS) accelerated the setting of the cement and reduced carbonation. All of the cement pastes exhibited compressive strengths >58 MPa after hydrothermal curing at 250°C for 20 hr. Subsequent exposure to a 0.05 M Na_2CO_3 solution at 250°C for 120 days indicated strength changes over the first 28 days due to the growth of crystalline phases, after which the compressive strength remained constant. Measurements of the $CaCO_3$ concentrations produced during the 120 days indicated values of <0.4 wt% for all of the cements except the one rich in CA (#80). A conventional portland cement-based well completion material will form ~10 wt% $CaCO_3$ after only 7 days exposure to the same environment.

The susceptibility of the various CPC matrices to carbonation was in the following order, #80 > RE > LU > #41. However, although #80-derived CPC specimens exposed for 120 days had the highest $CaCO_3$ concentration of ~1.7%, this value was considerably lower than that of autoclaved neat calcium aluminate, API class G and H cement pastes. The loss in compressive strength for all the CPC specimens occurred in the first 30 days of exposure, but beyond this time, there was little change. Thus, this retrogression of strength is more likely to be associated with the phase transformation of amorphous ammonium calcium orthophosphate salt and $Al_2O_3 \cdot xH_2O$ gel into crystalline HOAp and

γ-AlOOH, respectively, rather than the detriment of cement bodies caused by $CaCO_3$.

The incorporation of inorganic and organic microsphere fillers into CPC produces a lightweight, moderate strength and highly durable cement. An aluminosilicate-based hollow microsphere (EX), with a density of 0.67 g/cc and a particle size of 75 to 200μm, produced the most suitable results, a low slurry density of ~1.3 g/cc and a compressive strength greater than 6.89 MPa. This microsphere-filled lightweight CPC exhibited the following characteristics; 1) after autoclaving at 200°C, amorphous ammonium calcium orthophosphate (AmCOP) salt and $Al_2O_3 \cdot xH_2O$ gel phases, formed by the reaction between calcium aluminate cement and an $NH_4H_2PO_4$-based fertilizer, were primarily responsible for the development of strength, and 2) at a hydrothermal temperature of 300°C, the microsphere shell moderately reacted with the CPC to form an intermediate reaction product, epistilbite (EP), while crystalline hydroxyapatite (HOAp) and Boehmite were yielded by the phase transformations of AmCOP and $Al_2O_3 \cdot xH_2O$, respectively.

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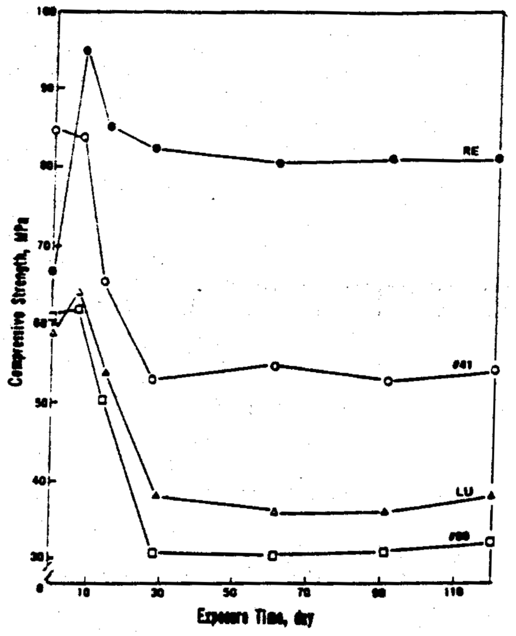

Figure 1. Changes in compressive strength of various CPC specimens as a function of exposure time to a 250°C-Na_2CO_3 solution.

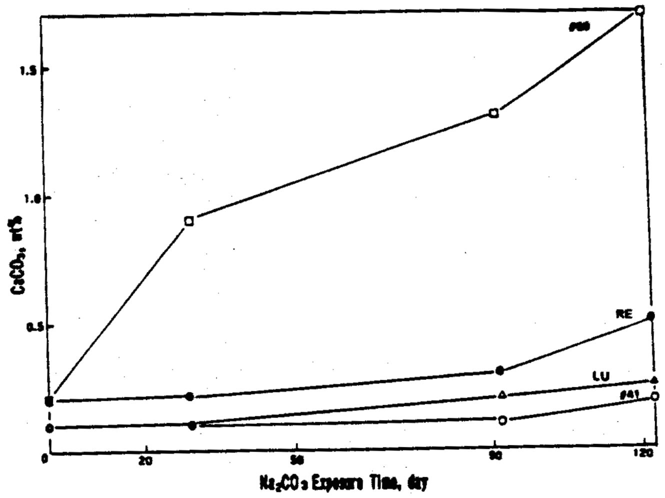

Figure 2. Concentrations of $CaCO_3$ formed in various calcium aluminates-derived CPCs after exposure for up to 120 days to Na_2CO_3 solution at 250°C.

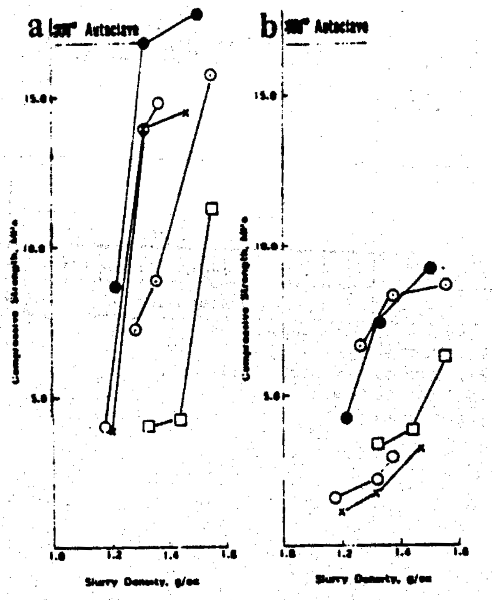

Figure 3. Compressive strengths of LCPC specimens as a function of slurry density. (a) 200°C-autoclaved, (b) 300°C-autoclaved, (o: Q-C, •: EX, □: MA, x: GL, o: DU).

Table 1
Properties of Microspheres

Microsphere (symbol)	Type	Density g/cm^3	Particle Size µm	Chemical Composition of Shell Surfaces,% Si	Al	B	C	K	O	Fe	Ca	Na
Q-cel 650 (Q-C)	Borosilicate Glass	0.50	6-95	11.0	-	21.3	15.2	2.3	37.3	-	-	12
Extendospheres (EX)	Aluminosilicate	0.67	75-200	13.1	10.1	-	37.8	2.0	36.5	-	-	0
Macrolite (MA)	Nepheline Syenite Ceramic	1.25	300-450	6.4	19.7	-	30.8	1.8	36.8	2.3	-	2
Glass Bubbles (GL)	Soda Lime Borosilicate Glass	0.38	5-45	11.6	-	16.9	25.7	2.4	31.7	-	1.9	9
Dualite (DU)	Acrylonitrile Copolymer w/$CaCO_3$ Coating	0.13	25-100	-	-	-	50.9	-	33.1	5.0	11.0	-

TABLE 2
BOND STRENGTHS AND PHASE COMPOSITIONS AT CEMENT/METAL INTERFACES

Cement*	Metal Substrate**	Shear Bond Strength (MPa)	Phase Composition at Interfaces Major	Minor
CPC	CRS	0.75	δ-AlOOH	Na-zeorite, HOAP***
CPC	SS	0.47	Na-zeorite.δ-AlOOH	HOAP
CGC	CRS	1.65	Fe_2O_3, Xonotolite	--
CGC	SS	1.43	Xonotolite	Fe_2O_3

* CPC: calcium phosphate cement
CGC: class G Cement
** CRS: AISI 1008 cold-rolled steel
SS: AISI 304 stainless steel
*** HOAP: hydroxyapatite

DIRECT-CONTACT CONDENSER APPLICATIONS

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PROJECT OBJECTIVE : The objective of this project is to demonstrate the use of advanced direct-contact condensers for improving the utilization of geothermal resource and handling of non-condensible gases. Because of a substantial potential for improving the efficiency of the condensation and gas removal processes and thus the overall utilization of geothermal resources, the outcome of this effort will be important to the geothermal industry.

APPROACH : This project is pursued via a Cooperative Research and Development Agreement (CRADA) between NREL and PG&E. Based on designs under development at NREL, PG&E will retrofit an existing direct-contact condenser (at Unit #11 at The Geysers) with advanced structured packing and other internal modifications, with cocurrent and countercurrent segments to enhance its overall performance with respect to steam and non-condensible handling.

The condenser at the chosen plant operates at less than optimum performance with a high back pressure and a high concentration of steam in the vented non-condensible gases. With the proposed modifications, a potential back pressure of not more than 10% over a theoretical minimum for the operating conditions can be realized. The steam concentration in the vented gases can also be reduced substantially (to not more than 10% over the corresponding theoretical minimum for the operating conditions), which would reduce the steam flow requirement for the jet ejectors currently used to vent the non-condensible gases.

The proposed work will be carried out in three phases, as indicated:

I. Conceptual Design Development
   a. Condenser modeling code upgrade
   b. Selection of packing
   c. Performance projections
   d. Conceptual design
   e. Decision analysis for proceeding to the following phases

II. Engineering Design and Installation
   a. Steam, gas and water chemistry acceptability assessment
   b. Engineering design
   c. Procurement and Installation

III. Operational Tests
   a. Instrumentation
   b. Operational tests
   c. Model validation
   d. Reporting

The next overhaul of this condenser for major cleanup and retrofit is scheduled to occur in June 1996. Various activities of the first two phases of this project will be carried out in a timely manner such that installation can occur in June 1996. Detailed discussion of the phases, duration and work breakdown structure follow.

Phase I. Conceptual Design Development

The FY 1994 task at NREL will address the first phase of the CRADA.

The primary responsibility for this phase will rest with NREL. NREL researchers will upgrade existing direct-contact condenser models to address specific issues related to their operation with geothermal steam. The major areas of departure from NREL's prior work will be in that the condenser operating pressure ranging up to 6 inches of mercury and in handling increased number of non-condensible species, as many as eight, which must be tracked through the condenser. These non-condensibles include hydrogen sulphide, carbon dioxide, ammonia and, methane, among others. The solubility system for these gases in pure water will have to be developed for accurate evaluation of the ratio of each gaseous species that will be distributed between the gaseous phase and in solution in the liquid (commonly termed as "partitioning").

Two separate computer codes, one for a cocurrent and one for the countercurrent sections of the condenser subsystem are being developed. An appropriate model will also be developed to calculate the mass transfer of dissolved non-condensibles in the cooling tower. Upon completion of the model and simulations of the condenser operation, NREL will develop conceptual designs for the modifications of the existing condenser.

PG&E will assess the commercial availability and cost of suitable packings for the geothermal applications. Key considerations in the selection of a packing will be its cost and susceptibility to fouling. Packings commonly used in the cooling-tower applications, are generally made of polyethylene and handle similar water temperatures as would be expected in this application. They are also made to withstand harsh outdoor environments and accommodate a certain degree of fouling without significant loss in performance. PG&E will evaluate cooling tower packings and other metallic packings for use in these condensers.

Upon completion of the model development and packing selection, NREL will develop performance projections for the modified condenser design. The performance will address the water flow requirements, temperature rise, condenser back pressure, and non-condensible concentrations at various points internal to the condenser and in the incoming and exiting streams. Based on these, projections for the power consumption for venting the condenser and cooling water circulation will be ascertained to demonstrate the potential benefits of the proposed retrofit.

PROJECT STATUS

Background

Although direct-contact condenser is not a new technology, significant improvements have occurred over the past decade as a result of DOE-directed research efforts in low-temperature power-cycle technologies. These improvements have the potential to significantly reduce the cost and increase the efficiency of geothermal power systems. However, a U.S. manufacturing base for these systems is not available today, and needs to be developed. Information developed in this work will help to spur the development of a U.S. manufacturing base and provide research results in public domain through publications and technical reports.

Pacific Gas and Electric Company owns and operates a set of approximately fourteen power plants at The Geysers, utilizing the geothermal steam resource. PG&E produces up to 750 MW_e from The Geysers steam resource, making the power available to California consumers. On some of the power systems (called Units), PG&E has experienced poor performance from existing condensers as evidenced by increased operating back pressures and a high concentration of steam in the vented stream of non-condensible gases. Over the years, PG&E has pursued different approaches to improving the condenser performance with only limited success.

NREL has worked in the development of advanced direct-contact condensers for ocean thermal power systems over the past thirteen years, conducting experiments, developing computer models and workable designs. NREL has also developed innovative condenser arrangements for mitigating the influence of non-condensible gases present in the vapor stream.

PG&E recognizes the potential merit of the NREL-developed condenser concepts for gaining substantial improvement in the condenser performance. DOE is also interested in development and implementation of advanced direct-contact condenser concepts to help US industry to improve the performance and economic viability of geothermal power systems. NREL, DOE and PG&E have a mutual interest in carrying out a collaborative research and development effort to develop field test equipment and test data which will quantify the potential heat-transfer performance and non-condensible gas handling characteristics of these advanced condenser concepts.

Research Results

NREL researchers have initiated work in four areas:

- o generating cocurrent condenser modelling equations capable of handling as many as eight non-condensible gaseous species present in the steam as well as dissolved in the cooling water, and as many as fifteen varied ionic species contained within the liquid stream.

- o modeling the chemical reaction that occur between the dissolved gases and the ionic species in the liquid. It appears that the reaction rates are faster than the rates at which mass transfer takes place--allowing these reaction systems to be treated as a set of non-linear algebraic equations for calculating equilibrium compositions, rather than differential systems.

- o coding cocurrent and countercurrent condenser portions of the system to track the concentration of the steam and other non-condensible gases as they progress through the condenser packing. At present, this code handles eight non-condensible species in the steam and an additional fifteen ionic components in the liquid. The code is designed such that these numbers can be adjusted up or down as needed for future applications. These code have been compiled and produce results at this stage. The verification of the results and modification of the codes are in progress.

- o discussing selection of suitable packings to be introduced in the condenser with PG&E engineers. PG&E personnel have an extensive background in cooling-tower packing selection, testing and performance and is expected to guide NREL researchers in their choice. The packing selection effort will address potential fouling properties of the materials as a key issue, since the packing will not be accessible for maintenance on a regular basis, except perhaps once in three years during a major overhaul.

The NREL Technology Transfer Office of NREL has been working with the legal office of PG&E to finalize the CRADA.

Plans

NREL plans to complete the code development and generate a conceptual design by the end of CY 1994.

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Session 5: Drilling

Chairperson:
Marc W. Steffen,
Calpine Corporation

DRILLING SESSION
Introductory Comments

Marc W. Steffen
Calpine Corporation

The Geothermal Drilling Organization (GDO) continues to be actively involved in identifying and sponsoring geothermal drilling projects that qualify for joint participation and funding between industry and government. There are several projects in various stages of development. The current status of these projects is: High temperature air motor (Baker Hughes Inteq) - An 8" prototype tool per terms of the contract is now ready for field testing. Various elastomer rubber compounds were tested along with several bearing assemblies. A specific field application is now needed to further evaluate the tool and complete the project agreement. Additional lab testing has also been done on a 4¾" and 6¾" tool. Rotating head elastomers (A/Z Grant) - Further refinements to the design and type of rubber compound are being made. Prototypes should be ready for field tests later this year. Retrievable whipstock (A/Z Grant) - A 13⅜" prototype tool has been fully developed and is now waiting for a field application. The contract will be fulfilled when field testing and evaluation is completed.

One of the primary objectives of the GDO in the future is to continue to expand membership to better represent all sectors of the industry. More representation means more diversified projects and more industry participation. Project sponsorship would continue to be a function of merit and available funding. Field applications at the rig site will still be a very necessary requirement in the future to demonstrate the viability and effectiveness of various project development. The GDO and its members have to remain in touch with new technologies and methodologies and their application to the enhancement of geothermal drilling. The credibility of the GDO can continue to be enhanced by more project completions and successful implementations in the field.

It is very important that communication be maintained between the GDO and various government lab personnel relating to new project development and funding issues. This will serve as a direct link regarding project prioritization and DOE budgeting policies that will impact future developments. It would be very informative and useful if a DOE representative could, periodically, attend one of our GDO meetings to discuss budgeting matters, future trends, project priorities, future goals and objectives, etc. This knowledge could help guide the GDO on identifying new project ideas. It would also serve as a forum where ideas could be exchanged on a workable balance of projects that have more of an immediate application and benefit to geothermal drilling versus projects that have longer range science objectives.

GEOTHERMAL DRILLING TECHNOLOGY - OVERVIEW

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Abstract

The Geothermal Drilling Technology project is directed at reducing the costs of drilling and completing geothermal wells. Current projects include: lost circulation control, borehole instrumentation, acoustic telemetry, slimhole drilling, hard-rock bits, and projects of the geothermal drilling organization.

Accomplishments during the year include completion of a slim hole drilling project with Far West Capital at Steamboat Hills. This hole confirmed the validity of slim hole drilling for exploration and reservoir assessment in highly permeable regions. New field measurements of attenuation in drill pipe at the Long Valley Well confirmed our analysis of previous data and showed very low attenuation in length-ordered pipe. Data transmission to depths of 10,000 feet appear to be feasible. New low-cost memory tools were completed and tested during the year. Precision temperature and pressure tools are now available for operation in geothermal wells at temperatures to 400 C. Eight rolling float meters for accurate measurement of drilling fluid outflow are in operation. Several critical components of the drillable straddle packer were successfully tested and construction of a large-scale packer test facility was initiated. A number of new cutter designs for hard-rock bits have been evaluated and one series of bit tests completed at Amoco's Catoosa test facility. The Geothermal Drilling Organization has four projects that are currently being developed by industry to solve near-term drilling problems.

Program Summary

Drilling technology development at Sandia is organized by work in six task areas. This year, three of the tasks will be described in following presentations on hard-rock bit development, slimhole drilling, and memory tools for high-temperature borehole measurements. I will briefly describe accomplishments in the remaining three tasks: lost circulation control, acoustic telemetry, and projects of the Geothermal Drilling Organization. Most of our work is carried out in close collaboration with industry including cost-sharing in projects. Included during the past year are: A-Z Grant/International, Baker Hughes INTEQ, California Energy Co., Calpine, DBS (Baroid), Dennis Tool Co., Far West Capital, Megadiamond, Smith International, and Unocal Geothermal.

The lost circulation project is attacking the number one cause of trouble encountered when drilling geothermal wells. On average, lost circulation problems account for from 3.5 to 10% of the total cost of geothermal power projects. The goal of the Sandia program is to develop and transfer to industry new technology that will reduce lost circulation costs by 30-50%. Work is focused in two areas: improved characterization of lost circulation zones and new downhole tools for improved control of lost circulation events.

The first step in loss zone characterization is accurate measurement of drilling fluid flow rates both into and out of the well. Accurate measurement of outflow in the partially-full return line has been a problem for many years. The recently developed rolling float meter does significantly improve outflow measurement. Eight rolling float meters were fabricated and loaned to service companies for field testing. Good results have been obtained on land rigs, but problems have arisen on offshore rigs due to very heavy muds and improper use. Geothermal service companies are still evaluating these meters. We are also evaluating commercial non-intrusive flow meters for inflow measurement. We are using our wellbore hydraulics flow facility to determine sensitivities of the commercial meters to fluid property changes and rig-type noise. Results of this evaluation will be available to industry.

Several new tool concepts have been developed to reduce time and costs associated with plugging lost circulation zones. Our current work is directed primarily at developing a low-cost drillable straddle packer. This packer will make more effective use of cement treatments by increasing cement delivered to the loss zone while minimizing excess cement in the wellbore. The packer uses two fabric bags that are inflated by the cement being pumped into the loss zone. Since the loss zone is underpressured, sealing pressures in the wellbore are low. The fabric bag only needs to support about 20-40 psi differential pressure. All critical component testing for the drillable straddle packer is complete. Two bag designs for reliably sealing 20 psi have been proven. The drillstring coupling/decoupling mechanism has been fabricated and tested. We are in the process of modifying bag designs to increase pressure capability. Also, we are testing the packer with side loads to evaluate deployment in deviated holes. Finally, we have started construction of a large packer test facility that will be used to evaluate downhole tools in typical borehole conditions. The facility will have a borehole through constructed layers of permeable gravel and impermeable clay where pressures in the permeable layers can be independently controlled. The facility will be used to demonstrate how cement flows into a wellbore from open-end drill pipe, to demonstrate the function and effectiveness of a full-scale drillable straddle packer, to conduct large-scale cement and cementitious mud tests, and to conduct full-scale tests of other lost circulation tools and fluids.

The acoustic telemetry task has the objective of developing a commercial MWD system that communicates through the steel drill pipe from the near-bit environment to the surface. The major advantage of such a system is a 100-fold increase in data rate. The work has produced 4 patents which are licensed to Baker Hughes. During this past year, we repeated measurements of attenuation at the Long Valley Exploratory Well. Last year similar measurements produced a theory of one major attenuation mechanism based on variations in pipe length. This year, the measurements were repeated using the same drill string, but with pipes ordered in increasing length. Back-off shots were again used for an acoustic source. This years data confirmed the predictions for attenuation, and attenuation was modest for the 7,000 foot ordered drill string. Our field measurements to date have been used to develop preliminary specifications for a "reasonable first commercial system" as shown below.

* 20 to 30 bits/sec with a 100 watt downhole generator
* single stage (w/o repeater) transmission distance:
  * poor drillstring length control - 8,000 feet
  * average drillstring length control - 10,000 feet
  * tuned (ordered) drillstring - 15,000 feet

During the year, we also designed and fabricated a downhole sub that can be used in existing drillstrings to measure important acoustic properties of the drillstring in various hole geometries such as deviated wells. These acoustic properties and downhole noise as a function of frequency are needed to design the first commercial system.

The Geothermal Drilling Organization (GDO) brings together DOE and industry joint funding of near-term projects that result in a new product or service that benefits the geothermal industry. Four projects are currently active:

1. Improved rotating head seals with high-temperature operation capabilities - being developed by A-Z/Grant International.

2. High-temperature Positive Displacement Motor for air drilling - being developed by Baker Hughes INTEQ.

3. Retrievable whipstock for multiple completion of geothermal wells - being developed by A-Z/Grant International.

4. Advanced cements for completion in corrosive environments - being developed by BNL, Unocal, and Halliburtion.

SLIMHOLE DRILLING FOR GEOTHERMAL EXPLORATION

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ABSTRACT

Sandia National Laboratories manages the US Department of Energy program for slimhole drilling. The principal objective of this program is to expand proven geothermal reserves through increased exploration, made possible by lower-cost slimhole drilling. For this to be a valid exploration method, however, it is necessary to demonstrate that slimholes yield enough data to evaluate a geothermal reservoir, and that is the focus of Sandia's current research.

BACKGROUND

Although the vast majority of drilling technology used in the geothermal industry is derived from the oil and gas industry, geothermal requirements are qualitatively different. There are hard, abrasive, and fractured rocks; high temperatures; and underpressured formations, frequently containing corrosive fluids -- all these factors create a more rigorous environment than normally found in oil and gas drilling. The service and drilling tool industries have little incentive to address these problems, since the number of geothermal wells drilled in a year is about 0.1% of the corresponding number for oil and gas. This lack of commercial R&D is the primary rationale for DOE's support of technology development.

Drilling costs associated with exploration and reservoir assessment are a major factor affecting future geothermal development. The geothermal industry (utilities and operators) needs to reduce these costs to be competitive in meeting the expanding requirements in the western United States for environmentally benign, alternative energy sources. Slimhole drilling has been shown to reduce oil and gas exploration costs by 25 to 75%, but the more hostile conditions for geothermal resources present technology challenges which must be solved before the cost impact there can be thoroughly evaluated.[1] Once demonstrated, slimhole drilling technology will have application to geothermal exploration and reservoir assessment in both the U. S. and international markets.

RECENT ACTIVITIES

Sandia first established the basic feasibility of slimhole exploration with in-house analysis, field experiments on existing geothermal coreholes, and collection of an extensive data set from comparable drilling in Japan (collection and analysis of the Japanese data is an ongoing activity.) We then negotiated an agreement with Far West Capital, which operates the Steamboat Hills geothermal field, to drill and test an exploratory slimhole on their lease. Steamboat Hills geothermal area is located about eight miles south of Reno, Nevada, and currently supports two power plants with a rated total output of approximately 36 MWe. Production zones for the power-plant wells are typically shallow (less than 1000'); of moderate temperature (~325°F); characterized by large, steeply dipping, well-connected fractures in granodiorite; and extremely permeable - test data indicate values of transmissivity exceeding 1,000 da-ft. Wells previously drilled here showed temperature reversals (see Figure 1), with the maximum temperature shallower than 1000',

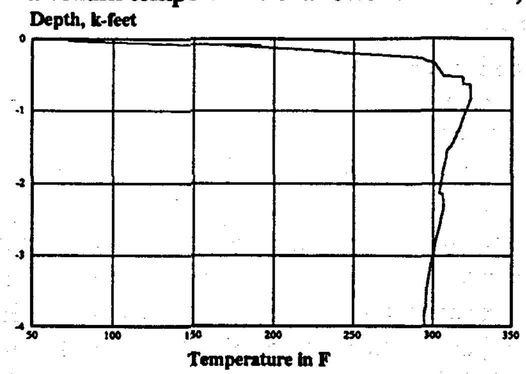

Figure 1 - Temperature log (with Sandia tool) in SNLG 87-29; Sept 22, 1993

however, a nearby power plant on another operator's lease draws from a reservoir at approximately 420°F, indicating that a hotter resource might lie beneath the one currently produced for the Far West power plants. Extensive previous development in this field meant that drilling conditions were reasonably well-known, but because most of the existing wells are shallow, there was an opportunity for slimhole exploration in search of a deeper, hotter reservoir.

The exploratory well (number SNLG 87-29) was specifically designed (see Figure 2) for

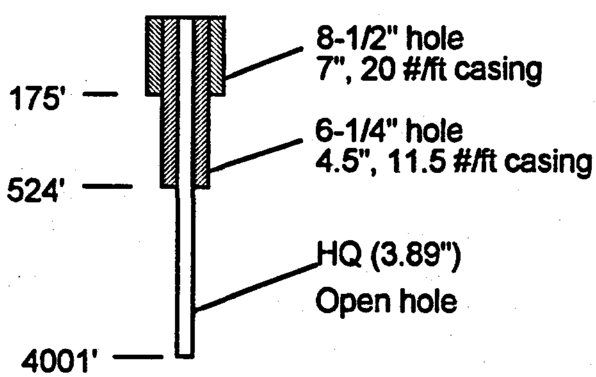

Figure 2 - Well design for SNLG 87-29

extensive production and injection tests so that those results could be compared with production and injection data from existing wells in this developed field. In fact, the exploratory well was drilled approximately 30 feet from an existing, but unused, production well. The principal objectives for the slimhole were development of slimhole testing methods, comparison of slimhole data with that from adjacent production-size wells, and definition of possible higher-temperature production zones lying deeper than the existing wells.

During the project we suspended drilling four times for a series of production/injection tests, each time taking downhole (pressure, temperature, spinner) and surface (wellhead pressure and temperature, James tube lip pressure, flow rate) data. These test series were done at well depths of 968, 1510, 2930, and 4000 feet. In general, the surface data, including a comparison of different flow rate measurement techniques, were consistent and repeatable. Downhole data were more difficult to compare because of some malfunctions in the logging tools and because the two logging service companies used different tools and different calibrations. By comparing the downhole readings with the corresponding surface data, and by comparing the service companies' tools with Sandia temperature logs, it appears that most of the ambiguities in the downhole data are resolved.

TEST RESULTS

The results discussed below are based on data from the first series of tests, conducted during August 5-6, 1993, at a total well depth of 968 feet. A large fracture system at 815' was verified by spinner measurements to be the primary production zone for this series of tests and was observed after completion of drilling to be the major feed zone for the 4001' well. Hence, the flow and injection tests conducted during this first series are representative of the performance observed in subsequent tests when the well was deeper.

Flow testing: In Figures 3, 4, and 5 the temperature, pressure, and spinner response are plotted versus depth. These measurements were made at a total (liquid plus vapor) production rate of 7.1 kg/s (56,000 lb/hr). The liquid water flow rate was 100 gpm at 192°F (6.1 kg/s, 48,000 lb/hr). Numerical flow simulations are included in Figures 3 and 4 for comparison and are discussed later. The spinner response, which clearly shows a feed zone at 815', is proportional to the rotational speed of the impeller, but it was not calibrated as a quantitative measure of relative flow velocity.

Wellhead pressures, measured during production for all test series, are plotted versus total mass flow rate in Figure 6. Mass flow rate and total enthalpy were calculated from measurements made with James tubes of various diameters. Unsteadiness of the two-phase flow in the James tube and flash tank created significant scatter in the measurements of James tube lip pressure, flow rate, and wellhead pressure. Nevertheless, the data in Figure 6 are typical of two-phase flow from a liquid-dominated geothermal well.

Reservoir transmissivity: The fracture system at 815' has such large apparent permeability that only very small pressure increases were observed when relatively large volumes of water were injected. Difficulties with downhole instrumentation and with the injection equipment precluded an accurate estimate of reservoir transmissivity based on these injection tests, but we can estimate some reservoir properties by considering the downhole pressure response during flow rate changes in production tests.[2] During the first series of flow tests, very small, abrupt, changes in downhole pressure were observed when the flow rate was varied in relatively small increments. For flow rate changes between 6 and 16 gpm, pressure changes ranged from 338 to 470 Pa. If we assume steady-state conditions, the apparent effective transmissivity, or permeability-depth product *kh*, can be estimated from the Dupuit, or Theim, formula[3]

$$\Delta p = \frac{\mu \Delta Q}{2\pi kh} \ln \frac{r_o}{r_w},$$

where Δp is the pressure change, ΔQ is the change in volumetric flow rate, r_w is the well radius, and r_o is the outer radius of the reservoir. An arbitrary value of 100 m is selected for the outer radius, recognizing that the logarithmic term makes the Dupuit formula relatively insensitive to this parameter. Using the proper viscosity for these downhole conditions, the transmissivity is then estimated to lie in the range 160-600 da-m, with an average value of 400 da-m. In reservoirs with much lower apparent transmissivity, application of the Theis equation would be the preferred method to estimate reservoir properties.

It is informative to note that laminar, axisymmetric, creeping flow in a horizontal fracture is described by an equation similar to the Dupuit formula if the transmissivity is replaced with the quantity $b^3/12$, where b is the fracture aperture. Assuming flow occurs in a single fracture, and using the same numerical values used to estimate the transmissivity, the predicted fracture aperture lies in the range 1-4 mm, which is consistent with fractures observed in the core samples, but much less than the apparent size of the production zone based on drilling data (drillstring dropped approximately 2', without rotating, when it reached this interval). This indicates that, although we may have penetrated a large void, a much smaller fracture can carry the amount of fluid produced. It also indicates that the wellbore diameter, not the reservoir, was the parameter limiting flow rate.

Analysis of spinner data: Spinner data, in some cases, can be the most informative measurement taken in a flowing well. In holes which penetrate several potential production or injection zones, it is frequently difficult to analyze internal flow in the wellbore, and good spinner data can be extremely useful in this aspect of interpretation. Interpreting spinner response is difficult, however, because the instruments are not usually calibrated to give absolute flow velocity, or even velocity relative to the tool, but instead to give a number of counts that measures how fast the impeller on the tool is rotating. In some instruments, such as those used in our tests, it is not even possible to determine flow direction relative to the tool.

There are, however, two features of the test configuration which make it possible to, in effect, calibrate the spinner after the fact: (1) the logging line speed, or tool velocity, is known in all cases, and (2) total mass flow rate is known and, in the casing where flow is single-phase, fluid velocity can be accurately calculated. Combination of the logging tool speed and absolute fluid velocity gives the fluid velocity relative to the logging tool, and repetition of this procedure at several flow rates produces a "calibration curve" for the spinner tool. In deriving these calibration curves, only the cases in which the relative fluid velocity was toward the bow of the spinner tool were considered; generally, we felt that the tool body shadowed the impeller when relative flow was from the tool's stern. Use of these calibration curves to analyze flow test data revealed that flow from the major production zone at 815' is divided, with the majority of the fluid going up the well and the remainder going down. The down-going flow rate, which varies from approximately 20 to 50 gpm, is a very weak function of the wellhead flow rate. The down-going flow velocity was less than the logging line speed, so that the relative velocity of the fluid was toward the bow of the tool.

Simulations: Numerical simulation of flow in a wellbore is critically dependent on the correlation or mathematical model used to describe the two-phase flow regime. Depending on well depth and temperature of the surrounding formation, representation of heat transfer between the formation and the wellbore may be equally important. We are currently investigating the computational packages described below for numerical simulation of flow in slimholes.

- GEM requires input of downhole pressure, formation-temperature profile, and wellhead pressure, and then calculates flow rate[4]. It allows simulations with no slip in the two-phase region or with either of the slip models proposed by Orkiszewski[5] and Hughmark.[6] In GEM, heat conduction in the surrounding formation is simulated using finite differences.

- WFSA requires input of downhole pressure, formation temperature, and flow rate, and then predicts wellhead pressure. It allows for multiple feed zones and the effects of dissolved solids, is based on the work of Hadgu[7], and uses a specially developed two-phase flow model. Heat transfer between the formation and the wellbore is described with an analytical model.

Both of these codes can be used to iterate a series of solutions with varying initial conditions to produce a curve of flow rate versus wellhead pressure, along with the associated predictions of downhole pressure and temperature. This predictive capability can be scaled up to a larger well in the same reservoir, if we assume that the downhole pressure remains the same. In this highly permeable situation, that assumption was valid, but in other reservoir types the pressure drawdown during production might seriously distort the predicted output. This phenomenon emphasizes the need for a coupled wellbore-reservoir simulator.

GEM and WFSA were used for our initial simulations of flow in the slimhole. In Figures 3 and 4, the pressure and temperature distributions with depth, assuming adiabatic flow, are compared with downhole measurements for the first test series (well depth is

968'). The GEM simulations used the Orkiszewski two-phase flow model. Most of the calculations are in good agreement with the measurements, but near the surface we suspect that unmodeled heat transfer mechanisms are responsible for the difference between predictions by WFSA and observed temperature distributions. The two-phase flow correlation used in GEM apparently causes it to under-predict wellhead pressure, as shown in Figures 4 and 6, and there is a slight variation of temperature with depth in the single-phase region, shown in Figure 3, as contrasted with the constant-temperature assumption in WFSA; otherwise, temperature and pressure distributions predicted with GEM differ little from those predicted with WFSA.

The agreement among the computational approaches and experimental data is reasonable, considering the variability of the measurements involved and the sensitivity of the simulations to the two-phase flow correlations employed. These comparisons should be viewed as preliminary since we are still evaluating various approaches to the simulation of wellbore flows.

Keeping all parameters except wellbore diameter fixed, GEM and WFSA predictions were applied to a full size production wellbore with diameter of 12.25 inches. For a mass flow rate of 62 kg/s, wellhead pressures of 56, 66, and 55 psia were predicted, respectively, with WFSA, GEM(Orkiszewski), and GEM(Hughmark). The flow rate of 62 kg/s corresponds to a 1990 test of the nearby 12.25" production well Hot Air-4 (HA-4), which produced 900 gpm of liquid water at a wellhead pressure of 72.5 psia. When corrected for flashing, that measured flow rate corresponds to a total mass flow rate of approximately 62 kg/s. The production from well HA-4 is associated with a production zone at 729', which is somewhat shallower than the slimhole production zone at 815'. However, tracer tests in the Steamboat Hills geothermal field indicate pervasive interconnections between fracture zones, so it does not seem unreasonable to expect similar production rates among nearby fracture zones. Based on a single test, simulation of a production well extrapolated from a slimhole tends to indicate a lower wellhead pressure at a specified mass flow rate than that observed experimentally. The results are, however, encouraging since the differences appear to be within a normal range of variation for the experimental measurements and the models used in the simulations.

CONCLUSIONS

The last two conclusions are specific to the Steamboat Hills geothermal field, the others relate to slimhole exploration in general.

1. Slimholes can be flow-tested, with successful surface and downhole measurements. Relatively cheap and simple surface measurements (James tube and weir box) can give flow rate and downhole enthalpy.
2. The strategy used for these tests appears to have produced the necessary test data, taken with appropriate accuracy, to evaluate the commercial potential of a larger well at this location..
3. Numerical simulation of flow in the wellbore can yield a predictive curve of flow-rate versus wellhead pressure, as shown in the slimhole data. Applied to a larger diameter well, this same simulation will give the same kind of production curve, giving a measure of the reservoir's commercial potential. Extrapolation from the slimhole data to the wellbore diameter of a near-by production well gave a reasonable estimate of the larger well's actual flow rate for a given wellhead pressure.
4. It is desirable to develop a coupled wellbore-reservoir simulator, and to extend this exploration strategy into other reservoir types, to validate the predictive capability of that model.
5. The deeper, hotter reservoir postulated in this location was not encountered down

to 4000'. There is, however, significant permeability below the 815' production zone, implying that water hotter than 300°F can be pumped from deeper zones, or water from a power plant could be injected into these zones.

6. The existing reservoir is extremely permeable; calculations of transmissivity are probably lower bounds.

RECOMMENDED FUTURE WORK

Although the test results here are encouraging, the highly fractured, highly permeable, reservoir may not be generally representative of other geothermal resources. The next step in the slimhole program should be exploratory drilling and testing in reservoirs with different flow characteristics, and comparison of those results with production wells in the new reservoirs. From preliminary negotiations with geothermal operators, we are confident that this can be done, given adequate funding in the near term.

DISCUSSION

Drilling is cheaper for slimholes than for production wells because the rigs, crews, locations, and drilling fluid requirements are all smaller; because site preparation and road construction in remote areas is significantly reduced, up to and including the use of helicopter-portable rigs; and because it isn't necessary to repair lost-circulation zones before drilling ahead. As a comparison, the Steamboat Hills slimhole, including all testing and overhead, cost approximately $150/foot while the neighboring production well (12.25" production diameter) cost $377/foot. Although the slimhole's greater total depth reduced its overall cost per foot, the intermediate cost of drilling the slimhole to the same depth as the large well was less than 60% of the large well's total cost.

If the resource evaluation program calls for production or injection tests from an exploratory well, these are also easier with a slimhole because they involve handling much less fluid than a larger well. Finally, the same attributes that reduce the cost also greatly reduce the environmental impact. As exploration expands into new areas such as the Pacific Northwest, this may become the critical criterion in regulatory agencies' decisions on whether to issue permits. This technology appears to be the best hope of increasing exploration in an attempt to enlarge the nation's proven geothermal reserves.

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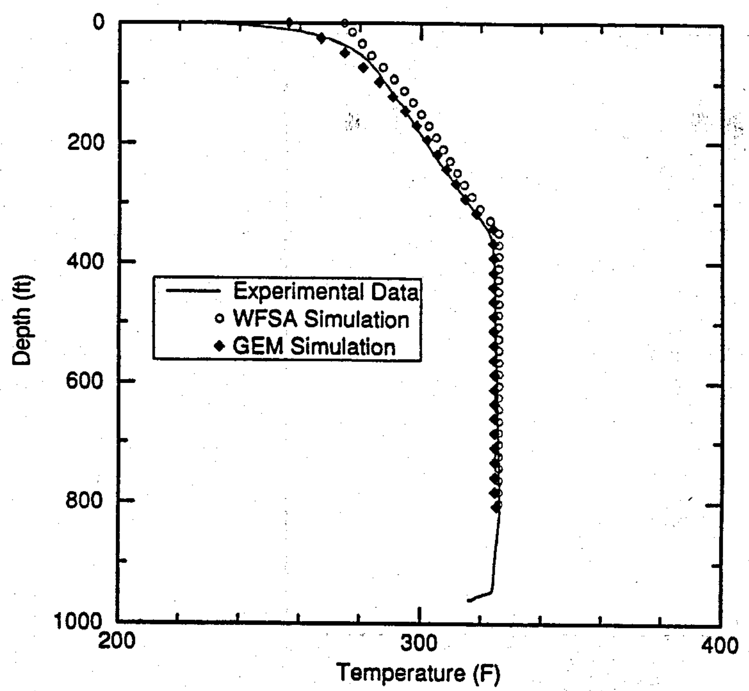

Figure 3. Downhole temperature versus depth: field data and numerical simulation.

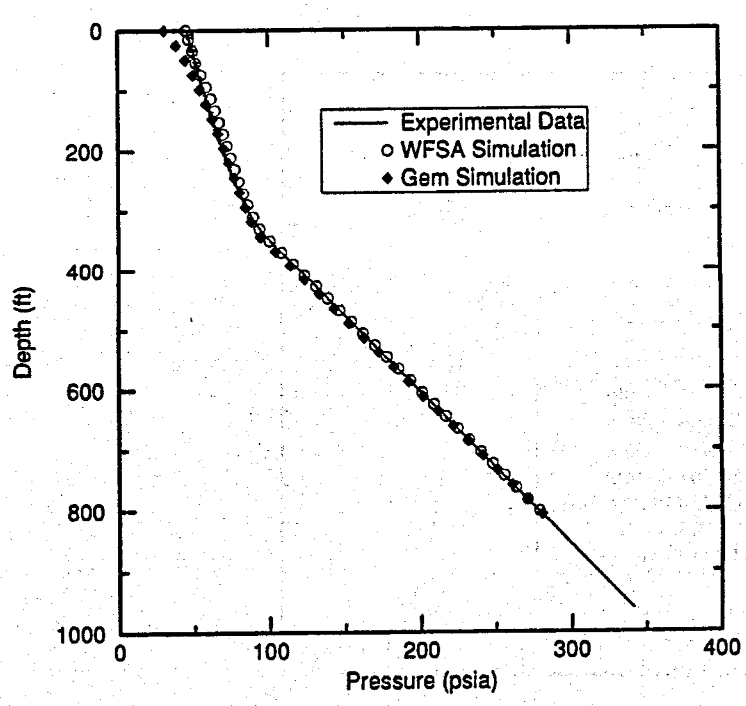

Figure 4. Downhole pressure versus depth: field data and numerical simulation.

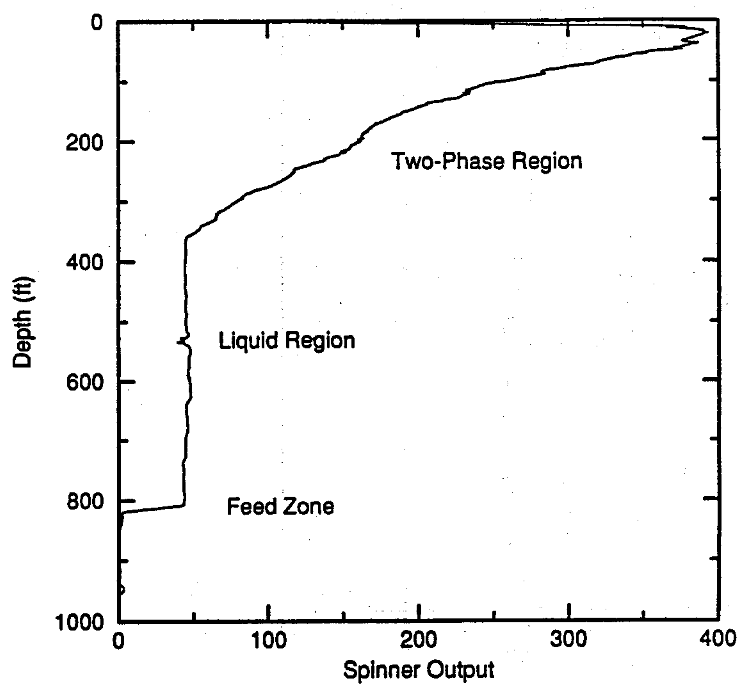

Figure 5. Spinner response versus depth while flowing 56,000 lb/hr.

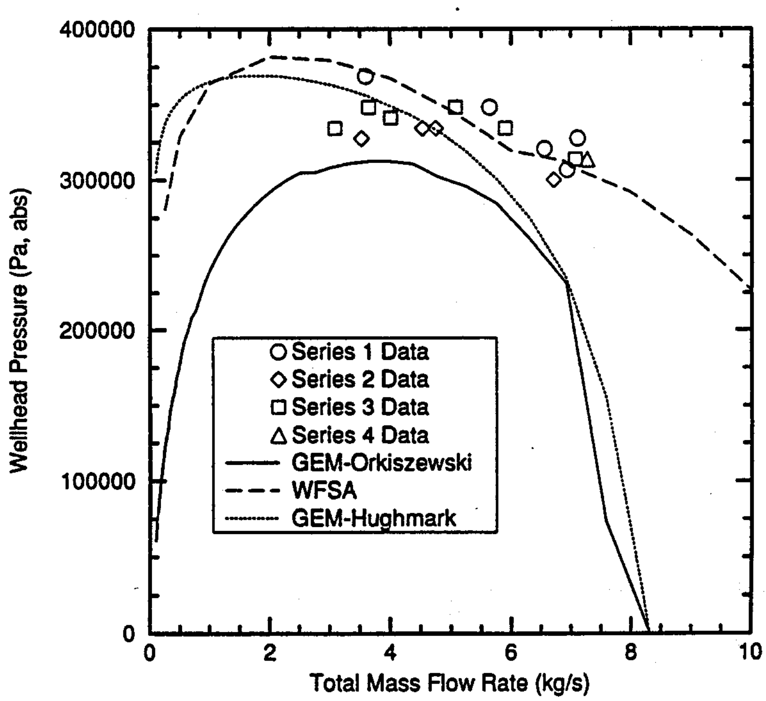

Figure 6. Wellhead pressure versus mass flow rate: field data and numerical simulation.

Development of Advanced Synthetic-Diamond Drill Bits for Geothermal Drilling

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ABSTRACT

The advanced synthetic-diamond drill bit project is a cooperative research program aimed at developing synthetic-diamond drill bits capable of drilling into hard-rock formations. Eight drill bit companies have teamed with Sandia National Laboratories to work on five projects as part of a cooperative national laboratory-industry effort to advance the state of the art in synthetic-diamond drill bit design and manufacture. These projects comprise a variety of approaches to bit design and, consequently, a variety of approaches to developing the technology. Each of these approaches builds on the respective companies' capabilities and current product interests, as well as Sandia's testing and analytical capabilities. The objective of each project is to develop advanced bit technology that results in new commercial products with longer bit life and higher penetration rates in hard formations. An overview including objectives and plans for each research project is presented.

INTRODUCTION

The ability of the geothermal industry to contribute to the nation's energy supply is dependent on drilling to prove and access available reserves. Geothermal reservoirs are typically found in or beneath hard, abrasive, and fractured formations. Because of this, geothermal wells are often difficult and expensive to drill; well costs represent 35-50% of the total costs of a geothermal project [1]. The potential of geothermal power in this country will not be fully realized unless additional significant reserves can be proven and accessed through a vigorous exploration and development program.

Drilling costs in soft to medium-hard formations have been significantly reduced by replacing roller bits with synthetic-diamond bits, which drill faster and last much longer than roller bits in many softer rock types. For instance, drilling costs in the Gulf of Mexico have been cut in half in some cases by using PDC bits; cost savings of $100,000 per bit run have also been reported in the literature. The hard, abrasive, and fractured rock formations drilled to access geothermal reservoirs are generally considered beyond the capabilities of current synthetic-diamond bit technology. Roller bits, which are generally used for this application, suffer from inherently low penetration rates, accelerated bit wear, and often severe loss of hole gauge and roller bearing failure. If the synthetic-diamond bit technology can be extended into harder rocks, it would have a significant cost-saving impact in the geothermal industry.

A study by Maurer Engineering [2] found that about 70% of the total time associated with drilling a deep (>14,700-ft) gas well is spent drilling ahead and tripping. The bit penetration rate and bit life, therefore, have major impacts on well costs. If both penetration rate and bit life could be doubled, an average 20% reduction in drilling costs would result. A study by Sandia National Laboratories reached similar conclusions for geothermal drilling [3]. A generic well-cost model was used to examine the cost impacts of various potential technology improvements. A 15% reduction in well costs was predicted to result from a hypothetical doubling of bit life and penetration rate. Technology development in the field of synthetic-diamond bit design has the potential for providing such improvements in bit performance in both petroleum and geothermal hard-rock drilling.

In 1993, funds were allocated to Sandia National Labs to develop a joint national lab/industry research program aimed at developing advanced synthetic-diamond drill bits for hard-rock applications. The result, DOE's Advanced Synthetic-Diamond Drill Bit Program, teams Sandia National Labs with eight industry partners working on a variety of drill bit and cutter technologies. The program, funded equally by industry, DOE Fossil Energy Division, and DOE Geothermal Division, includes joint and cost-shared work over a two-year period. This paper provides an overview of the program. A more detailed program plan can be found in Reference 4.

CURRENT SYNTHETIC-DIAMOND CAPABILITIES AND LIMITATIONS

The economics of drilling for petroleum or geothermal reserves is a strong function of the type of drill bit selected for the job. Achieving a lower cost-per-foot is often a matter of achieving the correct balance between the instantaneous penetration rate and bit life. Discussed below are some parameters that affect the penetration rate and life of the various types of synthetic-diamond drill bits.

Polycrystalline Diamond Compact (PDC) Bits

Bits with large (e.g., 1/2" diameter) PDC cutters are widely used by the oil and gas industry in medium-soft to medium-hard formations, primarily for drilling production wells where the lithology is well known. In these circumstances PDC bits are very effective because their rock-cutting action is inherently efficient, giving them much higher rates of penetration (ROP) than comparable roller bits. If the cutters stay intact, the bits' lack of moving parts also contributes to long life, reducing bit replacements and trips. These advantages have, in many case histories, more than offset the higher procurement cost of PDC bits and have led to an increasing PDC market share in the oil patch.

The corresponding disadvantage of PDC bits is that cutter degradation can lead to sudden and complete bit failure. Experience shows that this kind of failure usually occurs in hard and/or fractured rock, such as that typically encountered in geothermal drilling and frequently found as stringers in either exploration or infill petroleum drilling. Bit replacement, especially if unexpected, is expensive in terms of tools and trips, so companies often forego the advantages of drilling with PDC bits in geothermal drilling and in petroleum drilling where hard stringers may be encountered. As a result, PDC bits have not found significant application in geothermal drilling or in petroleum exploratory drilling.

When drilling hard, fractured formations with PDCs there are two general modes of cutter wear and failure: abrasive and impact. Thermally accelerated abrasive wear occurs in hard-rock drilling when cutter temperatures exceed approximately 350°C [5]. Extreme thermal stresses, caused by temperature gradients and differential thermal expansion between the diamond and the tungsten carbide compact, greatly exacerbate normal abrasive wear mechanisms in addition to causing tensile cracking of the microstructure. At temperatures above 650°C, differential thermal expansion between the diamond grains and the entrapped cobalt in the PDC causes further microfracturing of the diamond structure. Improved cutter materials and processing techniques are necessary to overcome the thermal limitations of PDC cutters in hard-rock applications.

Impact failure of PDC cutters is caused by dynamic loading resulting from fractures, hard-rock stringers, or vibration due to unbalanced forces on the bit. Proper cutter placement can force-balance the bit and eliminate much of the bit-induced vibration [6]. In addition, Amoco Production Research has developed and licensed methodology for designing anti-whirl bits that are also effective in eliminating most bit-induced vibration [7]. Amoco's approach entails placement of the cutters such that the net cutter force acting on the bit has a significant side component. This bit side force is directed toward a low-friction pad on the side of the bit, which balances the bit and reduces vibration during drilling. However, even bits that have a balanced or anti-whirl design often exhibit impact failure when drilling hard formations.

Security Diamond Products is developing track-set technology as a technique for reducing bit vibration in hard rock drilling [8]. The track-set concept employs redundant cutters placed at specific radial locations on the bit. Each track or groove in the bottom of the borehole is much deeper than is normal with conventional PDC bit designs. In hard rock, such deep tracks provide a significant stabilizing effect on cutters by preventing or retarding lateral movement and vibration.

In addition to improved bit design techniques that prevent and mitigate downhole vibration, improvements in cutter designs and materials are needed to impart inherent hard-rock cutting capability to PDC cutters. Significant strides toward cutters with greater impact resistance have been made in recent years with the introduction of claw cutters by DBS and Dennis Tool Company [9] and the introduction of dome cutters by Smith International and Megadiamond [10].

The claw cutter differs from conventional PDC cutters in that the tungsten carbide substrate to which the diamond layer is attached is grooved before being placed on top of the polycrystalline diamond powder in the diamond press. This produces a sintered product in which diamond fills the grooves in the tungsten carbide substrate, resulting in alternating ribs of tungsten carbide and diamond that run parallel to the cutting direction. During cutting, the tungsten carbide ribs wear faster than the diamond ribs, resulting in diamond "claws" that impose significant stress concentrations on the rock surface and maintain rapid rock penetration as the cutters wear. The layering of tungsten carbide and diamond also improves the shock resistance of the cutters several-fold and has been shown to improve bit life in harder rock formations.

Dome cutters employ a convex-shaped diamond surface on the leading face of the cutter. This shape creates an effective rake angle that is variable with the depth of cut, allowing smaller effective rake in soft rocks at high penetration rates and greater effective rake in hard rocks at low penetration rates. This results in effective rake angles that more closely match the optimal rake angles required for increased cutting efficiency and cutter life in various rock types. Dome cutters also provide some degree of side rake, which is beneficial for improved bottomhole cleaning and faster penetration. Improved shock resistance with dome cutters has been obtained by employing transition layers between the PDC face and the tungsten carbide compact. Field testing has shown that dome cutters successfully drill much harder rock formations than are possible with conventional PDC cutters.

A major goal of this program is to build on the potential demonstrated by these new types of PDC cutters and advanced bit design concepts to further improve their hard-rock drilling capabilities. This will be done by conducting fundamental studies to better understand the rock and cutter failure modes prevalent in hard-rock drilling and by optimizing cutter materials and bit designs through analytical and experimental study.

Impregnated Diamond Drill Bits

Impregnated diamond bits are routinely used in drilling very hard rocks where roller bits and PDC bits have short lifetimes. This includes a large fraction of boreholes drilled with slim-hole coring rigs for minerals exploration and scientific study of geothermal systems. Slim-hole drilling techniques are also increasingly being studied, developed, and used for petroleum and geothermal exploration.

An impregnated bit consists of numerous small diamonds, either natural or synthetic, that are imbedded in a metal matrix. The matrix is designed to wear away, exposing the diamonds that cut the rock. The cutting loads are distributed over many cutting elements, thereby maintaining individual diamond loads at a low level. In extremely hard formations where high temperatures can develop at the cutter-rock interface, the high-temperature capability of pure diamond gives impregnated bits their advantage over PDC bits. Furthermore, when a diamond does fracture or fall out, it is quickly replaced by another diamond that is exposed by the wearing matrix.

Because of the small exposure of the diamond cutters, however, impregnated bits inherently drill slower than PDC and roller bits. Penetration rates below 5 ft/hr are common with impregnated bits. If the imbedded diamonds could be given greater exposure in the balance between matrix wear and diamond retention, greater depths of cut and higher penetration rates would result.

New diamond coating technology developed by Hughes Christensen Company for surface-set diamond bits has the potential for improving diamond retention and allowing greater diamond exposure [11]. A goal of the program is to apply this technology to impregnated diamond bits and to develop a technique for optimizing impregnated diamond drill bit design for any specified hard-rock environment.

Thermally Stable Polycrystalline (TSP) Drill Bits

Like PDC cutters, thermally stable polycrystalline (TSP) cutters are a sintered diamond product in which cobalt is used as a catalyst to bond individual diamond grains into a larger diamond structure. TSP is made when the cobalt is leached from the diamond structure, eliminating the stresses caused by differential thermal expansion between the diamond and the cobalt. As a result, TSP cutters are thermally stable to at least 1200°C and are, therefore, less susceptible to the thermal damage prevalent in hard-rock drilling.

Without the cobalt in the diamond structure of the TSP, however, it has not been possible to bond the diamond to a tungsten carbide substrate for structural support and impact resistance. Furthermore, the cobalt leaching process embrittles the diamond structure, making it more susceptible to mechanical damage. Consequently, TSP cutters are inherently smaller than PDC cutters, and TSP bits generally drill at much lower penetration rates.

The tradeoff between bit life and penetration rate with TSP bits in hard rock has not yet been fully explored. Maurer Engineering and Slimdril International have recently completed a laboratory study for the Gas Research Institute that demonstrated dramatic improvements in bit performance using larger TSP cutters than had previously been tested [12]. A goal of the program is to evaluate several design options for hard-rock TSP bits and to determine the potential for using such bits to reduce drilling costs in exploratory drilling.

TECHNICAL APPROACH

The state of the art is different in each branch of synthetic-diamond bit technology being pursued in this program. For impregnated diamond and TSP bits, specific technologies and designs are being developed, and the most direct method of evaluating such technologies and designs is to build and test drill bits in the laboratory. For claw-cutter PDC bits, optimization of specific cutter configurations can best be accomplished with numerical stress modeling and single-cutter testing to characterize cutter performance and wear. Single-cutter tests and enhancement of cutter force and wear models are necessary and will be undertaken to optimize the design of track-set cutting structures. To further advance the state of the art in dome cutters and transition layers, it has been concluded that a more fundamental understanding of rock and cutter failure mechanisms in hard rock drilling is necessary, and appropriate studies are planned.

Common features of each study include: the establishment of a performance benchmark based on current hard-rock drilling capabilities to measure each participant's progress under this program, the targeting of cutter and bit designs toward a specific set of hard rock types, laboratory and field testing of promising designs, and the publication of a final report summarizing results of the project. Details related to the specific design and manufacturing process of cutters and bits as well as results of specific tasks funded and conducted solely by the company will remain proprietary to each company involved. However, research results funded by the Department of Energy will become public information.

In addition to the companies and projects described below, Amoco Production Research will participate in the program by making available their Catoosa Test Facility (CTF) for use in evaluating concepts related to hard-rock synthetic-diamond bit design. The lithology of the test site is well mapped to a depth of 2600 ft, and it contains a hard-rock interval that is a challenging formation for PDC bits. The test site is, therefore, ideal for obtaining data that can be used in bit development, as well as for performance testing of bits designed for hard-rock applications. A field-test opportunity will be offered to each participating bit company team. Amoco will evaluate each proposed field test based on the objectives of the program and Amoco's drilling experience in the laboratory, at the CTF, and in other field drilling operations (subject to confidentiality constraints). Amoco will make recommendations concerning the proposed tests, including any changes that may improve evaluation of the concepts to be tested.

Sandia will provide program management and consultation with the participants in the program and conduct several research tasks. These tasks include cutter testing and wear evaluation, development of dynamic test methods, cutter thermal and stress analyses, rock properties measurements, and rock-cutter interaction studies.

PROJECT DESCRIPTIONS

Advanced PDC Cutter Development and Bit Design with Smith International and Megadiamond

Smith International and Megadiamond will team with Sandia Labs in a multi-year program to study fundamental rock failure and bit wear mechanisms in hard rock, then build upon the findings to design, fabricate, and test hard-rock PDC cutters and bits. Based upon the success of their domed cutters in rocks harder than those normally drilled with PDC cutters, Smith and Megadiamond believe that greater understanding of hard-rock drilling mechanisms is necessary to take full advantage of the hardness and abrasion resistance of synthetic diamond.

At the beginning of the program, hard-rock formations that represent a drilling challenge for current PDC bit technology will be defined and characterized. This will include a complete determination of engineering properties, and an evaluation of the response each rock invokes on the various well logs that are typically run in petroleum wells, such as sonic velocity and gamma ray logs.

One goal of this project is to develop laboratory test methods that simulate both the abrasive and the dynamic environment that is encountered in hard-rock drilling. To accomplish this, the failure modes exhibited by PDC cutters in hard-rock drilling will be characterized and prioritized. Field measurements will be conducted as necessary to characterize the downhole environment. Laboratory tests will be developed that simulate the measured environment and produce the same type of failures exhibited during actual drilling. These laboratory test methods will then be used to test single cutters to identify cutter wear and failure modes and investigate fracture propagation mechanisms in the cutter materials.

Another goal of the project is to gain a more fundamental understanding of rock-failure modes exhibited during drag cutting of hard rock. Rock samples will be cut and examined, and the results will be used to develop mechanistic models for the PDC cutting process and failure modes in hard rock. To the extent possible, these failure modes will be related to rock properties, such as angle of internal friction and fracture toughness, to evaluate the effects that changes in rock properties have on rock failure mechanisms.

Finally, as a part of this program, Smith will conduct tests in its flow visualization test stand to develop design concepts for bit hydraulics designs for hard-rock drilling. General criteria for the hydraulics design of hard-rock PDC bits will be developed.

During later phases of the project, laboratory cutter tests will be completed, full-scale bits employing the best cutter designs will be laboratory tested, additional design software development will be undertaken, and field testing will be initiated. Field testing will be expanded, bit designs will be optimized for hard-rock drilling, and commercialization of the bits will be initiated.

Optimization of Track-Set Cutting Structure with Security Diamond Products

Security Diamond Products will team with Sandia to investigate methods of enhancing their track-set cutting structure and to explore this cutting structure's ability to provide for more stable bit rotation and extend PDC bit applications into harder formations. This will be accomplished through the enhancement of current modeling techniques and the testing and evaluation of several track-set configurations.

At the onset of the project, a study will be conducted to compare field drilling results with results obtained using drilling models. This will be done to identify both the limitations in the current models and possible enhancements that would significantly improve the models. This process also may identify alternative formation characteristics other than compressive strength that affect drilling and wear characteristics.

Both single-cutter and dual-cutter tests will be conducted to explore the alternative engagement geometries and wear modes that result from the track-set configuration. The testing will investigate typical track-set engagement geometries with various cutter types and geometries in a variety of hard rocks. In the dual-cutter tests, the strength of the ridge formed between cutters during track-set cutting action and its interaction with the matrix bit body will be investigated. The possibility of rock prefracturing by chisel-shaped cutters also will be investigated at this time.

Security will analyze the results of the cutter testing and use the analysis to enhance the drilling force and wear models as necessary. The results of both the testing and model enhancement will be used to optimize the design of a track-set bit. This bit will then be field tested in various rock types and strengths to establish the bit's capabilities.

Claw Cutter Optimization with Dennis Tool Company and DBS, a Barold Company

Dennis Tool Company and DBS will optimize the design of their patented claw cutter for hard rock drilling. This work will be done through an analytical and experimental study that evaluates various claw cutter configurations.

Alternative configurations of the claw cutter, including variations in the width, depth, shape, and spacing of the grooves in the tungsten carbide substrate will be designed and fabricated. These cutters will then be abrasion tested by cutting hard rock under atmospheric, water-cooled conditions in the laboratory. The relative cutting performance and life of each cutter in hard rock will be evaluated and compared.

Numerical thermal and stress analyses will be performed to help guide the design of the alternative configurations. Parametric studies will be conducted to find optimal designs for reducing material stresses and improving cutter life. The modeling and testing of the cutters will be performed in parallel: results of the stress analysis will be used to optimize the design of the cutters and results from the laboratory testing will be used to validate the model.

The most efficient and wear-resistant cutter designs identified will be incorporated into core bits. The core bits will be laboratory tested in hard rock or simulated hard rock. The cutting performance and relative wear of each cutter will be evaluated to determine the most efficient and wear-resistant cutter designs.

If the results of previous tasks indicate that significant improvements in hard-rock drillability have been achieved with the optimized claw cutters, full-face PDC bits incorporating the optimized claw cutter designs will be designed, fabricated, and field tested.

Optimization of Impregnated Diamond Drill Bits with Hughes Christensen Company

Hughes Christensen Company (HCC) will improve impregnated bit performance in hard rock by developing a methodology for matching the diamond-matrix impregnation design to the rock being drilled. In addition, HCC believes that significant increases in both penetration rate and bit life are possible with impregnated bits by applying recent advances in diamond technology. These advances are related to the coating of synthetic diamonds to enhance the retention of the diamonds in the metal matrix and have not yet been exploited in impregnated bits. A properly designed impregnation with coated diamonds should make it possible for each diamond to work longer and at greater exposure, which means greater bit life and faster penetration rates.

HCC will conduct drilling experiments in several rock types that commonly require impregnated bits in actual field applications. Rocks will be selected representing a range of properties that can affect drilling, and laboratory core analysis will be performed on each sample. The experiments will be conducted in a laboratory setting with impregnated bits incorporating advanced diamond coating technology and various impregnation designs.

As part of this program, a mechanistic drilling model for impregnated bits will be developed. This will include adapting existing mechanistic drilling models to include parameters important to the process of drilling with impregnated bits. This development will be conducted in parallel with the drilling tests. The drilling tests will be designed to calibrate the mechanistic drilling model which will then be used to search for performance optimums.

The resulting calibrated drilling model will be used to develop specific bit designs and operating recommendations for each rock type investigated. These bits will be fabricated and evaluated in laboratory drilling tests.

Advanced TSP Drill Bit Development with Maurer Engineering and Slimdril International

Maurer Engineering Inc. (MEI) and Slimdril International Inc. will improve the design of TSP drill bits for hard rock drilling by designing and testing several different types of TSP bits and evaluating their relative performance.

First, instrumented single-cutter tests of TSP cutters will be performed to evaluate the performance and wear of various cutter configurations and grades under hard-rock drilling conditions. These tests will serve as a screening tool for cutter types to be used in the various bit designs.

Three types of 3-inch-diameter TSP drill bits will be designed and fabricated using the results of the single-cutter tests:

- Optimized GRI TSP bit, a surface-set TSP bit developed by MEI under a GRI contract for medium-hard rock formations;

- TSP large cutter bit, which employs large, non-cubic TSP cutters mounted on a matrix bit body; and

- TSP-impregnated bit, which uses TSP chips impregnated in a metal matrix that wears away to expose the chips.

Laboratory drilling tests will be conducted in hard rock at atmospheric pressure to evaluate the relative performance of the different designs. Penetration rate, bit weight, and drilling torque will be recorded, and the condition of individual TSP cutters and the general condition of the bits will be evaluated and documented at regular intervals during the drilling tests.

The bit that performs best in these tests will then be field tested in hard rock in one or more wells. To the extent possible, field evaluations will include comparative data obtained with other bit types, such as roller bits and PDC bits.

CONCLUSION

A cost-shared program has been developed between the Department of Energy (through Sandia National Labs) and industry. The goal of the program is to develop synthetic-diamond drill bits that are capable of efficiently drilling hard, fractured formations. The successful development of hard rock synthetic-diamond drill bits would have an impact on both the petroleum and geothermal industries. Increasing bit life and rate of penetration can significantly reduce the cost of drilling a well which encourages domestic exploration and development of our deep natural gas and geothermal reserves.

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DESIGN OF A PRESSURE/TEMPERATURE LOGGING SYSTEM FOR GEOTHERMAL APPLICATIONS

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ABSTRACT

Past memory logging tools have provided excellent pressure/temperature data when used in a geothermal environment, and they are easier to maintain and deploy than tools requiring an electric wireline connection to the surface. However, they are deficient since the tool operator is unaware of downhole conditions that could require changes in the logging program. Tools that make "decisions" based on preprogrammed scenarios can partially overcome this difficulty, and a suite of such memory tools is under development at Sandia. The first tool, which forms the basis for future instruments, measures pressure and temperature. Design considerations include a minimization of cost while insuring quality data, size compatibility with diamond-cored holes, use in holes to 425°C (800°F), transportability by ordinary passenger air service, and ease of operation. Prototype tools are available for evaluation by the geothermal industry.

INTRODUCTION

Downhole temperature measurements are necessary for the evaluation of geothermal reservoirs, and they have been accomplished through the use of numerous ingenious devices. Simple measurements are made by using maximum-reading thermometers, or by using tabs constructed of temperature-sensitive materials that change color whenever a critical temperature is exceeded. Both devices return one point per deployment, so a continuous recording of the borehole temperature is a tedious endeavor, and it can be erroneous if the temperature profile bends back on itself. Continuous logs from a single deployment are made by tools that return data to the surface through the use of an electric wireline, or from memory tools that store data either mechanically (by scribing a curve on a rotating cylinder) or electronically.

At one time or another, all measurement techniques were used by the Geoscience Research Drilling Office in its support role for the US Continental Scientific Drilling Program. Temperature tabs and maximum reading thermometers were found useful in diamond coring operations since drilling fluids cool the upper portions of the hole effectively eliminating the bend-back phenomena; they were deployed on the overshot device used to retrieve core. While such measurements were not detailed and their reliability was sometimes in question, they were easy to obtain, and they enabled an approximation of the bottom-hole-temperature.

Continuous, and repeated temperature measurements were found to be much more desirable, especially when made at convenient times during a drilling operation such as when the drill was receiving maintenance. The resulting data yield valuable information pertinent to the reservoir, and they helped in the design of the well itself. For example, even small lost-circulation zones produce a fine-structure on a temperature log, and these zones are candidates for future production since they exhibit above-average permeability. Furthermore, exercises involving the injection of cool fluids into the casing-formation annulus were used to identify zones that possess an unsatisfactory cement bond, c.f. Figures 1(a) and 1(b).

Repeated measurements were available to the Drilling Office since its research-oriented mission obligated it to own and operate a suite of logging tools. However, these operations necessitate the maintenance and deployment of a logging truck, and the resulting overhead was not trivial. Attempts to minimize overhead, and thereby make log data more available, led to the extensive testing of memory tools. These tools are attractive since deployment is based on the cable found at all drilling operations. The use of memory tools does place certain restrictions on the logging operation (Lysne, 1992). But the bottom line is that memory tools generate quality logs at a price that can be attractive, especially if efficiencies can be found in the design of the tools.

To further this effort, the Department of Energy is developing a suite of tools based on the memory concept (Lysne, 1992). The first tool in this suite is a pressure and temperature measuring device that will possess the following attributes: (1) the tool will be smart in the sense that it can be programmed to make "decisions", (2) cost will be minimized within the constraint of satisfactory performance, (3) the logging tool and ancillary equipment (with the exception of the cable assembly) will be transportable by ordinary passenger air service, (4) measurements will be traceable to national standards, (5) the tool will be compatible with diamond-core hole dimensions, (6) the tool will be operable to borehole temperatures of 425°C (800°F), (7) personnel training necessary for deployment and data retrieval will be minimized, and (8) the prototype tool will form the basis for more advanced instruments. This paper documents decisions leading to the attainment of these attributes.

TOOL DESIGN

It is convenient to discuss the pressure/temperature tool in terms of subsystems, and this approach will be taken. However, one must note that the subsystems are coupled through the attributes listed above. For example, the sizes of the computer, sensors, heat-sink material, and battery influence the length and diameter of the pressure vessel, but the dimensions of the pressure vessel is constrained by attributes (3) and (5).

Dewar/Pressure Vessel

As a practical matter, attribute (5) means that the tool should fit through a "H" size bit and into an "N" size hole, that is the diameter of the tool should be about 50 mm (2 inches). Furthermore, attribute (3) means that the overall length of the tool should not exceed that of a pair of skis, and attribute (6) means that elastomer "O"-rings cannot provide the primary seal since they fail above 300°C (570°F). Finally, attribute (2) means that the pressure vessel should be made of a material that is adequately stable in environments that may be corrosive, but that it should not be over-designed.

A request for quotations was submitted to manufacturers of pressure vessels that also provided an insulating capability, and a contract was awarded to National K Works (Houston, TX) for construction of three units. These vessels feature a metal-to-metal seal that has proven itself on many occasions. The 1.84 meter (72 inch) long by 50 millimeter (2 inch) diameter vessels are made of 17-4 stainless steel. It is felt that this alloy will be satisfactory for applications in usual geothermal environments, but it must be proven in hotter, and more corrosive wells such as found in the Imperial Valley of California. The mass of the completed tool (including interior components) is 18 Kg (40 pounds), and two or more tools may be joined together to enable multiple measurements on a single logging run. This latter feature will become important as tools with different capabilities become available. The cost of the Dewar/pressure vessels, including a pressure port and associated filter, is

$7,100. Cost savings may be achieved if vessels are ordered in quantity.

Computing System

Past memory tools have recorded data at set intervals, and these intervals could be changed based on instructions programmed before deployment. The intent of attribute (1) is to further compensate for the lack of control that an operator experiences when going from a tool that transmits data to the surface, to a memory device. Specifically, the new tool is required to make "decisions" based on time, on measured parameters such as the pressure and temperature, and on information deduced, perhaps in a complicated way, from these data. Stated otherwise, the computing system must support a program language, and attribute (7) requires that the language be advanced, i.e. not machine language.

Attribute (8) regarding future versions of memory tools means that the computing system must support more input signals than required by the relatively simple demands of the prototype pressure-temperature tool, and that the system must provide output information to control devices such as the solenoid valves used in fluid-sampling applications. Finally, attributes (2) and (5) place constraints on the cost and size of the computing system.

Onset Computing Company (North Falmouth, MA) makes a line of computers that have seen use in remote-sensing applications. Their Model 5F is of a size compatible with the 38 millimeter (1.5 inch) interior diameter of the pressure vessel, it is programmable in a version of the BASIC language that includes extensions that allow for frequency and voltage measurements. Features include one frequency (or period) port, eight 12-bit analog-to-digital voltage ports, and fourteen I/O ports that can pass information to another computer or to switches, relays, and other control devices. The Model 5F is programmed from an IBM compatible personal computer through a RS-232 connection, and programs of about 10 Kbytes may be stored permanently in a 32 Kbyte non-volatile flash memory that also contains the BASIC language and operating system. The volatile memory of the chosen device is 128 Kbytes, of which 96 Kbytes is available for data storage, and 32 Kbytes for ancillary program storage (the 512 Kbyte version of the Model 5F was found unsuitable for use at high temperatures).

While the above features made the Model 5F suitable for the prototype tool, the system was not rated for operation at 150^{o}C, the anticipated maximum operational temperature of electronic components. A series of oven tests proved the system to be functional at this temperature, but the crystal-controlled clock (and hence, frequency measurements) possessed an unacceptable temperature dependence. The clock was subsequently replaced with a Statek Corporation (Orange, CA) Model CX-1-03 unit which is a direct replacement for the crystal on the Model 5F, and offers greater temperature stability. Other ancillary control circuits were placed on a board designed to physically mate with the computing system. The resulting package contains all control components for the present tool, and for a fluid sampling system which is in the design stage. The cost of the electronic components, including the Model 5F and the ancillary circuit board is about $1,000.

Pressure/Temperature Sensors

Pressure measurements are needed to define the characteristics of a producing reservoir. Furthermore, pressure and temperature measurements provide a determination of depth provided that the equation of state of the borehole fluid is known (Lysne, 1991). Measurement requirements are satisfied if pressure determinations can be made to +/- 0.07 atm (+/- 1.0 psi). Quartz-oscillator transducers are capable of exceeding this accuracy requirement, and their frequency output is conveniently fed into the Onset computer after division by a factor of two to accommodate the 30 KHz maximum frequency response of the Model 5F computer. (Note, pressure determinations exceeding the nominal requirements are possible, but the tool must remain stationary in the hole for times on the order of one minute. This mode of operation may be initiated by programming the tool to take high resolution measurements if it senses, through pressure measurements, that it is stationary.)

Paroscientific, Inc. (Redmond, WA) Model 46K-178 pressure sensors were initially chosen for pressure measurements since they fit conveniently into the pressure vessel, and they were secondary standards used by the calibration teams at Sandia. While these sensors performed satisfactorily when used downhole, they are sensitive to shock, and one unit was damaged in transit. Currently, Quartzdyne, Inc. (Salt Lake City, UT) Model QB-10K sensors are being evaluated. These units reportedly possess a shock absorbing capability commensurate with tool requirements. The cost of the Paroscientific Model 46K-178 and Quartzdyne Model QB-10K sensors are $4,350 and $5,400, respectively. Both instruments are temperature-compensated, and certified calibrations are provided by the manufacturer.

Temperature measurements are made with a RDF Corporation (Hudson, NH) Model 218A(SP)-21-20-A-96 platinum-resistance thermometer that is calibrated in the Sandia standards laboratory. The voltage arising from the injection of a constant current into these devices are converted to frequency (using a AD 537-SH voltage-controlled oscillator), and the resulting frequency, after dividing by a factor of two, is recorded by the computing system. The voltage-to-frequency conversion is necessary since temperature-induced voltage changes are small, and would not be resolved by the 12-bit converter of the computing system. The temperature resolution of the prototype tool is +/- $0.1^{o}C$ (+/-$0.18^{o}F$), the cost of the platinum thermometer is $80.

Since frequency measurements are used for the determinations of both pressure and temperature, and since accurate measurements require that a characteristic number of cycles pass by the counter on the Onset computer, limitations are placed on the rate at which data may be taken by the tool. This limit is presently eight seconds for a pair of measurements, and the storage capability of the Model 5F allows for about seven hours of recording at this rate. Since frequency measurements may be made in the background on the Model 5F computer, foreground computations of sophistication may be possible.

Power Supplies

A fifteen-volt, 37 milliampere power supply is required to drive the computing system, the pressure and temperature sensors, and the ancillary components located on the circuit board during steady-state operating conditions. In addition, a short-duration current drain of several amperes may be needed to open the fluid sampling valve.

Ideally, the battery pack would be operable to the temperature maximum of other electronic components, it would be of low cost and readily available, it would be transportable by passenger air service, and it would not produce hazardous waste. These requirements were found to be in conflict. Since the tool is intended for use in remote locations perhaps outside of the United States, the determining factor was deemed to be battery availability. Thus, the main power supply was constructed from five 2/3-A size photo-flash cells. These cells are rated at 1,300 milliampere-hours, and they can deliver up to 4 amperes for a short duration. Unfortunately, they are rated to only $60^{o}C$ ($140^{o}F$). While laboratory experiments indicate that the cells are operable to at least 100°C (212°F), the current tool is degraded by the 60°C (140°F) temperature limit since the behavior of energetic devices containing corrosive chemicals is unpredictable. (Oven experiments on the whole tool suggest that it will function for at least two hours in a 350°C (660°F) environment if the batteries are pre-cooled to their lower-operating-limit of -40°C (-40°F).) In addition to the main battery pack, a high-temperature lithium/thionyl chloride cell (Type 1018-HT-BP2S, Battery Engineering, Inc. Hyde Park, MA) is used to maintain the volatile memory should the main power source fail. This cell has a very long lifetime. The cost of five 2/3-A cells is $35.

System Calibration

System Calibration was accomplished by placing the electronic components in an oven: the oven temperatures simulated the varying temperatures inside of the pressure vessel, and they were recorded with a calibrated thermometer. Borehole temperatures were simulated through inputs from a calibrated resistance box. Pressures were imposed on the pressure transducer with a calibrated dead-weight test device. All calibrations are traceable to the National Institute of Science and Technology thereby satisfying attribute (4). Data from the calibration experiments are smoothed through curve-fitting routines, and the resulting coefficients are used in reduction routines. Temperatures internal to the tool are recorded using thermisters.

Ancillary Equipment

Depth recording is accomplished by an encoder attached to calibrated wheels that rotate as the logging cable is moved. Necessary support electronics, including depth and velocity displays, are contained in a box that is air-transportable. An IBM compatible computer running Microsoft Windows is necessary for tool deployment; sub-notebook size computers are sufficient. If the personal computer is battery-operable, the entire operation (excluding the cable drive) is independent of external sources of power. The cost of the support electronics is $1,100.

A logging exercise is started through the use of a program on the personal computer that sends instructions to the Model 5F, that initiates the logging tool, and that initiates the depth-time recording system. The program displays messages containing operating instructions, and menus prompt for information concerning well name, date, etc. At the completion of a logging run, other menus supplies detail steps necessary to strip the pressure-temperature-time data from the tool. The tool data are combined with depth-time data from the depth recorder to obtain a depth-data curve. Joining of data sets and subsequent plotting of the data are accomplished using popular spread-sheet programs. A default logging scenario is contained in the flash memory of the Model 5F computer. While it is sufficient for simple applications and it is easily customized, detailed instructions involving logging contingencies are the responsibility of the operator, and may be entered into the tool using BASIC language instructions. Instructions to the tool and data from it are readily transmitted world wide over ordinary telephone lines or through the INTERNET.

In addition to the components discussed above, the pressure/temperature tool requires machined parts including heat sinks and support members for the electronic components. The cost of these items is estimated to be $200. Maintenance of the tool includes a new set of "O"-rings and a new battery pack for each tool deployment. The cost of these items is less than $40.

CONCLUDING REMARKS

The design of the prototype pressure/temperature tool was accomplished by first identifying a set of attributes, and then using these attributes to choose system components. However, the final design was arrived at in an iterative procedure since the attributes themselves were interrelated. For example, it was desired both to minimize the cost and operate the tool in common geothermal environments. Interactions with geothermal operators were used to define the "common geothermal environment", and this environment was not an extreme case. Thus, the pressure vessel was not constructed from exotic materials, and an action that would have increased cost considerably was avoided. Similarly, while the use of commonly-available batteries is not optimal from the standpoint of long-duration logging runs, it does result in a greater overall versatility for the tool, and high-temperature batteries may be used should the need arise.

The pressure vessel constitutes one-half of the cost of the prototype tool. Savings could be achieved if 300°C (570°F) "O"-ring seals were compatible with the downhole environment. Furthermore, constructing the vessel from less-costly exterior components, perhaps using passivating materials or coatings to combat corrosion, would enable further cost reductions. Such issues are under consideration.

The total component cost of the pressure/temperature logging system (excluding the IBM-compatible computer, Microsoft Windows, a spread-sheet program, and a printer) is estimated to be $16,000; a system that measures only temperature is estimated to cost $10,500. These costs reflect the component parts, and they do not take into account engineering overhead, and any profit that a service company would require if it is to undertake support of the tool. Furthermore, they do not reflect the cost of calibration. In regard to this latter cost, the intent of the Sandia program is to identify components that are sufficiently pedigreed by their manufacture so as to minimize or eliminate the need for a calibration laboratory. Effectively, this means that the cost of calibration is included in the component cost.

In the near future, Sandia will initiate discussions so as to find the best way to transfer the present technology to the geothermal industry. Several avenues are open. For example, a tool company may choose to market or rent tools to operating companies, or the operating companies may choose to build tools from Sandia specifications. Input regarding possible scenarios is sought by the Sandia Drilling Office. To facilitate these discussions, and to promulgate the use of memory tools, the pressure/temperature tool (and engineering support for tool deployment) is being offered to operating and other companies for demonstration.

The pressure/temperatue logging system is illustrated in Figure 3. Other tools presently under construction at Sandia include a natural-gamma-ray spectroscopy tool (built by Geophysical Research Corporation, Tulsa, OK), and a fluid/gas sampling tool. These tools will see deployment in the near future.

ACKNOWLEDGMENT

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Lysne, Peter, 1993. "Memory Logging Tools", Proc. DOE Geothermal Review Number XI, Berkeley, April 27-28.

Figure 1(a). Temperature profiles from the VC-2B Corehole, Valles Caldera, NM. The log of 23 October, 1988 was made just after the circulation of relatively cool drilling fluid was terminated. It shows fine-structure characteristic of permeable, lost-circulation zones that are candidates for fluid or steam production. Such detail was lost as the well aged; this phenomenon may be noted by comparing the early log with the log of 7 May, 1990. The expanded portion of the later log shows the boiling interface that occurred near 91°C (196°F) at the elevation the VC-2B hole.

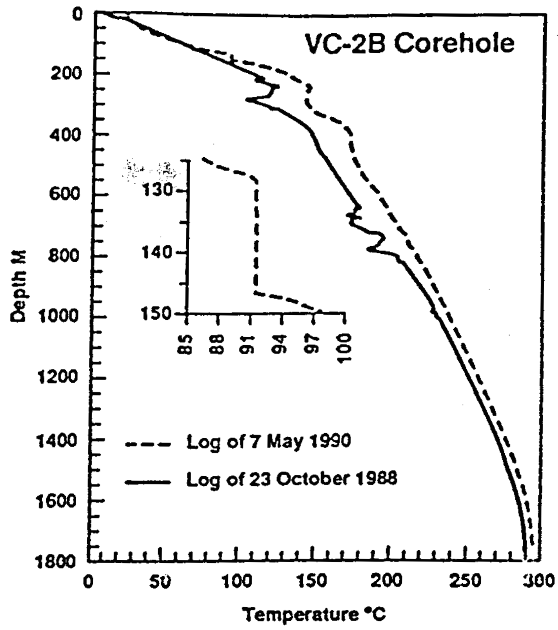


Figure 1(b). Temperature logs used to locate the top of the cement following an unsuccessful attempt to seal casing in VC-2B. The log of 30 September was made just after completion of the operation. Cool water was then introduced into the casing-formation annulus while the second log was run. Together, these logs indicate that cement had migrated into the permeable zone located at a depth of 275 meters (902 feet). This zone also is apparent in Figure 1(a). Repeated temperature logs provided a multitude of information concerning formation and hole conditions in wells drilled by the Geoscience Research Drilling Office.

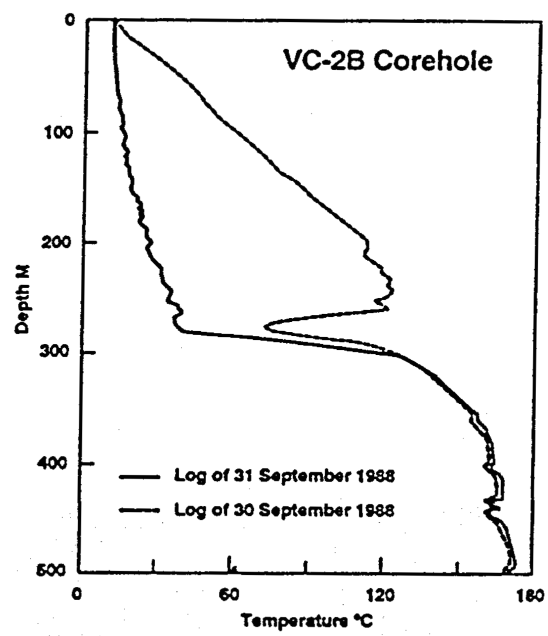
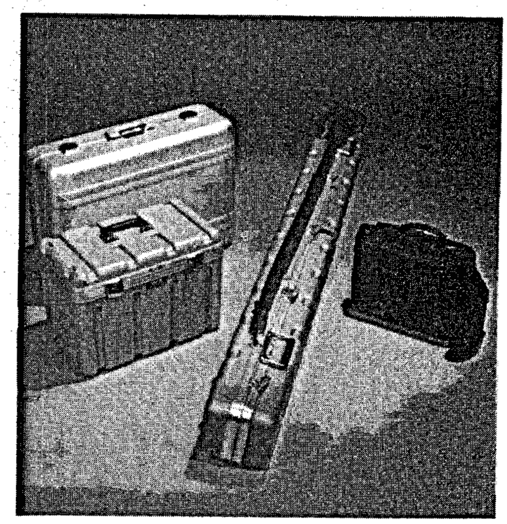


Figure 3. The pressure/temperature logging system. The aluminum boxes contain the logging tool (long box), the ancillary equipment to display depth and velocity information (small rectangular box), and spare parts (suitcase). The black package contains an IBM compatible computer. All equipment is transportable by passenger air service. Instructions to the tool and data from the tool may be transmitted over telephone lines or by the INTERNET.



Session 6: Geothermal Heat Pumps

Chairperson:
John D. Geyer,
Citizens Power & Light
Corporation

GEOTHERMAL HEAT PUMPS

Utility & Regulatory Perspectives and Funding Methods

John D. Geyer
Citizens Power & Light Corporation

Introduction

No developmental or commercial aspect of geothermal energy is enjoying more attention or growing more rapidly than Geothermal Heat Pump ("GHP") technology. With nationwide installations increasing twenty to thirty percent annually since 1990, the GHP is redefining popular concepts of geothermal energy. GHPs have established a presence in recent energy and environmental legislation which higher temperature geothermal power generation has long sought but failed to capture. With this surge in interest is coming new entrants to the geothermal community. These include a new manufacturing sector, electric utilities remote from hydrothermal systems of the far West, and a large constituency which already embraces solar energy and demand side technologies. Ironically, after years of effort to achieve broader recognition, major groups within traditional geothermal circles reject claims of GHP as bonafied geothermal energy. This fragmentation of identity and internal dissent can work against geothermal interests in general.

This geothermal image "make-over" presents geothermal energy as available nationwide, as environmentally "clean", and as consistent with other energy goals and policies. A significant number see GHPs as closer in spirit and potential to solar technology than to high temperature geothermal generation. In any case, the GHP industry is decentralized and market driven rather than led by technical specialists. Further, GHPs offer multiple, sustainable benefits to both utilities and end users.

Utility Perceptions

GHPs offer electric utilities financial and system operating benefits which are valuable and predictably available. This technology can serve as a major Demand Side Management (a.k.a. "DSM", "Conservation") program element for years to come. It poses low regulatory risks and enjoys high customer acceptance and satisfaction. It is heavily co-funded by customers. With costs resembling many DSM applications, GHPs improve operational and economic benefits of supply side (i.e., generation) resources. This is most true during peak load conditions of very high or low temperatures. GHP's main problem is their high capital cost (a.k.a. first cost) and complex installation relative to other supply-side appliance choices available to consumers.

Regulatory commissions report few conceptual problems with GHPs but exhibit little current knowledge. Few regulated utilities have advocated GHP use and, therefore, little distinction is made yet from air-to-air heat pumps. GHP use in all parts of the country continues to be led by self-regulating public utilities. While future involvement by large, regulated, investor-owned utilities is essential for GHPs to approach market potential, a sound rationale is needed before regulators will endorse high first costs. This justification comes from GHP life-cycle cost analysis.

Numerous GHP funding and incentive options exist but are little used by utilities or commercial lenders. Activation of these can and probably will become the vehicle to sustain high recent growth rates. This will most likely be led by GHP manufacturing sectors and by financiers of public utility systems. Traditional accounting and non-traditional valuation methods exist to document GHP's net-positive value(s) to electric utilities. Future competitive pressures on both utilities and lenders will likely cause these to be reviewed and adopted as marketing tools.

DOE's California GHP Initiative

In 1993, the Department's Geothermal Division asked why GHP activity was lowest on the West Coast and whether and how a GHP market could be stimulated in California. One goal was to identify GHP issues and solutions usable elsewhere. The volunteer California Geothermal Heat Pump Committee was formed to pursue these questions. Local interests formed into self-assigned groups to: (1) site, facilitate and collect performance data from two dozen pilot GHP installations; (2) conduct a two-phase paper study of GHP economics and performance results at several California locations; (3) modify State energy efficiency codes for buildings and appliances to recognize GHPs; and (4) create a regional GHP Training Center in Davis, California, to serve utilities, builders, researchers and GHP marketers.

In 1994, the California Energy Commission selected GHPs for its Opportunity Technology Commercialization program (OTCOM). A Commercialization Collaborative was formed to produce and implement a Sustained Orderly Development plan in the state. At the same time, the California Geothermal Heat Pump Committee has been renamed the Western Geothermal Heat Pump Committee to promote GHP market development elsewhere, concurrent with California events.

GEOTHERMAL HEAT PUMPS

"THE 30% GROWTH TECHNOLOGY"

U.S. Department of Energy
Geothermal Program Review XII
April 27, 1994

John D. Geyer
Citizens Power & Light Corporation

GEOTHERMAL IMAGE "MAKE OVER"

GHPs are seen as:

- Available Nationwide
- "Clean" and "Correct"
- Decentralized Industry
- Closer to Solar Community than to Traditional Geothermal Industry
- Multiple Benefits to both Utilities and End Users

Citizens Power & Light Corporation

ELECTRIC UTILITY VIEW

- DSM - Program Anchor for 1995 to 2000 +
- High Efficiency / Low Operating Cost
- Source of Peak Shaving and Load Shaping
- Build / Retain Electric Market Share
- Customer Co-Funded
- Low Regulatory Risk

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Preliminary Problem is High First Cost

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REGULATORY VIEW

- Global Change Program – Action Item No. 26
- Highly Cost Effective on Life-Cycle Cost Basis
- Measurable, Accountable & Durable
- Market-Driven

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Rationale Needed for First Cost Allowance

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FUNDING & INCENTIVE OPTIONS

- Energy Efficiency Mortgages
- Appliance Energy Efficiency Code Credits
- Local / Federal Tax Credits
- Utility Rebates, per DSM Programs
- Appliance Financing Programs
- Waiver of New Hook-Up Fees
- Time-of-Use Rate Structures
- Alternative-to-Transmission Capital Programs

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UTILITY COST RECOVERY

- Shared Savings Repayment
- DSM Performance Incentives
- Regulatory Capital Investment Allowance
- Reduced Peak Power Purchases or Plant Investment
- Increased Total Sales
- Increased System Load Factors
- Economic Dispatch Gains
- Commercial Mortgage Partnership Discounts

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DOE QUESTIONS - 1993

1. Why minimal West Coast GHP activity?
2. Can GHP market be created in California?

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<u>California GHP Committee</u>
Utility Data Collection
Economic & Performance Study
Regional Training Center

~ ~ ~ ~ ~ ~ ~ ~ ~ ~

<u>California Energy Commission</u>
OTCOM, SOD, Collaboratives

Citizens Power & Light Corporation

GEOTHERMAL HEATING & COOLING WITH HEAT PUMPS--
AN OVERVIEW OF DOE PROGRAMS

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PREVIOUS RESEARCH

Although little emphasis has been placed recently on developing technology or market penetration for geothermal heat pumps, heating and air conditioning with earth and groundwater coupled heat pumps was a topic of consideration in the late 1970's and early 1980's as part of the geothermal direct use program. The early research, principally at the Idaho National Engineering Laboratory (INEL) studied heat pump equipment and the coupling of the heat pump to low temperature geothermal fluids and shallow earth. As funding for geothermal research decreased during the latter half of the 80's geothermal heating and cooling activities ceased in the geothermal program. However a significant amount of research on heat pumps, particularly those for industrial applications continued at the INEL until the early 1990's.

In recent years several investigations into geothermal heating and cooling were initiated. The first of these was a study of the utilization of geothermal heat pumps in northern Virginia conducted for the INEL by Roger D. Congleton at the Center for Study of Public Choice at George Mason University. His study showed that heat pumps were marginally economic for residential customers without utility rebates or incentives. However, the study clearly showed that from a utility standpoint there were clear economic advantages. Increased use of geothermal heating and cooling also would provide utilities considerable ability to shape load and utilize demand side management to conserve the use of expensive power sources during periods of peak heating or cooling load.

CURRENT RESEARCH

Review of geothermal heating and cooling and the availability of suitable groundwater and soil for geothermal heat pumps was initiated and continues under the current low-temperature assessment program. This program is managed by the INEL and utilizes research capabilities at the Idaho Water Resources Research Institute (IWRRI), Oregon Institute of Technology -- Geo-Heat Center (OIT) and the University of Utah Research Institute (UURI). This program has two major thrusts; a review and revision of the assessment of low-temperature geothermal resources in the western United States and the characterization of these resources for commercialization, and studies related to the utilization of geothermal resources for heating and cooling through utilization of heat pump technology. The assessment is led by OIT and UURI and utilizes geologic teams from many of the western states.

The heat pump portion of the program involves preparation of educational materials at UURI and OIT on geothermal heat pump applications, engineering and economic studies of geothermal heating and cooling conducted at OIT and described in the paper by P. J. Lineau in this proceedings. Researchers at IWRRI have reviewed the location of suitable near-surface conditions for geothermal heating and cooling and have prepared a new national map of near surface groundwater temperatures. A paper by L. L. Mink describing the IWRRI work is contained in this proceedings volume.

Sandia National Laboratory is studying development of new trenching and drilling technology to provide less costly methods of installing the piping needed to provide coupling between the heat pump and the thermal energy of the earth. They are also conducting research on the heat transfer between the geothermal system and the heat pump.

The DOE Geothermal Program, the Environmental Protection Agency (EPA) and several utility groups have sponsored several teleconferences that provide training and information concerning the installation, utilization and economics of heating and cooling through the use of low temperature geothermal resources coupled to heat pumps. DOE is also participating with EPA and the Department of Defense (DOD) in the Strategic Environmental Research and Development Program (SERDP) to increase the awareness within DOD of the benefits of geothermal heating and cooling, to provide technical assistance to DOD and to participate in demonstration projects. The geothermal program is also providing limited technical and financial assistance to the Atlanta Committee for the Olympic Games, to showcase the utilization of geothermal heating and cooling at several venues of the 1996 Olympic Games.

HEAT PUMP PROGRAM MANAGERS

Additional information on the geothermal heating and cooling program may be obtained from:

Lew W. Pratsch
Geothermal Division
U.S. Department of Energy
Forrestal Bldg., CE-122
1000 Independence Ave., S.W.
Washington, DC 20585
202-586-1512;

and on the Olympic support from:

Stanley D. Calvert
Forrestal Bldg., CE-122
1000 Independence Ave., S.W.
Washington, DC 20585
202-586-8021.

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GEOTHERMAL HEAT PUMP PERFORMANCE and UTILITY PROGRAMS

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ABSTRACT

Geothermal heat pump systems are one of the promising new energy technologies that has shown rapid increase in usage over the past ten years in the United States. These systems offer substantial benefits to consumers and utilities in energy (kWh) and demand (Kw) savings. The purpose of this study was to determine what existing monitored data was available mainly from electric utilities on heat pump performance, energy savings and demand reduction for residential, school and commercial building applications. Information was developed on the status of electric utility marketing programs, barriers to market penetration, incentive programs, and benefits.

INTRODUCTION

The Department of Energy (DOE) and the Environmental Protection Agency (EPA) are rapidly expanding their involvement in programs to promote increased use of both renewable-energy resources and energy-efficient technology. Federal implementation of the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992, and other regulations still under development are a result of an increasing worldwide environmental consciousness. Further, the environmental and efficiency aspects of energy production and use are expected to remain top priority items in President Clinton's Administration. Geothermal heat pump (GHP) systems can help meet the challenge by increasing our energy efficiency, with resulting benefits to utilities in better load management, to customers in lower utility bills and to society in a cleaner environment (Pratsch, 1992).

Electric utilities are the ultimate market target for GHPs, especially utilities which are already committed to demand side management (DSM). Recommendations must be consistent with prevailing energy policies and supported by data. The data must show that the resource, and technology is available, reliable, and cost competitive with other options. Concerns of utilities considering GHP technology as a DSM option include:

- Amount of demand and energy savings.
- First cost of ground loop and wells.
- Effect of ground loop temperature increase for summer and long-term operation, especially for commercial applications.
- Utility rebates and other incentives.
- Infrastructure availability of heat pump dealers and loop installation contractors.

The objective of the Geothermal Heat Pump Performance Evaluation study was to compare as many types of like case studies, with monitored data, taken from as many sources as possible throughout the United States. The monitoring strategy for GHPs can be classified into:

Basic parameters:

- Heat pump demand (kW) and energy (kWh).
- Supply and return ground-loop temperatures.
- Flow in ground-loop, a one-time measurement.

Comprehensive parameters:

- Ground-loop pump kW and kWh.
- Fan kW and kWh.
- Air flow.
- Air supply and return temperatures.
- Space and outside temperatures.

Due to the complex variations that affect a systems performance, it is difficult to exactly compare two different applications. The goal of this study was to compare as many case studies of similar data as possible to establish a pattern rather than attempt to remove the variables for an exact comparison.

PERFORMANCE

The energy performance of GHP systems can be influenced by three primary factors: the heat pump machine, the circulating pump or well pump, and the ground-coupling or groundwater well.

The heat pump is the largest single energy consumer in the system. It's performance is a function of: the rated efficiency of the machine and the water temperature produced by the ground-coupling or well (either in the heating or cooling mode). The most important strategy is to start with an efficient heat pump. It is difficult and expensive to enlarge a ground-coupling to improve the performance of an inefficient heat pump.

Ground-coupled heat pumps are currently rated by the American Refrigeration Institute (ARI). Under the standard (ARI 330), ratings for cooling EER and Heating COP are published as single point values rather than seasonal values as in the case of air source equipment. The EER is the ratio of cooling provided by the system in Btu to energy consumed by the system in watt-hours and COP is the ratio of energy provided by the system to the energy consumed by the system. Cooling EER values are based on an inlet water temperature of 77°F. Heating COP values are based on a heating inlet water temperature of 32°F. These values are characteristic of a northern climate.

The current ARI directory contains equipment with EER ratings of less than 10 to a high of 18.6 and COP values range from 2.8 to 3.6. Based on these values it is evident that the performance of the equipment can vary by nearly 100% according to the quality of the heat pump purchased.

The actual performance of the equipment is function of the water temperature produced by the ground-coupling, which is a function of the ground temperature, pumping energy, and the design of the ground-coupling. For example, in a region where the local ground temperature is 60°F and the ground loop is designed for the customary 20° to 25°F above ground temperature, a heat pump rated at an EER of 16.8 would actually operate at an EER of 14.2 under peak load conditions. A poorly designed loop which forces the unit to operate at 30°F above ground temperature would reduce the value to less than 13.0. These values are for cooling operation which is the dominant load in commercial applications. The same relationship holds for heating operations however.

In summary it is necessary when evaluating a ground-coupled system to consider the efficiency of the machine, the adequacy of the ground-coupling and the nature of the pumping design to fully understand the efficiency of the system.

CASE STUDIES

In order to verify the performance of geothermal heat pumps, information from 217 case studies was collected on residential, commercial and school systems from primarily utilities throughout the United States. Fifty-nine of these 217 case studies met the criteria that the system was compared to another energy source. These were compiled into a database. The database includes dates, location, GHP system description, application, capacity/demand, energy/economics, and data monitored.

Residential

Residential case studies (32) represent systems located in north central (11), eastern (8), southern (6), and western (7) climates. The systems were monitored for various parameters, ranging from only energy (kWh) input to the heat pump to eight other parameters. Unfortunately, there were very few case studies with a complete set of monitored data available. A wide variety of testing techniques were used; but, ultimately the goal was to determine annual energy usage and peak demand savings for the homes.

The percent of GHP energy savings over ASHPs ranged from 13% to 60% with a mean of 33%. Savings relative to electrical resistance systems with air-conditioning units ranged from 25% to 70% with a mean of 52% (Figure 1). Winter peak demand reduction ranged from 3 to 7 kW compared to air-source heat pumps for typical homes. Summer reductions in demand only ranged from 0.5 to 1.5 kW. Figures 2 and 3 are examples of peak day demand reduction graphs from Minnesota. Utility coincident demand reduction with residential systems was when monitored about 33% less than the non-coincident demand.

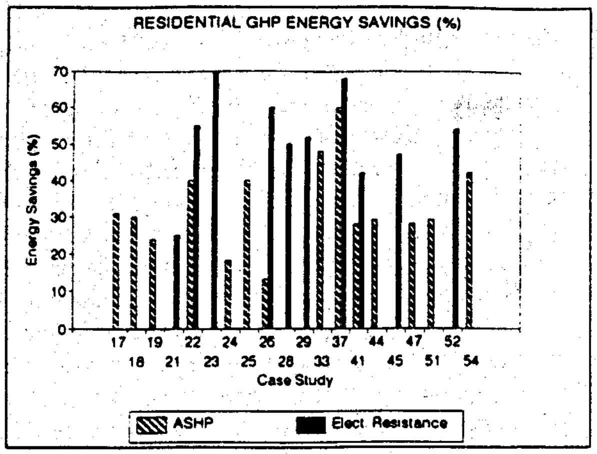

Figure 1. Residential GHP energy savings (%) compared to air-source heat pumps and electric resistance/air-conditioning systems.

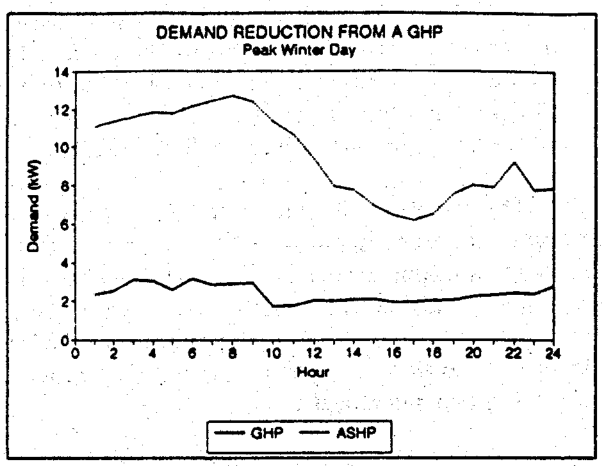

Figure 2. Residential GHP peak winter day demand (kW) reduction compared to an air-source heat pump in a north central climate.

GHP systems were analyzed for simple payback. The largest barrier to faster payback of GHP systems is the cost of the ground loop. The EPA (L'Ecuyer,1993) has identified vertical loop costs for residential systems to be in the range of \$700 to \$1,000/ton; while horizontal systems cost \$500 to \$670/ton. Spiral loop systems are expected to cost between \$350 to \$500/ton. Residential system simple payback ranged from 2 to 6.8 years with a mean of 4.3 years.

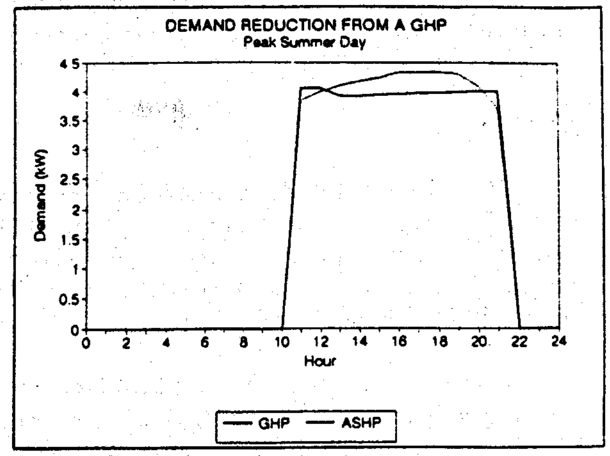

Figure 3. Residential GHP peak summer day demand (kW) reduction compared to an air-source heat pump in a north central climate.

School Systems

Most school districts in the nation make every effort to keep expenses at a minimum while still providing top quality education and a comfortable environment. Conserving energy dollars is one of the most direct and effective ways of reducing expenses.

The potential for energy savings in schools throughout the United States is demonstrated by two case studies described in Table 1. The first is a middle school in Wahpeton, ND employing a ground-coupled system and the second is a high school located at Junction City, OR employing a groundwater system.

Table 1. School Ground-Coupled and Groundwater GHP Systems.

School	Wahpeton, ND	Junction City, OR
Start Date:	1988	1988
System:	286 boreholes (150 ft)	Prod. & inj. wells (55°F)
Application:	Middle Sch., 57,400 ft²	High School, 55,300 ft²
Design Cond:	8564 HDD, -25°F	4793 HDD, 17°F
Capacity:	220-tons	101-tons
Energy:	678,000 kWh/yr	193,133 kWh/yr
Installed Cost:	\$418,000	\$265,000
Savings/year:	106,800 therms of gas*	31,602 therms of nat. gas

* Calculated

For ten case study schools located throughout the nation the reduction in energy dollars over alternative electric heating systems per month ranges from $300/mo to $2,700/mo.

Commercial

Case studies (12) documented for GHPs in commercial buildings ranged in capacity from 30 to 4,700-tons employing ground-coupled well fields of up to 370 boreholes for a 850-ton system to 3 wells for a 4,700-ton groundwater system.

The percent energy savings was 22% for an air-source heat pump system and 40% to 68% over electric heat with air-conditioning equipment. Demand reduction for commercial buildings ranged from 32% to 65% for three electric VAV systems.

UTILITY PROGRAMS

Geothermal heat pumps are one of many technologies electric utilities are considering or implementing for demand-side management (DSM), especially aimed at improving the efficiency with which customers use electricity. The result of DSM programs aimed at energy efficiency provide two benefits: they save energy and reduce peak demands.

Information was developed on the status of DSM programs for about 60 utilities and rural electric cooperatives including: marketing programs, barriers to market penetration, incentive programs, number of GHP units installed in service area, and the benefits to the utility. The most common marketing programs were newspaper and radio/TV advertisement, test and demonstration of GHP system performance, education programs, and home shows.

The primary barrier to marketing GHP systems according to a majority of the utilities is the incremental cost of installing the ground loop. Other deterrents of the implementation of GHPs cited by the utilities are: natural gas is inexpensive; lack of manufacturers, suppliers, dealers and loop installers; and customer resistance to heat pump technology.

Utilities have designed a number of incentive packages to encourage the installation of GHPs. In most cases, these incentives include cash rebates, low cost financing, discounted energy rates, and in a few cases ground loop installations. For one utility, an innovative lease/purchase program was designed to knock down the main barrier to marketing GHPs - their high installation cost (Cochran, 1994). The program includes two general types of leases. Under the first type, designed for new homes, the utility leases GHPs to customers over the life cycle of the equipment. Customers pay for use of the systems through their monthly electricity bills. Under the second option, designed for existing homes with standard efficiency levels, the utility offers a monthly contractual lease. In either case the utility buys the GHPs directly from manufacturers at wholesale price and passes the savings on to customers. Annual inspection and routine maintenance are provided by the utility through certified contractors as part of the program. The program has created a boom in GHP installations in the utility's service area with more than 100 systems installed in less than a year compared to 150 installed in the previous eight years.

CONCLUSIONS

Geothermal heat pumps are an effective means to reduce both consumer energy consumption and electric utility peak loads. To date, the geothermal heat pump industry has been primarily residential and has been most successful in areas characterized by winter peaking utilities, moderate electric rates and moderate to severe winter heating requirements.

The two items that influenced geothermal heat pump performance in one locality apart from others, are ground characteristics and climate. Software is currently available from both manufacturers and independent sources to predict performance under specific conditions, given input on ground characteristics and climate.

Current and up-to-date information on the geothermal heat pump designs, especially used in the commercial sector, are not easily found. There is a need to further document information on the operating experience with this technology and report on success and/or failure encountered at various locations in the United States.

Future Work

For large commercial buildings, there are two general approaches to the installation of a GHP system: ground-coupled or groundwater, which are being examined by the Geo-Heat Center in terms of capital costs and pumping energy requirements of the ground source portion of these systems. The following is a brief discussion of the issues involved and outline of the direction this research will take (Rafferty, 1994).

"Under the ground-coupled design, the installation consists of drilling a number of vertical boreholes and installing the loop piping in the boreholes. Generally, the cooling load dominates the length requirement for the ground loop. Cost per foot in the $5.00 or less range is not uncommon. Although there is some reduction in the unit cost per foot in larger installations, the cost of any installation is directly related to system capacity (tons) since a fixed number of feet per ton is required at a fixed cost per foot. This results in a cost curve (150 ft/ton @ $5.00 per foot) as shown in Figure 4 (Rafferty, 1994).

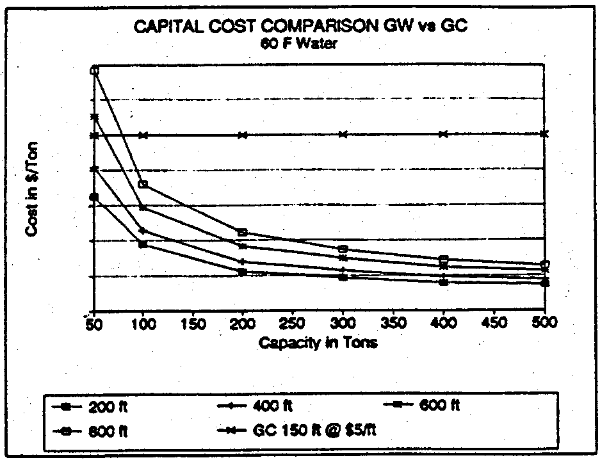

Figure 4. Capital cost comparison of groundwater vs ground-coupled GHP systems.

Groundwater systems are those in which the heat rejection and supply are accomplished by delivering the groundwater from a well to a heat exchanger installed in the heat pump loop. Costs associated with groundwater wells are to some extent similar to those for vertical bore ground-coupled systems. That is, they are frequently characterized by a cost per foot of depth. However, the flow rate produced by the well rather than its depth determines the wells capacity to meet heating and cooling loads. Ground water systems also incur costs for other items such as the well pump(s), heat exchangers, piping, frequency drive, controls, injection wells if used, and testing. Cost curves for groundwater systems (lower curve 200 ft production and injection wells; upper curve 600 ft wells) would appear as shown in Figure 4. Assuming groundwater is available, a single well may be capable of supporting several hundred tons of heat pump capacity, the cost per ton under certain conditions may be much less than a ground-coupled system in larger projects. The ground-coupled system is likely to enjoy economic advantage in smaller projects."

ACKNOWLEDGEMENT

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THE SANDIA/DOE PROGRAM ON GEOTHERMAL HEAT PUMPS

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Abstract

The Geothermal Heat Pump (GHP) concept was originally developed in the 1940's. It has recently increased in popularity because of increasing energy costs, utility interest in the concept, and the development of relatively simple and durable ground source heat exchangers. Today, approximately 35000 GHP systems are being installed annually in the United States[1]. Where measurements have been made, the results indicate that GHP's can reduce peak demand and overall heating and cooling costs considerably[2].

Sandia National Laboratories (SNL) through its sponsor, the Department of Energy (DOE), has been conducting a program aimed at understanding GHP technology and improving the penetration of the concept. There are three major elements to the program: data acquisition to quantify the performance of GHP's; R&D to reduce the installation cost of ground source heat exchangers; and support of DOE efforts to increase awareness and market the GHP concept. SNL also receives funding from the Department of Defense through the Strategic Environmental R&D Program (SERDP) aimed at increasing the use of GHP's on military installations. The SERDP activity is conducted in parallel with the DOE program, but SERDP demonstrations, R&D, and marketing efforts are targeted to DoD needs and facilities.

This paper describes the current status of our program and plans for future activities.

Background

There are a wide variety of configurations commonly used to construct a GHP system, some of which are shown in Figure 1. GHP's are

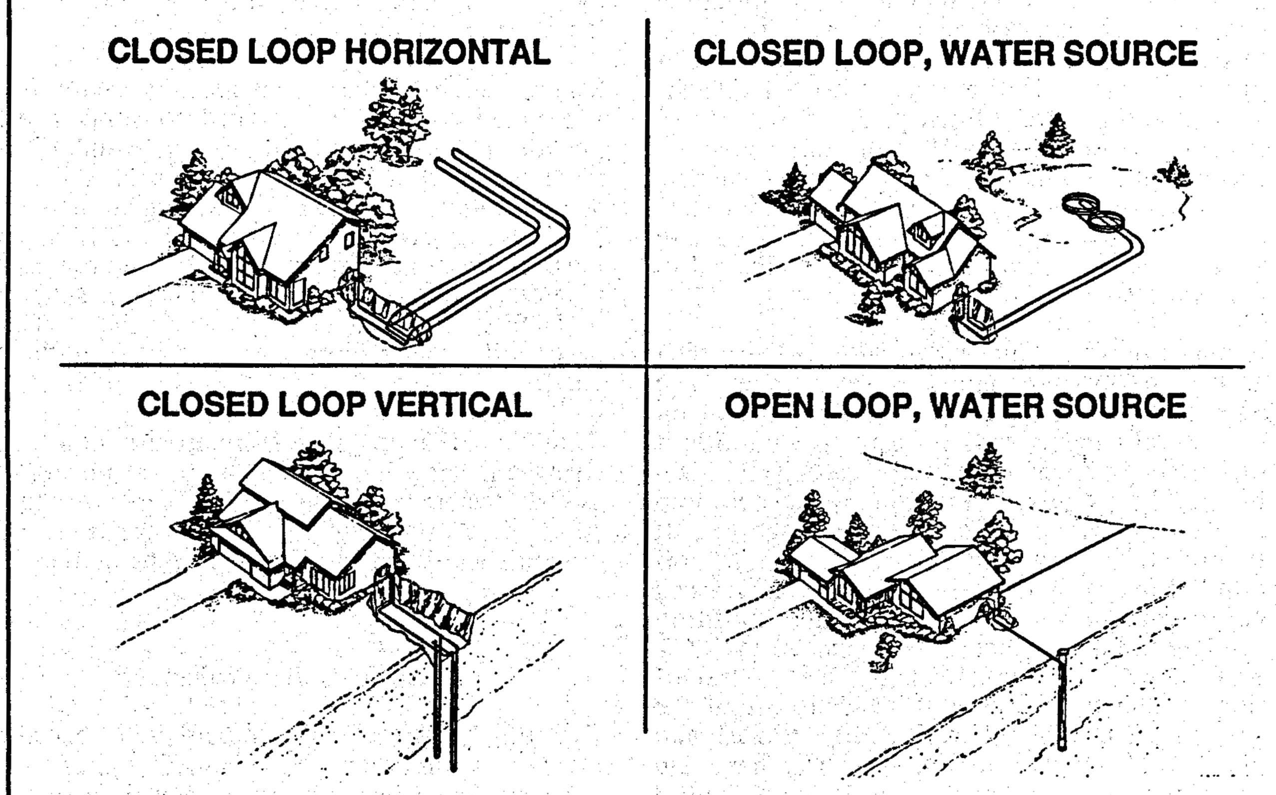

Figure 1 Typical residential GHP installations

technically similar to conventional freon air conditioners or heat pumps: there is a compressor, expansion valve, air-to-freon heat exchanger and a blower. The GHP also has a reversing valve (in common with conventional heat pumps) to allow it to supply heat in the winter and cooling in the summer. The difference lies in the heat source or sink external to the conditioned space. Conventional air conditioners and heat pumps use outside air through an air-to-freon heat exchanger. Alternatively, the GHP uses water or anti-freeze circulated through a ground source heat exchanger. Most of these concepts use high density polyethylene pipe as the basis for the ground heat exchanger. This is a very durable, inexpensive pipe with relatively high thermal conductivity. (PVC pipe is a poor conductor and does not make a very effective heat exchanger). The heat exchanger fluid is circulated with a small pump through a water-to-freon heat exchanger inside the heat pump unit.

The GHP concept has a number of important advantages over conventional alternatives. The GHP unit may be contained entirely inside the heated space and needs no venting. There is no need for above-ground hardware outside the building and all the freon connections in the unit are completed at the factory. There is less freon used relative to conventional air conditioning units or air-source heat pumps because the water-to-freon GHP heat exchanger is much smaller than the outdoor air-to-freon unit needed with air-source equipment. Finally, the warm (cool) temperature of the earth 10 ft or more below the surface relative to the air in winter (summer) significantly increases the capacity and efficiency of GHP's. It also allows GHP's to be effective in a wide range of climates--they are not limited to temperate areas only.

A major disadvantage with GHP's is the capital cost of the ground source heat exchanger. The size of the heat exchanger is strongly dependant on the soil conductivity, but usually about 500 ft of buried pipe per ton of GHP capacity (12,000 btu/hr) is required (a typical 3 bedroom residence needs about 3 tons). A rough rule of thumb (the real answer depends on soil conditions, availability of experienced contractors, weather conditions, building insulation, etc.) is that GHP's cost 50 to 100% more than conventional alternatives[3]. Most of this difference is due to the added cost of the ground heat exchanger. Utility rebates and substantial savings in energy costs have led progressive residential and commercial consumers to install GHP's and most are pleased, both in terms of performance and life cycle costs. Enhanced penetration in the future will probably require a combination of increased awareness about GHP's and reduction in capital costs through rebates, manufacturing economies, and technical improvements.

The cost of operating GHP systems relative to alternatives varies considerably with climate, effectiveness of the heat exchanger, and local energy costs. For cooling, electricity use with GHP's is usually 20-25% less than with conventional electric air conditioning. Heating is more complex owing to the diverse set of alternatives. Relative to resistance heat (still widely used in areas with low electric costs or low heating loads), GHP's can reduce consumption by factors of 2 to 4. Relative to natural gas, fuel oil, or propane, the energy costs for heating with GHP's is about the same. This conclusion depends on the relative cost of fossil fuels to electricity, which varies regionally.

For emissions of greenhouse gases and other pollutants, the EPA[3] sees GHP's as having potential to yield significant reductions--provided their market penetration is increased. DOE has established an ambitious goal[4] of increasing installations to 400,000 units per year by the year 2000 through marketing, R&D, and incentive programs.

Sandia National Laboratories recently established a program on GHP's designed to support the growth of the industry. The program today has three major components: support of selected demonstrations and data acquisition projects, to solidify the performance claims for GHP's; an R&D component directed toward reducing costs of ground source heat exchangers; and, support of DOE's efforts to market the concept. This paper will summarize progress and plans in these areas.

Sandia's GHP program is relatively new and changes in direction and emphasis are inevitable as GHP technology evolves. Comments on more appropriate directions or other suggestions are welcome and should be directed to the author.

Demonstration Projects

One of the first GHP projects SNL became involved with is the new HVAC system for Stockton State College in southern New Jersey.

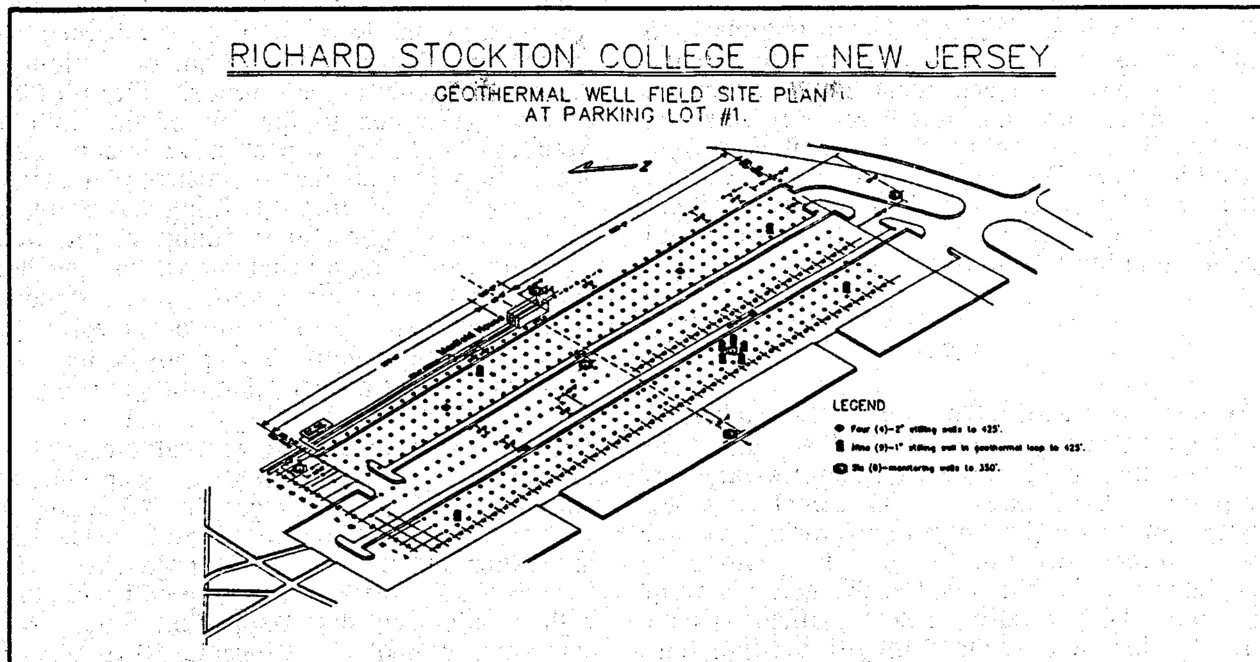

Figure 2 Layout of vertical GHP loops at Stockton College

Their GHP system is one of the largest, closed loop installations built in this country. It supplies cooling and heating for a 360,000 sq ft academic complex. There are 400 vertical closed-loop wells serving 1500 tons of roof-mounted GHP's. The wells are each about 450 ft deep and are located (Fig. 2) under one of the college parking lots.

The roof-mounted GHP units replaced, one-for-one, natural gas/electric AC units which had been in service since the early 1970's. SNL sponsored a comprehensive electrical demand measurement program through the summer of 1993 to establish baseline data to compare with the new GHP system. The GHP hardware was put into operation in January, 1994, and measurements are planned through 1994. These measurements, combined with the baseline data, should provide an excellent basis for assessing GHP effectiveness.

The Strategic Environmental R&D (SERDP) program is a DoD activity with funding identified to encourage the use of GHP's on military installations. Through SERDP, GHP measurement and/or demonstration projects are underway at three military installations, and about ten others are under consideration. Ongoing projects are underway at Ft. Polk (LA), Patuxent River Naval Air Station MD), and Dyess AFB (TX). A partial list of candidate sites are

Site	Project
Ft. Polk, LA	4000 housing units + two 50 ton admin bldgs
Patuxent River NAS, MD	84 ton admin bldg.
Dyess AFB, TX	25 housing unit demo
NAS Oceana, VA	12 ton admin/storage bldg demo.
Ft. Hood, TX	3 housing unit demo
Sebille Manor ACS site, MI	378 housing unit rehab (now resistance heat)
Naval Sec. Grp., VA	52 housing unit rehab (now air source HP)

Table 1.Partial list of SERDP sites

summarized in Table 1.
SNL's role in the SERDP demonstrations is to provide limited seed funding to reduce the first cost and to conduct and document measurement programs. The measurement programs are generally carried out by universities, private contractors, or DoD laboratories. We expect that the SERDP will ultimately provide an excellent source of data on GHP performance of use to both the military and private sector.

R&D

As mentioned above, the ground heat exchanger is a major cost element for GHP systems. The configuration of these heat exchangers vary, but can be roughly classed as horizontal (installed with trenchers or backhoes) or vertical (installed with rotary drilling rigs). In residential applications, the horizontal exchangers are more popular. They usually cost less, particularly with the development of the Slinky™ configuration by Oklahoma State University[5]. This concept buries loosely coiled pipe, rather than straight loops, and reduces the net volume of excavation needed for each installation There are many cases, however, when vertical loops are the best option due to space limitations. They are not always more expensive than horizontal if drilling conditions are favorable and local drillers skilled in the art of ground loops are available.

SNL is currently focusing its R&D efforts on vertical installations. This is because of its experience with geothermal drilling technology and the belief that low-cost, vertical techniques are necessary to increase the penetration of GHP's.

We contracted for a survey (Huttrer[6]) of drilling and completion techniques now being used for vertical, closed loop installations. The survey revealed that experienced loop drillers can profitably install loops for under $5 per foot of well depth. Depending on soil conditions, the installed cost per ton ranges from $750. to $2000. Experience is a key factor in well costs. Water well drillers not accustomed to ground loops tend to charge much higher per foot rates, in line with their water well experience. The survey concluded that substantially lower costs are possible with a steady market to support competitive drillers with enough work to develop their own productivity improvements.

Another vertical heat exchanger concept mentioned in the survey is the standing columnwell[7]. This concept is a semi-open loop which uses water wells to create a geothermal heat exchanger. Water is drawn from the bottom of the standing water in the well and most of it (85% or more) returned to the top of the column. Standing column wells have been used successfully in a number of commercial sites in the New England area. Drilling costs are, of course, much higher for standing column wells than for closed loop installations, but the heat exchanger is more effective--a typical standing column well can support a ton of capacity with about a 60 foot column. SNL plans in the future to support further investigation of this idea.

To gain experience with vertical closed loop installations, SNL installed an experimental closed loop heat exchanger in Albuquerque. This was a water-filled, cased well (to facilitate installation and removal of test loops) installed in very dry soil (Fig 2). The loop was monitored with an automated data acquisition system for a constant heat input. Two separate 50 ft deep dry instrument wells were installed a 3 and 20 ft radii from the test well, respectively. These instrument wells monitor ground temperature, so that heat diffusion from the loop may be observed. The heat transfer fluid in this loop is tap water circulated with an adjustable speed pump set at 2.5 GPM. The loop temperature is measured at four locations in the loop (hot water heater inlet and outlet, and heat exchanger inlet and outlet)

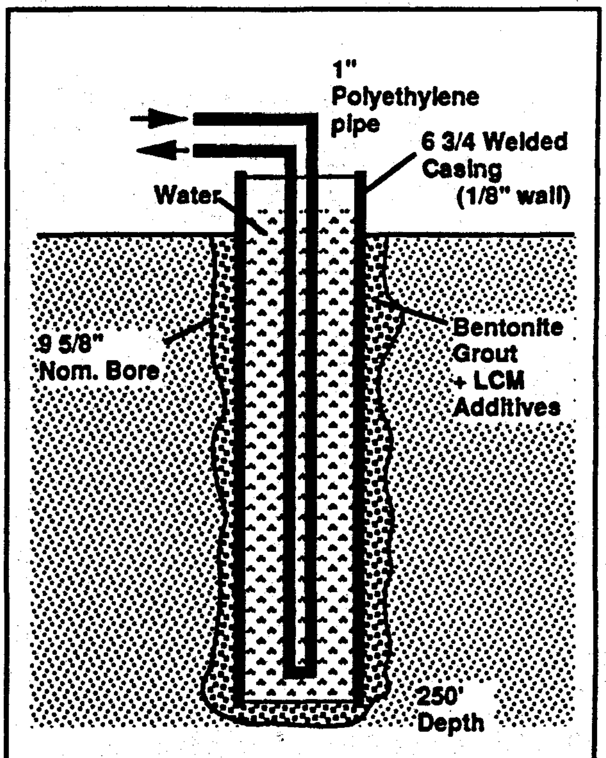

Figure 3. Details of SNL test loop

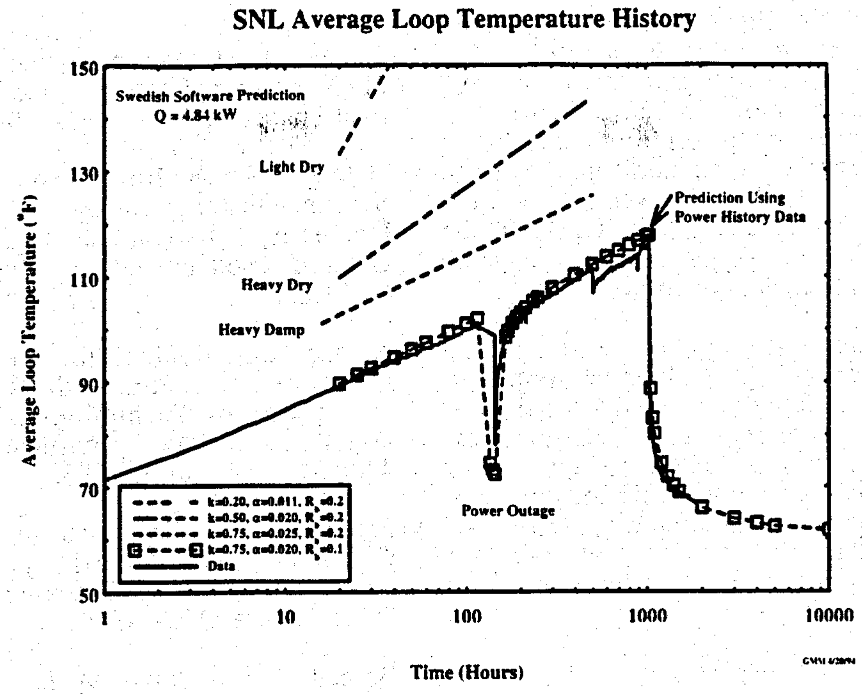

Figure 4 Thermal response of vertical heat exchanger at SNL

using four-wire immersion type platinum resistance thermometers. Copper constantan thermocouples were used on the two 50ft dry wells to monitor formation temperature at various depths around the heat exchanger.

We learned much from the installation of this well. The drilling was done by a local water well contractor (Albuquerque has no GHP contractors) and cost roughly $20/ft. This included the welded casing (a special requirement of our test) and a much larger diameter bore (9 3/4 in) than is normally used for this application. The casing was grouted to the formation with bentonite, a commonly used backfil for vertical heat exchangers[8]. The dry soil in this area would not contain the bentonite, so the grout level would not stay at the surface. Several additional treatments of bentonite and lost circulation materials (LCM) were added to limit loss of bentonite, but the loss continues. Clearly, bentonite does not work very effectively in this bore. For future installations, we will backfill with cementaeous materials or other alternatives. The experience reinforced the need for research on completion methods for GHP wells. NRECA and EPRI are sponsoring such research at South Dakota State University.[9]

The thermal behavior of the loop has been measured and is summarized in Fig. 4. This test consisted of applying a constant 4.8 kW (corresponding to 15000 btu/hr, or roughly 1.9 tons of GHP capacity) heat removal rate from the heat exchanger. This test ran continuously (excepting power outages) for about 1000 hours. The loop temperature peaked at about 120°F from an initial temperature of 63°F. This, of course, is a much higher loop temperature than would be realized with a 1.9 ton GHP, because installations do not operate at a 100% duty cycle.

The squares on the figure are results using Lund[10] software, a commonly used vertical heat exchanger design tool. We have not yet independently measured the soil properties at our site (this is planned for this summer), but did adjust the conductivity and diffusivity values to match the measured data. Another parameter needed to apply the Lund model is R_b, the thermal resistance (in btu/hr-ft) per foot of bore between the loop pipes and the water-filled casing. Tables included with the Lund package recommended R_b of .2. For our configuration we found .1 to fit the data better. The lower thermal resistance may be due to free convection in the water. The Lund software matches the data very well, but only after adjusting all the properties to fit.

This loop performed much better than we expected, as we thought the soil properties at the site would be more like the "light dry" soil prediction shown in Figure 4. The "light dry" soil properties are from Ref. 2, which also has properties for "heavy dry" and "heavy damp" soils.. This needs more investigation, as the ability to estimate local soil properties has a profound influence on loop performance. The grout which was added to the well between the casing and formation also plays a role in the performance of this loop, and it is not accounted for with the Lund predictions in Fig. 4.

Our plans for this test program are to continue work with vertical polyethylene loops to investigate ways to improve predictive analysis of their performance, attempt to install some test loops at lower cost, and identify other means of completion which are more stable for this area. We also intend to do comparative testing of alternative geometries and/or materials for ground loops which may offer improved heat transfer.

Marketing Support

A major factor in limiting GHP penetration today is the lack of awareness by consumers and heating, ventilating, and air conditioning (HVAC) contractors and designers. This has been demonstrated by the enhanced use of GHP's in regions where utilities have introduced marketing campaigns.
There are still large regions of the country where current technology would probably be cost-effective, but there is limited local knowledge or infrastructure to support GHP's.

SNL's program is designed to contribute toward marketing GHP's through its support of demonstration projects, publication of performance data and research results, and participation in DOE's broader marketing plan[5]. We welcome also the possibility of joint projects with utilities, equipment manufacturers, installers, and university researchers. We believe that such joint efforts are inherently more visible and productive.

Concluding Remarks

The GHP concept appears to be one of the most appealing and simple renewable energy concepts. We have attempted to develop a program and initiated an R&D program which we hope will contribute to encourage growth of the GHP industry.

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GEOGRAPHICAL VIABILITY OF GROUND WATER GEOTHERMAL HEAT PUMPS IN THE UNITED STATES

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ABSTRACT

Ground-source heat pumps can provide a cost-efficient alternative to standard air-source heat pumps. However, for the earth-coupled and ground water heat pump systems, developmental factors such as ground water availability and installation costs tend to weigh against using these systems. To promote the feasibility of the ground water heat pump, it must be demonstrated to manufactures and consumers that there is a ready and constant supply of economically obtainable ground water in many areas of the United States. A set of figures, depicting areas of shallow ground water and its average temperature, demonstrates that well over one-half of the United States, particularly the central and southeast, possess the hydrogeologic characteristics necessary to make the ground water heat pump a viable option. Linking these plates with population demographics demonstrates that regions with hydrogeologic characteristics favorable for the use of ground water heat pumps coincide with densely populated regions of the continental United States. This implies a readily available resource for a large section of the population.

INTRODUCTION

The Idaho Water Resources Research Institute (IWRRI) at the University of Idaho is currently engaged in a cooperative program with the University of Utah Research Institute (UURI) and the Oregon Institute of Technology (OIT) to develop and promote the use of ground-source, or geothermal heat pumps. At the Idaho Water Resources Research Institute research addressing the feasibility and application of geothermal heat pumps has focused primarily on both the earth-coupled and the ground water heat pump systems. To promote the further use of ground water geothermal heat pumps, IWRRI has produced a set of three plates of the United States, describing potential favorable near-surface ground water supplies which may be used for ground water heat pumps.

Background

Ground-source heat pumps are manufactured in three varieties: the earth-coupled, the ground water, and the lake-source heat pump. All three operate using the same general process: a fluid is circulated by a heat pump (exchanger) through tubing, where it releases heat or absorbs heat, depending whether the unit is cooling or heating. Earth-coupled heat pumps achieve this goal by pumping the fluid through tubes buried in the ground. Lake-source heat pumps circulate fluid through tubing submerged in a standing body of water. Ground water heat pumps can use ground water pumped directly from an aquifer as their fluid, or they may circulate a fluid through tubing placed within wells drilled into the ground water system. This fluid is then passed through the heat pump where heat is either absorbed from or released to the building or home. If ground water has been extracted and used for fluid it is then returned to the aquifer through an injection well. Today, the two most widely used geothermal heat pump systems are the earth-coupled and ground water systems.

Purpose

According to Dr. Steve Kavanaugh of the University of Alabama, ground-source (geothermal) heat pumps are receiving increasing attention as a higher-efficiency, lower-cost alternative to traditional air-source heat pumps. Of the three types of ground-source heat pumps, the ground water heat pump is less costly to construct than the earth-coupled heat pump, owing to the fact that the earth-coupled type requires burying pipes below ground. However, since ground water conditions necessary for the optimum functioning of a ground water heat pump are not usually obvious to the eye, these are often shunned in favor of a more traditional heating/cooling system. Even when a ground water source does exist, prohibitive economics can be a factor against using ground water heat pumps. One of the more restrictive elements of a ground water heat pump is the initial construction cost of the system. Drilling costs for a ground-source system can vary widely in price, depending on physical conditions at the site, the nature of the subsurface geology, and more importantly the depth of the hole required by the selected system. However, these costs can be offset by utilizing a suitable, pre-existing source. The drill hole depth and static water level are of special concern in developing a ground water heat pump system. One must reach a sustainable source of ground water which provides a reasonable pumping rate. Ground water heat pumps require between 1 to 1.5 gpm per ton of heating or cooling capacity (K. Denbraven, written commun., 1993). In addition, the return temperature from the heat pump must be kept above approximately 37°F to prevent freezing of the water, and at 1 gpm/ton a drop of 15-20°F can be expected across the heat pump from inlet to outlet. The purpose behind the accompanying figures is to provide a preliminary assessment of areas in which use of ground water geothermal heat pumps may be feasible.

Recent work by OIT (Lienau, personal commun., 1994) indicates significant economic energy savings can be realized through the development of deep ground water sources. These deep ground water sources are often warmer than shallow ground water systems present in the same area. Utilization of deeper systems are of greatest benefit to a large-scale commercial or industrial user who can take full advantage of the increased energy potential as balanced against additional development costs.

METHODS

The package produced by IWRRI includes six figures. The research consists of four figures depicting: (1) aquifers associated with shallow alluvial valleys (Figure 1), (2) aquifers associated with unconsolidated and semi-consolidated sedimentary deposits (Figure 2), (3) ground water temperatures in wells at depths of 100 to 200 feet (Figure 3), and (4) interpreted shallow ground water regions of the United States (Figure 4). These figures are supplemented by a map displaying the regional ground water systems of the United States (Figure 5) (Thomas, 1952) and selected population densities for metropolitan areas (Figure 6) extracted from 1990 U.S. census figures (Mattson, 1992). The base map used (not presented in this paper) is the USGS publication, *Physical Divisions of the United States*, by Nevin M. Fenneman (1949), a polyconic projection at a scale of 1:7,000,000. This map was chosen for its excellent depiction of river drainages, as well as its manageable scale.

The first two figures depict those aquifers which are known to produce water within a relatively shallow depth (within approximately 100 to 200 feet of land surface is the intended range). The alluvial valley figure (Figure 1) depicts those aquifers of thick sand and gravel deposits beneath floodplains and stream terraces associated with existing streams or rivers. The hydrogeologic properties of these types of sediments in combination with the river or stream acting as a constant recharge source, give the alluvial valley deposits strong potential for providing shallow ground water.

The unconsolidated and semi-consolidated sedimentary deposits (Figure 2) display areas of water-bearing sands and gravels and sandstones of the Cenozoic and Mesozoic ages. These unconsolidated sediments are often found as alluvial valleys, alluvial basins, thick alluvial deposits, glacial deposits, or as interbeded sands and silts. These unconsolidated or semi-consolidated deposits are often found near-surface, and many contain shallow unconfined, or water table aquifers. Further, the hydrogeologic properties of the sands and gravels that form these types of unconsolidated and semi-consolidated sediments allow for sustainable quantities of ground water at relatively shallow depth, assuming there is a dependable source of recharge to the aquifer.

The ground water temperature figure (Figure 3) is included as a general reference to determine the possible ground water temperatures encountered for use in a ground water geothermal heat pump. Although existing ground water temperature maps may show much greater detail (Hart, 1986) for some areas, and should be referred to if available, this map provides an adequate representation of temperature on a national scale and is designed to be used with the other plates. It should be noted that ground water temperature is higher and more seasonally consistent than ambient air temperature, resulting in more efficient heat transfer.

Ground water systems show an increase in temperature with depth, so deeper systems often exhibit elevated temperatures compared to the shallow ground water temperature presented in Figure 4. The *geothermal gradient*, which is the rate at which the temperature increases with depth below land surface, is a function of the lithology of the hydrogeologic system and the heat flow present in the area (Blackwell, 1992). In most aquifers, the lithology varies spatially throughout the aquifer, so a single aquifer may have different gradients at different depths. However, *heat flow*, which is a measure of the amount of thermal energy conducted from the earth's interior to the surface, for a particular area or region can be determined and used instead of the geothermal gradient to gain both a qualitative and quantitative measure of the subsurface temperatures in a particular region. Regions with higher heat flows will have higher geothermal gradients than regions with lower gradients for a particular lithology (thermal conductivity). Blackwell (1992) presents a comprehensive picture of the heat flow for the United States. As a generalization, the region east of the Rocky Mountains to the Atlantic Ocean has an average surface heat flow of 50mW/m^2, the region west of the Rocky Mountains to the Cascade Range has an average surface heat flow of 80mW/m^2, and the region from the Cascade Range to the Pacific Ocean has an average surface heat flow ranging from 30-50mW/m^2 in Oregon and Washington to 50-80mW/m^2 in California.

In comparing the amount of heat flow from the earth, averaging about 40-50mW/m^2, to the amount of heat received and reradiated by the earth from the sun, averaging 400W/m^2 (Fowler, 1992), it is believable that most of the heating of the shallow ground water and to a lesser extent deeper ground water is derived from a solar source. However, the subsurface effect of solar heating on a daily and annual basis is very limited. The depth to which solar energy penetrates the subsurface is related to the properties of the conductive material (the earth) and the periodic nature of solar energy influx. A complete discussion is given by Fowler (1992): to summarize, the depth below land surface to which solar heating will cause a daily variation in temperature is 17 cm or roughly 7 inches, for annual variation the depth is 10-20 m or roughly 30-60 feet and for variation over a very long period of time (100,000 years) the depth is up to 1 km or one-half mile. However, the variation in temperature, or the amount of solar effect, decreases with depth below land surface. At 5 feet below land surface, the annual variation or disturbance caused by solar effects is 6.2°C or 11°F, while at 30 feet below land surface the disturbance is 0.6°C or 1°F; below 30 feet the amount of disturbance or solar energy input on an annual basis is negligible (Williams after Lienau, written commun., 1994).

This is not to say that shallow ground water systems are not effected by solar influx. In examining the shallow ground water temperature map (Figure 3) it is apparent that an increasing temperature gradient exists from the northern United States to the southern United States, east of the Rocky Mountains. This gradient is due primarily to the temperature of the water upon its entry into the ground water system. Surface water temperatures in the northern U.S. are colder than those in the southern U.S.; consequently, the water recharging shallow aquifers in the northern U.S. is colder, implying colder shallow ground water temperatures than are present in the southern U.S. Once in the shallow ground water system, the water is influenced by geothermal heat flow and the minimal amount of annual solar influx. In a deeper, regional ground water system, the ground water temperatures are driven by geothermal heat flow present over the region and the ground water becomes characteristic of the heat flow in that particular region.

INTERPRETATION

Combining the ground water potential delineated by the alluvial valley figure (Figure 1) and the unconsolidated and semi-consolidated figure (Figure 2), it is estimated that a large portion of the continental United States contains shallow ground water which is potentially available for heat pump use (Figure 4). Using the 10 ground water regions (Figure 5) as a physiographic classification system, an estimation of the ground water heat pump viability for each region can be made. Much of the Atlantic and Gulf Costal Plain region would be supplied by ground water from unconsolidated or semi-consolidated aquifers with ground water temperatures ranging from 54 to 72°F. In the Glaciated Central Region, sand and gravel aquifers offer some potential production, but alluvial valley aquifers would provide most of the possible shallow ground water, ranging in temperature from 44 to 58°F. The Glaciated Appalachians, Unglaciated Appalachians, and Unglaciated Central Region show sparse areas of shallow ground water, which appears to be confined to particular river valleys at temperatures from 44 to 70°F. The High Plains region shows excellent potential for both unconsolidated and semi-consolidated aquifers and alluvial valley aquifers, with ground water temperatures from 54 to 68°F. The Colorado Plateau, as well as the Columbia Lava Plateau, are two regions which both show sparse shallow ground water potential; however, both of these regions possess productive deep aquifers, many with a distinct geothermal character. The Western

Mountain Ranges and the Alluvial Basins appear to have an varied distribution of shallow ground water sources, most of which are of the unconsolidated and semi-consolidated variety, but many of these small sources are collocated with the more populated regions of the west. Ground water temperatures in these two regions average between 48 and 74°F.

Upon comparison of Figures 3, 4, and 6, ground water resources and temperatures display a good correlation with densely populated areas where heating and cooling needs are greatest. The Gulf States through the Mississippi Valley northward along the Atlantic Costal area are all favorable regions for ground water heat pump use along with the Ohio River Valley and portions of the Great Lakes Region. In the western U.S., the major populations of Oregon, Washington, California, and Arizona coincide with potential ground water resources for heat pump use.

RECOMMENDATIONS AND CONCLUSIONS

Upon examination of regions with viable sources for ground water heat pumps (Figure 4) in conjunction with generalized population densities (Figure 6) from the 1990 United States Census, a distinct correlation between shallow ground water sources and population centers is evident, particularly in the eastern and central United States. This correlation enhances the viability of ground source heat pumps as a readily available alternative to conventional heat pumps for both individuals and industry.

Ground water and earth-coupled heat pumps have the potential to become a highly-efficient, low-cost method of providing heating and cooling to private and commercial interests in the United States. To make this technology available to consumers on a large scale, it first must be demonstrated to the interested parties -- utilities, manufactures, and possible manufactures of ground-source heat pumps -- that the ground water resource exists on a broad scale and that the technology is economically viable and attractive.

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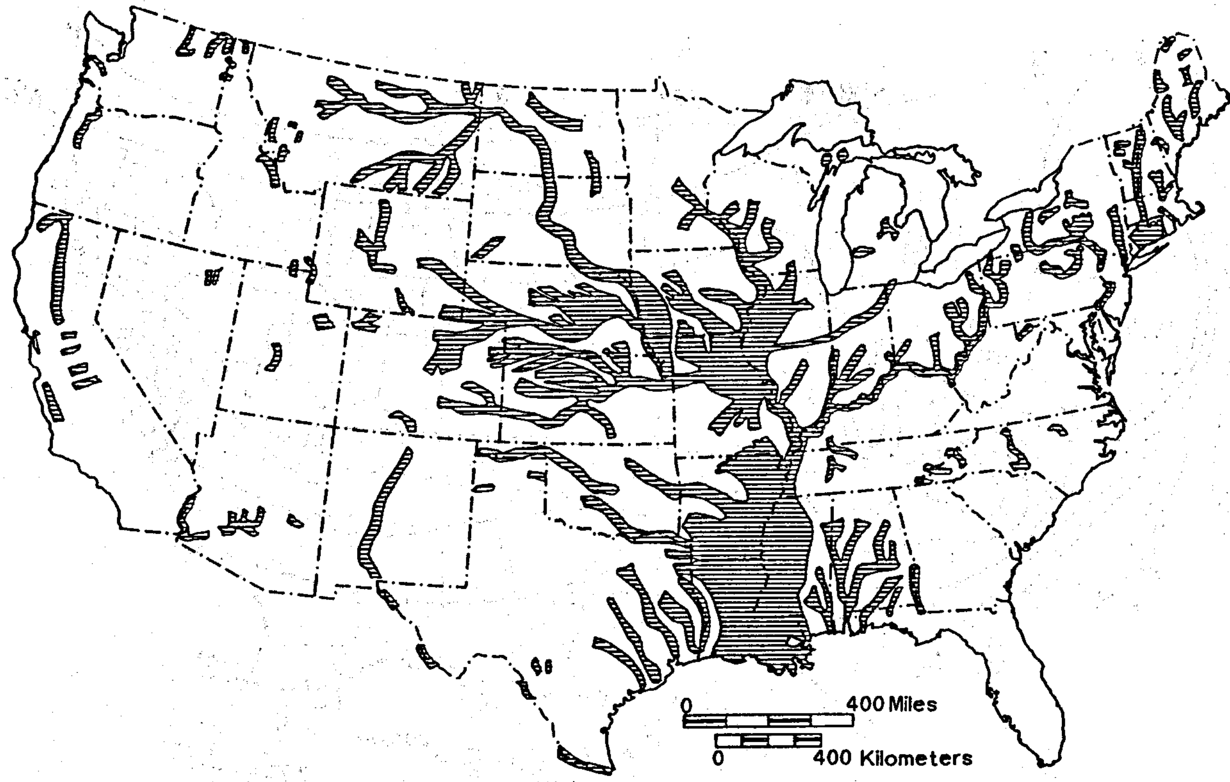

Figure 1. Shallow aquifers associated with alluvial valleys (Modified from Heath, 1984).

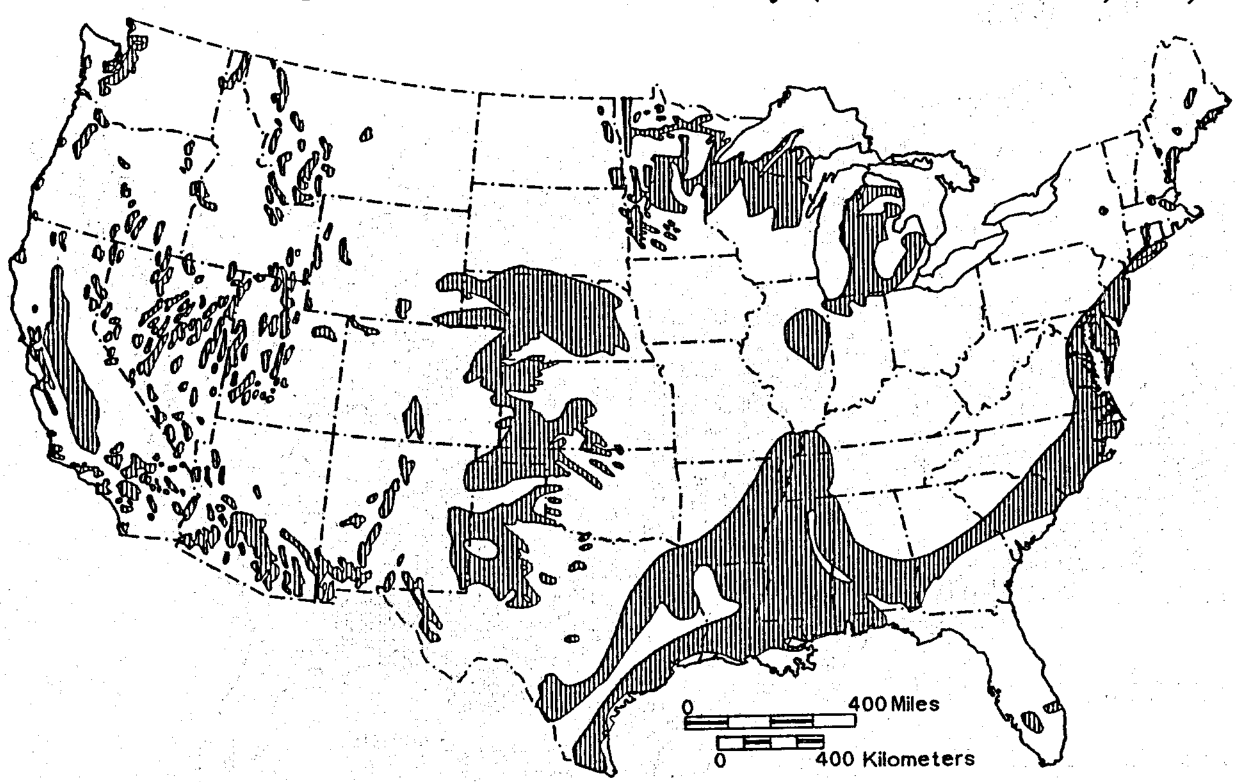

Figure 2. Unconsolidated and semi-consolidated sedimentary deposits of the United States (Modified from Heath, 1984).

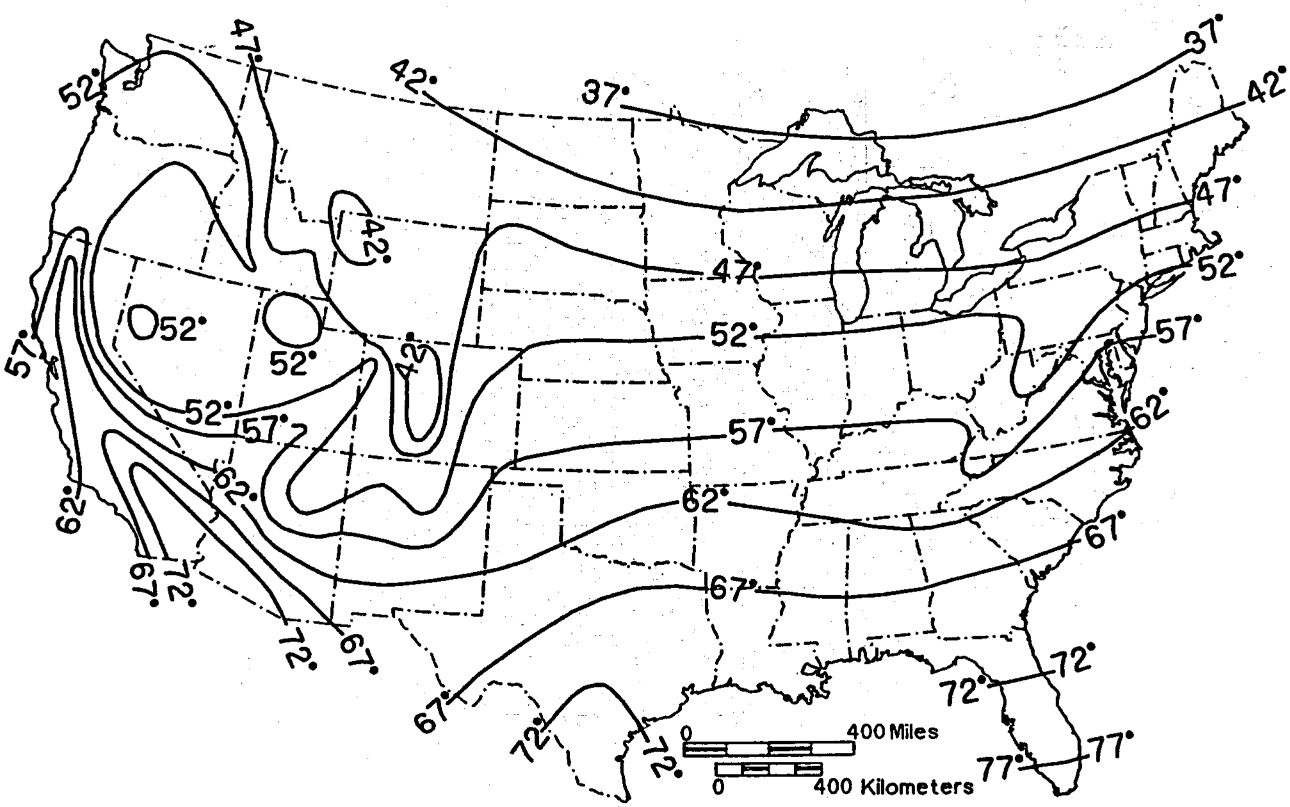

Figure 3. Ground water temperatures from depths of 50 feet to 150 feet (Modified from Hart, 1986).

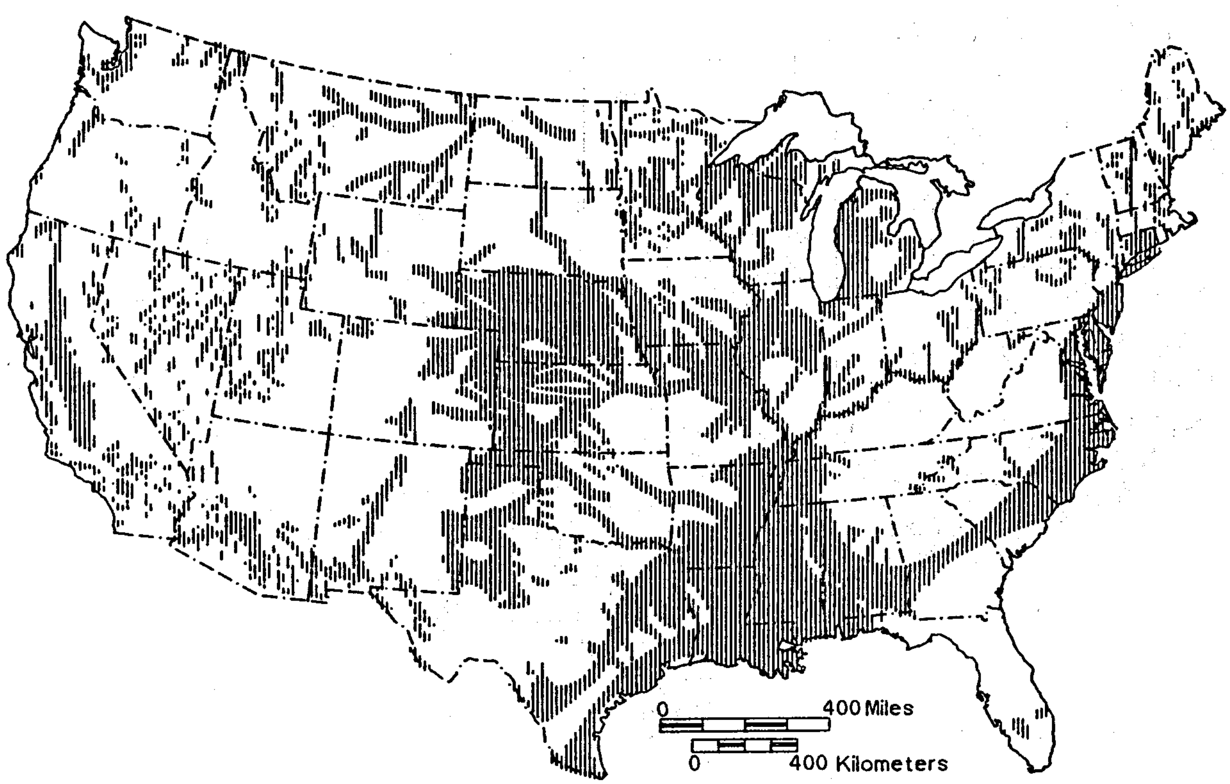

Figure 4. Inferred shallow (100 feet to 200 feet) ground water areas of the United States.

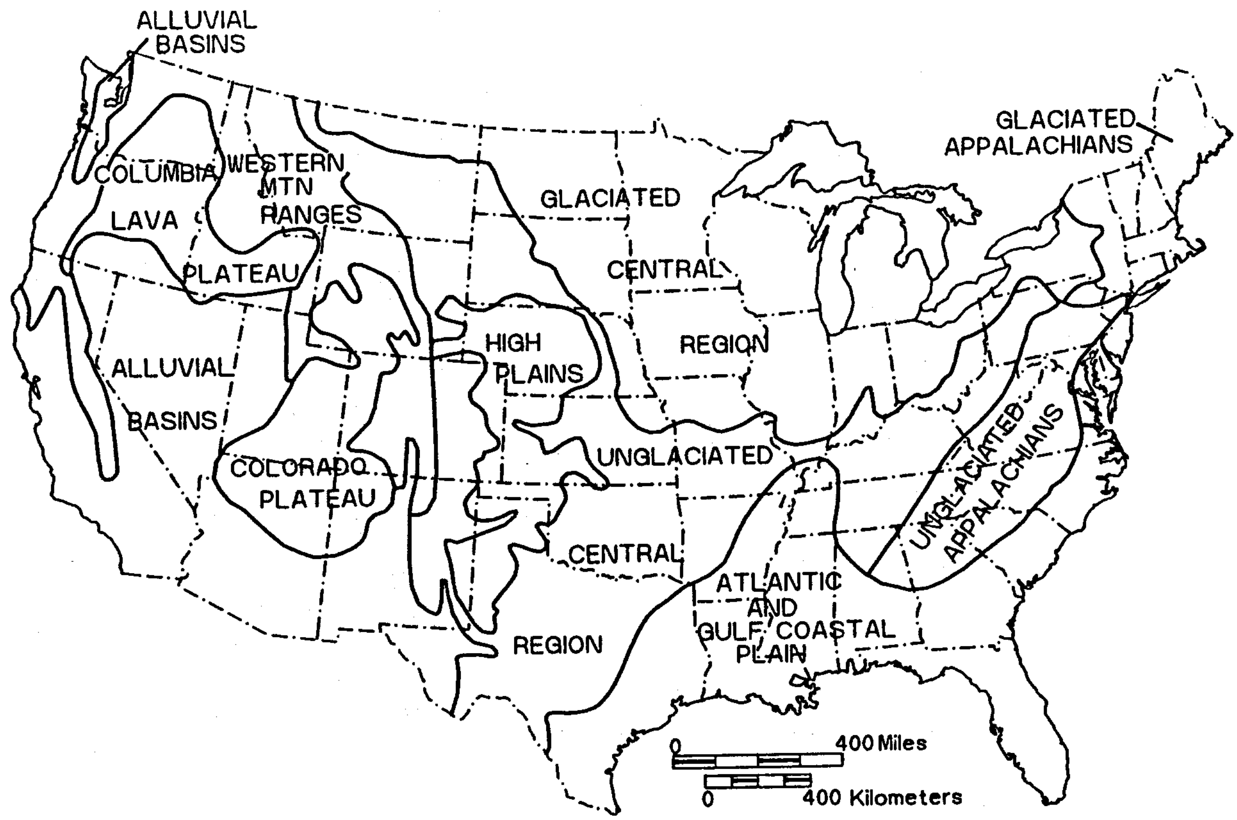

Figure 5. Ground water regions of the United States (From Thomas, 1952).

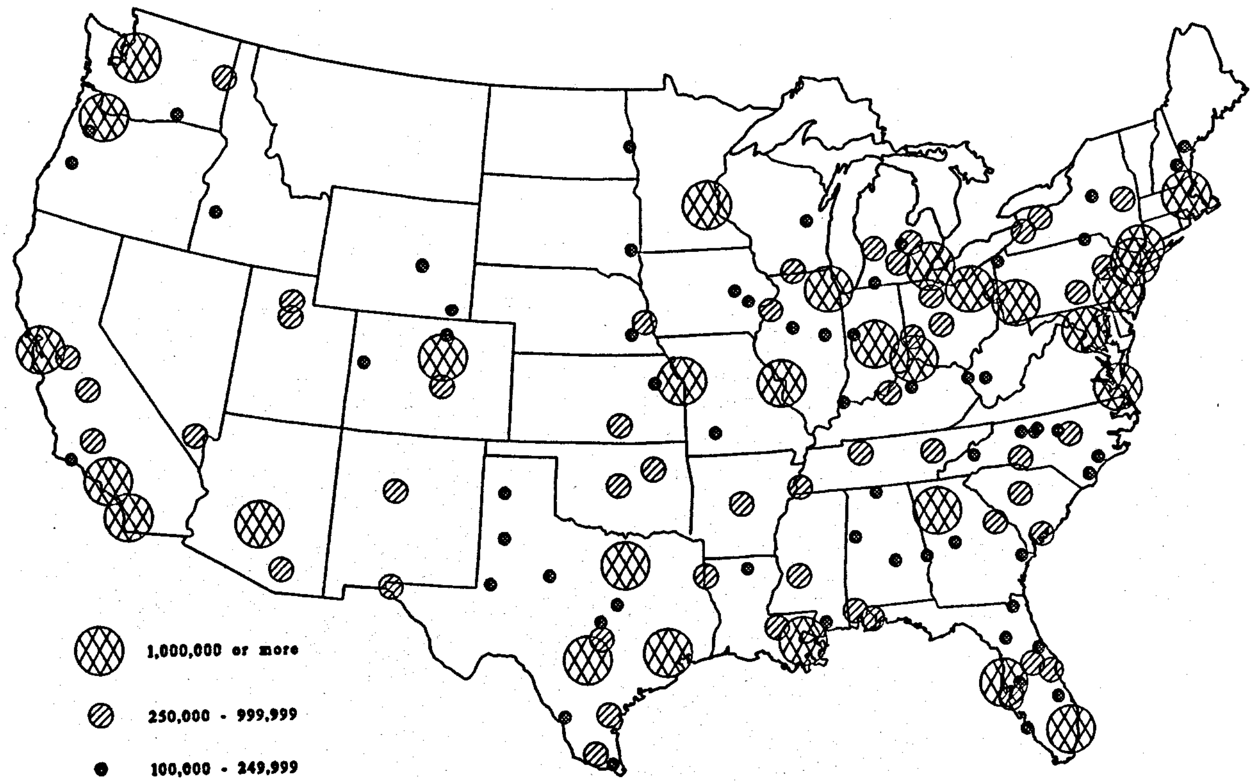

Figure 6. Selected 1990 population densities for the continental United States (Modified from Mattson, 1992).

Session 7:
Technology Transfer

Chairperson:
Dan Sanchez,
Albuquerque Operations Office,
U. S. Department of Energy

TECHNOLOGY TRANSFER
Session Overview

Dan A. Sanchez
Albuquerque Operations Office
U.S. Department of Energy

In the past, the results of high-tech research and development at DOE facilities have not been easily or often transferred to the private sector. Recognizing a growing need to bolster the United State's competitiveness in the world industrial market-place, Congress passed the National Competitiveness Technology Transfer Act in 1989, establishing a legal framework for the Department of Energy's laboratories and facilities to enter into a diversity of partnerships with U.S. industry, therefore enabling them to share their expertise.

The United States is challenged with securing reliable and abundant energy sources while at the same time developing a cleaner environment in which the efficient use of energy results in higher profits and less pollution. Meeting this challenge involves the objective of building a stronger, more competitive private sector which will be able to maintain U.S. leadership in critical world markets.

Technology Transfer is one of the primary missions of DOE. We seek to provide added benefits to the American people, and to promote economic enhancement and industrial competitiveness, through partnerships that build on key research areas such as Geothermal Energy Technologies.

Presentation highlights are summarized below:

APPLICATIONS OF BIOCHEMICAL PROCESSES IN GEOTHERMAL AND OTHER INDUSTRIES This topic was presented by Eugene Premuzic, Deputy Division Head, Biosystems and Process Sciences Division, Department of Applied Science, Brookhaven National Laboratory and Professor at Long Island University. Laboratory studies aimed at the development of economically and technically feasible, and environmentally acceptable technology for the disposal of geothermal sludges have led to the development of biochemical processes which meet the above conditions. A pilot-scale plant has been constructed and used to identify process variables and optimize processing conditions. The total process is flexible and can be used in several modes of operation which include (1) solubilization and removal of many metals, including radionuclides, from brines and sludges; (2) selective removal of a few metals; (3) concentration of metals; (4) recovery of metals; and (5) recovery of salts. The end product is a silica-type material which meets regulatory requirements, while the aqueous phase meets drinking water standards and can be reinjected and/or used for irrigation. Preliminary engineering studies of the metal and salt recovery technologies have indicated that significant cost benefits could be obtained by means of combined processing.

HOT DRY ROCK - A CLIMATE CHANGE ACTION OPPORTUNITY FOR INDUSTRY

David Duchane, HDR Program Manager of Los Alamos National Laboratory presented the current status of the HDR site at Fenton Hill, NM and an upcoming commercialization opportunity. This HDR pilot facility was completely automated and routine operations were carried out with virtually no human intervention, indicating the potential for low operating overhead in future commercial HDR plants. The benign geochemistry of the circulating fluid as well as the repair record during operations provided positive evidence that maintenance of HDR facilities should not pose major problems with regard to either cost or downtime. Finally, short experiments with modified operating cycles and reservoir modeling studies conducted in conjunction with the testing showed that further improvements in the productivity of HDR systems should be achievable by the application of relatively straightforward engineering and operating procedures.

On the basis of these encouraging test results, DOE Albuquerque Operations Office issued a solicitation of private industry interest in the construction and operation of a HDR facility to produce and market energy from HDR resources. The proposed project will be industry-led but will involve government financial participation to reduce the capital risk. Hard figures on capital construction costs associated with the development of practical HDR plants will be developed as the plant is designed and built. The revenues generated from energy sales will pay for the operating costs and, hopefully, produce a profit for the developer of the facility. The stage will then be set for the full commercialization of HDR technology to help generate the large amount of clean power that will be required both in developed and rapidly developing countries as the 21st century unfolds.

USER FRIENDLY MODELS FOR CHEMICAL AND THERMOPHYSICAL PROPERTIES

John Weare, Professor of Chemistry at University of California, San Diego, presented his work associated with the chemistry of aqueous brines and associated gas phases. The objective of his Geothermal program is to improve the productivity of geothermal resources by providing modeling tools for predicting and mitigating chemical problems associated with the extraction of energy from geothermal brines. These easy to use models will provide reliable predictions of the behavior of a resource under arbitrary conditions, thereby providing operators, engineers and designers with the ability to rapidly analyze potential problems and test strategies for problem abatement and resource enhancement.

Recently, efforts have been made to improve the user friendliness of this program by developing a graphical interface. This interface allows potential users to input data without interference from formatting requirements. Input is readily accessible for review and correction. The options of the program are implemented by the selection of icons or by simple typed commands. The output is presented in a simple editor. These improvements have been implemented for the TEQUIL program. A similar interface will soon be developed for the GEOFLUIDS software.

APPLICATIONS OF BIOCHEMICAL PROCESSES IN GEOTHERMAL AND OTHER INDUSTRIES

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ABSTRACT

Laboratory studies aimed at the development of economically and technically feasible, and environmentally acceptable technology for the disposal of geothermal sludges and wastes have led to the development of biochemical processes which meet the above conditions. A pilot-scale plant has been constructed and used to identify process variables and optimize processing conditions. The total process is flexible and can be used in several modes of operation which include (1) solubilization and removal of many metals, including radionuclides, from brines and sludges; (2) selective removal of a few metals; (3) concentration of metals; (4) recovery of metals; and (5) recovery of salts. The end product is a silica-type material which meets regulatory requirements, while the aqueous phase meets drinking water standards and can be reinjected and/or used for irrigation. Preliminary engineering studies of the metal and salt recovery technologies have indicated that significant cost benefits could be obtained by means of combined processing. The emerging biochemical technology also has led to several spin-off applications. Particularly promising, are the applications in the treatment of fossil fuels such as upgrading of low grade heavy crudes and the downstream processing of crude oils. Recent accomplishments in the development of new biochemical technologies will be discussed in this paper.

BACKGROUND

Within the Hydrothermal-Energy Conversion R&D effort and as a part of the overall Renewable Geothermal Energy Research which is aimed at the development of economical geothermal resources production systems, the aim of the Advanced Biochemical Processes for Geothermal Brines effort at Brookhaven National Laboratory (BNL) is the development of economic and environmentally acceptable methods for disposal of geothermal wastes and conversion of by-products to useful forms. It is known that microorganisms can interact with metals by means of several mechanisms such as surface adsorption, oxidization, reduction, solubilization and/or precipitation. These mechanisms served as a basis for the development of a technology which allows to use biochemical processes for removal and concentration of toxic metals present in the wastes converting them into environmentally and regulatory acceptable byproducts. A number of process variables have been identified which range from reactor size and co-processing to recycling of biocatalysts[1-4]. Optimization of parameters which influence these variables has resulted in fast kinetics of metal removal, i.e., rates of better than 80% in 25 hours or less at a pH of 1-2, and temperatures of up to 50-55°C. Because of corrosive conditions, the temperature-acidity conditions, for example, are just one of the several process parameters that must be considered in the design of bioreactors and processing streams. Further, different types of wastes have to be also considered. There are circumstances in which one is dealing with large quantities of sludges (such as those produced at a rate of 5000 lbs/h) consisting of predominantly benign silica containing traces of toxic and valuable metals to waste residues containing only one or two metals, such as arsenic and mercury. Toxic and valuable metals are present in small, however regulated, quantities. Biochemical methods are particularly suitable for handling of such large quantities containing low concentrations of contaminant. On an annual basis, accumulation of such wastes can become a valuable metals resource (e.g., silver, gold, etc.) and may justify combined "detoxification" and "valuable metals recovery" processes. In addition, the brines themselves are a resource of commercial products such as potassium chloride. It is to be emphasized that we are dealing with unique scenarios in which a technology is being developed and applied to satisfy regulatory requirements. However, the cost of such technology can be offset by combining it with processes which produce income generating by-products. Given such circumstances, recovery of some metals and salts may become an attractive possibility. Some of these possibilities will be discussed in this paper. In addition to Brookhaven's studies of biochemical processes which may lead to novel applications in industries associated with power and energy production, the geothermal waste processing technology has led to several spin-offs. Recent studies have shown that applications of biochemical processes in treatment of crude oils and oil products are feasible, particularly in such areas as enhanced oil recovery, upgrading of heavy crude oils, downstream processes and refining, and coal modifications 1[9,10]. Some of these applications will also be briefly discussed.

RESULTS AND DISCUSSION

Biochemical technology for the treatment of geothermal sludges, brines, and wastes depends on several process variables, such as tank size, agitation, pH, temperature, recycling, and others. These have been discussed in detail elsewhere[1-4] and will not be dealt with here. In this discussion, particular attention will be paid to the production of biocatalysts, integration with the total process and scenarios dealing with the combination of several processes.

In the design of a total biochemical process, the cost of the production of the biocatalysts has to be factored in. The rates of production of different biocatalysts vary, hence the yields per unit volume also vary. These variables have to be considered and the biocatalyst production units designed in such a manner that the rates and yields satisfy the input into the bioreactor needed to process the geothermal sludge under optimum operating conditions. In this discussion, only block diagrams and total cost estimates/requirements will be used. The treatment of geothermal brines requires two types of biocatalysts: one whose rate of production is fast, designated as Biocatalyst 1, and another whose rate of production is slow, designated as Biocatalyst 2. Thus, in order to meet the requirements for a continuous treatment of geothermal sludge at capacity of 5130 lb/h and an equal mix of Biocatalyst 1 and 2, an input of biocatalysts at a rate of 1 m^3/h (=250 gal/h) of each is required. Significant cost variations are associated with the production of biocatalysts at rates required by the processing conditions. There are several factors that influence the costs. These include: (1) Slow rate of production which requires large volume reactors and holding tanks. For fast rates of production, the opposite holds; (2) Cost estimates have to factor in whether plant space and utilities (e.g., power, water, etc.) are in place; and (3) Relative concentration of biocatalysts.

All of the data presented describing cost calculations and process block diagrams were produced by a computer program developed at BNL and published data[5,6]. "Tons" in all calculations are metric. Requirements for a 250 gal/h production are shown in Figures 1 and 2, and meet the input needs for a total process shown in Figure 3. Each of the processes shown in Figures 1 and 2 and process streams shown in Figure 3, can be further optimized leading to significant overall cost savings as shown in Table 1. Optimization involves construction, materials, biocatalyst ratios, and recycling.

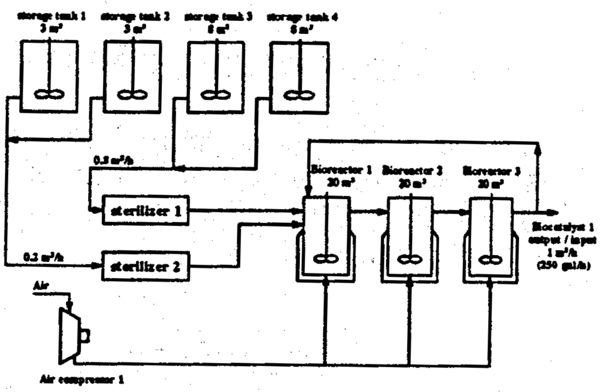

Figure 1. Process diagram for the production of Biocatalyst 1 at a rate of 250 gal/h.

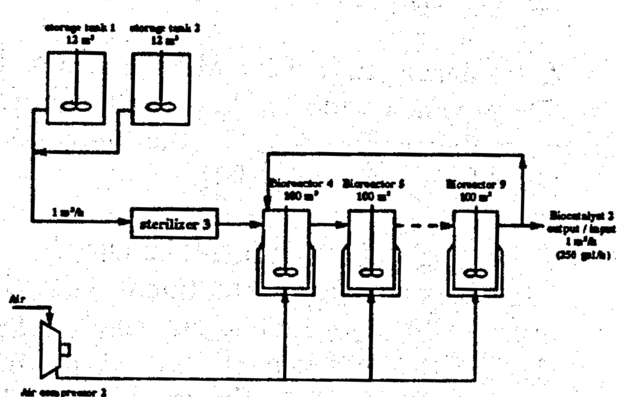

Figure 2. Process diagram for the production of Biocatalyst 2 at a rate of 250 gal/h.

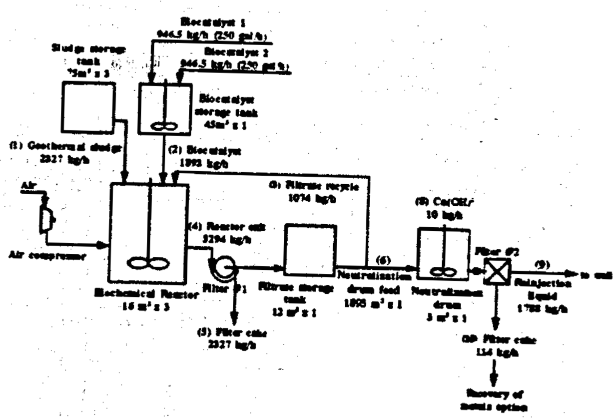

Figure 3. Total biochemical process for the treatment of geothermal sludge produced at 5130 lb/h.

Additional cost-saving, as well as revenue generating scenarios, have also been explored. For example, in Figure 4, an integrated geothermal sludge/brine process is shown in which the waste becomes a commercial resource by combining detoxification steps with sodium chloride, potassium chloride, and gold recovery processes. The stream concentrations given in Figure 4 are based on published data[7]. The metal recovery is based on an absorption process[8] and serves only as an example because other valuable metals may be extracted at this stage. The waste brine prior to reinjection into the crude, can be further treated using several possible processes for additional valuable metal recovery. It is to be noted, that the biochemical processes and applications scenarios are flexible and can be modified in a variety of ways to make the total technology particularly suitable to a set of field conditions. A plausible cost-processing scenario is shown in Table 2. In this version, a detoxification and potash producing plant operating under optimum conditions, is envisioned. Using published figures[6,7], the total process may lead to an additional net gain of over five million dollars for a 50 MW plant.

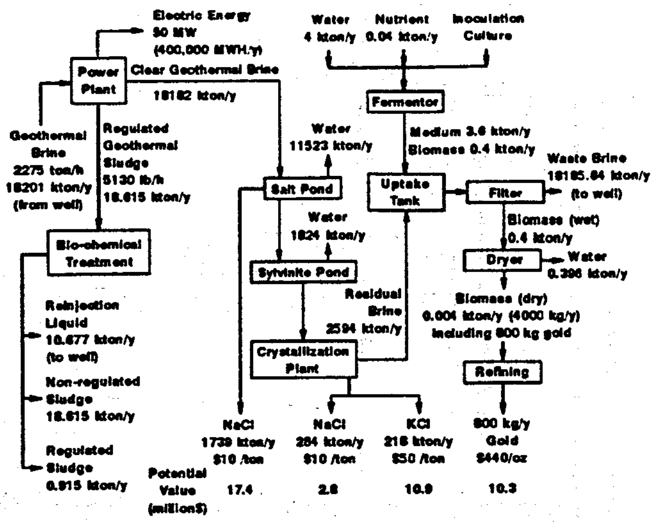

Figure 4. Biochemical processing of geothermal sludge and brine. Combined processes for (1) sludge and brine detoxification, (2) salt recovery, and (3) gold recovery.

The results discussed in the preceding paragraphs are descriptive of cost efficient and environmentally acceptable biochemical processing of geothermal sludges. The technical information currently in hand is being projected to field applications and full-scale trials. The promise of this novel biochemical technology has led to variations of the base technology. These modifications have led to technologies applicable in fossil fuel processing[9], including enhanced oil recovery, enrichment in lighter hydrocarbons of heavy crudes, and upgrading of heavy crude oils by biochemical alteration of organosulfur and organometallic species present in crude oils. The former allows to use high sulfur crude oils of low rank as feed stock and biochemically produce an economically attractive oil product[10]. Additional applications in downstream processing have also been defined, such as for example, extension of catalysts operating efficiency and others.

CONCLUSIONS

1. Biochemical technology for geothermal sludges is cost efficient and environmentally acceptable.

2. Biochemical processing is flexible and adaptable to various feedstocks.

3. Biochemical processing can be integrated with other technologies.

4. The combination of technologies enables the conversion of geothermal waste stream into usable resources.

ACKNOWLEDGMENTS

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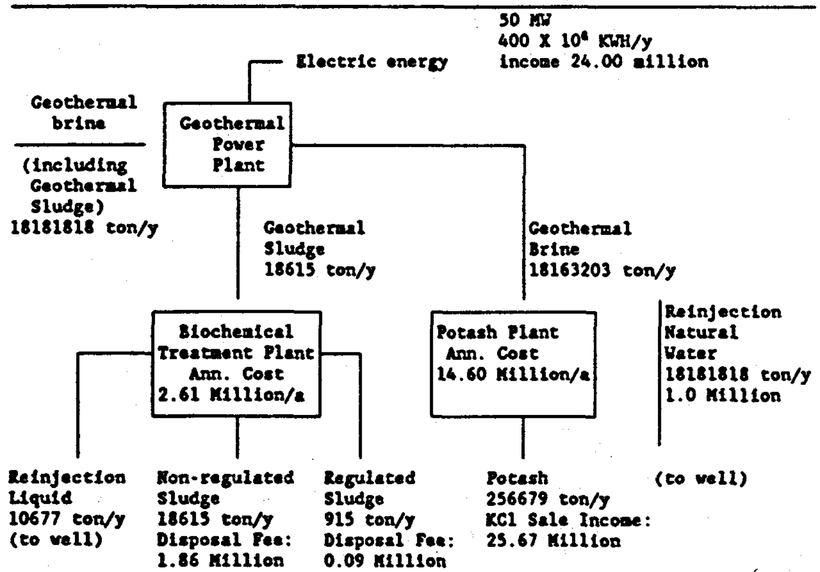
Table 1. Optimization of Biocatalyst Mix: The Effects on the Total Bioprocess Costs Per Metric Ton of Sludge

	*BC1:BC2 250 gal/h: 250 gal/h	BC1:BC2 425 gal/h: 75 gal/h	BC1:BC2 106.25 gal/h: 18.75 gal/h
BC1			
Capital Cost (CGR)	1,838,000	2,556,000	1,196,000
Annual Treatment Fee	1,097,000	1,778,000	820,000
Unit Treatment Fee ($/metric ton)	145	138	255
BC2			
Capital Cost (CGR)	7,017,000	2,573,000	1,002,000
Annual Treatment Fee	3,683,000	1,687,000	736,000
Unit Treatment Fee ($/metric ton)	486	743	1,298
BC1 + BC2			
Capital Cost (CGR)	8,855,000	5,129,000	2,199,000
Annual Treatment Fee	4,449,000	3,466,000	1,556,000
Unit Treatment Fee ($/metric ton)	316	229	411
Total Bioprocess Costs Including Biocatalyst Production			
Capital Cost (CGR)	10,195,000	6,493,000	3,415,000
Annual Treatment Fee	5,882,000	4,578,000	2,614,000
Unit Treatment Fee ($/metric ton sludge)	316	246	140

*BC = Biocatalyst

Table 2. Total Biochemical Process Cost Estimates Including Potash Plant Option Under Optimized Conditions



KCl Sale Income: 25.67 Million/y

Expenses:		
	Biochemical Treatment Fee	2.61 Million/y
	Nonregulated Sludge Disposal Fee	1.86
	Regulated Sludge Disposal Fee	0.09
	Potash Production Fee	14.60
	Natural Water for Reinjection	1.00
	Total Expenses	20.16/y

Balance: 25.67 - 20.16 = 5.51 Million/y Gain

HOT DRY ROCK-A CLIMATE CHANGE ACTION OPPORTUNITY FOR INDUSTRY

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Abstract

Geothermal resources in the form of heat found in rock that is hot but is not in contact with sufficient mobile fluid to transport that heat to the surface are a large, as yet virtually unexploited, source of clean energy. The technology to extract useful amounts of energy from this ubiquitous hot dry rock (HDR) geothermal resource has been under development for more than twenty years. During the last two years, flow testing at the Fenton Hill HDR pilot facility in New Mexico has answered many of the questions about the viability of HDR heat mining. While the most important issue of thermal longevity of the artificial geothermal reservoir that is the heart of an HDR energy system was not fully resolved, the test results provided good reasons to be optimistic that such reservoirs can have long lifetimes. No decline was observed in the temperature of the fluid produced during the relatively short test period and tracer testing indicated that the reservoir may be thermally self sustaining. In addition, water consumption during the circulation test was reduced to very low levels, the production of significant excess energy over that required simply to operate the system was verified, and routine energy production with virtually no emissions to the environment, except waste heat, was demonstrated.

The HDR pilot facility was completely automated and routine operations were carried out with virtually no human intervention, indicating the potential for low operating overhead in future commercial HDR plants. The benign geochemistry of the circulating fluid as well as the repair record during operations provided positive evidence that maintenance of HDR facilities should not pose major problems with regard to either cost or downtime. Finally, short experiments with modified operating cycles and reservoir modeling studies conducted in conjunction with the testing showed that further improvements in the productivity of HDR systems should be achievable by the application of relatively straightforward engineering and operating procedures.

On the basis of these encouraging test results, the Department of Energy issued a solicitation of private industry interest in the construction and operation of an HDR facility to produce and market energy from HDR resources. The proposed project will be industry-led but will involve government financial participation to reduce the capital risk. Hard figures on capital construction costs associated with the development of practical HDR plants will be developed as the plant is designed and built. The revenues generated from energy sales will pay for the operating costs and, hopefully, produce a profit for the developer of the facility. The stage will then be set for the full commercialization of HDR technology to help generate the large amount of clean power that will be required both in developed and rapidly developing countries as the 21st century unfolds.

Background

Geothermal resources are widely recognized as clean sources of energy. Typical geothermal plants generate far lower quantities of carbon dioxide, sulfur dioxide and oxides of nitrogen per unit of energy produced than any fossil-based energy facilities including those powered by natural gas. Unfortunately, conventional geothermal resources of steam and hot water are limited in both absolute quantity and geographical distribution. These hydrothermal resources, however, constitute but a small fraction of the total geothermal resource base. An almost unlimited amount of geothermal energy lies stored in rock that is hot but is not in contact with a natural source of mobile fluid to transfer that heat to the surface for use by man. Development of this hot dry rock (HDR) resource presents an opportunity for the geothermal energy industry to make a major contribution to the mitigation of climate change while at the same time building a large and profitable energy business.

The technology to extract energy at useful rates from the vast and ubiquitous HDR resource has been under development for the past 22 years. The concept upon which all l HDR development work has been based originated in the early 1970's and was disclosed in a patent, now expired, issued to the Los Alamos National Laboratory in 1974 (Potter, et al). A small HDR reservoir was created at Fenton Hill, NM during 1974-1978 and operated intermittently during 1978-1980 to prove the scientific feasibility of extracting energy from HDR. During 1980-1986, a larger, deeper, and hotter HDR reservoir was developed at Fenton Hill. Between 1987 and 1991, a surface plant, designed to power-industry standards and capable of extended operation, was constructed and mated to the large HDR reservoir. Flow testing of this Phase II HDR system was conducted during 1991-1993. The results of that flow testing have demonstrated the potential for HDR to be a practical source of geothermal energy. These results, as well as related work in modeling the behavior of the Fenton Hill HDR reservoir, are described in some detail below.

Recent Flow Testing at Fenton Hill

The Long-Term Flow Testing Program

The goal of the long-term flow test (LTFT) program at Fenton Hill was to demonstrate that HDR reservoirs could be operated on a continuous basis to produce useful amounts of energy over an extended period of time. In the process of conducting this test, answers were sought to questions involving the expected thermal lifetime of HDR reservoirs, water consumption, operating and maintenance costs, and the geophysical, geochemical, and environmental effects of long-term operation of an HDR system.

As a result of intensive discussions with the HDR Program Industrial Advisory Group, the LTFT was designed to simulate as closely as possible the conditions under which a commercial HDR power plant might operate. The pressure under which water was pumped into the injection wellbore was adjusted to the highest level that could be maintained without leading to expansion of the reservoir volume, as indicated by the onset of microseismic events and a very high rate of water consumption. Experience had shown that, for the Fenton Hill reservoir, this pressure was just under 27.5 MPa (4,000 psi).

A pressure of 9.7 MPa (1400 psi) was typically maintained on the production wellhead during steady-state circulation in order to prop open, by means of this imposed backpressure, the fluid carrying joints in the relatively low pressure region of the reservoir immediately adjacent to the production wellbore. The system pressure was reduced to about 4.8 MPa (700 psi) through a control valve at the outlet of the production wellhead and this pressure was maintained until the water was returned to the injection pump for repressurization and reinjection into the reservoir. The plant was computer-controlled, with fluid circulation maintained continuously on a 24-hour-a-day basis under these constant operating conditions. For much of the test period, the facility was manned only during the daylight hours. On a number of occasions, usually as a result of power failures caused by local weather conditions, the plant went into an automatic shutdown mode. In every such instance, the computer control system performed flawlessly.

Important system parameters such as pressure, temperature, and flow rate were monitored continuously. Measurements of the geochemistry of the circulating fluid were made several times a week. Diagnostic procedures such as production-well temperature logging and tracer analyses were implemented every few weeks or at critical junctures in the test program.

Fluid circulation began at the Fenton Hill HDR plant on April 8, 1992 and continued with only minor interruptions for 112 days. Then, the first phase of testing was terminated when leaks developed in both diesel-powered, reciprocal injection pumps within a two-day period. A subsequent investigation showed that the leaks were due to hairline cracks in the cylinder blocks of the pumps. The fatigue cracks appear to have been initiated at points of stress concentration in the stainless steel alloy from which the blocks were cast. The stress concentrations in turn arose from phase separation of the alloy as the blocks were cooled after casting. Although the pump failures were not related to HDR technology, the ensuing lapse in testing while suitable replacement pumping capacity was being evaluated, procured, and installed, was a serious setback to the LTFT effort.

By mid-February 1993, a replacement pump was installed at Fenton Hill and a second continuous phase of flow testing was begun. The new pump was a leased centrifugal unit powered by electricity. Once the appropriate modifications to the electric power supply at the site had been implemented, it proved to be highly reliable. The second continuous test period ran for 55 days until mid-April 1993, when the available funding was exhausted. Typical operating parameters during the two steady-state test phases are summarized in Table 1.

TABLE 1
LTFT OPERATING DATA

	July 21-29 1992	April 12-15 1993
Injection		
Pressure, psi (mpa)	3958 (27.3)	3965 (27.3)
Flow, gpm (l/s)	107 (6.8)	103 (6,5)
Temperature, °F(°C)	66 (19)	72 (22)
Production		
Pressure, psi (mpa)	1400 (9.7)	1400 (9.7)
Flow, gpm (l/s)	89.7 (5.7)	90.5 (5.7)
Temperature, °F(°C)	361 (183)	363 (184)
Water Consumption		
Rate, gpm (l/s)	12.5(0.79)	7.3 (0.46)
% of Ingected Volume	11.7	7.0

Results of Recent Steady State Flow Testing

Substantial new information was generated during the LTFT in regard to a number of important aspects of HDR technology. The most significant findings are discussed individually below:

Thermal Stability: The data of Table 1 indicate that there was no decline in the temperature of the fluid produced at the surface over the course of the flow-test period. At several points during testing, the production temperature was measured at depth by conducting a wire-line log of the production well while circulation was maintained. Figure 1 compares the temperature profiles obtained from three such logs.

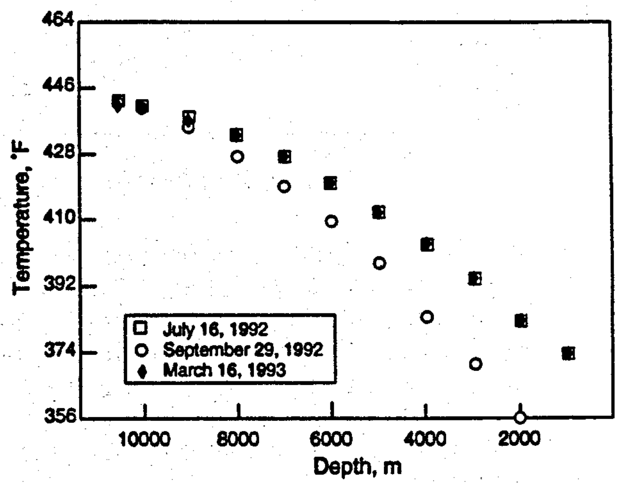


Figure 1. Temperature profiles obtained from logging runs during recent flow testing. The temperature remained constant at the deepest part of the wellbore but the thermal loss to the surrounding rock as the hot water traveled up the production wellbore was greater in September when the flow rate was lower.

In all cases, the temperature measured at 3.27 km (10,800 ft), the depth which marks the top of the reservoir, was essentially the same. The logs indicate that a significant amount of energy is lost to the surrounding rock as the water travels up the wellbore to the surface. This energy loss becomes progressively greater as the rate of flow declines. Thus, the log conducted in

September 1992, during a period of sub-optimal pumping and lower flow, shows the same temperature at depth as the other two logs, but a much lower temperature at the surface.

Tracer evidence provided even more encouraging data with regard to reservoir thermal stability. The results of a series of tracer tests conducted during the period of recent flow testing are presented in Figure 2.

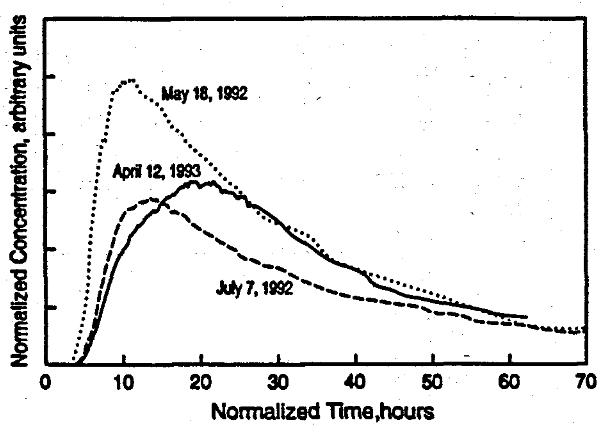


Figure 2. Results of tracer tests conducted during recent flow testing. The times to initial appearance of the tracer and to the point of maximum rate of tracer return became longer as shorter, ostensibly cooled, flow paths closed and longer, more circuitous flow paths through the reservoir rock developed.

Remarkably, the tracers took longer to appear at the production well as the testing proceeded. The time to the point of maximum tracer return also lengthened. In effect, the tracer material (and by implication the circulating water) was taking longer and longer to get through the hot rock reservoir, indicating that more of the fluid was traveling across the reservoir via longer flow pathways and the shortest, perhaps most rapidly cooled, flow paths were closing off. This is exactly the opposite of the typical behavior in which water, once having found a route through a medium, continually enlarges that pathway. The reason for this seemingly anomalous behavior has not been determined but it may be related to fluid viscosity increases in the cooled pathways. In any event, this tracer evidence strongly suggests that the reservoir is self-sustaining to at least some degree, since the flowing fluid is continually gaining access to new hot rock within the reservoir.

Water Consumption: The amount of water that is lost to the subsurface in operating an HDR facility is a major concern, especially in those regions such as the American west where water resources are scarce. Table 1 shows that water consumption averaged about 12% toward the end of the first continuous phase of the LTFT, but only 7% near the end of the second phase. The slow but steady decline in water consumption confirmed earlier static pressure testing results which indicated that water losses decline as the microcrack fabric of the rock at the periphery of the reservoir becomes saturated at any particular pressure level (Brown and Robinson 1990; Brown 1991).

Net Energy Production: Thermal energy was regularly produced during the LTFT at a rate of about 4 thermal MW. This is approximately 6.3 times the thermal energy content of the diesel fuel and electricity consumed in running the system during the first phase of the test. In other words, the heating value of the fuel used to operate the plant was increased by a factor of more than six by using it to pump geothermal energy to the surface rather than using it directly as a heat source.

Environmental Effects: Under normal operating conditions there were no emissions from the HDR pilot facility except waste heat. The dissolved gases in the circulating fluid remained at low and essentially constant levels throughout the test. The only gas present in significant amounts was carbon dioxide. At the concentration found in the geofluid, all the gases remained in solution at pressures in the range of 2 MPa (300 psi). Since the circulating system pressure was kept at 4.8 MPa (700 psi), the gases in the fluid remained in solution and were not released to the atmosphere.

One important gas often encountered in underground fluids is hydrogen sulfide. This extremely toxic compound is heavier than air and tends to settle in low spots if it is released. Although signs posted at the Fenton Hill HDR site warn of the potential danger from hydrogen sulfide and a number of automatic alarms would announce its presence at a level well below that at which it would present any danger, the concentration of hydrogen sulfide in the circulating fluid at Fenton Hill has always been extremely low (typically less than 1 ppm). Even in the event of an unexpected release to the atmosphere, the risk arising from this low level of hydrogen sulfide would be very small.

The dissolved solids found in the circulating fluid were generally those characteristic of normal slightly saline fluids, mostly sodium, magnesium , calcium, and chloride, but with small amount of other materials, such as silica and arsenic, which tend to be present in crystalline rock. At a total solids content of about 0.4%, the Fenton Hill fluid was nearly an order of magnitude less saline than the ocean which contains about 3% salt.

System Maintenance Issues: Except for the injection pump breakdown mentioned earlier in this article, no major maintenance problems were encountered during the flow test period. Based on the low and stable levels of dissolved gases and solids, the almost total absence of suspended solids, and the relatively neutral pH of the circulating water (always greater than 5), neither scaling or corrosion would be expected. A caliper log of the injection tubing was conducted in late 1993, several months after the flow test was terminated. In spite of the fact that the tubing had been installed nearly 10 years earlier, the walls showed no signs of deterioration or of excessive scale formation. In short, all the evidence at Fenton Hill indicates that facility maintenance should be relatively simple and inexpensive for HDR systems utilizing reservoirs created in hard, crystalline rock.

Results of Recent Cyclic Operations Testing

Observation of the pressure response on a number of occasions when circulation was halted by closing both well heads had indicated that most of the resistance to flow across the HDR reservoir was concentrated in the region of the reservoir near the production wellbore. Expressed another way, the majority of the pressure drop between the 27.3 MPa (3960 psi) injection pressure and the 9.7 MPa (1400 psi) production pressure applied during the LTFT occurred near the production wellbore. In concept, the production from the HDR reservoir therefore could be increased by periodically pressure dilating the joints near the production wellbore. This could be accomplished by closing the production well briefly, and thereby causing the pressure on the joints in the vicinity of production well to increase toward the pressure applied at the injection wellbore. If the joints were rapidly jacked open by this increased pressure, but they closed only slowly when the production well was reopened, it might be possible to obtain an overall increase in system productivity.

Near the end of the LTFT, a short experiment was conducted to test this idea (DuTeau 1993). It entailed brief shut-ins of the production wellbore once every 24 hours for three consecutive days. Figure 3 shows the production wellhead pressure and the production flow rate over the span of this short cyclic experiment.

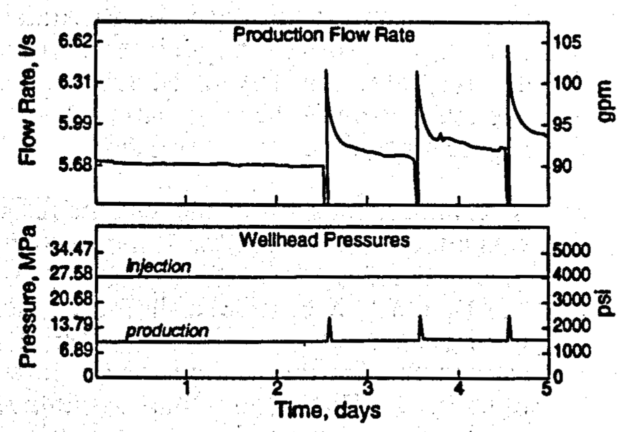


Figure 3. Injection and production wellhead pressures and flow rates during the first cyclic test at the close of the LTFT.

As discussed above, the pressure peak at the production well during each short shut in appeared to jack open the reservoir joints in the region of the production wellbore The very high rate of production immediately following each shut-in period reflected both the release of pent-up fluid and the opened joints. The production rate declined rapidly at first as the surplus water was released, and then more slowly as the joints continued to close. After 24 hours, however, the production rate was still higher than it had been just prior to the shutdown. As shown in Figure 4, the total daily energy production increased by about 2% during each day of the test.

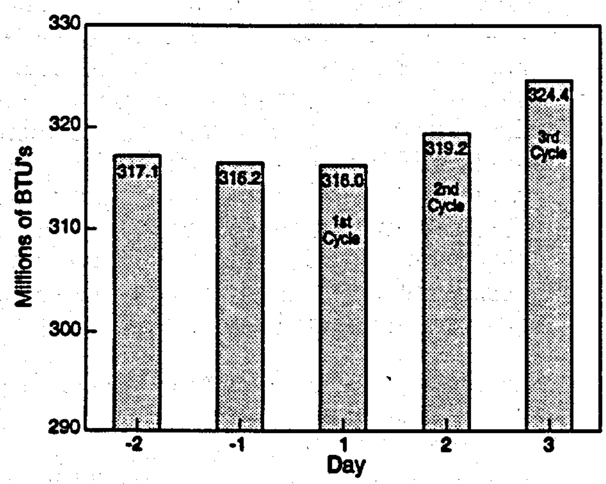


Figure 4. Total daily energy production just prior to- and during the first cyclic test at the close of the LTFT.

Had the test gone on longer, these daily rate increases would not have been maintained, but this short experiment clearly demonstrated that the long-term production decline evident in the early part of the data of Figure 4 could be easily reversed.

In a subsequent short cyclic test, the reservoir was alternately shut in for 16 hours and then operated for 8 hours (Brown 1993; Brown 1994). On May 6, 1993, a short time into the third production cycle of this experiment, a sudden and unexpected increase in flow was observed. Within less than a minute, the production flow rate increased nearly 48%. At this increased flow rate, the production temperature soon increased to over 190°C. Rather than continue the cyclic experiment, the system was brought into steady-state operation. Table 2 compares steady-state operating conditions a few days after the flow increase was observed to those of about a month earlier when phase II of the LTFT was still underway.

TABLE 2
Operating Data Before and After
Sudden Flow Increase of May 6, 1993

	May 13 1993	April 12-15 1993
Injection		
Pressure, psi (mpa)	3860 (26.6	3965 (27.3)
Flow, gpm (l/s)	130 (8.2)	103 (6,5)
Temperature,°F(°C)	75 (24)	72 (22)
Production		
Pressure, psi (mpa)	1400 (9.7)	1400 (9.7)
Flow, gpm (l/s)	122 (7.7)	90.5 (5.7)
Temperature,°F(°C)	374 (190)	363 (184)
Water Consumption		
Rate, gpm (l/s)	*	7.3 (0.46)
% of Ingected Volume	*	7.0

* Because of the Overpressurization during the 16-hour production shut-ins in early May, the apparent water consumption was less than zero (apparent net production of water) during the steady-state testing period following the sudden flow increase.

Note that although the production flow rate was much higher in May than in April, the injection pressure was lower. This was because the centrifugal injection pump could not maintain the maximum flow rate that was now possible in the altered reservoir. Unfortunately, funding limitations prevented testing of the altered reservoir beyond a few days. However, these dramatic results demonstrated that significant impedance reductions can be achieved by carefully designed pressure manipulations of HDR reservoirs.

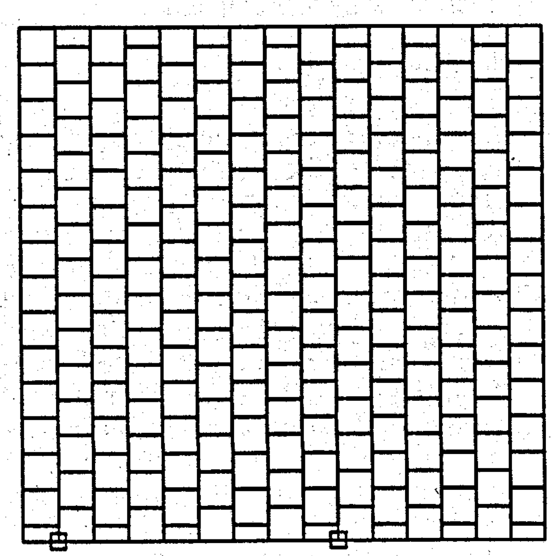
The two cyclic experiments discussed above highlight the potential for maximizing the productivity of HDR reservoirs by the studied manipulation of operating schedules. Further experiments of this sort would no doubt bring additional improvements in reservoir performance and a better understanding of HDR systems. The funding for such important testing is not currently available, but as the feasibility of HDR for practical energy production becomes established, these experiments may form the basis for further work to improve the productivity of HDR systems.

Reservoir Modeling

GEOCRACK Application and Modification

Progress continued this year in the application of the GEOCRACK Finite Element Model to the simulation of flow in the Fenton Hill HDR reservoir. Recent results have shown good agreement between observed and modeled flow conditions at several different injection and production pressures. Consideration of tracer results obtained during recent long-term flow testing have prompted the incorporation of random flow blockages in the model flow matrix. These blockages distribute the flow through a broader region of the matrix and result in what appear to be more realistic flow paths.

As an example, Figure 5a shows a typical rock-block/flow-path mesh used in the GEOCRACK Model. In this construction, the injection point is at the lower left and the production point is at the lower right of the diagram (this figure shows only one quadrant of the modeled volume). The flow paths for a simulation based on this mesh, with one-third of the flow pathways randomly blocked, are shown in Figure 5b.



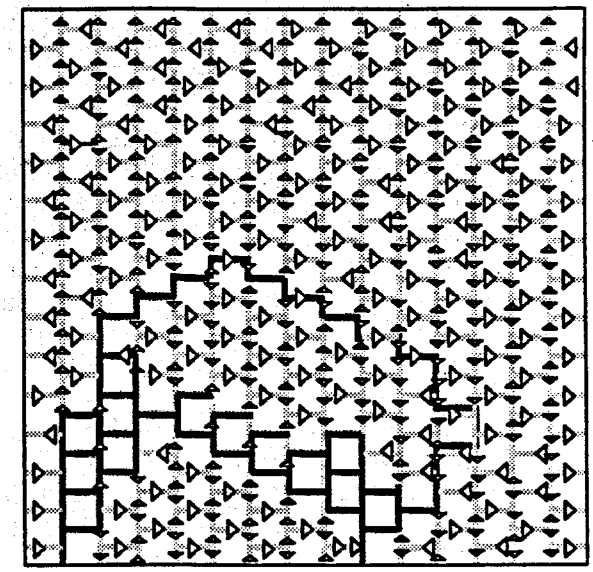


Figure 5. (a) A typical rock-block/flow-path mesh used in the GEOCRACK finite element HDR reservoir model. (b) Flow paths for a HDR flow simulation based on the GEOCRACK finite element mesh with one-third of the flow pathways randomly blocked.

The goal of these simulations is to construct a picture of the fluid flow which emulates the real conditions within the reservoir to a degree adequate to be of value in addressing important reservoir issues. These include engineering questions such as the optimum spacing and number of production and injection wells, as well as the effects of a wide variety of potential modes of reservoir operation on the productivity and longevity of HDR systems.

In tandem with the experimental results of recent flow testing, the GEOCRACK Model is providing some critical information about the HDR reservoir at Fenton Hill and, hopefully, HDR reservoirs in general. Initial observations include the following:

Most of the reservoir impedance occurs near the production well. Reducing only this near-wellbore impedance may greatly increase productivity. Likewise, increasing the distance between the injection and production wells may give access to significantly more hot rock with only a marginally deleterious effect on overall system impedance.

While a localized increase in permeability (reduction in impedance) in the vicinity of the production well may lead to an increase in production, this advantage may be partially lost since one effect may be to simply move this impedance barrier out to the boundaries of the increased-permeability zone.

There appears to be a limit to the maximum injection pressure that can applied before the pressure relief value of the production well is exceeded and reservoir growth ensues. A single production well at each end of the reservoir may thus not provide the optimum pressure sink. A line of kick-off wellbores positioned across the width of the lowest-stress direction of the reservoir zone may be required to provide the most effective pressure relief and permit the use of the highest possible injection pressures without continual reservoir expansion.

Summary

After about 22 years of research and development, recent testing has clearly demonstrated the potential of HDR technology to produce clean energy on a continuous, highly-automated basis. The environmental advantages claimed for HDR technology have been verified in actual practice, concerns about water consumption have largely been laid to rest, and significant excess energy production over that required to conduct the HDR operation has been demonstrated.

Because the total circulation time (about 8 months) was short compared to the total time that an HDR reservoir would have to be operated in order to justify construction of commercial power plants. The thermal longeuity of such deep HDR reservoirs was not fully demonstrated in recent testing. The data obtained, however, were extremely promising. The temperature of the produced fluid showed no decline over the span of the test and tracer results indicated increasing access to hot rock with time. Concerns about short-circuit pathways developing and thereby causing a rapid decline in the temperature of the produced fluid proved to be unfounded and, in fact, the shorter flow paths appeared to carry proportionately less fluid as testing proceeded.

Routine operation of the HDR pilot facility, often with no manpower on site, demonstrated that HDR plants can be automated to the same degree as conventional hydrothermal facilities and that operational labor costs should be low. Operating experience indicated that both routine and special maintenance procedures should be relatively simple and inexpensive. The benign water chemistry as well as plant equipment and component inspections indicated neither corrosion nor scaling as serious problems.

Limited cyclic testing showed the potential for maintaining and even increasing the production from such HDR reservoirs by the application of a variety of operating scenarios. Modeling based on actual test results has been applied to predict that significantly larger reservoirs can be created and operated without significantly increasing the pressures required (and thus the pumping costs) to circulate fluid through the system. In short, recent testing, while limited in some respects, has given every indication that it will be possible to operate HDR plants in a commercially viable manner.

Future Plans

In light of the recent encouraging operational test results, the greatest challenge to the implementation of HDR technology now appears to be in the area of capital costs related to the development of the underground system. To date, all HDR reservoirs created throughout the world have been conceived and developed as research facilities. In all cases, more attention was paid to the collection of scientific data and to assuring the provision for a variety of experimental procedures than to a rigorous control of the costs of building the facility. As a result, no hard data on the capital requirements for the construction of a commercial-grade HDR plant are available.

A number of studies have been conducted to estimate the costs of constructing HDR electricity plants. These have relied on a variety of assumptions in regard to overall plant size, resource quality, drilling and fracturing costs, surface plant design, conversion efficiency, and the cost of money. Results have therefore been highly variable ranging from about $1,200 to more than $6,000 per installed kilowatt (Pierce 1993; Tester and Herzog 1990). Capital costs for HDR projects will obviously be highly site- and project-specific, but developing a better basis for making even general estimations of capital-cost factors is extremely important to the future development of an HDR industry.

The primary objective of HDR Program activities during Fiscal Year 1994 will be to support the move toward an industry-led HDR effort to construct and operate a facility to produce and market power from HDR resources in the competitive energy market. In the process of developing such a facility, the important capital cost issues relevant to HDR will be addressed and documented. Subsequently, operational costs, which should be fully covered by revenues generated from the sale of the energy produced, will be verified in a practical setting and for a meaningful period of time.

As a first step in developing an industry-led HDR initiative, the U. S. Department of Energy issued a Notice of Program Interest in late Fiscal Year 1993 soliciting private industry input with regard to a joint industry-government HDR effort. The replies that have been received in response to this Notice will form the basis for the development of the industry-led project. The program envisioned may involve further work at the Fenton Hill HDR site or the development of a second domestic HDR facility at a new location.

The Fenton Hill HDR pilot facility will be maintained on a standby basis during 1994. However, limited low-cost testing is being carried out with the objective of obtaining answers to questions which private industry may deem important to the success of the industry-led HDR development effort. Scientific and engineering support activities are being directed toward reviewing, analyzing, and documenting the results of recent flow-testing is underway. Again, the focus of the effort is on providing the important data needed for the impending industry-led HDR initiative.

Hopefully, the HDR work during 1994 will help set the stage for early commercialization of HDR by U. S. industry and lead to U. S. dominance of the extremely large clean-energy market that will develop for HDR in the coming decade. The end result should be a significant contribution to the growth and stability of the domestic geothermal energy industry, as well as energy-independence, trade, and job-creation benefits for the U.S. economy as a whole.

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User Friendly Models for Chemical and Thermophysical Properties of Geothermal Fluids

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PROJECT OBJECTIVE

The objective of this program is to improve the productivity of geothermal resources by providing modeling tools for predicting and mitigating chemical problems associated with the extraction of energy from geothermal brines. These easy to use models will provide reliable predictions of the behavior of a resource (*e.g.*, scaling and breakout) under arbitrary conditions, thereby providing operators, engineers and designers with the ability to rapidly analyze potential problems and to test strategies for problem abatement and resource enhancement. Our project objective also includes effective communication with the geothermal industry in order to exchange ideas and transfer technology.

PROJECT APPROACH

In order to have the predictability required for geothermal applications, it is necessary to have highly accurate models of the chemical behavior and physical properties of the resource formation, working fluids and their interactions with associated minerals. Using recent developments in the chemistry of fluids and gases and with careful attention to parameterization, we have developed models that accurately reproduce the measured chemical behavior of brines (*e.g.*, scale formation), the solubility and liquid/vapor coexistence of gases, and other thermodynamic properties (*e.g.*, heat content). The models have been applied to well determined production situations with remarkable success. Our brine models handle the special problems of phase equilibrium prediction in complex mixtures, introduce a relatively low number of parameters and are highly accurate and flexible. Our gas modeling approach utilizes phenomenological equations, we have recently developed, which can reproduce PVT properties in both the liquid and gas phases, liquid/vapor coexistence and other useful thermodynamic functions.

USES OF A BRINE SIMULATION MODEL	
Exploration	• *Predict Scale Formation* • *Predict Gas Behavior* • *Predict Water Chemistry* • *Predict Recoverable Energy* • *Predict Evolution of Resource*
Plant Design	• *Predict Scale Formation* • *Predict Phase Separation* • *Simulate Chemical Treatments* • *Test Energy Optimization Strategies* • *Minimize Operations Costs* • *Support Laboratory Simulations*
Waste Treatment	• *Simulate Mineral Recovery Strategies* • *Predict Environmental Hazards* • *Simulate Reinjection Strategies*

There is a continuing effort to develop new phenomenologies by the first principles simulation of complex brines and gas phases and to incorporate these new phenomenologies in our models.

As the models are developed, they are included in an user-friendly application package called GEOTHERM which can be be loaded from disketts to PCs or Mackintosh computers. A user oriented graphical interface is being developed to facilitate the use of the software. Periodically, workshops are given in the use of these programs to treat problems of interest to the geothermal community (see Table 1). An instruction manual is updated as new technology is ready for application.

PROJECT STATUS

Background

Many of the most significant problems limiting the economical development of geothermal power are related to the chemical properties of the high temperature and high pressure brines from which the energy is extracted. The properties of these fluids and the dissolved gases which evolve from them are very difficult to predict. However, if the system is near equilibrium they can be calculated from the thermodynamic and physical properties of the system as summarized by the free energy, G. For brines, G is a complex function of the concentration of all the species in the phases present and the temperature. For brines G is a weak function of the pressure; however, for gas phases G varies with the pressure. All these variations must be accounted for in a successful phenomenology. By minimizing G subject to mass and charge balance constraints, the distribution of solids, gases and liquid phase species may be calculated.

We have developed highly accurate models incorporating phenomenological equations for the free energy of gas, liquid and solid phases. These equations are soundly based on theoretical results but contain parameters that must be established from binary and ternary experimental data. This is a difficult problem, but once the parameters have been evaluated the models can be applied to the much more complicated systems common in the energy production industry. We have demonstrated that these equations can accurately describe complex geothermal brine behavior to high concentration and high temperature (0° - 250°C). Our gas phase model of the CH_4–CO_2–H_2O system accurately predicts PVT and free energy behavior from 50 to 1000°C and from 0 to 1000 bars. The new model of the NH_3–H_2O system accurately predicts the phase equilibria and PVT properties from 0 to 1200 bars and 0 to 400°C. This model has application to naturally occurring gases as well as to power extraction cycles (see below). Most recently we have developed a model of the important CO_2–NaCl–H_2O system for temperatures from 300 to 1000°C and pressures from 0 to 1000 bars. This model can describe phase equilibria and PVT properties of this very complex system. It has many applications in fluid inclusion studies important to exploration and resource evaluation as well as in operations.

We emphasize that for chemical models to be useful for geothermal applications they must be both highly flexible (able to treat wide ranges of variables) and highly accurate, as well as easy to use. We believe that the GEOTHERM programs are the only models presently available that meet these demanding criteria.

Prior Research Results

The capabilities of the geothermal brine models we have developed to date are summarized in Table 2. These models will predict saturation ratios, scaling behavior, pH, formation porosity changes, gas breakout in production wells, and liquid/vapor compositions throughout various brine flow and heat extraction systems and during reinjection procedures.

Parameterization of the $CaCO_3$–SiO_2–$CaSO_4$–NaCl–CO_2–H–H_2O system and of the seawater system, Na–K–Ca–Mg–Cl–SO_4–H_2O, is complete to high temperature (0°C - 250°C) and to very high ionic strength. These models will treat all the major components of seawater-type brines in addition to the important carbonate, sulfate and silica scale-forming minerals and CO_2 solubility.

Our equations of state (EOS) for the $CH_4 - CO_2 - H_2O$, the NH_3–H_2O and the NaCl–CO_2–H_2O systems can predict behavior from the two phase region to the homogeneous region. We consider this to be a breakthrough in thermodynamic modeling of natural processes.

Model calculations compare remarkably well with both laboratory and field data. Our models typically retain the reliability of the experimental data on which they are based. For example, the present calcite and silica scaling model predicts all the laboratory data we could find for calcite, amorphous silica, and CO_2 solubility for a temperature range from 0°-250°C within the accuracy of the measurements. The EOS also predict the compositions of coexisting gas and liquid phases within experimental error. Our models, therefore, provide an effective means of summarizing, comparing and validating the brine chemistry data presently available. They also provide a reliable standard of comparison for both field and laboratory measurements being collected in programs supported by DOE and other agencies.

New Results

The NH_3–H_2O *system:*

Mixtures of ammonia and water have been suggested as working fluids in geothermal energy conversion systems. NH_3 also occurs as one of the major gases in geothermal reservoirs, such as the Geysers Geothermal Field. In order to predict the chemical behavior of NH_3, we have produced an equation of state using the methods described in Duan, Mϕller and Weare (1992a,b).

SELECTED CAPABILITIES OF PRESENT MODELS
• Predicts Behavior of Calcium Carbonate Scale Formation in NaCl and $CaCl_2$ Brines for T = 0° to 250°C
• Predicts Solubility of CO_2 and CH_4 in NaCl Brines for T = 0° to 250°C
• Predicts Solubility of Amorphous Silica Scale in Brines for T = 0° to 250°C
• Predicts pH and Complete Carbonate Equilibria in Seawater Brines at 25°C
• Calculates Precipitation Characteristics (Scaling) of Rock-Water Systems Containing Na, K, Ca, Mg, Cl, and SO_4 for T = 0° to 250°C
• Predicts Onset of Two Phase Behavior (gas breakout) in NaCl Brines
• Predicts Solubility of Hydrogen Sulfide System (0° - 90°C; 0 -60 atm)
• Predicts Partial Fugacity in Mixed Gas System (CO_2–CH_4–H_2O) T = 0° to 1000°C and P = 0 to 1000 bars
• Predicts Gas-Liquid Equilibrium in the CO_2 – CH_4 – H_2O System
• Predicts Gas-Liquid Equilibrium in the NH_3 – H_2O system
• Predicts Gas-Liquid Equilibrium in the NaCl – CO_2 – H_2O system

The modeling process begins by parameterizing highly accurate phenomenological equations of state (EOS) for the end member gases, pure H_2O and NH_3. The H_2O EOS for this system is the same as described in prior work. The NH_3 model was developed after carefully reviewing the existing literature to identify a complete and consistent data base. Extensive data for pure NH_3 have been published (Duan, Møller and Weare, to be submitted). The resulting EOS predicts densities within 1-2% of the measured values for a range of temperatures from 0 to 400°C and pressures from 1 to 1200 bars. With the end member EOS established, an EOS for the mixed system is formed by a mixing rule roughly based on the virial expansion. Again, data are needed to evaluate ternary parameters. When this process is completed the predictions of the mixed system (NH_3–H_2O) EOS can be compared to the experimental data. Typical examples of the results are given in the accompanying figure. After much testing the resulting model is ready for incorporation in the GEOFLUIDS software (included in GEOTHERM package).

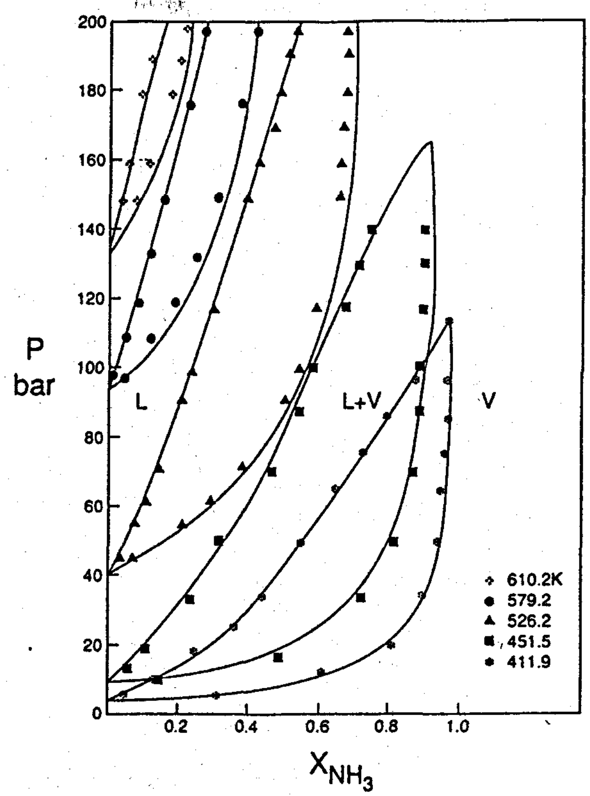

Figure: Vapor-liquid equilibria in the NH_3–H_2O system. Solid line: predictions of GEOFLUIDS.

The H_2O–CO_2–NaCl *system:*

Fluids with major components in this system are by far the most commonly encountered in geothermal systems. The analysis of many problems associated with geothermal operations requires the ability to predict the properties of this system as a function of composition, temperature and pressure. We have a continuing program developing models of very complex brines at liquid densities(see next subsection). However, this year we have begun to model this system for a much wider range of temperatures and pressures. This requires a new approach similar to equation of state approach we used for the H_2O–CH_3–CO_2 system described in Duan, Moller and Weare (1992). This case is however more difficult since one of the end members is a solid. A new mixing model had to be developed which takes in the unique properties of the subsystems. Our initial results are vey positive. The predictions of the model are roughly within the experimental error. An example of two phase coexistence predictions is given in the figure. Note the large increase in the two phase region with the presence of salt.

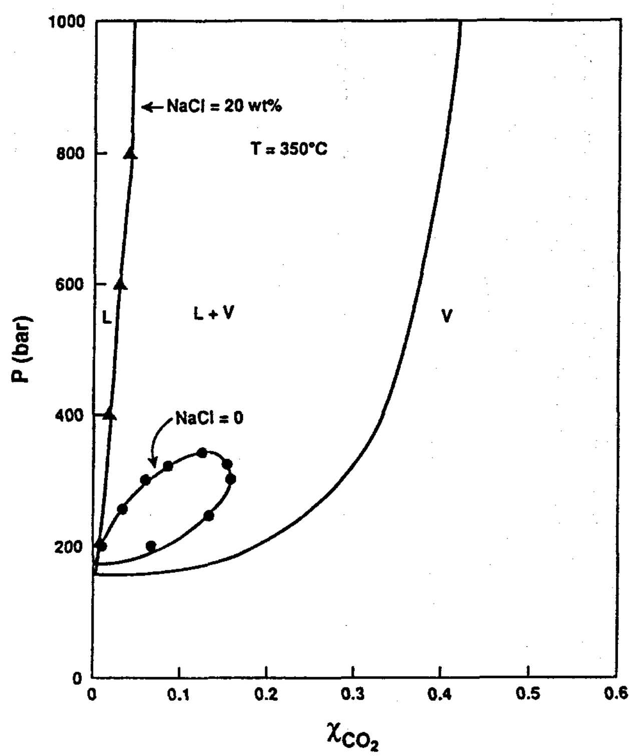

Figure: Vapor-liquid equilibria in the H_2O–CO_2–NaCl system. Solid line predictions of GEOFLUIDS.

Liquid Density Brines to 250 °C

Our current efforts in solubility modeling of subcritical brines have focused primarily on completing the basic seawater (Na–K–Ca–Mg–Cl–SO_4–H_2O) system for the 0° to 250°C temperature range. Binary and ternary solubility data are used to establish temperature functions for the binary solution (e.g., NaCl–H_2O) parameters ($\beta^{(0)}$, $\beta^{(1)}$, $\beta^{(2)}$ and C^{ϕ}), the ternary mixing solution (e.g., NaCl–KCl–H_2O) parameters (θ and ψ) and for the chemical potentials of the various single and double salts stable in the seawater system from 0°C to 250°C. The metastable behavior of many of these salts is also modeled. Except for the chemical potentials of complex salts, such as polyhalite ($K_2SO_4 \bullet MgSO_4 \bullet 2CaSO_4 \bullet 2H_2O$) and kainite ($KCl \bullet MgSO_4 \bullet 3H_2O$), found in higher order systems, the temperature functions determined from binary and ternary systems are all that are necessary to complete the basic seawater model and to predict behavior in any brine within the basic seawater field. Comparisons with solubility data not used in the model parameterization (quartemary, quinary and the full seawater systems) are used to validate this model. For example, recent predictions of gypsum and anhydrite solubilities in highly concentrated magnesium-containing brines at high temperature ($T > 200°C$) are in very good agreement with the laboratory data. Temperature functions for polyhalite and kainite, both important in the analysis of formations derived from seawater, have been established from solubility data in the quartemary systems, K_2SO_4–$CaSO_4$–$MgSO_4$–H_2O and KCl–$MgCl_2$–$MgSO_4$–H_2O, respectively.

User Friendly Graphical Interface:

An important objective of our program is to provide technology for designers, engineers and scientists to accurately predict the chemical and thermodynamic properties of geothermal systems. In order to make our models easy to use and to facilitate technology transfer, we have developed new graphical interfaces.

Previously, the user had to edit a file and input, in formatted columns, data such as the number of iterations, temperature, species concentration, and phases to withhold as well temperature and concentration change per iteration. This can be a tedious process, particularly to users who are more familiar with modern "point and click" and dialog box interfaces, rather than file or card deck input that had been common until the last decade.

Our new interface, though easier to use, has lost none of the functionality of the old input file version. Indeed, it has increased, since now, for example, a user may more easily calculate mineral supersaturation.

These innovations have now been released for the brine model operating of SUN workstations, MAC's, and PC's running WINDOWS. (A similar interface is under development for the GEOFLUIDS model) The interfaces for the three platforms look somewhat different but their functionality is the same. Upon start-up, a window appears that contains a selection list for the pure phases (solids and gases), a selection list of all species including pure phases, and a summary list of all species giving the values chosen by the user. All three lists have scroll bars in case the number of items in each list exceeds the dimensions allocated to the list on the screen. By clicking on an item from the phase selection list, a new window appears that gives the user a choice of either allowing a phase to precipitate if it becomes supersaturated, or withholding the phase from consideration in the phase selection process. After dismissing this window, the words "Yes" or "No" appears next to the phase.

By clicking on an item in the species selection list, a menu appears that allows the user to enter data for that particular species: number of moles, change in moles per iteration, change in percent of moles per iteration (most commonly used with the water species in the simulation of an evaporation sequence), and a specification for the activity which is used to set the fugacity of a gas phase species. When this window is dismissed, the new data appears in the summary list. Edit boxes for specifying the number of iterations, the temperature, and the temperature change per iteration always are visible. For the SUN version, clicking on the "Calculate" box executes TEQUIL and then opens up an xterm window that displays the output file. For the Macintosh and Windows versions, because of asynchronicity in the execution of external applications from within SuperCard and Microsoft Visual Basic respectively, clicking on the "Calculate" box just executes TEQUIL; a separate "Edit" box is present which opens a window containing the output file.

This is a first attempt at a user interface and we are making changes to improve it as we get feedback from users. A version of the new code may be obtained by contacting our group, Gladys Hooper or Marshall Reed.

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Duan Z. Møller N. and Weare J.H. (1992b) An Equation of State for the CH_4-CO_2-H_2O system. II. Mixtures from 50 to 1000°C and 0 to 1000 bar. *Geochim. Cosmochim. Acta* 56, 2619-2631.

Session 8: Geothermal Opportunities

Chairperson:
Robert Creed,
Idaho Operations Office,
U.S. Department of Energy

Geothermal Opportunities
-- Session Summary --

Robert Creed
Idaho Operations Office, U.S. Department of Energy

Due to time constraints, there were no substantive introductory remarks.

National Advanced Drilling and Excavation Technologies (NADET) Program: A New Research Initiative, Allan J. Jelacic, Geothermal Division, U.S. Department of Energy

NADET is a new research initiative proposed for the FY95 budget to develop advanced drilling systems with capabilities beyond conventional drilling methods. Stakeholder involvement (academia, government, and mining, geothermal, oil, and gas industrial partners) and independent review will help to ensure that NADET research and development results in improved drilling technologies. NADET will decrease the risks and costs associated with geothermal drilling and enable the U.S. industry to regain dominance in international drilling markets.

Update on Bonneville Power Administration (BPA) Geothermal Activities, George Darr, Bonneville Power Administration

The BPA has negotiated power contracts for 30-megawatt geothermal projects at Vale, and Newberry Volcano, Oregon. Exploration drilling began at Vale in January, 1994. An environmental impact statement (EIS) is being prepared for Newberry, with records of decision due in July, 1994. Public concerns about the Newberry project focused on air emissions, impacts on groundwater and hot springs, visual impacts, responsibility for decommissioning costs, and how the project might affect the newly-created Newberry National Volcanic Monument. An innovative public involvement process helped to make sure that these concerns were identified and addressed.

Small Geothermal Electric Systems for Remote Powering, Daniel J. Entingh, Princeton Economic Research, Inc.

This report explores conditions and costs at which quite small (100 to 1,000 kilowatt) geothermal systems could be used for off grid powering at remote locations. The report provides detailed performance and cost estimates for a modal system, and estimates of the impacts on the cost of electricity for variations in many small system parameters. The results suggest that small geothermal systems will generate electricity at costs considerably less than diesel or photovoltaic systems. Important markets include off grid sites in both developed and developing countries.

NADET – A New Research Initiative

Allan J. Jelacic
Geothermal Division
U.S. Department of Energy

The geothermal resources of the United States are extremely large and virtually inexhaustible. In fact, geothermal is the nation's largest energy resource, comprising almost 40 percent of the total resource base from all sources. Geothermal developers face the challenge of converting a significant portion of that resource base into viable, economic reserves that can be put to good uses.

We have long recognized that the cost of drilling wells has hindered the development of geothermal resources. Geothermal wells typically cost two to four times as much as comparable oil and gas wells, and the return on a barrel of geothermal brine versus a barrel of oil can make a geothermal well a very risky investment. The situation is summarized in Figure 1 which shows a range of geothermal well costs versus depth compared to the average cost of oil and gas wells. The graph clearly shows the exponential cost increase with depth commonly associated with conventional drilling practices. With incremental improvements to conventional techniques, the cost of geothermal wells may one day approach that of oil and gas wells. However, given the differential value of the commodities involved, such cost improvements are unlikely to produce growth in development commensurate with geothermal's potential.

One way in which to reduce risk and allow geothermal to achieve its full potential would be to improve radically the economics of drilling, ultimately producing a linear cost variation with depth (Figure 1). In order to attain such an ambitious goal, a whole new, *revolutionary* means of drilling and completing wells is required.

While the needs of the geothermal industry for cheaper ways to drill wells are obvious, many other industries have an interest in obtaining more economic access to the underground. Drilling costs incurred by oil and gas companies can run as high as 80 percent of field development costs. Underground transportation systems and utility conduits are becoming increasingly common in crowded urban areas, but their cost can be prohibitive. Caverns for the storage of commodities and the disposal of hazardous wastes have gained increased attention as viable options for materials handling. And, of course, mining and other extractive industries depend entirely on breaking, moving, and processing earth materials. These industries would reap substantial added benefit from a new technology that creates underground space quickly and cheaply.

Certain common tasks or needs exist in making usable underground space regardless of whether the space is large or small, deep or shallow, vertical or horizontal. Those tasks include breaking or penetrating rock, disposing of the rock fragments, maintaining the size of the opening, supporting the opening, and controlling or guiding the whole process. In order to make an underground opening, every drilling or excavation system must perform these tasks, independent of the intended use of that opening. On the basis of this commonality of needs, the idea of a new research initiative, the National Advanced

Drilling and Excavation Technologies Program (NADET), was born.

The purpose of NADET is to develop a new integrated approach to drilling rock. The approach will be embodied in a drilling system that effectively optimizes the common tasks of making underground space with the goal of reducing costs while improving safety, reliability, and productivity. If NADET achieves its goal, we expect that the energy extraction and mining industries will become revitalized, and the U.S. will regain competitive advantage lost to foreign companies. Massive tunneling projects to ease urban traffic congestion and rebuild the civil infrastructure will become practicable. And underground facilities for manufacturing, storage, or waste disposal will have economic as well as environmental benefits.

As currently conceived, the NADET program has three stages. During the feasibility/planning stage, the cost and performance of potential novel drilling techniques will be evaluated relative to today's conventional drilling technology. Stakeholders from government, industry, and the research community will be identified. And a program plan will be prepared. In the second stage, the most promising rock penetration techniques will be investigated. Novel drilling systems will be designed and analyzed; components will be fabricated and tested. Eventually, one or more prototype systems will be built and tested in the field. During the final stage, industry stakeholders will market commercialized systems based on the prototype(s). These systems will undergo extensive testing for different applications in a variety of environments. By the end of the third stage, one or more new systems will have emerged and achieved full commercialization.

Table 1 gives a preliminary estimate of the budget for NADET over a projected eight year span to completion. Due to the scope of the proposed program and the current financial stresses on drilling and related industries, government will bear the majority of costs; industry will take on greater financial responsibilities during the commercialization stage.

Currently, we are in the first stage of implementing NADET. In May 1992, at the behest of the Geothermal Division, the Massachusetts Institute of Technology established an organizing committee to develop a proposal for a national program on advanced drilling and excavation technologies. This was the first real effort to investigate the desirability of pursuing an advanced drilling program. The committee included representatives from various industries and academic institutions. In April of this year the committee issued a report that contains a justification and rationale for the NADET program and a proposed organizational structure.

In an attempt to gauge the private sector's interest in advanced drilling research, the Geothermal Division contacted over 400 companies in early 1993. The companies were selected based on strong business interests in drilling, mining, and excavation or associated service industries. As shown in Figure 2, about one fourth of the companies responded, and 80 firms, including 23 geothermal companies, indicated a willingness to participate in NADET. The 80 prospective participants offered their own resources, ranging from funding to research experience, for the NADET Program. Table 2 gives a breakdown of the assistance offered. The extent of the response and the pledges of support from industry serve as strong endorsements for NADET.

In addition to establishing industry's interest in NADET, we have identified a group of Federal agencies who have a stake in drilling and excavation technologies. Those agencies are listed in Table 3. Over the past year, three meetings of representatives of these agencies have been held to exchange information about activities in drilling and excavation research. Further meetings are planned, but at this point no formal ties among the agencies to coordinate their efforts have been established.

Perhaps the keystone of all activities during NADET's first phase has been a feasibility study by the National Research Council. The study, cosponsored by four offices of the Department of Energy and the Gas Research Institute, will examine the viability of different advanced drilling techniques and make recommendations on improvements likely to have the greatest impacts on drilling economics. A Committee on Advanced Drilling Technologies was formed by the Council to conduct the study. The committee is co-chaired by Professor Neville Cook of the University of California at Berkeley and Professor Ali Argon of Massachusetts Institute of Technology and consists of distinguished experts from industry and academia. For the past year the committee has been working on its final report, due later this spring.

During the course of seeking stakeholders in advanced drilling and excavation technologies, we have identified over 250 persons with an interest in NADET. In order to keep them informed of developments, the Geothermal Division has established a newsletter that we publish as events warrant. Thus far, two newsletters have been issued, and they have been circulated throughout industry and academia, enabling more people to become acquainted with the program.

NADET's initial stage has proven quite successful. We have found that substantial interest exists in a new research program in advanced drilling and excavation, to the point of garnering pledges of cost sharing by the private sector. We feel encouraged to pursue the program with a formal budget initiative. Accordingly, the President's Budget Request for Fiscal Year 1995 in geothermal energy contains $2 million for NADET. In addition, the Office of Fossil Energy has requested funds for advanced drilling research under its natural gas and oil research initiative. Several background studies are proceeding, including an exhaustive search of the Russian literature on advanced drilling by Maurer Engineering, Inc. and a characterization of advanced drilling systems spearheaded by Sandia National Laboratories. The work to date lays a solid foundation for NADET's next stage which we hope to begin next fiscal year.

Drilling and excavation are activities vital to the well-being of the national economy. The social and economic benefits to be gained from a new technology for drilling rock are substantial. We are confident that NADET will usher in a new era of expansion and prosperity for those whose business depends on access to the subterranean world. Perhaps someday, thanks to the efforts begun with NADET, the conventional drilling rig we know so well will become just another museum curiosity.

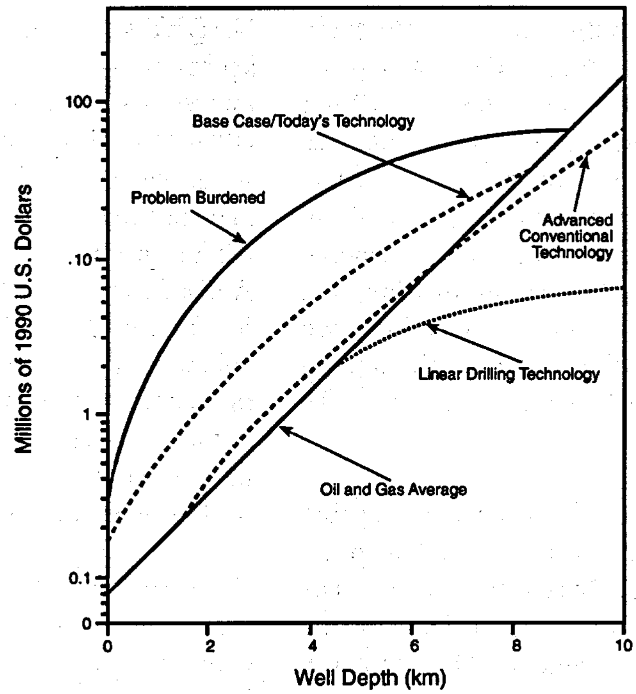

Figure 1. Drilling costs for completed geothermal wells (adapted from Tester and Herzog, *Economic Predictions of Heat Mining: A Review and Analysis of Hot Dry Rock (HDR) Geothermal Energy Technology*, MIT-EL 90-001).

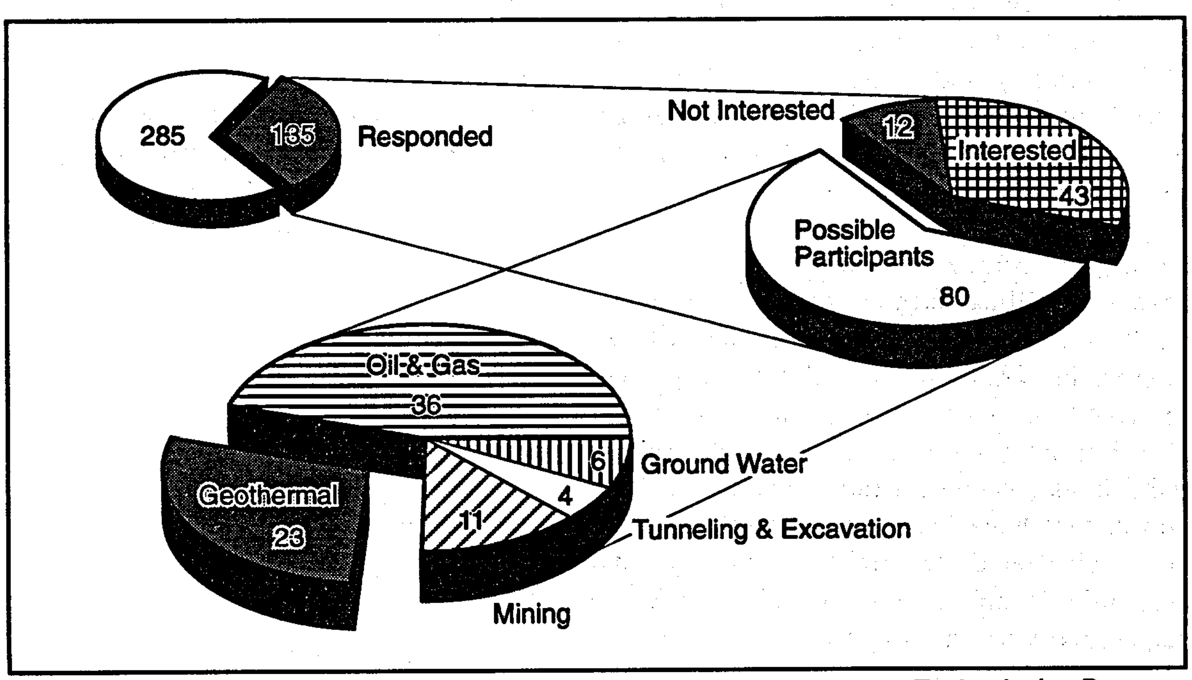

Figure 2. Responses by industry to a National Drilling and Excavation Technologies Program.

Table 1. Estimated budget profile ($ million) for the NADET Program.

Funding Source	FY94	FY95	FY96	FY97	FY98	FY99	FY00 +	Total
Government	< 1	3	10	20	40	30	30	134
Industry	0	0	1	5	10	20	80	116
Total	< 1	3	11	25	50	50	110	250

Table 2. Potential offers of support for NADET received from industrial stakeholders.

Type of Assistance Offered	Oil & Gas	Geothermal	Mining	Tunneling & Excavation	Ground-water	TOTAL
Financial Support	3	1	1	---	---	5
Equipment	16	9	7	1	3	36
Laboratory Facilities	16	7	4	2	---	29
Data Bases	8	6	4	2	---	20
Field Testing Facilities	8	6	6	2	---	22
R&D Experience / Personnel	25	20	10	3	4	62
Other*	4	2	1	1	---	8

*Other types of assistance offered include geophysical measurement, low stress level drill string design, technical expertise in corrosion-resistant materials, and heat treatment services.

Table 3. Federal Agencies Interested in Drilling and Excavation Technologies.

AGENCY	OFFICE	Areas of Interest
Energy	Geothermal Division Fossil Energy Energy Research Civilian Radioactive Waste Environmental Management	Geothermal development Gas exploration Earth science Radioactive waste disposal Waste handling
Transportation	Federal Highway Administration Federal Transit Administration	Tunneling Tunneling
National Science Foundation	Ocean Drilling Program Earth Sciences Division Geomechanical, Geotechnical and Geoenvironmental Systems	Deep water operations Earth science Tunneling; excavation; construction
Environmental Protection Agency	Oil & Gas Industry Underground Injection Control Office of Solid Waste	Regulation Waste disposal Waste disposal
Interior	Bureau of Mines U. S. Geological Survey	Mining; excavation Earth science
Defense	Army Research Laboratory Defense Nuclear Agency	Projectile drilling Drilling; tunneling
Nuclear Regulatory Commission	Nuclear Regulatory Research	Radioactive waste disposal
National Aeronautics & Space Administration	Planet Earth Study Office	Drilling; excavation
Commerce	National Institute of Science & Technology	Drilling; excavation

Update on Bonneville Power Administration Geothermal Activities

George D. Darr
Bonneville Power Administration, Portland, Oregon

ABSTRACT

The Bonneville Power Administration's (BPA) geothermal program includes two 30-MW pilot power projects at sites with potential for additional units. The project developers are Trans-Pacific Geothermal Corporation at Vale, Oregon, and the California Energy Company at Newberry Volcano, Oregon. Exploration drilling is already under way at Vale. The environmental impact statement process is almost complete at Newberry, and the three federal agencies involved expect to issue records of decision in July 1994. Exploration drilling is expected to begin in the fall. Issues raised during the process are discussed.

BACKGROUND

The main goal of BPA's geothermal program is to initiate geothermal development in the Pacific Northwest, to make sure it will be available to meet the region's energy needs. The program has focused on developing pilot power projects at sites with potential to support at least 100 megawatts (MW) of capacity. As an incentive to developers, BPA offered to buy the output from up to three projects. A request for proposals was advertised in July 1991, leading to contract negotiations with three developers — the California Energy Company for a 30-MW project at Newberry Volcano, Oregon, Trans-Pacific Geothermal Corporation (TGC) for a 30-MW project at Vale, Oregon, and Unocal Geothermal Corporation for a 30-MW project at Glass Mountain, California. Negotiations were completed and memoranda of understanding were signed for the Newberry and Vale projects in December 1992 and January 1993, respectively. The Eugene Water & Electric Board (EWEB) is a partner in the Newberry project, and the Springfield Utility Board is a partner at Vale. Both projects are expected to achieve commercial operation in late 1996 or early 1997.

The pilot projects were supported by over 30 other activities aimed at increasing public knowledge and acceptance of geothermal technology. These activities included environmental studies, economic impact studies, public education projects, videos, technology development, outreach to environmental groups, and geothermal heat pump projects. Most recently, the Geothermal Education Office and the Oregon Department of Energy held a workshop in Bend, Oregon, to distribute curriculum materials for teaching students in grades 4 to 8 about geothermal.

The purpose of this paper is to give a status report on the Vale and Newberry projects.

VALE GEOTHERMAL PROJECT

Trans-Pacific's Vale leasehold is in the Vale Known Geothermal Resource Area, located one to five miles southeast of Vale, Oregon, near the Oregon-Idaho border. A Plan of Exploration to drill and test up to ten wells was approved by the Bureau of Land Management (BLM) in October 1993. An exploration well was spudded in late January 1994, and was terminated at 5750 feet at the end of February. TGC is currently evaluating the drilling data.

TGC conducted a public involvement program that appears to have won the support of most of the local community. If successful, the project will contribute about $1.5 million annually to the local economy through property taxes and royalties returned to Malheur County, making it the largest source of county revenue.

The next step in the project will be to begin the environmental process for the development and production phases.

NEWBERRY GEOTHERMAL PILOT PROJECT

This is a 30-MW project located in central Oregon on the west flank of Newberry Volcano. It is being developed as a joint venture between CE Exploration Company (CEE) — a Portland-based subsidiary of the California Energy Company — and EWEB, Oregon's largest publicly-owned utility. The project is in the Deschutes National Forest and is adjacent to the recently created Newberry National Volcanic Monument. The project location is shown in Figure 1. In January 1993, the Forest Service, BLM, and BPA began the environmental analysis required by the National Environmental Policy Act of 1969. A draft Environmental Impact Statement (EIS) was issued for public review on January 29, 1994. The public comment period ended March 21. The agencies are currently reviewing and responding to comments, and expect to issue the final EIS and records of decision by early July. CEE hopes to begin exploration drilling in late 1994.

Public Involvement. CEE and EWEB undertook an innovative public involvement program aimed at informing community leaders in the Bend - Sunriver - La Pine area about the project and making sure local concerns were addressed. The Central Oregon Geothermal Working Group (COGWG) had about 20 members, including "ex officio" representatives from the Forest Service, BLM, BPA, and the Oregon Department of Energy. The COGWG represented a wide range of interests, from the Sierra Club to the Lodgepole Dodgers, a La Pine-based snowmobile club. The group met monthly for almost two years. The meetings were professionally facilitated and were open to the public. The meetings typically centered around a topic or issue, such as environmental baselines or air emissions, and usually featured an outside speaker. There were field trips to the plant site and to operating geothermal plants at The Geysers.

The COGWG was not asked to be, nor did they necessarily become, advocates for the project. They are, however, a source of information for the groups they represent and for the community. Their value in winning public acceptance for the project will be clearer after the federal agencies issue their decisions and the appeals period opens.

Alternatives in the EIS. CEE proposed to develop sufficient resources to supply the initial 30-MW plant and to confirm a 100-MW reserve. Temperature gradient, exploration, and production wells would be drilled at up to 14 locations. A single plant site was identified. After examining several possible routes, a route along an existing Forest Service road was proposed for the 115-kV H-frame transmission line.

The Forest Service's alternative identified 20 well pad locations, 14 of which could be used, and 3 power plant locations. Analysis was done on 40-acre blocks for the well pads, within which specific pad locations would be chosen based on environmental considerations. The power plant sites were within 30-acre blocks. One reason for multiple plants sites was to allow the plant to be located near the wells, if the wells turned out to be concentrated in one area, and to minimize the amount of piping needed. A single-pole transmission line design and a route away from the Forest Service road (to minimize its visibility to visitors to the Monument) were proposed.

MAJOR ISSUES AT NEWBERRY

The draft EIS is practically a textbook on geothermal development, and is currently over 600 pages long and growing. A separate document will deal with environmental monitoring. The Newberry EIS is more than twice as long (and cost twice as much) as a recent BPA EIS for a gas-fired project eight times larger. Some of the issues that emerged from public comments were easy to predict, others were not. The major concerns were:

Air Emissions. Hydrogen sulfide releases during well venting and plant upsets are a major concern, despite air quality modeling predicting imperceptible impacts during normal operation and only minor, localized, temporary impacts under worst case conditions.

Impacts on Groundwater. Groundwater contamination from surface releases or well casing rupture is a major concern to the public. Anticipating this concern, the U.S. Department of Energy, Forest Service, and BPA have funded hydrologic baseline data collection and monitoring by the U.S. Geological Survey since 1991. A wide range of physical and chemical parameters have been measured at 21 sites. The monitoring program will be continued until it can be shown it is no longer needed.

Impacts on Hot Springs. Although the shallow geothermal system that feeds thermal seeps along the shores of Paulina and East Lakes appears to be separate from the deep system, impacts on these "significant thermal features" is an issue. The agencies will probably address this concern through continued monitoring.

Visual Impacts. The EIS contains visual simulations showing how the plant will look under worst-case conditions (biggest steam plume) from key observation points. Public comments have been very appreciative. CEE will minimize steam plumes by over-sizing the cooling tower.

Is Geothermal Renewable. Project opponents have tried to create an issue out of the supposed non-renewability of geothermal, citing The Geysers as evidence to support their case.

Staged vs. Cumulative Development. CEE convinced the agencies that it was feasible to do a single EIS covering all phases of the project, from exploration to decommissioning. The main reason for this was to avoid possible delays caused by sequential environmental processes — one for exploration and another for develop-ment, production, and utilization. Structuring the environmental process this way created a "catch-22" for the agencies. Some project opponents objected to doing an EIS before exploration drilling had established production well sites and fluid chemistry. This stepwise approach would, of course, allow the project to fail by itself if no reservoir was found, or give them an opportunity to challenge the project again in the development EIS. Others, ironically, wanted greater detail in the EIS about possible cumulative impacts from development beyond the first power plant.

Impacts on the Newberry National Volcanic Monument. The Newberry Monument legislation was created through a public process involving a wide range of interests, including environmental advocates. The legislation explicitly preserves the right to develop geothermal resources at Newberry. Nevertheless, some argue that power plants should not be located near the Monument.

Decommissioning. This was probably the least anticipated issue. Public awareness was heightened by the premature decommissioning of the Trojan Nuclear Plant. The public wants to know who will pay for site restoration, regardless of when project shutdown occurs.

CONCLUSIONS

BPA's geothermal program has been successful in initiating development at Vale and Newberry. These two projects have gone a long way toward winning public acceptance of a technology that is new to the Pacific Northwest and which has potential for meeting a significant share of the region's future energy needs.

Extensive restructuring is in progress at BPA. Near-term resource needs have been met, and it may not be necessary to acquire additional resources for eight years or more. Geothermal-related research and development activities in progress are being completed. No new projects will be proposed until BPA management provides direction.

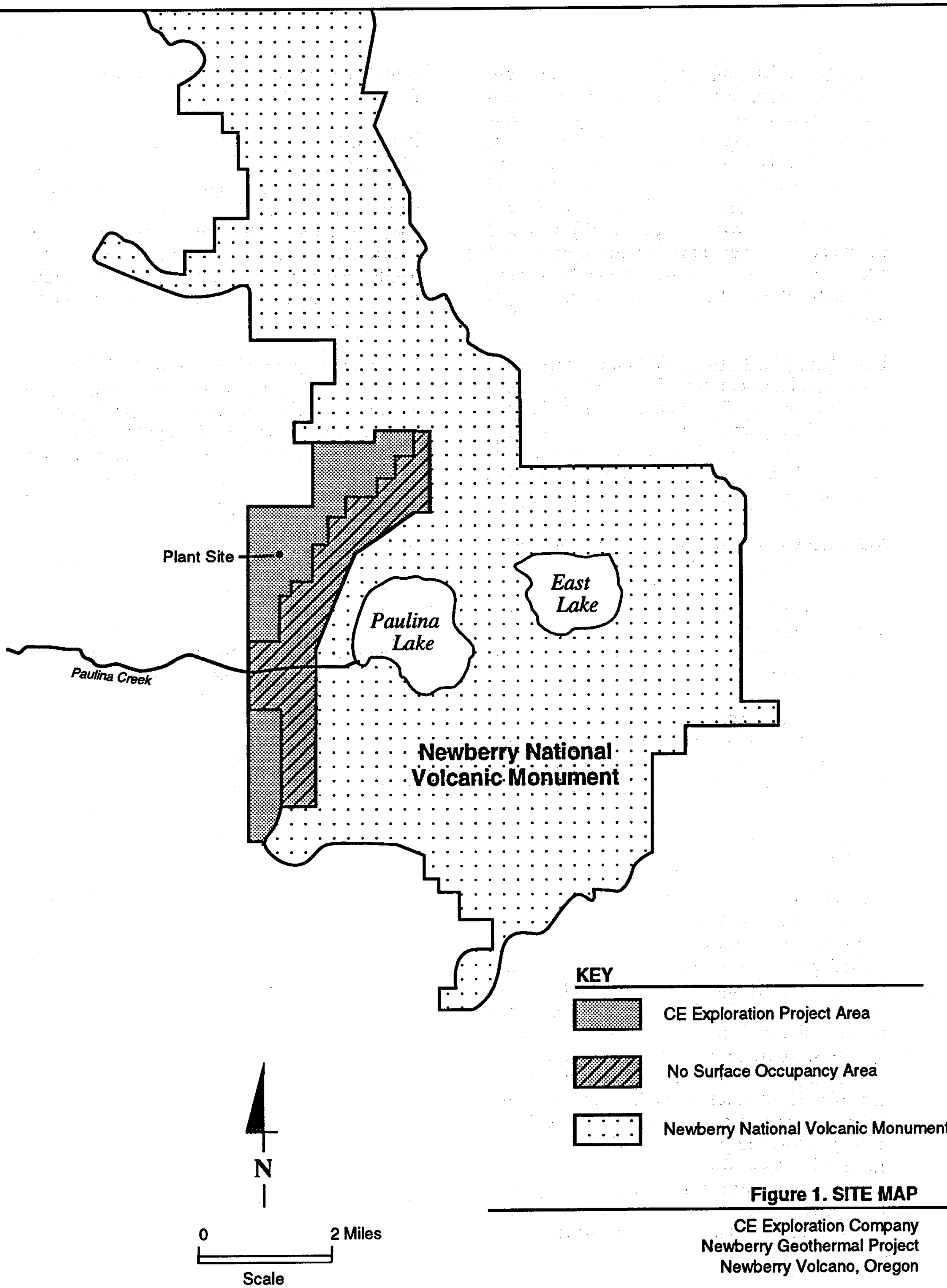

Figure 1. SITE MAP

CE Exploration Company
Newberry Geothermal Project
Newberry Volcano, Oregon

SMALL GEOTHERMAL ELECTRIC SYSTEMS FOR REMOTE POWERING

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ABSTRACT

This report explores the conditions and costs at which quite small (100 to 1,000 kilowatt) geothermal systems could be used for off-grid powering at remote locations. This analysis is a first step in a larger process of determining locations where and conditions under which markets for such systems could be developed. The report provides detailed performance and cost estimates for a modal system of 300 kilowatts capacity working from a resource temperature of 120°C, and estimates of impacts on the cost of electricity for variations in many system parameters. The purpose of the detail is to assist interested parties in making estimates of where such systems could be economically useful.

The results suggest that small geothermal systems offer substantial economic and environmental advantages for powering off-grid towns and villages. Geothermal power is likely to be economic if the system size is 300 kW or greater, down to reservoir temperatures of 100°C. For system sizes smaller than 300 kW, the economics can be favorable if the reservoir temperature is above about 120°C. Important markets include sites remote from grids in certain developing and developed countries.

BACKGROUND

The U.S. geothermal industry has built substantial amounts of geothermal electric capacity in the last decade. About 300 MWe of this have been "binary" units, which are well-suited to moderate-temperature geothermal reservoirs. While most of those units have capacities of 5,000 kilowatts and larger, U.S. firms have manufactured and installed binary units as small as 300 kW. [1]

The systems of interest here have net capacities on the order of 100 to 1,000 kW. These systems would be suitable for powering towns and small cities with populations ranging from 100 to 5,000 people, depending on the estimated per capita demand.

Because these systems are substantially smaller than the grid-connected geothermal electric systems recently built in the U.S. (1 to 20 MW), special attention is paid here to considerations of how certain project costs scale to system size, and to ensuring reliability of power for portions of the load when the system is not available. This report concentrates on binary power conversion systems, because they are the most likely to be economical at geothermal reservoirs with relatively low fluid temperatures. Flashed-steam power plants, useful at temperatures above 150°C, have also been constructed in small sizes. [2]

SYSTEM DESCRIPTION

General Description

The power system gets its energy from a geothermal reservoir containing hot water. Geothermal fluid is produced through a well that is similar to an oil well, and piped to the power plant.

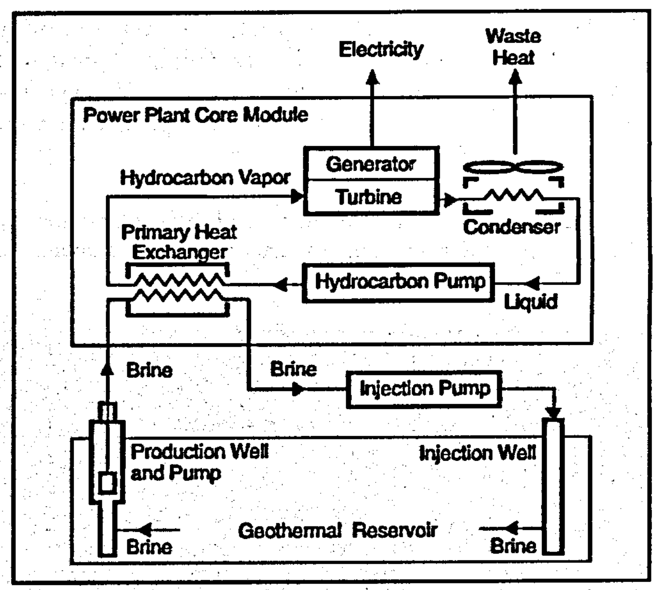


Figure 1. System Schematic

The geothermal fluid passes through the tube side of the primary heat exchanger and then is pumped back into the reservoir through an injection well. Because the geothermal fluid is always contained within pipes and vessels, it releases no gases to the atmosphere. A hydrocarbon working fluid on the shell side of the primary heat exchanger is vaporized to a high pressure to drive the turbine-generator. Low-pressure vapor from the turbine is liquefied in the condenser and repressurized by the hydrocarbon pump. Waste heat is ejected to the atmosphere through the condenser.

Typically, the systems described here will require only one production well and one injection well (or other means of brine disposal). However, if the resource temperature is relatively low, then plants of capacities on the order of 500 kW or greater may require two production wells.

Special Features of the Technology

Some special features of the technology are described here.

1. Power plant output lies in the range of 100 to 1,000 kW. For 100 to 300 kW plants, the entire plant, including the cooling system, will fit on a single skid that fits in a standard shipping container.

2. Binary power plants can accommodate a wide range of geothermal reservoir temperatures, 100 to 150°C. (Above 150°C, flashed-steam plants are usually less expensive.) However, the thermodynamic efficiency of the process becomes quite low at the lower temperatures, and therefore the overall cost of the power plant becomes more expensive. Reservoir temperature is the physical factor to which project overall costs are most sensitive.

3. The demand for electric capacity per person at off-grid sites will range from 0.2 kW in less-developed areas to 1.0 kW or higher in developed areas. A 100 kW plant could serve 100 to 500 people. A 1,000 kW plant would serve 1,000 to 5,000 people.

4. The design of the power plants and their interactions with the wells include provisions for handling low instantaneous loads, ranging from 0 to 25 percent of the installed capacity. The provisions could include a brine surge tank, partial bypassing of brine around the plant, or resistive power-dissipation loads. Also, power plant designs emphasize a high degree of computer-based automation, demonstrated successfully at the Wineagle and Wendell-Amedee plants in California.

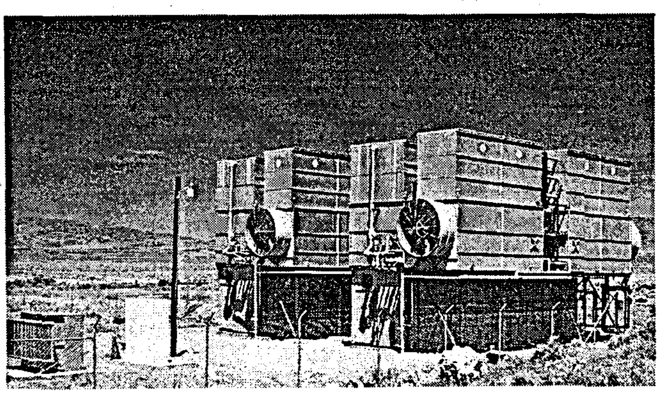


Figure 2. Barber-Nichols 2 X 350 kilowatt plant at Wineagle, California. The plant has been available more than 98 percent of the time since installed in 1985.

5. The system releases no greenhouse gases (CO_2, NOx, or SOx) to the atmosphere. There may be very small leakages of the hydrocarbon working fluids, but these do not contain chlorine or fluorine and are non-greenhouse gases. [3]

6. All wells would be drilled by truck-mounted rigs, either heavy-duty water-well rigs or light-duty oil/gas-well rigs. The modal case assumes a 300 meter (984 feet) production well at a cost of $200 per foot. For large geothermal projects, the cost per injection well is usually about the same as that of a production well. This is not the usual case for small systems. Since the geothermal flow rates here are small, there will rarely be a need to inject the fluid back into the production reservoir. Any shallow aquifer that is not used for drinking water will do. The modal injection well is estimated to be 200 meters (656 feet) deep and cost $131K. If the fluids are clean enough to be disposed of on the surface, then the brine disposal capital costs are estimated to be only $50K.

7. Field piping costs are low. All wellheads are located near the power plant module. Inexpensive plastic or carbon steel pipe is used to connect wells, at a total cost of $10K per production well, and $25K per injection well.

8. Geothermal direct heat applications can be attached to these electric systems inexpensively. Such systems might be attached in series to the power-plant fluid outlet line. Some production wells will have greater flow capacity than that needed by the power plant - - part of this fluid could be used for direct uses connected in parallel to the power plant.

9. Critical backup need is estimated to range from 1 to 5 percent of the installed geothermal capacity. The very high availability factors for geothermal systems, on the order of 98 percent, substantially reduce the cost of special features needed to ensure that power is always available. Small critical loads, e.g., medical refrigeration or pumping of drinking water, could be supported against brief unscheduled outages by small amounts of battery storage. Planned outages for system maintenance, and the rare instances of longer-duration unscheduled outages could be supported by mobile (truck-mounted) small diesel generators. One such rig would be able to service 5 to 30 small geothermal units.

COMPONENT COST AND PERFORMANCE DETAILS

System design considerations and cost estimates are described here. The estimates were combined in a PC-computer model, GT-SMALL, to estimate the overall system costs and the cost of power. Copies of the model can be obtained from D. Entingh [10]. Some of the inputs and results below are described for a "modal" system that assumes 300 kW installed at a 120°C reservoir.

Power Plant Core Module

Estimates of the cost and performance of small binary power plants form the most critical and novel part of this analysis. The detailed estimates of power plant performance and cost in Tables 1 and 2 were provided by Ken Nichols, of Barber-Nichols Inc., Arvada, Colorado, a manufacturer of small binary units. The estimates have been reviewed by Dan Schochet, of ORMAT, Inc., Sparks, Nevada (another manufacturer of such units) and found to be reasonable for U.S. installations.

The scope of the equipment costed in Table 1 includes that within the "power plant core module" in Figure 1: brine-to-hydrocarbon heat exchanger, hydrocarbon circulation pump, turbine, generator, and dry cooling condenser and fans. The power consumed by those pumps and fans is accounted for within the plant core module. These values were fitted to equations in the model, to estimate the cost of power from systems with parameters intermediate from those in the tables. The values supplied by Nichols can be fitted closely using a cost-scale-to-size exponent of 0.88, which is consistent with values in the literature for this technology.

The following adjustments were made to the costs shown in Table 1. (a) The cost and power consumption of brine production pumps and injection pumps are calculated separately. (b) The values in Table 1 are for typical grid-connected plants, running at an annual capacity factor of about 80 percent. Seven percent was added to those costs to cover modifications to these plants to allow them to follow instantaneous loads as low as about 15 percent of the nominal net capacity. (See further discussion and Table 3, below.) (c) $80/kW was added to cover the costs of a power transformer and relay equipment.

Nichols indicated that the unit cost of O&M labor in the U.S., 1993, was about $25/hr for the operator-monitor, and about $55/hr for skilled maintenance workers (fully loaded costs.)

Features to Ensure System Reliability

The systems described here are envisioned as not being connected to a power grid. Therefore, selected items have been added to the general design and cost estimates to ensure that the system can follow relatively low instantaneous loads and that critical loads can be maintained during brief periods of unplanned and planned system outage. These features are described in Table 3. The features described here are representative of what might be included, and would not be prescribed for every system.

U.S. geothermal electric systems are designed to work at high

TABLE 1. Power Plant Capital Cost and Brine Flow Requirement

Power Module Net Size, kWe	Plant Inlet Temperature, Degrees Celsius					
	100°C		120°C		140°C	
	$/kW	Klb/hr	$/kW	Klb/hr	$/kW	Klb/hr
100 kW	2535	110	2210	52	2015	30
200 kW	2340	220	2040	104	1860	60
500 kW	2145	500	1870	244	1705	144
1000 kW	1950	1000	1700	500	1550	286

TABLE 2. Power Plant O&M Requirements, as Hours or Cost per Year

Plant Size:	100 kW	200 kW	500 kW	1000 kW
Operator-Monitor (hr.yr)	300	400	500	800
Maintenance (hr/yr)	200	250	300	400
Working Fluid ($/yr)	200	400	850	1200
Maintenance Parts ($/yr)	400	500	600	800

TABLE 3. Estimates for System Reliability Factors

(Values for the modal system are shaded.)

Format: [Name of dependent variable]	Independent Variable: [Name], [Values] [] .. []						
	Dependent Variable: [Name], [Values] [] .. []						
Scale Plant Cost to Lowest Instantaneous Load Factor (LILF)	LILF, percent of net capacity	0	5	10	15	20	25
	Plant Capital Cost Multiplier	1.20	1.15	1.10	1.07	1.06	1.05
Battery Backup Cost as function of kW rating (BBUPR)	BBUPR, kW	5	10	15	20	30	40
	Capital Cost, $K	34	68	102	136	204	272
Diesel Truck Backup Cost	Specs: 50 kW capacity, at site 7 days/year.						
	Capital Cost, $K		10	O&M Cost, $K/year			5

constant throughput. A "Lowest Instantaneous Load Factor" (LILF) was defined here to account for costs incurred to allow these plants to follow relatively low instantaneous loads in non-grid applications. As defined here, the LILF implies a multiplier applied to the power plant core module capital cost. Presently, this multiplier is a rough estimate made by the authors. Further details will have to be developed for the exact manner in which these systems can support relatively low partial loads. We envision that three aspects come into play: (a) Simple throttling of the turbine in the LILF range of 50 to 100 percent, with brine flow relatively unabated; (b) Some production well throttling, plant bypass valves, and a brine surge tank added to the system, to accommodate the LILF range of 10 to 50 percent; (c) Shedding power into a dissipative resistive load to accommodate LILF in the range of 0 to 10 percent.

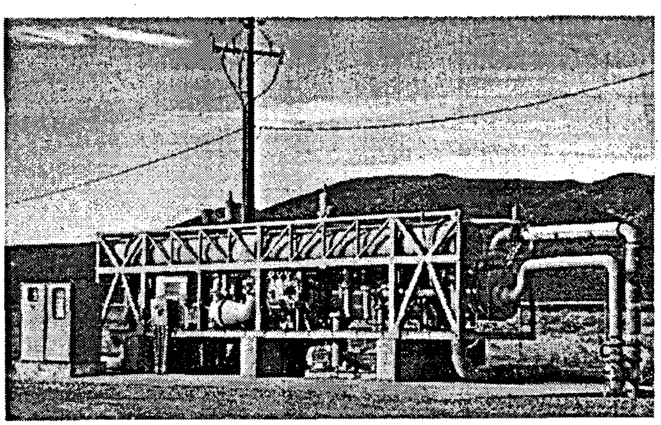


Figure 3. This 880 kW ORMAT unit at Wabuska, Nevada is water cooled. It was installed in 1984.

Battery backup costs are estimated as follows. The longest duration needed is 7 days, time enough to move a diesel truck to the location for longer backup. Utility-grade lead-acid batteries cost about $150 per kWh of storage. The utilization factor for critical loads (capacity factor, CF) for use of this critical storage is estimated to be 0.25. Thus 7 days X 24 hours/day X 0.25 (CF) X 10 kW = 420 kWh storage need, and thus the battery cost = 420 X 150 = $63K. The balance of system costs (inverters, structural supports, wiring), at $500 per kW, is $5K. The total capital cost is $68K. The O&M costs for this subsystem are essentially nil. [4]

For the diesel truck backup, it is estimated that a 50 kW diesel truck would cost $100K and that $5K would cover operating this for one week of scheduled maintenance at each site. It is assumed that there would be about 10 of these small plants in a region served by one truck, resulting in a $10K initial capital cost per geothermal system for this aspect of backup power.

Other Estimates and Assumptions

Additional detailed assumptions are described here.

1. <u>Exploration Cost</u>: The cost to discover the local geothermal resource cannot be ignored. The estimate of $200K assumes an organized regional approach to exploration and test drilling, so that each stand-alone system does not bear all of the risk of exploration failure at any particular site.

2. <u>Casing Plan</u>: The casing plan for the two 1000-foot production wells at the 100°C, 1,000 kW plant at Wendell-Amedee, California is: 13 5/8 inch O.D. to 750 feet, then 9 5/8 inch O.D. to 1000 feet [9, Meidav]. The production well should, in general, be sized to allow setting a line-shaft brine

production pump at about 600 feet.

3. Production Well Cost: Footage costs are estimated to be: $200 per foot for wells up to 1500 feet in depth; $250 per foot for intervals between 1500 and 3000 feet; $300 per foot for intervals deeper than 3000 feet. The modal well here is set at 300 meters (984 feet). One production well will generally be sufficient, unless the design entails both low reservoir temperature and "high" (e.g., 1,000 kW) capacity.

4. Injection Well Cost: This is assumed to cost $200 per foot for a 200 meter (656 feet) well. This well is assumed to inject fluid in a "disposal" manner into an aquifer that lies above the geothermal reservoir.

5. Field Piping Cost: a. Production Wells: It is assumed that the power plant is located very near the wellhead, and that $10K will cover hookup costs. b. Injection wells: These will be located within 500 feet of the power plant; the pipe will cost about $25K.

6. Geothermal Fluid Pumps: The cost of the fluid pumps is included in the cost estimate for the field, and is estimated from background literature. (Variable-speed motors are sometimes used for helping the plant follow varying loads.) a. Downhole Production Pump: The pump is sized to produce a pressure boost of 200 psi plus other losses equivalent to about 30 psi. Horsepower is estimated from a standard flow X pressure boost equation. The pump is overhauled at 3-year intervals. b. Brine Injection Pump: An 80 psi pressure boost from this pump is assumed.

7. Pumping Power Requirements: The estimated power (kW) needed for the brine production and injection pumps is subtracted from the net output of the power plant core module. In precise terms, this means that the real net output of the systems will be about 5 to 15 percent lower than indicated by the nominal net output shown in the results.

8. Surface Disposal Cost: Disposing the brine to the surface is included as an option in the GT-SMALL model. If the number of injection wells in the model is set to zero, then the brine disposal cost is set to $50K. This is reasonable to cover the cost of disposal gutters, ditches, etc. In addition, the following terms are set to zero: Injection well cost, Injection piping cost, Brine injection pump cost, and Brine injection pump power. Using this option reduces the cost of power for the modal case system by about 1.5 cent/kWh, so the cost saving is considerable if surface disposal is acceptable from an environmental point of view.

9. Field O&M: The field annual O&M cost is set at 4 percent of total field capital cost (excluding costs of exploration and of production pumps). For the modal case system, this is about $18K per year. This is reasonable, since

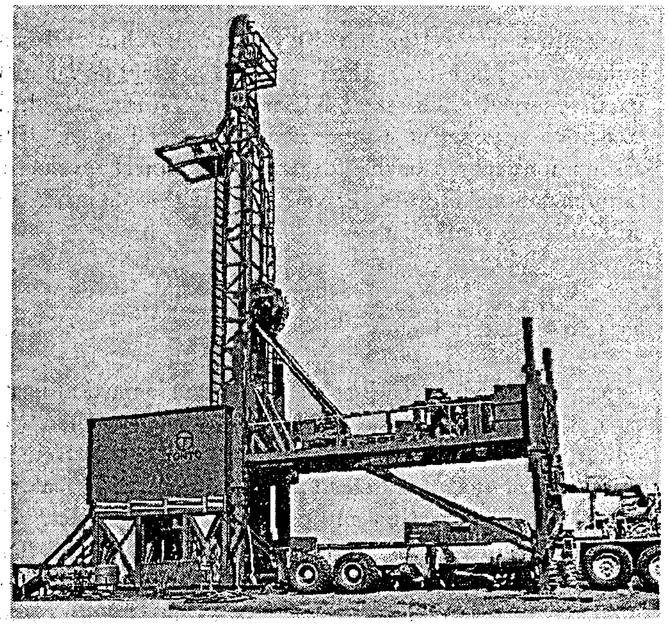


Figure 4. Truck-mounted drilling rig. Such rigs can drill to 2 km or more, at relatively inaccessible locations.

the reservoir temperatures are relatively low compared to some systems for which general O&M requirements would be a higher percentage per year (e.g., 6 to 7 percent). Additional costs for refurbishment of downhole production pumps are calculated separately.

10. Cold-Start Power: These plants may require some electrical power to start them from cold conditions. If the geothermal well flow is artesian, then the plant will self-start once the primary heat exchanger is warmed up. Under other conditions, 5 to 10 percent of the plant's nominal capacity may be needed to start the plant. For purposes of conservativeness in costing, the plants costed here assume a self-starting diesel is included, sized at 7 percent of the capacity of the power plant core module. This adds about 1.3 percent to the overall capital cost.

11. Flashed-Steam Alternative: Geothermal Power Company has indicated that noncondensing flashed-steam power plants, operating from 150°C steam and sized between 500 and 1,000 kW, can be installed for about $1350 per kW. [2]

12. Economics Assumptions: Costs are shown in mid-1993 dollars. The cost of power (cents/kWh) is calculated using levelized revenue requirements equations. The assumptions used are those employed in recent U.S. Department of Energy analyses. [5] The nominal discount rate is 11.0 percent. The assumed rate of future inflation is 3.9 percent. The real discount rate is consequently 6.8 percent. The project life is assumed to be 30 years. Taxes, tax incentives, and royalties are ignored. The consequent current-dollar annual fixed charge rate for capital items is 11.67 percent. The O&M cost

levelization factor (for the 30 year project life and stated inflation rate) is 1.453. The equivalent constant-dollar annual fixed charged rate is 8.03 percent. Interest during construction is set at 8 percent of the capital costs. These assumptions are reasonable for funding of project development through national utilities. Private financing would increase the cost of funds somewhat.

System Capacity Factor

Capacity factor (international term: "system annual utilization factor") is explicit in the GT-SMALL model. The cost of power values shown in this report assume capacity factors of 0.80, typical of U.S. baseload plants. The capacity factor has a very strong impact on any capital-intensive project. U.S. grid-connected geothermal power plants are typically run at capacity factors of about 80 percent. Off-grid applications might see this reduced to as low as 30 to 40 percent, especially during the initial few years of operation in instances where the geothermal system provides the first substantial electricity to a local market. Electricity cost will be inversely proportional to the capacity factor actually experienced. E.g., for a capacity factor of 0.50, the cost of power will be 8/5 times that estimated for a capacity factor of 0.80.

COST OF POWER RESULTS

Parameters and costs for the modal system are shown in Table 4. The cost of power from this system installed in the U.S., 11 ¢/kWh, is quite acceptable for many remote applications. Costs outside of the U.S. might be 5 to 20 percent higher.

Useful estimates of the costs against which these geothermal systems compete come from the Department of Energy Office of Solar Energy Conversion [6]. In 1991 dollars, electricity from diesel generators costs 46 to 103 ¢/kWh, (under fuel prices ranging from \$0.40 to \$1.00/liter). Electricity from solar photovoltaic systems (including battery storage) cost 75 to 100 ¢/kWh in 1991, and is projected to cost 34 to 60 ¢/kWh in 2000. In that study, the equivalent cost of extending an electric grid was estimated to be as high as 12 to 15 ¢/kWh per mile of grid (7 to 9 ¢/kWh per km of grid) for systems of low capacity. Considering those estimates, it seems likely that geothermal electricity that costs as much as 30 ¢/kWh would be economically attractive in many settings.

Table 5 shows the impacts on the cost of power from certain variations in the system parameters. These can be used to make rough estimates of the cost of power for locations where conditions are known.

MARKETS FOR THE TECHNOLOGY

The estimated market potential for these systems is large. Rough estimates of the geothermal resource potential, in units of MW capacity for 30 years (1 MW = 1,000 kW), for high-temperature resources for a number of countries are shown in Table 6. [7] The available amount of lower-temperature resource in each country will tend to be larger.

The characteristics of off-grid markets for electricity present certain challenges for governmental and/or commercial decision makers and geothermal developers. The general task is to find locations where currently unsatisfied demand or rapidly-growing demand for electricity is collocated with relatively easy-to-access geothermal resources. It is probably also important that the proposed geothermal facilities not be situated too far from locations with some mechanical-servicing capability, to keep ordinary maintenance costs reasonable.

TABLE 4. Details of Modal System

Technical Parameters:		Estimated Costs: (1993\$)	
Resource Temperature, °C:	120	A. Capital Costs, \$1000	
System Net Capacity, kW:	300	Exploration:	200
Number of Wells:	2	Wells:	328
Production Flow, 1000 Kg/hr:	70	Field, Other:	127
Plant Flow Need, Kg/kWh:	235	Power Plant:	655
Self-Start Power, kW	21	Self-Start Power:	18
Critical Backup (via batteries):	10 kW for 7 days	Backup Systems:	78
		B. O&M Costs, \$1000/Year	
Scheduled Backup:	50 kW for	Field:	31
	7 days/year	Plant:	26
Capacity Factor:	0.80	Backup Systems:	5
Electricity Cost, (levelized in constant 1993 dollars\$):			11.0 Cents/kWh

Situations where geothermal systems will be of economic or societal advantage include: (a) Substitution for oil-fired capacity where baseload demand is already established (e.g., on some islands); (b) Indications of pent-up demand in commercial, manufacturing, or mining operations; (c) Locations where geothermal can be paired with other generation options, such as hydropower or biomass [8]; and (d) Situations where it is feasible to site a new socially-necessary facility (e.g., a regional hospital or educational center) near a geothermal resource.

Perhaps the single most important thing that can be done to identify and define such markets is to broadcast information about the availability, performance, and costs of small geothermal electric systems to non-U.S. officials and entrepreneurs who are aware of locations and conditions where such systems would be useful.

TABLE 5. Multipliers for Effects on the Cost of Power of Varying Project Parameter Values

(Values for the modal system are shaded.)

Parameter						
1. Power Plant Net Output, kW:	Value:	100	200	300	500	1000
	Multiplier:	2.16	1.30	1.00	0.76	0.56
2. Geothermal Reservoir Temperature, °C:	Value:	100	110	120	130	140
	Multiplier:	1.53	1.17	1.00	0.90	0.83
3. Production Well Depth, meters:	Value:		200	300	500	1000
	Multiplier:		0.95	1.00	1.10	1.39
4. Injection Well Depth, meters: [a]	Value:	0		200	300	
	Multiplier:	0.86		1.00	1.04	

Note: [a] The 0 meter injection well depth assumes disposal is to the surface.

TABLE 6. Potential for Geothermal Electric Power in Developing Countries (Megawatts for 30 years)

Africa		Asia-Pacific		Caribbean		Latin America	
Burundi	50	China	2,000	Dominica	500	Argentina	1,000
Comoro Is.	50	Fiji	50	Grenada	100	Bolivia	1,000
Djibouti	500	India	200	Monteserrat	100	Chile	1,500
Ethiopia	5,000	Indonesia	16,400	Nevis - St. Kitts	50	Colombia	1,500
Kenya	3000	Papua N G	300	St. Lucia	100	Costa Rica	3,500
Malagasy	300	Philippines	8,000	St. Vincent	50	Ecuador	1,000
Malawi	50	Solomon Is.	50			El Salvador	2,000
Mozambique	50	Taiwan	200	**Eastern Europe**		Guatemala	4,000
Rwanda	200	Thailand	100			Honduras	500
Somalia	50	Tonga	50	NIS (FSU)	4000	Mexico	8,000
Sudan	300	Vanuatu	40	Greece	500	Nicaragua	4,000
Tanzania	600	Vietnam	100	Hungary	300	Panama	200
Uganda	500			Poland	50	Peru	1,000
Zaire	500			Turkey	500	Venezuela	500
Zambia	50			Azores	100		
TOTAL							**77,500**

REFERENCES AND CREDITS

[1] Firms with experience in the design and/or construction of small binary or binary-like geothermal power plants include: Barber/Nichols, Arvada, Colorado; Ormat, Inc., Sparks, Nevada; Ben Holt Company, Pasadena, California; Exergy, Inc., Hayward, California.

[2] Firms with design and/or construction expertise for small flashed steam plants include: Ben Holt Company, Pasadena, California; Geothermal Power Company, Elmira, New York; Douglas Energy Systems, Placentia, California.

[3] See P.M. Wright, Geothermal Resources Council Transactions, 1993, page 537, for estimates of emissions from geothermal electric plants.

[4] Estimates for battery storage costs were drawn from the Electric Power Research Institute Technical Assessment Guide (Supply, 1986) and the California Energy Commission Energy Technology Characterizations, 1990.

[5] U.S. Department of Energy, Energy Information Administration, report Annual Energy Outlook - 1993.

[6]. Solar 2000, A Collaborative Strategy, Volume 1, Figure 8, U.S. Dept. of Energy, February 1992.

[7] Geothermal Resource Potential, brochure of the U.S. National Geothermal Association, March 1993.

[8] Tsvi Meidav and Joshua Meidav, "Renewable Energy Development in Frontier Areas," International Conference on Regional Development, Ben Gurion University, Beer Sheva, Israel, December 1993.

[9] The authors are indebted to the following for various details of system performance and cost, and reviews of earlier versions of this report: Ken Nichols, Barber-Nichols Inc., Arvada, CO; Dan Schochet, ORMAT Inc., Sparks, NV; Tvsi Meidav, Trans-Pacific Geothermal, San Francisco, CA.

[10] This work was supported by Sandia National Laboratories contract AG-2384 to NOVA Analytics, 3025 Pine Spring Road, Falls Church, VA 22042, and Department of Energy contract AC01-93CE353060 to Princeton Economic Research, Inc., 1700 Rockville Pike, Suite 550, Rockville, MD 20852.

[11] For more information, contact: Dr. Allan Jelacic, Geothermal Division, U.S. Department of Energy, Washington, DC, 20585 (Telephone: 202-586-6054, Fax: 202-586-5124); or David Anderson, Executive Director, Geothermal Resources Council, 2001 2nd Street, Suite 5, Davis, CA 95616. (Telephone: 916-758-2839, Fax: 916-758-2839)

NOTICE

Session 9:
Summary

CLOSING REMARKS

Roland R. Kessler
Director, Office of Renewable Energy Conversion
U.S. Department of Energy

This program review has highlighted the accomplishments of the Geothermal Program, particularly its close and productive partnership with industry. Despite flat funding levels that have been further deflated by Congressional mandates, the Program has made some major accomplishments. Over the last decade, it has contributed to increasing domestic electrical generation capacity from 600 MWe to 2,700 MWe and a doubling of geothermal heat pump installations (from 20,000/year to 40,000/year). As we look towards the future, three messages should be communicated since they will affect the direction of DOE's Geothermal Program. These are Secretary Hazel O'Leary's Total Quality Management (TQM) initiative, the Geothermal Program's improved funding outlook, and the need for a continued emphasis on technology transfer.

Secretary O'Leary firmly believes in TQM and its link to strategic planning. Whereas strategic planning defines the vision, mission and core values that direct the Department activities, TQM is the process which the Secretary plans to use to achieve the strategic plan's goals. Christine Ervin, the new Assistant Secretary of Energy Efficiency and Renewable Energy, is moving towards fully instituting TQM in her office.

The Geothermal Program, for years, has essentially been practicing the key elements of TQM -- continuous improvement, customer focus, and teaming. Continuous improvement is virtually a watchword for the Geothermal Program. The Program is customer focused with its plans reviewed routinely by industry for compatibility. Teaming is not a new concept either as evidenced by the Program's established industry partnerships and long history of cooperative efforts. Consequently, the Program has been able to present a strategic plan that has captured the interest of the new Assistant Secretary.

As a result, the funding outlook for the Geothermal Program is more optimistic, although guardedly so, than it has been for quite some time. Fiscal Year 1995 funding is expected to be 50% above current levels which is hopefully the beginning of a trend that can be sustained. The increased funding is largely due to implementation of the Climate Change Action Program (CCAP) and the Energy Policy Act of 1992 (EPAct). CCAP's focus on accelerated deployment of the best available technologies for mitigating factors contributing to global climate change is a natural extension of existing geothermal activities. EPAct is a Congressional mandate that provides good possibilities for geothermal energy as it is the only renewable energy form with significant potential in the near term.

With these major budget increases, the Program can end the 1990s in a ***Win-Win*** situation; The Geysers stabilized, identification of at least 25 new resource areas, development of at least 8 new producing reservoirs, and technological advances that will result in 5,000 MWe on-line at costs of 3-7 cents/kWh. As Tom Sparks said, we must continue to make geothermal technologies more cost effective, raise productivity and be more active in the marketplace.

Finally, sustaining a trend of increased funding and market penetration will require that technology transfer, in all its forms, must continue to be emphasized. This includes effectively delivering the message on the benefits and potential of geothermal energy, as well as moving promising technologies into the marketplace. As Dave Cox said, the geothermal community must organize, lobby and market; organize to act quickly and as one voice to counter incorrect impressions of geothermal so that lobbying and marketing can be carried out effectively. Cox and Sparks both pointed out that the Program and industry have a poor record of speaking out. Randy Berggman made a very valid argument for the need to build up public support through more outreach since market behavior alone may not provide enough grounds for geothermal energy use. In the more traditional areas of technology transfer, the Geothermal Program has led other renewables in direct technology transfer and spinoffs. Some examples are high temperature elastomers, polymer cements and PDC drill bits. This success is directly connected with the close working partnerships, developed between government, industry, laboratories and utilities, forming TEAMS. As the old saying goes, TEAM means Together Everyone Achieves More.

In summary, DOE's Geothermal Program looks forward to a brighter future where the continued partnership with industry, full institution of Secretary O'Leary's Total Quality Management, improved funding and continued emphasis in all aspects of technology transfer will work together in expanding the role of geothermal in domestic and international energy use. Thank you to all the meeting planners, PERI, Meridian, Al Jelacic and his staff. A special thank you to the old standby, Dave Anderson. Finally, thank you to all the participants and attendees for making this a worthwhile Program Review.

Session 10: Industry Critique

Moderator:
Tsvi Meidav,
Trans-Pacific Geothermal
Corporation

Geothermal Energy Association

INDUSTRY CRITIQUE

Moderator:

Tsvi Meidav
Trans-Pacific Geothermal Corporation

Panelists:

Exploration	Tsvi Meidav, Trans-Pacific Geothermal Corporation
The Geysers	W. Thomas Box, Calpine Corporation
Reservoir Engineering ...	Michael Barnes, Unocal Corporation
Drilling	Marc W. Steffen, Calpine Corporation
Energy Conversion	Ben Holt, The Ben Holt Company
Geothermal Heat Pumps ..	Gerald W. Huttrer, Geothermal Management Company, Inc.

CRITIQUE OF EXPLORATION TECHNOLOGY

Tsvi Meidav
Trans-Pacific Geothermal Corporation

ELECTRICAL AND ELECTROMAGNETIC METHODS

Basic rock properties

The commonly held view that lower electrical resistivities in liquid saturated rocks signifies higher temperatures is not necessarily correct. There are some well documented cases where high temperature geothermal reservoirs are characterized by **higher** resistivities. Research by members of the Icelandic National Energy Authority shows that this phenomenon may be due to metamorphism of highly conductive montmorillonites into the highly resistive sepiolite at temperatures in excess of about 240°C. The lack of certainty about the relationship between temperature and resistivity makes all electrical methods of exploration ambiguous, reducing their usefulness.

The assumed relationship between resistivity and porosity in crystalline rocks is quite different from that in sedimentary rocks. Although some work has been carried out to determine that relationship, it is still far from satisfactory.

Little is know about the relationship of pressure and resistivity in crystalline rocks.

Controlled source audiomagnetotellurics (CSAMT)

CSAMT, as a reconnaissance technique for vertical electrical soundings, has grown in popularity in recent years, due to the great reduction in cost per sounding. However, the technique is still fraught with interpretation problems, limiting its reliability:

1. The resistivity pseudo-sections can be considered reliable at a distance away from the transmitting dipole which is sufficiently large to make the transmitted signal a quasi-plane-wave, i.e., at a distance equal to four or five skin-depths away. This greatly limits the usefulness of the technique. There is a need to develop the analytical tools which would permit the utilization of CSAMT even at relatively short distances away from the transmitting dipole.

2. Current analytical procedures ignore the effect of topography on the radiating electromagnetic waves, resulting in resistivity anomalies which may have no relationship to the apparent resistivity distribution around the area of the receiving dipole. This may result in false anomalies which do not accurately reflect the true electrical stratigraphy of the rocks.

Electromagnetic methods

A variety of loop-type EM methods exists to carry out vertical electrical soundings. They are slower and more cumbersome than the CSAMT method, but claim a lesser impact from static effects due to lateral inhomogeneities. It would be useful if an assessment was made of the relative merits of CSAMT versus centrally symmetrical EM techniques.

Self Potential

Substantial progress has been made in developing field techniques that provide repetitive readings which are relatively noise-free. It is known that the magnitude of the SP anomaly is dependent upon the rate of convection of fluids in the subsurface. For example, leakage from behind dams has been successfully mapped with SP because of the streaming potential caused by the leakage. A number of case histories have been published in recent years showing that SP can identify the location of convective flows in geothermal systems. However, the magnitude of the SP anomaly is a function of the resistivity of the rocks, temperature differentials, and coupling factors, as well as pressure differences (i.e., convection rate). SP shows promise of becoming a potentially useful tool in determining the natural convection rate in the system, thus providing an important input for reservoir analysis.

SEISMIC TECHNIQUES

3-D seismic reflection

3-D seismic has revolutionized the exploration for oil by providing much finer detail and definition of physical properties than the conventional 2-D seismic reflection. Yet it appears that 3-D seismic reflection has never been attempted in geothermal exploration, despite the fact that geothermal field developers have run into tremendous difficulties in delineating the continuation of permeability, even in fields where production has already been established.

Passive seismics

Microearthquake seismology has been useful in defining active faults and in distinguishing between steam-saturated and liquid-saturated zones, but the massive data gathered in various areas (such as The Geysers) has not been fully analyzed to determine what other useful information about structure, rock properties, and related physical parameters may be extractable from the data.

INTEGRATION

There is an insufficient number of case histories that combine different types of geophysical techniques and geological data which could be the basis for greater confidence in exploration of blind targets. Such questions as the temperature of a potential reservoir, its productivity, and its volume are not yet answerable with any degree of confidence without a substantial amount of exploration drilling.

THE FOCUS OF CURRENT AND FUTURE DOE GEOTHERMAL PROGRAM RESEARCH AND DEVELOPMENT ACTIVITIES

W.T. BOX
CALPINE CORPORATION

Members of the geothermal industry have long been involved in recommending and prioritizing DOE funded geothermal R&D programs. This effort began with the formation of the LBL-industry Advisory Panel in 1984 and continues today. During this time, the geothermal industry has grown from an industry focused on exploration and development to one focused on sustaining project output while lowering production and operating costs in the face of changing contractual conditions. The near term potential for growth of the geothermal industry is limited by the difficulty in securing long term, competitive, electric power sales contracts which allow project financing to be put in place. This difficulty stems from the current surplus and low cost of electric power, particularly in areas with geothermal power potential.

The growth of the geothermal industry in the 1980's, outside The Geysers was fueled primarily by the 20 year Interim Standard Offer 4 contracts for the sale of electric power to specific utilities. The first 10 years of these contracts contain a very favorable, fixed, electric price for energy with the final 10 years being priced at the utilities "avoided" costs. Capacity payments are also included in these contracts. Between 1985 and 1990 approximately 800 mw of geothermal capacity was developed to supply electricity under these contracts. During the next 5 years the majority of these geothermal projects will complete operation under the initial fixed price period of their contracts and the price paid for the electricity generated by these projects may drop to as low as 25 percent of their current electric price. Obviously, the long term survival of many of these projects depends upon their ability to continue to operate profitably in the face of dramatically reduced revenues. Operators, faced with these changing economics, must reduce operating expenses, including fuel development costs in order to remain economically viable. The DOE geothermal program should focus, in part, on projects designed to reduce existing project operating cost in the very near term (5 years). Projects that can have a positive effect on reducing costs are:

1) Well drilling advancements including drill bit design and advanced directional drilling systems.

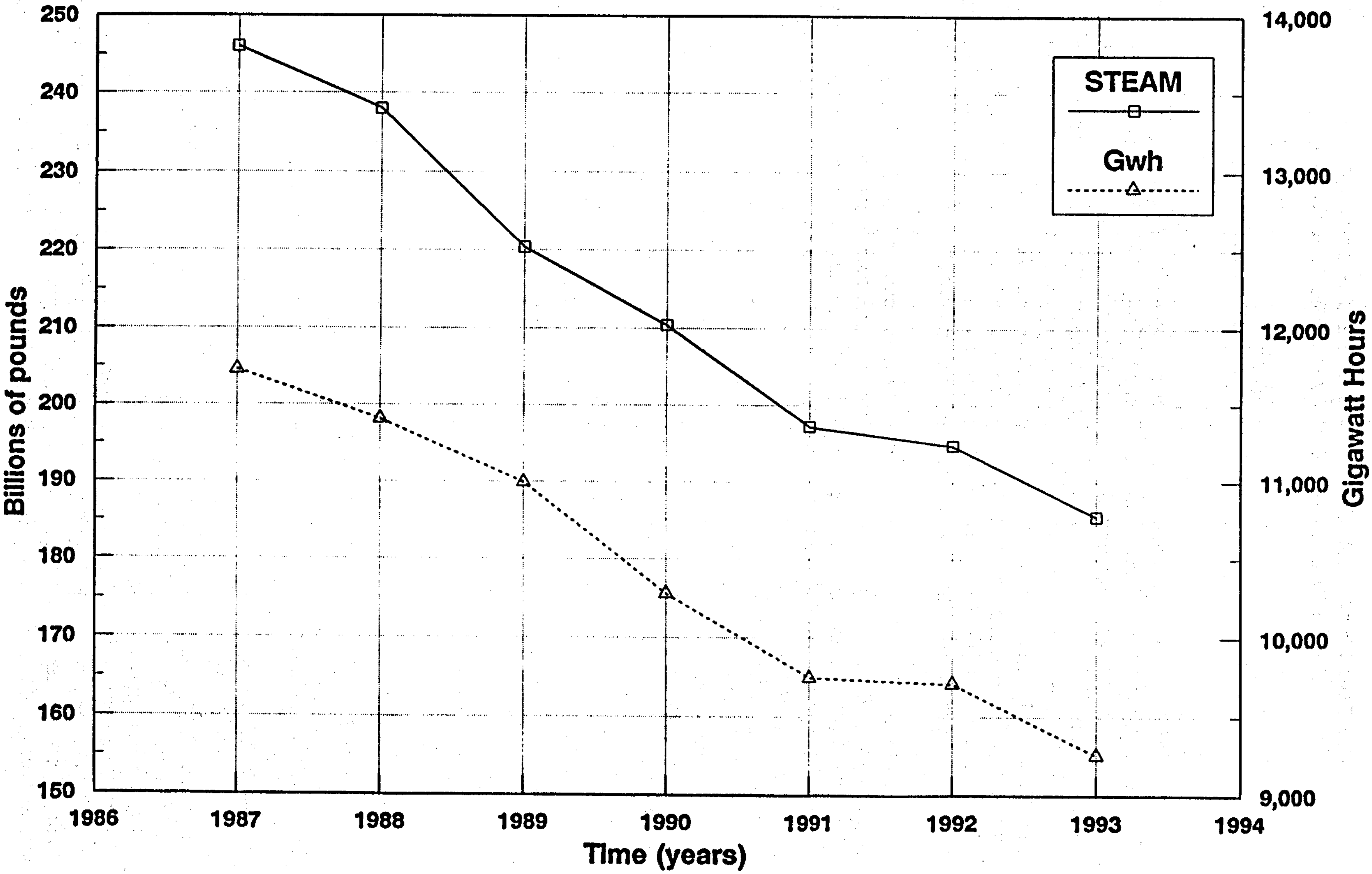
2) An improved understanding of effect of injection into geothermal reservoirs through modeling and cost shared field experiments.

3) Chemical treatment of flashed brines to control scaling and corrosion.

The depletion experienced in The Geysers field between 1987 and 1993 (Figure 1) has had a profound effect on the perception by the financial and business communities, of the resource risk associated with existing and new geothermal developments in The Geysers, as well as other geothermal fields. This perception has underlined the need for careful assessments of the ultimate potential of all developed or new geothermal reservoirs and for the development of useful reservoir management programs designed to result in the optimum recovery of the heat in place in these reservoirs. The DOE/Industry supported R&D program in The Geysers should remain focused on the development of reservoir modeling techniques, particularly as they related to production forecasting and the quantification and prediction of the effects of water injection.

FIGURE 1

ANNUAL PRODUCTION
GEYSERS FIELD



Programs designed to support the development of a long term injection strategy at The Geysers are particularly beneficial (i.e. tracer development, cost shared field experiments) as the continued extraction of heat from this reservoir depends upon successful injection strategies. Finally, DOE programs designed to provide materials and processes to control corrosion and handle high noncondensible gases would be immediately useful at The Geysers , as well as other geothermal fields.

In summary, the DOE geothermal program should focus on R&D programs and cost shared projects with the potential to provide near term economic benefit to the geothermal industry.

Comments on the Reservoir Engineering Program

Michael Barnes
Unocal Corporation

The greatest research need is in developing real-time answers for problems industry is currently experiencing. The cost-shared program at The Geysers has been very focused in this regard and the results of these efforts will be applicable to other geothermal fields, especially as more fields experience decline.

From my point-of-view, the industry-coupled efforts should have the highest priorities; however, research-type projects are also useful. The three most important reservoir engineering areas are (1) injection enhancement experiments in The Geysers; (2) tracer studies to follow fluid flow; and (3) water saturation, adsorption, and desorption studies to determine reservoir depletion mechanisms.

CRITIQUE OF DRILLING PROJECTS

MARC W. STEFFEN
CALPINE CORPORATION

Drilling costs continue to be a major component of geothermal exploration and development programs. A concerted effort should be maintained between industry and government to continue research and development projects that have significant merit to geothermal drilling operations. As there continues to be more competition for available project funding, there are several areas where R&D programs should focus. Reducing drilling costs has to be a primary objective when assessing the relative benefit to the geothermal industry. Minimizing costs permits more projects to be economically feasible which, in turn, enhances the prospects of new resource development.

When evaluating projects as to their merit, value, and application to the drilling industry relative to cost reduction, there are three approaches that can be taken. The first is to identify specific drilling problems that can be mitigated or prevented by utilizing a better methodology or type of equipment. Drilling problems associated with lost circulation is such an example. A straddle packer tool is being developed at Sandia for the purpose of placing cement in a specific fracture zone where it can provide the most benefit. This kind of project has tremendous potential value because it represents a specific solution to a serious drilling problem and can be easily field tested for evaluation on its future application. Development and testing of cementitious muds that can be used as an alternative to cement plugs for lost circulation control is another project that has considerable merit and could provide immediate rewards. The second approach is to identify areas where performance can be enhanced from more efficient operations and a more optimum use of drilling capital. A good example of this is slimhole drilling. This technique needs to be applied in various resource areas with different drilling and reservoir characteristics to determine its fullest potential and value. This will take considerable time and resources, but the potential cost benefit and impact on future geothermal exploration programs is extremely significant. Development of enhanced bits for hard rock drilling and a high temperature drilling motor for air drilling applications are projects that, once implemented in the field, will certainly result in more efficient drilling performance. The third approach when determining the project merit and applicability is to keep extending technology to new levels. This requires significant resources as well as constant input and feedback from the geothermal drilling industry as to what is needed and what has the most practical application. New technology is needed to meet future drilling challenges, however, the cost of developing this technology needs to be weighed against the applicability, need, and actual cost benefit of such an advancement. This kind of information can best be supplied by drilling operator and service companies.

The continued partnership of industry and government is becoming more critical than ever. Service companies with their own R&D programs have supplied new technology and equipment to the drilling industry for many years. However, as budgets continue to be reduced and streamlined, the need for cost sharing of new drilling projects becomes even greater. The quest for lower cost and more efficient drilling to meet future drilling needs can be greatly accelerated if government and industry can continue to work together effectively. A cooperative and effective partnership that works together with common goals can create new opportunities enabling the drilling industry to meet tougher challenges in the future.

A continued interaction and communication needs to be maintained between industry and the DOE. This will assist in identifying trends and establishing a focus on specific goals and objectives to best serve the needs of a changing geothermal drilling industry. When assessing what technologies are needed and have the most applicability and merit, industry R&D programs have to be flexible and adaptable to changing conditions. Conversely, industry has to continue to communicate to government what is needed, what the major problems are, and what needs to be done to drill less expensively and more efficiently. This can be accomplished through groups like the Geothermal Drilling Organization (GDO) and the Geothermal Technology Organization (GTO), where a forum is created to promote projects or exchange information. This kind of forum, where members include all sectors of the geothermal community, is where the balance of science objectives versus projects having an immediate and measurable impact on drilling performance can be discussed. When competing for a finite budget that has to service many sectors and interests, prioritizing projects by merit and value can be very difficult.

When it comes to developing new projects and technologies to meet new drilling challenges, the drilling industry has several advantages. Drilling a well as inexpensively and efficiently as possible are objectives of all operators. Many drilling problems are common to different geothermal areas. New technologies and products developed to meet these problems can be tested and implemented at the rig site with an immediate measurable benefit. As a result, the value and merit of new project development can be relatively, quickly assessed.

The next five to ten years will be critical in exploring and developing new geothermal resources for our industry to continue to grow into the twenty-first century. With diminished drilling and R&D budgets and the prospect of marginal economics, new technologies and drilling methods will need to be developed to take full advantage of emerging opportunities.

Critique of the Energy Conversion Program

Ben Holt
The Ben Holt Company

I want to begin by applauding the improved working relationship with DOE. Twenty years ago, there was a good partnership which was permitted to languish. Now a true partnership has developed again.

Research being conducted on binary conversion technologies has shown some promising results. Significant increases in performance appear possible and have been estimated by the proponents to be about 40% for the Kalina cycle, 20% for the new Bi-phase technology, and 8% for supercritical cycles. However, it should be noted that a "standard" against which these improvements can be measured has not been specified and therefore, there is no common basis for comparison of these technology improvements. The Ben Holt Company is currently involved in an evaluation of these cycles for EPRI which we hope will enable us to establish a credible basis for comparison.

I am also encouraged by the supercritical expansion experiments through the dome, but a long-running experiment is needed to determine if erosion problems develop. Erosion could have significant impacts on equipment costs.

One of the biggest problems we encounter is silica scaling, particularly in binary power plants and bottoming cycle applications. Unocal has patented a method to control silica scaling by adjusting the pH, but other techniques may work as well. Silica deposition in the formation also occurs which reduces formation permeability. Work is needed to develop effective ways to prevent or lessen the precipitation of silica. I would hope that Dr. Weare's modeling work could be extended to include reaction rates as well as chemical equilibrium.

Industry considers corrosion a serious problem. Further work on corrosion is encouraged and is ideal as a collaborative industry/DOE effort. Ways of reducing corrosion in wells, the gathering system, and turbines need to be developed and improvements in metallurgy and non-metallics are needed, especially for use in turbine components.

The presentation on small-scale geothermal power plants was extremely interesting. There is a growing need for this type of power unit; however, the economics of such a venture may be a hindrance at the present time, so we need to work in conjunction with the utilities in the foreign host countries. I can envision the installation of many of these small plants in the African Rift Valley, for example.

Comments on the U.S. Department of Energy Geothermal Heat Pump Program

Gerald W. Huttrer
Geothermal Management Company, Inc.

On April 27, 1994, five papers were presented on geothermal heat pump-related topics. Each of these focused on specific work in progress that is sponsored by the U.S. Department of Energy (DOE) and which ultimately seeks to promote proliferation of the technology together with reduction of first costs of ground loop installations. Their content is briefly summarized below:

- John Geyer's introduction and subsequent remarks presented the utility and regulatory points of view, gave funding options for end users and cost recovery methods available to utilities. Knowledge of these ways in which geothermal heat pumps can meet the requirements and overcome the objections of end users and utilities will facilitate the successful promotion of the technology to them.

- Joel Renner's paper served to outline DOE's geothermal heat pump program for follow-up elaboration by others.

- Dr. Paul Lienau's recitation of comparative costs, monitoring data and his support for ground water heat pumps provided confirmation of the win-win aspect of geothermal heat pumps for utilities, conservationists and for end users.

- William Sullivan described Sandia National Laboratories' geothermal heat pump demonstration project, the monitoring that they are conducting at several heat pump installations across the US and their marketing support functions.

- Roy Mink illustrated the extent to which shallow groundwaters are co-located with population centers. His data synthesis can be used to excellent effect when promoting the use of geothermal heat pumps in moist to wet ground conditions that provide optimal thermal transfer.

I believe that the content of these papers confirms that progress is being made on technology proliferation and on first cost reduction and that DOE funds are being well spent.

I would, however, like to make several more observations and recommendations regarding the DOE geothermal heat pump program.

First, notwithstanding my full support for the ongoing program, I believe that its scope should be somewhat broadened. Currently, it focuses primarily on geothermal heat pumps installed in soft to moderately hard rock environments that are damp to semi-saturated. I think that additionally, the DOE should plan increased assistance to and promotion of: (a) groundwater-coupled heat pumps including both "production-injection" and "pump and dump" (under certain circumstances), and (b) hard rock installations such as "standing column wells" and vertical loops able to stand, uncased, in competent granitic and metamorphic terrains such as those in Scandinavia.

Extension of DOE assistance to these two geothermal heat pump types would broaden the geographic scope of their outreach and, in light of the existence of extensive "hard rock" regions in the western states, serve to unify the eastern and western portions of the US geothermal heat pump industry that appear to be undesirably segmented.

Second, since all of the April 27 speakers mentioned high first costs as an important barrier to market penetration, I would like to encourage DOE to continue its attention to their reduction. Achievement of this objective will depend on education and research, both of which can be effectively accomplished by DOE through its laboratories and their subcontractors. The two mechanisms I believe to be most important for cost reduction are:

1. Improved drilling rates that can be effected by the bit research underway at Sandia and by the planned NADET program and

2. Education of more loop installers so as to increase competition and thus drive down first costs. Vertical ground loops should be available at costs below $600 per ton and this will happen when pencils have to be sharpened to beat competitors.

Finally, I would like to say that, though money is always welcomed by growing technologies, I believe that it would be imprudent to use federal financial "props" in the geothermal heat pump business. The widespread use of such assistance in the early years of the solar and wind industries did boost their acceptance initially, but when the "propping period" expired, these technologies virtually collapsed. I would hate to see that scenario reenacted. There is nothing wrong with rebates and financial incentives available through the utilities. These can be used case-by-case beneficially. It is the industry-wide, tax-based devices that seem to encourage schemes that have marginal business merit and their renewed use should be avoided.

Final Agenda

U.S. DEPARTMENT OF ENERGY
GEOTHERMAL PROGRAM REVIEW XII

Geothermal Energy and the President's Climate Change Action Plan

April 25-28, 1994

Final Agenda

MONDAY, APRIL 25

7:00 pm to 9:00 pm	Registration and Reception

TUESDAY, APRIL 26

8:00 am to 9:00 am	Registration and Continental Breakfast

SESSION 1: OVERVIEW
9:00 am to 12:00 pm — **Chairperson: John E. Mock, Director, Geothermal Division, U.S. Department of Energy**

9:00 am	◆ **Welcome and Announcements** John E. Mock, Director, Geothermal Division, U.S. Department of Energy
9:05 am	◆ **DOE Welcoming Remarks** Richard H. Nolan, Acting Assistant Manager for Energy Programs, Oakland Operations Office, U.S. Department of Energy
9:15 am	◆ **The Role of Geothermal Energy in the Evolving Utility Sector** Robert L. San Martin, Deputy Assistant Secretary for Utility Technologies, U.S. Department of Energy
9:45 am	◆ **4000 by 2000 -- Designed Growth in a Competitive Market** David W. Cox, Vice President, California Energy Company and Co-Chairman, Geothermal Energy Association
10:15 am	Break
10:45 am	◆ **Resource Planning and Development: A Public Involvement Process** Randy Berggren, General Manager, Eugene Water and Electric Board
11:15 am	◆ **Electric Power -- A New Era** Thomas R. Sparks, Manager of Government Relations and Utility Affairs, Unocal Corporation and Chairman, Independent Energy Producers Association
11:40 am	◆ **Geothermal Technology to Meet the Nation's Environmental Goals: A 20 Year Perspective** John E. Mock, Director, Geothermal Division, U.S. Department of Energy

Final Agenda (continued)

TUESDAY, APRIL 26 (CONTINUED)

12:00 pm to 1:30 pm	◆ **GEA Luncheon: The Recent Biennial Resource Plan Update (BRPU) Solicitation in California and the Future of Renewables in the Electric Utility Industry** Janice G. Hamrin, Principal, Hansen, McQuat, Hamrin and Rhode, Inc.

SESSION 2: THE GEYSERS
1:30 pm to 3:10 pm — **Chairperson: W. Thomas Box, Calpine Corporation**

1:30 pm	◆ **Introduction** W. Thomas Box, Calpine Corporation
1:40 pm	◆ **Overview of Industry/DOE Cooperative Research in The Geysers Field, California** Phillip M. Wright, University of Utah Research Institute
1:55 pm	◆ **Geysers Injection Modeling** Karsten Pruess, Lawrence Berkeley Laboratory
2:20 pm	◆ **Effects of Adsorption on Production and Reinjection at The Geysers** Roland N. Horne, Stanford University
2:45 pm	◆ **Seismic Velocity and Attenuation Studies at The Geysers** John J. Zucca, Lawrence Livermore National Laboratory
3:10 pm	Break

SESSION 3: EXPLORATION
3:30 pm to 4:45 pm — **Chairperson: Tsvi Meidav, Trans-Pacific Geothermal Corporation**

3:30 pm	◆ **Introduction** Tsvi Meidav, Trans-Pacific Geothermal Corporation
3:40 pm	◆ **Overview of the DOE Geothermal Exploration Program** Marshall J. Reed, Geothermal Division, U.S. Department of Energy
3:55 pm	◆ **Advances in the Self-Potential Method for Geothermal Exploration** Michael Wilt, Lawrence Livermore National Laboratory
4:20 pm	◆ **Geothermal System Size and Structure** Dennis L. Nielson, University of Utah Research Institute
4:45 pm	Adjourn for the Day

Final Agenda (continued)

WEDNESDAY, APRIL 27

7:30 am to 8:30 am	Continental Breakfast

SESSION 4: ENERGY CONVERSION AND MATERIALS
8:30 am to 10:10 am — **Chairperson: Michael Forsha, Barber-Nichols, Inc.**

8:30 am	◆ **Introduction** Michael Forsha, Barber-Nichols, Inc.
8:40 am	◆ **Overview of Energy Conversion and Materials Programs** Raymond J. LaSala, Geothermal Division, U.S. Department of Energy
8:55 am	◆ **Field Investigations Examining the Impact of Supersaturated Vapor Expansions on Turbine Performance** Gregory Mines, Idaho National Engineering Laboratory
9:20 am	◆ **Lightweight CO_2-Resistant Cements for Geothermal Well Completions** Lawrence E. Kukacka, Brookhaven National Laboratory
9:45 am	◆ **Direct-Contact Condensers** Desikan Bharathan, National Renewable Energy Laboratory
10:10 am	Break

SESSION 5: DRILLING
10:30 am to 12:10 pm — **Chairperson: Marc W. Steffen, Calpine Corporation**

10:30 am	◆ **Introduction** Marc W. Steffen, Calpine Corporation
10:40 am	◆ **Drilling Technology Overview** James C. Dunn, Sandia National Laboratories
10:55 am	◆ **Slimhole Drilling for Geothermal Exploration** John Finger, Sandia National Laboratories
11:20 am	◆ **Development of Synthetic-Diamond Drill Bits for Geothermal Drilling** Diane Schafer, Sandia National Laboratories
11:45 am	◆ **Design of a Pressure/Temperature Logging System for Geothermal Applications** Peter Lysne, Sandia National Laboratories
12:10 pm	Lunch (not hosted)

Final Agenda (continued)

WEDNESDAY, APRIL 27 (CONTINUED)

SESSION 6: GEOTHERMAL HEAT PUMPS

1:30 pm to 3:10 pm — **Chairperson: John D. Geyer, Citizens Power & Light Corporation**

1:30 pm	◆ **Introduction** John D. Geyer, Citizens Power & Light Corporation
1:40 pm	◆ **Geothermal Heating and Cooling with Heat Pumps -- An Overview of DOE Programs** Joel Renner, Idaho National Engineering Laboratory
1:55 pm	◆ **Geothermal Heat Pump Performance and Utility Programs** Paul Lienau, Geo-Heat Center, Oregon Institute of Technology
2:20 pm	◆ **The Sandia/DOE Program on Geothermal Heat Pumps** William Sullivan, Sandia National Laboratories
2:45 pm	◆ **Ground Water Resource Assessment for Heat Pump and Low-Temperature Geothermal Applications** Leland L. Mink, Water Resources Institute, University of Idaho
3:10 pm	Break

SESSION 7: TECHNOLOGY TRANSFER

3:30 pm to 4:55 pm — **Chairperson: Dan Sanchez, Albuquerque Operations Office, U.S. Department of Energy**

3:30 pm	◆ **Introduction** Dan Sanchez, Albuquerque Operations Office, U.S. Department of Energy
3:40 pm	◆ **Biochemical Processes Applications in Geothermal and Other Industries** Eugene T. Premuzic, Brookhaven National Laboratory
4:05 pm	◆ **Hot Dry Rock: A Climate Change Action Opportunity for Industry** David V. Duchane, Los Alamos National Laboratory
4:30 pm	◆ **User Friendly Models for Chemical and Thermophysical Properties of Geothermal Fluids** John H. Weare, University of California at San Diego
4:55 pm	Adjourn for the Day

Final Agenda (continued)

THURSDAY, APRIL 28

7:30 am to 8:30 am — Continental Breakfast

SESSION 8: GEOTHERMAL OPPORTUNITIES
8:30 am to 9:25 am — **Chairperson: Robert Creed, Idaho Operations Office, U.S. Department of Energy**

8:30 am
- **Introduction**
  Robert Creed, Idaho Operations Office, U.S. Department of Energy

8:40 am
- **NADET: A New Research Initiative**
  Allan J. Jelacic, Geothermal Division, U.S. Department of Energy

8:55 am
- **Update on BPA Geothermal Activities**
  George Darr, Bonneville Power Administration

9:10 am
- **Small Geothermal Electric Systems for Remote Powering**
  Daniel J. Entingh, Princeton Economic Research, Inc.

SESSION 9: SUMMARY
9:25 am to 9:40 am

9:25 am
- **Closing Remarks**
  Roland R. Kessler, Director, Office of Renewable Energy Conversion, U.S. Department of Energy

9:40 am — Break

SESSION 10: INDUSTRY CRITIQUE
10:00 am to 12:00 pm

10:00 am
- **Comments by Geothermal Energy Association Panel followed by Open Discussion**
  Moderator: Tsvi Meidav, Trans-Pacific Geothermal Corporation

12:00 pm — Conference Adjourns

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