



GEOHERMAL PROGRAM REVIEW XI

PROCEEDINGS

"Geothermal Energy- The Environmentally Responsible Energy Technology for the Nineties."

**April 27-28, 1993
Berkeley, CA**

Sponsored by:

MASTER

**U.S. Department of Energy
Assistant Secretary, Conservation and Renewable Energy
Geothermal Division
Washington, DC 20585**

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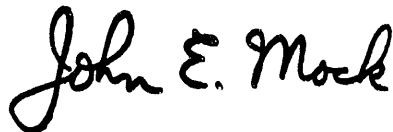
PREFACE

Once again the geothermal community came together for an in-depth review of the research and development program of the Geothermal Division of the U.S. Department of Energy. Meeting in Berkeley, California on April 27-28, 1993, the group focused on the theme "Geothermal Energy -- the Environmentally Responsible Energy Technology for the '90s." Attendees included representatives of the geothermal development industry, utilities, investment community, federal, state, and local agencies, and national laboratories.

Industry representatives chaired the various technical sessions and introduced each R&D topic with brief commentaries on industry's perspective of on-going research activities. DOE-funded researchers then reported in detail on the status of specific research projects, progress over the past year, and plans for future activities. This program format -- of industry-government interchange of information pertinent to each technology under development -- reflected the structure of the geothermal R&D program itself and highlighted the success of industry and government working closely together in a partnership that has been notably successful in its achievements for over 20 years and for which the future looks especially bright.

The entire geothermal community has every reason to feel pride -- and some excitement -- in sentiments of overriding importance expressed at the program review. First, utility spokesmen expressed the view that the reliability of geothermal power generation technology is without question. This level of trust in a technology as new as geothermal flash steam technology is unprecedented. Another announcement validated the program/theme -- an informal consensus of regulators at all levels of government that the geothermal industry exhibits responsible environmental behavior and no incidents of noncompliance by operating plants were reported. While enjoying this well-deserved reputation, we must remain eternally vigilant and mindful that continued incident-free performance is paramount to our future.

I want to express my thanks to all who contributed to the success of this conference and wish to invite your continuing participation in DOE's geothermal R&D program.

A handwritten signature in black ink that reads "John E. Mock". The signature is written in a cursive, flowing style with a large initial 'J'.

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

OVERVIEW

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

THE OFFICE OF ENERGY EFFICIENCY AND RENEWABLE ENERGY:
A POLICY OVERVIEW

Presented by:
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U.S. Department of Energy

On behalf of:
Allan R. Hoffman
Associate Deputy Assistant Secretary
Office of Utility Technologies
U.S. Department of Energy

Introduction

Changes due to passage of the Energy Policy Act last fall and the new administration have resulted in much discussion about the 3Es; Energy, Environment and Economic objectives. The Department of Energy, as a whole, and the Geothermal Division in particular are doing their best to present fresh logic that shows receptivity and responsiveness to these changes, as evidenced by the theme of this year's Program Review, "Geothermal Energy -- The Environmentally Responsible Energy Technology for the Nineties".

As part of these changes, The Office of Conservation and Renewable Energy has been renamed the Office of *Energy Efficiency and Renewable Energy* (EE), although by no means does this indicate "CONSERVATION" has gone out of style. The new title is simply one of the more visible changes reflecting the Department of Energy's new direction under the leadership of Hazel R. O'Leary, the recently appointed Energy Secretary. This is only one of many new modifications brought about by the Department of Energy to achieve the Administration's energy, environmental and economic objectives for a changing world.

The new Assistant Secretary of EE has not yet been appointed. Allan Hoffman is serving as Acting Deputy Assistant Secretary for the Department's Office of Utility Technologies (OUT) while Dr. Robert San Martin serves as Acting Assistant Secretary of EE. Both are continuing to work to fulfill many of the Administration's new objectives for developing clean energy sources to meet the needs of the economy while protecting the environment. Geothermal energy is a prime example of EE programs to balance power generation and the environment.

This paper discusses some of the new thrusts and directions of DOE brought about by the change in leadership. The new Energy Secretary has recently restructured the DOE to facilitate the new direction for the Department. The organizational realignment mirrors the broader philosophy of the new Administration and the Clinton/Gore Plan, an ambitious commitment to increase energy efficiency and conservation, increase natural gas use, expand the use of

renewable sources of energy, and -- in keeping with the theme of Program Review XI -- advocate a safe, environmentally sound policy. EE, and more specifically, OUT, has a mission to work with industry to improve the cost and performance of renewable energy technologies, including geothermal energy. Geothermal energy is a domestic energy resource with economic, reliability, and environmental advantages over other energy sources. Finally, the major piece of legislation, the Energy Policy Act of 1992 (EPAct), is discussed as relevant to renewable energy in general and geothermal in particular.

Restructuring DOE

In early April 1993, Secretary Hazel R. O'Leary announced a restructuring of the DOE to achieve the Clinton Administration's objectives. According to the Secretary, "Our goal in restructuring the Department is to carry out our piece of the promise President Clinton brought with him into office: to reinvent Government to make it responsible, accountable, and cost-effective, and to put the public's interests first. We must enable ourselves to achieve as much success in new missions that mirror the priorities of a changed world."

The restructuring reflects the Administration's plan for achieving energy, environmental, and economic objectives for a changing world. The Department is focusing on: 1) developing clean energy sources to meet the needs of the economy while protecting the environment, 2) enhancing U.S. competitiveness by transferring technologies from our labs to the private sector, and 3) cleaning up former weapons production facilities to protect public health and safety. The restructuring will also emphasize science, math, and engineering education. Important elements of this plan are:

- Energy, environmental and economic policy must be mutually supportive and work in concert to encourage the production of adequate, reliable supplies of energy; rejuvenate the environment; and

stimulate a healthy economy. The best policies unleash the creative energies of innovators throughout our economy by creating a market that rewards invention and enterprise.

- **National security depends on economic security.** To maintain the nation's competitive posture in intensely competitive world markets, and create more jobs for U.S. citizens, the scientific and technological resources must be fully utilized and the transfer of these achievements from our national laboratories to the private sector facilitated if national and economic security is to be achieved.

- **Cleaning up weapons facilities must be emphasized.** To protect the health and safety of the public and the environment, as well as create new jobs and enhance competitiveness, the impacts of the past 50 years of weapons production must be mitigated by cleaning up and restoring nuclear weapons facilities.

- **A strong science and technology base must be built and fortified.** The DOE has a unique role to play in this science and technology initiative. One of the nation's most important research and development assets is the human and technological resources of the DOE laboratories. These diverse laboratories have made immeasurable contributions to the nation's security, technological advancements, and energy supplies during the Cold War era. They now offer

research capabilities with a redefined mission: developing innovative energy technologies; supporting the transfer of new technology to U.S. industry; developing techniques for waste clean-up and environmental protection; and conducting basic research and supporting the goal of advanced science, math, technology, and engineering education.

DOE Mission Teams

The restructuring will consolidate the functions of several organizations with related responsibilities into three mission teams: **Energy Programs, Weapons/Waste Clean Up and Science and Technology.** The consolidation will concentrate resources and focus the teams on helping to: 1) share technology research and development with private industry to create jobs, 2) reorient weapons production operations to a mission of safeguarding the health and safety of American citizens as clean up and environmental restoration efforts are undertaken, and 3) provide better and more efficient management of the Department's resources to control spending and continuously improve services to the public.

EE is located within the Energy Programs mission team (Figure 1). William White, nominated by President Clinton to be Deputy Secretary for Energy will serve as the Department's Chief Operating Officer and direct the Energy Programs mission team. This team translates the Administration's energy strategy into departmental energy programs in order to achieve stated goals, including reduced reliance on foreign oil, leadership in protection of the global climate and increased emphasis on energy efficiency and renewable energy. The restructuring ensures all energy supply and demand programs report to the same official. The grouping will enable close integration of efforts in energy efficiency, production, supply, and commercial nuclear waste management.

The Science and Technology mission team is also relevant to the geothermal community because of its Office of Laboratory Management. This office is responsible for the Department of Energy Laboratories, one of the Nation's most important research and development assets. These national laboratories contain human and technological resources that can contribute to the creation of high-skill, high-wage jobs for American workers, enhance national security (military and economic), help develop environmentally beneficial "green" technologies and support advanced science, math and engineering education.

Office of Energy Efficiency and Renewable Energy

The Office of Energy Efficiency and Renewable Energy organization has not changed. The Geothermal Division is still found in the Office of Renewable Energy Conversion which is part of the Office of Utility Technologies. EE is arranged around the four main energy users -- utilities, industry, transportation, and buildings -- as well as an outreach arm of technical and financial assistance (Figure 2). This orientation toward end users has helped the technology development programs focus on addressing the needs of the marketplace.

Over the last four fiscal year (FY) period the annual budget for the Office of Energy Efficiency and Renewable Energy has grown by approximately 23% (Figure 3). The largest portion of the EE budget is for technical and financial assistance (support for state weatherization assistance programs, etc.) followed by utility and transportation technologies.

The main impetus for the overall growth in the EE budget has been increased spending in the areas of transportation and utility technologies. Over the four year period budgets for transportation technologies have grown from approximately \$78 million dollars in 1991 to over \$200 million requested for FY 94. This represents an increase of almost 160%. During the same period the budget for utility technologies has increased 105%, from \$117 million in 1991 to \$240 million requested for 1994.

EE's mission is to develop and promote the adoption of cost-effective renewable energy and energy efficiency technologies and practices in cooperation with the States and with industry partners. These technologies and practices are to benefit the economic competitiveness, energy security, and environmental quality of the Nation. The mission of the Office of Utility Technologies is to:

- To encourage utilities, in their decision-making processes, to consider energy efficiency options on an equitable basis with energy supply
- To address the technological and institutional constraints that impede utility adoption of renewable energy and energy efficiency technologies.

- To work cooperatively with industry and the utility sector to realize the full market potential for energy efficiency and renewable energy technologies, both in the U.S. and in other countries.

New Administration, New Legislation

President Clinton presented Congress and the nation with a bold, fair and credible plan constructed of long-term deficit reduction, spending cuts, and investment in human and capital resources. The plan lays out specific spending choices needed to reduce the federal deficit and to provide for greater private investment. Major investment initiatives include increased funding for renewable energy and energy conservation programs, DOE's weatherization assistance program, natural gas utilization R&D, and restoration and waste management activities at DOE facilities. The President's plan will require interagency cooperation in areas such as natural resource and environmental protection.

The Energy Policy Act of 1992 (EPAct), passed in October of last year, lays the foundation for a more efficient, less vulnerable, and environmentally sustainable energy future. It defines international, commercial, regulatory and technological policies that will substantially diversify U.S. sources of energy supplies and offer more efficiency in the way energy is transformed and used. Specifically, the Act holds the promise to spur more efficiency and competition throughout the energy sector, expand the fuel and technology choices available to the Nation, improve U.S. research and development, and support the international leadership the United States exercises in energy, economic, security, and environmental policy. Major provisions of EPAct address the following issues:

- Renewable Energy
 - Research Development & Demonstration
 - Tax and Production Incentives
- Technology Transfer/Export Promotion
- Increased Competition in Power Generation
- Integrated Resource Planning
- Environmental Protection

EPAAct is an authorization bill. If adequately funded by follow-up appropriations bills, 37 sections could impact geothermal energy. These sections fall into five topical areas: R&D and co-funded projects, incentives and tax treatment, international markets, direct use applications, and integrated resource planning. Several EPAAct sections deal specifically with geothermal energy: Section 3013 on geothermal heat pumps, and Sections 2501 and 2502 on hot dry rock (HDR). Geothermal is eligible under section 1202, authorizing demonstration and commercial application projects in renewable energy. Section 1212 provides a renewable energy production incentive of 1.5 cents/kWh for qualified facilities. The energy investment tax credit (10%) for qualifying geothermal properties is extended permanently. Geothermal heat pumps can benefit from provisions in the Act dealing with Integrated Resource Planning (IRP), Demand-Side Management, and development of least-cost energy strategies.

Expanding on sections of EPAAct dealing with renewable energy research, development & demonstration (RD&D), and tax and production incentives that would interest the geothermal community are:

Section 1202. Demonstration and commercial application projects for renewable energy technologies. This provision amends the Renewable Energy and Energy Efficiency Technology Competitiveness Act (P.L. 101-218) to further the commercialization of renewable and energy efficiency technologies through a five-year program of demonstration and commercialization application projects. Eligible projects, selected with the assistance of an advisory committee, include: (1) production/sale of electricity, thermal energy or other forms of energy using a renewable technology; (2) increasing efficiency of energy use; or (3) improvements/expansion of facilities for manufacturing renewable/energy efficiency technologies. Financial assistance includes grants, joint-ventures, cooperative R&D agreements and buy down interest rates. Twenty percent cost-sharing is required for R&D projects, which can be eliminated if the R&D is of a basic or fundamental nature. Projects include high and low temperature geothermal.

Section 1212.

Renewable energy production incentive. Directs DOE to provide production incentive payments of 1.5 cents per kWh to publicly-owned (e.g., muni, coop, PUD), qualified renewable energy facilities. A qualified facility is one which generates electricity using solar, wind, biomass, or geothermal energy. Municipal solid waste and geothermal energy produced from a dry steam geothermal reservoir are not considered qualified facilities. Payments to qualified facilities will be based upon the number of kWh of electricity generated from renewable energy and may be made for 10 fiscal years beginning in FY 94. The incentive will be inflation-adjusted.

Section 1916.

Business energy tax credit for solar and geothermal property. Permanently extends the 10 percent business energy tax credit for qualified investments in solar and geothermal property effective July 1, 1992. Qualified geothermal property includes equipment that produces, distributes, or uses energy derived from a geothermal deposit. For electricity generated by geothermal power, qualified property does not include the electrical transmission structures.

Section 2111.

Renewable Energy. Requires DOE to prepare a five-year program plan to provide cost-effective options for the generation of electricity from renewable energy sources for grid and non-grid applications, including field demonstration of sufficient scale to prove technical and economic feasibility.

Section 2501.

Hot dry rock geothermal energy. The Department of Interior, acting through the United States Geological Survey (USGS) and in consultation with DOE, will establish a cooperative government/private-sector hot dry rock program on public lands or lands managed by the Department of Agriculture.

Section 2502. **Hot dry rock geothermal energy in eastern United States.** USGS, collaborating with DOE, is to convene a workshop of interested private and public sector parties to discuss the regional potential of HDR in the Eastern U.S. The workshop was held in Philadelphia, on January 15, 1993, and reviewed HDR's recoverability status as well as the specific geologic, technological, and economic obstacles to be overcome. USGS is to submit a report to Congress summarizing the findings and conclusions.

Section 3013. **Geothermal Heat Pumps.** DOE shall encourage States, municipalities, counties and townships to consider two actions: to use geothermal heat pumps, and to permit water recipients to use water flow for operating geothermal heat pumps. This section specifies residential as well as commercial heat pumps, and also public and private water mains. Local authorities are not discouraged from inspecting heat pump connections for reasons of public health and for proper accountability of water use.

EPAct's technology transfer and export promotion provisions include sections on renewable energy export technology training (Section 1203) and technology transfer (Section 1211). The renewable energy export technology training program is to be established by DOE, via AID, to train individuals from developing countries about operation and maintenance of renewable and energy efficiency technology for (1) water pumping; (2) heating and purification; and (3) the production of electric power. An innovative renewable energy technology transfer program is outlined in Section 1211. DOE, via AID, shall establish a renewable energy technology transfer program to encourage exports of U.S. renewable energy technology and services, utilizing innovative and appropriate financial mechanisms. Project selection is via AID and should maximize participation of U.S. firms.

IRP related provisions within EPAct that could influence the potential markets for geothermal resources are found primarily in section 111 that amends PURPA, and section 1602 that requires the development of a national least-cost energy strategy. Section 111 is designed to encourage investments in conservation and energy efficiency by electric utilities. It amends section 111(d) of PURPA to require each State regulatory authority and each

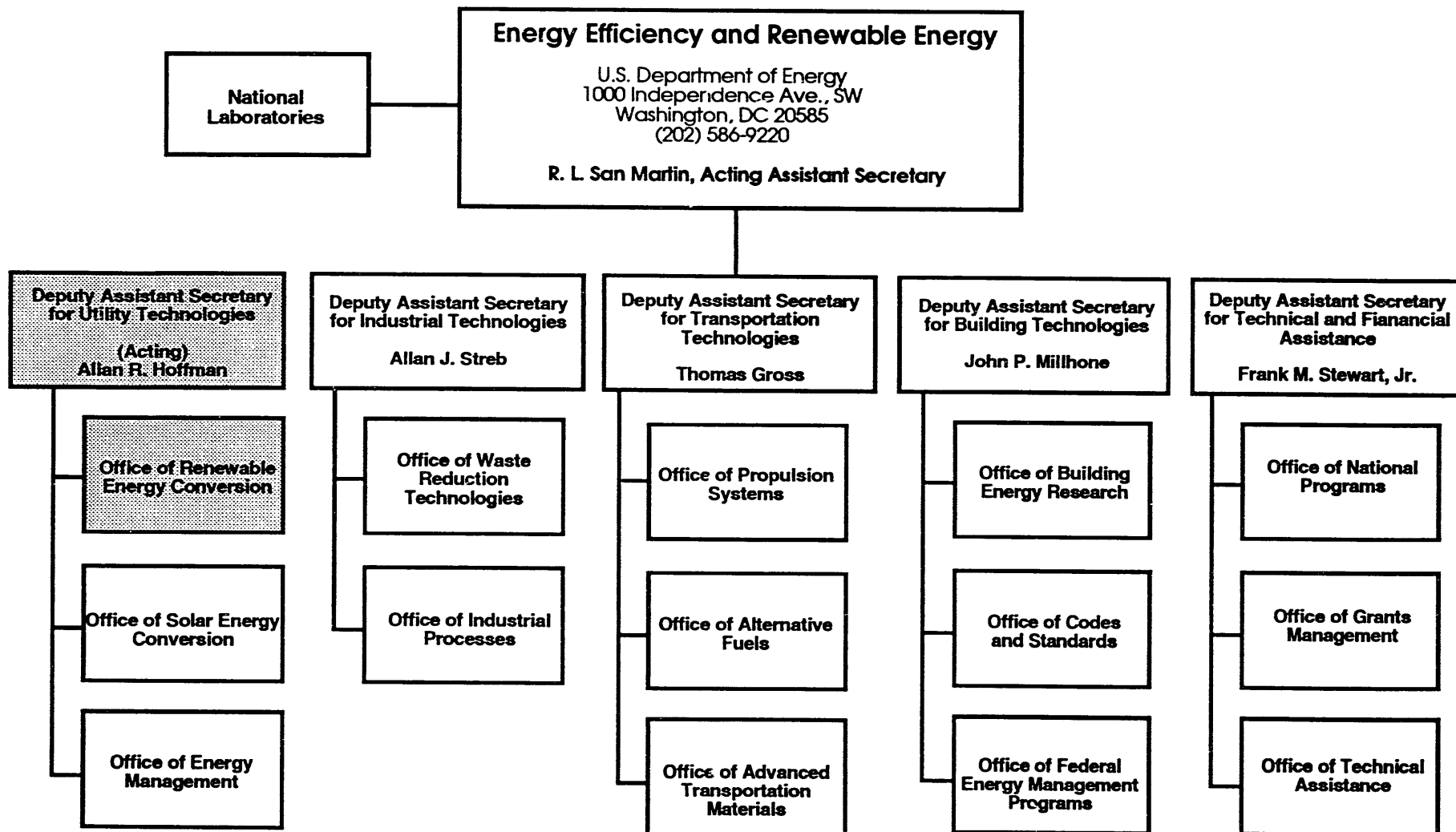
nonregulated electric utility to consider IRP and determine whether or not IRP is appropriate. In addition, each State regulatory authority must consider the appropriateness of allowing the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures to be as profitable as investments in generation, transmission, and distribution facilities. Section 1602 requires the first National Energy Plan submitted to Congress after February 1, 1993, and each subsequent plan, to include a least-cost energy strategy. The plan shall consider the economic, energy, social, environmental, and competitive costs and benefits, including jobs. The plan shall achieve, to the maximum extent practicable and at least cost to the Nation, an increased percentage of energy from renewable resources by 75% over 1988 levels by the year 2005, and promote the use of renewable energy resources, including geothermal.

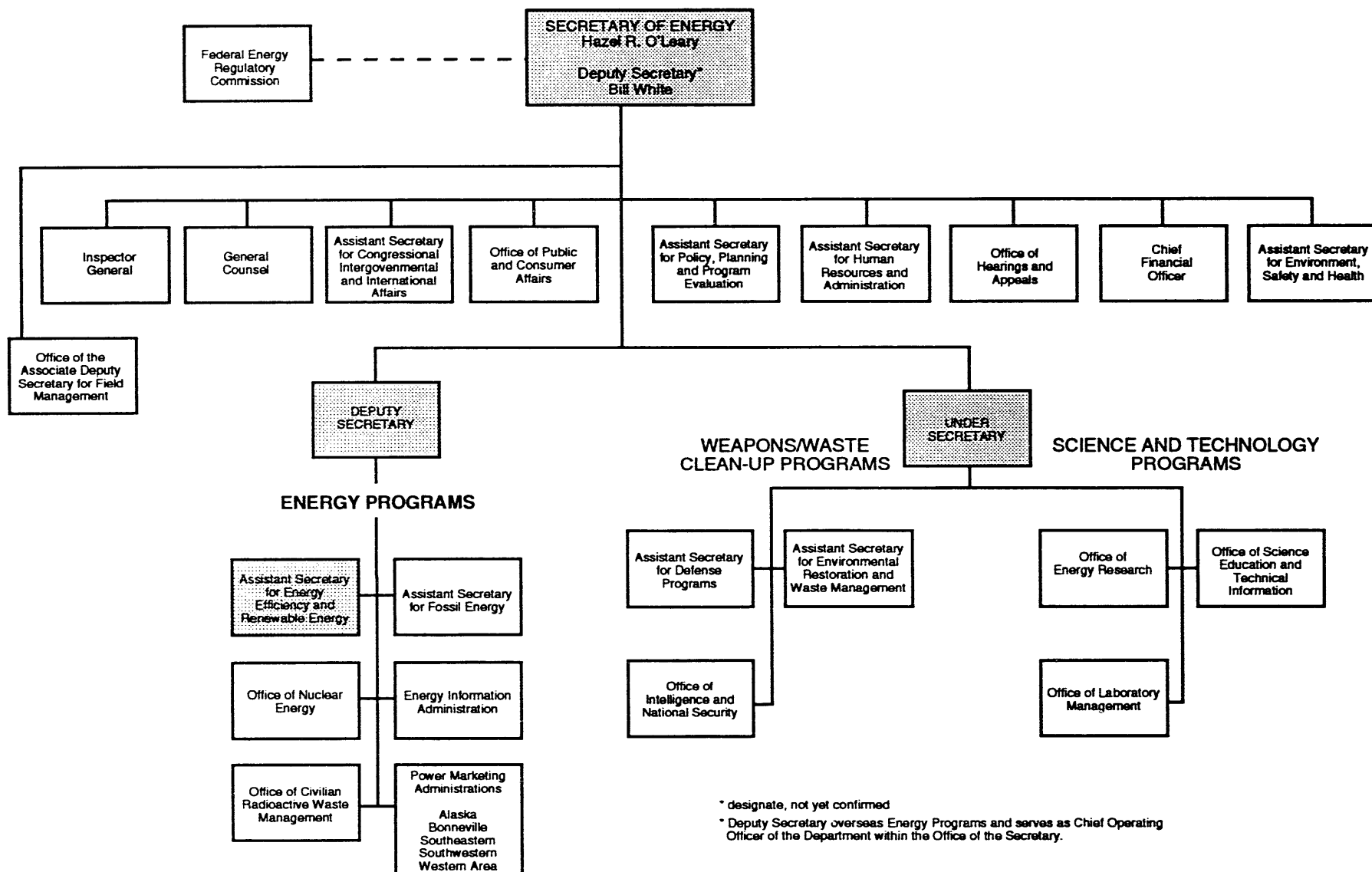
Conclusion

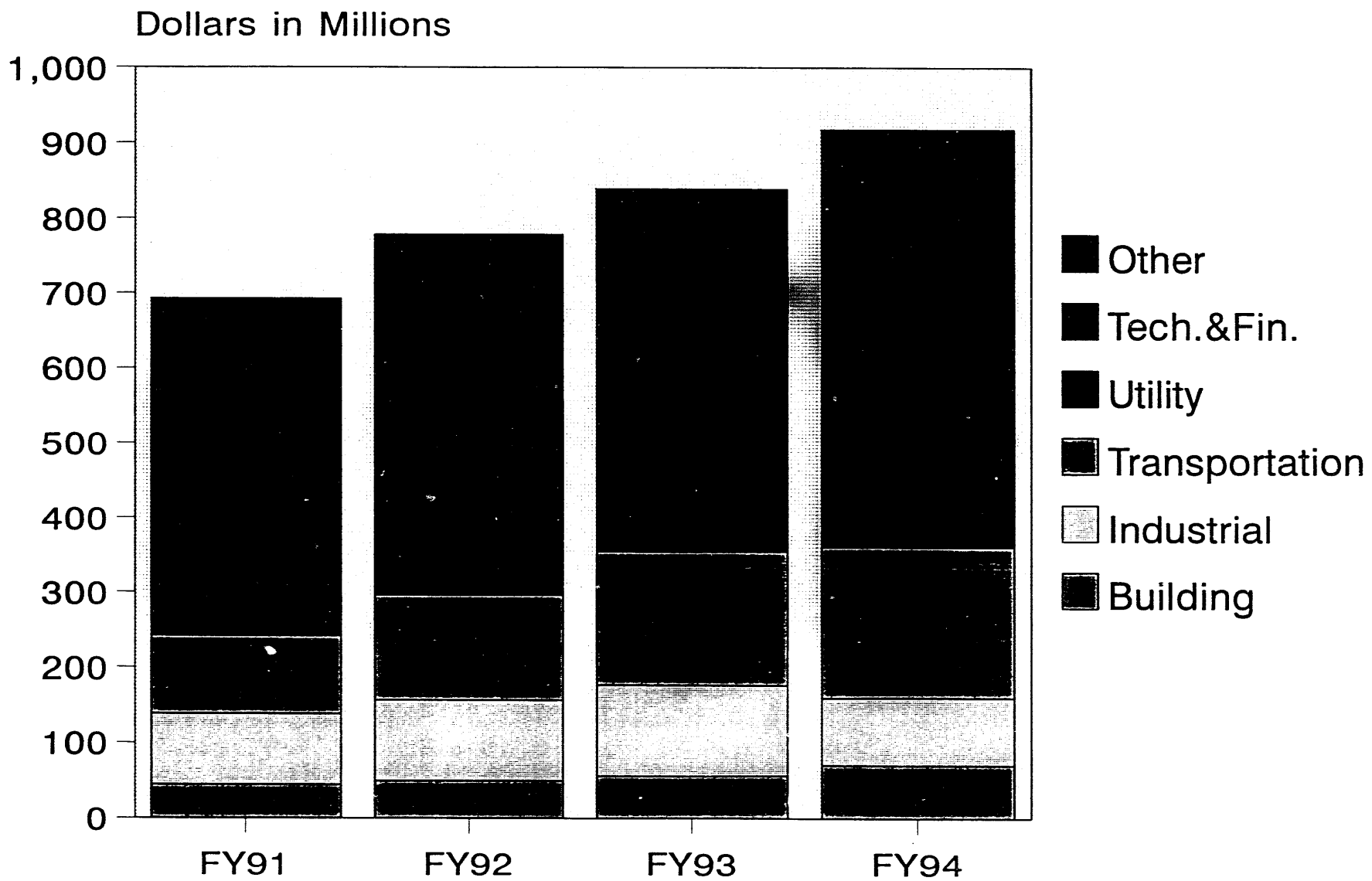
While much is changing in Washington DC, one thing does not change -- the Geothermal Division's partnership with industry has always been vital and has resulted in many benefits. Even though energy policy stressed long-term, high risk R&D through much of the 1980's, the Geothermal Program maintained active working relationships with industry, encouraging technology transfer through the creation of the Geothermal Drilling Organization (GDO) and the Geothermal Technology Organization (GTO). The GDO and GTO consist of members drawn from the geothermal industry who pool their resources with those of the Department to fund high-priority research projects with near-term payoffs. Such projects foster the early commercialization of new technology developments.

In the 1990s, with a renewed emphasis on cooperation with industry on meeting near-term, priority needs, the Department is moving actively to reinvigorate existing ties with industry, groups such as GDO and GTO, and establishing new ones, such as the cooperative slimhole drilling coring effort and industry-coupled drilling. One of the major purposes of this Program Review is to apprise the geothermal industry of the Department's ongoing and planned activities in geothermal R&D. We encourage comments or recommendations from industry representatives especially on areas of potential collaboration in the future. This input will be extremely valuable in helping set research priorities.

The recent opening of offices in Washington, DC by the Geothermal Resources Association and the National Geothermal Association is another positive step towards strengthening ties among the members of the geothermal community. These offices will facilitate day-to-day communication between industry and government. Geothermal contributions and opportunities must be made more visible if there is to be a viable program in the future. In upcoming years an ever stronger partnership between industry and the government will ensure that geothermal energy meets its great potential as an important energy source for the nation.







**GEOHERMAL ENERGY -- THE ENVIRONMENTALLY
RESPONSIBLE ENERGY TECHNOLOGY FOR THE 90s:
A FEDERAL PERSPECTIVE**

John E. Mock, Director
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Changing Perceptions of Geothermal
Characteristics

The perception of geothermal energy as an environmentally responsible energy technology is not a new perception although the resource has not always been recognized as such. In 1970, the report of the Senate Committee on Interior and Insular Affairs on the Geothermal Steam Act stated that development of the resource on federal lands would result "in new supplies of pollution-free power..."

However, subsequent perceptions in the 70s labelled the steam in use at The Geysers as a source of "dangerous" air contaminants. The odor of hydrogen sulfide, pessimistic press reports, and a well-organized coalition of environmental activist groups created an unfriendly atmosphere which in turn produced strict regulatory actions -- lengthy, repetitive, and costly environmental impact reports (EIR) on each plant and the imposition of stringent H₂S emission standards. Over time and observation of plant performance, the rigid EIR requirements were reduced and history has shown that the standards have been met. In fact, in 1991 the Lake County Air Quality Management District, which embraces a large portion of development at The Geysers, was the first and only California AQMD to be cited for full compliance with all of the state's tough Clean Air Act ambient air quality standards. In order to attain this award, extensive monitoring and a perfect record had to be maintained for three years.

Concurrently with the conflict at The Geysers, plans for hot water development were announced, and state and local authorities were confronted with the necessity to formulate regulations governing the production and use of a "new" and "puzzling" resource. It was recognized that it was not a Geysers-type H₂S problem, but the nature of the resource was nevertheless sufficiently unknown as to other characteristics -- e.g., solids content and potential naturally-occurring radiation -- that a balance between environmental protection and freedom to use the resource economically was not always easy to achieve. Again, history has shown that the regulators and industry, working together, have managed to achieve this balance successfully.

Today, because of the performance of the resource, briefly documented below, the pendulum has come full swing to the perception of geothermal energy as an environmentally preferable and responsible source of energy.

Documented Comparisons of Geothermal Power Plant
Performance with Fossil-Fired Performance

A great deal of statistical information has been developed to illustrate the more benign nature of the use of geothermal fluids for power generation compared with the use of fossil fuels. However, for purposes of this presentation, only a brief review is presented.

Exhibit 1, taken from data compiled by the Department of Energy's Energy Information Agency, compares the relative emission levels of three major air pollutants -- carbon dioxide, sulfur dioxide, and nitrogen oxides -- from coal plants and flash steam and binary geothermal plants. The environmental preference for geothermal over coal is readily discernible. In addition, while natural gas is the cleanest burning of the fossil fuels, and is being looked upon as a panacea in air quality management in some quarters, available statistics show that geothermal operations generate even less of these pollutants than natural gas, and, as shown by Exhibit 1, none in some cases. In Exhibit 2, CO₂ emissions (cradle-to-grave) from geothermal power plants which practice reinjection are compared with those of other renewable energy technologies and the current fuel mix (coal, oil, hydro, etc.) electric generating technologies.

Exhibit 1. Annual Pollutants per 3000 MW
Effective Electric Plant Capacity Coal = U.S.
Average, 1990

	Tons of CO ₂	Tons of SO ₂	Tons of NO _x
Coal Plant	28,700,000	270,000	106,000
Geothermal Plant			
Flash Steam	14,000	800	0
Binary	0	0	0
Source: Coal Data DOE/EIA-0348(90)			

Most of the airborne particulate matter associated with geothermal use is generated by drilling, a temporary source, and are effectively controlled by mechanisms first developed at The Geysers. While solids may also be entrained in cooling tower drift at The Geysers, air monitoring has indicated that levels are within California and federal standards.

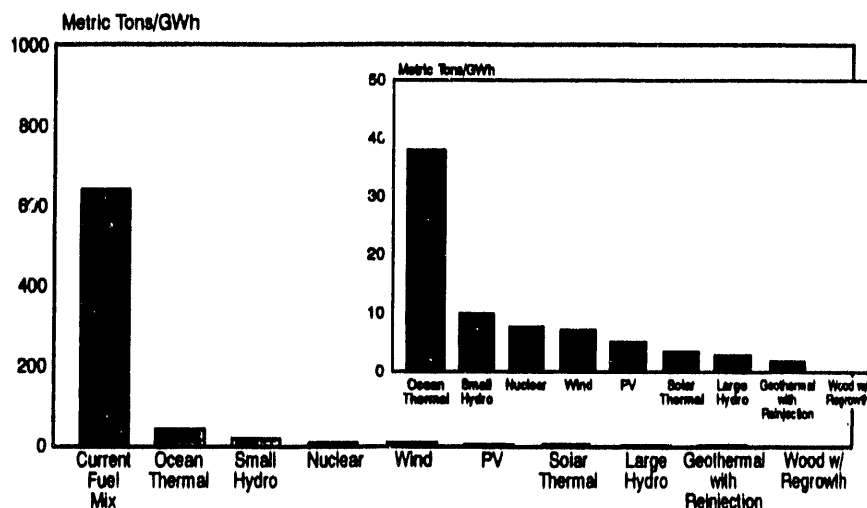


Exhibit 2. CO₂ Emissions from Electric Generating Technologies

Surface water quality is unlikely to be affected by geothermal fluids since 1) injection of wastewater is desirable and/or required in most cases, and 2) where surface discharge is permitted, the chemistry of the geothermal fluid is benign and likely to be identical to natural springs in the area. Regulators report that spills from geothermal operations have been greatly minimized by operator practices. As to the environmental impact of injecting geothermal fluids, the Environmental Protection Agency found after a 1987 study of geothermal injection wells that they are generally sited, constructed, and operated in such a manner as to prevent contamination of underground drinking water sources.

Also in 1987, EPA exempted most geothermal wastes destined for land disposal from federal regulation of hazardous wastes (Subtitle C, Resource Recovery and Conservation Act) and left these "low-risk" wastes to state jurisdiction. It is understood from Imperial County regulators that Magma Power Co. has constructed its own on-site disposal area to receive its Salton Sea residual wastes (e.g., process sludges, drilling muds) which is triple-lined and exceeds state requirements. Since the solids contents of the fluid in that area are the highest known in any geothermal field (i.e., ~ 30 percent) and contain naturally-occurring radioactivity, the ability to operate the several Salton Sea plants economically within environmental constraints is tantamount to the pollution-control success at The Geysers where H₂S concentrations are as high as any yet encountered. However at The Geysers, the wide range of hazardous materials used for air pollution control require segregation and treatment on an individual basis. The Department of Energy is pursuing methods to detoxify geothermal wastes through biochemical processes

for precipitating out the entrained metals which will further enhance environmental protection and reduce waste disposal costs.

The amount of land needed to support various types of power generation facilities is compared in Exhibit 3. It can be seen that the amount of land disturbance in geothermal use is minimal in comparison with other renewable sources of energy and with coal. In addition, the impacts on land fertility have been minimal -- during most of the 80 years of field development at Larderello, Italy, the surrounding land has been used for various agricultural purposes, and, today, irrigated crops extend to the power plant property line in Imperial Valley. Mitigating measures used in plant siting and construction, such as those employed at the plants near Mammoth Lakes, California, illustrate that plants can coexist with highly scenic and recreational land values.

Exhibit 3.

Technology	Land Occupied
	(square meters per gigawatt-hour, over 30 years)
Coal ¹	3,642
Solar Thermal	3,561
Solar Photovoltaics	3,237
Wind ²	1,335
Geothermal	404
¹ Includes coal mining	
² Land actually occupied by turbines and service roads	
Source: Worldwatch Institute	

Environmental Choice in Direct Use

EPA analysis has shown that the geothermal heat pump, in addition to its economic advantages, also provides environmental benefits in that the GHP (with its low power requirements) has the lowest CO₂, SO₂, and NO_x emissions of any home heating and cooling system. A July 1992 EPA study concluded that aggressive promotion of GHPs could cut the nation's CO₂ output by 10.9 million metric tons per year. In addition, the refrigerant used is recognized by EPA as a potential solution to ozone destruction caused by other air conditioner refrigerants.

Most direct commercial/industrial applications of geothermal fluids also offer environmental advantages. Many of them utilize low-temperature, chemically-benign resources in small, closed heat exchanger systems. The fluid purity also permits use in some operations where there is direct contact between the fluid itself and equipment/process/materials.

Status of Geothermal Energy in "Externality" Cost Planning

The competitiveness of geothermal power costs can be enhanced when a regulatory agency takes into account, and sets a monetary value on, the social costs avoided by geothermal use, thus, in effect, placing a penalty on other fuels. For example, the California Energy Commission has stated that "air pollution imposes real costs on society, such as impaired health and damage to buildings, crops, and forests. It is because these costs are not all directly reflected in electricity prices that economists define them as external costs." Thus, the Commission is working toward the use of a "damage function approach" in calculating such values for resource planning activities. This action by California plus a growing trend toward penalizing more polluting fuels in other states -- e.g., Nevada -- will tend to level the playing field for geothermal energy in the new competitive climate in the power market.

Views of Federal/State Regulators on Geothermal Environmental Performance

In preparing this presentation, the views of a number of cognizant federal and state agencies were sought on the environmental performance of geothermal operators. All reported "good behavior," and no incidents of noncompliance were reported; it was stated specifically that all California plants subject to CEC licensing requirements are meeting them.

The major new environmental problem identified in this informal survey is induced microseismic activity at The Geysers. State officials consider this concern valid, and will require installation of a seismic monitoring system concurrently with installation of a pipeline to bring treated wastewater from Lake County for injection at The Geysers. A scoping document has been prepared on the wastewater pipeline -- planned as a means to mitigate steam decline at the field -- which will require siting, etc. so as to avoid any future opportunity for ground or surface water contamination.

Results of Industry's Good Environmental Performance

The results of the geothermal industry's good environmental performance can be illustrated in several ways. California, the bellwether environmental state, provides grants and loans for direct geothermal use and small power projects to both private developers and public entities. Funding may be applied to all developmental steps, including environmental assessment of development impact. California has also set aside a portion of new capacity for geothermal plants, the only state to do so, and the externality considerations there and in Nevada are expected, as noted above, to improve the status of geothermal energy at the negotiating table.

In the scenic areas of the Pacific Northwest, geothermal development was facilitated by a "consensus agreement" among environmental interests, land users such as snowmobilers and hunters, and commercial interests such as timber, tourism, and geothermal as well federal (Forest Service/Bureau of Land Management,) state, and local governments. This led to the formation of the Newberry National Volcanic Monument and protection of the acreage within it from geothermal development, but agreement at the same time to permit development on the flanks of the volcano. While there is some continued localized objection to specific proposed geothermal activity, the agreement was described as a "win-win" situation even though the geothermal industry would forego a major percentage of the potential resource value of the area, and the federal government would potentially lose millions of dollars in royalties. In any event, it seems rather certain that geothermal development would not be this close to fruition in the remote, pristine areas of the Pacific Northwest without the consensus agreement -- and the agreement would not have been reached except for the good environmental record of geothermal energy in other areas.

Experience in The Geysers has also shown that geothermal development conflicts can be reduced to an environmentally acceptable level. In addressing this problem, Lake County officials stated: "Nonetheless, development within environmentally sensitive areas requires sufficient financial and staff resources (including state or federal funding) to establish credible local permitting, monitoring, and enforcement programs. Furthermore, a high degree of cooperation is required between state and local agencies, the geothermal industry, and the public. In addition, considerable public involvement and the use of best available control technology helps to defuse public controversy and litigation. Once concerns over the environmental impacts of development have been resolved, the economic and energy benefits to the community may be more fully appreciated." (Hinds, Reynolds, and Dellinger, GRC Transactions, Vol. 14, Part 11, Aug. 1990.)

Need for Constant Vigilance to Maintain Incident-Free Performance

In any case where poor design, maintenance, or operation of a geothermal facility permits environmental degradation, the responsible geothermal operator will pay heavily in two ways. First, the cost of cleaning up such damage -- amply illustrated in the literature by examples of clean-up costs to the oil and gas and other industries -- will add to his O&M costs and in turn affect the profitability of the operation. More importantly, however, are the intangible costs of reduced public/regulatory acceptance of geothermal energy and the potential loss of "externality" gains. Each site operator is thus responsible in a very direct way for maintaining the good environmental reputation of the resource as enunciated by a Sierra Club spokesman: "Geothermal production is a valid, nonpollutant

source of energy and, as such, is in keeping with the Sierra Club doctrine of nonpollution." (Ms. Billie Schwartz, Fort Irvin, California 1992.)

Who Should Continue to Inform Decision-Makers and the Public on Geothermal's Performance?

The simple answer to this question is: all of us. The entire membership of the geothermal community -- government, the involved scientists and engineers, and industry ownership/management -- has an individual and collective responsibility to inform those who regulate us, compete with us, and buy from us to make our voices heard.

Edison's QF Experience

William R. Gould
Southern California Edison
Manager of QF Policy and Contract Development

Good Morning. I appreciate the opportunity to come and meet with you and to describe Edison's QF experience.

This opportunity reminds me of the story of the man that came home from work tired, beaten up by his boss, and anxious to have as pleasant an evening at home as a bad day will allow. Much to his surprise, he was met at the door by his pretty wife who said, "I have good news, and I have bad news, which would you like first?" The man, looking at his wife, said, "Oh, you know, it's been a real bad day, why don't you give me the good news first." "OK," she replied, "The air bag worked."

In a similar fashion, I bring you both good news and bad news. The good news is that the geothermal technology has matured. Personally, I am very impressed with what you as an industry have done. However, the bad news is that the current contract relationship is not good from Edison's perspective.

As such, my message today is:

In the beginning, Edison's embraced the development of alternative and renewable resources. Our initial enthusiasm was short-lived and turned to dismay as the cost of these alternatives and renewable resources became a burden to our customers and threatens the competitiveness of our corporation. However, the longer term holds the potential promise of improving this relationship if we work together to establish a traditional supplier/customer relationship.

I would like to begin by discussing Edison's early involvement in the development of non-utility generation. In 1980, our company set a new direction for the utility industry by embracing the concept of utilizing alternative and renewable resources provided by third party power producers.

In 1980, we proudly announced:

"It is the policy of Edison to devote our corporate resources to the accelerated development of a wide variety of future electrical power sources which are renewable rather than finite."

"...(W)e have more than doubled the present amount (to be obtained from renewable or alternate sources) and Edison has set a new goal of about 30%, or 1,900,000 kW (1900 MW) of its anticipated 6,000,000 kW of additional generation needs in 1990 from renewable and alternate sources."

William Gould, Chairman
October 17, 1980

This was a bold move on our part. It was not received well by many of the companies in our industry. In order to understand why the Edison Company would embrace such revolutionary thinking, one must understand that Edison, like many utilities at that time, was burdened by increasing uncertainty of an assured fuel supply; escalating construction costs; new and increasingly stringent environmental regulations; and we were faced with the responsibility of serving a rapidly growing electrical demand. In short, we looked to the development of alternate and renewable energy to contribute toward meeting the challenges of providing lower cost-reliable service in our increasingly uncertain environment.

A little over a year following Edison's announcement of our corporate commitment, the CPUC also iterated its interest in promoting cogeneration and small power production.

"California has a long standing demonstrated interest in promoting cogeneration and small power production."

"This decision orders the major California electric utilities to file standard offers for power purchases based on avoided cost principles."

D. 82-01-103
January 21, 1982
California Public Utilities
Commission
John Bryson, President

Unlike the majority of other states, most of which encouraged utilities and QFs to negotiate contract terms on a case by case basis, California's Public Utility Commission established a standard offer agreement. Initially, the Commission ordered the utilities to offer short-run avoided cost contracts with firm capacity commitments. However, it became apparent that the capital market would not participate in the development of alternative and renewable technology without assurance of stable pricing. Therefore, the Commission directed the state utilities to offer a long-term standard offer with fixed energy prices. This became known as Interim Standard Offer No. 4. The Interim Standard Offer No. 4 Contract required each project to complete development of its project within five years of signing the contract. This five-year development period was then followed by a 10-year period of pricing certainty with fixed energy prices which were based upon a fuel-oil cost forecast that started at \$40 per barrel and rose to \$100 per barrel. Following the first 10 year's of pricing certainty, the energy price was to revert to the then current "Short Run Avoided Cost (SRAC)." At

the time, it was projected this pricing framework would cause little disruption in price continuity. In addition to providing encouraging pricing terms, the Commission required the utility to sign as many contracts as were presented by the potential project developers. As a result of this, over 600 contracts were signed by Edison.

Approximately 400 projects are now in commercial operation. These 400 contracts provide approximately 5000 MW of on-line capacity--3500 of which is considered to be effective capacity in Edison's resource base. Because of the high forecasted energy prices and the inability of the utility to limit the number of contracts signed, the amount of QF capacity that was developed far exceeded our expectations. These QFs currently supply about 17 percent of our capacity need and 32 percent of our energy requirements. Because of the high cost, this QF contribution represents 65 percent of Edison's energy budget. It is a \$2 billion dollar per year industry which is vibrant, has demonstrated it is reliable, and in most cases is both environmentally and thermally efficient. Table 1 shows the magnitude of commitment Edison has toward utilizing alternative and renewable energy. The contract terms of these contracts generally vary between 20 and 30 years and all technologies are operating efficiently.

Technology	Projects	Capacity (MW)	Generation (GWh)	(c/KWh)	Payments (\$ Millions)
Biomass	30	324	1,866	11.3	211
Cogeneration	208	21	15,988	5.9	937
Geothermal	21	681	5,820	11.3	657
Small Hydro	50	132	218	6.5	14
Solar	15	369	695	15.1	105
Wind	76	923	1,598	10.9	174
Total	400	5,048	26,185	8.0	2,098

Table 1. Summary of Edison's QF Projects On-Line in 1992

To say the least, it has been a challenge to integrate this power into our system. In response to the contractual commitment imposed, Edison has had to turn down our own still useful resources, and in some cases relegate them to mothballs in order to purchase this third party power. At this point, as you can imagine, the hoped for solution became a challenge.

I would like to draw your attention to Figure 1. This graph illustrates the present concern that we have about the price of QF power. The cross-hatched line shows the Interim Standard Offer No. 4 forecasted energy price that I referred to earlier. The solid line shows Edison's actual and projected avoided cost price which is representative of Edison's replacement energy cost using our own available resources in lieu of accepting the alternate and renewable power under Interim Standard Offer No. 4. Figure 2 shows the difference between the cost currently being incurred under the QF contracts and Edison's replacement energy cost. The drop off in cost during the 1996-99 time period is commonly referred to as the "QF Cliff." This is presently the subject of much discussion with QFs and in the regulatory arena.

In truth, the forecast could have gone either way and could have benefitted Edison's ratepayers. But it didn't. It is not surprising that the forecast was wrong. Indeed, it is widely known that the only thing certain about any forecast is that it will be wrong. The cause and effect of the present situation is simply that the contracts had no provisions to adjust for either energy price forecast changes or the utilities' need for capacity. Consequently, what was originally considered to be a valid forecast of future energy price turned out to be a nightmare, which is currently expected to cost Edison's customers between 6 and 8 billion dollars more than if supplied from other sources. Of course, hindsight has twenty-twenty vision.

Yet to be faced is whether all projects will be able to economically survive the QF cliff. Another factor is the impact that QF baseloaded resources, because of the contractual requirement for Edison to buy the power from the projects when delivered, will have on future resource planning.

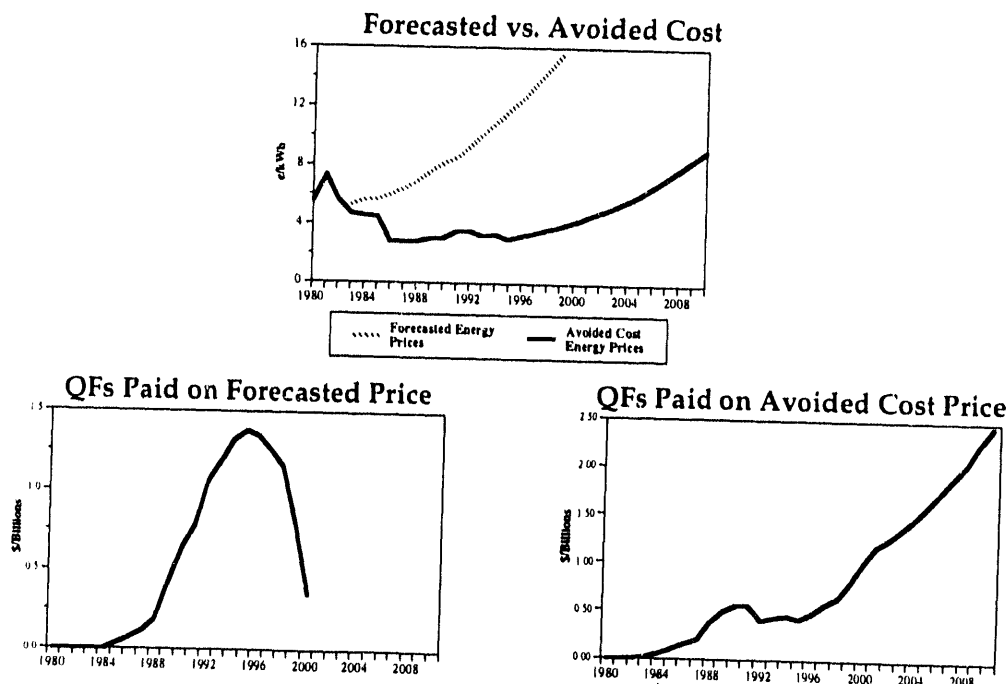


Figure 1. Energy Price Impact

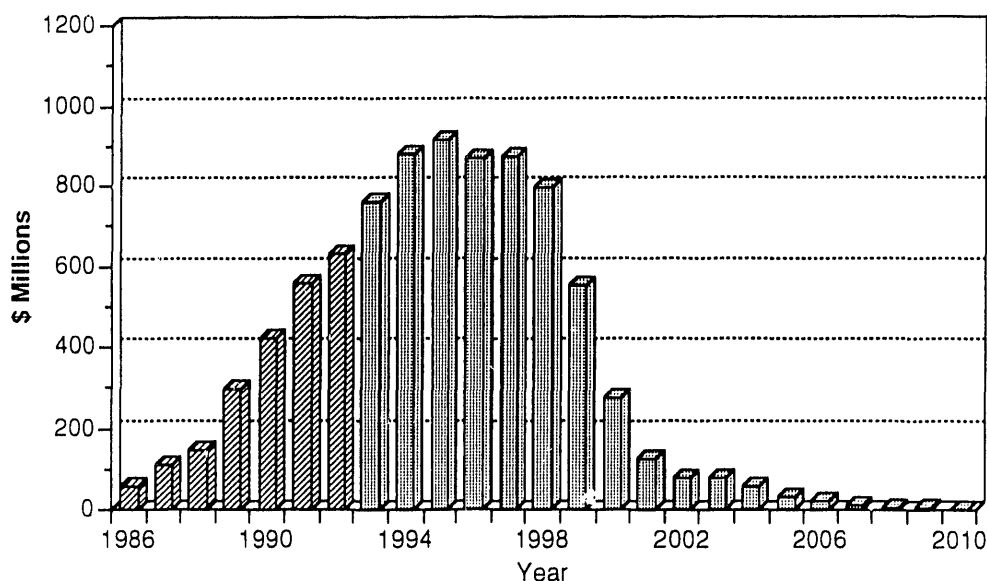


Figure 2. Energy Payment Differential
(Differential = Forecast Less Avoided Cost)

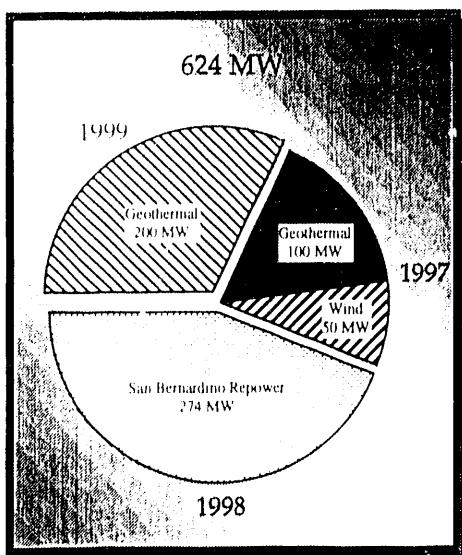
In looking toward the future, we see continuing challenges. In particular, three major ones are: 1) The restructuring of existing contracts to achieve a more cost effective relationship and operating flexibility with QFs; 2) The completion of the current Final Standard Offer No. 4 bidding process to determine the value and mix of future resources; and, 3) Meeting the challenge of what the future--beyond the FS04 bidding process, holds in the way of allowing the marketplace to determine the optimum integration of additional capacity to serve customer load growth.

Edison is committed to improving communication with QFs. We have a strong desire to learn more about the improvements of various QF technologies and the operating requirements of existing and future projects. We want to explore new contractual relationships not only to meet the challenge of the 90s, but into the next century as well. To this end, we have been holding many "Town Hall" type meetings. We have and are inviting and encouraging discussion with all existing and prospective projects to strive for a more synergistic relationship.

Across the U. S., we are observing intensified efforts to restructure early contracts to bring the benefit of QF power to the customer in line

with the expectations from a mature industry. This is also the case for Edison. Our objective for restructuring contracts is directed toward providing an equitable balance of risk and benefits to all participating parties. Some of the principles Edison believes are important to achieve this objective are: 1) The project must be viable without restructuring; 2) The contract restructure must not create additional Edison system operational problems or energy supply risk; 3) There must be an equitable sharing of risks and benefits; 4) Any restructure must be subject to CPUC pre-approval since they retain ultimate authority over the reasonableness of any contractual relationship.

Edison is about to undertake its first solicitation for major new QF contracts since the mid-1980s. This is the much talked about Final Standard Offer No. 4 which has commanded the attention of QFs interested in supplying electricity to the California market; potential investors in capital intensive electric generation projects; and, the utilities who will purchase power. Figure 3 shows that the total amount of capacity Edison will solicit for bid is 624 MWs in the 1997-1999 time frame. This includes 175 MWs that *must* be filled by renewable resource capacity. In this process, potential bidders will compete with Edison's



- First solicitation for major new QF contracts since mid 1980's
- Renewable set asides
- Transmission costing
- Anticipated timeline of key events

Figure 3. The FSO4 Bid Process

projected cost to supply the electricity from three identified sources: geothermal (300 MWs), wind (50 MWs), and repowering of Edison's existing San Bernardino facility (274 MWs). The request for bid will be made available as early as August 1993 with contract execution estimated to occur in the 4th Quarter of 1994.

Edison's goal is to acquire the most cost effective, environmentally acceptable mix of diverse resources. California is fortunate to be rich with options to utilize both conventional and newly developed renewable resources to achieve this objective. We believe there is a need to simplify the current process for acquisition of resources. It must be market-driven and more responsive to electric consumer requirements. This mandates a business partnership between the utility and its suppliers. Edison believes the best approach is to simplify the implementation of regulatory policy by establishment of a broad framework of guidelines, which will permit the supplier and the utility to develop an optimum beneficial relationship.

I will close by reviewing the three things I said at the beginning of my speech: 1) In the beginning, Edison embraced the development of alternative and renewable resources for the reasons stated. 2) Our initial enthusiasm was short-lived and turned to dismay as the cost of

alternative and renewable resources became a burden to our customers and threatens the competitiveness of our corporation. 3) However, Edison is optimistic about the future. It holds the promise of the development of a beneficial relationship between mature suppliers and the utility.

I thank you for inviting me to speak to you. Edison always welcomes the opportunity to exchange experiences and ideas of mutual interest in forums like this.

GEOTHERMAL POWER

HOW DOES IT FIT INTO THE NATIONAL ENERGY AGENDA?

A speech given at the DOE Geothermal Program Review XI.

April 27, 1993

Berkeley, California

Thomas C. Hinrichs
Magma Power Company

With the passage of the National Energy Policy Act and the ushering in of a new administration our industry must once again assess our strengths and weaknesses and attempt to use to our advantage the government environment in which we find ourselves. The source of energy which we promote has been utilized by man for his comfort longer than any other, with the exception of fire.

The development of geothermal energy as a source for electric power generation was initiated in the US with the typical arrangement of a resource developer selling a product (natural steam) to a utility who in turn built the generating plant which converted the natural steam to electricity.

My remembrance of geothermal electric power becoming part of a national energy agenda was in the early 1970's. Two events focused the government to seriously consider geothermal and other renewables as part of a national agenda. The Arab oil embargo, in conjunction with a perception that we were running out of natural gas caused the development in those times of the "Project Independence" mentality.

Basic R&D, Environmental Baseline Data Accumulation, 10 Megawatt Pilot Plants and 50 Megawatt Demonstration Plants were the buzz words of the agencies which had governmental responsibilities to foster supporting programs for the industry to assist in reaching the goal of energy independence from foreign oil.

It started in the National Science Foundation, went to the Division of Applied Technology of the AEC, then to ERDA and finally to the Department of Energy. Electric utilities played a major role through their own corporations and the funding of much work through the Electric Power Research Institute (EPRI).

A shift in emphasis occurred in the late 1970's and early 1980's due to the passage of the Public Utility Regulatory Policy Act (PURPA) which provided the incentive for the geothermal developers to move from solely resource development to building and owning the power generation facilities.

With the passage of PURPA the determination of the development of geothermal power was addressed in the arena of resource planning by state and local regulatory agencies responsible for the regulation of private and municipal utilities. In this arena the initial attempt at evaluating the social benefits of non-polluting power occurred.

In California a great deal of effort has been expended on establishing the cost of air pollution. The low capital cost of gas fired power plants, particularly repowering of existing, older units, and the low costs of natural gas has made it difficult for renewables to be cost effective with the values that have been suggested.

The value of social benefits, of course, are subjective and different depending on a ones perspective. I have a concern that this could become a morass because it may well be used to push policy decisions to support individual perspectives. The list of social benefits can always be manipulated to support desired policy.

Our industry is impacted by the national energy agenda to protect the environment, and the overall agenda for improving the economy, including creation of jobs and minimizing energy costs. The environment and jobs is our strength and costs is perceived to be a weakness of our industry since there are short term lower cost alternatives. Let me, briefly, address these agendas.

ENVIRONMENT

In February of this year a brochure titled "Geothermal Energy ... for a Cleaner Environment" was published under the auspices of the National Geothermal Association and the Geothermal Resources Association. Copies of this are available at the registration desk. Let me summarize several of the points in the brochure which point out the environmental benefits available through utilizing geothermal resources for the generation of power by showing you the tables.

The first table shows the difference in air emissions from a coal plant and geothermal plants. This differences become significant when one realizes that electric power generation accounts for 70% of the sulfur-dioxide emissions, 33% of nitrogen-oxide emissions, 20% of green house gases and 50% of all nuclear wastes.

The next table shows the comparison of emissions with coal, oil and natural gas. Natural gas is relatively clean burning but does emit carbon dioxide in significant quantities.

The next table shows the land requirements for coal, geothermal and other renewables - again geothermal has advantages since it

utilizes less land than other renewables and coal plants. Gas fired and nuclear plants require less space where installed, however if the off site facilities required to support them were included (such as gas wells and mining operations for uranium and disposal areas for nuclear waste) those facilities could require more land than a geothermal plant.

Existing geothermal projects are in environmentally sensitive areas and our industry has an excellent record of being compatible with the surrounding environment. Magma's plants at the south end of the Salton Sea are surrounded by agriculture and fish and wildlife preserves. The following slides demonstrate the compatibility of those plants with agriculture and the wildlife in the area.

Mammoth Pacific has three geothermal plants located in the highly environmentally visible area of the Eastern Sierra, near Mammoth Lakes, California. This slide shows the pristine setting of these facilities with Mammoth Mountain in the background. These plants were designed specifically around the concerns of the area and have become accepted neighbors to those watching over the flora and fauna of the area.

Water is a precious commodity in the Eastern Sierra and these plants were built with air cooling condensers allowing no water to be consumed in the process. The power process is binary which allows power generation to occur with absolutely no emissions, and 100% reinjection of the geothermal fluid back into the reservoir.

Throughout the west water is in short supply. Flash geothermal plants such as those in Imperial and Inyo Counties and the Geysers utilize the steam condensate coming from the geothermal reservoir for the cooling water requirements. Hydropower, Solar and Wind are the only other power generating sources which don't require an external source of cooling water.

The geothermal industry has a great deal to offer to the agenda of environmental protection. Delivering this message should be the commitment of all of us in whatever sphere of influence we operate.

JOBS

One of these days we as a nation are going to come to the realization that a very important part of our environmental analysis will be the inclusion of a valuation of how many new jobs are created by a project.

In 1983 I attended the dedication ceremony put on by Unocal, for the Salton Sea Unit #1. Many of you in this room also attended

that event. Fred Hartley, deceased former head of Unocal, gave the address at that gathering and the thing that he said that most impressed me was that he believed that one of the environmental responsibilities of Unocal was to create jobs. He indicated that competing projects being evaluated by Unocal had the number of jobs created as one of the criteria utilized in the decision process.

He quickly indicated that Unocal had not become a socialistic organization and had not lost the profit motive, but that among projects which were comparable in meeting corporate financial objectives those with the greatest number of jobs created were favored.

A healthy expanding geothermal industry is a wonderful producer of new jobs. We have a multi-discipline industry with front line technical requirements in solving the problems and designing the systems from the bottom of production wells, through utilization facilities to the bottom of injection wells. Project development teams are needed for the sales contracting and financing. Project management, construction and finally, operations, create a multitude of well paying jobs which are desperately needed in our country.

There is a general consensus developing in our country that much of our infrastructure needs rebuilding. Electric generation is part of that infrastructure. We are becoming more aware of the age and deterioration of existing electric production equipment. Old gas fired plants are becoming targets for repowering; nuclear plants are being taken out of service earlier than scheduled and the desire to reduce emissions from coal plants will put them under pressure for early retirement.

There would be no better stimulus to our economy than a job boom associated with the rebuilding of the electric production part of the utility industry. With the ongoing development of the independent power industry, of which geothermal is a part, the risk and financing of it would not be on the tax payers as many other proposed stimulus program would be. Our friends in the electric utility business will be quick to point out, however, that my suggestion would be a burden to the electric ratepayers. That takes me to my concluding aspect of the national agenda which is lowering the cost of electric power.

COSTS

In 1991 the Alliance to Save Energy, the American Council for an Energy-Efficient Economy, the Natural Resources Defense Council and the Union of Concerned Scientists teamed together to put together a comprehensive study which was titled **"America's Energy Choices -**

Investing in a Strong Economy and a Clean Environment." (Show slide of cover) The study had four cases which were modeled. The cases are as follows:

- Reference Case:** Current policies and trends.
- Market Case:** Selects technologies based on the goal of minimizing the cost of energy services purchased by consumers.
- Environmental Case:** Assigns monetary values to the environmental impacts of energy use.
- Climate Stabilization Case:** Seeks to meet predetermined targets for the reduction of CO2 emissions.

Each successive case assumed greater utilization of energy efficiency and renewable technologies. Let me quote from the overview of the Executive Summary:

" For each scenario, we estimate how much energy the US would need, how much of it would come from renewable sources, how emissions of key atmospheric pollutants would change, and the resulting net costs to energy consumers. In all cases, steady growth in GNP was assumed.

The results of the analysis were stunning. If current policies and energy-use trends continue until 2030, national energy consumption will rise 41 percent, renewable energy will continue to make only a modest contribution to our energy supply mix, petroleum consumption will increase by 16 percent, and carbon dioxide emissions will increase by 58 percent.

By contrast, the three other scenarios achieve dramatic reductions in energy use and air pollution emissions, a greater penetration of renewable technologies, and successively greater monetary savings. In our most aggressive case (the Climate Stabilization scenario):

* national energy requirements in 2030 would be cut nearly in half from the Reference case, with renewable energy sources providing more than half of our energy supply

* our nation's petroleum consumption would steadily decrease to just one-third of current levels by 2030

* carbon dioxide emissions would be cut by more than 25 percent from 1988 levels by 2005, and by more than 70 percent by 2030

* consumers would save \$5 trillion in fuel and electricity costs over the next 40 years; subtracting the \$2.7 trillion additional investment needed to achieve this, we estimate a net saving of some \$2.3 trillion.

Our Conclusion: whether one simply wants to minimize costs to consumers, or to mitigate global warming, vigorous adoption of energy-efficiency measures and accelerated use of renewable energy sources make sense."

The probability of all of this occurring is in the same realm as that of President Fessler's (California Public Utilities Commission) famous quote "like teaching my arthritic cat to tap dance". However, it demonstrates that a long term view favors an emphasis on the renewables.

Geothermal, even on a short term basis, will be competitive with all future generation resources with the exception of natural gas fired projects.

CONCLUSION

Geothermal does fit into the national energy agenda due to the environmental benefits. It will be favored for continued development even if it is not able to be shown to be "cost effective" as compared to natural gas in the short term.

Our industry needs to develop an alliance with the other renewables, energy efficiency advocates and the natural gas fueled power developers to establish a consensus on a efficient development plan which maintains the appropriate role for all these parties who are the key players in the national energy agenda.

Our industry specifically needs to be assured of an ability to continue to build commercial plants to allow incremental improvements in capital and O&M costs to occur and we need to enhance the R&D support of DOE to allow technical breakthroughs to occur and new reservoirs to be established.

Thank you for your attention - it has been a pleasure sharing these ideas.

THE GEYSERS

**Chairperson: Kathleen Eney
Pacific Gas & Electric Company**

SESSION 2: THE GEYSERS - INTRODUCTORY NOTES

Kathleen L. Eneidy
Pacific Gas and Electric Company

It is a pleasure to welcome all of you to Session 2 on The Geysers. As economic times become more difficult, it is imperative to optimize research dollars spent at The Geysers. I feel that DOE and industry have made progressive strides toward attaining this goal.

HISTORY OF DOE/INDUSTRY GEYSERS RESEARCH PROGRAM

Some history of The Geysers is necessary to understand how the DOE/Industry Geysers Research Program was formed. The Geysers, which is the world's largest commercial geothermal development, has seen significant increases in installed capacity from 1982 to 1989, averaging nearly 150 MW per year. Although overall generation peaked in 1987, it reached peak installed capacity of 1,993 MW in 1989. Twenty-four generating units currently operate at The Geysers at an installed capacity of 1,801 MW and a generation level of about 1,250 MW. Utilities and steam suppliers have over 3.5 billion dollars of capital invested in their facilities at The Geysers. However, after 32 years of production, over 90 percent of the heat energy still remains in the reservoir rock.

At the request of the utilities and steam producers, DOE initiated a research program at The Geysers focusing on the following problems:

- Higher than anticipated productivity and reservoir pressure decline.
- Production of highly corrosive HCl.
- Increase in non-condensable gases (which decrease condenser efficiency).

From 1990 through 1992, \$6 million DOE research dollars have been spent on this joint Program. For 1993, another \$2.5 million is budgeted for the DOE/Industry Geysers Research Program.

CURRENT DOE/INDUSTRY GEYSERS RESEARCH PROGRAM

In 1991, Dr. Carel Otte was hired as a consultant to review the program and make recommendations to improve it. Dr. Otte interviewed both industry representatives and DOE principal investigators to gain perspective and insight into the current research program. Otte's study concluded that the overall research program was good and he recommended the following:

- More focus on projects not just research.
- More sense of urgency to provide near-term results.
- More communication with periodic progress reports.

As a result, in May 1992, four Working Groups were formed. These groups consist of steam supplier and utility representatives, in addition to DOE principal investigators. Mike Wright of UURI is the Working Groups facilitator. The groups cover the following disciplines:

1. Field Geological and Geochemical Models
Chaired by Bill Smith of NCPA
2. Injection Techniques
Chaired by Kathy Eneidy of PG&E
3. Field Performance Prediction
Chaired by Ben Barker of Unocal
4. Power Generation, Pipelines, Injection Water Corrosion Control
Chaired by Dan Ballantine of PG&E

The first working group session was held on June 3, 1992, in Santa Rosa. The tasks before each working group were threefold:

- Discuss current research projects pertaining to the group's discipline.
- Examine technical problems that led to decreased steam production and generation at The Geysers.
- Recommend modifications to on-going research.

The session lasted all day, with the four groups meeting separately in the morning to actualize the tasks, a plenary session was held after lunch to discuss the resulting ideas and finally the groups met again independently to refine their recommendations. A report was issued by Mike Wright on June 25, 1992, which included a summary of what was accomplished during the meeting along with recommendations from each of the four Working Group Chairs. The working group meeting was an opportunity for industry and researchers to get together and discuss some of the real problems facing us at The Geysers, how they came about, possible solutions and what is needed in the near-term. The discussion was lively as well as productive. It was an opportunity for technical transfer in addition to looking at The Geysers from others' perspectives. The consensus was that the current research program was sound, was providing useful results, and should be continued.

Three additional projects resulted from the June 3 meeting.

- Field Test of Water Injection and Tracers in Unit 18.
- Field Wide Maps of Various Reservoir Parameters.
- Deep Well Continuously Cored through The Geysers Reservoir.

Work has already begun on these projects and Mike Wright of UURI will provide you with the details. Before I turn the program over to Mike, I'd like to let you know that we have four speakers for this session that will give us valuable insight on some of the excellent research being done at The Geysers today.

SUMMARY OF THE DOE-INDUSTRY 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. Planning for these projects is underway, and they should begin in late 1993.

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. The Department of Energy has initiated a program to help the industry mitigate the effects of the decline. 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. 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 direct 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 from the companies involved, 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-condensable 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-condensable 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), Phil Molling (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), Joel Brown (CCPA), Mark Walters (RREC), Kathy Eney (PG&E), Ben Barker (Unocal), Mike Adams (UURI), Karsten Pruess (LBL), Dave Faulder (INEL), Roland Horne (Stanford). Kathy Eney 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), Kit Bloomfield (PG&E), Ben Barker (Unocal), Steve Eney (NCPA), Robert Emslie (RREC), Bo Bordvarsson (LBL), Hank Ramey (Stanford), Mike Shook (INEL), Roland Horne (Stanford), Marcelo Lippmann (LBL), Shubo Shang (Stanford), 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-plant technology 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-condensable 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), Shaun Brady (PG&E), Vincent Fesmeyer (Stone & Webster), Murray Grande (NCPA), 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 definitely address some of the goals of the working groups, the limited money available precludes working on all of the problems that are important.

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 viewers, 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.

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-condensable 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.

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

Corehole

A subgroup of people interested in this project has been formed from the working groups, and this subgroup has met on two occasions for discussions. The Department of Energy has made the amount of \$400,000 available through the Geothermal Drilling Organization for coring.

Several industry people have also met periodically to site the hole. The considerations are to select an existing well which could be taken out of production or injection and which penetrates into the upper part of the reservoir from which the coring could begin. It is apparent that a location on Unocal property will be selected. At the present time, a science plan is being put together by UURI from input supplied by various industry people, laboratories and universities. We anticipate that drilling will begin in late 1993. All contracting and permitting work will be done by Unocal, and they will let and supervise the drilling contract.

Injection Test in Unit 18.

This project is being implemented through the Geothermal Technology Organization, which will furnish the Department of Energy share of \$500,000. Unocal is writing the proposal to the GTO, and the project will be a joint effort among Unocal, NCPA, Calpine and DOE-funded people. This project should be underway in 1993.

Field-Wide Maps

This project is being carried out on a time-available basis by INEL at the present time.

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ACKNOWLEDGMENT

This work was supported in whole or in part, by the U.S. Department of Energy, through Contract No. AD-1703 with Sandia National Laboratories. Such support does not constitute an endorsement by the U.S. Department of Energy of the views expressed in this publication. The author would like to specifically acknowledge the time and efforts of the industry participants in this working-group effort. The working-group chairs have indeed guided the process that has resulted in the projects developed and recommended to date.

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GEYSERS RESERVOIR STUDIES

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INTRODUCTION

LBL is conducting several research projects related to issues of interest to The Geysers operators, including those that deal with understanding the nature of vapor-dominated systems, measuring or inferring reservoir processes and parameters, and studying the effects of liquid injection. All of these topics are directly or indirectly relevant to the development of reservoir strategies aimed at stabilizing or increasing production rates of non-corrosive steam, low in non-condensable gases. Only reservoir engineering studies will be described here, since microearthquake and geochemical projects carried out by LBL or its contractors are discussed in accompanying papers (i.e., Majer et al., 1993; Truesdell, 1993).

Three reservoir engineering studies will be described in some detail, that is: (a) Modeling studies of heat transfer and phase distribution in two-phase geothermal reservoirs; (b) Numerical modeling studies of Geysers injection experiments; and (c) Development of a dual-porosity model to calculate mass flow between rock matrix blocks and neighboring fractures.

There are two other on-going projects that should also be mentioned. The testing of the six-liter downhole fluid sampler in a high-temperature, high-pressure chamber is scheduled for early June 1993. After two disappointing experiments in a UNOCAL Geysers well, it was decided to test the tool in a controlled environment. It is felt that the sampler is failing to perform as planned because of field procedures and not due to design problems. However, before going to the effort and expense of a third field experiment, it was decided to test the tool in a chamber and then suggest changes in field procedures that might affect the electronic and mechanical components of the sampler.

The other project that will not be described here involves laboratory measurements of porosity, permeability and capillary pressure in Geysers cores. This low-key effort is just starting at LBL and results are expected to be reported during the next DOE-Industry Geysers Working Group meetings.

CONCEPTUAL MODEL STUDIES OF VAPOR-DOMINATED SYSTEMS

Although long exploited (i.e., Larderello, Italy, from 1904; The Geysers from 1960), vapor-dominated reservoirs are not fully understood. Over the years several quite different conceptual models have been proposed to explain

the reservoir processes in these fields.⁺⁺ Early models involved vaporization only at a liquid-vapor interface or original deep upflow of supercritical steam with near surface condensation. Others proposed models involved counterflow of ascending steam and descending condensate. In these models boiling at a deep brine "water table" was assumed, with steam moving upward in large fractures along the pressure gradient produced by boiling, and then condensing at the top of the reservoir because of conductive heat loss to the surface. This condensate flowed downward by gravity through the rock matrix and small fractures.

Recently high-temperature zones have been found deep in the vapor-dominated systems at The Geysers and Larderello. A conceptual model for the origin of these high-temperature zones as relicts of hot rock not yet cooled by a downward expanding vapor-dominated reservoir was suggested by Truesdell (1991). It is not possible to reconcile this model with those involving boiling brine or with movement of condensate from marginal zones of condensation to central boiling zones. Apparently conceptual modeling has reached its limits and more data from experiments and analytical/numerical studies are required.

Two-phase liquid-dominated systems can have shallow vapor-dominated zones (e.g., Olkaria, Kenya), single-phase shallow (e.g., Krafla, Iceland) or deep liquid zones (e.g., Ahuachapán, El Salvador), or present two-phase liquid-dominated conditions throughout. Two-phase vapor-dominated systems such as The Geysers, Larderello, and Kamojang (Indonesia) have a thick two-phase vapor-static zone but may be underlain by a superheated vapor zone or by a two-phase zone with sub-hydrostatic pressure and possibly overlain by a liquid-saturated condensate zone (D'Amore and Truesdell, 1979). For these reservoirs, the observed natural-state temperature and pressure in the main reservoir is approximately 240°C and 33.4 bars. These conditions have been hypothesized to be related to the enthalpy maximum of saturated steam (James, 1968).

Results of Recent Numerical Studies

Lai et al. (1993) conducted a numerical study of steady-state flow, phase distribution, and heat transfer processes in two-phase geothermal reservoirs using the computer code TOUGH2 (Pruess, 1991). A two-dimensional porous slab with a localized heat flux from below was used as an idealized model for a geothermal system (Figure 1). In the study effects of initial mass of fluid in-place (i.e., steam saturation), permeability and capillary pressure on the phase distribution and heat transfer processes were analyzed. The

⁺⁺ Relevant references are given in Lai et al. (1993).

results showed that when an initial steam saturation of 25% and a rather high permeability of $1 \times 10^{-13} \text{ m}^2$ are employed, a two-phase vapor-dominated zone overlying a single-phase liquid zone is formed (Figure 2). In the two-phase zone, a balanced liquid-vapor counterflow develops. The vapor rises up to the reservoir top where it is condensed to liquid by releasing latent heat which is transferred to the caprock by conduction. The condensate trickles down to the liquid zone. In the liquid zone, a convective flow field extends laterally over the entire reservoir. However, if the length of the heat source varies, the flow characteristics in the liquid zone may be different from that observed in this study.

The strength of the convective flow strongly depends on the mass of fluid in-place and the permeability of the reservoir. With an increase in initial steam saturation from 25 to 50%, the convective flow field extends only over the left half of the reservoir, resulting in lower heat transfer rates. As the steam saturation is increased to 70%, a vapor-dominated heat pipe prevails in the entire system. Because a heat pipe efficiently dissipates heat generated from the heat source, the temperature variation in the system is very small, ranging from 240 to 245°C. However, when the steam saturation is further increased to 75%, the amount of mobile liquid is reduced and the heat pipe does not develop in the entire system (Figure 3). Under such a circumstance, although a vapor convective flow exists, it is not as efficient as liquid convective flow in dissipating heat, resulting in a high-temperature superheated vapor zone underlying the two-phase vapor-dominated zone. Such a high-temperature zone has been found at The Geysers and Larderello.

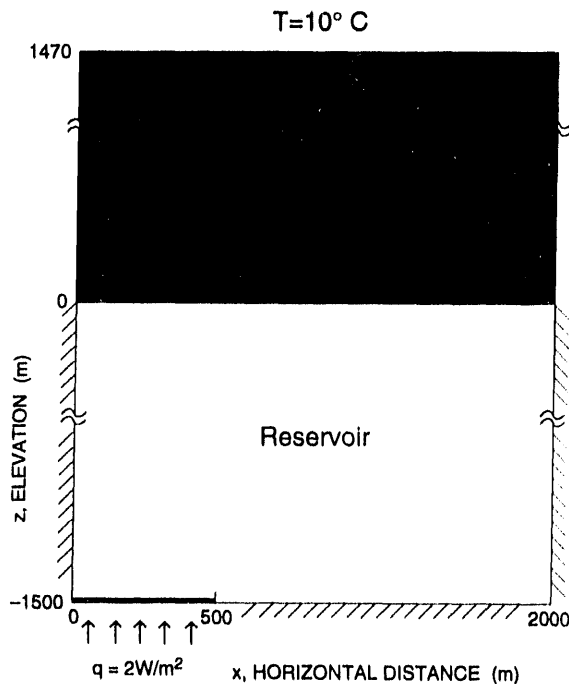


Figure 1. A schematic representation of the physical problem studied (from Lai et al., 1993).

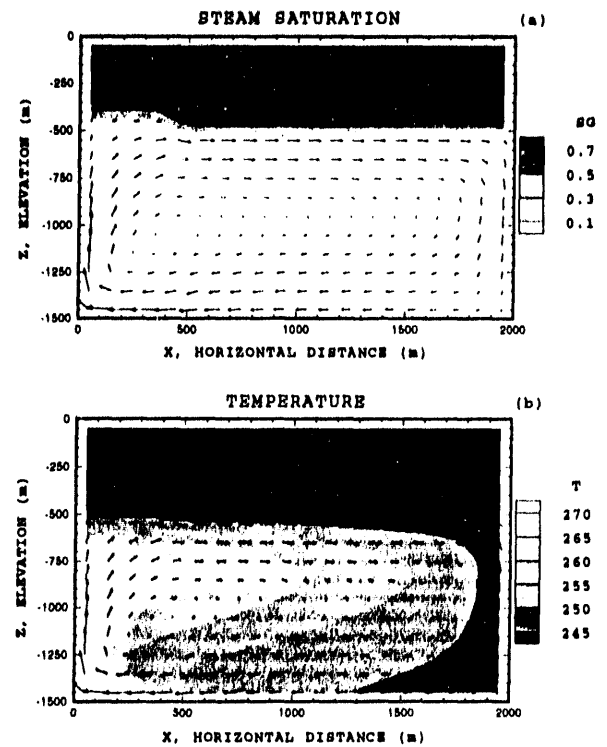


Figure 2. Computed steady-state distribution in the reservoir of (a) steam saturation and (b) temperature. Assumptions: Initial steam saturation 25%; permeability $1 \times 10^{-13} \text{ m}^2$. Arrows indicate mass flux; their length is proportional to flux magnitude (from Lai et al., 1993).

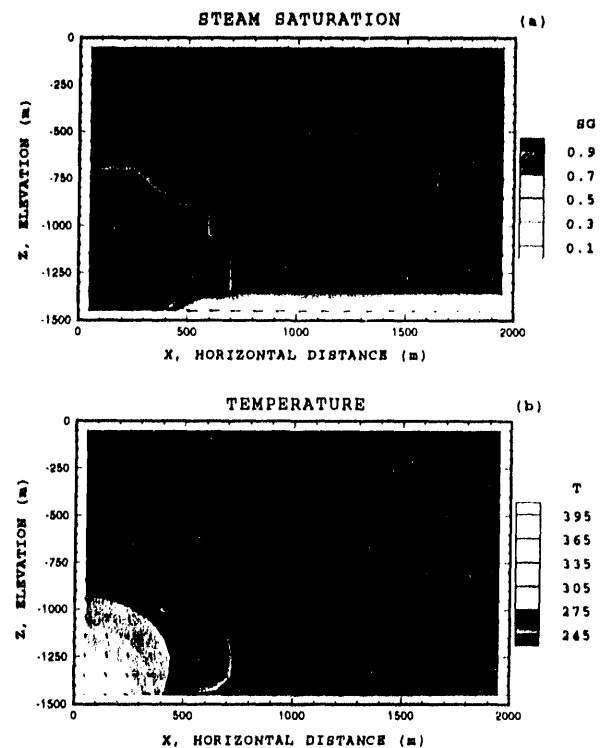


Figure 3. Computed steady-state distribution in the reservoir of (a) steam saturation and (b) temperature. Assumptions: Initial steam saturation 75%; permeability $1 \times 10^{-13} \text{ m}^2$. Arrows indicate mass flux; their length is proportional to flux magnitude (from Lai et al., 1993).

In general, the smaller the permeability considered in the model, the smaller the portion of the liquid zone affected by convective flow, leading to a reduction in heat transfer rates. When a low permeability of $1 \times 10^{-15} \text{ m}^2$ with an initial steam saturation of 25% is used, a two-phase liquid-dominated zone develops (Figure 4), which is consistent with field data from several geothermal fields including Olkaria. To investigate the effects of capillary pressure on features of two-phase geothermal reservoirs, Lai et al. (1993) performed a simulation considering a large capillary pressure, with a steam saturation of 25% and a permeability of $1 \times 10^{-15} \text{ m}^2$. The results show that when a large capillary pressure is considered in the model, lower steam saturation is found in the upper two-phase zone, and a wider boiling zone is obtained in the vicinity of the heat source. In addition, the temperatures surrounding the heat source are much lower, because capillary pressure pulls liquid water into a relatively dry and high-temperature zone located above the heat source.

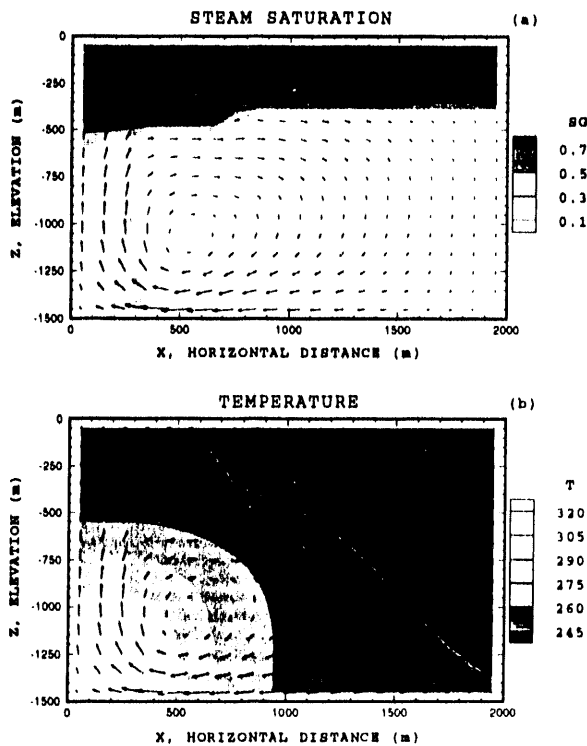


Figure 4. Computed steady-state distribution in the reservoir of (a) steam saturation and (b) temperature. Assumptions: Initial steam saturation 25%; permeability $1 \times 10^{-15} \text{ m}^2$. Arrows indicate mass flux; their length is proportional to flux magnitude (from Lai et al., 1993).

NUMERICAL MODELING OF INJECTION EXPERIMENTS

In an attempt to identify reservoir conditions and processes that could cause the striking patterns of injection interference between wells Q-2 and Q-6 in the Southeast Geysers (Figures 5 and 6), Pruess and Enezy (1993) first developed hypothetical models that may explain such behavior. Subsequently the viability of proposed models was evaluated by means of numerical simulation, and conclusions were drawn for design and monitoring of injection systems.

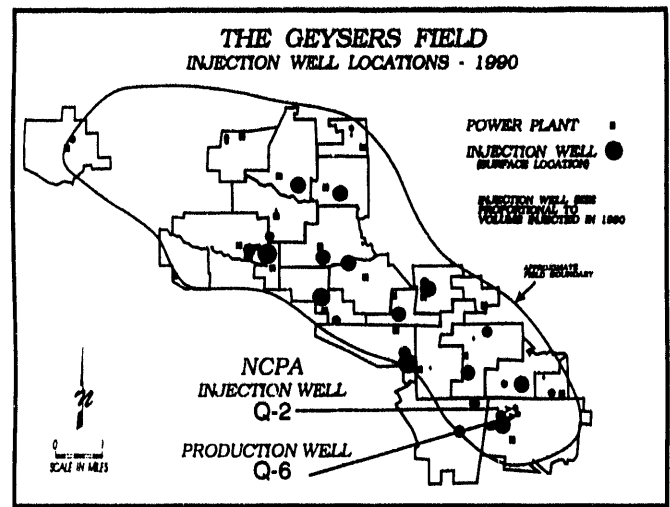


Figure 5. Injection well locations at The Geysers (from Pruess and Enezy, 1993).

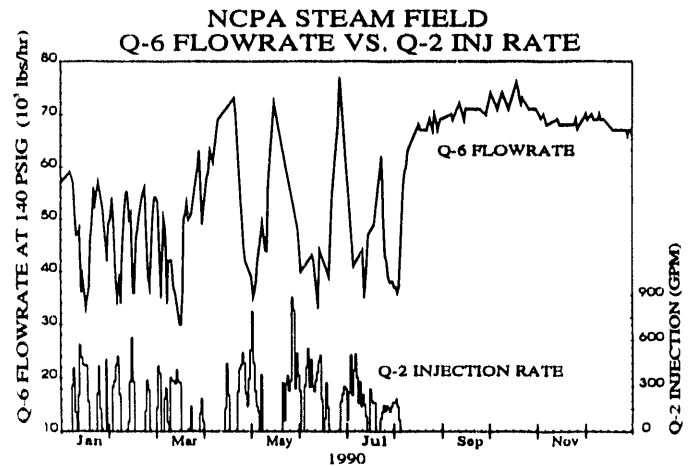


Figure 6. Injection rates into Q-2 and observed production from Q-6 (from Pruess and Enezy, 1993).

Conceptual Model

According to Pruess and Enezy (1993) the strong and fast interference between Q-2 and Q-6 (Figure 6) suggests that both wells intersect some of the same fractures or fracture zones. These fractures would accept much of the fluid injected into Q-2, and provide important paths for flow of reservoir vapor to well Q-6 steam entries. During injection a plume of heating and partially boiling liquid will spread around the injection well. Depending on rates of fluid injection, and heat transfer from the reservoir rocks to the injection plume, two-phase zones with declining temperatures may develop. Because of the one-to-one correspondence between temperatures and pressures in two-phase conditions, fluid pressures in parts of the injection plume and the surrounding reservoir may decline, causing flow rate declines in neighboring wells. In addition, injected liquid in the fractures may partially block the vapor

flow paths from the reservoir "at large" to well Q-6 feeds. This interference of injection-derived liquid with vapor flow can be thought of as a relative permeability effect.

After injection is stopped the injected liquid will, in part, boil away, migrate to greater depth, or be sucked by capillary force away from the fractures into the low-permeability rock matrix. Removal of the liquid will clear the fracture flow paths for vapor, causing production to recover. The observed over-recovery indicates that the injected liquid becomes available as a significant additional source of steam, boiling close to Q-6 ("close" in the sense of good hydraulic communication), with excellent access to reservoir heat. Heat transfer to the fluid could occur either by conduction to the fractures, with fluid boiling in the fractures, or injected liquid could be imbibed into the rock matrix, boiling there from local heat exchange.

Based on the foregoing discussion, the most important component in the model will be the fractures that connect Q-2 and Q-6. The fractures will take a portion of the fluid injected into Q-2, and will supply part of the production to Q-6. They will be coupled to matrix rock of small but finite permeability, that will transfer heat to the fluids in the fractures by conduction, while absorbing liquid from the fractures by capillary force. In addition to the specific fractures that connect Q-2 and Q-6, there is a general "background" reservoir that supplies long-term production to the local fracture system, and may also absorb some of the injected fluid.

The available field data do not provide the detailed geometry of the local fracture system on the scale of the distance between Q-2 and Q-6 feeds, of order 300 m. Pruess and Enedy's (1993) approach was to start with the simplest assumptions and flow geometries that would seem capable of explaining the strong and rapid negative production interference during injection, and the (over-recovery) following injection shut-in. The modeling assumptions were then revised and refined to reduce discrepancies between predicted and observed behavior. The most "stripped down" model would seem to need two essential ingredients: (i) a single fracture intersecting both Q-2 and Q-6, and (ii) a large "background reservoir" connected to this fracture. Even in this most simplified model the flow geometry would be three-dimensional, and fluid and heat flows would need to be considered over a very large range of thermo-hydrologic parameters and spatial scales. Indeed, permeabilities range from microdarcies in the rock matrix to perhaps tens or hundreds of darcies in the fractures. Relevant spatial scales for the important flow processes are of the order of centimeters for flow in the fractures and imbibition into the rock matrix, several decimeters for penetration of heat conduction into wall rock over several days, and hundreds of meters for reservoir perturbation from long-term production. When coupled with the extremely non-linear process complexities of two-phase vaporizing flows, this leads to impractical computational demands, and further simplifications must be made.

Pruess and Enedy (1993) simplified the flow geometry by modeling the fracture and the background reservoir as two separate two-dimensional systems with appropriate coupling, although in reality the local fractures are of course embedded in the reservoir. The background reservoir was modeled as a large radially-symmetric layered (R-Z) system; the fracture as a rectangular vertical (X-Z) section. Although the fracture itself requires only 2-D gridding, consideration of fluid and heat flow between the fracture and the surrounding reservoir rock will still make the system three-dimensional.

Numerical Simulation Approach

A schematic of the fracture-reservoir flow model used is shown in Figure 7. The assumed model parameters are discussed by Pruess and Enedy (1993). These parameters were not specifically selected for the local conditions in the study area; rather, they were intended to be generically applicable to The Geysers reservoir. Generally speaking, hydrologic parameters needed for two-phase flow modeling are not well known for Geysers rocks. As in previous studies of vapor-dominated reservoirs (e.g., Pruess and O'Sullivan, 1992), Pruess and Enedy (1993) borrowed data for welded tuffs from nuclear-waste related studies. Welded tuffs have permeabilities in the microdarcy or fraction-of-a-microdarcy range, and are believed to have similar capillary and relative permeability behavior as unfractured graywacke or felsite from The Geysers.

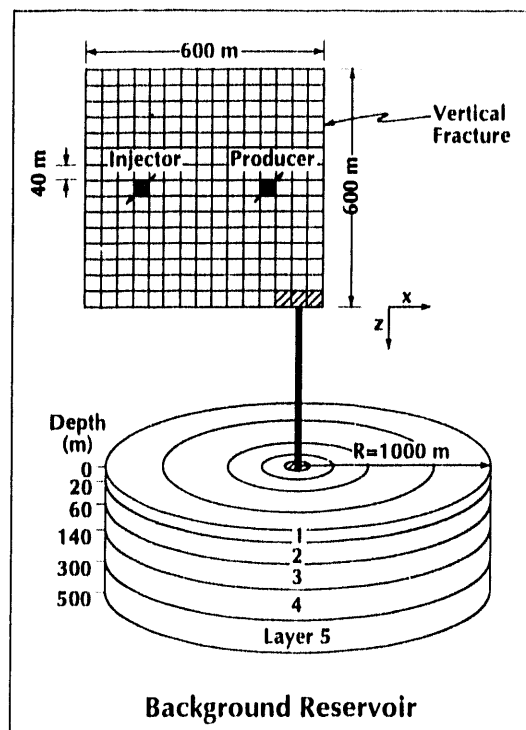


Figure 7. Schematic diagram of fractured reservoir model used in numerical simulations. Injection and production wells are intersected by the same vertical fracture, which is connected to a large background reservoir. Fluid and heat flow perpendicular to the fracture plane is also taken into account (from Pruess and Enedy, 1993).

Vertical fractures of different total area were modeled, from 300 x 300 m² to 600 x 600 m². The fracture was modeled as a high-permeability porous medium with a small effective void space thickness of 1 cm, and a permeability-thickness product of 40 Darcy-meter. Relative permeability and capillary pressure behavior of fractures is not well known. Recent theoretical and experimental studies by Pruess and Tsang (1990) and Persoff et al. (1991) have suggested that two-phase flow behavior of fractures may be similar to that of three-dimensional porous media of high permeability. It was assumed that fracture capillary pressures are negligibly small, and that relative permeabilities may be represented by standard Corey-curves.

In the model the distance between injection and production wells is 240 m. The background reservoir was modeled as a layered porous cylinder of 500 m height and 1,000 m radius. It was conceptualized as a dual-permeability fractured porous medium with average porosity of 4% and a total permeability-thickness product of 21.6 Darcy-meter. Dual permeability behavior was modeled with an "effective porous medium" description. Chiefly, this consists of an effective relative permeability with a very high (80%) irreducible liquid saturation (Pruess and Narasimhan, 1982). The "background reservoir" serves as a means to provide stabilized long-term flow to the local fractures; simulated injection interference is not sensitive to detailed specifications of the background reservoir.

As a starting point for simulating "natural" pre-exploitation conditions, the entire flow system was initialized with a temperature of 240°C and a corresponding saturated vapor pressure of 33.44 bars. Initial water saturation is 80% in the background reservoir and 0% in the fracture. Boundary conditions in the background reservoir were held constant to initial conditions at the cylinder mantle ($R = 1000$ m). Top and bottom boundaries were modeled as semi-infinite (thermally) conductive half-spaces. Lateral boundaries in the fracture were "no flow"; perpendicular to the fracture plane different boundary conditions were explored, including semi-infinite conductive half-spaces, and permeable matrix rock. The latter requires a fully three-dimensional fracture-matrix grid, while conductive boundary conditions can be efficiently modeled with a semi-analytical technique.

The production well representing Q-6 was placed on deliverability. Prior to startup of injection an extended production period of 5 years was modeled, to simulate appropriate reservoir depletion in the area of the NCPA injection experiments. Subsequently water injection was started into the fracture at a distance of 240 m from the production well, and at the same elevation. Water at a temperature of 20°C was injected at rates from 12 to 25 kg/s for periods of from 1 to 3 days. During injection the production well continued to operate at the same deliverability conditions as before, with interference effects manifest in changing flow rates and enthalpies. The simulation was continued past the termination of injection to investigate recovery behavior. Pruess and Enezy (1993) carried out only one single injection cycle; interference effects

and constraints from repetition of many cycles have not yet been explored.

All calculations were done using LBL's general-purpose reservoir simulator TOUGH2 (Pruess, 1991). This code incorporates the general "MULKOM" architecture for multiphase fluid and heat flow (Pruess, 1983), and includes special provisions for modeling geothermal flows in fractured-porous media.

Results of Recent Numerical Studies

- (1) The Pruess and Enezy (1993) numerical simulation studies predicted strong interference between injection into and production from the same fracture. During injection production rates mostly declined, with over-recovery observed after injection was stopped. The simulated behavior is similar to field observations in the Q-2/Q-6 experiments, lending credence to the underlying conceptual and numerical model.
- (2) The most significant reservoir processes during injection include gravity-driven downward migration of injected water, local heat exchange with reservoir rock swept by the injection plume, conductive heat transfer from rocks of very low permeability to the injection plume, capillary-driven imbibition of injected liquid into the matrix rock, away from the fractures, vapor condensation in the cooler portions of the plume, and boiling in the hotter portions (Figures 8-10).

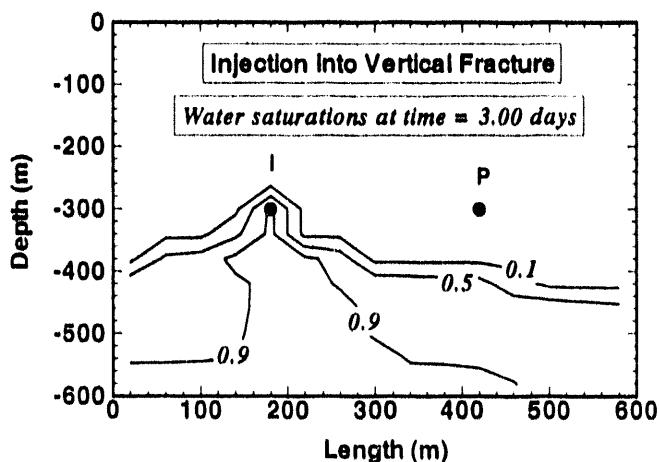


Figure 8. Water saturations in the fracture after 3.0 days of injection, case with permeable fracture wall (I-injector, P-producer; from Pruess and Enezy, 1993).

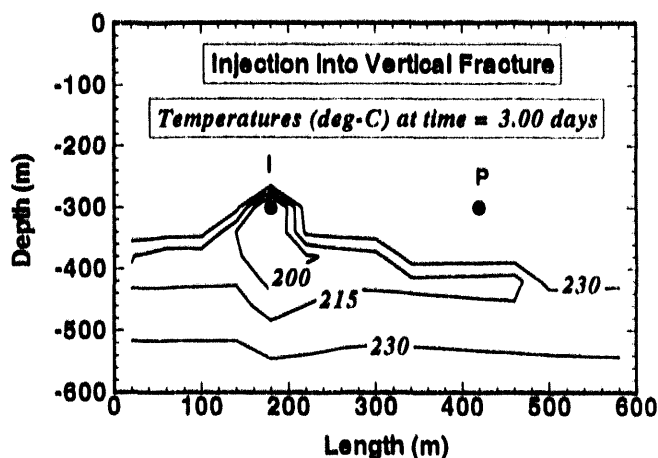


Figure 9. Temperatures in the fracture after 3.0 days of injection, case with permeable fracture wall (I-injector, P-producer; from Pruess and Eneidy, 1993).

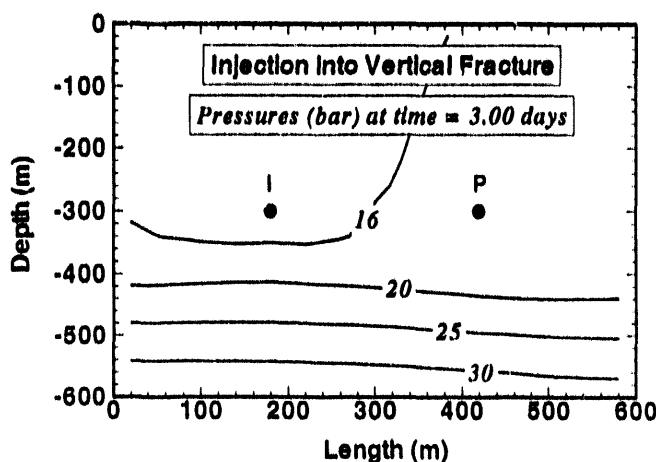


Figure 10. Fluid pressures in the fracture after 3.0 days of injection, case with permeable fracture wall (I-injector, P-producer; from Pruess and Eneidy, 1993).

- (3) The simulated production declines were stronger than seen in the field. This can be explained by noting that in Pruess and Eneidy's (1993) model all injected water entered one single fracture, and all production came from that same fracture, whereas in the field several fractures will participate in taking up injectate, and delivering fluid and heat to the production well.
- (4) The simulations clearly demonstrated that injection is subject to heat transfer limitations. Production rate decline from injection is caused primarily by temperature decline in the injection plume and associated drop in vapor pressure. Cool portions of injection plumes act as low-pressure sinks that can consume large amounts of vapor by condensation. Temperature decline depends on injection rate and on the heat

transfer capacity of the reservoir, which is a function of available heat exchange volume, heat transfer area, and permeability for vapor flow.

- (5) Based on the foregoing, Pruess and Eneidy (1993) expected that each injection well has a limitation on the rate at which water can be injected without causing significant reservoir pressure decline, and consequently negative interference with neighboring producers. They concluded that acceptable limits for injection rates may be difficult to predict, as these depend on geometric properties of the local fracture system that usually are poorly known. However, in practice such limitations could be established empirically by monitoring neighboring production wells.
- (6) Pruess and Eneidy (1993) indicated that injection should not be concentrated into a few wells that would take up large rates. Because of heat transfer limitations, injection wells should generally be operated at moderate rates well below their capacity for accepting fluids (Eneidy et al., 1991).

NEW SIMULATION METHODOLOGY FOR FRACTURED GEOTHERMAL RESERVOIRS

Although the majority of geothermal reservoirs reside in fractured rocks, most models developed to analyze their behavior have been based on porous medium approximations. In these models, the hydraulic behavior of the fractures and the matrix blocks are represented together as a locally-homogeneous porous medium. It is well-known, however, that porous medium models are poorly suited for predicting certain aspects of the behavior of geothermal wells, especially enthalpy transients, thermal front migration due to injection, and chemical tracer movement. Nevertheless, in many cases the porous medium approximation must be invoked, due to constraints of computer time or cost. There is, consequently, a great need for improved numerical capabilities for the modeling of fractured geothermal reservoirs, using accurate and appropriate models. Zimmerman et al. (1993) developed a new type of dual-porosity model to simulate two-phase flow processes in fractured geothermal reservoirs. The main concept behind their approach was to analyze the heat and mass flow processes occurring within the matrix blocks—processes generally governed by diffusion-type partial differential equations—by simplified equations that made a detailed discretization of individual matrix blocks unnecessary. The diffusive processes were modeled using nonlinear ordinary differential equations that relate the average thermodynamic properties in the block to those in the fractures.

The first stage of this work, dealing with isothermal flow of a single-phase fluid, was described in Zimmerman et al. (1992). Since then the general approach has been extended to treat thermal conduction within the matrix blocks. This extension is straightforward, as shown by Pruess and Wu (1993), since the governing equation for conduction is exactly analogous to that for single-phase flow. A fur-

ther expansion of this approach to processes involving two-phase conditions in which the liquid phase is immobile, is described in Zimmerman et al. (1993). The newly developed semi-analytical dual-porosity model was implemented as a modification to the TOUGH2 simulator (Pruess, 1991).

Results of Recent Numerical Studies

To test the accuracy and computational efficiency of the modifications made to TOUGH2, Zimmerman et al. (1993) simulated various problems using essentially the computational grid and reservoir properties proposed by Spivak (1991) to test geothermal codes. This is a three-dimensional model of a vapor-dominated geothermal reservoir with properties considered appropriate for The Geysers. This hypothetical reservoir (see Figure 11) is 1524 m thick; the cross-sectional shape in any horizontal plane is a rectangle with sides of 914.4 m and 609.6 m. Each layer is broken up into 24 gridblocks, each of length 152.4 m in the two horizontal directions. The thicknesses of the five layers are as shown in Figure 11.

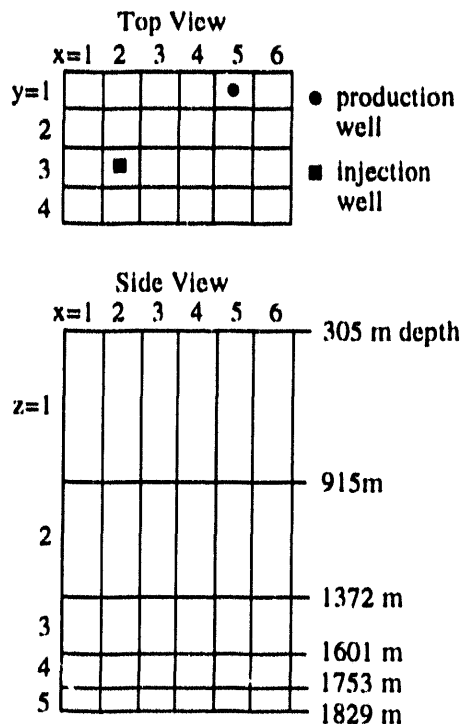


Figure 11. Schematic diagram of the grid used in simulations of a hypothetical geothermal reservoir. Dimensions of the gridblocks, and the physical properties of the fractures and the matrix blocks, are listed in the text (from Zimmerman et al., 1993).

A production well (Well #1) and an injection well (Well #2) are located in gridblocks $xyz = 511$ and $xyz = 231$ (see Figure 11), and are completed only in the topmost layer of the reservoir. The matrix blocks are cubes of 67 m on each side, with matrix permeability $k_m = 1 \times 10^{-19} \text{ m}^2$, matrix porosity $\phi_m = 0.04$. (A somewhat low matrix permeability is used so as to avoid having the liquid saturation rise above its irreducible value near the injection well). The rock has density $\rho_r = 2648 \text{ kg/m}^3$, and heat capacity $C_r = 1000 \text{ J/kg-K}$. The fracture network has an overall porosity $\phi_f = 0.01$, and permeability $k_f = 2.0 \times 10^{-14} \text{ m}^2$. The relative permeabilities of both the fracture network and matrix blocks are taken to be linear functions of saturation, with the irreducible saturations for the liquid phase, and for the vapor phase in the matrix blocks, set to zero. The irreducible saturation for the liquid in the matrix blocks is 0.25. Capillary pressure and thermal conductivity effects are neglected in both the fractures and matrix blocks. The initial conditions are that the liquid saturation in the matrix blocks is at its irreducible value of 0.25, and the pressure in the uppermost layer is 3.45 MPa. The initial temperature in the uppermost layer is therefore equal to the saturation temperature at this pressure, which is 242°C.

All outer boundaries of the reservoir are impermeable to fluid flow, and the lateral boundaries are also closed to heat conduction. A heat flux of 0.5 W/m^2 is conducted vertically upwards through the reservoir. The remaining initial conditions, such as the pressures in the lower layers and the saturations in the fractures, were found by running a simulation to steady state, with no injection or production from the wells. In the sample problem whose results are shown in Figures 12–14. Well #1 produces 5 kg/s of fluid, and Well #2 injects 5 kg/s of liquid water at 95°C.

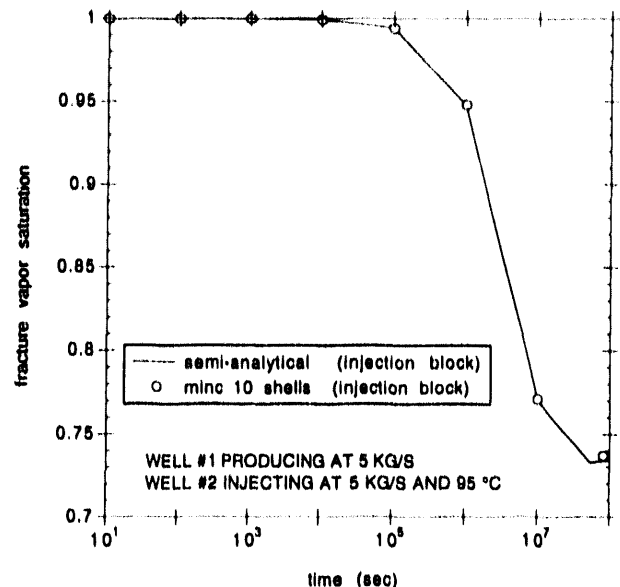


Figure 12. Vapor saturation in the fractures of gridblock 231, for the problem described in the text (from Zimmerman et al., 1993)

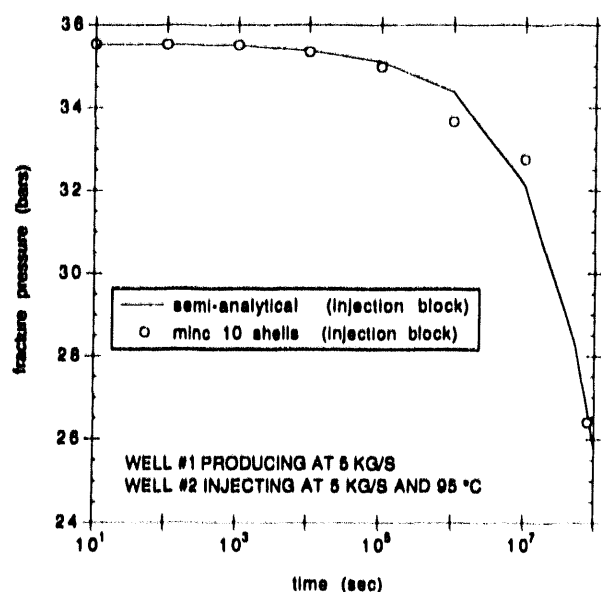


Figure 13. Pressure in the fractures of gridblock 231, for the problem described in the text (from Zimmerman et al., 1993)

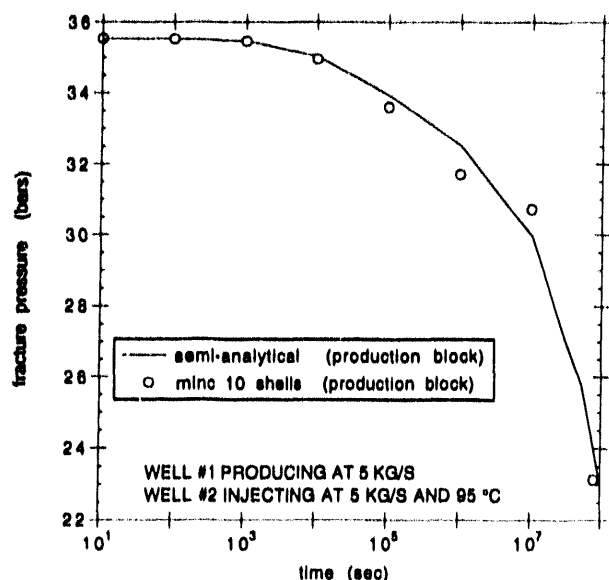


Figure 14. Pressure in the fractures of gridblock 511, for the problem described in the text (from Zimmerman et al., 1993)

The computed vapor saturations and pressures for the fractures in gridblock 231 are shown in Figures 12 and 13, respectively. The solid lines denote the values obtained using TOUGH2 with the modifications described above, whereas the open circles denote values computed with TOUGH2 using the MINC method (Pruess and Narasimhan, 1992) to discretize each equivalent matrix block into ten concentric gridblocks. The fracture pressure in gridblock 511 is shown in Figure 14. The vapor saturation in the fractures in gridblock 511 remains very close to 100% through both simulations, and is not shown. The predictions of the new method are in all cases very close to those of the MINC simulations. Due to the relatively complex geometry of this problem, and the physical nonlinearities arising from phase-changes, etc., no analytical solution is available for comparison.

Comments

At this time, the model developed by Zimmerman et al. (1993) is limited by the assumption that the liquid phase in the matrix blocks remains immobile. By utilizing the effective compressibility concept developed for water/steam mixtures in porous rocks (Grant and Sorey, 1979), flow within the matrix blocks can be modeled by a single diffusion equation. This equation is in turn replaced by a non-linear ordinary differential equation that utilizes the mean pressure and mean saturation in the matrix blocks to find the rate of fluid flow between the matrix blocks and fractures. This equation has been incorporated into the numerical simulator TOUGH2, as a source/sink term for computational gridblocks that represent the fracture system. The accuracy of this new method has been tested by simulating a three-dimensional reservoir containing partially-penetrating injection and production wells, and comparing the results to simulations in which the matrix blocks are each discretized into ten concentric shells.

FINAL REMARKS

Lawrence Berkeley Laboratory continues to work in close cooperation with the US geothermal industry. Since FY-1991 about half of LBL's research has been devoted to understanding the behavior of The Geysers field and other vapor-dominated geothermal systems. Because of this emphasis and a recent decrease in funding levels, the study of other US fields, as well as basic research work at LBL has been adversely affected.

In light of the possibility of future increases in DOE's geothermal budget, LBL organized and hosted the March 16th, 1993 meeting of the LBL Industry Review Panel on Geothermal Reservoir Technology. The purpose of the meeting was to get input on how DOE's Geothermal Reservoir Technology Program can be tailored to respond to the short- and long-term needs of the US geothermal industry. Thirty-six industry representatives (field and power plant operators, and consultants) attended; a summary of the meeting and the recommendations made were discussed during this Review by the chairman of the Panel,

Dick Benoit of Oxbow Power Services, Inc. In light of these recommendations it appears that LBL's geothermal activities continue to be well focused on industry's top research priorities (i.e., case studies, injection, instrumentation, well testing, reservoir modeling, field exploration and evaluation).

ACKNOWLEDGMENTS

Special thanks to Teklu Hadgu and Emilio Antúnez for reviewing this paper and Judith Peterson for producing it. This work was supported by the Geothermal Division of the U.S. Department of Energy, under Contract No. DE-AC03-76SF00098.

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Southeast Geysers Injection and Reservoir Model Study

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INTRODUCTION

Water injection at The Geysers began in 1969 as a means of cooling-tower waste-water disposal. Simple disposal of water has gradually evolved into an accepted means of maintaining reservoir production. However, operator success with injection has varied widely (Enezy et al., 1993). If injection is to be expanded at The Geysers, it is important to understand the processes of injection, vaporization and production of injectate and then to use this understanding to predict the behavior of the field during injection. Insight into these processes can be gained by studying historical injection at The Geysers and then using reservoir simulators to predict reservoir performance under various injection plans.

A calibrated model of a portion of the Unit 13 area in the southeastern region of The Geysers steam field (Figure 1) was used to evaluate historical injection efficiency of two injection wells and to then optimize reservoir performance through studying several injection scenarios. This study used historical production data to model reservoir performance using the TETRAD simulator (Vinsome and Shook, 1993). Naturally occurring isotopic data was utilized as a tracer of injected fluid and a measure of injection derived steam (IDS) in a manner as discussed by Beall et al. (1989). This area of The Geysers was selected for study because injection spans thirteen years and includes two injection wells, exploitation started at essentially undisturbed conditions and reservoir performance is well documented in the literature.

SYNTHESIS OF DATA

Reservoir Model

Three water components were used in the model to allow the explicit tracking of the native reservoir fluid and injectate from each of the two injection wells. This method allows a comparison between the observed isotopic data (Beall et al., 1989) and the model estimates of IDS recovery from each injection well.

The basic model construction has been discussed previously (Faulder, 1992) and is only briefly reviewed here. The study area has areal dimensions of approximately 10,000 by 12,000 feet, and an average thickness of 5,000 feet. The top of steam and top of felsite were used to define the top and bottom of the reservoir and hence the model thickness. The top of felsite was used as a proxy for the bottom of the reservoir model and is justified by the observation that in the study area very few wells penetrate the felsite. The study area has a large amount of vertical relief on these two surfaces, especially the top of felsite (over 5,000 feet).

Previous studies have demonstrated the importance of reservoir structure in the movement and recovery of injectate in vapor-dominated reservoirs (Shook and Faulder, 1991; Faulder, 1992).

The study area was discretized using a total of 1,650 grid blocks (11 by 15 by 5) in a dual porosity mode. The five vertical layers decreased in thickness with depth with the bottom layer uniformly 75 feet thick, keeping with the observations of Lai and Bodvarsson (1991) on the importance of grid refinement with depth when studying cold water injection into a vapor-dominated reservoir. The reservoir model has closed boundaries on the east, south, and west sides, while the north boundary was set at a constant pressure. This was necessary to prevent the accumulation of a large body of liquid water due to injection. Steam production in offsetting leases outside the study area occurs to the south, west, and northwest of the study area.

Petrophysical Properties

The matrix porosity was assigned consistent with the findings of Gunderson (1990) using the algorithm for porosity assignment presented by Williamson (1991). Matrix porosity varied from 4.6% to 2.96%, decreasing with depth. The fracture porosity varied from 2.0% to 1.45%, again decreasing with depth. The matrix permeability was set at a uniform 8 μ D. Fracture permeability is more variable with increased permeability to the southeast. Data supplied by the operator confirmed the general trend but indicated a fracture permeability range from 20 to 100 mD, increasing to the southeast in the study area.

An initial matrix water saturation of 82% was used and is consistent with previous model studies at The Geysers, (Williamson, 1991; Pruess and Narasimhan, 1982). Matrix and fracture relative permeability and capillary pressure have not been reported in the literature for The Geysers. In the absence of this information, parametric expressions were used to generate relative permeability and capillary pressure relationships. Typical Geysers petrophysical properties were used in the study.

MODEL STUDY

A previous model study of the southeast Geysers utilized a rate-constraint approach (i.e. measured production and injection rates are fixed) and a three-component system to explicitly track injectate movement from each injection well in both phases (steam and water), (Faulder, 1992). That study demonstrated the injectate migrated to the north, down the surface of the bottom of the reservoir model (i.e. top of felsite), and away from the production wells into an

undeveloped area. That model was updated and refined for the current study using a pressure-constraint approach (i.e. measured production wellhead pressures are fixed and well productivity indices are adjusted to match measured production rates).

The reservoir model was allowed to equilibrate for 20 years prior to the start of exploitation in 1980, which allowed the initially specified fluid saturations and pressures to equilibrate. The equilibrated model was used as a starting point for history-matching the exploitation reservoir response.

Model IDS recovery is defined as:

$$IDS_R = \frac{\text{cum production of component "a"}}{\text{cum injection of a component "a"}}$$

The IDS_R is based on cumulative values. IDS_R is damped by previous production and may be misleading regarding the instantaneous IDS fraction. IDS_R will vary between 0 and 1.0. The IDS_R changes with time so a reference date is needed to specify the time since the start of injection.

An alternative method of measuring model IDS response is to calculate the instantaneous fractional recovery of produced injectate. This is defined as:

$$IDS_P = \frac{\text{current production rate of component "a"}}{\text{current injection rate of component "a"}}$$

The second approach can result in an IDS_P fraction greater than 1.0 due to several reasons; (a) the current production of IDS may include a mixture of recently vaporized and older injectate and (b) as the current injection rate may vary. Using both measures provides more information on the IDS production and injection efficiency.

Production Match

Production data from the start of operations in early 1980 to September 1992 were used. This production data was matched using a pressure-constraint approach.

McKinley 5 started injection operation May 1980, at an injection rate of about 1,200 gal/min. This resulted in the development of a plume of water migrating to the north and away from the developed area. Water break-through problems were experienced in offset production wells and in November 1984, therefore the injection rate was reduced to about 400 gal/min. The balance was diverted to Thorne 7, located to the north of McKinley 5.

The individual production well productivity indices (PI) were adjusted until modeled production rates reasonably well matched the measured production rates. Some of the production wells located to the east side of the reservoir model did not produce the observed rates at the observed wellhead pressures past 1988, probably due to the closed boundary on the east. The limited model reservoir volume and the production interference of new production wells drilled in after 1987 in this portion of the study area contributed to this effect. The reservoir extends to the east of the study area and provides pressure and fluid support

(Truesdell et al., 1993), but was not included in this study for simplification. The final production history-match for a select well and the total study area is presented in Figures 2 and 3. The overall history-match is considered to be very good.

Injection Match

Figure 4 shows a comparison of the modeled fraction of IDS (of the well's total steam production) compared to the measured fraction of IDS using the δ deuterium of Beall et al. (1989) for wells Bianchi 3 and McKinley 1, located near the injection wells. Note that Bianchi 3 is located to the north of McKinley 5 and McKinley 1 is located to the south. This figure also demonstrates the qualitative nature of using δ deuterium data with only three measurements during thirteen years of exploitation to constrain modeling. While these nearby wells produced a significant fraction of IDS, the total study area received little benefit. Figure 5 presents the modeled total study area IDS_P attributable from each injection well.

The modeled injectate movement provides some clues for the low overall IDS production. Thorne 7 is a peripheral injection location, located north of McKinley 5, down structure of the top of the felsite. Liquid injectate from McKinley 5 migrated to this area by the time Thorne 7 had started injection. The migrated liquid injectate from McKinley 5 cooled the fractures, creating a large pool of liquid and resulted in low IDS_R from Thorne 7. This is demonstrated by a comparison of IDS_R for the total study area, from the two injection wells from the history-match with a IDS_R of 22.2% and 5.9% from McKinley 5 and Thorne 7, respectively. These results are in very good agreement with the previous rate-constrained IDS_R , (Faulder, 1992).

Injection Optimization

Several lessons from successful injection management in a vapor-dominated reservoir are apparent from the literature for the Unit 13 and 16 areas (Goyal and Box, 1992); from the C-11 injection test southwest of the study area (Enezy et al., 1991); the NCPA leases, south of the study area (Enezy et al., 1993); and from Larderello, Italy (Cappetti et al., 1982). Low reservoir pressure (i.e. high reservoir superheat), high permeability, low injection rates, no previous injection, and dense well spacing in the area of the injection well are all characteristics that have been identified as enhancing the recovery of IDS. Also, reservoir geometry, especially the bottom surface, strongly influences the migration of injectate. Injection locations should be selected with these aspects in mind so injectate migration will be to areas with favorable properties, enhancing the likelihood of favorable IDS recovery. A final practical criterion would be to select production wells for injection with currently low or sub-economic rates.

McKinley 4 was selected as meeting the above criteria for the evaluation of injection optimization. Injection optimization Case 1984 assumed injection into McKinley 4 started November 1984 the same time as historical injection began in Thorne 7. Historical injection well, Thorne 7 was

shut-in and was not used for further model studies. Injection into McKinley 5 continued at historical rates to study the sensitivity of injection rate into McKinley 4 to IDS recovery. The average model fracture temperature and pressure were 471 °F and 437 psia, corresponding to 17 °F of superheat. A series of sensitivity runs was made at injection rates of 100 to 2000 gal/min, representative of the range of injection experience at The Geysers.

A pronounced sensitivity of injectate recovery to the injection rate into McKinley 4 was noted, with a peak IDS_R of 56% (after 1500 days) at an injection rate of 600 gal/min. The injection rates in McKinley 4 did not affect the IDS_R from injectate into McKinley 5, which was constant at 22%. The benefit of injection was observed to diminish with time, due to cooling of the fracture surfaces and an increase in reservoir pressure, both suppressing boiling. Figure 6 presents the total study area IDS_R and IDS_F at the optimum injection rate of 600 gal/min. Note the rapid increase in IDS_F and then a gradual decrease with time, indicating that injection efficiency is diminishing.

In Case 1988, the reservoir model was allowed to undergo additional depletion with injection continuing into McKinley 5 at measured rates. Model injection into McKinley 4 started January 1988. The average model fracture temperature and steam pressure were 467 °F and 373 psia, corresponding to 31 °F of superheat. A second series of sensitivity runs was made at injection rates from 100 to 2000 gpm. Peak IDS_R of 56% (at 600 days) was achieved at an injection rate of 325 gpm. IDS_R is less sensitive to injection rate, with less decline in efficiency at higher rates. Figure 7 presents the IDS_R and IDS_F at the optimum injection rate of 325 gal/min. A comparison of IDS_R (at 1800 days) versus injection rate for the two different cases is presented in Figure 8.

Results and Discussion

The alternative injection case results are in very good agreement with recent injection experience in the southeast Geysers reservoir. The results demonstrate that the recovery of injection-derived steam is influenced by the injection rate, the degree of superheat existing in the reservoir prior to the start of injection, and the duration of injection.

The benefit of injection begins to diminish, as indicated by the IDS_F , after about 1,500 days for the 1984 case and after about 600 days for the 1988 case. One potential strategy would be to discontinue injection when the maximum benefit has been reached as indicated by the IDS fraction and to initiate injection at other locations. This approach would distribute the injectate in the reservoir to areas that have not previously experienced injection.

CONCLUSIONS

Reservoir simulation can be used as a tool to evaluate historical injection response in a vapor-dominated reservoir. Furthermore, simulation can be used to evaluate and determine an optimum injection strategy and develop a reservoir management plan. Favorable injection-derived

steam recovery is enhanced by relatively low injection rates, the optimum injection rate in the study area is estimated to be in the range of 300 to 600 gal/min.

An understanding of the existing reservoir conditions and the use of reservoir modeling can be useful to optimize the injection rate for the most efficient use of available injectate. Simulation can be used to estimate the IDS recovery from each injection well, using historical deuterium-shift data. This can be useful for injection diagnostics and in the optimization of the existing injection well operation.

ACKNOWLEDGMENTS

I would like to thank Mr. W. T. Box, Jr. and Dr. Keshav Goyal of Calpine Corporation for their support of this project. Appreciation is given to Messrs. J. L. Renner and G. M. Shook for their review of the manuscript.

Work supported by the U.S. Department of Energy, Assistant Secretary for Energy Efficiency and Renewable Energy, Geothermal Division, under DOE Contract No. DE-AC07-76ID01570.

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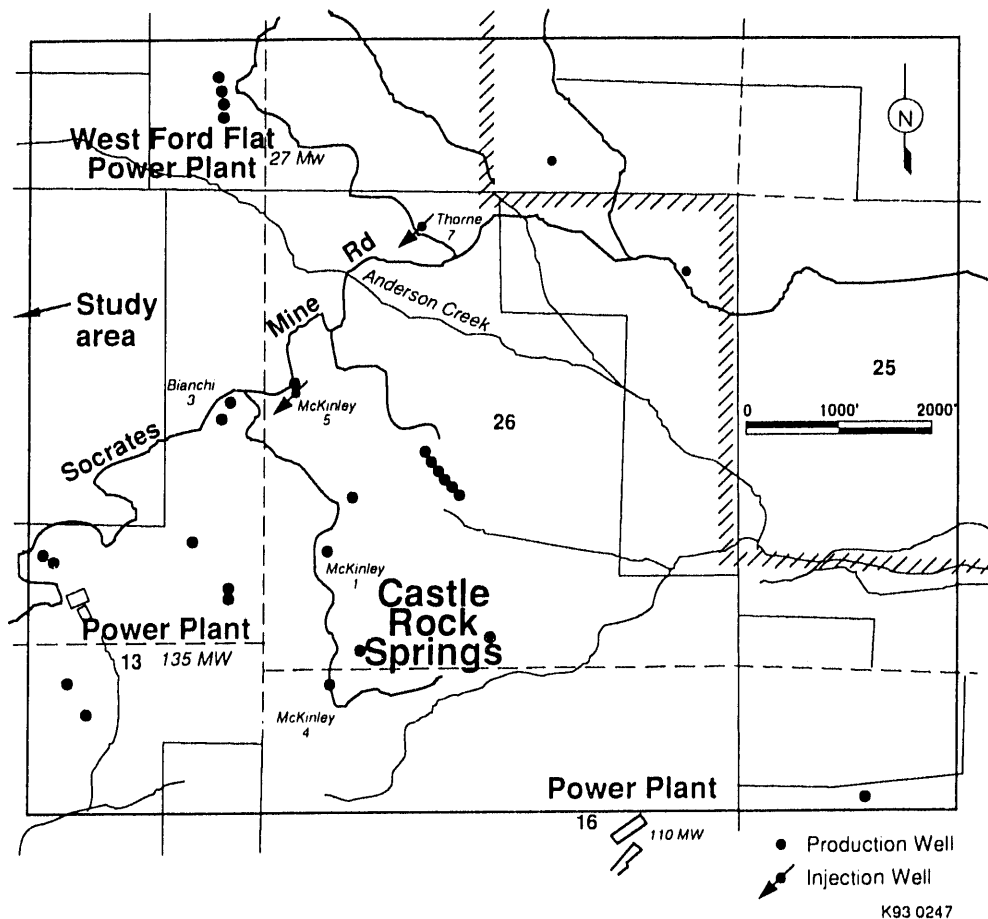


Figure 1. Location of study area.

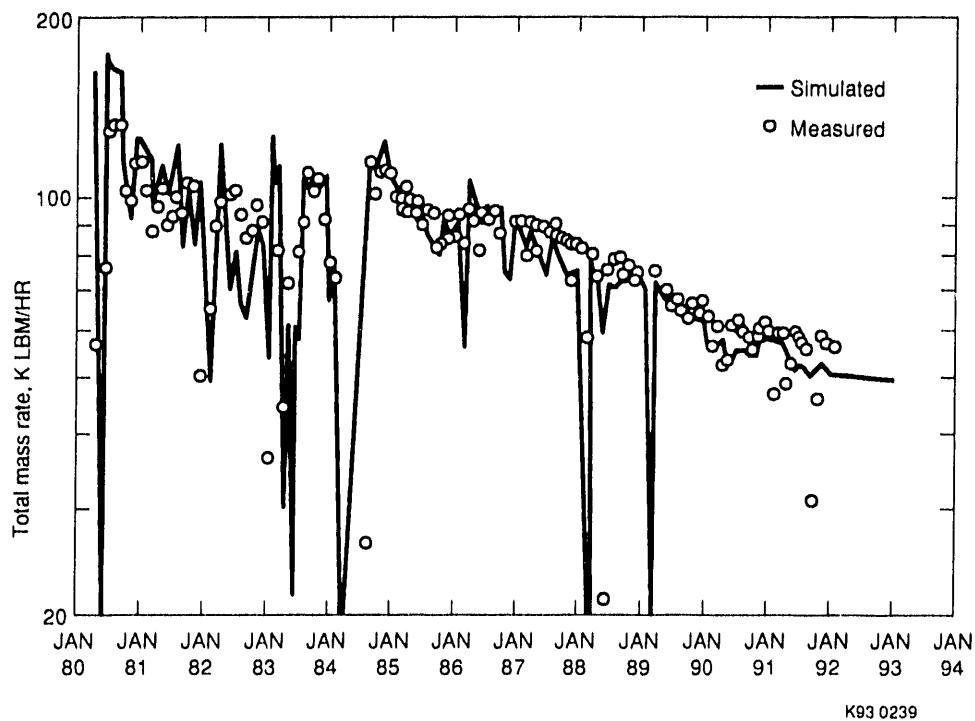


Figure 2. History-match, McKinley 3.

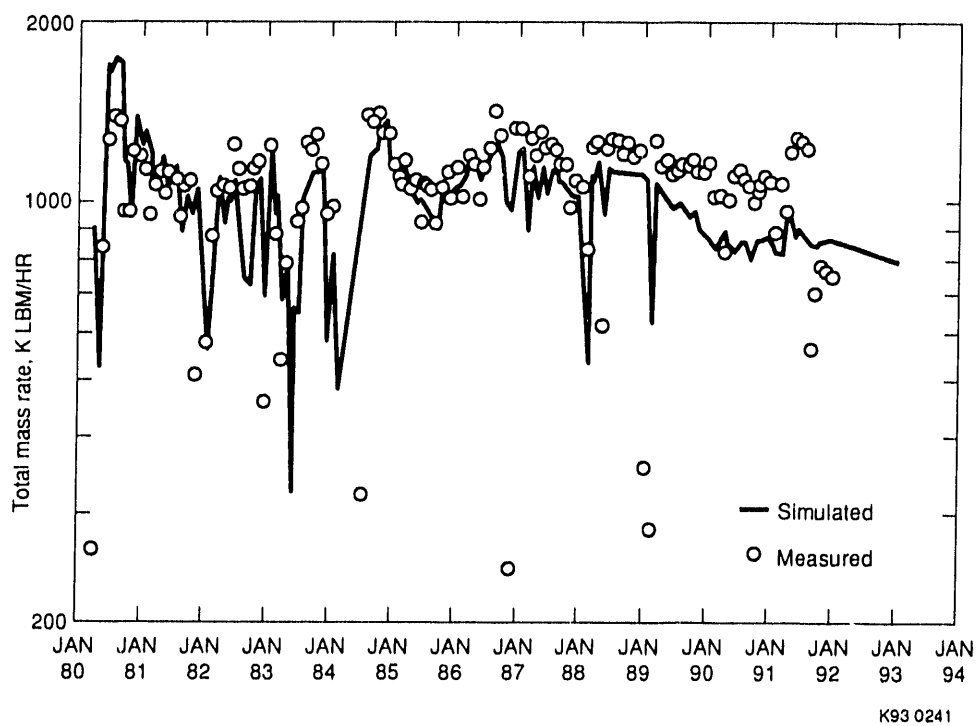
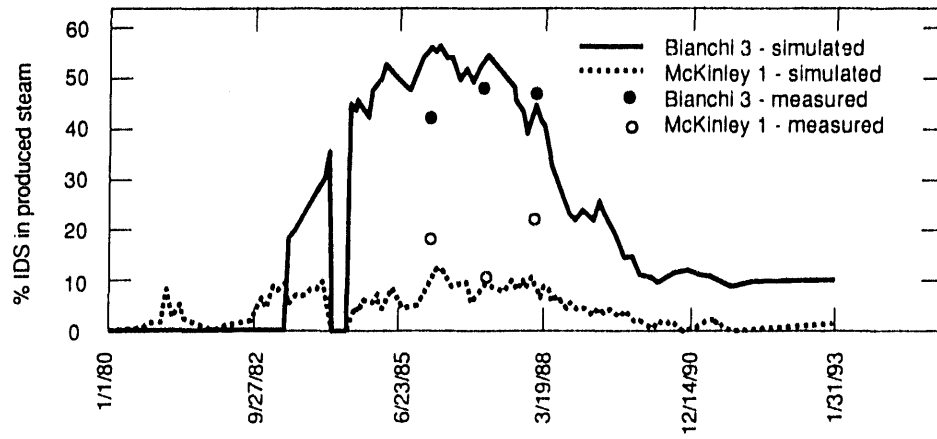
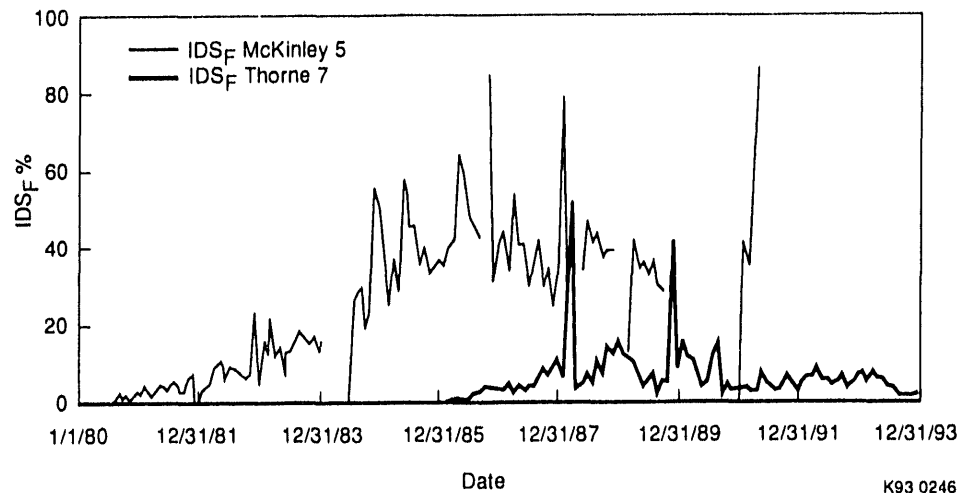


Figure 3. History-match, study area.



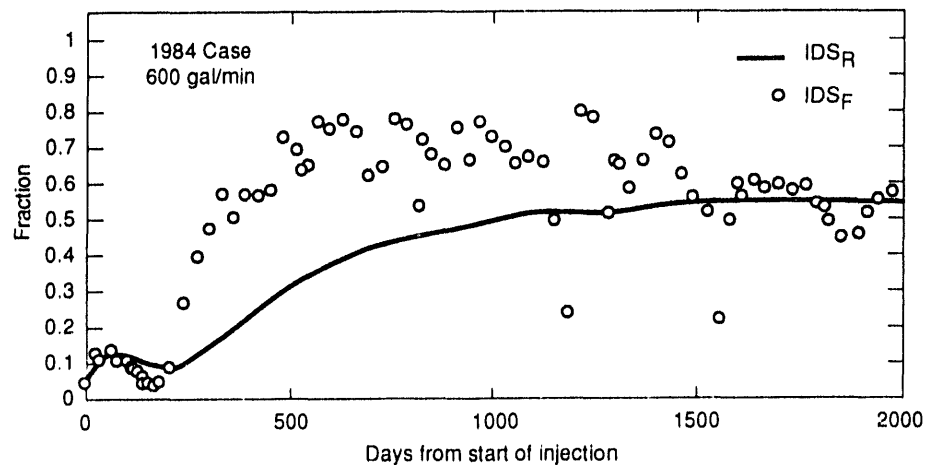
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Figure 4. Comparison of measured and simulated injection-derived steam recovery.



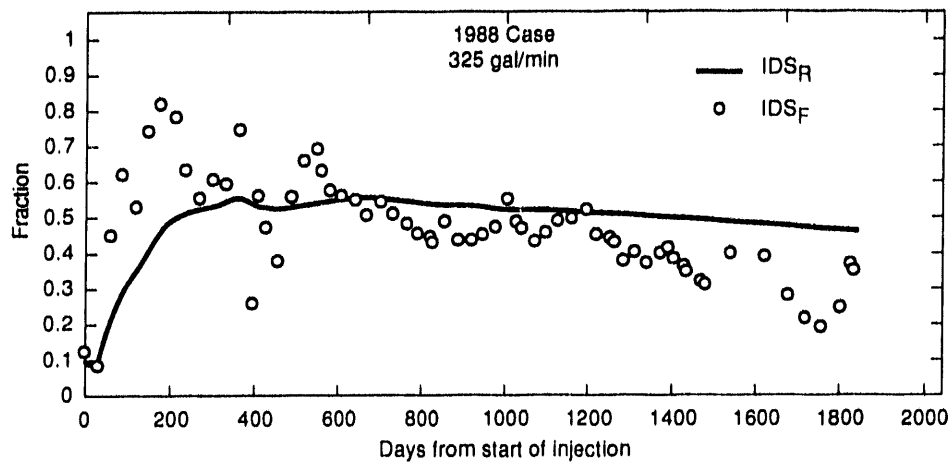
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Figure 5. Study area modeled IDS_F for injection wells McKinley 5 and Thorne 7.



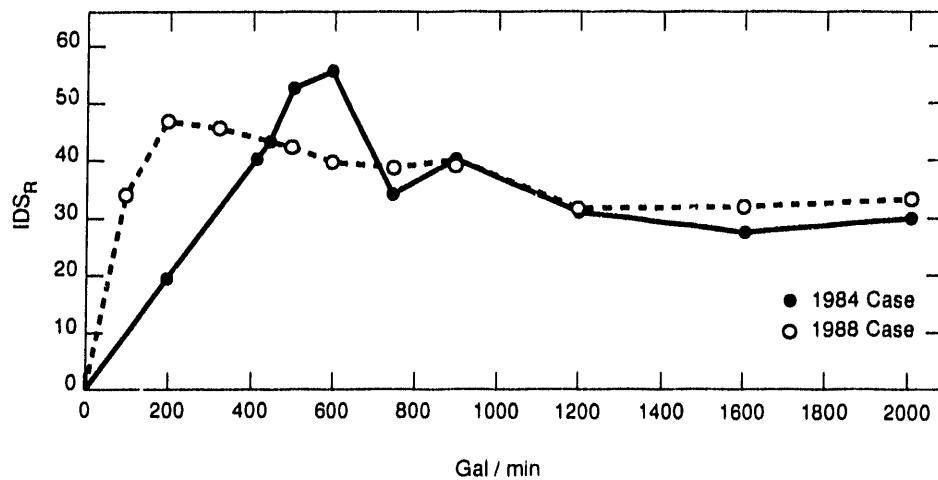
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Figure 6. Total study area injection-derived steam recovery and fraction from injection well McKinley 4, 1984 case.



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Figure 7. Total study area injection-derived steam and fraction for injection well McKinley 4, 1988 case.



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Figure 8. Comparison of IDS recovery versus injection rate for the 1984 and 1988 cases.

Seismic Monitoring at The Geysers

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Introduction

During the last several years Lawrence Berkeley Laboratory (LBL) and Lawrence Livermore National Laboratory (LLNL) have been working with industry partners at The Geysers geothermal field to evaluate and develop methods for applying the results of microearthquake (MEQ) monitoring. It is a well known fact that seismicity at The Geysers is a common occurrence, however, there have been many studies and papers written on the origin and significance of the seismicity. The attitude toward MEQ data ranges from being nothing more than an curious artifact of the production activities, to being a critical tool in evaluating the reservoir performance. The purpose of the work undertaken by LBL and LLNL is to evaluate the utility, as well as the methods and procedures used in of MEQ monitoring, recommend the most cost effective implementation of the methods, and if possible link physical processes and parameters to the generation of MEQ activity.

One of the most promising uses of MEQ monitoring that has been proposed is monitoring the flow of fluids during injection activities. Another proposed use has been to define active fault and fracture patterns that could be possible targets for in-fill drilling. A more recent use has been to use the microearthquakes as sources to image the physical properties within the reservoir area. The success of all of these proposed uses, as well as any other, will depend upon the resolution obtained and the understanding of the physical and chemical processes causing the MEQ activity. The use, or misuse, of MEQ data is critically dependent upon the quality and resolution of the data. In this sense The Geysers offers an excellent and unique test case due to the diversity of MEQ studies carried out at The Geysers and the supporting geological, geophysical, hydrological, and geochemical information potentially available.

To address the objectives above the MEQ work can be categorized into two types of studies. The first type is the direct analysis of the spatial and temporal distribution of MEQ activity and studying the nature of the source function relative to the physical or chemical processes causing the seismicity. The second broad area of study is imaging the reservoir/geothermal areas with the energy created by the MEQ activity and inferring the physical and/or chemical properties within the zone of imaging. The two types of studies have obvious overlap, and for a complete evaluation and development require high quality data from arrays of multicomponent stations. Much of the effort to date at The Geysers by both DOE and the producers has concentrated establishing a high quality data base. It is only within the last several years that this data base is being fully evaluated for the proper and cost effective use of MEQ activity. Presented here are the results to date of DOE's effort in the acquisition and analysis of the MEQ data.

Background

One of the earliest published reports on MEQ's at The Geysers was done by Langue and Westphal in 1969. In this paper, it was reported that the recorded seismicity was shallow (≤ 5 km) and at a rate of 4 events per day. In 1972, Hamilton and Muffler observed activity of similar amounts, with the activity localized in the production area. At this time, the power generation was 82 MW. As time passed and the steam production rate increased, the MEQ activity also increased. By September of 1976, with a power generation of 550 MW, the activity rate had increased to 25 to 30 events per day (Majer, 1978). In these early studies, the magnitudes and detection thresholds were not well defined but magnitude zero seemed to be the lower detection threshold of these surveys. By 1984, when the production had increased to 1000 MW, it had become quite clear that there was a direct relationship between production and seismicity. Since the early work on microseismicity at the Geysers, a number of authors have reported the empirical link between production activities and seismicity (Marks, et al, 1978; Ludwin and Bufe, 1980; Peppin and Bufe, 1980; Bufe, et al, 1981; Allis, 1982; Denlinger and Bufe, 1982; Ludwin, et al, 1982; Eberhart-Phillips and Oppenheimer, 1984; Oppenheimer, 1986; Stark and Majer, 1989) just to name a few. Oppenheimer, (1986) quite clearly showed that the location of earthquakes with $M \geq 1.2$ for the periods 1976-1984 spatially correlated with the growth in the number of power plant. Most of these authors agree that the seismicity is not associated with any dominant through going fault system. The activity seemed to occur somewhat at random and appeared to be clustered in the production region. Most of the events recorded in these studies were strike-slip and normal in nature (Oppenheimer 1986), but also exhibited some thrust activity at shallow depths. Again, as noted on the early surveys, the seismicity was very shallow, and almost all less than 5 km in depth below the surface.

The arrays that were used in locating the above-mentioned events were mostly analog recording with low frequency (< 50 Hz) response. Also, the stations spacings were on the order of several kilometers at best, thus yielding location error of ± 1 km to $\pm .5$ km, in general. In the last several years, however, several arrays with high frequency digital borehole 3-component recording have been installed at The Geysers, (Figure 1). One such array is in the Northwest Geysers, which was installed by Geothermal Energy Operators (GEO), and now owned by the Central California Power Association (CCPA) and is operated by the Russian River Energy Company. Its intended purpose is to monitor MEQ activity associated with production activities. The CCPA array is unique in its capability because of the dense station coverage (16 stations), high frequency digital sampling on three components (400 samples/second/channel), and its boreholes sensors. The data from this array make it ideal for evaluating MEQ monitoring techniques. In addition to CCPA array, Unocal operates an analog array in the central and southeast Geysers region. The

exploration and/or monitoring tool would be provided. On a fundamental level, the basic mechanism of an earthquake is a sudden loss of cohesion or strength of a material. The factors controlling failure are: rock type, confining pressure, temperature, amount and manner of directed stress, solubility of the material, time and rate of strain (Spencer, 1969). Although all these factors are closely interrelated, an obvious characteristic to examine in geothermal regions is the temperature. Though not always consistent, the effect of increasing temperature is to lower the brittle-ductile transition pressure, (Griggs, Turner, and Heard, 1960). Increasing temperature may also tend to decrease the rate of microearthquakes (McNally, 1976). However, only at temperatures in excess of 400°C does this effect begin to dominate. At these temperatures, the motion on a fault becomes stable gliding rather than a series of discrete, rapid slips or "stick-slip" (Stesky, 1977). Therefore, in a region that is anomalously hot, microearthquakes may be expected to be absent or to exist only at shallower depths. An increase in temperature also tends to increase the fault angle with respect to the principal stress direction (Handin, 1966). In a region that is under relatively uniform stress, a hot area may be indicated by anomalous fault plane solutions compared to the cooler surrounding areas. In the Geysers, one mechanism in particular that may be causing MEQ activity is the conversion of a seismic slip to aseismic slip due to an increase in coefficient of friction due to exsolved silica into fracture surfaces (Allis, 1982).

Increased temperature may also have an indirect effect by influencing the content of the pores. If the temperature is high enough, steam, rather than water, may be present. A common failure criteria is the Coulomb relation, the total shearing resistance offered by an isotropic material to failure, is proportional to the effective normal stress, the difference between the actual normal stress, and the pore pressure. If the pores contain steam, which is highly compressible, is small; thus is larger than in an adjacent area where the pores are filled with water and is large. Therefore, would be expected to be higher in a steam filled region, thus resulting in fewer earthquakes compared to an adjacent region. This assumes, of course, that all other parameters remain constant, which is not the case. Injection, or withdrawal of fluids may also affect the normal stress, thus either decreasing or increasing the threshold of failure, respectively.

In a convective geothermal system, the temperature gradients in the zone of convection are not as large as the temperature gradients on the edges of the reservoir. If the reservoir is a vapor dominated resource, pore pressure may also remain relatively constant within the steam zone, especially compared to a hydrostatic gradient. However, the pressure differential between the outside and inside of the reservoir would vary considerably from the top to the bottom. These pressure differentials may be evident in the stress drops or available stresses for an earthquake. If there is a systematic variation in the magnitude of microearthquakes with depth, or in relation to steam zones, such a differential pressure effect may be responsible.

Another parameter most likely to be affected by geothermal activity would be the rock type. The high temperatures and hydrothermal activity undoubtedly alter the rocks within the reservoir. A possible mechanical effect is to weaken the rocks in certain regions and possibly strengthen the rocks in certain regions and possibly strengthen the rocks where the hydrothermal solution cools and deposits its dissolved solids. Along with hydrothermal activity, such factors as differential expansion due to larger temperature gradients, weakening from dehydration erosion, and hydrolytic weakening of quartz may all lower the failure criteria of the material, thus encouraging seismicity.

Unfortunately, geothermal reservoirs are not describable in steady-state terms, especially if the resource is being exploited. Continual fluid movement, phase-changes, and heat transfer will change the state of the reservoir. If microearthquake activity is related closely to these processes, then the seismicity will also be in continual state of flux. Microearthquake activity may indicate the balance between the withdrawal of fluids and the recharge of fluids from the surrounding water supply. Volumetric changes occur when the fluid is withdrawn, and, because of finite permeability, the recharge is not instantaneous. McGarr (1976) has shown that for volume changes due to mining operations, there is a close relationship between the volumetric moment due to seismic failure and the amount of rock removed. Although rock is not being removed in the geothermal case (other than the amount by dissolution), compaction would be expected to occur with possible failure consistent with the direction of the maximum principal stress. If more fluid is being withdrawn than replaced by ground water recharge or reinjection, an increase in microearthquake activity could be expected. Also, as this occurs and pore pressure drops a steam zone may develop if ample heat is available. Therefore, rather than an exploratory tool, microearthquake monitoring may prove useful for determining areas of recharge and depletion within a producing reservoir.

Microearthquake Location and Occurrence Studies

As stated earlier the two broad areas of investigation have been in the characterization of the MEQ activity (space and time) and in the use of the MEQ activity for imaging the subsurface. Presented in this section are the results of the location and occurrence work in the northwest Geysers and the southeast Geysers. The data from this work has come from the CCPA network and the Unocal network augmented LBL/LNL stations in the southeast Geysers.

Northwest Geysers

In March of 1990 LBL, in conjunction with the Coldwater Creek Operator Company (CCOC), (Now CCPA) undertook the collection, analysis processing, and interpretation of the microearthquake (MEQ) data from the 16 station, digital, 3 component, high frequency CCOC array in place at the northwest Geysers geothermal field. To date the processing has concentrated only on data collected prior to full production and injection in the NW Geysers and for approximately after one year full production and injection activities started (1988). (This involved detailed analysis and processing of approximately 5000 events.) During this time the injection occurred at two different sites, Prati 8 and 9, but with the main injection at Prati 8. The array has been out of operation due to legal and technical complications, however, it is anticipated that the array will be brought back into operation in 1993 to begin background monitoring prior to new injection activities.

Several previous studies have concluded that the high seismicity in The Geysers region is related to geothermal development (Eberhart-Phillips and Oppenheimer, 1984; Stark, 1990). Results of the present study indicate further that seismicity rate is related to production and injection and that reservoir property changes due to exploitation may be detected. Figure 2 presents in plan view the relocated hypocenters of the events around the CCPA area. Microearthquakes are concentrated within the CCPA field extending south and east into the older sections of the producing field. Seismicity is low to the north and west in the direction where the field is undeveloped. Seismicity occurs in two distinct 2 zones: a broad, shallow zone between 1 and 3 km depth, presumably related to the production zone, and a deeper cluster between 3.5 and 5 km depth just beyond the southeast edge of the field, (see Figure 3). A cluster of microearthquakes with focal depths between 2 and 3 km is located beneath the injector

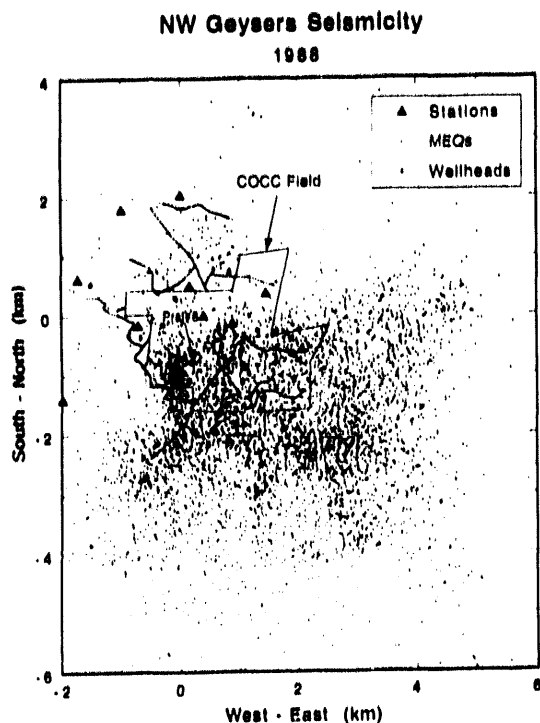


Figure 2. Map view showing the locations of microearthquakes during 1988 in the CCPA geothermal field. Microearthquakes are concentrated within the central part of the field extending south and east. Seismicity is low to the north where the field is not being produced.

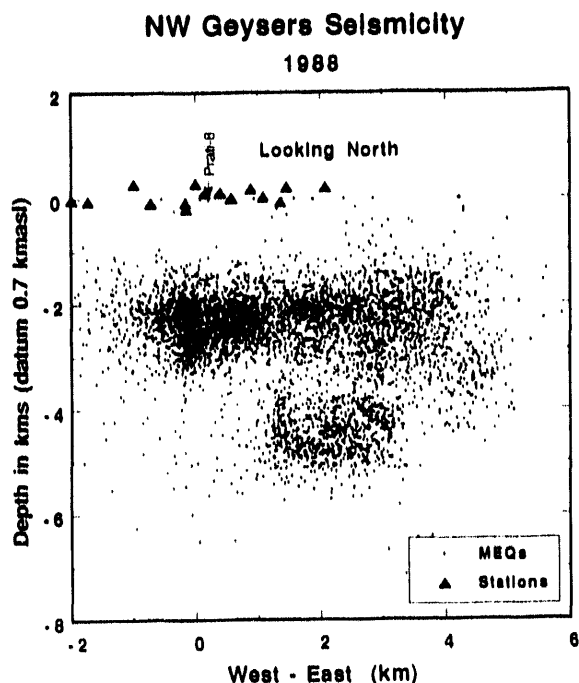


Figure 3. Cross section (East to West) of seismicity through the northwest Geysers. Note the two distinct zones of seismicity, shallow in the production zone and deep below the production zone. Note the clustering of events beneath the injector Prati 8. Datum plane is 0.7 kmsl.

well Prati-8, as shown in Figure 3. The microearthquake distribution seems to define a vertical planar structure striking roughly north-south. Figure 4 is an expanded view of the seismicity around Prati 8. As can be seen there is a strong spatial correlation of the seismicity to zone around the bottom of Prati 8 and extending several hundred meters beneath the well. Current pressure data from Prati 9 suggest that injection does have an effect on the saturation of the formation as fluid is invading the zones around the well. (Pers Comm, M. Walters, Russian River Energy Corp) If this also occurred around Prati 8 then the seismicity may indeed be an indication of the zone of invasion of the fluid.

In terms of temporal correlation, Figure 5 presents a comparison between the seismicity rate within the CCPA area and the field-wide steam production rate. Beginning at Julian day 90, 1988, seismicity increased significantly to approximately 20 events per day, more than double the pre-production seismicity rate. High seismicity was sustained during the course of steam production except during a short lull between Julian days 225 and 270 when production rate decreased temporarily. Figure 6 presents a comparison between Prati 8's injection history and seismicity rate nearby. Note the good correlation between peaks in seismic activity and injection rate. Seismicity increased with the start of sustained injection, and peaks in seismicity occurred during periods of maximum injection. Spatial and temporal correlation between injection activity and seismicity provide compelling evidence for induced seismicity around Prati 8.

In addition to investigating the characteristics of the microearthquakes themselves, the temporal changes in the velocity structure and seismicity patterns in response to geothermal activity are also being investigated. Particular attention has focused on the changes in the V_p/V_s structure because of its sensitivity to fluid

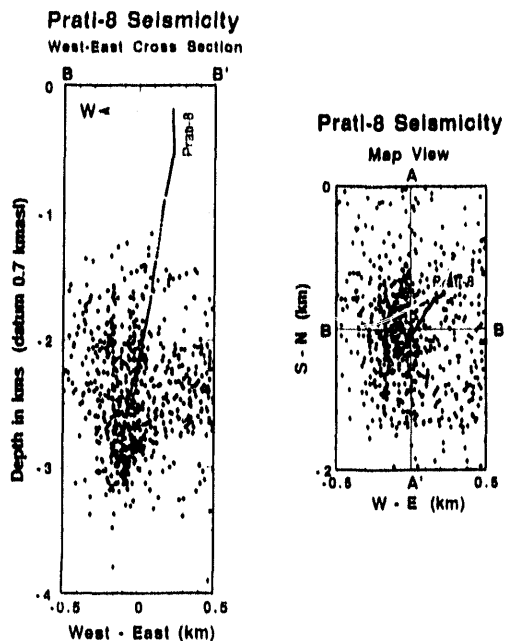


Figure 4. Expanded and cross sectional view, and map view of microearthquake locations around the injector Prati 8. The microearthquake distribution seems to define a vertical plane striking N-S. Datum plane is 0.7 kmsl.

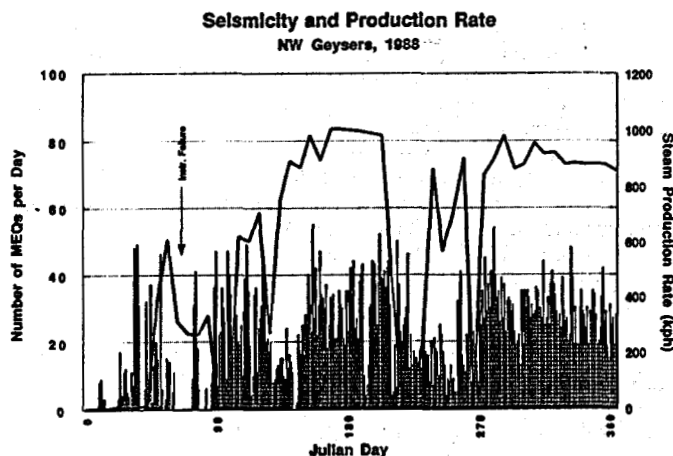


Figure 5. Comparison between the seismicity rate within the CCPA area and field-wide steam production rate. Seismicity more than doubled with the start of sustained production.

saturation changes expected in a geothermal region. The data set consists of carefully hand-picked P- and S-wave arrival times recorded by the 16- element borehole network. From the 5000 events recorded in 1988, 300 high-quality events distributed evenly through-out the field were selected for each of the time periods for the joint hypocenter-velocity inversion. The region was parameterized into a 3-D rectangular grid with velocities assigned to each nodal point. The grid contains 294 nodes spaced at 1 km horizontally, and 0.5 km vertically. The joint problem for 3-D velocity structure and hypocenter locations is solved using the progressive inversion scheme proposed by Thurber (1983) with cubic spline interpolation (Michellini, 1991).

No substantial change in the V_p/V_s structure was evident during the monitoring period. One possible reason is that one year may not be sufficient time to detect appreciable changes in reservoir properties. However, note in Figure 7 the high V_p/V_s ratio at the location of Prati 8, again possibly indicating an invaded zone around the bottom of Prati 8. The production zone is marked by a low V_p/V_s ratio between depths of 1 and 4 km, suggesting undersaturation of the reservoir rocks in response to continued steam withdrawal. The zones to the northwest indicate that the structure in this area may be controlled by a southwest to northeast cross cutting structure, possibly separating the high temperature reservoir from the main reservoir body to the southeast.

The results of the work to date in the northwest Geysers study have shown that the velocity structure and the seismicity pattern in the northwest Geysers area seem to be related to geothermal exploitation. The low V_p/V_s ratio within the producing zone is consistent with continued depletion of reservoir rocks as the field is produced. Ongoing monitoring of V_p/V_s may be useful in tracking the expansion of the steam zone, or as seen in high V_p/V_s ratios around Prati 8, the tracking of injectate with time. Spatial and temporal correlation between seismicity and geothermal activity provide compelling evidence for induced seismicity. High resolution microearthquake locations hold promise for inferring fluid flow paths, especially in tracking injectate. Processing of the data has revealed a strong correlation between injection and seismicity. However, in addition it can be said that the injection seismicity is superimposed on a more general pattern of seismicity related to such factors as "natural" seismicity and effects of withdrawal. At this point in time we have a good characterization of the seismicity patterns in this area and their

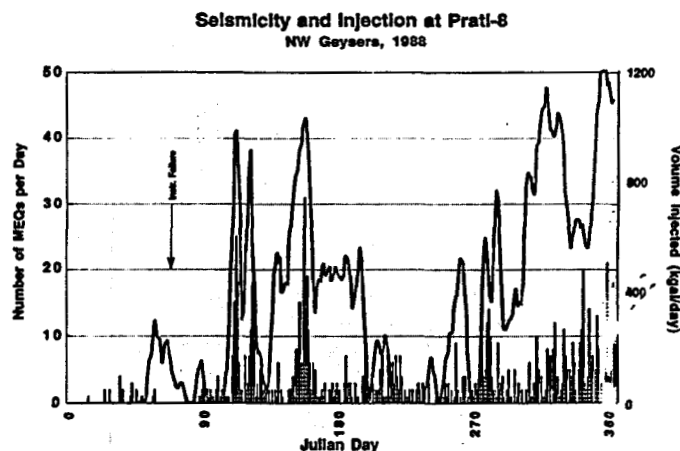


Figure 6. Comparison between injection history of Prati 8 and seismicity rate nearby. Note the good correlation between peaks in seismic activity and injection rate.

relationship to various reservoir parameters. In 1993 the NW Geysers Array will be brought back into operation (the legal and technical problems have been overcome) in order to collect background data for future injection experiments.

Southeast Geysers

In addition to the work in the northwest Geysers several operators (Calpine, NCPA, and Unocal) in the southeast Geysers region have undertaken a cooperative effort to more fully understand the mechanisms associated with reinjection activities. To date, MEQ rates and location have shown a good correlation with injection activities (Stark, 1990). UNOCAL is presently operating an analog array of MEQ stations in the injection region. Although this array has been very useful, precision location of events dictates digital acquisition at higher frequency contents using three component data. The work in the northwest Geysers has demonstrated the utility of multicomponent, high-frequency, digital data. During the last year LBL (8 stations) and LLNL (5 stations) installed a high frequency array in the SE Geysers to apply this technology to an injection experiment. It has become obvious that the split array operation is not providing reliable data on a timely basis, however, LBL is now in the process of buying 5 stations to replace the LLNL stations in order to have all of the data coming to one central point. This would streamline the data collection and processing. The data rates (seismicity) are not as high as in other areas of the field (150 to 200 events per month) so it is reasonable expect that with the split array problem solved the data processing could be done on a more timely basis than now. The objectives of the southeast MEQ study is to demonstrate the utility of high resolution, multicomponent, microearthquake data (MEQ) for understanding the effect of condensate injection. The study has been underway for a year and is not as far along in data processing as the northwest Geysers study. The work in the southeast Geysers to date has concentrated on collecting data for location and occurrence studies as well as for imaging the injection activities. With high frequency data it is also hoped that one can correlate source mechanisms (size, slip, moment, etc.) with injection activities and available stress information, as well as monitor changes in the above parameters as a function of time.

Shown in Figure 8a is the station distribution in the southeast Geysers. Also shown in Figure 8a are the locations of 610 high quality (recorded on 5 or more stations) events during the time

NW GEYSERS V_p/V_s MODEL

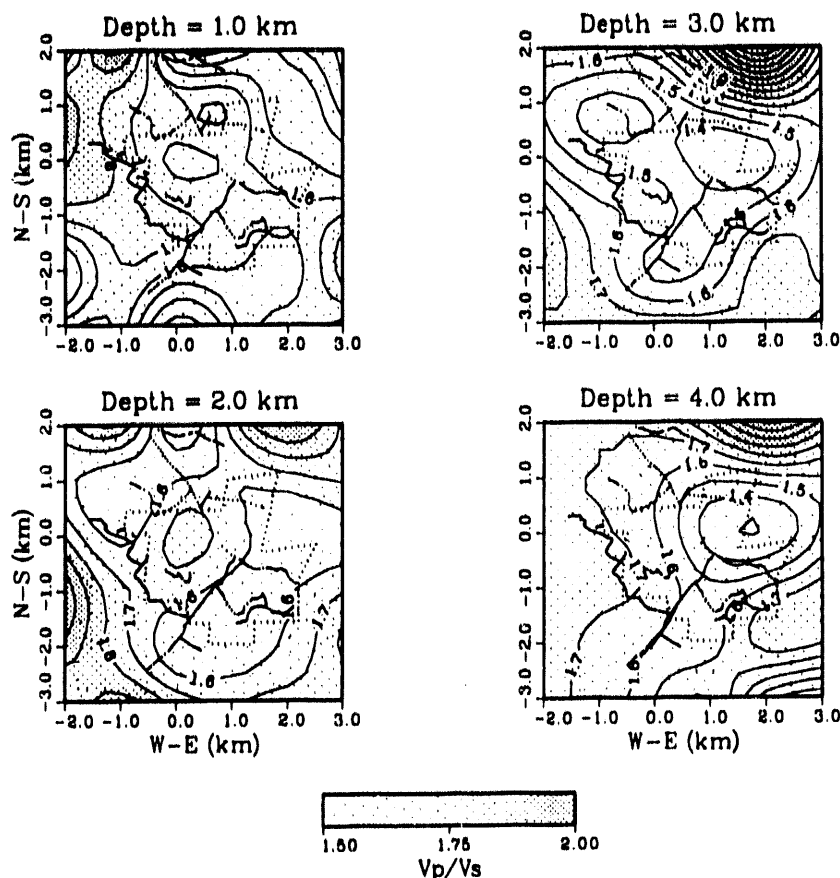


Figure 7. The V_p/V_s model of the CCPA field derived from inverting the 1988 MEQ data. Each square is a horizontal slice through the model at different depths.

period of January to September 1992. Figure 8a shows an East-West cross section projected onto a plane running through the origin (0) on Figure 8b. Figure 9 shows the reservoir pressure in isobars as of 1988, and the location of some of the MEQ stations used in this study. Also shown in Figure 9 are the locations of the wells NCPA is using for injection and the traces of the wells projected to the surface. As observed by Enezy et al. (1993) the events cluster around the injection wells. In depth, the events also cluster around the wells and less so beneath the wells, unlike the northwest Geysers. Also, as Enezy et al. (1993) showed the events do not locate within the felsite, but above it. The locations also show a good correlation to the zone of injectate, as inferred from deuterium analysis, (Enezy et al., 1993).

The locations shown in Figure 8 were derived using the same methods as developed for the analysis in the northwest Geysers, using a 3-D velocity model. In the case of the southeast Geysers the rate of activity is lower so only 231 events were used for the inversion to obtain the 3-D velocity model. Also, the spatial coverage throughout the field is not as complete as the northwest Geysers, so the resolution near the edges of the model suffers. Figure 10 is a horizontal slice of the velocity model at 1.0 kilometers below the datum. The model was derived from the joint inversion of 231 events. Also, plotted on this figure are the 610 events located with this model. As seen in the northwest Geysers there is a strong degree of lateral heterogeneity reflected in the velocity model. Correlation with the geologic structure has not been done at this time.

Seismic Imaging for Saturation Conditions

In-situ knowledge of saturation conditions at the Geysers is important for understanding the role of fluid injection in resource replenishment and to prospect for new drill sites. LLNL is engaged in a three phase project to infer these properties from seismic imaging data. Phase 1 of the project is complete and the results are reported here. The objective is to compute seismic compressional-wave velocity and attenuation images in terms of the geologic structure and fluid saturation. Data are still being collected as part of the southeast Geysers study to provide information on the injection experiments. Later phases of the work will concentrate on applying the methods to specific zones within the field, and expanding the analysis to include such parameters as amplitudes from spectral ratios and spectral matching.

Fluid saturation conditions of the matrix rock of a reservoir have traditionally been estimated from core samples. However, the data obtained in this manner tend to have a large uncertainty since the fluid in the pores tends to flash to steam due to the drop in pressure bringing the sample to the surface. If saturation data could be reliably obtained in-situ this information could be used to manage production and understand the role of injection. We are attempting to use seismic imaging to determine fluid saturation. Compressional wave velocities are sensitive to both lithology and saturation conditions so it has been traditionally difficult to separate the two effects. Our method is to include compressional wave attenuation in the analysis to try remove the effect of lithology.

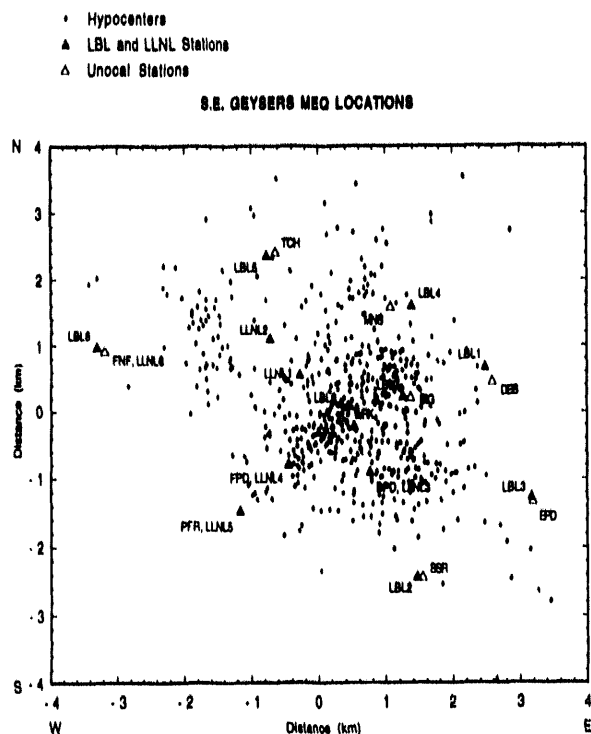


Figure 8a. The station locations and a plan view of the 610 high quality events located in the southeast Geysers during January to September, 1992 using a refined 3-D velocity model.

Figure 11 shows the location of the study areas with respect to the boundaries of the known steam reservoir. The LLNL project consists of three phases. Phase 1 has a large target area and was an attempt to get more or less field-wide definition of saturation conditions. The data consist of approximately 300 earthquakes that are of magnitude 1.2 and distributed in depth between sea level and 2.5 km. The data were collected by the UNOCAL-NEC-Thermal (U-N-T) partnership. Phases 2 and 3 are smaller scale studies focused on specific fluid injection experiments. At the time of the writing of this paper (April 1993), the collection of the phase 2 data set is almost complete, but the analysis has not yet started. The collection of the phase 3 data is planned to begin in the Spring of 1993. Both of these projects are cooperative with the Lawrence Berkeley Laboratory as part of the southeast Geysers experiment. We base our interpretation of the velocity and attenuation data on the laboratory results of Ito et al. (1979) who carried out velocity and attenuation measurements on Berea sandstone samples at elevated temperatures and varying degrees of saturation to approximate reservoir conditions. Their measurements show that P-velocity increases with saturation but that Q (seismic quality factor = change in energy/energy per cycle) decreases. In addition, Q falls dramatically when the rocks are partially saturated. These laboratory results were for frequencies near 10,000 Hz, raising the question of their applicability to field measurements at lower frequencies. However, results from Evans and Zucca (1988) and Zucca and Evans (1992) show that P-wave attenuation and seismic velocity structure contain complimentary information at Medicine Lake and Newberry volcanoes, and may be used to predict the location of geothermal drilling targets. They found that regions with low and normal-to-

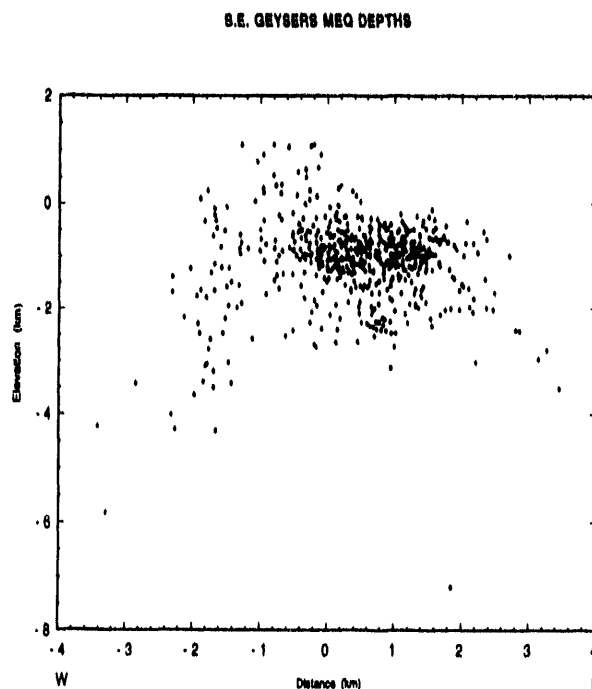


Figure 8b. An East-West cross section of Figure 8a.

high P-wave velocity are suggestive of boiling water, in areas independently identified as good geothermal prospects by other means.

Method and Data

Compressional-wave (i.e. P-wave) arrivals are used in the analysis. A first arrival is picked to measure the P-wave arrival time and the elapsed time between this arrival and the first zero crossing to measure the pulse width. The P-wave travel times and pulse widths are related to the velocity and attenuation, and related through an empirically determined constant. Integration is carried out along the ray path. Velocity is held constant during the calculation of the attenuation structure. To compute velocity and attenuation structure, we used the Thurber inversion method (Thurber, 1983) as modified by Eberhart-Phillips (personal communication, 1989) to compute a three-dimensional model of velocity. We modified the algorithm to compute attenuation structure recognizing the similar nature of the two parameters. U-N-T provided us with waveforms and hand-picked first arrivals (Debbie Turner, Unocal Inc., personal communication, 1990). Because of the abundance of data, we selected the best events to further process and obtain P-arrival times and pulse widths. We used only arrivals with at least 10:1 signal-to-noise ratio of the first pulse observed at 8 or more stations. We examined each pulse by eye for evidence of multipathing. The first arrival pick was also examined by eye to see if further adjustment was necessary. The estimated error in the arrival time reading is less than +0.01 s (one sided error). The measurement error in the first zero crossing is small compared to the error in the first arrival pick.

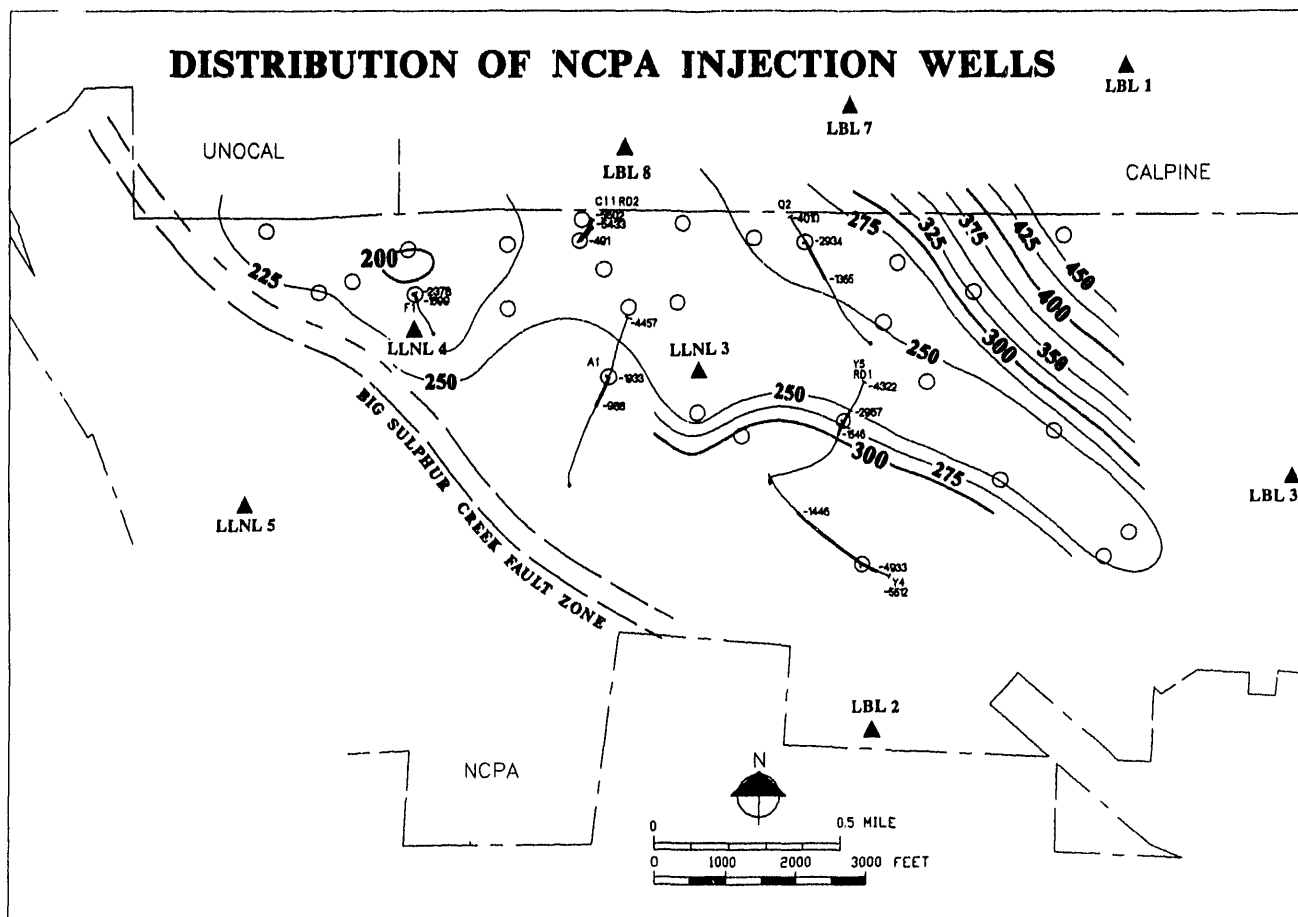


Figure 9. A map showing the distribution of seismic stations and the distribution of the NCPA injection wells. Also shown are the isobars of the reservoir pressures.(this figure was provide by NCPA)

Inversion Results

The three-dimensional inversion for velocity resulted in a 75% weighted variance reduction over the one-dimensional starting model. The velocity inversion results are shown in Figure 12. The results are displayed as horizontal slices through the three-dimensional velocity volume. Although the model extends from the surface to a depth of almost 4 km, we present only the two layers at 0.9 and 1.5 km depth for the sake of brevity. In general, the velocity increases with depth. The central portion of the model tends to have the highest relative velocities down to at least the 0.9 km depth level. At the deepest level shown at 1.5 km depth, the lower (i.e. south) part the image has the highest overall velocities. For the attenuation inversion, we were only able to achieve significant data variance reduction with the one-dimensional model. The 1D model had a starting data variance of 0.000309 s and a final data variance of 0.000073 s after calculation of the source term and variations. This is a net variance reduction of 76%, however most of this is due to solving for, the source

contribution to the pulse width. Only about 15% of the variance reduction is due to the structure. The results are shown adjacent to the velocity results in Figure 12.

Interpretation

We find that the velocity structure correlates with known mapped geologic units and the location of reservoir. In Figure 12, the layer at 0.9 km depth shows low velocity correlated with the reservoir. The next layer down is at 1.5 km depth and shows the felsite intrusion associated with a blotchy series of high velocity anomalies. Although the felsite and the indurated gray wacke reservoir rocks should have roughly equivalent velocity, the felsite is likely to be less fractured and could exhibit slightly higher velocity. The weak velocity contrast could explain the blotchy nature of its signature in the velocity image. The high Q in the upper part of the reservoir is consistent with the earlier results of Majer and McEvilly (1979) who also found relatively high Q in this region. The low Q in the lower part of the reservoir

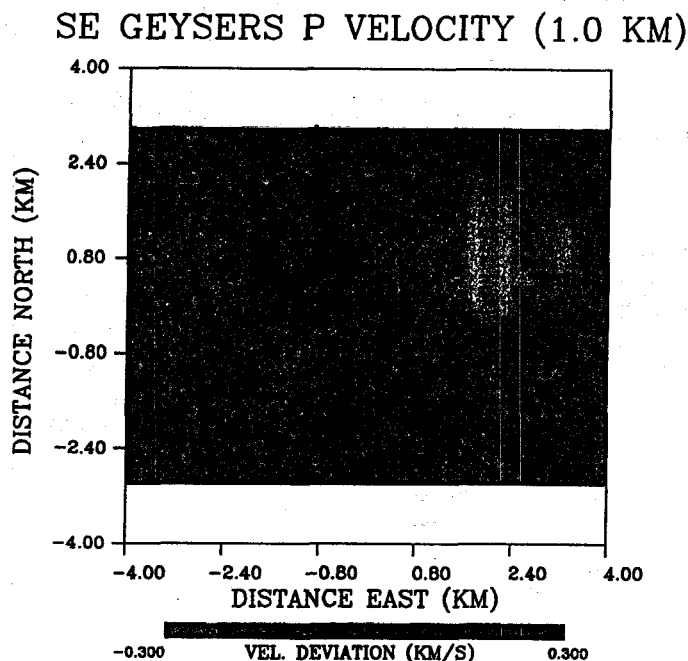


Figure 10. The V_p model derived from inverting the data from the MEQ data. This is a horizontal slice at 1.0 kilometers depth. Also plotted are the locations of the earthquakes.

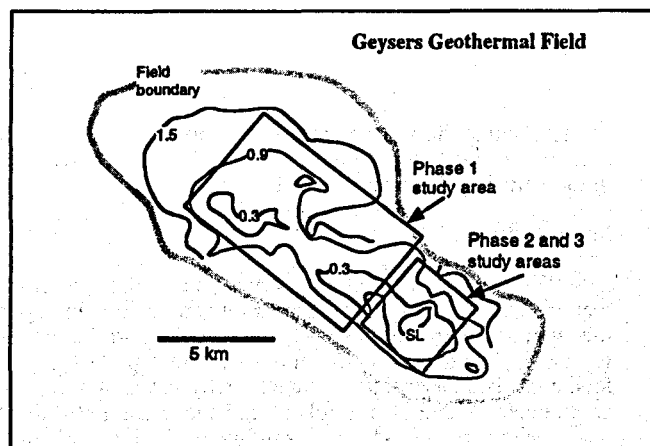


Figure 11. Location map of the Geysers study area used in the attenuation study. Base map is the depth to the dry steam reservoir (Industry Consortium, 1989). Datum is sea level, contours are in kilometers below the datum.

suggests that the saturation is in the 30 to 70% range while saturation at the top of the reservoir could go up or down and still agree with the lab results for Q alone obtained by Ito et al. (1979). A drop in saturation at the top of the reservoir below about 30% seems the most likely since the velocity is lower in the reservoir compared to the country rocks indicating a drop in saturation compared to the country rocks.

For phase 1, we have calculated the velocity and attenuation structure of the Geysers region using local earthquakes. Our data for the inversion consist of P-wave arrival times and pulse widths which we used to compute three-dimensional compressional wave velocity structure and one-dimensional compressional wave attenuation structure. Our velocity structure correlates well with the surface geology and published studies on the structure of the reservoir. The reservoir appears to exhibit low velocity with the surrounding country rock. The Q decreases with depth which we infer to indicate partial saturation (30 to 70%) at depth with drier conditions near the top of the reservoir. We plan to apply a similar analysis to the data we are currently collecting for phases 2 and 3 of our work.

Summary and Conclusions

The work to date indicates that MEQ data can, and are, being used to infer then flow of injectate within the reservoir area. Recent results of the imaging indicates that the attenuation and V_p/V_s results possibly could be used to infer fluid saturation. Several unique high resolution data sets have been obtained and plans are being made to monitor several new injection projects in the near future. Cooperation with industry has yielded results that have guided and focused the work in an effective fashion. Without this cooperation the work would not have been possible.

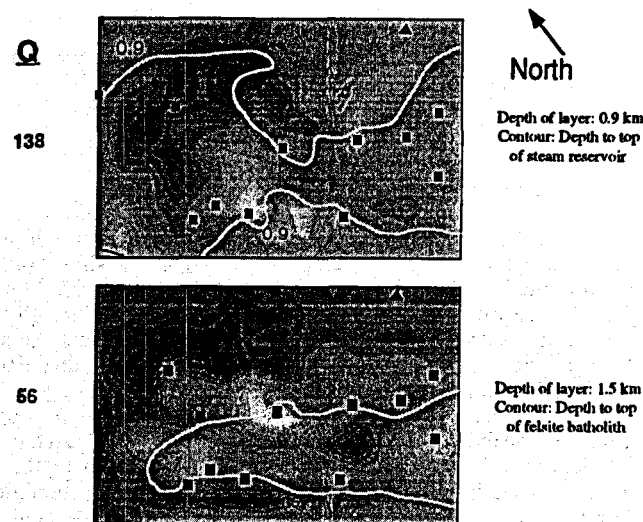


Figure 12 Horizontal slices through The Geysers reservoir. The images show the P-wave velocity variations from the 1D starting model. Dark indicates low velocity and light indicates high velocity. The attenuation (Q) for the layer is printed to the left of the image. The solid squares are the locations of the power plants. The contours show the intersection of the image plane with a known structure, i.e., in the upper image the contour is the known steam reservoir, in the lower image the contour is the known felsite body.

Acknowledgment

This work was performed at Lawrence Berkeley Laboratory and Lawrence Livermore National Laboratory and was supported under the Geothermal Technology Division and the Assistant Secretary for Conservation and Renewable Energy of the U.S. Department of Energy under contract DE-AC03-76SF0098 and W-7405-ENG-48. We would also like to thank the operators of The Geysers field, Calpine, CCPA, NCPA, and Unocal for their cooperation, and in particular Mark Walters, Bill Smith, Mitch Stark, and Joe Beal for their interaction.

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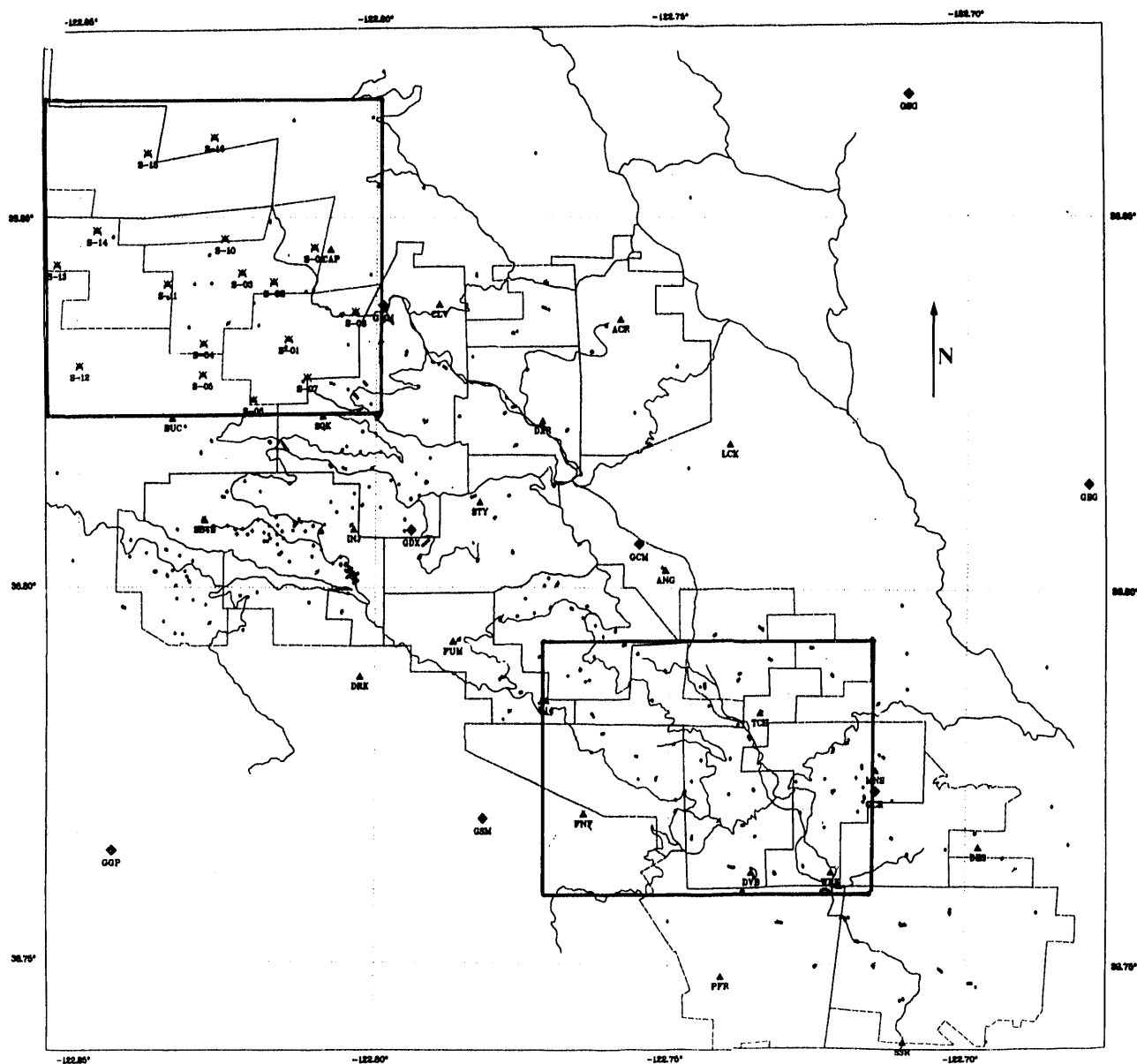


Figure 1. The locations of the seismic monitoring stations in The Geysers area. The northwest and southeast Geysers microearthquake arrays being used in this study are highlighted. Also shown are some of the USGS stations used in previous studies. Note the density of the stations used in this study to the station spacing used in the studies using the USGS stations.

Unocal southeast array has been augmented by equipment from LBL and LLNL with 13 high frequency (480 samples/second/channel) digital three component stations. The CCPA array and the southeast array have been the source of the majority of the data for the results reported here. These arrays are routinely collecting microearthquakes down to magnitude -1. With this improved capability the goal is to be able to improve on early studies and hopefully determine a more precise relation between production activities and seismicity. Overall the objectives of the MEQ work are:

- (1) Demonstrate the utility of high resolution, multicomponent, microearthquake data (MEQ) for:
 - (a) Locating high permeability paths in the reservoir.
 - (b) Aid in the location of in-fill well drilling.

- (c) Monitor effect of condensate injection in real time.
- (2) Develop 3-D model of reservoir.
 - (a) P- and S-wave velocity and amplitude structure.
 - (b) Poissons ratio model.
 - (c) 3-D structural model using MEQ locations for inferring flow paths.

To fully understand the relation between microearthquakes and a geothermal environment, many different factors must be considered. A crucial question to answer is: does such a phenomenon as a "geothermal earthquake" exist? If so, a useful

EXPERIMENTAL STUDY OF WATER ADSORPTION ON GEYSERS RESERVOIR ROCKS

by

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ABSTRACT

ple was found to influence the amount of water adsorbed. At low relative pressures, adsorption is Experimental isotherms of water vapor adsorption/desorption on three geothermal reservoir rock samples have been measured at temperatures of 80, 100, 120 and 140°C. Initial surface status of the samthe dominant process of water retention onto the rock samples. Adsorption/desorption hysteresis was observed to exist over the whole pressure range at all temperatures. Similar observations were made for all three samples. The results of this study suggest that adsorption is important in storing water in geothermal reservoir rocks not only in itself, but also in inducing capillary condensation.

INTRODUCTION

In vapor dominated geothermal systems, it has been proposed that liquid might exist as adsorbed liquid in micropores (White, 1973). Evidence from both laboratory studies (Hsieh, 1980, Herkelrath et al., 1983) and field data indicates that storage of liquid as micropore fluid is reasonable. As pointed out by Ramey (1990) that if the only mechanism for liquid storage is adsorbed water, then the desorption curve provides important information for performance matching and production forecasting. It is therefore obvious that measurement of adsorption/desorption of water vapor on reservoir rocks is a crucial step in determining whether adsorption is the storage mechanism for these systems, and if so, what would be the appropriate procedure for performance prediction of vapor dominated geothermal systems.

Water vapor desorption was regarded as a simple and reliable technique in core analysis by Melrose (1988). In a comprehensive study to determine capillary pressure in the low-saturation region, Melrose (1991) compared results obtained using different techniques, and concluded that water vapor desorption method gave capillary pressure

in good agreement with those obtained using the centrifuge and the porous plate methods. However, it should be pointed out that water vapor desorption in this case referred to the part of the desorption curve at relative pressures greater than 0.9, and the corresponding saturations are higher than 3.3% for the berea sandstones studied by Melrose (1988). At high relative pressures, adsorption is accompanied and complicated by capillary condensation, and it is likely that water held by capillary force constitutes a large part of the desorbed water.

Literature on water adsorption has been largely concerned with pure adsorbents, with carbon and silica being the most popular (Dubinin, 1980, Stoeckli, et al., 1983). The majority of the water adsorption studies are associated with the characterization of porous material. Willems et al. (1988) reported studies of water adsorption on hardened cement pastes and observed large adsorption/desorption hysteresis at 25°C. Carrott et al. (1991) studied water adsorption on synthetic zeolites in order to elucidate the relative influence of surface chemistry, pore size and pore shape upon the form of the water adsorption isotherm. A common feature of these studies is that the adsorption tests were all made at low temperature (between 0 to 25°C) and some special behaviors of water (Gregg and Sing, 1982) were observed.

Reservoir related water adsorption investigation is limited, particularly at high temperatures. Hsieh (1981) constructed a BET type of apparatus for high temperature water adsorption measurements. He conducted a number of adsorption measurements on berea sandstone and unconsolidated silica sand. Conclusions reached in his study were that adsorbed water is an important source of steam in vapor dominated geothermal systems and that water vapor pressure lowering in a rock is dominated by micropore adsorption (Hsieh and Ramey, 1983). Luetkehans (1988) continued Hsieh's research by improving the apparatus. Measurements of N₂ adsorption were made for berea sandstone, cores from the

Geysers, California, and Larderello, Italy. Water adsorption/desorption tests were also conducted. However, the true magnitude of the amount adsorbed was suggested to be in question due to difficulties in establishing equilibrium. In addition, the long equilibrium time required made the leakage of high temperature valves a significant factor in causing the experimental error. Laboratory studies of water adsorption on porous media were also conducted by Herkelrath *et al.* in association with their work on steam flow in porous media (Herkekrath et al., 1983) and the disposal of nuclear waste (Herkekrath and O'Neal II, 1985). They reported similar findings to those by Hsieh and Ramey (1983). Linear adsorption isotherms were claimed to fit data on Topopah Spring welded tuff up to a relative vapor pressure of 0.9. The problem of leakage in long equilibrium time was also identified in their work.

Clearly, there was a need to improve the apparatus in order to obtain reliable data of water adsorption at high temperatures. Harr (1991) performed preliminary investigation on the use of an automated sorptometer from Porous Material Inc. (PMI) for high temperature water adsorption measurements. To our knowledge, this is the first commercial sorptometer built for high temperature adsorption tests. Considerable time was spent to investigate various problems associated with the sorptometer both by Harr and in the present study.

APPARATUS AND PROCEDURES

The sorptometer consists of basically three parts. (1) a set of valves and pressure transducers kept in a high temperature chamber, (2) a sample chamber for loading and unloading samples, and (3) the electronic part for automatic control. During normal operation, the operator only needs to load the sample and the rest of the procedures are accomplished via a computer keyboard.

The principle of the adsorption/desorption measurement is the same as a BET type of experiment. The quantity one measures is the pressure of water vapor in the system before and after adsorption/desorption. System volumes are predetermined by expanding N_2 and measuring the corresponding pressures. The amount adsorbed/desorbed can then be calculated from mass balance. Knowing the weight of the rock

sample, we can obtain the amount of water adsorbed per unit weight at a given pressure.

Due to the limitation of the size of the sample holder, rock samples had to be broken into granulars with equivalent diameters of approximately 8mm. New samples were all heated at 180°C under vacuum overnight to get rid of any surface residuals before running the adsorption test. Upon adsorption, water vapor is added incrementally to the system from a steam reservoir, which is kept at a temperature higher than the test temperature, and time was allowed for the system to reach equilibrium. Desorption commences at the end of adsorption test. In this case, water vapor is gradually pumped away until the adsorbed water is completely desorbed. The sample is reweighed at the end of the tests.

RESULTS AND DISCUSSION

The experimental studies reported here are the results of water adsorption/desorption tests performed on Geysers shallow reservoir core, Monteverdi well #2 rock and Berea sandstone using the PMI sorptometer. As mentioned previously, the size of the rock samples used for an adsorption test is limited by the geometry of the sample holder. This should not impose any problem since the only change caused by breaking the core is surface area and the change is likely to be small. It was found to have negligible effect on the amount of water adsorbed (Harr, 1991). On the other hand, using small size samples reduces diffusional time and the time required for adsorption/desorption equilibrium. Knowing the complexity of the adsorption process, it is important to ensure that the rock surface has the same condition prior to each adsorption/desorption isotherm test. This was achieved by heating the sample at 180°C under vacuum for 3 to 4 hours. Reproducible isotherms were obtained after this pretreatment.

Figures 1 to 3 show the adsorption/desorption isotherms obtained at 120°C for Geysers shallow reservoir core, Berea sandstone and Monteverdi #2 sample, respectively. As shown in the figures, the amount of water adsorbed at a relative pressure of 0.7 is 1.3mg/g for Geysers shallow reservoir core, 1.0mg/g for Berea sandstone and 0.5mg/g for Monteverdi #2 samples. These quantities agree reasonably well with data

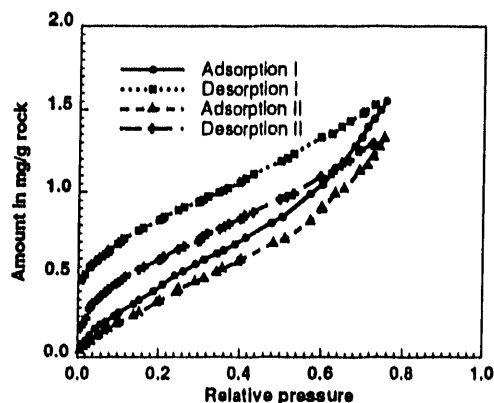


Figure 1 Isotherms on Geysers Shallow Reservoir Core

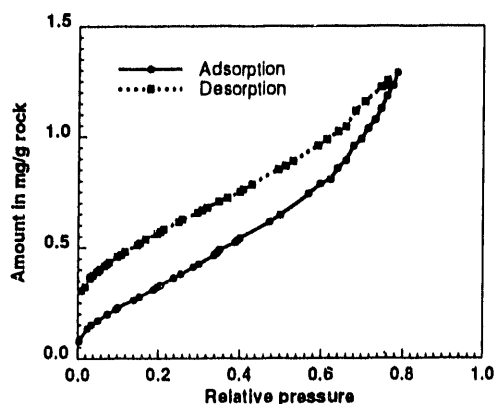


Figure 2 Isotherms on Berea Sandstone

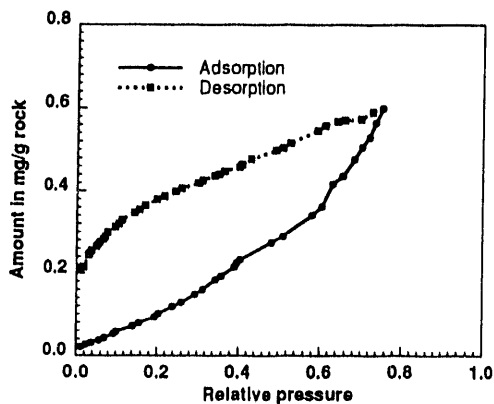


Figure 3 Isotherms on Monteverdi #2 Core

obtained by Hsieh (1980) and Luetkehans (1988). There is an obvious adsorption/desorption hysteresis in each case, and it exists at near zero pressure. In Figure 1 are two sets of adsorption/desorption isotherms from two tests.

The difference between these tests are that test II was performed without pretreating the sample, i.e. starting the second adsorption test at the end of the first desorption cycle. Comparison of the two sets of isotherms indicates the presence of irreversible adsorption.

Adsorption/desorption hysteresis

It is clear that significant hysteresis exists for steam adsorption/desorption on all samples tested. As shown by scanning electron micrographs (SEM), all the rock samples have complicated physical structures. This physical heterogeneity of the rock must be responsible for the presence of the adsorption/desorption hysteresis. Capillary condensation provides a basic explanation of the phenomena at high relative pressures (Adamson, 1990), and it can be quantitatively described using network models while applying the Kelvin equation to both adsorption and desorption isotherms (Mason, 1982, 1988)

However, hysteresis exists at very low relative pressures in the samples tested in this work. A plausible explanation for this behavior is that irreversible changes may occur in the pore structure on adsorption so that the desorption situation is different from the adsorption one (Bailey et al., 1971). For the adsorption of water at high temperatures, it is likely that the interaction of polar water molecules with rock surface causes irreversible adsorption at low relative pressures, i.e., there is some weak chemisorption for the first monolayer. Weak chemisorption of water onto cement pastes was reported by Willems *et al.* (1988) at room temperature. The observed low pressure hysteresis in this work is at least partly caused by weak chemisorption. The repeated tests without pretreatment in between provide some support for this assumption. Evacuation at test temperature mainly removes physically adsorbed water. So for the subsequent test, the surface of the sample was partly, if not completely, covered by chemisorbed water molecules. Thus, the amount of water adsorbed in the subsequent tests is smaller than that for the first one, and the amount of water retained at the end of desorption isotherms was also reduced.

Due to the presence of adsorption/desorption hysteresis, the measured desorption isotherms can

be very different from the adsorption one. Understanding of the hysteresis phenomena bears significance to the reinjection process since the desorption isotherm is directly related to steam production in geothermal reservoirs.

Adsorption and capillary condensation

Adsorption is a surface phenomena and is affected not only by the surface area of the material but also by its chemical composition. Capillary condensation is related to the geometry of the porous media and for a given adsorbate it only depends on the geometric structure of the porous material. These processes are similar in nature, *i.e* they both cause vapor to condense onto the solid. They are related in such a way that adsorption provides a precursor for capillary condensation. One can divide the physical processes of adsorption in porous materials into three steps: (1) submonolayer adsorption, (2) multilayer adsorption with transition to (3) capillary condensation. The pressure range at which the transition from multilayer adsorption to capillary condensation occurs depends on the structure of the material. If the material is microporous (pore diameters not exceeding 20 Å), the pore space will be filled up (commonly termed as volume filling) before multilayer adsorption is developed. What happens physically is that as multilayer adsorption develops, the micropores become filled by a meeting of the adsorbed molecules from opposing walls. In large pores, multilayers of adsorbed water form as pressure increases. In reservoir rocks, there exist pores of different shapes and sizes. Due to the variation in pore size, capillary condensation occurs at different relative pressures. Since it is difficult to obtain the actual pore size distribution, it is hard to tell at what pressure capillary condensation will take place. Volume filling exists to a small extent in the rock samples studied in this work, and this suggests the presence of micropores in the rocks. However, the percentage of the micropores must be small judging from the shape of the adsorption isotherms. Thus, volume filling is not considered in the present discussion.

Figure 4 shows adsorption isotherms on the three rock samples obtained at 80°C. At relative pressure below 0.6, the amount of water adsorbed can be approximated by a linear function of

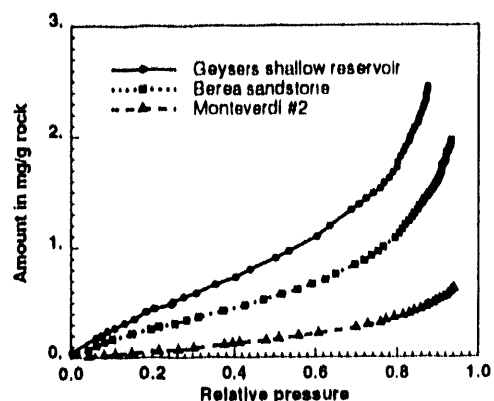


Figure 4 Comparison of Adsorption Isotherms at 80°C

relative pressure in all three cases. However, the linear relationship breaks down as pressure increases and the amount of water adsorbed increases rapidly with pressure. This change in the shape of adsorption isotherm is an indication that capillary condensation takes place and its contribution to total water retention onto the reservoir rock becomes more significant as pressure is further increased.

Due to equipment problems, we have not yet been able to obtain reliable data at relative pressures greater than 0.9 for higher temperatures. Based on the above discussion and the experimental data at 80°C, we expect similar adsorption/condensation phenomena for higher temperatures. The magnitude of water retention is yet to be measured.

Effect of temperature on water adsorption

Figures 5 to 7 show comparison of adsorption isotherms at different temperatures obtained on Geysers shallow reservoir core, Berea sandstone and Monteverdi #2, respectively. The effect of temperature on the amount of water adsorbed varies from sample to sample. For Geysers shallow reservoir core and Berea sandstone, as shown in Figures 5 and 6, appreciable changes in the amount of water adsorption did not occur until the relative pressure reached 0.65. However, for the Monteverdi #2 sample, considerable difference in the amount of adsorption at different temperatures appears at very low relative pressures, and this difference increases as the relative pressure increases, as shown in Figure 7.

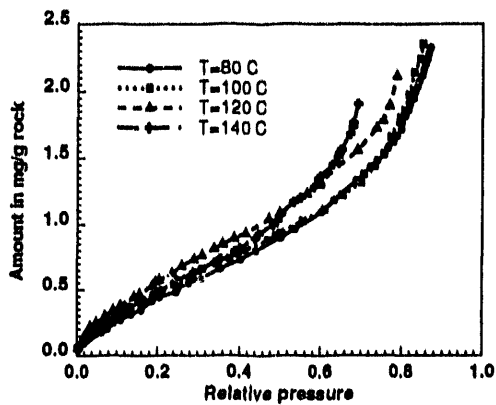


Figure 5 Comparison of Isotherms on Geysers Shallow Reservoir Core

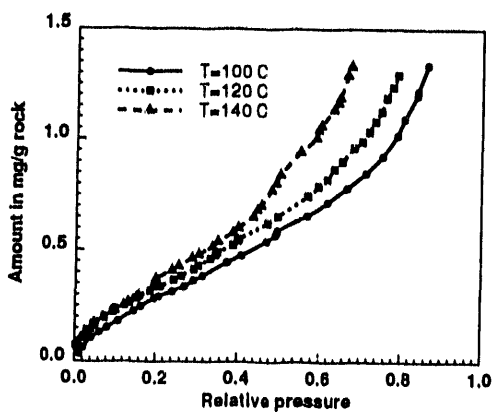


Figure 6 Comparison of Isotherms on Berea Sandstone

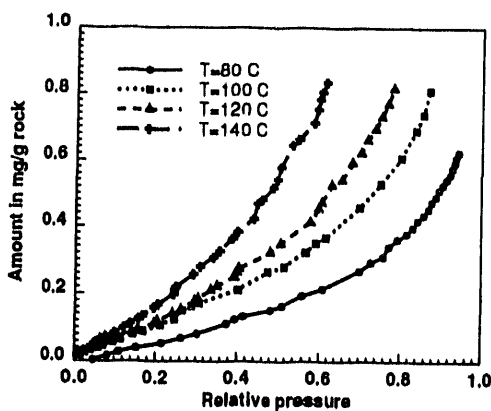


Figure 7 Comparison of Isotherms on Monteverdi #2 Core

The reason for the different temperature dependence is not clear.

Salt in solution has long been considered to cause the low vapor pressure of water in vapor dominated geothermal systems (Ramey, 1990). So far in our discussion, we have ignored the possible effect of salt on water retention and vapor pressure lowering. We believe that if there are minerals present in the rock sample, they will dissolve in the adsorbed water film and influence the adsorption/condensation process.

Finally, Figure 8 shows a comparison of the adsorption isotherms measured on Monteverdi #2 core from the present study with that obtained from transient pressure analysis (Qi, 1993). Although the two isotherms differ in magnitude, the trend is similar. The transient nature of the pressure analysis technique implies that the process is away from equilibrium, thus the amount of adsorption determined from the transient pressure analysis is lower. Further work is required to evaluate and compare the two techniques currently employed in our laboratory to measure water adsorption/desorption isotherms.

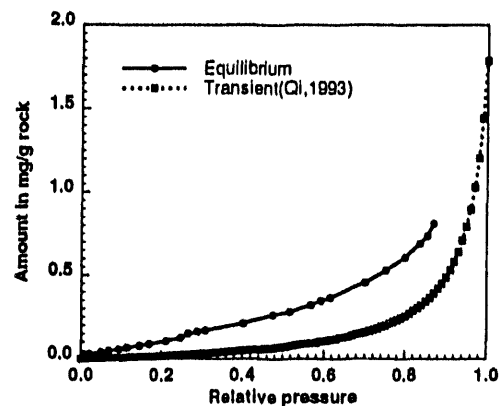


Figure 8 Comparison of Isotherms from Equilibrium and Transient Tests

CONCLUSIONS

Adsorption is important in geothermal reservoirs, not only in itself but also in inducing condensation to take place easier than in the absence of adsorption. It is logical to suggest that the system is adsorption dominated at lower relative pressures, and changes to capillary condensation dominates as pressure increases. Both adsorption and capillarity cause vapor pressure lowering. However, it is hard to

determine the cause of this vapor pressure lowering since the status of the rock surface is largely unknown.

Significant hysteresis exists for water adsorption/desorption on the rocks tested and it is shown to be caused, at least partly, by weak chemical interaction. The amount of water adsorption is affected by temperature and its effect is found to be sample dependent.

Much work needs to be done to measure the amount of water adsorbed/condensed at higher relative pressure. Additional work will be undertaken to investigate the possibility of running adsorption test at temperatures higher than 140°C so that we can simulate geothermal field conditions as closely as possible.

There is an obvious need to develop a model to describe the adsorption--capillary condensation process. The combination of Frenkel--Halsey--Hill (Halsey, 1952, Adamson, 1990), used for adsorption, and the Kelvin equation, used for capillary condensation, provides a good basis for such a model. Current work on this subject is in progress.

ACKNOWLEDGMENTS

The authors acknowledge the financial support from DOE, geothermal division. We thank Mr. Paul Pettit for help in the face of hardware problems.

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EXPLORATION AND RESERVOIR CHARACTERIZATION

**Chairperson: Dick Benoit
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LBL INDUSTRY REVIEW

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INTRODUCTION

On March 16, 1993 the LBL Industry Review Panel on Exploration and Reservoir Technology convened as three subpanels;

1. Exploration for new discoveries (chaired by Dick Benoit).
2. Mapping reservoir properties and monitoring production/injection (chaired by Jim Lovekin).
3. Well testing, reservoir simulation, and predicting future reservoir performance (chaired by Tony Menzies).

The current DOE funding for projects in these general categories covers a wide range of topics, but there is a definite focus on the Geysers in terms of geography and several studies are primarily, if not totally, applicable only to vapor dominated reservoirs. This has been justifiable, given the Geysers' past and current preeminence in total geothermal megawatts produced in the United States. Also justifying this is the wide range of well-known problems impacting the Geysers, pressure decline, chemical problems, and injection to name but a few. An apt homily for this situation would be the squeaky wheel gets greased.

However, in the past few years other geothermal reservoirs have commenced commercial production and have encountered questions or problems of their own. As most of these other reservoirs are primarily liquid in nature, a different type of squeak is making itself heard. By way of example, injection in liquid dominated reservoirs has become a limiting factor in perhaps half of the other U. S. fields in production to date. Should production increase to near the field potential in the other half it is expected many of these will also bump up against injection limitations. We apparently do not yet understand how to consistently formulate a "best" injection strategy or predict thermal breakthrough. Over the coming years it is logical to expect the focus on the Geysers to diminish due to a completion of the current studies and a developing requirement for a more thorough understanding of other types of reservoirs.

On March 16 the panels did not discuss individual ongoing or potential future studies and only briefly covered specific topics. The time allowed only broad discussion for the overall direction of the program. Before going further, I will point out that the overall conclusion of the panels was basically the same as in

1988. However, the "spin" is different primarily due to the progress of industry in getting more projects on line, changes in the financial structure of most projects, development of operating histories, and more specific targeting of problems or limitations.

The common conclusion for all three subpanels was a need for case studies, including unsuccessful or partially successful cases, and some covering smaller resources. As the geothermal industry continues its consolidation, more reservoirs are becoming owned by fewer parties. This is gradually resulting in a lessened requirement to keep confidential information out of the hands of competitors in both undeveloped and producing properties. Thus, the opportunities for comprehensive case histories of all scopes should be increasing.

RESULTS OF PANEL ON EXPLORATION FOR NEW DISCOVERIES

As should be expected, the discussion in the panel on exploration for new discoveries brushed a wide range of topics, several of which used to be beyond the scope of normal exploration but universal approval of the following sentence is evidence of the changed nature of exploration. Of primary importance, is being able to discover reservoirs in a cost effective manner and, as quickly and cheaply as possible, define proven and probable resources, and get the project financed. The explorationist of today needs to be able to visualize the project all the way through the stages of financing, construction, and going on line.

There was sentiment that the basic geology and conceptual thinking have been overlooked during the past few years and that even defining reserve categories, such as proven, possible, etc., is a topic for improvement. A need for testing the validity of various geophysical exploration techniques in differing and known geologic settings was noted. Geochemistry had its proponents, particularly for advanced knowledge and interpretation of noncondensable gases.

The era of making discoveries near large active silica terraces is over in the United States. There is a wide range of opinion on the economic validity of exploring for blind systems. But, if the industry is to prosper over the long term (many decades) in the United States, the discovery and development of blind systems or high-temperature systems hidden beneath apparent low-temperature systems seems to be a requirement. This

drove the second widely accepted conclusion of the panel that industry would respond favorably to the concept of an industry coupled, cost-shared program focused on the discovery of new resources.

RESULTS OF PANEL ON MAPPING RESERVOIR PROPERTIES AND MONITORING PRODUCTION/INJECTION

Much of the discussion in this panel can be lumped under the broad topic of the need to prioritize what information or physical properties need to be determined to most effectively produce a reservoir and how these data can be obtained and integrated into a conceptual model. A need to closely monitor more field types than vapor dominated was identified (more case studies).

A variety of tool improvements, such as reliable downhole sampling tools, spinner tools, higher temperature limitations for electric logs, improved temperature and pressure tool precision and accuracy, and the development of memory tools which may permit lower cost logging in remote areas were noted. Development of slim hole logging tools was pointed out as a way of decreasing the cost of determining reservoir properties. Ideal log suites are expected to be site specific and variable.

Geochemistry again had its proponents, particularly regarding obtaining data in three dimensions. A need for standardized lab procedures for geochemical analyses was discussed and the possibility of establishing such standards through ASTM guidelines was noted. The creation of a core repository as a resource for petrophysical properties was considered. Microseismicity received extensive discussion with particular emphasis on its importance in monitoring the effects of injection and cross-boundary fluid movements.

The topic of adsorption and desorption continues to be of high interest for those companies involved in the Geysers and in maturing fields that evolve from liquid to vapor-dominated. Those considerations can make a major impact on reserve estimates.

RESULTS OF THE PANEL ON WELL TESTING, RESERVOIR SIMULATION, AND PREDICTING FUTURE RESERVOIR PERFORMANCE

The major emphasis of this panel was on the need to improve the accuracy of predicting future reservoir behavior with as few wells as possible. This will assist both in reservoir management and will expedite financing of new projects. This goal requires continued research into the fundamentals of simulation, particularly for two phase systems where the effects of relative permeability and capillary pressure are important. While boundary conditions vary from field to field, it would be useful for comparative studies to have

a larger base of published case studies from reservoirs with extensive and documented production histories. Also, integration of wellbore and reservoir simulations will enable a more comprehensive study of the total reservoir and production system.

We should continue to develop and improve models that incorporate geochemical and geophysical data as well as the conventional temperature and pressure information. Improved modeling of the impact of short-term transients, such as peak load operation, on reservoir parameters is encouraged.

The development of powerful geothermal reservoir simulation codes has been successfully undertaken at Lawrence Berkeley Laboratory, but there needs to be improvement in the transfer of this technology to industry. Although the LBL simulation codes are available to the public and can be run on 386 or 486 computers, a majority of the companies within the geothermal industry have elected to utilize the TETRAD simulator. TETRAD is a commercially available product with greater upfront cost, but this balanced by its greater simplicity of use on small computers available to any entity in the industry. As a cited example, the simulation of the Salton Sea reservoir was undertaken on a 486 with TETRAD in a field office.

There is a need to standardize procedures for conducting well tests and investigation of improved methods of measuring discharge flow rate and enthalpy. Chemical tracers are showing promise in this area. Well testing can also be improved by developing methods to reduce the long-term drift in pressure transducers routinely used in monitoring observation well pressure changes.

CONCLUSIONS

Every panel focused in on the need for publication of case histories covering virtually every subject mentioned as the number one priority. While it is interesting to have case histories of the "elephants", industry recognizes its future in the United States lies in efficiently producing the more numerous, smaller reservoirs and case histories from smaller projects, even less successful projects will prove invaluable.

Cost sharing in these competitive times will be popular with most of the industry, should funding be available. This not only includes the drilling of new wells, but also may encourage industry personnel to put forth the effort to produce comprehensive case histories which benefit the industry worldwide.

OVERVIEW OF EXPLORATION AND RESERVOIR CHARACTERIZATION RESEARCH -- THE RESERVOIR TECHNOLOGY PROGRAM

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Reservoir Technology is a program of about 50 interrelated research projects. Several of the research projects are discussed in the following papers of this section of this proceedings volume. Most of the research projects of the Reservoir Technology Program, including those mentioned below, are summarized in "Geothermal Reservoir Technology Research Program -- Abstracts of Selected Research Projects" edited by Marshall J. Reed (1993).

The research of the Reservoir Technology Program ranges from relatively pure research to applied cooperative work with the geothermal industry. Four types of research are carried out: basic research, applied research, cooperative research with industrial partners and research that is cost shared with industry. The Reservoir Technology Program's major interest is the answering of questions posed by the industry.

Although the basic research doesn't directly answer these questions. This research is providing fundamental data needed to properly understand the applied development problems of the industry. The geochemical research at Oak Ridge fits into this category. The fundamental research on volatility of HCl is one such project. The ORNL researches are providing fundamental chemical data which will be used to assist operators at The Geysers with control of corrosives in the steam. Other ORNL data is used to expand the chemical modeling efforts of John Weare at the University of California San Diego.

Joint research with industry includes most of The Geysers research described in the papers on The

Geysers Research program. In addition several projects are underway developing case studies of several successful geothermal projects: Coso and Roosevelt Hot Springs.

The Reservoir Technology Program conducts cost-shared research with the geothermal industry through an agreement with the industry's Geothermal Technology Organization. Two past projects dealt with seismic activity and injection at The Geysers and two current projects are investigating improved interpretation of seismic data using data sets from the Coso geothermal field. Several additional projects are pending. The most notable of these are a major injection test and a geochemical study at The Geysers.

We expect a major expansion in the cooperative portion of the Reservoir Technology Program, primarily for a new industry coupled drilling program.

REFERENCE

Reed, M. J., ed., 1993, Geothermal Reservoir Technology Research Program -- Abstracts of Selected Research Projects: U. S. Department of Energy DOE/CE-0397, March 1993, 142 p. (The report is available by mail or telephone through the National Technical Information Service, U. S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161, (703) 487-4650 or (800) 553-6847; \$27.00 paper copy, \$9.00 microfiche.)

Acknowledgement: Work 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.

GEOLOGY, ALTERATION, AND MAGMATIC-HYDROTHERMAL HISTORY OF THE GEYSERS FELSITE -- POTENTIAL APPLICATIONS FOR EXPLORATION AND DEVELOPMENT

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ABSTRACT

The "felsite" is a shallow, young, granitic intrusive body centrally located within and beneath The Geysers steam field. The field and the felsite are coaxial, and hydrothermal alteration effected by hot-water-dominated geothermal systems antedating the modern steam reservoir shows systematic vertical zonation with respect to the pluton. It is certain that intrusion of the felsite and development of coeval, liquid-dominated hydrothermal convection systems was essential for evolution of the currently exploited steam field. The research summarized in this communication was undertaken both to clarify the role of the pluton in reservoir evolution, and to characterize critical felsite-specific controls on the field's deep porosity and permeability.

The felsite comprises at least three major intrusive phases. Two are high-silica granites probably older than 1.3 Ma. The third is granodiorite (1 Ma), temporally and chemically equivalent to overlying extrusive dacites of the Clear Lake volcanic field. All three intrusive phases are too old to be heat sources for the modern steam field, but probably were the heat engines for the prior liquid-dominant systems. Younger, deeper magmatic heat sources are strongly implied for the current vapor-dominated regime.

Porosity in the felsite is provided by: (1) Extensively mineralized fractures and breccias, probably of both tectonic and high-temperature hydrothermal origin; and (2) miarolitic cavities in the upper levels of the pluton. The latter could be analogous to calcite-dissolution cavities in overlying metagraywacke -- they could serve as storage sites for the field's liquid water reserves. Porosity in these fractures, breccias, and vugs is partially occluded by hydrothermal vein minerals deposited in prior hot-water-dominated systems --tourmaline, ferroaxinite, quartz, potassium feldspar, epidote, actinolite, prehnite, and many others. Such secondary mineralization conceptually could serve as an excellent exploration guide to potentially productive portions of the felsite beyond the field's present boundaries.

INTRODUCTION

The Geysers steam field (Fig. 1) exploits the world's largest known vapor-dominated geothermal system. That system evolved from an equally impressive, high-temperature (175->350°C) hot-water-dominated precursor (White et al., 1971; Lambert, 1976; Sternfeld, 1981; Walters et al., 1991; Moore, 1992). Both systems show a dramatic spatial correlation with a concealed, Plio-Pleistocene-age, felsic intrusive complex, informally known as "the felsite" (Fig. 2). Much of the steam

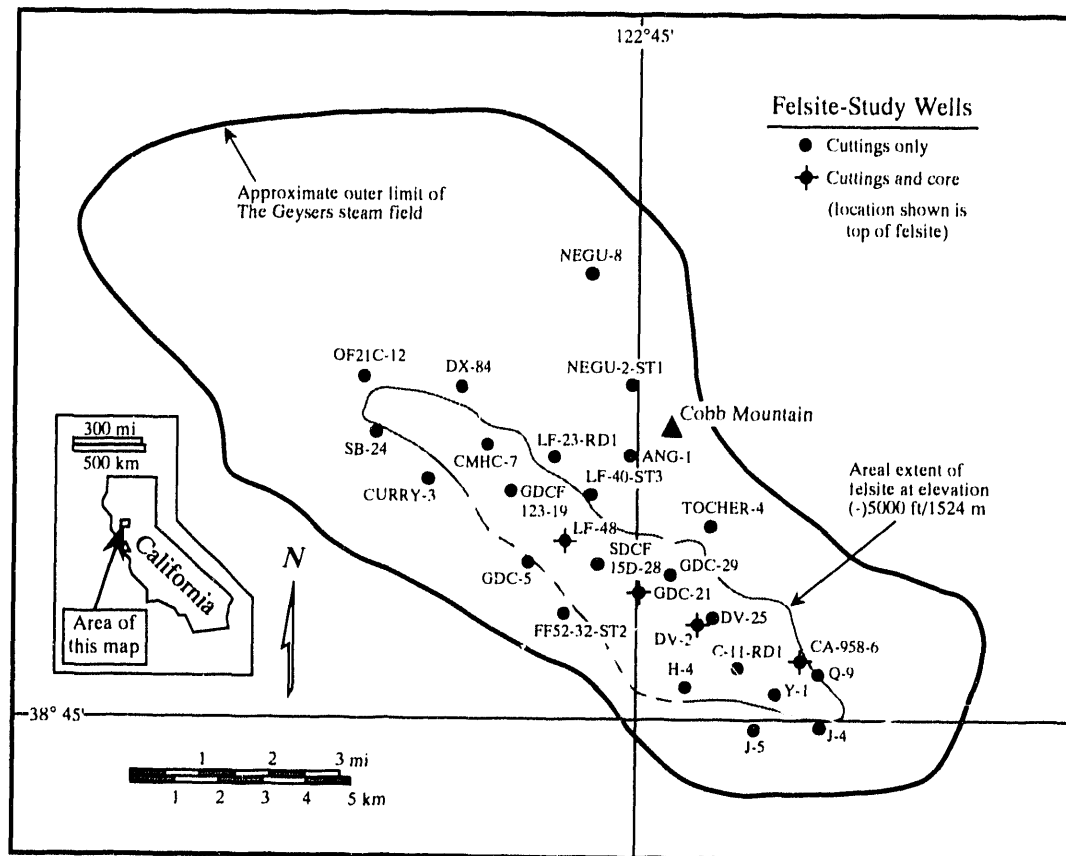


Figure 1. Map of The Geysers geothermal field, showing locations of felsite-penetrating geothermal wells (at pluton-top positions) utilized for this investigation.

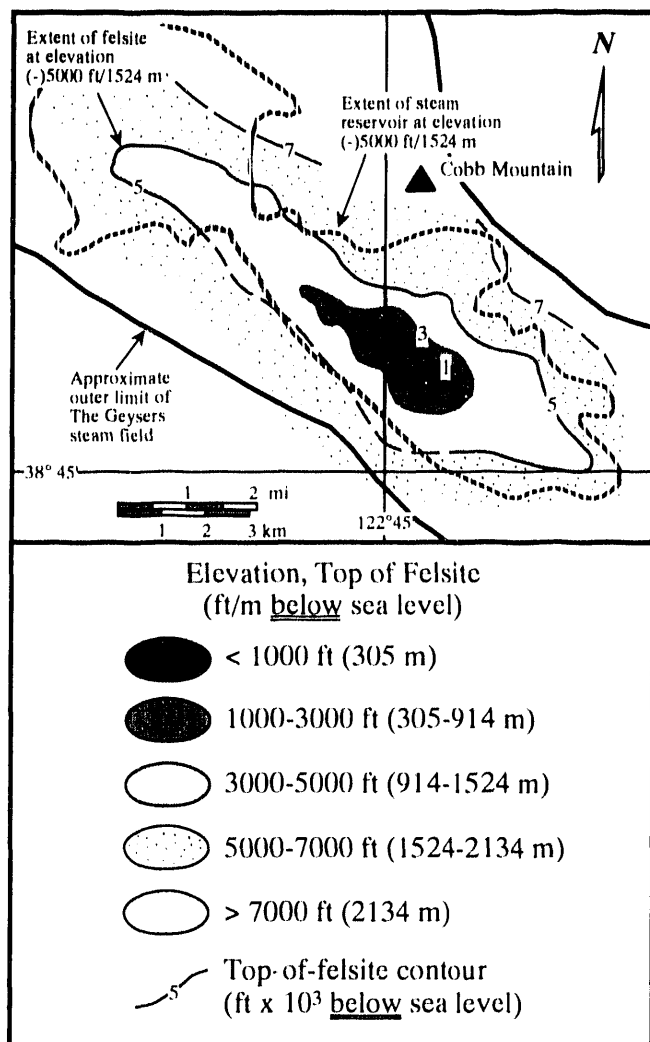


Figure 2. Top-of-felsite contour map, showing remarkable spatial correlation of the pluton with The Geysers steam field. Adapted from 1989 top-of-steam and top-of-felsite maps prepared cooperatively by Geysers steam-field operators.

field is hosted by the felsite itself; the portion outside the intrusive body occurs exclusively in a metamorphic/hydrothermal halo in Franciscan (late Mesozoic) rocks mantling the felsite. It seems clear from these relationships that intrusion of the felsite and development of associated hot-water systems were critical junctures in evolution of the modern steam field.

This study was undertaken to improve understanding of the Geysers felsite and its relationship to the contemporary vapor-dominated geothermal system. Specific practical questions addressed by our investigation include: (1) Is the felsite a single-phase stock, or does it comprise multiple intrusive phases? If so, are any of the component plutons associated with particularly productive sectors of the steam field?; (2) What are the ages of individual plutons in the felsite? Are any sufficiently young to serve as modern heat sources?; (3) What is the nature of felsite-hosted (or -induced) porosity and permeability -- especially critical variables in reservoir performance? Better knowledge of these reservoir parameters conceptually should be helpful to steam-field operators both for development and maintenance of known resources as well as exploration for new ones beyond the field's presently defined boundaries.

APPROACH, METHODS, AND PROCEDURES

Our investigation centers on detailed characterization of cuttings and sparse cores from 27 Unocal Corporation, Calpine Corporation, and NCPA geothermal wells (**Fig. 1**) penetrating the felsite and together spanning most of the explored length and breadth of the igneous body. These samples, from each well additionally incorporating 60-70 m of overlying, contact-metamorphic hornfels, represent over 16,000 m of drilling. These cuttings and cores are logged in detail; representative thin sections (800 in all) are petrographically examined and described, with appropriate support from X-ray diffraction, whole-rock geochemistry, and scanning-electron microscopy. Representative felsite samples are age-dated using precise ⁴⁰Ar/³⁹Ar techniques (Dalrymple, 1992). Combined results of these observations and analyses are interpreted and plotted as a series of maps, cross sections, and individual downhole lithologic and mineralogic distribution logs, for subsequent comparison with steam-entry frequency and quality as well as overall lateral and vertical variation in reservoir performance and fluid characteristics. For many of our felsite-study wells, these data remain proprietary; in such cases, their comparison with our research results will necessarily be undertaken privately by individual steam-field operators.

GEOLOGIC SETTING

The Geysers felsite, first described by Schriener and Suemnicht (1981) is an hypabyssal intrusive body at least 15 X 5 km in known areal extent (**Fig. 2**). The felsite intrudes a complex sequence of subduction-related, Franciscan-age rocks dominated by metagraywacke but including argillite, greenstone, chert, and various blueschist-facies lithologies (McLaughlin, 1981). The Franciscan rocks are disrupted by major subhorizontal thrust faults; all rocks are cut by northwest- to north-northwest-trending, high-angle wrench faults related to the San Andreas fault system (McLaughlin, 1981).

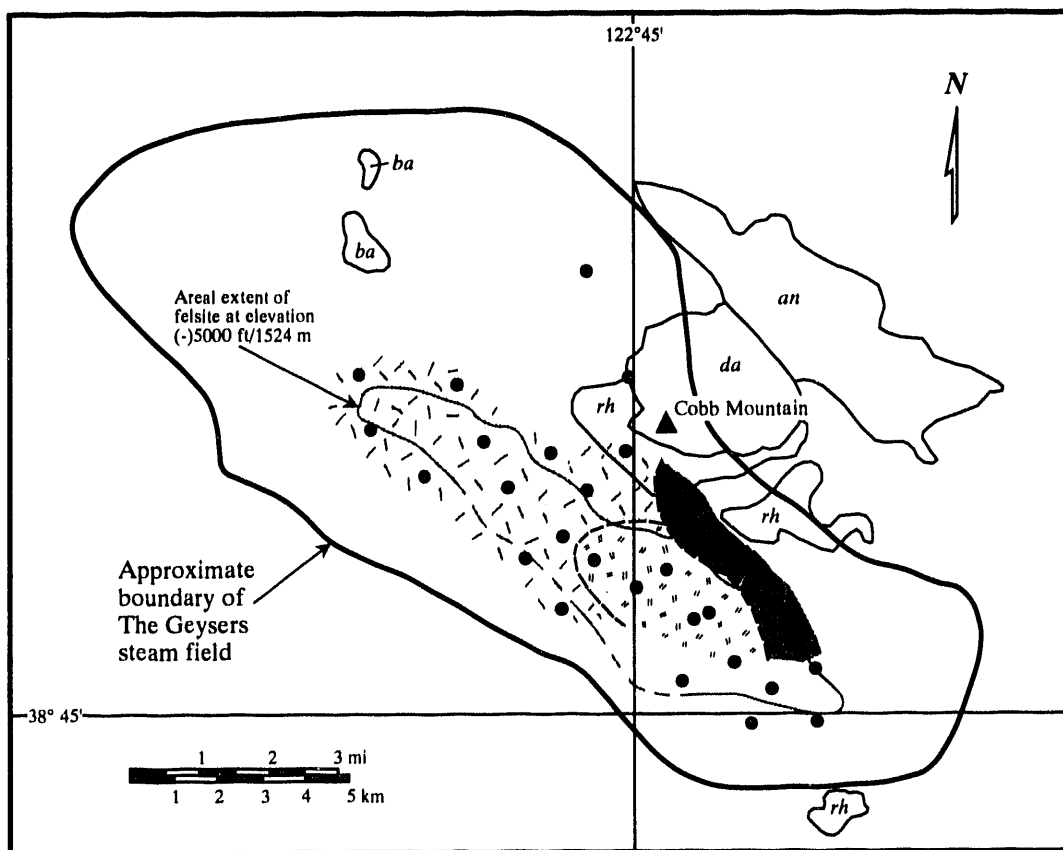
As documented by Sternfeld (1989), Walters et al., (1991), and Moore (1992), the Geysers felsite in numerous ways could have "prepared the ground" for eventual occupation by the modern steam field -- tensional fracturing in response to forceful intrusion; magmatic- and meteoric-hydrothermal fracturing and brecciation; and hydrothermal dissolution of carbonate and other phases by the prior hot-water system circulating in overlying Franciscan rocks (Hulen et al., 1992).

RESEARCH RESULTS TO DATE

Felsite Lithology, Chemistry, and Geochronology: Our work has shown that the Geysers felsite consists of at least three major intrusive phases (**Fig. 3**): (1) Orthopyroxene-biotite granite; (2) leucocratic biotite microgranite porphyry; and (3) hornblende-pyroxene-biotite granodiorite. Pulka (1991) has additionally documented several felsic dikes above the main body of the felsite in the southeast Geysers.

Microgranite porphyry forms the prominent "boss" on the felsite in the southeast Geysers (**Fig. 2**). This rock contains prominent phenocrysts of quartz, plagioclase, and potassium feldspar in a granophyric groundmass. The porphyry typically contains >76% SiO₂, making it compositionally a high-silica granite. Dalrymple (1992) dated a core of this porphyry from well DV-2 (**Fig. 1**) at probably >1.3 Ma.

Orthopyroxene-biotite granite, also silica-rich (>75% SiO₂), forms much of the northwestern half of the Geysers felsite (**Fig. 3**). The single core of this rock type (from Unocal well LF-48; **Fig. 1**) is conspicuously porphyritic. Most samples of the intrusive, however, are small-diameter cuttings,



Explanation

The Geysers Felsite (subsurface)	Nearby Clear Lake Volcanics (surface)
Hornblende-pyroxene-biotite granodiorite	Dacite
Leucocratic biotite microgranite porphyry	Rhyolite
Pyroxene-biotite granite	Andesite
	Basalt
Felsite-study well locations (at top of felsite)	

Figure 3. Geologic map, top-of-felsite, illustrating spatial relationship of this composite igneous body to nearby extrusive rocks of the Clear Lake volcanic field.

precluding recognition of such potentially diagnostic large-scale textural features. This widespread intrusive phase is also probably older than 1.3 Ma (Dalrymple, 1992).

A dark-colored, relatively mafic-rich, hornblende-pyroxene-biotite granodiorite (64-68% SiO₂) was cored in Calpine Corporation well CA-958-6 (Figs. 1 and 3). At the top of the felsite, this felsite phase is confined to the pluton's easternmost explored reaches (Fig. 3). A texturally and mineralogically similar granitic intrusive was cored in Unocal well GDC-21 (Fig. 1), but this rock, at 72% SiO₂, is chemically a low-silica granite. The GDC-21 variant could reflect later hydrothermal alteration, or could represent assimilation or magma mixing. The CA-958-6 granodiorite is chemically very similar to the overlying Cobb Mountain dacite

(Fig. 3). The radiometric ages of both the granodiorite and dacite (about 1 Ma; Donnelly, 1977; Pulka, 1991) permissibly suggest that they are intrusive/extrusive equivalents.

Even younger felsic-intrusive dikes occurring in the southeast Geysers have been described and dated by Pulka (1991). The dikes are sparsely scattered, locally spherulitic rhyolite porphyries which yielded two ⁴⁰Ar/³⁹Ar dates averaging 0.572 ± 0.091 m.y.

Felsite Alteration and Vein Mineralization: Most cuttings and cores of the Geysers felsite are hydrothermally altered. The nature and extent of that alteration and associated vein mineralization at and immediately above the top of the pluton are exemplified and graphically illustrated by Figure 4.

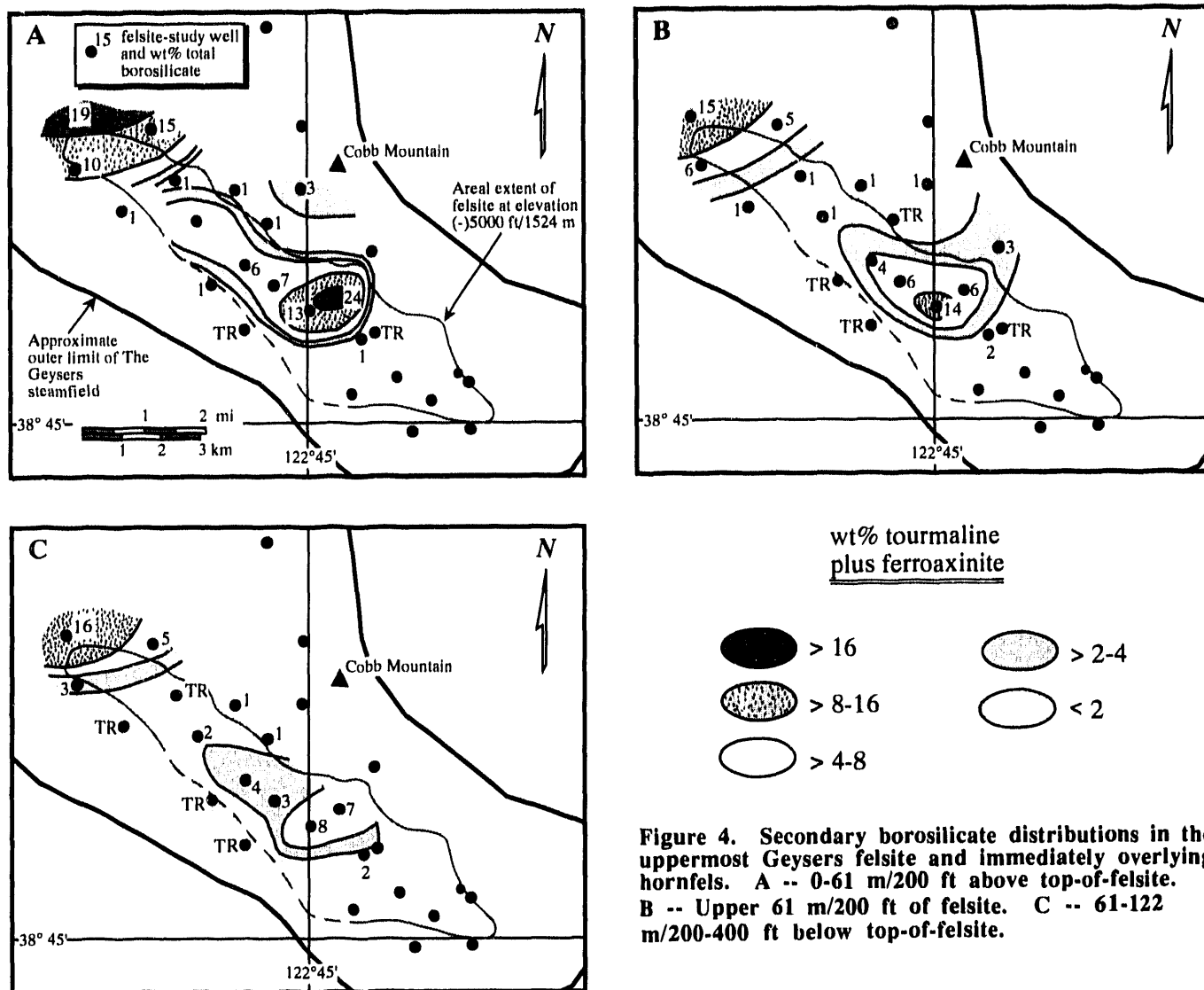


Figure 4. Secondary borosilicate distributions in the uppermost Geysers felsite and immediately overlying hornfels. A -- 0-61 m/200 ft above top-of-felsite. B -- Upper 61 m/200 ft of felsite. C -- 61-122 m/200-400 ft below top-of-felsite.

Both in hornfels mantling the felsite (Fig. 4A) and in the uppermost felsite itself, the borosilicate minerals tourmaline and ferroaxinite are considerably enriched, with combined percentages accounting for up to 24% of the affected rock. There are two prominent borosilicate anomalies -- one centered a little northwest of the microgranite porphyry "boss" in the southeast Geysers; the other in the northwestern portion of the field. A similar and partially coincident secondary-mineral enrichment is displayed by albite (not illustrated). Secondary potassium feldspar and sericite (micaceous illite) are concentrated at the top of the southeast Geysers microgranite porphyry "boss". Actinolite, epidote, chlorite, and prehnite, other common hydrothermal-alteration minerals at The Geysers, are apparently randomly distributed at the top of the pluton.

Figure 5 shows the downhole distribution of rock types and secondary minerals (alteration and vein) in cuttings from Unocal well GDC-21. Beneath contact-metamorphic hornfels, this well penetrated, in sequence, microgranite porphyry, a hybrid granodiorite/granite, biotite microgranite, more granodiorite, and finally deep pyroxene-biotite granite. With the exception of the deep granite, all these intrusive rocks have been moderately to intensely hydrothermally altered and veined. The most conspicuous alteration/veining is displayed by tourmaline

and ferroaxinite, which locally account for more than a third of individual 6-m cuttings intervals (Fig. 5). It seems likely that these secondary borosilicate and allied hydrothermal phases could define favorable zones of the pluton within which potentially productive steam-bearing fractures might selectively occur.

Felsite Porosity and Permeability: Most of the samples examined for this study are air-drilled and consequently small-diameter cuttings, from which little direct information about porosity and permeability can be obtained. Locally larger diameter cuttings and cores, however, clearly reveal the controls on these important reservoir parameters. Core from DV-2 (Fig. 1), for example, utilized by Dalrymple (1992) for age-dating studies, is locally disrupted by probable hydrothermal breccia. Such breccias are likewise observed in coarse cuttings from well FF-52-32 and others (Fig. 1). Known as important controls on mineralization (and therefore fluid flow) at numerous epigenetic ore deposits (e.g. Sillitoe, 1985), these breccias could provide equally effective steam conduits at The Geysers. The core from DV-2 also hosts tourmaline-chlorite-linedmiarolitic cavities. In the upper parts of the felsite, these cavities could serve the same function as calcite-dissolution voids in overlying Franciscan metagraywacke -- they could provide storage for the steam-field's liquid water reserves (see Williamson, 1991).

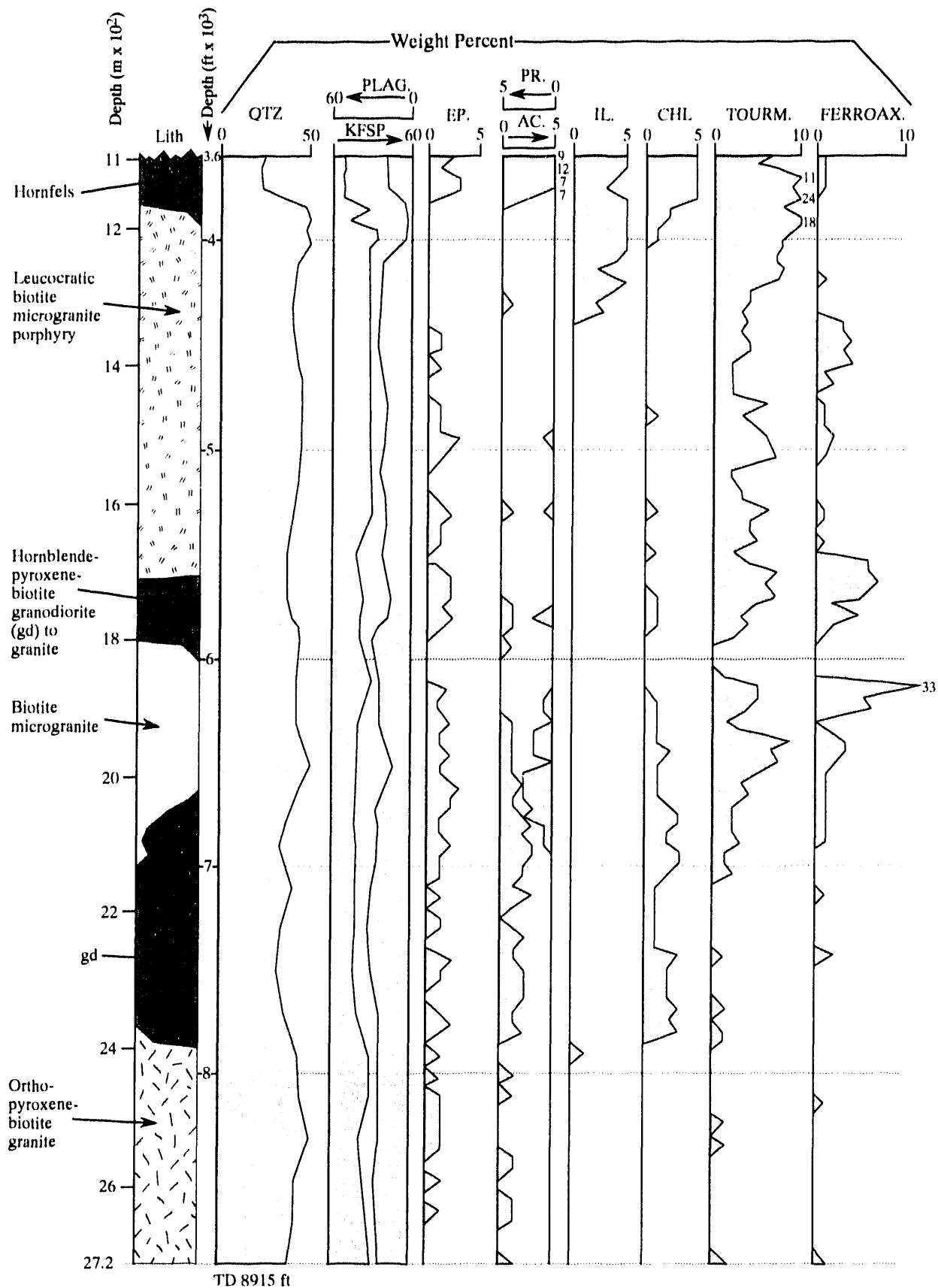


Figure 5. Downhole logs of rock type, hydrothermal alteration, and vein mineralization in the felsite intersected by Unocal well GDC-21. For location of this well, please refer to Figure 1.

CONCLUSIONS

1. The Geysers felsite, rather than representing a single intrusive pulse, is actually a composite pluton with at least three major intrusive phases, ranging in composition from granodiorite to high-silica granite.

2. Granitic phases in the felsite have been dated by Dalrymple as probably >1.3 Ma; Pulka (1991) dated the granodiorite at about 1 Ma, within the range of uncertainty the same age as overlying, chemically similar extrusive dacites of the Clear Lake volcanic field (Donnelly, 1977).

3. At these ages (1.3 to 1 Ma), the major felsite phases are probably too old (as first observed by Schriener and Suemnicht, 1981) to qualify as the steam field's modern heat sources (see Smith and Shaw, 1975). Deeper, younger plutons must serve that function. Shallow expressions of these hypothetical igneous bodies may be the felsic dikes described by Pulka (1991).

4. Porosity in the felsite and immediately overlying hornfels owes its existence in part to magmatic- or meteoric-hydrothermal brecciation; in the upper part of the felsite, some porosity could be provided by miarolitic cavities.

5. Igneous lithology, alteration, and mineralization in The Geysers felsite are reminiscent of many "porphyry-style" ore deposits, particularly those rich in tourmaline in the South American Andes (Hollister, 1978). While ore-grade copper mineralization has not been found in the steam field, deep hornfels cores utilized by Moore (1992) for fluid-inclusion studies are not only potassically altered like the interiors of many porphyry-type deposits, but contain conspicuous chalcopyrite and bornite. It is conceivable that "ground preparation" for The Geysers steamfield was effected by a weakly-mineralized, porphyry-type, magmatic/meteoric hydrothermal system.

ACKNOWLEDGEMENTS

This research is being sponsored by the U.S. Department of Energy's Geothermal Division, Contract No. DE/AC07/90ID12929; said support does not necessarily constitute a DOE endorsement of the views expressed in this paper. We gratefully acknowledge Unocal Corporation, Calpine Corporation, and NCPA for access to samples, insight into the steam field, and permission to publish. Rich Gunderson gave us the idea for this great project (many thanks). Line drawings are by Bob Turner. Wes Martin of Terra Tek, Inc. (Salt Lake City) completed SEM analyses. Merrienne Tolbert processed the manuscript.

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GAS GEOCHEMISTRY OF THE GEYSERS GEOTHERMAL FIELD

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ABSTRACT

Increases in gas concentrations in Central and Southeast Geysers steam are related to the decreases in pressure caused by heavy exploitation in the 1980s. When reservoir pressures in the central parts of the field decreased, high-gas steam from undrilled reservoir margins (and possibly from underlying high-temperature zones) flowed into exploited central areas. The Northwest Geysers reservoir probably lacks high-gas marginal steam and a decline in pressure may not cause a significant increase of gas concentrations in produced steam.

BACKGROUND

A nearly-fieldwide accelerated decline in pressure and steam production occurred at The Geysers in the late 1980s. As a result of this crisis, the U. S. Dept. of Energy has begun a program to examine the reservoir processes at The Geysers in greater detail with particular attention to understanding the sources of steam and noncondensable gas, and predicting changes in pressure, steam flow and gas content. As part of that program the Lawrence Berkeley Laboratory is studying the chemical composition of steam and mathematically simulating processes that affect steam composition as well as its temperature, pressure and flow.

In this study the aspect of greatest near-term importance is the prediction of changes in noncondensable gas concentrations in steam. Removal of gas is necessary to achieve low pressures at the turbine exhaust and high conversion efficiency. As part of the field management program recommended by the California Energy Commission Geysers Technical Advisory Committee, some power plants are being shut down and steam directed to other more-efficient plants and older ones are being refurbished. In addition, plans are being made to build new plants in the Northwest Geysers where some drilled areas are presently shut-in because of excessive gas concentrations. It is of great concern to the producers whether existing gas-handling equipment will be adequate for future gas concentrations and how much gas-handling capacity to provide in new and refurbished plants. Inadequate capacity may cause plant shutdown, while an excess costs money. For a 100 MW plant each percent of gas increase costs about a million dollars in gas-handling equipment.

CHANGES IN GAS CONCENTRATIONS

Noncondensable gas concentrations at The Geysers have risen sharply since the late 1980s. Examples of these

changes are taken from the Northern California Power Agency (NCPA) field in the Southwest Geysers (Figure 1). Wells at the center of the field (Figures 2 and 3) have relatively low gas, in part because of the effect of injection (particularly N wells, Figure 3). Wells at the field margins have much higher gas concentrations (Figure 4). Steam from most wells showed decreases in gas concentrations from start of production to 1987 and large increases afterwards. Exceptions to this increase include some N and Q wells affected by routine injection operations and, after 1990, some F and C wells affected by increased injection in well C-11 during injection experiments in the low-pressure area of the Southwest Geysers (Eneidy et al., 1992). In addition to maintaining reservoir pressures, vaporization of injected liquid causes dilution of gas in existing vapor and decreases wellhead gas concentrations. The long-term effect is an overall reduction in gas concentrations with detailed effects due to the amounts and location of injection and production. Similar increases in gas concentrations are observed in other parts of the Southeast and Central Geysers (PG&E engineers, pers. commun., 1993). These changes in gas concentrations seem to be related to decreases in reservoir pressure.

Pressure cross-sections of UNOCAL leases from Barker et al. (1992) show that by 1984 initial pressures near 500 psig had declined to 250 psig in the central ("Big Geysers") area, to 330 psig in the south-central (Unit 9-10) area, and to 440 psig in the southeast. By 1986 pressures dropped to 220 - 230 psig in the central and south-central areas and to 340 psig in the southeast. From 1986 to 1988 the rate of pressure change decreased in the central and south-central areas (180 and 200 psig in 1988) but continued in the southeast (250 psig in 1988). The rate of decline was greatest in the central area in 1970-1978, in the south-central area in 1980-1986 and in the southeast between 1984 and 1988. A separate cross section at right angles shows 1988 pressures at the southwest edge of the field near 400 psig and at the northeast edge near 500 psig, close to original values. Eneidy et al. (1990) show average pressure in the NCPA field decreasing from 420 psig in January 1985 to 270 psig in July 1987 and to 200 psig in February 1990. Thus, in the 1980s a large and increasing pressure gradient developed between the margins of the field and the central, highly exploited areas.

GAS CONCENTRATION PATTERNS

At The Geysers the composition of steam varies with position in the reservoir. Initial variations of total noncondensable gases and in oxygen isotopes are shown in Figure 5 (after Gunderson, 1989). In the Central and Southeast Geysers (and in Larderello, Italy) there is a characteristic

pattern of steam composition in which water-soluble salts and isotopes (e.g., boron and ^{18}O) are more concentrated in steam at the center of the field, and gases and isotopes less soluble in water (e.g., CO_2 , NH_3 , ^{16}O) are more concentrated at the margins (D'Amore and Truesdell, 1979; Truesdell et al., 1987). These patterns are produced by natural-state (pre-exploitation) lateral steam flow with partial steam condensation as heat is lost by conduction to the surface (Figure 6). This can be described as a Rayleigh or open-system process where the concentration of a component is a function of the amount of steam condensed and the relative solubility of the component in steam and water. Similar vertical variations in gas composition are caused by partial condensation of steam at the top of the reservoir (Figure 7).

Steam reservoirs may continue laterally (and vertically) beyond the margins of production zones. These areas tend to be initially rejected because of their high gas or low productivity, but they are connected to the central reservoir and can contribute to the total steam produced. Flow of marginal steam to central production areas depends on the pressure gradient. As discussed earlier, Barker et al. (1992) show that pressure gradients between field margins and central production areas doubled in the north-central area from 1984 to 1988, and in the southeast, from 1986 to 1988. Changes in the NCPA field were even greater where, with assumed marginal pressures near 500 psig, the gradient increased more than three times from 1985 to 1990.

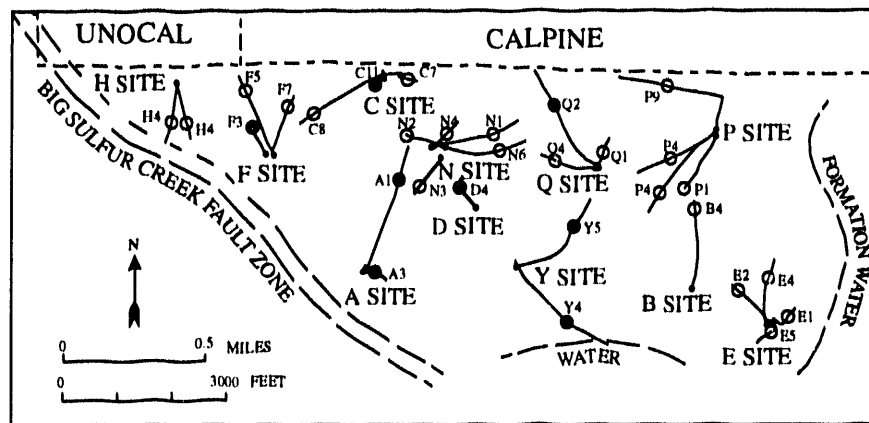


Figure 1. Map of the NCPA field at The Geysers (modified from a NCPA unpublished map) showing locations of selected well sites, mean steam entries (open circles) and mean injection points (solid circles).

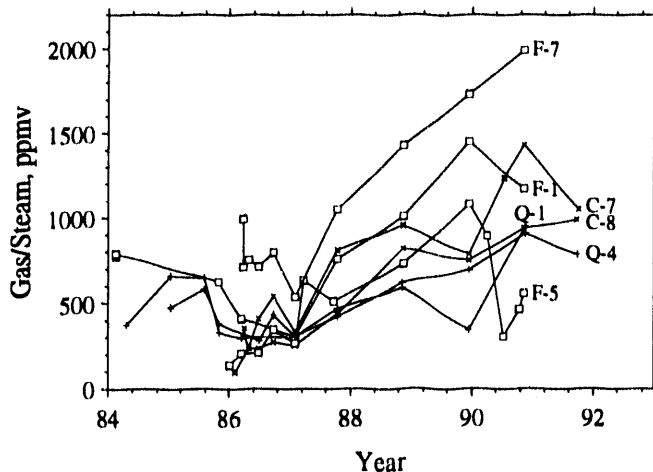


Figure 2. Changes with time of noncondensable gas concentrations (parts per million by volume) in steam from representative wells in the central part of the NCPA field that are not strongly affected by injection.

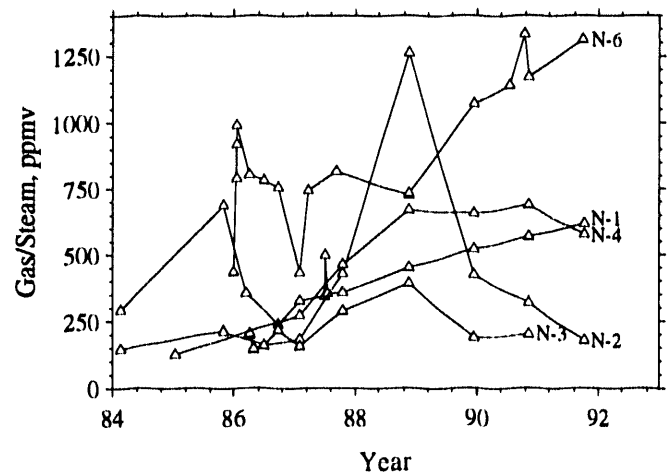


Figure 3. Changes in gas concentrations in steam from N wells in the central NCPA field which are strongly affected by injection.

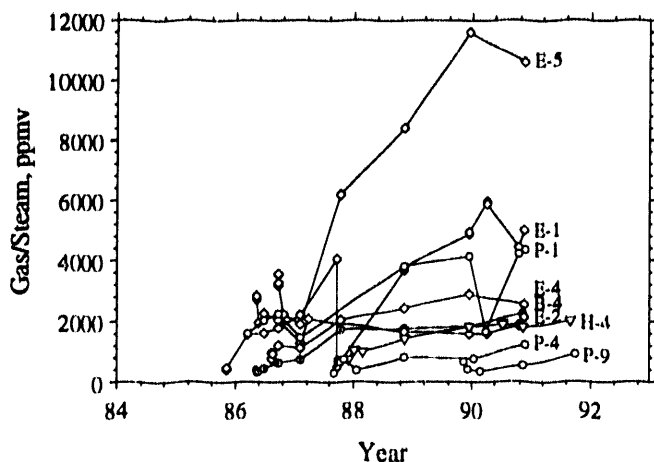


Figure 4. Changes in gas concentration in steam from representative wells at the margin of the field.

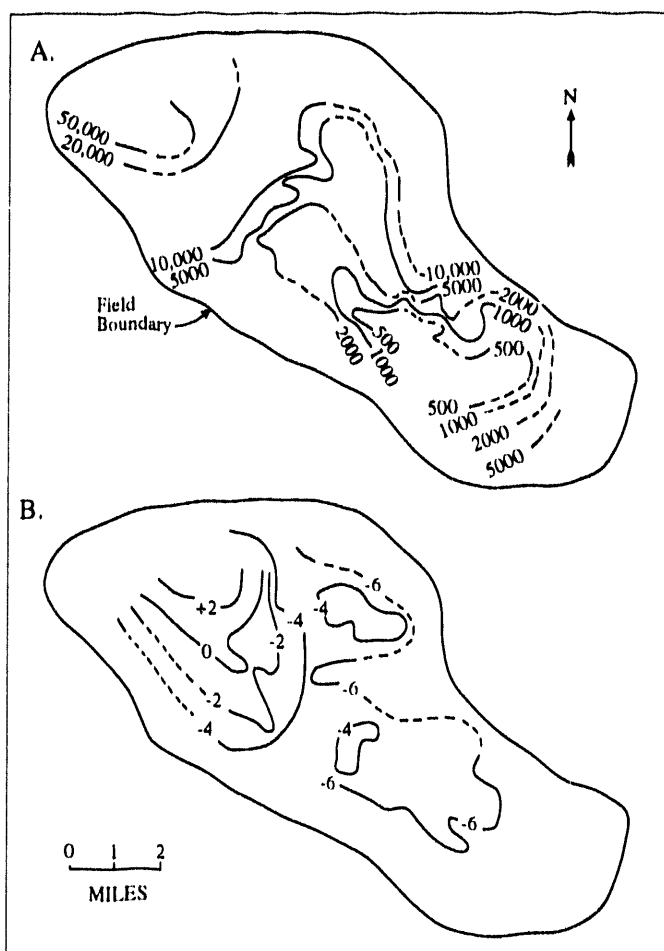


Figure 5. Initial (early production) variations in (A) non-condensable gas (parts per million by weight) and (B) $\delta^{18}\text{O}$ values (permil SMOW) in steam from The Geysers (after Gunderson, 1989).

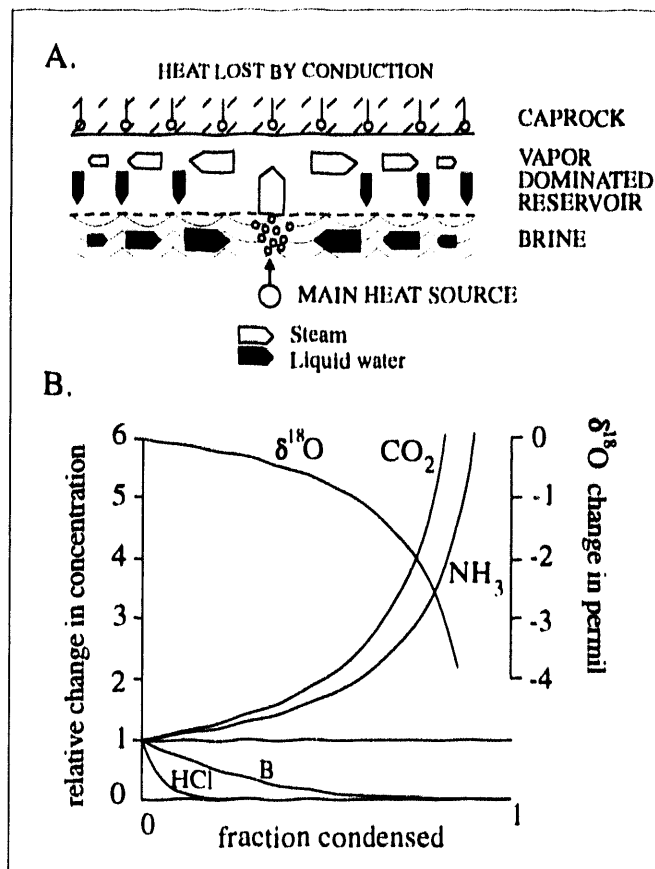


Figure 6. (A) Lateral flow and condensation in a vapor-dominated geothermal reservoir and (B) effects on gas concentrations and $\delta^{18}\text{O}$ values in steam undergoing partial condensation in a Rayleigh process during lateral flow (after D'Amore and Truesdell, 1977).

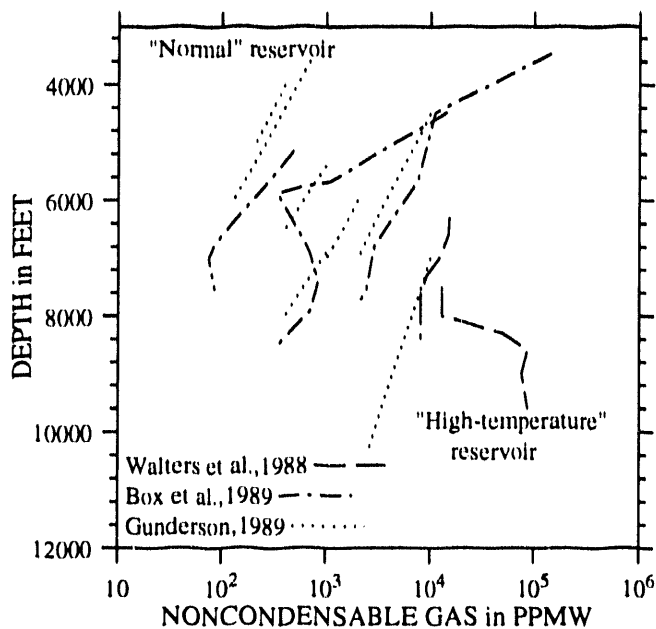


Figure 7. Variations with depth of gas concentrations (parts per million by weight) in The Geysers reservoir.

OTHER SOURCES OF GAS

In addition to noncondensable gas from reservoir margins, there may be other sources of increased gas at The Geysers. It is possible that gas pressures are maintained by mineral reactions. This process requires a reaction with gas as a product and a mineral or minerals as reactant(s). When the gas pressure decreases, more of the mineral reacts to raise gas pressure to equilibrium values until the mineral is exhausted. The mineral is said to "buffer" the gas pressure. Mineral buffer reactions are probably responsible for the increase of CO_2 with temperature in many geothermal reservoirs (Giggenbach, 1981; Arnorsson et al., 1983). For Larderello, this process has been suggested to account for the apparent excess production of CO_2 beyond that originally contained in the reservoir fluid (Pruess et al., 1985). Application of this process to The Geysers is limited by the lack of carbonate minerals in the reservoir. Other sources of carbon (coaly material, black shales) require oxidizing conditions to produce CO_2 . These conditions are ruled out by the high concentrations of H_2 observed in Geysers steam (Truesdell et al., 1987). For this reason mineral buffering is considered an unlikely source of increased gas at The Geysers.

A more likely source of gas is a high-temperature reservoir that may exist below the "normal" reservoir in parts of the field. In the Northwest Geysers a relatively thin normal (240°C) reservoir is underlain by a high-temperature (to 350°C) reservoir with up to 9% noncondensable gas and high $\delta^{18}\text{O}$ and HCl (Walters et al., 1988). Thus the appearance of HCl and high gas concentrations in steam from part of the Central Geysers (Unit 15 area) was interpreted to indicate the presence of a high-temperature reservoir below the exploited reservoir in this area (Haizlip and Truesdell, 1989). The high HCl and high $\delta^{18}\text{O}$ of the Northwest Geysers steam suggests that a magmatic component may be present. This is consistent with high $^3\text{He}/^4\text{He}$ in steam (7 to 9 times that in air) from the Central and Southeast Geysers reported by Torgersen and Jenkins (1982). A program of sampling and analysis of steam from all parts of The Geysers is proposed to examine this possibility.

THE NORTHWEST GEYSERS

Gas (and ^{18}O) in Northwest Geysers steam has a different pattern from that in the center and southeast (Figure 5). This results from the lack of Rayleigh condensation of laterally flowing steam. Condensate percolating downward from the normal reservoir into the high-temperature reservoir is immediately vaporized, so steam and condensate flow only up and down. The relation of the high-temperature reservoir to the "normal" reservoir in a schematic cross-section of The Geysers is shown in Figure 8. In the Northwest Geysers wells are completed in both reservoirs, with most production from the high-temperature one. The variation in wellhead gas concentrations

depends mainly on the proportion of steam produced from each reservoir. Because of the lack of lateral flow and condensation in this area, there is no equivalent of the marginal high-gas steam found in the central and southeast areas. Changes in gas in the Northwest Geysers will depend on changes in pressure in the production area and on the variation of gas concentrations in the interconnected normal and high-temperature reservoirs which may contain zones with lower gas concentrations than now produced (Mark Walters, pers. commun., 1992).

INJECTION OF LIQUID

Injection of liquid water into The Geysers reservoir produces rapid decreases in gas concentrations in steam both from increasing reservoir pressures and from dilution of existing gassy vapor with nearly gas-free vaporized liquid. The greatest benefit of injection are realized in underpressured, superheated areas of the reservoir in which original liquid has disappeared. These areas have been used in experiments in which almost all injected water was recovered in production. In the NCPA field the main injection wells are clustered in the center (Figure 1), with most injectate return produced from N and Q wells.

The fraction of injectate return can be calculated from changes in steam isotopic composition (e.g., Beall and Box, 1992), but the effects of injection are also shown in gas equilibrium calculations using "grid" diagrams (D'Amore et al., 1982). In these diagrams the temperature and steam fraction are calculated assuming that steam and water are in equilibrium in the reservoir, and that during production water vaporizes and mixes with in-situ steam without further equilibration. Figure 9 shows part of a grid for the equilibrium of CO_2 , CH_4 , H_2 and H_2O (y-axis) and of pyrite, magnetite (or other Fe oxide), H_2S , H_2 and H_2O (x-axis). Changes in temperature and steam fraction ("y" value) are shown for steam from well E-1 at the NCPA field margin, and well N-3 in the center, which is strongly affected by injection. Temperatures indicated are in the range of 230 to 265°C for both wells, and initial y values are the same (0.1), but steam from well E-1 at the margin evolves toward higher temperatures and much higher y values (near 0.25), while well N-3 changes temperature and y value within a small range.

These differences in behavior are interpreted as showing that well E-1 changed its steam source from local steam with low gas and moderate temperature (partly from vaporization of initial water) to high-gas, somewhat higher-temperature steam from the reservoir margin, while well N-3 produced low-gas steam largely from vaporized injectate. Pressures at field margins are near original values, so the amount of vaporization of liquid is less, resulting in larger y values. Variations in source temperatures calculated for N-3 steam are probably related to the variation of gas concentrations (Figure 3).

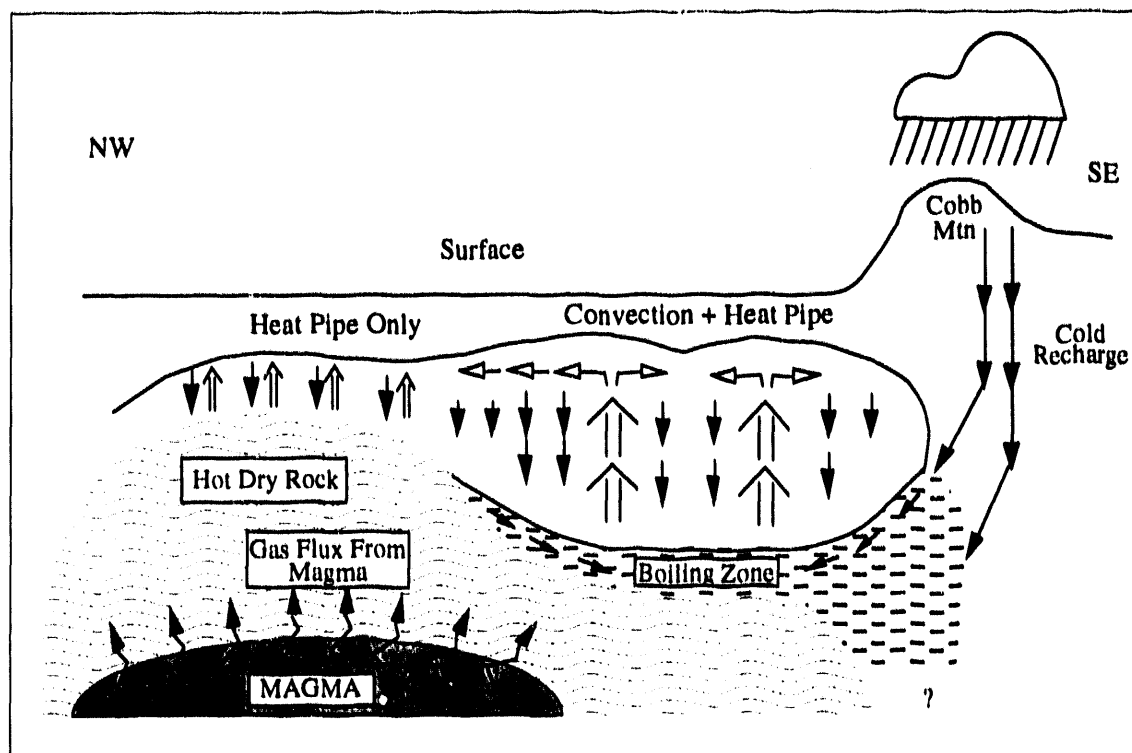


Figure 8. Schematic cross section of The Geysers geothermal system showing flow of steam (open arrows) and condensate (closed arrows) for convection in the northwest and central/southeast parts of The Geysers.

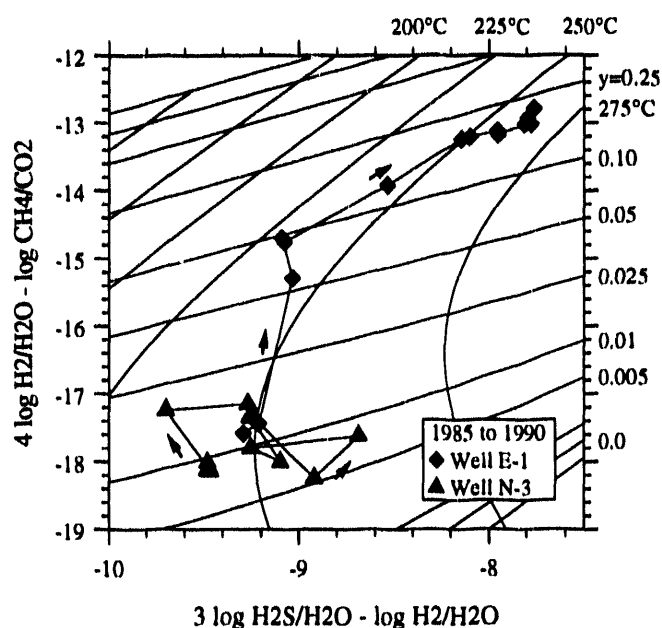


Figure 9. Temperature-steam fraction ("y") grid diagram showing changes with time for steam from a NCPA central well (N-3) affected by condensate injection, and for steam from a well on the field margin (E-1) affected by inflow of marginal steam.

SUMMARY

The decrease of pressure that occurred in the Central and Southeast Geysers reservoir in the late 1980s also caused an increase in noncondensable gas concentrations in the produced steam. The link between lower pressure and higher gas concentrations is due to the existence of high-gas marginal (and possibly overlying) zones connected to the exploited reservoir. Gas in these distal zones resulted from condensation of steam flowing laterally (and upward) under natural state conditions. When pressures in central zones decreased, higher-pressure steam richer in gas flowed in from the margins. This effect was greatest in the Southeast Geysers where the increase of exploitation was the most rapid. Other sources of gas include underlying high-temperature, high-gas steam reservoirs and less probably, mineral buffering reactions. Thus the reservoir first exploited in the center and southeast Geysers contained low gas but was connected to marginal zones with much higher gas. When central pressures declined strongly, marginal, high-gas steam flowed into the exploited zone. Deep, high-temperature reservoirs may also contribute high-gas steam to pressure-depleted production areas.

The Northwest Geysers reservoir is significantly different because the high-gas, high-temperature reservoir contains most of the steam resources and was exploited first.

In the northwest the lack of large scale convection prevented the formation of high-gas zones at reservoir margins and the steam produced now may contain close to the highest concentrations of gas in the reservoir. As a result the produced steam may not evolve toward significantly higher gas concentrations.

ACKNOWLEDGMENTS

Support for this work was from the Department of Energy, Geothermal Division through a contract with Lawrence Berkeley Laboratory. I wish to thank the operators at The Geysers, in particular Steve Eney and Bill Smith of NCPA, Tom Box and Joe Beall of Calpine and Mark Walters of Russian River Energy Co. for providing data and they, as well as my colleagues at LBL, for stimulating discussions.

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DEVELOPMENT OF CONCEPTUAL EXPLORATION MODELS OF GEOTHERMAL SYSTEMS

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ABSTRACT

This paper describes the results of petrologic and geochemical investigations being conducted at The University of Utah Research Institute on geothermal systems. The primary purpose of this work is to develop a set of conceptual models that describe the geochemical structure of geothermal systems in different geologic environments. These models will help the explorationist and developer to formulate more effective strategies for evaluating and developing new geothermal systems and for monitoring those already in production. The conceptual models that are being developed are based on the integration of chemical data from production wells and springs and the results of fluid inclusion, mineralogic, and isotopic measurements. In this paper, newly developed models for the high-temperature liquid-dominated geothermal system at Coso, California, and the vapor-dominated system at The Geysers, also located in California, are described.

INTRODUCTION

Conceptual models are used at all stages in the development of a geothermal resource. At the initial stage of a project, simplified conceptual models of different geologic environments assist in targeting new regions for exploration. At this stage, these models provide the explorationist with the framework needed to evaluate his initial observations and to site the first exploration wells. As the project proceeds and new information is obtained, the early generalized conceptual models are upgraded and modified to more accurately reflect local conditions. Later, these conceptual models become a working model of the system, and provide a baseline to monitor changes as the field is produced.

BACKGROUND

In the late 1980's, researchers at the University of Utah Research Institute (UURI) initiated a series of investigations designed to develop geochemical models of geothermal systems in a variety of geologic environments. In these investigations, chemical data was collected on well and spring discharges while fluid inclusion, mineralogic and isotopic studies were conducted to assess fluid compositions in regions of the reservoir that could not be sampled directly. Our initial efforts focused on the geothermal systems at Coso, California, Los Azufres, Mexico, and Zunil, Guatemala (Adams and Moore, 1990; Moore et al., 1989, 1990, 1992). These studies, which are among the most detailed of any conducted on geothermal systems, demonstrated that petrologic data, when combined with chemical analyses of the geothermal fluids, could be used to develop greatly refined

geochemical reservoir models. In addition, these data allow an evaluation of the changes that have occurred as the systems evolved.

In support of these fluid inclusion studies, a series of computer algorithms was developed to interpret the results of the fluid inclusion measurements. These algorithms allow calculation of boiling-point curves for varying salinities, gas contents and water table elevations, pressure corrections, calculation of ice-melting temperatures from chemical analyses, and the determination of fluid inclusion CO₂ contents based on ice- and clathrate-melting temperatures.

Our current investigations represent a continuation of these initial efforts. The need for this work reflects the results of a 1989 industry survey which reiterated the importance of developing a better understanding of reservoir processes, properties, conditions, and boundaries in different geologic environments. This paper describes the results of work conducted on geothermal systems at The Geysers and at Coso, California.

RESEARCH RESULTS

The Coso Geothermal System

Coso, which produces 240 MW of electric power, is one of five large, high-temperature geothermal systems located in the arid southwestern deserts of the United States (Fig. 1). Three of the five fields, Coso, California, Steamboat Springs, Nevada, and Roosevelt Hot Springs Utah, are developed in granitic and metamorphic host rocks while at Long Valley, California and Cove Fort-Sulphurdale, Utah, granitic rocks form part of the basement complex. Although granitic-hosted reservoirs have become increasingly important exploration targets within the last few years, the lack of data on their permeability distributions, the difficulties in separating geothermal from past hydrothermal events, and the general lack of published data on the reservoir fluids has hindered their development. In this section, some of the key features of the Coso geothermal system, which is the largest and most intensely explored of the geothermal systems developed entirely in granitic basement rocks are reviewed.

Since development of the Coso geothermal field began in 1977, the California Energy Company, Inc. has drilled more than 100 deep wells within an area of approximately 30 sq. km. Chemical analyses of the production fluids and measured thermal profiles demonstrate that the reservoir consists of an asymmetric thermal plume that originates in the southern part of

the field. Within the main upwelling zone, temperatures as high as 342°C and chlorinities of 6000 ppm have been measured. As the fluids move laterally and vertically from a depth of 1500 m in the core of the system to less than a few hundred meters in the north, they are progressively diluted and cooled. In contrast, changes in the compositions and temperatures of the fluids as they move to the south are related primarily to conductive cooling accompanied by only slight dilution. Chloride-enthalpy relationships indicate that the compositions of the reservoir fluids result from the mixing of two different high-temperature end members and a diluent with a temperature between 170° and 210°C.

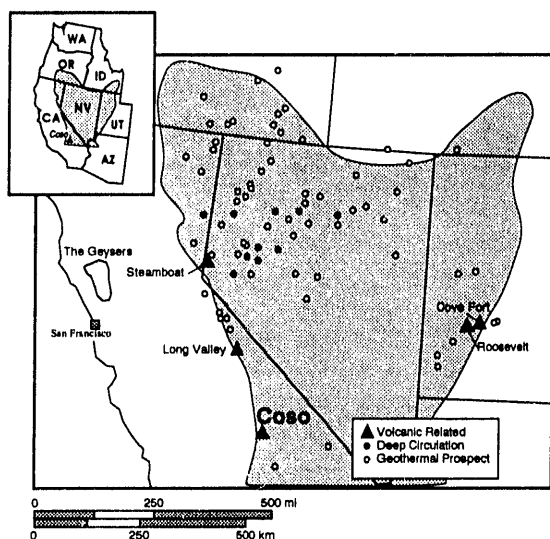
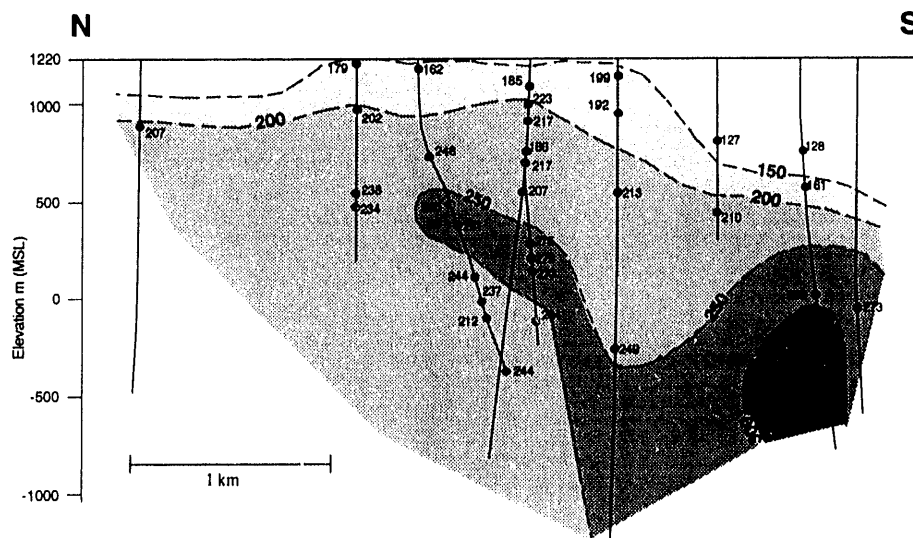


Figure 1. Distribution of geothermal systems in the Basin and Range province (shaded area). Systems related to recent volcanism are shown by the triangles; those related to deep circulation of meteoric fluids are shown by the circles. The location of The Geysers is shown for reference.

More than 1400 fluid inclusions from 19 core and rotary drilled wells were studied to augment the chemical analyses of the production fluids. The results of these investigations indicate that the main features of the system's present thermal structure were already developed at the time the fluid inclusions were formed. The thermal plume is equally well defined by both the temperatures and the salinities of the inclusion fluids. Figure 2 shows the homogenization temperatures of the fluid inclusions along a north-south cross section. Comparison of the fluid inclusion and measured temperatures indicates that cooling has occurred along the top and margins of the geothermal system while temperatures have continued to increase within the core of the field.

Figure 3 shows the ice-melting temperatures along the same longitudinal section as in Figure 2. This figure indicates that the apparent salinities of the fluid inclusions within the central portion of the plume were slightly higher than they are today. For example, the production fluids from the core of the upwelling zone sampled by well 72-19 yielded ice-melting temperatures of -0.8°C (1.4 equivalent weight percent NaCl) while ice-melting temperatures as low as -1.6°C (2.7 equivalent weight percent NaCl) were obtained on fluid inclusions in this well. Smaller differences in the ice-melting temperatures of the fluid inclusions and the production fluids are found in the northern part of the field. The compositional differences between the inclusion and production fluids reflects dilution by groundwaters and the sporadic flux of CO₂ generated by local boiling.

The fluid inclusion data also demonstrate that cool, low salinity groundwaters extended over much of the present geothermal system during the emplacement of the thermal plume (Fig. 3). This conclusion is significant because the measured thermal profiles and the compositions of the fluids



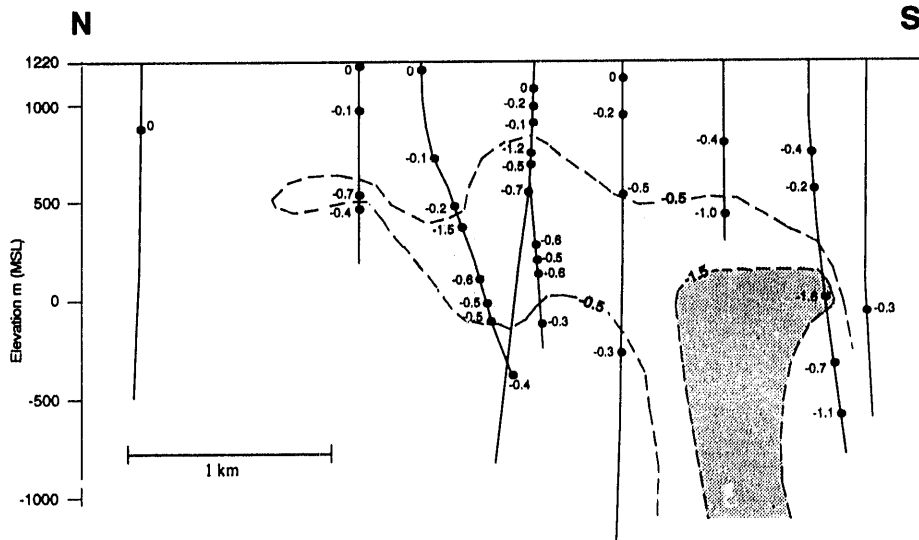


Figure 3. Variations in the ice-melting temperatures of the fluid inclusions shown in Figure 2. For reference, an ice-melting temperature of -1.0 corresponds to a salinity of 1.7 weight percent equivalent NaCl.

produced during drilling indicate that such cool groundwaters are not present above the main portion of the geothermal reservoir at Coso today (Moore et al., 1982). Dilution of the thermal fluids by these groundwaters occurred along the margins of the plume, resulting in the deposition clays, while carbonates were deposited above the reservoir as the groundwaters were heated. This mineralization reduced the permeabilities of the fractures above the plume, forming an effective seal over the thermal system that has strongly influenced the present configuration of the reservoir.

The Geysers

In contrast to the information obtained from chemical analyses of the waters found in liquid-dominated geothermal systems, the composition of the steam discharged from vapor-dominated systems provides only limited insight into the chemistry and history of the reservoir they were derived from. In this investigation, fluid inclusions and mineralogic data on cores and hand-picked cuttings were studied to establish the salinities and temperatures of the fluids that circulated through The Geysers at different times in its evolution and to place constraints on the origin of the corrosive HCl-bearing steam discharged from wells in the northwestern part of the field. In this study samples from the caprock, normal vapor-dominated reservoir (graywacke and felsite), and the high-temperature reservoir (Fig. 4) were examined. These samples were provided by Calpine Corp., Coldwater Creek Operator Corp., and Unocal Geothermal Division. The use of core in the present study has allowed us to: (1) characterize in detail the mineralogic relationships within the veins; (2) accurately establish the subsurface locations of the samples; (3) obtain mineral samples that are large enough to conduct fluid inclusion salinity and temperature determinations on; and (4) establish, in a few cases, the relative ages of the fluid inclusions.

In the present study, chemical and thermal data from more than 1800 fluid inclusions from two dozen wells were used (Moore, 1992; Sternfeld, 1981). These studies document how an early magmatically-heated, high-temperature liquid-dominated hydrothermal system evolved into the current vapor-dominated regime.

The conceptual model developed for The Geysers recognizes three distinct stages in its evolution (Moore, 1991; Moore and Hulen, 1992). The initial development of The Geysers began with the emplacement of a composite Plio-Pleistocene felsic intrusive complex that is generally termed "the

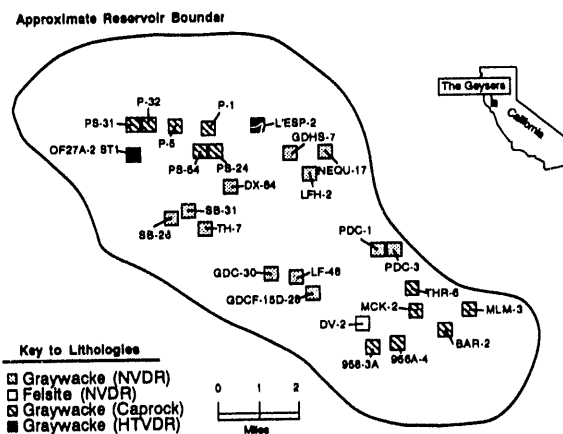


Figure 4. Locations and lithologies of the samples studied. Data from LFH-2 and SB-26 are from Sternfeld (1981). Abbreviations: NVDR = normal vapor-dominated reservoir; HTVDR = high-temperature vapor-dominated reservoir.

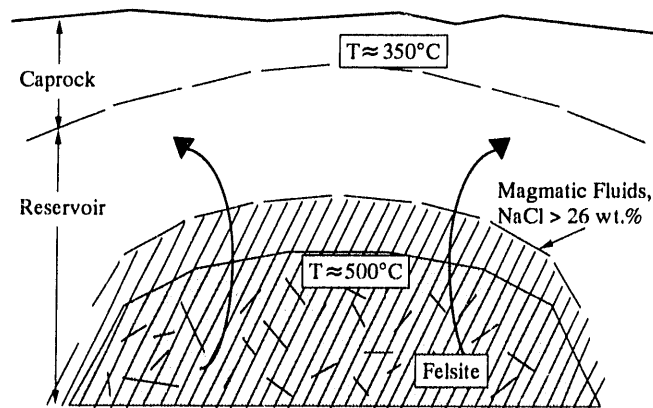


Figure 5. The initial stage in the development of The Geysers geothermal system. The temperatures shown in the figure are based on the fluid inclusion data. During this stage in the development of the system, the direction of fluid flow was predominately away from the intrusive contact as shown by the arrows. The diagonal lines show the regions of the thermal system through which hypersaline magmatic fluids circulated. The positions of the present vapor-dominated reservoir and caprock are shown in Figures 5 to 7 for reference.

felsite". As the intrusive complex was emplaced, a liquid-dominated hydrothermal system developed (Fig. 5), producing a well defined sequence of vein minerals. With increasing distance from the felsite, and/or decreasing relative age at a given elevation, the following sequence of vein assemblages formed within the metamorphic aureole surrounding the felsite: (1) tourmaline-quartz $\pm$ K-feldspar, albite, biotite, actinolite, and clinopyroxene; (2) quartz-biotite-actinolite $\pm$ K-feldspar, clinopyroxene, tourmaline; (3) quartz-K-feldspar-actinolite-epidote $\pm$ ferroaxinite, prehnite, calcite; (4) quartz-K-feldspar-chlorite-epidote; and (5) quartz-K-feldspar-calcite $\pm$ sericite.

The early liquid-dominated hydrothermal system was characterized by strong gradients in the temperatures and compositions of the fluids. Fluid inclusion homogenization temperatures ranged from 350°C near the base of the present caprock to more than 450°C near the intrusive contact while the corresponding salinities varied from 5 equivalent weight percent NaCl to more than 26 weight percent NaCl. These high-salinity inclusion fluids, which commonly contain crystals of halite, are representative of the dense magmatic brines that exsolved from the felsite and formed the tourmaline and biotite veins.

The second stage in the development of The Geysers thermal system occurred as temperatures around the felsite declined, causing the early liquid-dominated system to collapse upon itself (Fig. 6). Downward migration of low- to moderate-salinity waters resulted in dilution of the fluids that were present in regions now occupied by the zone of condensation and the normal vapor-dominated reservoir. These downward percolating waters deposited calcite within the fractures near the top of the present reservoir, leading to the formation of a low-permeability caprock.

The downward moving fluids do not appear to have breached the present high-temperature reservoir. Although fluid inclusion data are limited to two core samples, no evidence for the circulation of fluids with moderate temperatures (e.g. 260°C) and salinities (< 10 weight percent equivalent NaCl) was

observed. Indeed, pressure corrected homogenization data suggest that the last fluids to circulate through these rocks had minimum temperatures of 300°C. We suggest that the apparent failure of the rocks in the high-temperature reservoir to cool further, as those in the normal vapor-dominated reservoir did, and the presence of measured temperatures that reach 347°C (Walters et al., 1988) resulted from renewed intrusion in the northern part of the field. Furthermore, the apparent lack of low- to moderate-salinity inclusions leads to the conclusion that permeabilities within the high-temperature reservoir are lower than those in much of the normal vapor-dominated reservoir, where significant dilution of the liquid reservoir occurred.

The present vapor-dominated regime appears to be a relatively recent feature of the thermal system (Fig. 7). Fluid inclusions in the normal vapor-dominated reservoir suggest that, prior to boiling off, the precursor liquid had temperatures between 250° and 270°C and salinities of up to 7 equivalent weight percent NaCl. Boiling within the caprock produced veins of calcite and quartz. As the boiling proceeded, acidic condensate formed and was preserved as low-salinity fluid inclusions in the caprock and upper parts of the reservoir. This condensate reacted with the host rocks to produce sericite and in places, kaolin, which further reduced fracture permeabilities. Evidence of boiling within the reservoir rocks is limited to the presence of vapor-rich inclusions.

The fluid inclusion and mineralogic data place important constraints on the origin of the corrosive steam. These data indicate that there have been several important differences in the evolution of the normal and high-temperature reservoirs. They suggest that the formation of corrosive steam in the high-temperature reservoir could be related to lower permeabilities and the higher salinities of the liquid that existed in the high-temperature reservoir prior to its boiling off. These higher salinity fluids could have deposited greater concentrations of salt in the fractures as vapor-dominated conditions developed, leading to the formation of increased concentrations of HCl.

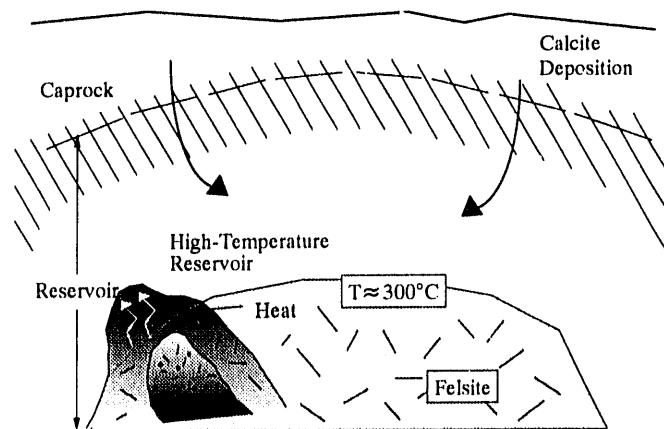


Figure 6. Collapse of the initial liquid-dominated regime during the second stage in the evolution of The Geysers geothermal system. During this stage, fluid movement was dominantly toward the intrusion as indicated by the black arrows. The high-temperature vapor-dominated reservoir began to develop at this time in response to renewed intrusion in the northern part of the field.

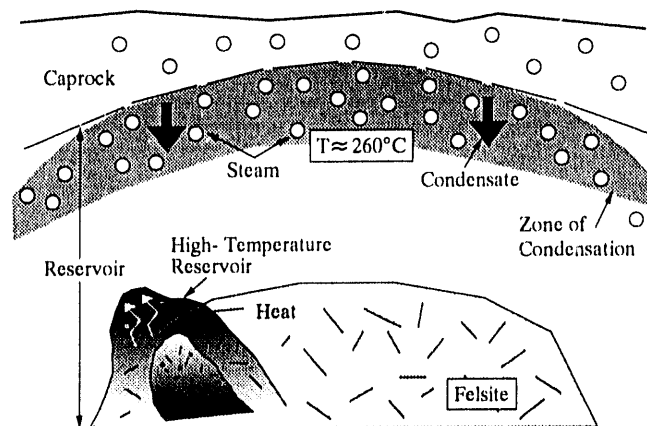


Figure 7. Initial development of the present vapor-dominated regime during the third stage in the evolution of The Geysers geothermal system. The open circles show the onset of boiling in the upper part of the system while heavy black arrows show the downward movement of acidic condensate.

CONCLUSIONS

Geochemical models are currently being developed for the geothermal systems at The Geysers and Coso, California. Investigations of the Coso field show that the geometry of the reservoir has been strongly affected by cool, low-salinity groundwaters that no longer exist over the field. The existence of this groundwater is reflected in fluid inclusion data and in the presence of clays and carbonates above the reservoir. These observations suggest that the geometries of other systems in the southwestern deserts may have similarly been affected and that petrologic investigation will be useful in their exploration and development.

Studies of The Geysers have documented the chemical and thermal characteristics of a large, liquid-dominated geothermal system that preceded development of the present vapor-dominated regime. These data suggest that both the initiation of vapor-dominated conditions and the development of the high-temperature vapor-dominated reservoir are relatively

recent features of the system. Presently available data suggest that corrosive HCl-bearing steam is associated with the high-temperature reservoir because the last liquid to boil off was enriched in NaCl relative to the liquids that produced the normal vapor-dominated regime.

Future project efforts will expand upon the geochemical models discussed in this paper. We are currently extending the models developed for Coso to Steamboat Hills, Nevada, and Roosevelt Hot Springs, Utah, which are developed in similar geologic environments.

We will continue to address questions regarding the origin and distribution of HCl-bearing steam at The Geysers. Studies will be conducted to determine the abundance of available Cl in the rocks and to relate these quantities to petrologic features of the rocks. Additional studies will be conducted on the isotope systematics of the reservoir with Unocal Geothermal Division personnel.

ACKNOWLEDGEMENTS

This work was supported by the U. S. Department of Energy under contract No. DE-AC07-90ID12929. Such support does not constitute an endorsement by the U. S. Department of Energy of the views expressed in this publication.

Work on this project would not have been possible without the assistance of the staffs of the California Energy Company, Inc. Calpine Corporation, Coldwater Creek Operator Corp., and Unocal Geothermal Division. In particular I would like to thank Joe Beall, Tom Box, John Copp, Rich Gunderson, Jim Moore, and Mark Walters for generously sharing their samples, data, and ideas with me.

DISCLAIMER

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DRILLING

Chairperson: Jerry Hamblin
Unocal Geothermal Division

INTRODUCTION TO DRILLING RESEARCH

Jerry Hamblin
Unocal Geothermal Resources and Power Generation

During April a technical review panel met in Albuquerque and heard presentations on drilling research projects currently in progress, primarily at Sandia National Laboratories. The technical review panel was composed of representatives of geothermal operators, drilling contractors and service companies. After each presentation, the panel was asked to complete a survey ranking the research in five areas. The five areas graded were overall importance, whether the project meets the needs of the geothermal community, the potential impact of the project, the appropriateness of the approach to the problem, and the quality and quantity of the project output. Scoring in the survey was based on a scale of one to five for each area, with twenty-five being the maximum available score.

Of the projects reviewed, Figure 1 shows the survey results for seven. The projects for which the results are tabulated are: hard rock bits, slimhole drilling, memory logging tools, lost circulation, Geothermal Drilling Organization, Long Valley, and Telemetry.

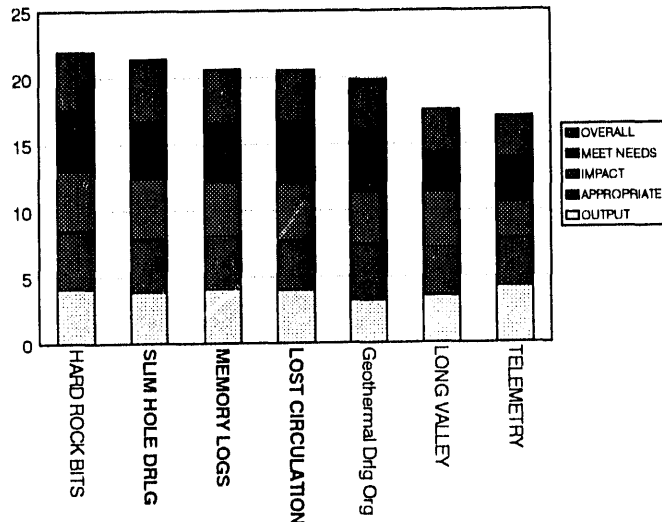


Figure 1. Survey Results of the Technical Review Panel.

Geothermal Drilling Organization, the Long Valley Exploratory Well and acoustic telemetry.

Since Lost Circulation Research, Memory Logging Tools and Slimhole Drilling are covered elsewhere in this document, a brief description of the remaining four projects follows.

The most highly rated project, hard rock bits, is intended to improve hard rock drilling capabilities of synthetic diamond bits. The research, which has not yet begun, will be conducted by six companies working independently of the others, but with each company working in conjunction with Sandia. This project will be only partially funded by the geothermal division of DOE.

The Geothermal Drilling Organization is set up so that cooperative research can be done with multiple sources of funding. Thus, even though geothermal drilling is a small market, research can be conducted economically. This organization also facilitates partial funding by the Department of Energy, and those contracts are administered by Sandia.

The Long Valley Exploratory Well was a part of the Magma Energy Program. Sandia is currently looking at ways to utilize this well in other research projects. The panel felt that other uses for the well were not yet clearly defined.

Acoustic telemetry is an ongoing project at Sandia. The purpose of the project is to increase the rate of data transmission possible from a Measurement-While-Drilling tool. There is currently an industry partner involved in the project. Because few geothermal operators run MWD's, the panel felt that this project was not as important as the others.

The projects that Sandia had already selected to include in this Program Review are the same projects that the technical review panel rated highest. This speaks well for the focus of the researchers, since their ranking of the importance of projects coincides exactly with the opinions of industry. Continued close cooperation between industry and the researchers will insure that the focus of research effort, as measured against the needs of industry, remains as accurate as it is today.

OVERVIEW-HARD ROCK PENETRATION

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Sandia National Laboratories
Albuquerque, New Mexico

Abstract

The Hard Rock Penetration program is developing technology to reduce the costs of drilling and completing geothermal wells. Current projects include: lost circulation control, borehole instrumentation, acoustic telemetry, slimhole drilling, geothermal heat pumps. A new project to improve synthetic diamond drill bits for hard rock drilling was initiated during the year.

Accomplishments during the year include completion of important acoustic telemetry tests in the Long Valley Well. These tests produced the first set of reliable, repeatable data in a drill hole. The results indicate the promise of acoustic transmission through drill pipe for great distances without repeaters. The rolling float meter for measuring drilling fluid outflow was duplicated and sent to six different companies for evaluation in the field. A new slimhole spectral gamma tool for operation at temperatures up to 300 C was fabricated and evaluated in the laboratory. Slimhole drilling for exploration and reservoir characterization was begun with several projects jointly completed with industry.

PROGRAM SUMMARY

Lost circulation control, borehole instrumentation, and slimhole drilling will be discussed in some detail in following talks. As Jerry Hamblin showed earlier, the new synthetic diamond bit project received good marks from our industry review panel meeting last month. This project includes participation and cost-sharing by all the major U.S. bit companies. Additionally, AMOCO's drilling test facilities near Tulsa will be used for comparative evaluations. The following figures summarize several aspects of this emerging project.

Important acoustic telemetry measurements were completed in the Long Valley Exploratory Well. Acoustic waves in drill pipe, generated by firing back-off shots at various depths, were measured at the surface. A total of thirteen shots were fired producing good quality,

ADVANCED SYNTHETIC - DIAMOND DRILL BIT PROGRAM

OBJECTIVE

Longer life and higher penetration rates in hard rock formations

APPLICATIONS

Geothermal, Oil, and Gas

COST SHARED BY DOE (EE & CE) AND 9
INDUSTRY PARTNERS

ADVANCED SYNTHETIC - DIAMOND DRILL BIT PROGRAM

PARTICIPANTS

Sandia National Laboratories
Baker Hughes INTEQ
Smith International and Megadiamond
Security Diamond Products
Dennis Tool Co. and DBS (Baroid)
Maurer Engineering and Slimdrill Int'l
Amoco Production Research

repeatable data. The results can be accurately modeled by accounting for the random lengths of drill pipe and by including mode conversion from extensional to bending waves. These somewhat unexpected conclusions offer the promise of greatly improving the drill pipe transmission channel by simply ordering drill pipe lengths. At this point, attenuation levels appear very favorable for commercialization of this MWD system which could improve transmission rates by two orders of magnitude.

Sandia's contribution to the geothermal heat pump project increased this year with the addition of a full-time staff member, Bill Sullivan. The following figure outlines our approach.

**DOE/SNL R&D PROGRAM ON GEOTHERMAL
HEAT PUMP SYSTEMS. TODAY'S VIEW:**



- GROUND SOURCE HEAT EXCHANGERS.
 - IMPROVEMENTS IN GEOMETRY, MATERIALS, AND INSTALLATION AIMED AT REDUCED COSTS AND IMPROVED PERFORMANCE.
 - APPROACH TO USE ANALYSIS AND TESTING. EMPHASIS WILL BE ON VERTICAL INSTALLATIONS.
- PERFORMANCE OF EXISTING HARDWARE.
 - OBTAIN HIGH QUALITY DATA ON PERFORMANCE OF INSTALLED EQUIPMENT. STOCKTON COLLEGE, FT. POLK CURRENTLY BEING MEASURED.
 - INSTALLATIONS OF HARDWARE ON MILITARY INSTALLATIONS MAY BE A SOURCE FOR ADDITIONAL INFORMATION.
- SYSTEMS ANALYSIS AND OPTIMIZATION OF HARDWARE
 - COMBINED EFFECTS OF HEAT PUMP AND HEAT EXCHANGER PERFORMANCE, AND LOCAL WEATHER, GEOLOGY, AND ECONOMICS INFLUENCE THIS CONCEPT. AIM IS TO ANALYZE THESE EFFECTS TO IDENTIFY MOST FRUITFUL R&D ACTIVITIES AND OPTIMIZE COMBINATIONS OF EQUIPMENT.

The Geothermal Drilling Organization, under the leadership of its new chairman Marc Steffen of Calpine, is showing renewed interest in identifying and completing cost-shared projects. The following figures give recent status of active GDO projects.

GDO - OFFICERS

- CHAIRMAN - MARC STEFFEN (CALPINE)
- VICE CHAIRMAN - JIM DUNN (SANDIA)
- SECRETARY - NIC NICKELS (INTEQ)
- TREASURER - SUE GOFF (LOS ALAMOS)

GDO - PROJECTS

- HIGH-TEMPERATURE TELEVIEWER
- STRIPPER RUBBER
- PDM FOR AIR DRILLING
- RETRIEVABLE WHIPSTOCK
- ADVANCED CEMENTS

HIGH TEMPERATURE TELEVIEWER

- PARTICIPANTS - UNOCAL, GEOTHERMAL RESOURCES INTERNATIONAL
- TOTAL COST - 1,000,000
- STATUS - IN USE BY INDUSTRY (UNOCAL)

STRIPPER RUBBER

- PARTICIPANTS - A-Z/GRANT, CALPINE, UNOCAL
- TOTAL COST - 430 K
- STATUS - FULL-SCALE TEST FIXTURE DEVELOPED, NEW CONFIGURATION DEVELOPED AND MARKETED, MODIFICATIONS TO THIS CONFIGURATION TO BE CONSTRUCTED AND TESTED

PDM FOR AIR DRILLING

- PARTICIPANTS - INTEQ, CALPINE, UNOCAL
- TOTAL COST - 300 K
- STATUS - PROJECT RECENTLY INITIATED

RETRIEVABLE WHIPSTOCK

- PARTICIPANTS - A-Z/GRANT, CALPINE
- TOTAL COST - 100 K
- STATUS - CONTRACT IN NEGOTIATION

ADVANCED CEMENTS

- PARTICIPANTS - BROOKHAVEN NAT'L LAB, UNOCAL, HALLIBURTON
- TOTAL COST - 900 K
- STATUS - PROJECT BEING FORMALIZED

STATUS OF LOST CIRCULATION RESEARCH

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ABSTRACT

This paper describes progress made in the Lost Circulation Technology Development Program over the period March, 1992-April, 1993. The program is sponsored at Sandia National Laboratories by the U. S. Department of Energy, Geothermal Division. The goal of the program is to develop technology to reduce lost circulation costs associated with geothermal drilling by 30-50%.

BACKGROUND

The most costly problem routinely encountered in geothermal drilling is lost circulation, which is the loss of drilling fluids to pores or fractures in the rock formations being drilled. Lost circulation costs represent an average of 10% of total well costs in mature geothermal areas (Carson & Lin, 1982), and they often account for over 20% of the costs in exploratory wells and developing fields. Well costs represent 35-50% of the total capital costs of a typical geothermal project (DOE, 1989); therefore, roughly 3.5-10% of the total costs of a geothermal project are attributable to lost circulation. Reducing the costs of lost circulation would help reduce overall project costs and help expand the role of geothermal energy in the electric utility sector.

For this reason, DOE sponsors the Lost Circulation Technology Development Program at Sandia National Laboratories. The goal of this program is to develop and transfer to industry new technology to reduce lost circulation costs by 30-50%. The program is developing technology in two general categories: lost circulation diagnostic techniques, and downhole tools for lost circulation control. Details of this program have been described previously in Glowka (1990), Glowka *et al.* (1991), and Glowka *et al.* (1992a).

Significant progress was made in the following areas during the current reporting period, March, 1992-April, 1993:

- Transfer of rolling float meter technology to industry;
- Planning for a comprehensive field evaluation of ultrasonic Doppler flow meters for drill rig inflow measurements; and
- Development of drillable straddle packer hardware.

This progress is described in this paper.

ROLLING FLOAT METER

Description

The rolling float meter was developed in 1991-92 to provide a method for accurately measuring drilling fluid outflow rates from a well during drilling. This is generally a difficult measurement to make because the drilling fluid return

line leading from the wellbore to the mud pit is an inclined, partially-filled circular pipe, and drilling mud is extremely abrasive. Consequently, full pipe measurement techniques do not function, and any probes introduced into the fluid are quickly eroded away.

A photograph of a working model of the rolling float meter is shown in Figure 1. The meter employs a solid polyurethane foam float or wheel that rides the surface of the fluid in the return line. The depth of the fluid in the return line is a measure of the total flow rate. This depth is sensed by measuring the angle of the pivot arm, to which the float is attached, with a pendulum potentiometer. Accordingly, there is a single voltage output from the meter that can be correlated with flow rate. To ensure a high level of sensitivity, the foam float is counterbalanced so that its net weight is only 20 gm. Bernoulli pressures generated by the fluid flowing beneath the float act to prevent the float from bouncing free of the turbulent fluid surface. Laboratory and field tests have demonstrated that the rolling float meter provides 1/2 to 2% long-term accuracy and is capable of detecting small fluid loss or production from the well. Further details of the testing and use of this meter are provided in Schafer *et al.* (1992), Loeppke *et al.* (1992) and Glowka *et al.* (1992b).

Progress During the Reporting Period

During 1992, two conference papers, Schafer *et al.* (1992) and Glowka *et al.* (1992b), and a detailed Sandia Report, Loeppke *et al.* (1992), were published on the rolling float meter. Significant industry interest was generated as a result of these publications. To foster that interest and transfer the technology to industry, a rolling float meter loan program was established during the current reporting period. Seven rolling float meter units were fabricated and loaned to seven different service companies in both the geothermal and petroleum drilling industries. The goal of the loan program is

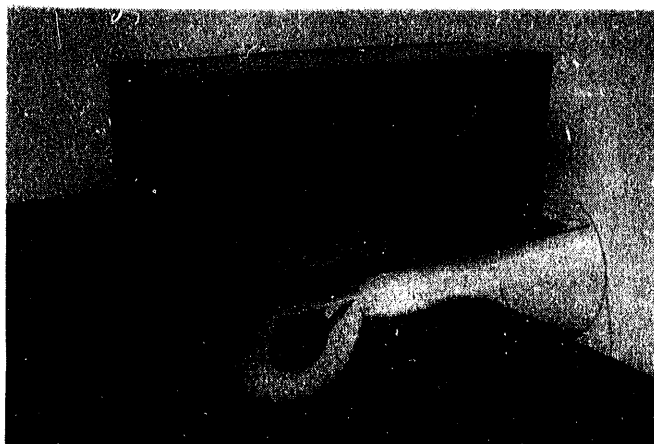


Figure 1 - Rolling float meter for measuring drilling fluid outflow rates.

to obtain independent field evaluation of the meter by the industries that would ultimately use the meter in drilling operations.

In addition to these seven units, one of the service companies built an additional five rolling float meters in order to expand their field testing program. The additional units were based on Sandia's design drawings, although we understand that some minor design changes were made. Details of the changes have not yet been released.

Field evaluation of the twelve rolling float meters is currently underway. Although no detailed results are yet available, we have been informed that the testing that has already been done has been favorable.

Plans for the rolling float meter are to continue working with industry to determine the utility of the meter for routine measurement of drilling fluid outflow rates. If practical utility can be demonstrated and sufficient interest remains, we will work with industry to develop a manufacturing capability for widespread distribution of rolling float meters to the drilling industry.

DOPPLER FLOW METER FIELD TESTING

Description

With the development of the rolling float meter's capabilities for accurately measuring drilling fluid outflow rates, the need for an alternative method for accurately measuring inflow rates has significantly increased. Inflow rates are currently commonly measured using mud pump stroke counters or rotary speed transducers. The mud stroke rate or rotary speed is then converted to inflow rates by assuming a pump efficiency. These methods suffer from inaccuracy due to the inability to accurately determine the pump efficiency, which changes constantly due to mud property changes, changes in pump pressure, and wear of pump plungers and liners.

Any technique which measures drilling fluid inflow rates must be relatively inexpensive and non-intrusive to the flow. The abrasive nature of drilling mud prevents the safe use of any probes or other intrusive component that may be eroded from its support and pumped downhole. Magnetic flow meters meet the second criterion by being non-intrusive, but they are subject to pressure limitations that usually require them to be placed on the mud pump suction line. Because of the large diameter of mud suction lines on most mud pumps, magnetic flow meters that will work in that application are extremely expensive, and there are often problems with silting in the suction lines, which causes inaccurate fluid flow rate measurements.

An alternative inflow measurement technique of significant potential is the ultrasonic Doppler flow meter. This type of flow meter is relatively inexpensive and is totally non-intrusive. The flow meter's transducers simply attach to the outer wall of the flow pipe downstream of the mud pump. Acoustic signals transmitted into the fluid by one transducer are reflected off solid or gaseous particles in the flowing fluid and detected by the second transducer. The Doppler shift in the acoustic signal frequency is directly proportional to the particle velocity and can, therefore, be correlated with flow rate. Electronic circuits for detecting Doppler shift differ in their degree of sophistication and purpose, some types being suitable for slurries and others being more suitable for cleaner fluids.

We have previously tested a Doppler flow meter on a drill rig without success (Schafer *et al.*, 1992 and Loeppke *et al.*, 1992). Drill rig vibration, electrical noise, and acoustic noise were probably all responsible to various degrees for the inaccurate readings that were obtained in measured inflow rates. Because of other testing concerns we were not able in those instances to optimize transducer placement in order to improve accuracy. Furthermore, more sophisticated Doppler-shift detection circuitry is now available and should be evaluated for this application.

Progress During the Reporting Period

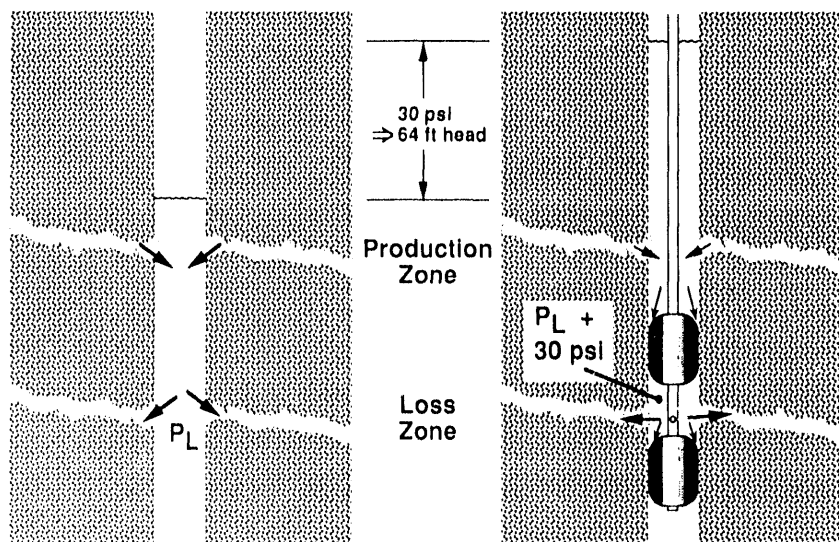
During the current reporting period, we made plans for a thorough evaluation of Doppler flow meters on an upcoming core drilling operation in the Steamboat Hills Geothermal Field, Nevada. We plan to instrument the inflow and outflow lines to the well with magnetic flow meters as well as Doppler flow meters of various designs. The magnetic flow meters will be used to provide a reliable measure of the inflow and outflow rates for comparison with the Doppler flow meter readings. At least three different Doppler flow meter detection circuits will be evaluated, each differing in its degree of sophistication and cost. Lost circulation and possibly fluid production are expected during drilling and will provide opportunities to evaluate the Doppler flow meters' capabilities for detecting and quantifying these off-normal drilling conditions. Data will be displayed on the rig floor and will be recorded to disk once per second over the several-week test period.

DRILLABLE STRADDLE PACKER

Description

The drillable straddle packer is a packer assembly under development for isolating and directing the flow of cement into a selected loss-zone interval, as seen in Figure 2. The purpose of this device is to maximize the volume of cement delivered to the loss zone while minimizing the volume of cement remaining in the wellbore. The packer assembly envisioned differs from conventional packers in three respects: 1) the drillable straddle packer is inflated simply, without the use of downhole valving, by the differential pressure generated during cement flow through the cement ejection ports located between the packer elements; 2) the drillable straddle packer is designed to provide low-pressure (30-psi) sealing capability, instead of the high-pressure (~2000-psi) sealing capability of conventional packer assemblies; and 3) the drillable straddle packer is fabricated of low-cost, drillable materials and is designed to be left in the bottom of the wellbore after the cementing operation and to be drilled through upon the resumption of drilling after the cement sets. Further discussion of the concept and descriptions of the proposed hardware design are provided in Glowka (1990) and Glowka *et al.* (1992a).

The significance of a 30-psi sealing capability is illustrated in Figure 2. Without a packer in place, connate fluids produced at other wellbore intervals tend to enter the loss zone at rates dependent on the relative pore pressures of fluid in the various zones. If an open-end drillstring is inserted to inject cement at the loss zone interval, the produced connate fluids tend to dilute the cement and push it farther out into the formation, reducing its effectiveness in sealing the loss zone from the wellbore. At the same time, density differences between the wellbore fluid (drilling mud) and the cement causes the cement to channel to the bottom of the wellbore, filling the wellbore up to the loss-zone interval before the fluid flows into the loss zone. As a result, most of the cement



Internal Wellbore Production

- Reduced cement dilution
- Reduced cement remaining in wellbore
- Increased cement volume in loss zone

Figure 2 - Drillable straddle packer concept, showing the significance of a 30-psi sealing capability.

volume may remain in the wellbore rather than flowing into the loss zone, requiring the drilling of significant intervals of cement to reach new rock formation at the bottom of the wellbore and, perhaps, inadequately plugging the loss zone.

Alternatively, if a 30-psi sealing capability could be provided, then connate fluids produced at other intervals may be substantially prevented from entering the loss zone and diluting the injected cement. A 30-psi sealing capability implies that up to 30 psi of additional fluid pressure could be imposed on the production interval. This pressure, equivalent to a 64-ft head of fluid in 9 ppg drilling fluid, may be enough in many situations to prevent or retard wellbore production at that interval. Reversing the pressure gradient across the packer, a 30-psi sealing capability implies that up to 30 psi of additional fluid pressure may be imposed at the loss-zone interval, meaning that more cement will flow into the loss zone and less will remain in the wellbore.

Progress During the Reporting Period

The design goal of a 40-psi burst pressure for the fabric bags on the drillable straddle packer was achieved during the current reporting period. This was accomplished by optimizing the design of the fabric-tube end closures and using a stronger woven-fiberglass fabric. Data from a successful burst test are shown in Figure 3. This test has been duplicated three times to confirm the minimum burst pressure of the bag. The tests demonstrate that the high-temperature fabric is capable of providing a 40-psi sealing capability.

A commercially available alternative to the developed fabric bag design was also discovered and is currently being evaluated. Petersen Products Company manufactures inflatable fabric stopper plugs for temporary sealing of pipelines and sewer pipes (Peterson, 1990). A photograph of a 15-inch-diameter Petersen bag is shown in Figure 4. End closure of the fabric tube is accomplished by swaging an aluminum cap over each pleated end of the fabric tube, which is supported by a steel pipe nipple. The assembly actually consists of two inner neoprene bags contained by an outer nylon-reinforced canvas

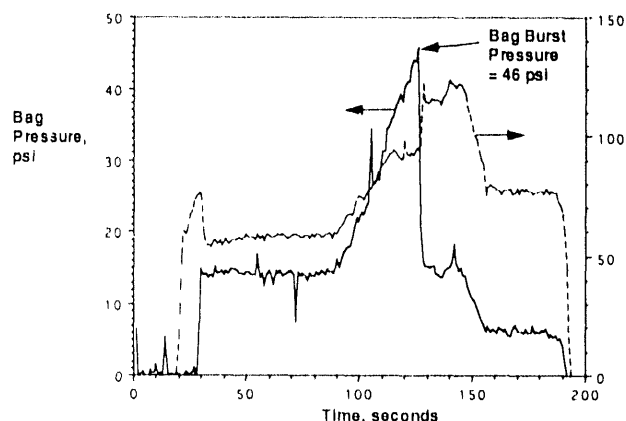


Figure 3 - Successful drillable straddle packer bag burst test results.

bag. The pressure capability of such a bag is comparable to that obtained with a high-temperature bag of our developed design.

The Petersen bag was tested in our Packer Test Facility to evaluate its sealing capabilities against internal wellbore production. The test facility is described in Glowka *et al.* (1991). Results are shown in Figures 5 and 6. In the first test, the bag was fitted with a 0.92-inch orifice and placed in the simulated wellbore of the test facility. The upper simulated production zone and the simulated loss zone were opened to allow fluid to exit the wellbore freely. As seen in Figure 5, the pressure differential, $P_L - P_W$, driving leakage around the bag increased to 33 psi as the flow rate through the bag, Q_p , increased from 0 to 128 gpm. Although a small amount of leakage around the bag occurred while the bag was being inflated, the leakage was quickly eliminated once the bag inflated. Leakage around the bag was not measurable thereafter, even with a 33 psi driving pressure.



Figure 4 Peterson Products Co. 15-inch stopper plug, partially inflated

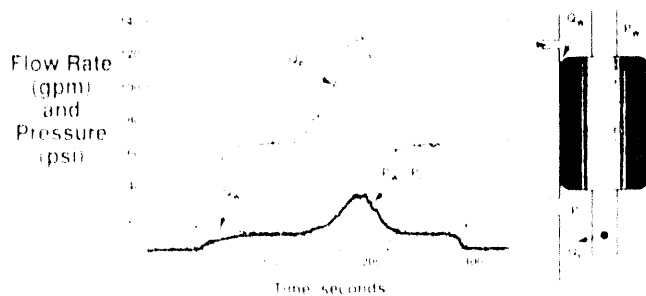


Figure 5 Bag flow by test results with smooth wellbore

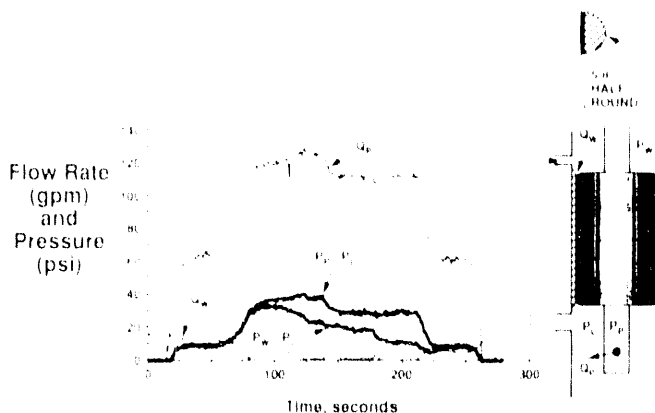


Figure 6 Bag flow by test results with rough wellbore

To test the sealing capabilities of the bag with an imperfect wellbore, a sealing test was run with a protrusion emplaced in the simulated wellbore. An 8 ft length of 5/8-inch, half round molding was bonded to a magnet strip along its entire length and placed on the inner wall of the casing that simulates the wellbore. The molding ran the entire length of the bag. As seen in Figure 6, leakage around the bag (along the wellbore wall) was reduced to less than 1 gpm once the bag was inflated. The small level of leakage in this case was due to leakage along the molding. By reducing the driving pressure differential, $P_i - P_w$, relative to the bag inflation differential pressure, $P_p - P_i$, the leakage could be totally eliminated. While not conclusive, this test indicates that the fabric bag is capable of providing significant sealing capability even in a rough wellbore. Further testing with other protrusions of different cross sectional shapes and sizes will be conducted to more thoroughly evaluate the leakage characteristics in a rough wellbore.

Further work will be conducted with Petersen Products Company to determine the feasibility of using Petersen's automated technique for fabricating low-pressure bags for the drillable straddle packer. Attempts will be made to fabricate bags with the high temperature fabric we have been using in our bag fabrication and testing program and to determine whether or not swaging of the fabric end-clamps can be accomplished on suitable drillable pipe such as aluminum, PVC, or CPVC plastic.

Future work on the drillable straddle packer will also concentrate on testing the packer's shroud mechanism (see Glowka *et al.*, 1992a, for a description of the mechanism). The tests will be conducted in the Packer Test Facility as shown in Figure 7. A single bag assembly and shroud

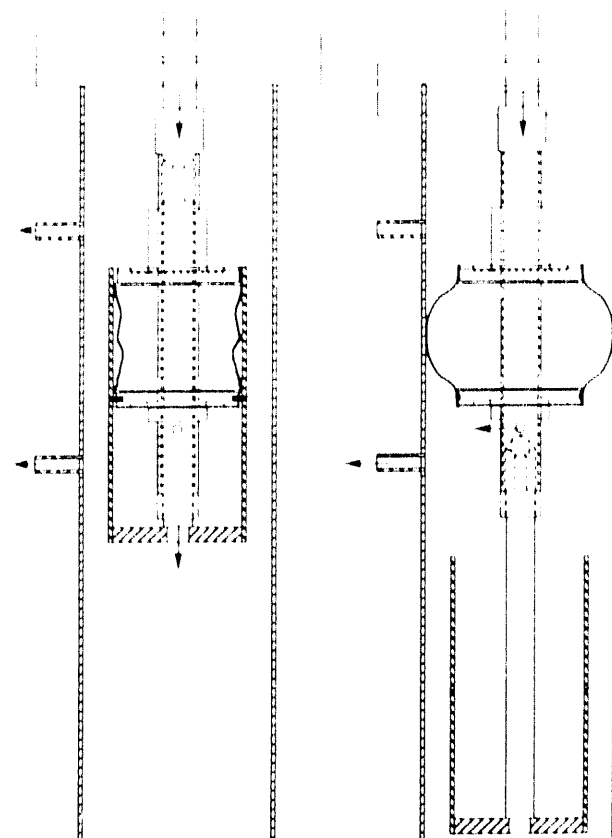


Figure 7 Schematic of planned shroud mechanism test

mechanism will be constructed and tested to determine the functionality and reliability of the mechanism.

Tests are also planned to demonstrate the drillable straddle packer and its zonal isolation capabilities with cement at full scale. A Packer Demonstration Facility such as shown in Figure 8 will be constructed. Concrete walls approximately 15-20 ft tall will be constructed and bermed to allow an engineered formation to be emplaced. Alternating layers of gravel and clay will be laid down on top of a concrete pad to simulate loss zones, production zones, and impermeable zones. A "wellbore" in the center of the facility will allow access to the various zones and provide for the emplacement of a drillable straddle packer assembly. With the bags situated at the impermeable zones, cement will be pumped through the packer and into the simulated loss zone. Both the target loss zone and the gravel layers above and below the target loss zone will be vented so that cement can freely enter any of the zones. After pumping a prescribed volume of cement, the engineered formation will be cross-sectioned with a back hoe to determine where the cement flowed. The volume of cement entering the loss zone, the wellbore, and the other permeable zones will be determined. This will allow an evaluation of the capability of the drillable straddle packer to isolate zones of interest for cement emplacement.

SUMMARY

In summary, significant advances have been made on wellbore hydraulics testing hardware and the drillable straddle packer during this reporting period. The rolling float meter is currently undergoing field evaluation by industry. Plans for a rigorous and thorough field evaluation of ultrasonic Doppler flow meters for drilling fluid inflow rates have been made. The drillable straddle packer concept has been found feasible, the 40-psi burst pressure goal for the fabric bags has been accomplished, and plans have been made for demonstration of the packer using cement at full scale.

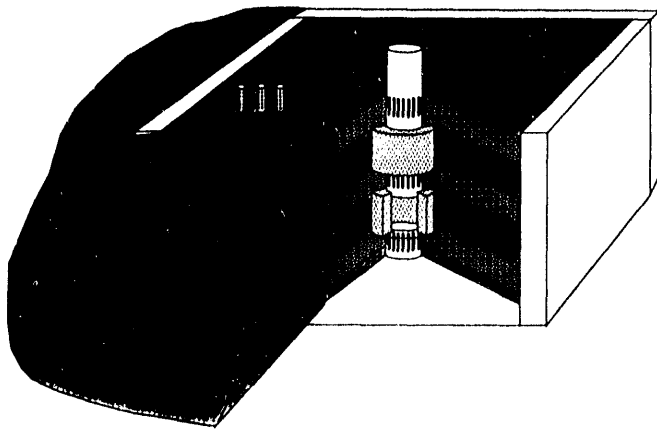


Figure 8 - Planned Packer Demonstration Facility.

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ACKNOWLEDGMENT

This work was sponsored by the U. S. Department of Energy at Sandia National Laboratories under Contract DE-AC04-76DP00789.

MEMORY LOGGING TOOLS

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ABSTRACT

A suite of memory logging tools is being developed for slim-hole, high-temperature applications. The first tool will measure pressure and temperature, and it is especially designed to be a low-cost, but very precise, device. This tool will be smart in the sense that it can make "decisions" downhole. A second tool will measure the gamma-ray emissions from formation material, and it will be an indicator of lithology. A fluid sampling tool will complement the spectral gamma tool in that it will further constrain the lithology by identifying dissolved formation materials. Plans are being made to integrate the tool responses into formation parameters of interest through cooperative efforts between geothermal operators and scientific drilling programs.

BACKGROUND

Downhole logging and surface geophysical measurements have become a backbone for hydrocarbon reservoir analysis. However, an effort of comparable magnitude is not a feature of the geothermal thrust in the United States. While some surface geophysical studies are used, these studies are limited, and there is a general lack of downhole measurements even though they are required to interpret geophysical surface studies, to extrapolate core data away from a hole, and to correct production difficulties.

An often-cited obstacle to downhole measurements is the fact that tools used in low-temperature formations are not compatible with the geothermal environment, and the cost of developing and maintaining a suitable tool suite exceeds the anticipated revenues from logging services. But a market can only be supported if measurements produce a meaningful output. Since interpretative techniques developed for hydrocarbon reservoirs are not proven in geothermal formations, a second obstacle is the general inability to relate log data to meaningful information. In some respects, the development of a viable geothermal logging industry is impeded by the chicken-egg syndrome.

The purpose of the Memory-Logging-Tool Program is to rectify the situation that exists in the geothermal industry by addressing the problems mentioned above. This program was instituted in 1992, and all programmatic development issues outlined in a previous publication (Lysne, 1992) have been accomplished. Instruments under development are: a precision pressure/temperature tool, a spectral gamma tool, and a fluid sampler. An outline of the program and its status is presented herein.

APPROACH

The thrust of the program may be broken into a set of four objectives, each of which involves an exchange of information between tool engineers and user groups. These objectives are:

Objective 1. To develop quality tools using self-contained, data-storing computers (memory tools) so that measurements can be made simply in extreme environments without the use of an electric wireline. The use of a "slick" line means that a logging service vehicle is not necessary for completion of a downhole measurement since well-site equipment can be used to deploy the tools.

Objective 2. To insure that the cost of tools and/or logging services is not prohibitive to the geothermal industry.

Objective 3. To develop appropriate inversion algorithms that relate tool response to geothermal production parameters.

Objective 4. To transfer tools and software to the geothermal and geothermal-support industries by integrating industry personnel in Objectives 1-3.

PROJECT STATUS

A. Computers for Memory-Logging Devices

An inherent difficulty with past "memory" tools is that an operator has been forced to "fly blind". The new generation of tools will be "smart" in the sense that some decisions may be made by the tool itself through appropriate programming of the on-board computer. A goal is to make this programming simple so that it can be done by inexperienced personnel.

The Onset Computer Company has a line of suitable computers, but they were not tested at high temperatures. A facility for temperature testing the Onset Model 5F computer was designed and used to prove this computer to repeated temperature cycles to 150°C. This means that the computing problem is approaching a solution.

B. Calibration of Memory-Logging Devices

Memory loggers are inherently self-contained. Thus, all measurements of voltage, frequency, phase, etc. must be made remotely, and appropriate standards for these measurements must be carried on-board the tool. Stated otherwise, references

traceable to US National Standards must exist in extreme environments.

Sandia standards, traceable to the National Institute of Science and Technology, were established in the Memory-Logging-Tool laboratory. These standards are used to qualify the analog-to-digital converters and the clock on the Onset Model 5F computer as the computer is being temperature-cycled. Similar standards will be used to calibrate all sensing devices; the DOE facilities at Grand Junction, CO, and Grants, NM, will be used to calibrate the spectral gamma tool.

C. Dewar/Pressure Vessels

The Dewar/pressure vessel is the one most costly item in a modern high-temperature logging system. A Request for Proposals was published to find a company willing to help develop a low-cost Dewar/pressure vessel, and the award was made to National K Works to design and vet a new protective vessel. The cost of the new Dewar system will be about \$7,000, and this value represents the major cost of the pressure/temperature tool.

A design constraint of the new Dewar/pressure vessel is that it be no longer than a pair of skis. The concept here is that all components of a logging system--electronics, spare parts, pressure vessel, etc.--be transportable by a logging engineer using ordinary commercial air carriers. This vision is considerably different from the present services that require mobilization of special trucks and supportive crews. It is hoped that the cost savings will provide the impetus for the establishment of logging as a common operation in geothermal operations.

D. Costs

Memory tools are relative new, and prototype tools have proven to be expensive. For example, the first slim-hole (2 inches diameter), high-temperature (750 degrees Fahrenheit) temperature-measuring tool cost \$58,000. Presently, with increases in technology and using a more practical approach to engineering design, similar tools should cost less than \$13,000 (Note, this figure includes 30% profit for a manufacturing company.). It is envisioned that this amount will drop even further.

An evolutionary step is to broaden the measurement capabilities by developing a modular tool that features a universal computer/battery section that may be attached to one or more sensor packages. While this vision is somewhat in the future, it is feasible, and it will result in further cost reductions.

E. Inversion of Tool Data

Inversions algorithms relate a tools response, be it formation temperature, gamma ray count rate, etc., to formation parameters of interest. Often these algorithms are formation-dependent, and proprietary. The intent of the Memory Logging Tool Program is to work with industry, to the extent possible, in the development of inversion algorithms. Interactions with the US Continental Scientific Drilling Program and the NSF Ocean Drilling Program are being developed.

PLANS

The ultimate goal of the Memory Logging Program is to establish a credited logging industry supportive of the needs of the geothermal industry. The first tool will be a low-cost temperature-pressure tool suitable for use in slim, diamond cored holes. The first few copies of the tool will be loaned to geothermal operators so that they may see the gains that are made when logs are run often. Even such simple logs will aid in reservoir evaluation and in establishing engineering solutions for such difficulties as lost circulation control.

The second tool is a spectral gamma device for the identification of Potassium, and the daughter products of Uranium and Thorium. These elements are carried by hydrothermal solutions, and they can be used to identify fractures when they are precipitated on, or leached from, the wall rock. The tool can also be used to identify scaling conditions when it occurs exterior to casing material, and it will be an indicator of lithology.

Another effort involves the development of a high-temperature fluid sampling device and the ancillary equipment required to analyze sampled specimens. The sampler tool will complement the spectral gamma tool in that it further constrain the lithology by identifying dissolved formation materials. The sampler program receives support from the DOE/OBES and the Ocean Drilling Program, and it will utilize industry wells for the testing of the combined sampling-analysis system. This thrust is another example of technical interactions between scientific programs and geothermal operators.

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SLIM-HOLE DRILLING FOR GEOTHERMAL EXPLORATION

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ABSTRACT: Drilling production-size holes for geothermal exploration puts a large expense at the beginning of the project, and thus requires a long period of debt service before those costs can be recaptured from power sales. If a reservoir can be adequately defined and proved by drilling smaller, cheaper slim-holes, production well drilling can be delayed until the power plant is under construction, saving years of interest payments. In the broadest terms, this project's objective is to demonstrate that a geothermal reservoir can be identified and evaluated with data collected in slim holes.

We have assembled a coordinated working group, including personnel from Sandia, Lawrence Berkeley Lab, University of Utah Research Institute, US Geological Survey, independent consultants, and geothermal operators, to focus on the development of this project. This group is involved to a greater or lesser extent in all decisions affecting the direction of the research. Specific tasks being pursued include:

- Correlation of fluid flow and injection tests between slim-holes and production size wells.
- Transfer of slim-hole exploration drilling and reservoir assessment to industry so that slim-hole drilling becomes an accepted method for geothermal exploration.
- Development and validation of a coupled wellbore-reservoir flow simulator which can be used for reservoir evaluation from slim-hole flow data.
- Collection of applicable data from commercial wells in existing geothermal fields.
- Drilling of at least one new slim-hole and use it to evaluate a geothermal reservoir.

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 impose 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 research and development is the primary rationale for DOE's support of technology development.

A recent systems analysis (Pierce and Livesay) identified drilling costs associated with exploration and reservoir assessment as a major factor affecting future geothermal development. The geothermal industry (utilities and geothermal operators) needs to reduce exploration and reservoir assessment costs in order to be competitive in meeting the expanding requirements in the West for environmentally benign, alternative energy sources. Slimhole drilling has been shown (Walker and Mi'heim) to reduce oil and gas exploration costs by 25 to 75%; however, the more hostile conditions for geothermal resources present technology challenges which must be solved before the cost impact can be thoroughly evaluated. Once demonstrated, slimhole drilling technology will have application to geothermal exploration and reservoir assessment in both the U. S. and international markets.

The principal reason for the lower cost of drilling slim-holes is the smaller size of crews and equipment. This reduction in drill-site size, road preparation, mobilization, and human traffic is also critical in minimizing environmental impact. If geothermal development follows its expected expansion into the Pacific Northwest, a relatively benign environmental presence will be critical to public acceptance and progress. Smaller equipment is also especially appropriate for geothermal exploration in Third World countries, or wherever financial and institutional support are minimal.

RESULTS TO DATE: Early activities in the project were concentrated on a survey of the geothermal industry to specify their exploration needs and to select areas of research where Sandia could provide effective help. There is considerable industry interest in slim-hole exploration, and it has been used in a few special cases (Combs and Dunn), but is not widely recognized as being informative enough to secure power plant financing. Results of the survey convinced us to begin a program of research into the validation of slim-hole drilling as an exploration tool.

Later, we addressed collection, evaluation, and combination of existing wellbore-flow computer codes, which will be used for the analysis of measurements made in the geothermal field at Steamboat Hills, near Reno, Nevada. Sandia has signed an agreement with Far West Capital, the company which owns and operates a 24MW power plant there, which allows testing of their existing core holes for comparison with existing production wells. Near the end of the Fiscal Year, we

performed flow and injection tests with simultaneous pressure-temperature-spinner logs in three core holes at Steamboat Hills.

Specific results for the past fiscal year were:

- An industry survey identified several sites (e.g., Steamboat Hills, Desert Peak, Coso, Roosevelt Hot Springs; see Combs and Dunn) where reservoir parameters measured in slim-holes and production-size wells could be compared.
- Flow and injection tests, with accompanying pressure-temperature-spinner logs, on coreholes at Steamboat Hills yielded flow data which were in excellent agreement with results obtained by using measured downhole conditions as input for wellbore simulator codes. This is necessary for extension of specific results at a well-characterized reservoir like Steamboat Hills to a more general predictive capability.
- Investigation of existing wellbore and reservoir codes indicates that these can be combined and/or slightly modified to produce a useful tool for analysis of reservoir parameters from wellbore flow data.

PLANNED WORK: For slim-hole exploration to become widely useful, it must be accessible to the small, independent geothermal developer. Our ultimate product will be the tools to bring about that result. These include, but are not limited to, the following:

- Guidelines for drilling and completing exploration slim-holes.
- Recommended test procedures and strategies, including data requirements, for the slim-holes.

- Improved downhole instrumentation to collect needed data.
- Data interpretation techniques, possibly in the form of a PC-compatible flow simulator which could be distributed at a nominal expense to independent developers. Use of this software would allow basic reservoir evaluation from slim-hole data and, once accepted as an industry standard, would be considered sufficient support for development financing.
- Publication of the analysis and experimental procedures which have led to the above products.

Successful technology transfer will require broad dissemination of our test results and analysis. This can be done by sponsorship of industry workshops, publication in technical journals, appearances at professional meetings and reviews, and personal contact through the working group and industrial partners.

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ENERGY CONVERSION

**Chairperson: Donald Stock
Oxbow Power Corporation**

NREL Energy Conversion Panel Review

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INTRODUCTION

On April 26, 1993, the NREL Energy Conversion Panel met to discuss the DOE Geothermal Program and to consider the direction that this program should take with regard to energy conversion technology. The results of these discussions are outlined below.

The Energy Conversion Panel agreed that DOE support is most appropriate in those areas that serve to strengthen the role of the geothermal industry in meeting the nation's energy needs. Discussion of the magnitude of this role indicated that the participants believed that while there may be thousands of MWs that could be brought on line over the coming decades, without improvements in technology and economics, only a small fraction of this potential would be realized. The greatest need for support is in the field of exploration, but the Panel identified a number of areas of investigation related to energy conversion technology that would be highly beneficial to the industry.

Ideally, DOE projects should result in widespread benefits, and the Panel looked for those projects that had the greatest degree of commonality between industry participants representing a range of technologies. Despite this objective, the industry is small, and when further subdivided into the different technologies and reservoir environments such as dry steam, flash plants, hypersaline brines and binary systems, each of which have their own sets of impediments to widespread expansion, it can be seen that many projects will be of most benefit to a relatively small number of participants. Still, there are clearly some projects with broad appeal, and others, while of benefit to a narrower group, are good candidates for support because of their potential impact on the industry.

The panel discussed a wide range of projects, both specific and general, which should be considered for further DOE support. The consensus was that support was most needed in three main areas:

- improvements in the cost competitiveness of new steam turbine plants
- improvements in the utilization of troubled or declining resources
- improvements in the utilization of low and medium temperature resources

A summary of some of the possible projects discussed in each category is contained below.

STEAM TURBINE COST COMPETITIVENESS

The panel was advised that the Electric Power Research Institute (EPRI) has initiated a study to develop innovative features to be incorporated into the next generation of geothermal power plants. Phase I of this project is to consider ideas for improvements to each item of equipment in a geothermal plant, and to evaluate their potential for improving the overall economics of a new plant. Phase II would involve industry cost sharing to field test some of the more promising proposals from Phase I. The panel considered that DOE support of this project would be a cost effective means of increasing the technological strength of the industry.

Another project that was considered promising was the investigation of variable speed centrifugal compressors for non-condensable gas removal. Existing equipment, either steam jet ejectors or liquid ring vacuum pumps are relatively inefficient and contribute to high levels of plant parasitic losses.

Support was expressed for work on advanced heat rejection concepts, particularly building on concepts already developed for the OTEC plant.

Corrosion and scale control are areas where geothermal developers and operators would benefit from improvements. In particular, improvements which allow a lower brine rejection temperature than is currently possible because of scaling problems would significantly improve the overall efficiencies of new plants, and thereby improve their competitiveness. Continued development of materials and coatings to control corrosion and scaling, particularly for hypersaline brines, but also for more benign environments, is recommended, as is continued work on bioremediation of geothermal brines and other wastes.

IMPROVEMENTS IN THE UTILIZATION OF DECLINING RESOURCES

The objective of the Energy Conversion Panel in this area is to look at means of mitigating the effects of declining output through improvements to conversion processes. The Geysers field is the highest profile example of a field that is in decline, but as other fields mature, the issue of declining resources may become more widespread.

The major project considered in this category was investigations into dry cooling systems. This project would have widespread benefits. In the Geysers, it would lead to greater recovery of condensate, and therefore higher rates of injection. In turn, this should lead directly to more regeneration of steam in the reservoir. In liquid dominated reservoirs, it has the potential to substantially reduce the net mass extraction from the reservoir, and dramatically extend the reservoir life. In arid regions where makeup water is not available, particularly for closed loop systems, more cost effective dry cooling would be of major benefit.

LOW TEMPERATURE UTILIZATION

The main area of interest regarding low temperature utilization relates to improvements in cycle design for binary systems. This includes further field testing of binary cycles utilizing metastable thermodynamic conditions through part of the turbine, which theoretically give improved efficiencies. It is recommended that this project be continued to the point where results can be demonstrated on a real turbine.

Further work on refining working fluid properties for binary systems would be beneficial, and in this regard, it was noted that there was potential to combine with other industry groups with areas of interest overlapping with those of the geothermal industry.

INSTITUTIONAL BARRIERS

As a final comment, the panel noted that there are a number of institutional barriers to the more widespread adoption of geothermal energy, including, for example, utility competitive bidding procedures, and the changing role of the various regulatory bodies. These are not specifically within the scope of the Energy Conversion Panel, but the panel views some of these issues as major impediments, and wishes to ensure that they are not overlooked.

ENERGY CONVERSION OVERVIEW

David B. Lombard
U.S. Department of Energy
Washington, DC

Energy Conversion is the last major step in the process of transforming a geothermal resource to electric power. The cost of constructing a plant and its associated plumbing accounts for up to half of the initial investment in a typical geothermal power project. Consequently, the conversion system offers a broad target for cost savings important enough to be reflected prominently in the cost of power. And because the plant and the above-the-ground piping and equipment are the most visible parts of the system, they are the most likely candidates for criticism on environmental issues. We hope that this session will show what the DOE geothermal research and development program is doing to reduce the cost and increase the environmental acceptability of geothermal energy conversion systems.

Our past program priorities in Energy Conversion have been motivated primarily the former. It still is critical. But as this industry begins to expand beyond CA and NV, and as public perceptions about energy sources continue to change, the geothermal industry -- and we in government -- will find our joint efforts to develop new technologies increasingly driven by environmental concepts.

In recent years, as these R&D efforts have faced extraordinary budgetary and policy pressures, we have adjusted the program to improve its responsiveness to industry needs, and have turned to industry -- not only for cost sharing on projects of mutual interest -- but

also for increasingly deeper industry participation in program planning and monitoring. The papers presented in this review session show some of the early results of this increased cooperation, as well as the increasing influence of environmental concerns in our program planning. Hopefully, they also will foreshadow future trends in this program area. In the overview, I would like to draw your attention to some of the highlights of the work you will review this morning. But before I begin that, I would like to make three announcements:

First, due to time limitations, Gene Premuzic, whose work really belongs in this session, will describe his innovative work on the bioremediation of geothermal byproduct materials later today as part of the "Potpourri" section. It's a very exciting technological breakthrough and I recommend that you go to hear him.

Second, George Darr of the Bonneville Power Administration will present a quick update on geothermal development in the Pacific Northwest at that same session. These developments are particularly relevant to the geothermal industry because geothermal power will find economic competition in that region from both conventional and other renewable energy resources. The geothermal potential of the Pacific Northwest is huge because of the great abundance of geothermal resources there, even though they are hard to locate, and because of the accelerating market demand. But

competition also will be conducted in a strong atmosphere of environmental acceptability, in this scenic part of the nation, where environmental sensitivities run as deep as they do in California, and where people have a historical tradition of working together to resolve such issues. So please listen to George Darr today. Third, during the past year or so, we have been in the process of transferring responsibility for the Energy Conversion parts of the DOE Geothermal Energy Program to the National Renewable Energy Laboratory in Golden, Colorado. This progress will be completed by the end of the fiscal year. I ask you to welcome that Laboratory's John Anderson and his colleagues to the geothermal industry and to extend to them every courtesy in getting up to speed.

Now on to the overview highlights. These are but a few of the exciting things we have done and are doing in the geothermal energy conversion area.

The Idaho National Engineering Laboratory has completed a series of experiments testing the industry codes used in designing certain geothermal heat exchange systems. This year the National Renewable Energy Laboratory is analyzing the data. We believe that the final result will point the way to significant reductions in plant costs and increases in efficiency.

We also have made excellent progress on an experimental program that uses a laser instrument to explore condensation in supersaturated expansion at the output end of a turbine inlet nozzle. If a commercial high pressure turbine on a geothermal binary system could be operated in this mode without blade degradation, one could increase power output by up to 10 percent with no increase in thermal input to

the system. We hope to find an opportunity for further testing at a commercial geothermal site. The DOE geothermal heat cycle research facility near Holtville, CA where this work was done, is scheduled to be closed down permanently by September 30th of this year.

The National Institute of Science and Technology is calculating and measuring the thermophysical properties ammonia - water mixtures so that plant designers can calculate their performance characteristics as binary cycle working fluids. The result will be improved plant designs capable squeezing more kilowatt-hours out of each pound of geothermal fluid.

The National Renewable Energy Laboratory is beginning work on a project to reduce costs, water consumption, and visible atmospheric emissions in heat rejection systems. This program has the potential for substantial economies in areas where surface water for cooling is expensive or simply not available, and for improving environmental visual acceptability.

Chemically aggressive geothermal fluids demand corrosion-resistant plant hardware. Such hardware often is constructed of expensive alloys of steel. Brookhaven National Laboratory scientists have developed an inexpensive thermally - conductive material that can be used to line well casings, heat exchanger tubing and other surface plant equipment. These linings are believed to resist scaling as well as corrosion. Engineers at the Idaho National Engineering Laboratory and the National Renewable Energy Laboratory have designed and built a portable test skid with the lined tubing. It will be tested this year at an industry site.

Again working with industry, Brookhaven has made excellent progress on a chemical coupling system to bond temperature-resistant elastomers (Rubber-like materials) to steel. Heretofore, the rubbery materials has defied all attempts to get it to stick to steel under geothermal field conditions. This situation poses a problem for geothermal developers: downhole and plant equipment and tools designed for petroleum industry use often fail when exposed to geothermal conditions. The new bonding technology will upgrade this essential hardware for geothermal service.

Two additional items on the Brookhaven work agenda actually are more relevant to drilling than energy conversion, but are reported here for convenience: 1) cements designed for use as lost circulation materials -- to plug subsurface fractures in wells being drilled; and 2) advanced cement formulations, lightweight and resistant to geothermal environments, for use in cementing casing into geothermal wells. Both efforts will contribute to economical drilling and to geothermal wells that have minimal environmental impact.

OVERVIEW OF THE GEOTHERMAL ENERGY CONVERSION EFFORTS AT NREL

John V. Anderson
National Renewable Energy Laboratory

ABSTRACT

Within the past year, several elements of the Geothermal Energy Conversion Program has been transferred to the National Renewable Energy Program (NREL, formerly SERI). NREL is working with the DOE Geothermal Division to maintain an aggressive industry orientation for these efforts. Although NREL's participation in the program has been too brief to produce substantial results, this paper will describe some of the relevant NREL experience in heat cycles and power generation systems, outline the current structure of the program for fiscal year 1993 (FY 1993), and briefly describe some of the efforts under consideration for FY 1994.

INTRODUCTION TO NREL GEOTHERMAL EFFORT

NREL involvement in advanced heat cycles and power generation dates back to the establishment of SERI in 1979. It was recognized at that time that cost-effective development of renewable resources would place significant demands on both the cost and the efficiency of the power generation equipment. Over the years, NREL has received a variety of awards and commendations for their contributions to the field of advanced power cycles.

The team currently working on the Geothermal Program has substantial background in using low- and intermediate-temperature heat sources for power generation. Team members have particularly strong capabilities in heat rejection subsystems, direct contact condensers, and rotating machinery. The most recent project undertaken by this group was for the Ocean Thermal Energy Cycle Program, where the challenge was to develop electric power from temperature differences as small as 20-30°C. A net power-producing plant based on NREL-developed designs is just now coming on line in Hawaii.

Since its inception, NREL has had a strong technology transfer component to its mission, and has worked to maintain close ties with the industry that is involved in commercializing renewable technologies. One of the principal objectives of the NREL geothermal effort will be to maintain a strong tie with the geothermal industry through industry associations and through contacts and projects with individual companies and plants. As part of that effort, NREL has been organizing meetings of the Technical Advisory Group and the Energy Conversion Panel, industry groups that offer guidance and advice on the direction of the DOE and NREL efforts.

FY 1993 GEOTHERMAL ENERGY CONVERSION ACTIVITIES

The energy conversion activities at NREL and the Golden Field Office of DOE cover a substantial range of topics. The following sections describe each of the major activities underway in FY 1993.

Advanced Heat Rejection

The objective of this effort is to identify and evaluate promising advanced heat-rejection options that will reduce water consumption and potentially improve heat rates in geothermal power plants.

Each geothermal power plant has a nearly unique set of characteristics, such as water availability and economics, climate, and environmental or other siting issues, that drive the design and operation of the cooling system. Based on this, it is important for the developers or operators of a plant to understand both the economics and the technical implications of the cooling options available to them. In response to this need, the task will:

- Identify and characterize the range of heat-rejection options
- Define the cost-effectiveness of these options on a basis that accounts for water conservation objectives
- Optimize the design and operation of these heat rejection systems in geothermal plants
- Test this methodology in collaboration with industrial partners for specific power plants.

Considerable information has been developed to model the thermal performance of plants using evaporative cooling as well as condensation or sensible heat exchange to an air stream. Predictions of performance and cost estimates for some of the available options were conducted mainly in the mid-70s to early 80s. Construction costs and operational experience of some advanced heat-rejection systems in power plants are also available.

These models need to be updated and expanded to incorporate recent developments in heat-rejection technologies, innovative approaches, direct-contact condensers, advanced heat-exchanger materials, and water-conserving operational strategies. The costs of these options also need to be

determined or updated in order to carry out an economic analysis in light of the current market and environmental conditions. The analysis will also review and incorporate the pertinent information recently developed and demonstrated in commercial refrigeration equipment applications.

This study will address critical issues such as overall thermal performance of the plant, land-area requirements, water consumption, steam-plume discharge, ambient temperature interactions, and other environmental impacts.

Based on their interest in The Geysers, Pacific Gas and Electric (PG&E) has also agreed to collaborate in this task. This collaboration will result in development of useful general tools for assessment of advanced cooling options that address some of the concerns of industry. It is also expected to provide near-term application of the technology at one of the PG&E sites. Other industry participation representative of other field conditions will be sought on an on-going basis, to provide additional guidance, review, and validation of the effort.

Heat Cycle Research

This is a subcontracted effort that will document the work done over a number of years by the Idaho National Engineering Laboratory (INEL) on a number of "advanced concepts" to improve binary cycle performance.

At the time that the Heber Binary Plant was being constructed, INEL began to consider a second-generation binary geothermal plant. Analytical studies have developed a number of "advanced concepts" that improved the performance of binary plants as measured by increases in the net geofluid effectiveness (net electrical energy produced per unit mass of geofluid, e.g., whr/Kg). At the same time the impact of these improvements on the cost of producing electricity was determined, along with the effect of the resultant increases on the market penetration.

All work is completed on this effort except for reporting the final results. This will consist of three reports to be issued by the end of this calendar year. The first report will bring together all of the work done on the project (with the exception of the supersaturated turbine expansion task that will be documented by INEL). This will include early analytical and experimental work, along with more recent experimental studies of the system with the condenser at a 60° inclination from the horizontal. This report will cover the material to a "reference" depth.

A second report, which will be more of a "guidebook" or "Users Manual", will be prepared to outline the significant lessons learned from the program and discuss how the results of the program effort can be used by plant engineers and designers to produce the most cost-effective binary power plants.

Drafts of both of these volumes are expected by the end of FY 1993.

Field Testing of Polymer Concrete Lining (PCL)

The polymer concrete lining (PCL) material developed by Brookhaven National Laboratory (BNL) has been recommended for use in heat exchangers in aggressive geothermal brine environments. PCL, when applied to a low-cost base metal surface (such as carbon steel), will protect the metal surface from exposure to a corrosive environment. Previous results have also indicated that PCL should reduce the build-up of fouling or scale deposits, without significantly reducing the thermal conductance.

NREL and BNL have undertaken a joint research task to investigate the heat transfer, anti-corrosion, and anti-scaling performance of polymer concrete lining for use in heat exchangers and to compare it to the performance of heat exchangers with conventional high-alloy steel tubes.

Analytical simulations of the PCL/carbon steel tubes and the high-alloy steel tubes have been conducted at NREL. Comparison of the results of this study with the measurements performed by BNL indicated that the PCL material had substantial potential to provide thermal conductance comparable to the high-alloy tubes.

These results bolstered the idea of conducting field experiments to characterize the anti-fouling and anti-corrosion performance of PCL tubes. A Cooperative Research and Development Agreement (CRADA) with Red Hill Geothermal for conducting field tests at Del Ranch Power Plant has been signed. These experiments will be conducted with geothermal brine at working temperatures and pressures. The PCL tubes will be mounted in parallel with other materials such as AL-6XN (a high-alloy steel tube).

The primary method of characterizing the anti-fouling and anti-corrosion performance of the material will be post-test dissection and examination. However, NREL has also identified a non-destructive technique for inspecting the thickness of the PCL in the 6 m (20 ft.) long carbon steel tubes. In this technique x-rays are used to produce detailed images of tubes. (This technique is commonly used for weld testing.) Resolution of the x-rays is quite high, and

they should allow detailed comparisons of pre- and post-test conditions.

The tests should be completed in late summer of 1993, and results should be documented by the fall.

DEMONSTRATION OF IMPROVED ELECTRIC GENERATION TECHNOLOGY

This project is being conducted by the Golden Field Office of the United States Department of Energy, with technical support from NREL. The objective of this project is to demonstrate the economic benefits of improved electrical power generation systems for geothermal applications. The Golden Field Office issued a solicitation requesting proposals for Cooperative Agreements.

The solicitation seeks to establish the economic benefits as derived from improvements in the technology of generating electricity from geothermal energy by either a) increasing power plant efficiency; b) reducing plant capital costs; c) reducing plant operating and maintenance costs or; d) increasing plant reliability.

Proposed projects are expected to demonstrate an innovative concept that is not currently used in commercial geothermal power plants. The technology demonstration must be applicable to performance of a commercial unit. A minimum of 50% cost sharing is required for the entire project. Awards for this solicitation are expected shortly.

IDEAS FOR THE FY 1994 GEOTHERMAL ENERGY CONVERSION ACTIVITIES

Early discussions on the FY 1994 program activities have just begun, and the specific projects that are carried out will depend heavily on the availability of funding and on overall DOE objectives. However, a number of ideas have already been suggested by the geothermal industry, and these are under consideration along with ideas generated from within the program.

Many of the activities begun in FY 1993 are likely to be continued into FY 1994. This will likely include the Advanced Heat Rejection task, which will be moving into an advanced phase of the effort, and will be seeking other industrial partners to test and validate the range of options and the methodology for evaluating those options that was developed in FY 1993.

The documentation of the extensive INEL effort in binary cycle improvements should be completed in FY 1993. However, given an emphasis in the DOE Geothermal Energy Conversion Program on binary cycles, work focused on consolidating the research already conducted in this area will be likely. One example is a cooperative

commercial demonstration of the meta-stable expansion concept developed by INEL. Other efforts in this area that have been suggested include blanketing effects in condensing and evaporating multi-component mixtures.

Results from the field testing of the PCL material will be available in the beginning of FY 1994, and the level of ongoing efforts in that area will be determined by analysis of those results. Several industry representatives have suggested that a broader materials effort might be useful to the geothermal industry. The DOE program has developed a significant capability in materials development and laboratory testing at BNL, and the PCL tests represent a strong effort to validate those laboratory results with field testing. If carefully focused on problems of concern to the geothermal industry, the combination of these capabilities might be able to offer some substantial value to the industry.

Another effort that is beginning in FY 1993 that will likely follow on into FY 1994 is the development of a multi-year plan for the energy conversion effort. Because it is so important that this document should reflect the inputs of the geothermal industry, we will be soliciting, formally and informally, inputs and reviews from industry associations and from individuals active in the industry. Only by freely discussing and understanding the needs and the challenges of the geothermal industry can the DOE Geothermal Program be as responsive and useful as possible in the years to come.

INVESTIGATIONS OF THE CONDENSATION BEHAVIOR OF SUPERSATURATED TURBINE EXPANSIONS

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ABSTRACT

In the Heat Cycle Research project, investigators are developing a technology base permitting an increased utilization of the moderate-temperature, liquid-dominated geothermal resource for the production of electrical power. Project investigations have focused upon improvements to the binary cycle which has the potential for a higher utilization of the resource, in terms of power produced per unit mass of brine, than the flash-steam cycle. Investigations to date, have confirmed the technology required to incorporate a number of the concepts which will result in the binary cycles having a performance approaching practical thermodynamic maximums. The final concept to be investigated for this optimized cycle, is the utilization of supersaturated turbine expansions. In these processes, the working fluid is expanded through the two-phase region, exiting the turbine at slightly superheated conditions. If during this expansion process, the working fluid was at equilibrium conditions, liquid condensate would form. If it can be shown that this expansion is a metastable process, where the condensate does not form, then additional cycle performance improvements can be realized. Relative to the performance of the advanced cycle, an additional 8% improvement in the brine utilization can be realized if it can be shown that these expansions can proceed without droplet formation and without significant performance degradation. Studies also indicate that performance cycles using single component working fluids and operating above the critical pressure can also realize performance improvements, though perhaps not to the same degree. Investigations in the project are defining those conditions which result in the formation of condensate, and whether the theoretical projections relative to when condensate would form, remain valid.

BACKGROUND

The objectives in the Heat Cycle Research project are to develop a technology base that will result in an increased utilization of the moderate-temperature geothermal resource for the production of electrical power. Analytical studies^{1,4} conducted earlier in the program, have shown that significant performance improvements are possible. A subsequent study⁵ showed that the advanced plant using a Rankine binary cycle operating at supercritical turbine inlet conditions and utilizing a mixed hydrocarbon working fluid, would operate near the thermodynamic maximum imposed by practical operating limits (equipment constraints). Field investigations conducted at the Heat Cycle Research

Facility (HCRF) subsequently confirmed the validity of the assumptions made in the performance projections, and have shown the viability of the technology required to design and build the components necessary to achieve these performance improvements in a commercial facility.

The final of these advanced concepts to be evaluated with field investigations is the supersaturated turbine expansion. The hydrocarbon working fluids which provide the optimum performance for the resource temperature range of interest, are mixtures where the major component is isobutane. The isobutane fluid, as well as the mixtures, has a retrograde dew point, or saturation curve when plotted on a T-s diagram (see Figure 1); these fluids tend to superheat, or become drier, when the vapor is expanded. Typically the turbines driven by the expansion of these vapors operate in the region where the process remains "dry". This typical cycle is shown in Figure 1 as the process defined by points 1-2-3-4-5. Demuth¹ suggested the use of a modified cycle, as defined by points 1-2-3'-5, where the turbine expansion process passes through the two phase region, exiting the turbine at the dew point, or slightly superheated. This cycle was shown to result in an additional improvement in the performance of the advance cycle.

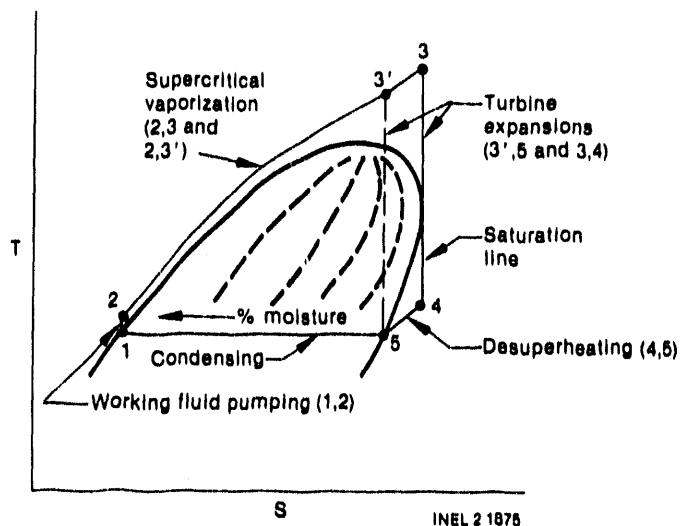


Figure 1. Binary Cycles Showing Two Types of Turbine Expansions

The expansion of a vapor into the equilibrium state two-phase region in a turbine is not unusual; it typically occurs in steam turbines. The "Wilson

Line" is frequently used for estimating the extent to which supersaturated water vapor can be maintained without condensation in a near-isentropic expansion. However relative to those expansions in a steam turbine, the supersaturated expansions of interest for the binary cycles would not necessarily be expected to behave the same. In a steam turbine, the condensation generally takes place at temperatures and pressures far from the critical values for water. In the expansions of interest with the hydrocarbon working fluids, the expanding vapor crosses the saturation line near the critical point. The water, in an expansion process in a steam turbine, tends towards a higher moisture content (becomes "wetter") as the expansion proceeds. In the expansion of these hydrocarbon working fluids, the moisture content first tends to increase until it passes the "knee" (the point on the saturation line where the entropy is at a maximum) on the T-s plot, then it tends to decrease or become "drier" on expansion. The properties of water and the hydrocarbon are also different, and those of the hydrocarbon less well known, particularly near the critical point.

Demuth⁶ theoretically examined the condensation behavior of these expansions for binary power cycles, and concluded that condensation droplets might not necessarily form when the process equilibrium states pass through the two phase region. Expansion processes which cross the saturation line near the critical point could result in the formation of condensation, however if droplets did form, they would be expected to remain small and tend to evaporate as the expansion process proceeded. As the entropy at which the expansion process crosses the saturation line increases, the tendency for condensation to occur would decrease.

PERFORMANCE IMPROVEMENT

Utilization of the supersaturated turbine expansions was projected to improve the performance of the cycle incorporating the advanced plant concepts previously investigated in the program. Relative to this advanced cycle, the utilization of the supersaturated turbine expansions was projected to increase the brine utilization by an additional 8%¹. The impact of the utilization of these expansions on the cost of electricity was also evaluated³, and shown to result in a decrease of ~5% relative to advanced plant.

The projected improvement in the cycle performance results from both decreasing the amount of energy required to vaporize the working fluid, as well as a shift in location where the minimum temperature difference occurs between the heating curve of the working fluid and the cooling curve of the brine; this is shown in Figure 2. As a result the brine can be cooled to a lower temperature, and less brine is required to vaporize a given quantity of working fluid.

The degree to which the brine utilization is increased by using these expansions depends upon a

number of factors, including the resource temperature, as well as the working fluid selected for the cycle. In general, for a given supercritical inlet pressure, as the resource temperature rises, the impact of these expansions on performance decreases. The impact of eliminating, or minimizing, the superheat in the vapor entering the condenser, can result in a decrease in the turbine exhaust pressure (lower condenser pinch point for fixed cooling water flow rate), or a decrease in the cooling water flow rate (for a fixed condenser pinch point). This decrease is potentially greater for a mixed working fluid as it does not condense at a constant temperature (as would a single component working fluid).

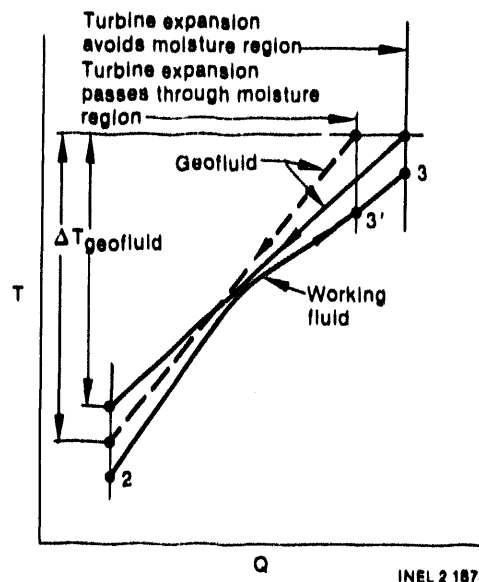


Figure 2. Temperature vs Heat Exchanged in Working Fluid Vaporization for the Two Types of Turbine Expansions

While the impact of these types of expansions on the cycle performance is potentially more significant with working fluid mixtures, supercritical cycles with a single component working fluid also yield a gain in performance. The following briefly summarizes the potential gain for a cycle using a single component working fluid. It does not represent an optimized cycle, though it is typical of the cycle utilized in existing facilities. The cycle selected for evaluation utilized an isobutane working fluid. The resource temperature was assumed to be 335°F. The turbine inlet conditions were assumed to be 285°F and 530 psia (just above the critical pressure of 529 psia). Though this inlet condition results in a turbine expansion well outside of the two-phase region, the conservatism is typical of that used in commercial facilities operating near these pressures. The turbine exhaust pressure was assumed to remain constant at 70 psia. The results of this evaluation are shown in Figure 3.

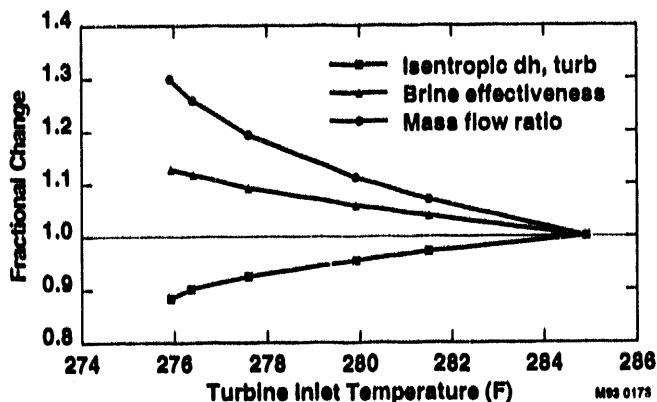


Figure 3. Impact of Supersaturated Expansions on Supercritical Cycle with iC_4 Working Fluid

In this plot, the turbine expansion (isentropic) would begin to pass through the two-phase region as the turbine inlet temperature is decreased below 280°F. From a turbine inlet temperature of slightly less than 276°F, an isentropic expansion to the 70 psia exhaust pressure would result in the vapor exiting the turbine within the two-phase region. As the turbine inlet temperature is decreased from 285°F, the isentropic enthalpy change (which represents the maximum work possible) through the expander also decreases; over the ~10°F range of interest, the isentropic enthalpy change in the turbine decreases by ~10% as the inlet temperature is decreased. Without a change in the ratio of the working fluid to brine flow rates, the brine effectiveness, as well as the plant output would decrease. However, as indicated earlier, and shown in Figure 3, the ratio of the working fluid to brine flow rates increases as the turbine inlet temperature is lowered. Over the temperature range shown, this the amount of working fluid which can be heated and vaporized by a given amount of brine increases by ~30%. Because of this flow increase, the brine utilization, or effectiveness, could increase by ~12%, if it could be shown that these expansions could proceed without condensate formation or degradation in turbine performance.

Although this example does not represent the impact on an optimized cycle, it is typical of existing operations and does show that the potential performance gains are not unique to power cycles utilizing mixtures.

FIELD INVESTIGATIONS

Demuth⁶ stated the major question to be addressed relative to attaining this performance improvement is: "Can the stable equilibrium states of a turbine expansion process pass through the two-phase region without resulting in sufficient condensation to reduce turbine performance, measurably, and/or to produce turbine damage?" The theoretical studies subsequently conducted to address this question, suggested that the expan-

sions of interest could proceed without condensate formation, however there were sufficient questions and concerns to warrant verification with field investigations.

To provide this verification, the project initiated a test program at the HCRF utilizing a two-dimensional expansion nozzle to simulate the near-isentropic turbine expansions of interest to determine those inlet conditions which resulted in the formation of condensate. The nozzle, which is shown schematically in Figure 4, has a window which allows the expansion process to be monitored either visually, or with instrumentation designed to detect the presence of condensate.

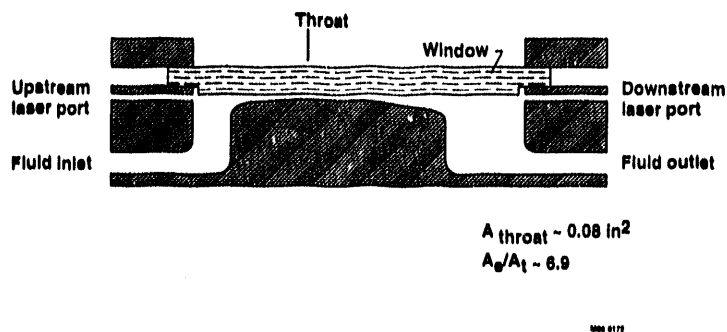


Figure 4. Schematic of Two-Dimensional Flow Nozzle

The theoretical studies⁶ indicated the most probable droplet resulting from homogeneous nucleation in the condensation process would contain only a few molecules as opposed to a large number. Because the expansion process tends towards less moisture, or drier, conditions, any droplets forming would lag in temperature relative to the surrounding vapor which is continually decreasing in temperature. The droplets, being at a higher temperature than the surrounding vapor, could no longer serve as a condensation site, thus new sites would have to form for the condensation process to proceed. It would be expected that any droplets forming would be expected to remain small, and perhaps evaporate as the expansion process proceeds.

In order to detect the presence of these small droplets, which might contain no more than a few molecules, a laser based technique was developed for the program by North Carolina State Agricultural and Technical University (NCA&T). With this system⁷, it is possible to detect particles as small as 10 angstroms in size. The basis of the technique is that particles of a size less than one third the wavelength of the incident light will scatter according to Rayleigh scattering theory. According to this theory, the intensity of the scattered light by very small particles will be the same in the forward as well as backward directions. By measuring the scattered intensity at two

or three different angles, the presence of Rayleigh scattering can be confirmed.

The system developed by NCA&T and subsequently installed at the HCRF utilized a Argon-Ion laser (operates at a wavelength of 488 nm) as the light source which would be passed through the two-dimensional nozzle during the simulation of expansions of interest. Any condensation droplets present during this expansion process would scatter the beam. This scattered light would be detected by photomultiplier tubes (PMT's) positioned at the nozzle window to detect the scattered light at different viewing angles.

In order to install this system at the HCRF, it necessary to modify this system to account for the safety considerations associated with the hydrocarbon working fluid. It was not possible to locate neither the laser or the PMT's in the nozzle area as they represented a potential ignition source for the hydrocarbon. The laser and PMT's were installed at a remote location (in the control trailer), and "connected" to the nozzle via fiber optic cables. The laser beam was "transmitted" to the nozzle through a polarization preserving fiber in order to maintain the polarization of the incident light (a requirement for the Rayleigh scattering measurements). Three light collecting lenses were mounted on a rail next to the nozzle windows. These lenses, which were focused on a small area within the nozzle, collected the forward and backward, as well as normal, scattered light and transmitted this light back to the PMT's.

The nozzle also had 14 pressure taps which allowed the pressure profile along expansion process to be monitored. If condensate did form, a weak shock was expected. A change in the pressure profile would provide an indication of a presence of the condensate.

The objectives of the field investigations with the nozzle were to 1) "map" the expansions of interest, identifying those nozzle inlet conditions which resulted in the formation of condensate, 2) determine the conditions under which condensate, once having formed, would evaporate, 3) determine the size of the droplets that formed, and 4) determine whether working fluid mixtures behave differently than the single component, isobutane working fluid being used for the initial testing. The accomplishment of the stated objectives was contingent upon the program requirement that testing be completed in sufficient time to allow for the completion of shutdown and closeout activities at the HCRF during FY-1993.

The procedure for "mapping" the condensate formation consisted of first establishing a nozzle inlet pressure at a level above the critical pressure. While maintaining this pressure, the inlet temperature was brought to a level which produced a completely dry expansion. The inlet temperature was decreased incrementally, and data collected to define the extent of condensation in the expansion process at each step. The inlet temperature was decreased until the expansion process was complete-

ly "wet". The extent to which condensate was present was determined by visual observations, the measured intensity of the light scattered by droplets present, and the nozzle pressure measurements.

With the identification of the inlet conditions at which condensation was initiated in the nozzle, the droplet detection system was utilized to attempt to size the drops being formed. Measurements of the intensity of the scattered light were made along the nozzle section where condensate was detected. While maintaining the nozzle inlet conditions, the intensity of the laser beam was varied, along with the polarization of the incident light and the sensitivity of the PMT's (supply voltage). The PMT output measurements provided an indication of the intensity of the light being scattered by any droplets present as the area of collecting lenses were focused on, was moved in and out of the nozzle region where condensate was forming. These measurements provided a more exact definition of where the condensate formation was beginning, as well as an indication of the size of the droplets present.

RESULTS AND CONCLUSIONS

The field investigations of the condensation behavior of the supersaturated turbine expansions were completed in mid-April, 1993 after five weeks of testing. Testing was terminated in order to allow sufficient time to complete the facility closure during FY-1993.

Because of the limited time available, these investigations were conducted only with the isobutane working fluid; no mixtures testing was conducted. The mapping of the nozzle inlet conditions to define those which resulted in condensate formation was completed for a range of pressures between 550 and 650 psia. In addition conditions resulting in condensate formation were identified when the exhaust pressure was varied along with the nozzle inlet temperature (while holding the inlet pressure constant). Limited testing was also conducted at a nozzle inlet pressure of 600 psia in attempting to size the droplets present as the condensation process started in the nozzle.

As the testing was just completed and little data evaluation has been done, it is premature to quantify any of the test results. The following observations however were made during the investigations conducted.

- The mapping investigations conducted confirmed that simulated turbine expansion processes whose equilibrium states pass through the two phase region do not necessarily result in the formation of condensate. As the point where the vapor crosses the saturation, or dew point, line approaches the critical point, condensate does form, even though an isentropic expansion to the exhaust pressure would result in the vapor being slightly superheated at that point. Until

the data has been examined in detail, it is not possible to state the degree to which these expansions can pass through the two phase region without condensate forming.

- The inlet temperature at which the onset of condensation occurs is repeatable for a given inlet pressure.
- At the onset of the formation of condensate in the nozzle, the droplets which form evaporate as the expansion process proceeds.

The testing conducted confirmed that relatively small changes in the nozzle inlet temperature can result in condensate formation, suggesting that a control system for a commercial turbine using the supersaturated expansions would be atypical. Although this control system might be different than that typically used, given the current state of the technology it should not preclude the use of these expansions.

The visual observations made with the nozzle suggest that it, or a similar device, might be utilized to provide a "site glass" to monitor the expansion process in a commercial turbine. The near-isentropic expansion of the vapor in the nozzle would simulate the expansion process in an impulse turbine; it might not, however, simulate the total expansion process in a reaction turbine, where a portion of the expansion occurs in the blading. If further analytical evaluation could confirm that the expansion process in a reaction turbine is no more severe, in terms of potential increase in moisture content, than near-isentropic nozzle expansion, then the nozzle could be similarly used for monitoring the process in a reaction turbine.

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Acknowledgement: Work 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.

GEOHERMAL MATERIALS DEVELOPMENT ACTIVITIES

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ABSTRACT

This ongoing R&D program is a part of the Core Research Category of the Department of Energy/Geothermal Division initiative to accelerate the utilization of geothermal resources. High risk materials problems that if successfully solved will result in significant reductions in well drilling, fluid transport and energy conversion costs, are emphasized. The project has already developed several advanced materials systems that are being used by the geothermal industry and by Northeastern Electric, Gas and Steam Utilities. Specific topics currently being addressed include lightweight CO₂-resistant well cements, thermally conductive scale and corrosion resistant liner systems, chemical systems for lost circulation control, elastomer-metal bonding systems, and corrosion mitigation at the Geysers. Efforts to enhance the transfer of the technologies developed in these activities to other sectors of the economy are also underway.

In FY 1992, the long-term hydrolytic stability and resistance to CO₂ attack of phosphate bonded calcium aluminate cements (CPC) were verified. Compared to conventional class H well cement which carbonized to form 9.5 wt percent CaCO₃ after exposure to a 0.5M Na₂CO₃ brine at 250°C for 7 days, the CPC produced only 0.2 wt percent in 120 days. Mixtures of the CPC with aluminosilicate-based hollow microspheres produced a slurry with a density of 10 lb/gal that when cured, fulfilled the requirements for geothermal well completions. Aluminum phosphate cements show equally promising results, but further characterization and long-term evaluations are necessary. Based upon these findings, plans to transfer the technology to industry by means of a Geothermal Drilling Organization (GDO)-sponsored program were formulated. Program participants will be BNL, a well service company and a major producer of geothermal energy. This effort will determine the technical and economic practicability of mixing and placement of large-scale quantities of the cements, and characterize their properties after one year downhole exposures at several sites. This GDO activity will start in the Spring of 1993.

R&D to determine the technical and economic feasibility of using thermally conductive polymer cement liners as a means for corrosion protection and scale minimization in heat exchanger applications, was continued. This work is being performed as a cooperative effort with the National Renewable Energy Laboratory (NREL) and Red Hill Geothermal. Analysis of the data from a FY 1991 field test using hypersaline brine indicated excellent corrosion protection and reduced surface fouling compared to

a AL-29-4C control. Work performed in FY 1992 included optimization of various process parameters for applying the liner, heat transfer calculations to define liner thickness limitations, and economic estimates. The latter indicated cost-effectiveness. Engineering-scale flow tests under conditions similar to those anticipated during "bottoming cycle" applications will be conducted starting in April 1993. An 80-ft long single tube shell-and-tube heat exchanger was fabricated for use in this test.

Considerable progress has also been made with chemical systems for lost circulation control. Previous work has indicated that a bentonite-ammonium polyphosphate-borax-magnesium oxide formulation mixed with fibers or particulates can be placed using three Sandia National Laboratories (SNL)-identified methods: 1) pumped through open drillpipe, 2) pumped through drillable straddle packer, and 3) pumped through drillstring-deployed porous packer.

In addition, exploratory experiments were started with three other cement systems: CaO·Al₂O₃-bentonite-ammonium phosphate-borax, CaO·Al₂O₃-CaO·(Al₂O₃)₂-bentonite-ammonium phosphate-borax, and class H cement-bentonite. Compared to the magnesium oxide-based system, the calcium aluminate formulations appear more suitable for the various placement technologies and yield more durable composites when exposed to moist environments.

Work to develop high temperature hydrolytically stable chemical coupling systems needed to bond elastomers to metal reinforcement continued. Until such systems become commercially available, it will not be possible to produce many important tools needed to reduce well drilling costs. Mixtures of polyaryl thermoplastic adhesives have given very promising results. Elastomer/metal joints bonded with these adhesives have survived 250°C hydrothermal conditions for several weeks without significant decreases in peel strength. These are remarkable results in comparison with previously tested commercial adhesives which typically undergo complete disbondment within 24 hr in similar environments. Additional work to enhance the bond strength is underway.

Cost-shared efforts with operators at The Geysers to evaluate the use of polymer concrete and polymeric liners to mitigate corrosion were continued. Small lined casing sections and full size collection piping tees are being tested. The results to date have been promising and larger-scale tests are anticipated.

INTRODUCTION

The Geothermal Materials Project is part of the Geothermal Division's (GD) Core Research Category and it has an impact on three tasks, Conversion Technology, Drilling Technology, and Reservoir Technology. The objective of the project is to provide information to industry which will result in reduced costs of geothermal well-field and power-plant design, construction, and operation. Specific goals to be achieved in realizing the objectives are to: 1) reduce costs associated with lost circulation episodes by 30 percent, 2) reduce the costs of deep wells and directionally drilled wells by 10 percent, and (3) reduce well-cementing problems for typical hydrothermal wells by 20 percent.

If the GD program objectives are to be met, it is essential that new materials of construction be available. In particular, improvements in lost circulation control, lightweight well completion materials, and hydrolytically stable chemical systems for bonding high temperature elastomers to steel substrates, would significantly reduce well costs.

As a result of the small and uncertain geothermal market, industry generally will not develop the special materials required for these critical components. Therefore, the purpose of the BNL project is to provide the technical and managerial basis for the performance of high risk/high payoff materials R&D so that the results are available to industry in the near term. To date, the work has resulted in many materials advances which are now routinely used by the geothermal industry. These include high temperature elastomers,^{1,2} polymer cement corrosion protective liners,³ and well cements.⁴

In FY 1992, R&D activities were focused on reducing well drilling, fluid transport, and energy conversion costs. Specific activities performed included lightweight CO₂-resistant well cements, chemical systems for lost circulation control, thermally conductive and scale resistant protective liner systems, corrosion mitigation in process components at The Geysers, and elastomer-metal bonding systems needed for use in high temperature well drilling and safety related applications. Technology transfer efforts also continued. Major findings during FY 1992 and the thrusts of the current efforts are summarized below.

1. Advanced High Temperature Lightweight Cements

- o Calcium and aluminum phosphate cements synthesized by acid/base reactions yield high strength CO₂-resistant cements.
- o Mixtures of hollow aluminosilicate-based microspheres with the cement matrix produce lightweight (10 lb/gal) cement slurries.
- o Long-term resistance to CO₂ attack demonstrated.

- o Large-scale mixing, placement and field exposure testing planned as a cooperative effort with industry.

2. Thermally Conductive Polymer Cement Liners

- o Field testing in hypersaline brine under heat exchange conditions indicated corrosion resistance and reduced fouling.
- o Thin (10-50 mil) and durable PC liners can be centrifugally cast on 20 ft lengths of 1-in. o.d. x 0.049-in. wall tubing and over welded joints.
- o Thermal conductivity of PCL carbon steel tubing ~60% of value for unlined carbon steel.
- o NREL preliminary analysis indicates adequate heat transfer and cost effectiveness.
- o Field testing for bottoming cycle applications in progress.

3. Chemical Systems for Lost Circulation Control

- o CaO·Al₂O₃-based formulations superior to MgO in strength, durability in moisture, controllability, and placement method versatility.
- o Compatibility between LCCM and fiber bridging materials confirmed.
- o Large-scale placement test using drillable straddle packer and downhole injector scheduled for Summer 1993 at SNL.

4. High Temperature Chemical Coupling Systems

- o Identified mixtures of polyaryl-type polymers as promising hydrolytically stable bonding systems.
- o An adhesive system consisting of 30% polyphenyletheretherketone, 70% polyphenylethersulfone meets the bond strength criterion.

5. Corrosion Mitigation at The Geysers

- o The use of polymer and composite liners on well head components can result in appreciable service life extension in low pH steam condensate environments.
- o Polymer composite lined tees in steam collection lines have given trouble free service for one year.
- o Technical feasibility established for the use of thin (.5-2μ) pre-ceramic coatings,

applied by sol-gel techniques, for turbine blade and pipeline protection.

6. Technology Transfer Activities

- o Consolidated Edison Company of New York R&D on steam district heating system utility vaults.
- o Long Island Lighting Company R&D on corrosion protection for air preheaters and turbine blades.
- o Gas Research Institute and Commercial R&D on corrosion protection for condensing heat exchangers.

RESULTS

1. Advanced High Temperature Lightweight Cements⁵⁻⁹

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. A recently identified problem is cement deterioration due to alkali metal catalyzed reactions between CO₂-containing brines and the calcium silicate hydrate compounds present in conventional well cements. Rapid reductions in strength, increased permeability, and corrosion on the outside surfaces of the well casing occur. Solving this materials problem is the goal of the current cement research activity.

The work is organized into five phases: 1) fundamental cement research, 2) mix design, 3) property characterization, 4) placement technology, and 5) downhole evaluations. Phases 4 and 5 are conducted as cost-shared efforts with industry to insure the practicability of the materials and technology transfer.

Phase 1 consists of fundamental work to synthesize calcium and aluminum phosphate cements and to elucidate the interactions that occur between them and a number of aluminosilicate-based microsphere fillers. State-of-the-art surface science analytical techniques are used in all parts of this phase. Phase 2 consists of the development of cement-filler mixtures and curing conditions to yield the desired properties. In Phase 3, the mechanical, physical and chemical resistance characteristics of promising formulations are determined before and after autoclave exposures to CO₂-containing hydrothermal fluids. The technical feasibility for use of the cement slurries in well completions using conventional placement technology is determined in Phase 4. This work includes the selection of retarding admixtures to extend pumpability and verification of this by the performance of consistometer testing in accordance with American Petroleum Institute standards. Industrial assistance in the selection of retarders is contributed by a well service company. In Phase 5, which is a cost-shared activity with a well service company and a well owner, the ability to mix and place the cements on a large-scale is

verified, and the long-term durability of samples cured in and exposed to downhole geothermal environments is determined.

In FY 1992, small-scale laboratory studies to determine the compatibility of several inorganic and organic microsphere-type fillers with phosphate modified calcium aluminate cements were successfully completed. Based upon the promising results, plans to transfer the technology to industry by means of a Geothermal Drilling Organization (GDO)-sponsored program were formulated. This effort will determine the technical and economic practicability of mixing and placement of large-scale quantities of the cement into geothermal wells, and characterize the properties of the cements after long-term downhole exposures at several geothermal sites.

In the laboratory studies, Phases 1-3, lightweight slurries were prepared by incorporating several types of microspheres into calcium phosphate pastes. The latter were derived from calcium aluminate cement as a base reactant and an NH₄H₂PO₄-based fertilizer as the acid reactant. Compared to the density of a neat calcium phosphate cement slurry which is 16 lb/gal, the addition of the microspheres reduced the density to the range 9 to 12 lb/gal. The density goal of the program is 10 lb/gal. These lightweight slurries were then cured in a hydrothermal environment at 200°C or 300°C. The following factors were found to govern the strength development and long-term stability of the cements: 1) phase composition and transformation of the matrix and the interfacial products formed by reactions between the microspheres and the cement, 2) changes in the microstructure developed within the matrix and at the matrix-microsphere interface, and 3) the susceptibility of the microspheres to hydrothermal decomposition. Aluminosilicate-based hollow microspheres produced the most suitable product. Its slurry density was 10.7 lb/gal, and upon hydrothermal curing at 200°C, it had a compressive strength >1000 psi. Autoclave exposures to Na₂CO₃ saturated brine at 250°C for 120 days indicated 0.2 wt percent conversion to CaCO₃. In comparison, conventional class H well cements yielded 9.5 wt percent CaCO₃ after only 7 days.

In FY 1993, aluminum phosphate cements will be fully characterized and then introduced into the GDO program for scale-up and downhole evaluation.

2. Thermally Conductive Polymer Cement Liners¹⁰

The technical feasibility for the use of high temperature composite materials for corrosion protection was demonstrated by BNL in the early 1980s, and since then they have been used successfully by the geothermal industry. It was then shown that significant increases in the thermal conductivity of the polymer-matrix composites could be achieved by the incorporation of high conductivity materials as fillers. In addition, it was shown that the addition of high temperature anti-oxidants into the composite significantly reduced the rate of scale deposition and adhesion to the surface.

Currently, work is being performed as a collaborative effort between BNL, the National Renewable Energy Laboratory (NREL) and private industry (Red Hill Geothermal, Inc.). BNL performs the fundamental and applied research necessary to define the polymer cement formulations, determines protective coating thickness requirements, and develops methods for the placement of thin, uniform coatings on heat exchanger tubes.

Engineering analyses and heat transfer tests are conducted by NREL. This work includes measurements of heat transfer coefficients, cost estimates, and the management of field testing.

Red Hill Geothermal is providing a field test site and ancillary equipment at a plant operating at the Salton Sea. Tests in an environment typical of that in a bottoming cycle application in a flash process are being performed.

The R&D is being performed in four phases. In Phase 1, a mechanistic approach is being used to obtain the fundamental knowledge needed to meet the research goals. The effects of compositional and processing variables on the resultant properties of the composite are determined in Phase 2. Parameters necessary to centrifugally cast smooth thin uniform composite liners onto long lengths (20-ft) of small diameter (0.75 to 1.0-in.) tubing are then defined. Phase 3 consists of the fabrication of test tubing at BNL and the performance of engineering-scale tests at NREL to measure fluid flow and heat exchange properties.

Field evaluations in bottoming cycle applications in one or more geothermal flash processes will then be performed in Phase 4 as cost-shared activities with the geothermal industry. This will be followed by the design of full-scale heat exchangers and cost analysis.

If the project is successful, high temperature thermally conductive and corrosion-resistant liner materials which can be used in heat exchanger applications in energy conversion processes will be available. Compared to the use of high alloy steels which are required to provide corrosion protection, the use of PC coatings on mild steel should reduce the tubing cost by 2 to 3 times.

In FY 1991, four 20-ft lengths of 3/4-in. o.d. by 0.049-in. wall, seamless hydraulic steel tubing were lined with a thermally conductive PC and sent to the Del Ranch Geothermal Power plant operated by Red Hill Geothermal for field testing. This test was completed and the tubes returned to BNL for analysis.

Examination of the tubes after 250 hr operation in hypersaline brine under heat exchange conditions indicated the following: a) scale was present on all tubes but the amount was less than that on the high alloy (AL-29-4C) controls. b) the thickness of the liner in each tube was very non-uniform and varied between an average of 0.006-in. to 0.024-in. and c) no corrosion of the metal beneath the PC was

detected. Thermogravimetric analysis (TGA) indicated there was no deterioration of the liner system. As a result of this field test, laboratory work was directed towards refining the centrifugal casting technique to produce a more uniform liner. This work is being done using tubing with a 1-in. o.d. Liners of relatively uniform thickness have been successfully cast in 20 ft lengths. Emphasis is being placed upon liner thicknesses ranging between 0.010-in. and 0.050-in. since calculations indicated that in this range, the thermal conductivity of the PC has minimal effect on the overall heat transfer coefficient.

In FY 1993 work to optimize the various process parameters for applying the liner and to determine the minimum liner thickness required to assure durability will be completed. NREL has completed heat transfer calculations and performed cost evaluations which confirmed the potential cost effectiveness of the materials system. R&D work to be completed this year includes the optimization of wall thickness with respect to corrosion resistance, and confirmation of the fabrication process. Engineering scale flow tests at Red Hill Geothermal, will then be conducted starting in the Spring of 1993.

3. Chemical Systems for Lost Circulation Control ¹¹⁻¹³

The objective of this activity is to reduce well drilling and completion costs by the development of advanced chemical formulations which can be used to rapidly plug lost circulation zones. The R&D is closely coordinated with well drilling and lost circulation control activities underway at SNL and consists of the development of cementitious formulations compatible with bentonite-containing drilling fluids and which will meet the mechanical and physical property criteria. Selection criteria include pumpability at various temperatures, degree of expansion upon curing, permeability, compatibility with fillers, and strength at early ages.

The most promising formulations are then optimized for use with one or more of the placement methods identified by SNL. This is followed by larger-scale pumpability and mud displacement tests.

The work is being conducted in four phases. In Phase 1, cementitious formulations are selected for evaluation. Emphasis is placed upon chemical interactions occurring between the cementing matrix and reactive fillers, and identification of the reaction phases formed. Mechanical, physical and chemical durability characterization is conducted in Phase 2. Optimization of the formulations for use with the advanced placement techniques identified by SNL is conducted in Phase 3.

Contingent upon these results, larger-scale laboratory and field tests are performed in which the cements and fillers are placed under simulated downhole conditions (Phase 4).

The most promising formulation identified to date consists of mixtures of magnesium oxide,

bentonite, ammonium polyphosphate and borax. Depending upon the placement temperature, control of the pumpability can be controlled by varying the magnesium oxide and borax concentrations. At placement temperatures $>60^{\circ}\text{C}$, microencapsulation of the magnesium oxide in organic compounds such as waxes, epoxies, or polyethylene is generally needed to extend the pumping time for >2 hr. The formulation was optimized for use with three placement technologies: 1) pumped through open drillpipe, 2) pumped through drillable straddle packer, and 3) pumped through drillstring-deployed porous packer.

Experimental work was started with three other cement systems: $\text{CaO}\cdot\text{Al}_2\text{O}_3$ -bentonite-ammonium phosphate-borax, $\text{CaO}\cdot\text{Al}_2\text{O}_3$ - $\text{CaO}\cdot(\text{Al}_2\text{O}_3)_2$ -bentonite-ammonium phosphate-borax, and class H cement-bentonite. Results to date indicate that the placement of these systems will be easier than for the MgO -based formulation, and upon curing, they yield higher strength more durable products.

In FY 1993, laboratory-scale experiments with calcium aluminate and calcium dialuminate-based systems will be continued. The most promising formulations from these systems will then be selected for optimization with respect to various placement methods and formation conditions. Larger scale flow and mud displacement tests will be initiated at SNL in mid-FY 1993. Placement utilizing a drillable straddle packer will be evaluated first.

4. High Temperature Chemical Coupling Systems^{14,15}

If the goals for reducing the costs of geothermal wells are to be met, it is essential that high temperature drillpipe protectors, blow-out-preventors, rotating head seals, and downhole drill-motor stators become available. The small size of the potential geothermal market currently precludes the performance of the private sector R&D necessary to produce these components.

In FY 1989, the GDO initiated industrial contracts to fabricate and test drillpipe protectors and rotating head seals. Future work on blow-out-preventors was planned. In the course of the work on the drillpipe protectors, it was determined that the lack of a hydrolytically stable chemical coupling system needed to bond a high temperature elastomer to metal reinforcement prevented fabrication of a tool which would meet GDO specifications. The development of the other tools was expected to be affected similarly.

As a result of this constraint, a program was initiated in mid-FY 1991 to develop advanced bonding systems. In Phase 1, a mechanistic approach is being used to obtain the fundamental knowledge needed to meet the project goals. Information elucidating interactions that occur at polyaryl-type polymer/conversion coating/metal and polymer/metal interfaces is currently being obtained. Laboratory characterization of promising bonding systems takes place in Phase 2. In Phase 3, the fabrication of prototype, and contingent upon the results, full-scale drillpipe protectors will be performed under

GDO sponsorship. Current commercial fabrication methods must be applicable. After successful engineering-scale evaluations, units will be field tested by GDO participants in Phase 4.

Polyaryl thermoplastic adhesives [polyether-etherketone (PEEK), polyphenylene sulfide (PPS), and polyphenylethersulfone (PES)], were evaluated. The tests showed that joints made of adhesive blends that contained greater than 50 percent PES survived simulated geothermal conditions (200°C and water vapor pressure of 200 psi) for several weeks without significant decrease in peel strength. The adhesives appear to be highly stable under the conditions required to make the joints and in subsequent exposure to the hot brine environment. These are remarkable results in comparison to previously tested adhesives, which typically undergo complete disbondment within 24 hr in hydrothermal environments. Currently, the peel strengths have not yet reached the generic goal of 40 psi. However, in some cases the actual peel strengths are not known because the elastomer tore before the interfacial bond failed.

Collaborative work with Regal International was started. In this effort Regal supplied metal coupons of compositions identical to those used as reinforcement in drillpipe protectors. BNL used these materials in bonding tests which were performed at Regal and BNL. Samples of the BNL-developed adhesives were then sent to Regal to determine their practicality with their commercial fabrication process.

In FY 1993, laboratory work to identify suitable bonding systems will be completed and work to transfer the technology to Regal International should be completed shortly thereafter. In FY 1994, work to optimize the systems for the lower temperature requirements for rotating head seals and blow-out preventors will be initiated.

5. Corrosion Mitigation at The Geysers¹⁶

The objective of the research is to decrease the operating costs of steam production, transmission and utilization at The Geysers by the identification and subsequent demonstration of low cost materials of construction which will withstand the highly corrosive acidic environments being encountered in some areas of the geothermal field. The approach being used to meet the project objectives is to optimize polymer and polymer cement formulations for specific end-use applications at The Geysers. The identification of needs, performance of prototype and full-scale field evaluations, and subsequent economic studies are performed as cost-shared activities with firms active at The Geysers.

Phase 1 of the project consists of the identification of specific materials problems, elucidation of the fluid environments, and the selection of candidate materials systems. Laboratory testing under simulated process conditions is then conducted to establish technical feasibility. Based upon these results, modifications to the systems are made

to maximize corrosion resistance. Phase 2 consists of small-scale field testing, and contingent upon the results, prototype component testing. Phase 3 consists of design studies to incorporate the technology into components, cost estimates, documentation, and the identification of potential commercial suppliers of the new technology.

The work emphasizes field evaluations of prototype and full-scale components. Tests are currently being conducted at the Northern California Power Agency (NCPA) plant in Middletown, CA, and the Russian River Energy Co. (RREC) facility in Cloverdale, CA. Results to date are summarized below.

A. NCPA Field Tests

Two 12-in.-diam. "T" sections supplied by NCPA and lined at BNL were installed. Both sections had a 5/16-in. thick cast-in-place polymer cement liner consisting of styrene, trimethylolpropane trimethylacrylate (TMPTMA) and Type III cement. One liner also contained 1/4-in.-long graphite fibers as reinforcement.

Both sections were installed in a steam collection line late in April 1992. The steam conditions are as follows: flow rate 30,000 lb/hr, pressure 120 psi, and temperature 173°C. The first visual inspection of the liners will be made in April 1993. To date, no problems with either unit have been reported.

B. RREC Field Tests

Four 8-in.-diam. casing spool sections were installed. Two were lined with a nominal 0.125-in. layer of PC, the others with a 0.002-in. coating of polyphenylene sulfide (PPS) polymer that was bonded to the casing using a transition metal modified zinc phosphate conversion process. After testing, the PC sections were returned to BNL for analysis.

One of the PC lined sections, was installed in the most chemically aggressive RREC well, a location where the service life of a 0.5-in. thick wall carbon steel is 14 days. After being in test for 23 days, a leak developed in the PC-lined section. The leak occurred just above one of the injection ports at the top of the section and may have been caused by backpressure which forced fluid under the PC and subsequent corrosion of the steel. Severe attack on the PC liner was also apparent.

A second section was tested in a slightly lower corrosive environment for 52 days. Visual examination indicated very little chemical attack on the liner but some delamination of the liner from the metal substrate did occur.

The two PPS-lined sections were placed into test in October 1992. To date, neither section has been inspected, but no leakage has been detected after six months in service.

C. Laboratory Testing

Laboratory-scale testing of PPS and various PC systems continued throughout FY 1992. These tests which are conducted in pH2 HCl at 200°C, are being performed to obtain preliminary information regarding potential field performance. To date, carbon steel tubes coated with PPS have been in test for 7 months without any apparent corrosion. PC samples exposed for 6 months exhibited increases in strength compared to the controls due to continued hydration of the cement, slight increases in volume, and increased porosity. Chemical attack due to the acidic environment was not evident.

In FY 1993, ongoing efforts with steam producers at The Geysers will be continued, a project with PG&E initiated, and others started as their needs are identified by the DOE/Industry Geysers Working Group.

With respect to the ongoing effort with RREC, Test Series No. 3 and 4 will be completed. Contingent upon the results, full-sized sections of lined well casing will be placed into test. Monitoring of composite lined tees by NCPA will also be continued. Contingent upon these results, plans for the testing of additional lined components will be developed and implemented.

6. Technology Transfer

In addition to the above activities which impact specific geothermal industry needs, efforts to transfer the technologies to other private sector organizations were continued. A notable success in FY 1992 was the transfer of work on polymer concretes for use as high temperature corrosion resistant construction materials. Based upon the results from extensive laboratory and field testing, the Consolidated Edison Company of New York is planning to install cast-in-place polymer concrete utility vaults in their steam district heating system in New York City. A material formulation similar to one of those being tested at The Geysers will be used in this full-scale demonstration that is scheduled to take place during the Summer of 1993.

Conventional steel reinforced portland cement concrete vaults are now used to house valves and other equipment. This is unsatisfactory since steam leaks combined with the high ambient temperatures (100° to 200°C) within the vaults result in rapid deterioration of the concrete. Due to the high strength, impermeability and resistance to chemical attack, use of polymer concrete will result in reductions in the required wall thickness, thereby lowering costs due to weight reductions, prevent ground water leakage into the vaults, and eliminate corrosion of the reinforcing steel and concrete deterioration.

Other extremely active technology transfer linkages are with the Gas Research Institute (GRI) and the Long Island Lighting Company (LILCO). For

the former, low cost thin corrosion resistant organic and pre-ceramic coatings are being developed for use on condensing heat exchangers installed on the exhaust of gas furnaces. Materials capable of long-term service in pH 1 200°C environments are needed. Tests performed using polymers such as polyphenylene sulfide and polyetheretherketone, and pre-ceramics such as polytitanosiloxane, all of which are being studied in the geothermal program as adhesives and corrosion resistant coating materials, have given extremely promising results.¹⁷ The GRI work has progressed to the point that two heat exchanger manufacturers are currently performing engineering-scale evaluations on prototype components. Potential LILCO applications of GD-developed technologies include acid resistant coatings for air preheaters in oil-fired electric generating processes, condensers, and for coatings on turbine blades. Field testing of prototype components for both applications will take place in FY 1993.

CONCLUSIONS

The Geothermal Materials Program continues to make significant advances in materials technologies that will help to further reduce the cost of geothermal well drilling, completion and energy conversion. In addition to the current commercial utilization of earlier BNL-developed materials by the geothermal industry, "spin-offs" to electric, gas, and steam utilities have occurred, and BNL-patented work has been licensed to industry for automotive-related applications.

In FY 1992, the GD-sponsored R&D project was focused on lightweight CO₂-resistant well cements, chemical systems for lost circulation control, thermally conductive and scale resistant protective liner systems, corrosion mitigation in process components at The Geysers, and elastomer-metal bonding.

Laboratory testing of BNL-developed phosphate modified calcium aluminate cements confirmed the hydrolytic stability and resistance to chemical attack by CO₂. Specimens exposed to Na₂CO₃-saturated brine at 250°C for 120 days, exhibited a compressive strength of 7800 psi and a CaCO₃ content of 0.2 wt percent. In comparison, conventional class H cement yielded 9.5 wt percent CaCO₃ after exposure for 7 days.

Pumpable cement slurries consisting of the advanced cement matrix and hollow aluminosilicate microspheres had densities in the range of 9 to 12.5 lb/gal, and upon curing in a 300°C hydrothermal environment, had compressive strengths of >1000 psi. They also appear to meet most of the other criteria for an advanced well cement. Larger-scale mixing and placement tests and downhole field exposures are scheduled to start in FY 1993 as a GDO-sponsored program.

Initial field testing of thermally conductive corrosion resistant polymer cement liners in flowing hypersaline brine under heat exchange conditions produced promising results. Compared to a high

alloy steel control, lined carbon steel tubing exhibited less scale formation at the brine-liner interface. No corrosion of the steel or deterioration of the liner was apparent. Based on these findings, plans for a second field test, this time under conditions approximating those for a bottoming cycle application, were initiated. Improvements have been made in the technology for centrifugally casting smooth thin liners on small diameter tubing. Non-destructive methods for measuring the liner thickness before and after exposure, and scale accumulation, were identified by NREL. Field testing of a 80-ft-long single tube shell-and-tube heat exchanger containing a ~0.030-in. liner will commence in April 1993. NREL-performed calculations indicated that liner thicknesses up to 0.050-in. would not significantly inhibit heat transfer and would be cost-effective.

Progress continues to be made in the development of advanced chemical systems for lost circulation control. Experiments performed with calcium aluminate-based formulations indicated that these materials appear superior to a previously studied MgO-based system, particularly in high temperature hydrothermal environments. Both materials are compatible with fiber or particulate-type bridging fillers, and appear to be usable with a variety of advanced placement techniques.

Work to develop high temperature hydrolytically stable chemical coupling systems is also underway. Until these become available, it will not be possible to fabricate the advanced tools needed to reduce drilling costs. To date, very promising results have been achieved using high melting point (>280°C) polyaromatic-type adhesives. Compared to the best commercially available coupling systems which will undergo complete disbondment from stainless steel upon exposure for one day in brine at 200°C, copolymers made from the polyaromatic materials show no disbondment or loss of bond strength after eight weeks. Additional work is required to improve the magnitude of the bond strength and to improve the thixotropic behavior of the adhesives in the liquid state.

Cost-shared efforts with operators at the Geysers to evaluate the use of polymer concrete and polymeric liners to mitigate corrosion were continued. Small lined casing sections are being tested by the Russian River Energy Company and full-size collection piping tees by the Northern California Power Agency. The results to date have been promising, and larger-scale tests are planned for FY 1993. If successful, the economic viability of wells currently undergoing severe corrosion problems may be restored, thereby helping to maintain electric generating capacity at The Geysers.

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ADVANCED SYSTEMS

**Chairperson: Louis Capuano
ThermaSource Inc.**

Geothermal Program Review XI

" Geothermal Energy - The Environmentally Responsible Energy Technology for the Nineties."

April 27-18, 1993

Chairman: Louis E. Capuano, Jr.

Advanced Systems

This section is titled "Advanced Systems" and the primary topic of discussion will be The Hot Dry Rock Project. For the past two years I have served as a member of the Hot Dry Rock Commercialization Board. This is a board comprised of industry representatives which was formed to exploit the commercial aspects of the HDR technology. I came to this board as an industry member who had worked on the project on several occasions in the early years of the project. I came to this Board very critical of the project but at the same time as a person who recognized the invaluable work that has been accomplished and the much needed technology research developed at HDR. The work accomplished at Fenton Hill using this project as a field laboratory where needs were important role in both the field of hot hole drilling and completion techniques as well as in energy conversion through heat mining.

This board met two weeks ago in Albuquerque, NM to discuss not only the results of the past year's long term flow test but also the future of the project. At that meeting held on April 15th we were informed of the long term flow test which was scheduled for shut down on April 19th due to the lack of funding.

The long term flow test will be discussed in detail in the papers to follow, however to summarize the test period, the test initially started up on April 9th, 1992 and lasted 16 weeks before both reciprocating injection pumps failed causing the test to be shut down on July 31, 1992. This was followed by a short 6 week test using alternative pumps from August 20 to October 2nd. The next flow period began on February 22, 1993 using a new high pressure centrifugal pump. This final phase has continued without interruption until the final shut down scheduled for April 19th. Therefore even

though this procedure is called a long term flow test it is by no means long term. After all the work and expense incurred at Fenton Hill (Approximately \$175 Million over a period of 20 years), the work has stopped because the project is out of funds. Many of you might say finally, however the HDR scientist are finally at the stage to complete the research of technology that can be commercialized in other areas of the U.S. as well as other Hot Dry Rock Projects in England, France/Germany and Japan but due to the lack of approximately \$600,000 to continue the test through the end of the year, the final report will remain incomplete.

A valuable point that was established at that HDR meeting was that in as far as the Hot Dry Rock Project is concerned all goals have been accomplished. That is the drilling of two wells and the creation of a fracture system connecting the two wells. Then the flow of fluid from the surface down the injection well and through the fractures to the production well and then the positive ability to transfer heat from the rock to the fluid and the flow of this heated fluid to the surface. Now to continue on with this project it would be correct to change the project's name to Heat Mining, because now that we have established what can be done, we must commercialize it now. Heat Mining using the technology developed at Fenton Hill should be able to be applied to many other areas and projects.

Investigations, studies and financial arrangements are presently being explored for an additional site in the Clearlake Area of Lake County California. Also at the same meeting a committee was formed to start the investigation of a Hot Dry Rock site on the east coast of the United States. This group will be

conducting meetings in the near future.

Today's talks will discuss the test results and the future of the Fenton Hill Hot Dry Rock Project. Details of the long term flow test will be given as well as an estimate of the cost of electric power generation from a Hot Dry Rock Project.

I urge all attendees to listen to these presentations, review the data obtained in the long term test and attempt to apply the technology to other projects. I feel that after making this analysis you will find that the Hot Dry Rock Project can benefit all area of the geothermal industry in many ways. If you come to this conclusion please urge your respective representatives of appropriate funds to complete this important project.

HOT DRY ROCK: WHAT DOES IT TAKE TO MAKE IT HAPPEN

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ABSTRACT

The ubiquitous heat in hot dry rock (HDR) is an abundant, widely distributed form of geothermal energy. Until recently, development of this energy source has been largely focused on understanding the scientific and engineering principles involved in forming and operating HDR reservoirs. During the past year, however, a pilot facility at Fenton Hill, NM has been run under steady-state conditions simulating the operation of a commercial HDR energy plant. Issues important to commercialization such as sustainability of thermal production, water loss, operating costs, and others have been addressed to the extent possible. The results, while not always definitive, have been encouraging. The stage is now set for the formation of an initiative led by private industry to take HDR technology from its current state of scientific and engineering demonstration to the production and marketing of energy in commercial quantities. Because of the technology risks involved, this can probably only be accomplished through a cost-shared industry/government effort. The potential rewards are great, since HDR represents the best, and perhaps the only, opportunity for geothermal energy to take its rightful place as a major energy source for the 21st century.

BACKGROUND

Efforts to mine the abundant energy resident almost everywhere in rock which is hot but dry have been underway for nearly twenty years. The technology currently being developed in several parts of the world (Duchane 1991) was patented in 1974 (Potter, Robinson, and Smith). Since that time, the possibility of heat mining by circulating pressurized water through an artificially created geothermal reservoir using one or more injection and production wells has been demonstrated several times (Dash, Murphy, and Cremer 1981; Dash 1989; Parker 1989; Yamaguchi, Hiwaki, Abe, and Okikawa 1992). During the period 1988-1991, a surface plant built to power plant standards was constructed at the US hot dry rock (HDR) site at Fenton Hill, NM. A long-term flow testing (LTFT) program was begun in 1991. To date, two significant test segments have been completed.

SUMMARY OF RECENT FLOW TESTING RESULTS

Technical results of these recent flow test segments are discussed in detail elsewhere in these proceedings and are only briefly summarized below:

1. No thermal drawdown was observed. Temperatures at the surface and at the outlet of the HDR reservoir showed no declines over the testing period.

2. As shown in Figure 1, tracer tests indicated that access to hot reservoir rock increased with time as flow testing proceeded.

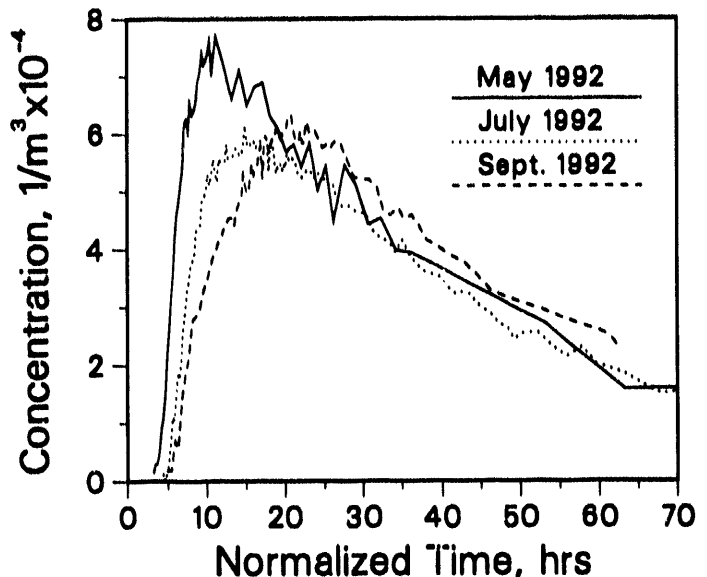


Figure 1. Tracers injected into the Fenton Hill system on three separate occasions took progressively longer to traverse the HDR reservoir. These data indicate that shorter flow paths closed and longer flow paths developed over time as water continued to circulate through the reservoir, implying ever increasing access to the hot reservoir rock.

3. Water consumption reached stable levels as low as 7% of the injected fluid.

4. Careful documentation of operating costs (electricity and fuel oil to run the plant, only) showed that a more than six-fold excess of thermal energy was produced and indicated a potential for a 50% excess production of electricity even at thermal-to-electric conversion rates of only 10%. Table 1 summarizes this operating cost data. It is important to note that labor costs, maintenance costs, capital costs, and other incidental costs are not included in these calculations, primarily because there is at present no way to realistically document them in the same manner as the fuel and electric costs.

Table 1

Hot Dry Rock Flow Testing Operating Power Cost Data					
Injection Power Source	Operating Power Costs	Produced Power Costs*	Thermal Productivity Factor	Electricity Productivity Factor	
	\$/MM/BTUs	\$/MM/BTUs		10% Conv.	15% Conv.
Diesel	5.20	0.81	6.4	—	—
Electric	26.36	1.74	15.1	1.51	2.27

Table 1. Fenton Hill operating power cost data. When diesel oil was used to power the injection pumps, more than 6 times as much thermal energy was produced as the thermal energy content of the diesel fuel and the additional electricity used to run other parts of the site. When electric injection pumps were employed, the thermal productivity factor was even greater, but because the process of conversion of thermal energy to electricity is inefficient, the net electrical energy gain would be much smaller and dependent upon the conversion efficiency. No electric energy was actually produced during the tests, therefore electric productivity factors shown are for assumed conversion efficiencies of 10% and 15%.

5. Suspended solids in the circulating geofluid were nil (1-2 ppm) and dissolved solids were very low (3,000-4,000 ppm). Dissolved gases consisted primarily of carbon dioxide and totaled less than 3,000 ppm. Hydrogen sulfide was generally present at concentrations of less than 1 ppm. All suspended and dissolved species quickly reached equilibrium levels which were maintained for the duration of the flow testing.

6. Under the test operating conditions, which entailed pressurization of all parts of the loop, there were no emissions to the environment during closed-loop operations except waste heat.

THE MAJOR REMAINING HDR ISSUES

A number of issues remain to be addressed as the technology to extract energy from HDR progresses toward full commercial viability. Most importantly, it must be clearly shown that HDR systems can deliver energy at practical rates, on a sustained basis, for a time period sufficient to return the large capital investment required to bring a plant on line. Flow testing during the past year has provided a start toward addressing sustainability, but perhaps the most practical way to clearly demonstrate this aspect of HDR technology is to simply build and operate a system designed to produce and market electricity at competitive costs. Because our current knowledge is limited, certain technology risks would be involved, but the research and development completed to date gives every reason to be optimistic.

Techniques to increase the net productivity of HDR systems also must be proven. As an example, it has been suggested that HDR systems with two or more production wells for each production well could result in substantial gains in productivity as well as increased recovery of injected water. Limited flow testing of a multi-well HDR system in Japan has lent credence to the validity of this hypothesis, but it remains to be demonstrated in a system specifically designed for sustained energy production.

Finally, it has not yet been shown that HDR systems can be constructed in a variety of geographical and/or geological

settings. While several sites exist around the world, these have been chosen for research rather than production purposes. It is necessary to begin constructing HDR facilities at sites where it is feasible to market the power from them. While resource quality will always be important, other considerations such as resource ownership, proximity to a market for power, transmission capability, and local support for clean energy technologies, may well be dominant factors in locating future HDR facilities

WHY SHOULD THE GEOTHERMAL INDUSTRY BE INTERESTED IN HDR NOW?

The abundance and worldwide distribution of HDR resources have been well documented (Edwards, Chiling, Rieke, and Fertle 1982). Although proven hydrothermal reserves are limited, the implementation of HDR technology could move the geothermal industry from today's position, where it is perceived to be of only regional importance, to worldwide status. This would both greatly expand the geothermal energy resource base and broaden the political support so necessary to the growth of all alternative and renewable energy forms.

The test results reported above, while limited in scope, have demonstrated the potential for thermal sustainability, shown that water consumption can be kept within reasonable bounds, provided verifiable evidence that excess energy can be produced in a HDR plant, indicated that low maintenance costs may be possible as a result of low levels of dissolved and suspended species in the geofluid, and confirmed the environmental advantages of the technology. All of these results, of course, are based on limited testing, but in each case, the documentation is sound and observed trends point to improved rather than deteriorating operating parameters with time. These data set the stage for the development of an industry-led program to capitalize on the potential of HDR and turn it into a practical, profitable energy source.

The resurgence in support for renewable energy as manifested in the professed policies of the new federal administration and in recent legislation (Energy Policy Act 1992) may enable energy firms to overcome some of the financial hurdles to the development of unique technologies such as HDR. In addition, increasing environmental regulations and new levies on fossil fuels, such as the proposed Btu tax, may well provide a marketing advantage for those industries ready to exploit new energy forms. For the geothermal industry, HDR technology represents perhaps the best chance to make a large impact on future clean energy markets worldwide.

INDUSTRIAL LEADERSHIP OF FUTURE HDR DEVELOPMENT

Since its inception, the U.S. HDR Program has been run by the Los Alamos National Laboratory. The technology has been demonstrated and, as outlined above, limited flow testing has indicated that it has the potential to take its place as a competitive energy source. Since commercialization will be entirely in the hands of the private industrial sector, it is important that private industry in the U.S. now take the leading role in directing the steps leading to implementation of HDR. Private industry has the expertise and interest needed to operate HDR facilities on a production basis and to market the power produced.

Because of the uncertainties involved in moving HDR to the production stage, which are typical of the risks encountered in bringing any new technology from the non-economic, experimental phase to the competitive marketplace, it will be necessary to minimize the risk to all parties. Institutionally, this can be accomplished by a number of steps including cost-shared industry/government programs to reduce the capital risk, the

formation of consortiums to spread that risk among several interested parties, and the application of legislative incentives for alternative energy production in developing a pricing and marketing strategy.

Undoubtedly, the first power-producing HDR facility should be of modest size in order to limit both the technical uncertainties associated with the creation and operation of larger HDR reservoir and keep total development costs within reasonable bounds. A hybrid plant capable of utilizing natural hydrothermal resources, natural gas, or other proven feedstocks in conjunction with fluid from a HDR reservoir could actually reduce the inherent risk in the above-ground plant to almost zero. At the same time, the use of standard or modular components would permit any capital equipment to be recovered if the HDR project should fail. All of the above, coupled with careful preliminary work in site selection and resource evaluation, could make a power producing HDR project a profitable undertaking and set the stage for participating organizations to become leaders in the development of a new industry based on HDR technology.

While the most obvious sites for the next stages of HDR development are high-gradient lands in the west, particularly the Clear Lake area of California, even medium gradient sites in other parts of the country may present opportunities if state and local legislation promoting the use of clean energy and/or regional of local funding opportunities come into being. While electricity generation is likely to be the first practical use of HDR technology, direct uses should not be discounted if the extremely specific nature of such applications can be addressed. Under the proper circumstances, it would even be possible to turn the Fenton Hill HDR test site into a private commercial energy production plant, but while such an effort might be the lowest capital cost route to a commercial-scale facility, obstacles to marketing the energy from this remote location might preclude its consideration in this regard.

SUMMARY

Flow testing during the past year has advanced the understanding of the operation of HDR facilities under practical conditions and addressed a number of concerns about the practicality of producing energy on a commercial scale. Issues of sustainability, productivity, and versatility remain, however, and these will not be answered until a power producing HDR site is developed that can help pay its way while important long-term operating data are accumulated. Only the private industrial sector is equipped, both technically and philosophically, to build and operate such a site. Because of the many technical uncertainties involved, construction of such a site will probably not be undertaken without government cost-sharing to reduce the risk inherent in developing this new technology.

HDR presents the geothermal industry with its best, and perhaps its only, opportunity to join alternative energy technologies such as solar, biomass, and wind, in being considered a major player in the clean energy market of the 21st century. The geothermal industry can respond by taking a leadership role in the development of HDR technology, or it can continue to rely on hydrothermal resources widely perceived to be limited in scope and potential. If the latter route is taken, geothermal energy may soon join hydropower as a resource which may be clean and renewable but whose day is seen to have passed.

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RECENT FLOW TESTING OF THE HDR RESERVOIR AT FENTON HILL, NM

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ABSTRACT

The principal objective of the recent flow testing of the Phase II Hot Dry Rock (HDR) reservoir at Fenton Hill, NM has been to demonstrate its long-term viability as a significant source of thermal energy. However, with an aggregate of only about 8 months of production to date, this objective has obviously not yet been accomplished. Starting in April 1992, two periods of steady-state reservoir flow testing were conducted, which are here referred to as the first (16-week long) and second (8-week long) phases of the Long-Term Flow Test (LTFT). These two segments of the LTFT -- April through July 1992 and February through April 1993 -- were conducted at an aseismic (nonextensional) injection pressure of about 3960 psi (27.3 MPa) and at a production well backpressure of 1400 psi (9.65 MPa). Other reservoir testing between these two phases of the LTFT included a lower-injection-pressure flow test lasting about 6 weeks and a 2-month period of flow testing at the LTFT injection pressure of 3960 psi, but at even higher levels of production well backpressure -- 1800 and 2200 psi (12.4 and 15.2 MPa).

The permeation loss from the boundaries of the reservoir decreased from an average of about 12.5 gpm (0.79 l/s) during the first phase of the LTFT to 7.3 gpm (0.46 l/s) near the end of the second phase of the LTFT. This low but apparently still declining water loss is remarkable considering the very large volume of fractured rock (about $16 \times 10^6 \text{ m}^3$) comprising the flow-connected Phase II reservoir region.

The long-term testing of the Phase II reservoir at Fenton Hill under stable, aseismic conditions has shown no thermal drawdown during almost 8 months of flow testing. This conclusion is based primarily on downhole measurements of the fluid temperature level just above the 1130-ft (344-m) multiple-entrance production zone in the production well, which indicate that there has been no change in the mixed-mean reservoir outlet temperature between July 1992 and March 1993.

In early May 1993, a brief period of cyclic production was begun as the final phase of the current reservoir flow testing. However, just after beginning the third daily cycle, a sudden and very large increase in reservoir production occurred. Unfortunately, due to severe funding constraints, the mechanism(s) accounting for this dramatic change in reservoir performance could not be assessed.

INTRODUCTION

The present Phase II HDR reservoir at Fenton Hill represents the successful creation and operation of a second, deeper and hotter engineered geothermal system for mining the earth's heat at this site in northern New Mexico. [A smaller and shallower reservoir was flow tested during the period from 1978 to 1980, with the longest test lasting over 9 months (Dash et al., 1981)]. This present reservoir is centered at a depth of about 11,500 ft (3500 m), with a mean rock temperature of 453°F (234°C).

The first phase of the planned Long-Term Flow Test (LTFT) began on April 9, 1992. However, it only lasted until July 31 due to premature failures of both primary piston-type injection pumps. Reservoir flow testing was then continued at a lower injection rate of 68 gpm (4.3 l/s) for the 6 weeks from August 20 to October 2. This period of lower-injection-pressure

flow testing, referred to as the Interim Flow Test (IFT), ended when a "terminal" failure occurred to a smaller backup injection pump. Following the end of the IFT, a used triplex mud pump was leased on a temporary basis to maintain reservoir pressure during the months of November and December, 1992. After leasing and installing a more suitable replacement injection pump -- a specially designed high-pressure centrifugal pump -- the second phase of the LTFT was conducted from February 22 through April 17, 1993. A summary plot of the pertinent operating parameters during the recent 14-month period of flow testing of the Phase II HDR reservoir is given in Figure 1.

The primary objective of the recent flow testing of the HDR reservoir at Fenton Hill has been to demonstrate its long-term viability as a significant source of thermal energy. In theory, this testing should have lasted long enough to produce a significant thermal drawdown of the produced fluid -- at least 15°C -- so that the effective size of the reservoir could be quantified. The time to achieve such a drawdown was thought to be at least one to two years, but conceivably could have been much longer if the thermal size of the reservoir were larger than the currently estimated minimum size, or if the fluid access to the more remote regions of the reservoir increased with time.

Associated with this primary programmatic objective was an ancillary technical objective: To measure the reservoir flow performance at other than the standard LTFT injection and production pressure levels. These measurements were necessary to provide critical information for our overall understanding of how an HDR geothermal system actually performs under a variety of steady-state operating conditions. With this knowledge, we will be able to engineer changes in the flow behavior of this specific reservoir to enhance its productivity, as well as to better optimize the design of future HDR systems.

RESERVOIR PERFORMANCE DURING THE FIRST PHASE OF THE LTFT

During 16 weeks of continuous reservoir flow testing from April 9 through July 31, 1992, as shown in Figure 1, the surface injection pressure was increased to about 3960 psi (27.3 MPa) while the production backpressure was generally maintained at 1400 psi (9.65 MPa). (The actual control variables were injection flow rate and production backpressure.) For the stagnant southern portion of the reservoir (that portion of the reservoir least accessible to the production wellbore), this injection pressure is inferred to be the reservoir boundary pressure in the absence of a significant outward pressure gradient. This maximum boundary pressure of 3960 psi produced no discernible microseismicity in this region of the reservoir indicating stable, nonextensional reservoir operation. The low and slightly declining rate of reservoir water loss provides further evidence that the reservoir was not extending during this time, as discussed later.

Figure 2 shows the surface injection and production flow rates during the first phase of the LTFT. While the injection pressure was gradually being increased to 3960 psi and then maintained at this level during the 16 weeks of testing, both the injection and production flow rates slowly declined by about 10 percent. Tracer evidence indicates that this decline in flow rate resulted from a gradual redistribution of reservoir flow, away

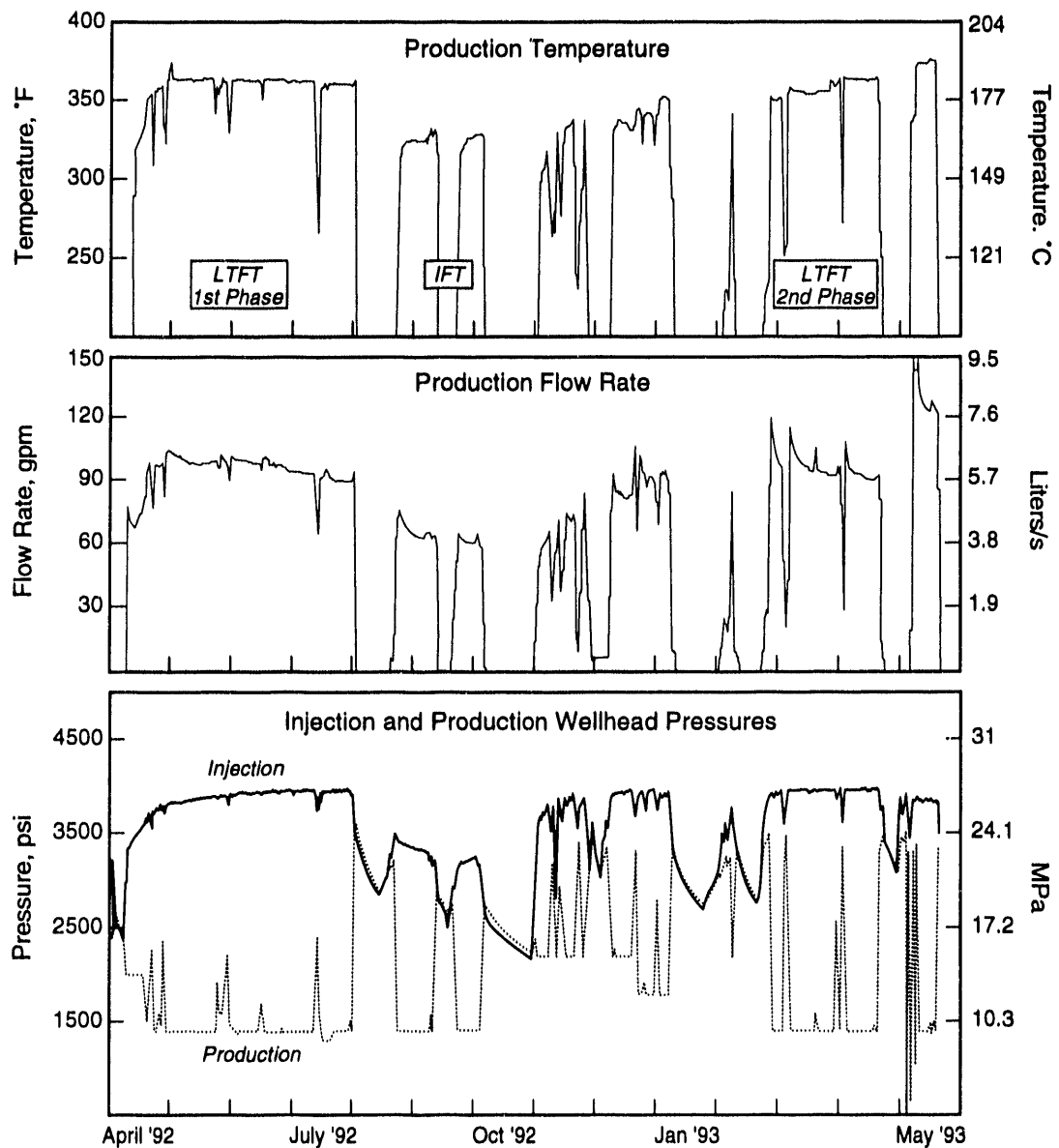


Fig. 1. Recent production testing of the Fenton Hill reservoir.

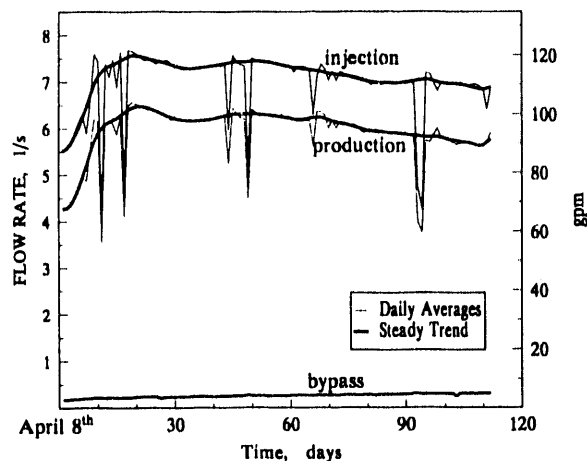


Fig. 2. Flow rates during the first phase of the LTFT.

from the more direct flow paths and toward the more circuitous and therefore higher impedance paths (Rodrigues et al., 1993).

Figure 3 shows the apparent rate of reservoir water loss during the first phase of the LTFT. This loss is the difference between the 24-hour mean injection and production flow rates shown in Figure 2, corrected for the small (about 5 gpm) annular casing bypass flow from the reservoir occurring at the injection well.

However, this calculated loss rate has not been corrected for the approximately 1.6 gpm of apparent "loss" actually resulting from additional fluid storage within the reservoir as a consequence of the continued cooling-induced contraction of the rock blocks near the reservoir entrance region and the accompanying joint dilation (Rodrigues et al., 1993).

As can be seen, the rate of water loss declined quite rapidly during the initial transient period, and then more slowly during the remainder of first phase of the LTFT, to a final value of about

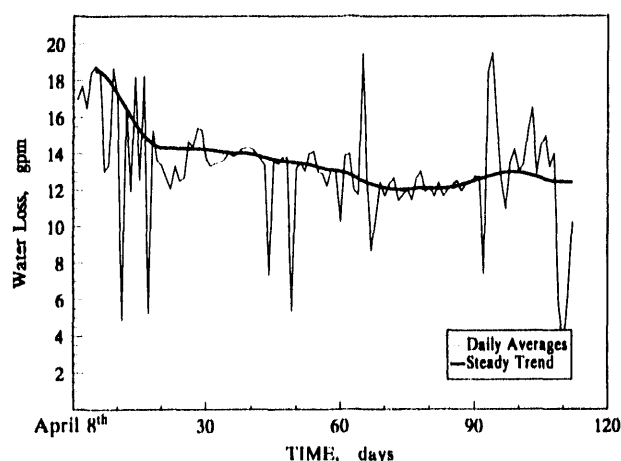


Fig. 3. Water loss during the first phase of the LTFT.

12.5 gpm (0.79 l/s). On the other hand, the injection pressure, and therefore the pressure on that part of the periphery of the fractured reservoir away from the production well where the majority of the diffusional water loss was occurring, was rising or constant. The inference is that the reservoir boundary was stable, and that the reservoir water loss rate was slowly declining with time as has been observed during previous static reservoir pressure testing (Brown, 1991).

INTERIM FLOW TEST

During the 6-week period from August 20 to October 1, referred to as the Interim Flow Test (IFT), reservoir flow testing continued at a lower injection rate of about 68 gpm (4.3 l/s) using a smaller-capacity reserve piston pump. Also included in this 6-week period, as shown in Figure 1, was a 1-week reservoir shut-in for necessary pump repairs. After establishing steady-state flow conditions near the beginning of the IFT, the injection pressure slowly leveled out at about 3240 psi (22.3 MPa) at the maximum sustainable injection rate of 68 gpm. Following the 1-week shut-in, the injection pressure more rapidly stabilized, again at a level of about 3240 psi.

Table I compares the principal reservoir performance data for the first phase of the LTFT and the IFT. It should be noted that these two flow tests were performed at essentially the same production backpressure level of 1400 psi (9.65 MPa), thus providing a direct measure of the effect of reduced injection pressure on reservoir flow at a constant production backpressure. These data have been essential in validating the GEOCRACK discrete-element reservoir flow/deformation model being developed at Kansas State University (Swenson and Beikmann, 1992).

Two observations can be made from the data presented in Table I. First, a 36% decrease in the injection rate between the first phase of the LTFT and the IFT (from 107.1 gpm to 68.8 gpm) correlates with a considerably smaller 18% decrease in the injection pressure. This shows the strong nonlinear relationship between joint flow and pressure. Second, the rate of peripheral water loss through the microcrack fabric of the rock mass surrounding the HDR reservoir region was markedly decreased by reducing the injection pressure from 3960 psi (27.3 MPa) to 3240 psi (22.3 MPa). The water loss data shows, for matrix flow in this case, the nonlinear dependency of permeation outflow on the mean pressure level between the reservoir boundary and the far-field.

Table I
Comparison of Reservoir Flow Performance
Between the First Phase of the LTFT and the
Lower-Injection-Pressure IFT

Test	LTFT	IFT
Measured Performance	7/21-29/92	9/29/92
<i>Injection Conditions</i>		
Flow Rate, gpm (l/s)	107.1 (6.76)	68.8 (4.34)
Pressure, psi (MPa)	3958 (27.29)	3243 (22.36)
<i>Production Conditions</i>		
Flow Rate, gpm (l/s)	99.7 (5.66)	61.1 (3.85)
Backpressure, psi (MPa)	1401 (9.66)	1399 (9.65)
Temperature, °C (°F)	183 (361)	165 (329)
<i>Water Loss</i>		
Rate, gpm (l/s)	12.5 (0.79)	3.6 (0.23)
Percent	11.7	5.2

HIGHER BACKPRESSURE FLOW TESTING

After a month of reservoir shut-in following the IFT, a leased positive-displacement mud pump was brought on line in early November, 1992. While reinflating the reservoir and establishing steady-state flow conditions, the pump operated for only a total of 20 days in November as materials and maintenance issues related to its operation were being addressed. During December, however, with newly designed pump plungers and liners, the pump operated on a near-continuous basis, and we were able to establish two higher-backpressure production flow conditions as shown in Table II.

Table II
Reservoir Flow Performance Under Conditions
of Higher Backpressure (2200 and 1800 psi)

Measured Performance	12/10/92	12/27/92
<i>Injection Conditions</i>		
Pressure, psi (MPa)	3963 (27.32)	3962 (27.32)
Flow Rate, gpm (l/s)	116.2 (7.33)	113.1 (7.14)
<i>Production Conditions</i>		
Backpressure, psi (MPa)	2201 (15.18)	1798 (12.40)
Flow Rate, gpm (l/s)	84.6 (5.34)	90.5 (5.71)
Temperature, °C (°F)	177.1 (351)	182.8 (361)

The three sets of production flow data at a constant injection pressure of 3960 psi given in Tables I and II -- 89.7 gpm at 1400 psi, 90.5 gpm at 1800 psi, and 84.6 gpm at 2200 psi -- indicate that there is a broad maximum in the production flow rate as a function of backpressure. However, due to small data uncertainties arising from the slowly changing flow distribution within the reservoir as a function of time, the most significant feature of the above flow vs. backpressure data is the 5% falloff in flow rate as the backpressure is increased from 1800 psi (12.4 MPa) to 2200 psi (15.2 MPa). Taken together, these three sets of steady-state data suggest that as the production backpressure is increased from 1400 psi to 2200 psi, the decrease in the driving pressure difference across the reservoir is approximately balanced by the increase in the flow conductance of the reservoir as the joints are increasingly pressure-dilated. The overall subject of reservoir

flow impedance is further discussed in DuTeau and Brown, 1993.

RESERVOIR PERFORMANCE DURING THE SECOND PHASE OF THE LTFT

Near the end of 1992, the Laboratory began negotiations to obtain a high-pressure centrifugal injection pump from Reda, a Division of Camco Inc. The reasons for the change in pump type (from positive displacement to centrifugal) were numerous, but our choice was mainly driven by cost and availability. Further, the engineering evaluation of a centrifugal pump for HDR applications was very appealing. A suitably sized electrically driven pump was leased and installed at Fenton Hill in late January 1993. However, with severe winter weather conditions, it then took almost a month to upgrade the site electrical power distribution system to adequately power the Reda pump and auxiliaries.

The second phase of the LTFT commenced on February 22 and ran until April 17, 1993 -- just under 8 weeks. During this time, as shown in Figure 1, there were several significant reservoir shutins. Invariably, these shutins were caused by continuing electrical and/or weather problems. During all of this time, the pump performed superbly with no mechanical problems whatsoever. Table III gives a comparison between the reservoir operating parameters for the two phases of the LTFT, for time intervals near the ends of each phase.

Table III
Comparison of Reservoir Performance Between the Two Phases of the LTFT

Phase	One	Two
Measured Performance	July 21-29 1992	April 12-15 1993
<i>Injection Conditions</i>		
Flow Rate, gpm (l/s)	107.1 (6.76)	103.0 (6.50)
Pressure, psi (MPa)	3958 (27.29)	3965 (27.34)
<i>Production Conditions</i>		
Flow Rate, gpm (l/s)	89.7 (5.66)	90.5 (5.71)
Backpressure, psi (MPa)	1401 (9.66)	1400 (9.65)
Temperature, °C (°F)	183 (361)	184 (363)
<i>Water Loss</i>		
Rate, gpm (l/s)	12.5 (0.79)	7.3 (0.46)
Percent	11.7	7.0

The most obvious feature of the data presented in Table III is the very close agreement between these two phases of the LTFT, separated in time by almost 7 months. The only real change is the decrease in the rate of water loss. However, if the LTFT first phase data trend for the rate of water loss shown in Figure 3 were to be logarithmically extrapolated out to one year, the one-year loss rate would be close to the observed loss rate of 7.3 gpm for the time period from April 12 to 15, 1993. It therefore appears that at a surface injection pressure of 3960 psi (27.3 MPa), the water loss from this specific reservoir can be attributed primarily to diffusion from the high-pressure boundaries of the fractured region (Brown, 1991) and not to additional reservoir growth, as would have been indicated by microseismic activity.

In summary, the observed permeation loss from the boundaries of the reservoir at this very elevated injection pressure decreased from an average of about 12.5 gpm (0.79 l/s) during the first phase of the LTFT to 7.3 gpm (0.46 l/s) near the end of the second phase of the LTFT. This low but apparently still

declining rate of water loss is remarkable considering the very large volume of fractured rock -- about $16 \times 10^6 \text{ m}^3$ with a corresponding surface area close to $360,000 \text{ m}^2$ -- comprising the flow-connected Phase II reservoir region (Robinson and Kruger, 1992).

An editorial note needs to be added at this point concerning this specific HDR reservoir at Fenton Hill, which is very elongate in plan view (Brown, 1990). If the stagnant southern portion of this reservoir were to be accessed with a second production well, this well would provide a low-pressure sink in this currently high-pressure region of the reservoir where most of the water loss is now occurring. Considering the added advantage of being able to operate the resulting two-production-well system at even higher injection pressures without any reservoir growth, the total rate of water loss -- which is only dependent on the levels and distribution of the reservoir boundary pressures -- would probably stay about the same in absolute terms while the reservoir throughflow would increase by almost a factor of four (x2 for doubling the production wells and x1.9 for being able to operate the reservoir at an injection pressure of up to 5500 psi with a backpressure of 2000 psi).

SUDDEN LARGE INCREASE IN RESERVOIR PRODUCTION

Following the end of the second phase of the LTFT, while the leased centrifugal pump was still available and before the site was shut down for the rest of the year, a 5-day period of cyclic reservoir production testing was begun at a roughly constant injection pressure, to obtain a brief data set representing this unique mode of reservoir operation. However, part way into the third daily production cycle, a sudden and unexpected increase in production occurred. In less than a minute, the production flow rate increased by almost 48% and the production temperature subsequently increased to over 190°C (374°F).

In over 20 years of experience in HDR reservoir flow testing, there has never been such a profound change in reservoir production resulting from pressure cycling. To have such a change occur following an oft-repeated event during the present testing sequence -- the shutting in of the production well for a few hours -- is very surprising and intriguing. Since at least 7 primary joints were previously supplying flow to the production interval, it appears safe to say that more than one new joint intersecting the production wellbore suddenly opened up to achieve this large increase in flow rate.

To assess whether the 6°C (11°F) increase in production temperature was due primarily to the increase in the production flow rate and the corresponding reduction in the wellbore heat loss per unit flow, or partially to an actual increase in the downhole production temperature, a mechanical (i.e., Kuster) temperature survey of the production well down to the bottom of the casing was performed on May 11. This survey showed a negligible change in the mixed-mean production temperature at a depth of 10,500 ft, suggesting that the newly opened flow paths were adding flow at about the mean reservoir production temperature that had existed previously.

Figure 4 shows the reservoir pressure and flow rate profiles for the period from May 6 through May 17, 1993. The sudden increase in production flow rate discussed previously is indicated by the "spike" in flow on the morning of May 6. Following this event, the reservoir was returned to a steady flow condition in an attempt to quickly assess the changes that had occurred. The backpressure was re-established at 1400 psi and the injection flow rate was increased to the absolute maximum available from the Reda pump -- about 130 gpm. However, at this injection rate, the injection pressure could only be maintained at about 3860 psi whereas previously, at the end of the second phase of the LTFT as given in Table III, an injection rate of 103 gpm resulted in an injection pressure of 3960 psi. This comparison provides another very clear indication that the overall impedance of the reservoir had dropped significantly.

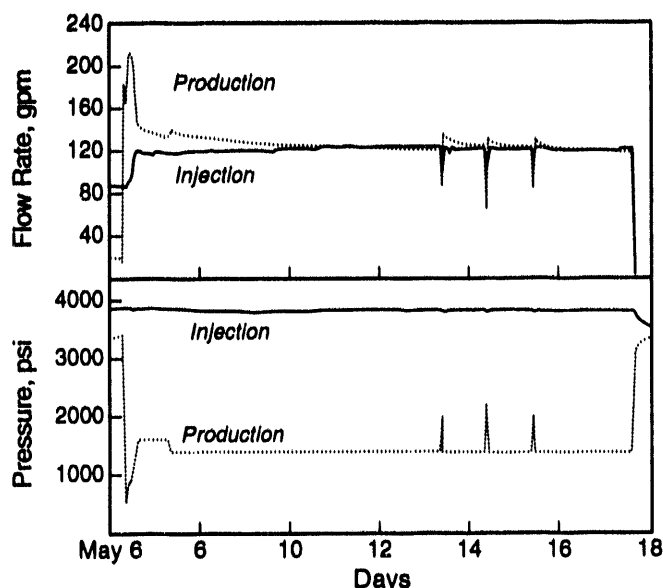


Fig. 4. Injection and production flow rates and pressures following the sudden increase in production flow on May 6, 1993.

The near-steady-state reservoir operating parameters that obtained for the first 8 hours on May 13 and for comparison, the operating parameters for the second phase of the LTFT, are given in Table IV.

Table IV
Comparison of Reservoir Performance Before and After the Sudden Increase in Production Flow on May 6, 1993

Measured Performance	May 13	April 12-15
Injection Conditions		
Flow Rate, gpm (l/s)	130.2 (8.22)	103.0 (6.50)
Pressure, psi (MPa)	3860 (26.61)	3965 (27.34)
Production Conditions		
Flow Rate, gpm (l/s)	122.0 (7.70)	90.5 (5.71)
Backpressure, psi (MPa)	1400 (9.65)	1400 (9.65)
Temperature, °C (°F)	190 (374)	184 (363)

If the injection flow rate for the second phase of the LTFT listed in Table IV were scaled downward to the somewhat lower injection pressure of 3860 psi existing on May 13, the corresponding flow rate would be about 87 gpm. Comparing this flow rate to the 122 gpm flow rate measured on May 13 following the sudden decrease in reservoir flow impedance, the steady-state increase in reservoir production flow would be almost 40%, again indicating a very significant change in reservoir impedance. However, it should be pointed out that insufficient time had been allowed for the reservoir to return to truly steady-state operating conditions following the "event" of May 6, and therefore the production rate listed in Table IV may be high by several gpm.

During the last 3 days of production flow, a dye tracer was injected to evaluate any significant changes in the distribution of reservoir flow paths. This tracer study revealed that the percentage of more direct flow paths had increased somewhat since the last tracer test in April 1993, but that these more direct flow paths were still not as numerous as those existing near the beginning of flow testing in May 1992. Unfortunately, due to severe funding constraints, the mechanism(s) accounting for this dramatic change in reservoir performance could not be assessed in further detail.

PRODUCTION TEMPERATURE AND POWER OBSERVATIONS

The variation of the surface production temperature during the recent 14-month period of reservoir flow testing at Fenton Hill is shown in Figure 1 (also refer to Tables I, II and III). During the first phase of the LTFT, the production temperature rapidly increased to a maximum value of 185°C (365°F) as equilibrium was reached, and then very slowly decreased to a final temperature of 183°C. During the IFT, the surface production temperature was considerably depressed to only 165°C (329°F) due to the drop in production flow rate and the concomitant increase in the heat loss per unit flow from the production wellbore to the surrounding rock. The surface production temperature during the second phase of the LTFT gradually increased to a final value of 184°C. Then, due to the significant increase in the production flow rate following the sudden decrease in reservoir flow impedance on May 6, the production temperature, as shown in Figure 1, further increased to 190°C (374°C) during the brief final phase of flow testing.

During the first phase of the LTFT, the mean production flow rate was 96 gpm (6.1 l/s) at a temperature of 184°C, resulting in a mean thermal power production of 4.2 MW. However, the actual power level declined from 4.5 MW to 3.9 MW during the 16 weeks of testing, primarily due to a gradually decreasing production flow rate as shown in Figure 2.

A declining production flow rate during the second phase of the LTFT resulted in a similar phenomenon, with the thermal power again slowly falling off to a final value of about 3.9 MW. Then on May 13, following the sudden increase in production flow, 5.5 MW of thermal power were being produced from the Fenton Hill reservoir, a 42% increase over the thermal power being produced just previously at the end of the second phase of the LTFT.

Figure 5 shows the wellbore temperature profiles for times during the first and second phases of the LTFT (Logs #1 and #3) and for a time near the end of the IFT (Log #2). Even though the surface production temperature of 165°C for the IFT shows a significant decline from those for the two phases of the LTFT due to the reduction in flow rate, the corresponding mixed-mean reservoir outlet temperatures at a depth of 10,500 ft (3200 m) indicate no measurable decline in the downhole production temperature over the 8 months of reservoir operation covered by these 3 production logs.

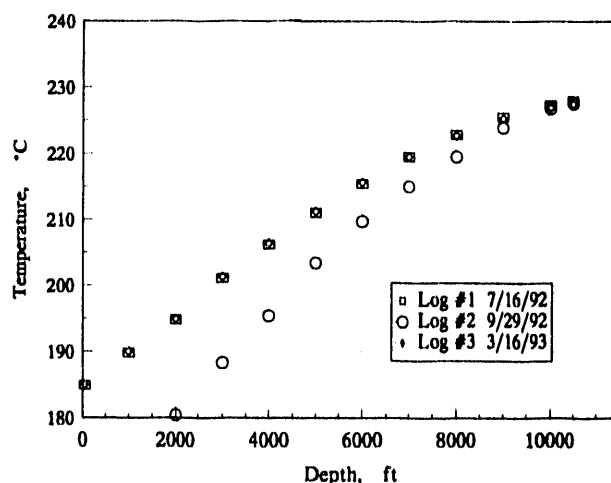


Fig. 5. Temperature surveys of the production wellbore under flowing conditions.

MAJOR CONCLUSIONS

Long-term flow testing of the Phase II reservoir at Fenton Hill under stable, aseismic conditions has shown no thermal drawdown of the reservoir for an aggregate testing period of almost 8 months. This conclusion is based primarily on fluid temperature measurements at a depth of 10,500 ft (3200 m), just above the 1130-ft (344-m) production zone in the production wellbore. These measurements indicate that there has been no change in the mixed-mean reservoir production temperature between July 1992 and March 1993.

The permeation loss from the boundaries of the reservoir decreased from an average of about 12.5 gpm (0.79 l/s) during the first phase of the LTFT to 7.3 gpm (0.46 l/s) near the end of the second phase of the LTFT. This low but apparently still declining rate of water loss is remarkable considering the very large volume of fractured rock (about $16 \times 10^6 \text{ m}^3$) comprising the flow-connected Phase II reservoir region. It is inferred that this diffusional water loss was occurring primarily from the boundaries of the stagnant high-pressure southern portion of the reservoir, where the pressure level of the fractured region was generally above 3900 psi (27 MPa) for most of the testing period.

During the initial 16-week phase of the LTFT which was conducted at injection pressures up to 3960 psi (27.3 MPa), the production backpressure was generally maintained at 1400 psi (9.65 MPa). The mean production flow rate was 96 gpm (6.1 l/s) at a temperature of 184°C (363°F), resulting in a mean thermal power production was 4.2 MW. However, the actual power level declined by about 13% during the first phase of the LTFT, primarily due to a gradually decreasing production flow rate. This decreasing flow rate in turn reflected a gradual redistribution of flow within the reservoir, away from more direct paths and toward more indirect paths.

In early May of 1993, a brief period of cyclic production was undertaken as the final phase of the current reservoir flow testing. However, just after beginning the third daily cycle, a sudden and very large increase in reservoir production occurred, with the flow rate increasing by almost 48% in less than one minute. The production temperature subsequently increasing to over 190°C (374°F). Following this event, the reservoir was returned to a steady flow condition to assess the changes that had occurred. The backpressure was re-established at 1400 psi and the injection flow rate was increased to the absolute maximum available from the Reda pump -- about 130 gpm. However, at this injection rate, the injection pressure could only be maintained at about 3860 psi whereas previously, at the end of the second phase of the LTFT, the injection pressure was above 3960 psi at an injection rate of only 103 gpm. This comparison provides a very clear indication that the overall impedance of the reservoir had dropped significantly, with a resulting increase in production of 40%.

This is the most profound change in reservoir production ever experienced in the HDR Project at Los Alamos. The sudden change in reservoir flow impedance appears to be the result of pressure cycling, but due to funding constraints, we were unable to investigate the causes of this reduction. However, since at least 7 primary joints were previously supplying flow into the production interval, it appears safe to say that more than one new joint suddenly opened up to achieve this large increase in flow rate. A tracer study following the sudden increase in reservoir production revealed that the percentage of more direct flow paths had increased somewhat since the last tracer test in April 1993, but that these more direct flow paths were still not as numerous as those existing near the beginning of flow testing in May 1992.

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An Estimate of the Cost of Electricity Production from Hot-Dry Rock

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Abstract

This paper gives an estimate of the cost to produce electricity from hot-dry rock (HDR). Employment of the energy in HDR for the production of electricity requires drilling multiple wells from the surface to the hot rock, connecting the wells through hydraulic fracturing, and then circulating water through the fracture system to extract heat from the rock. The basic HDR system modeled in this paper consists of an injection well, two production wells, the fracture system (or HDR reservoir), and a binary power plant. Water is pumped into the reservoir through the injection well where it is heated and then recovered through the production wells. Upon recovery, the hot water is pumped through a heat exchanger transferring heat to the binary, or working, fluid in the power plant. The power plant is a net 5.1-MW_e binary plant employing dry cooling. Make-up water is supplied by a local well. In this paper, the cost of producing electricity with the basic system is estimated as the sum of the costs of the individual parts. The effects on cost of variations to certain assumptions, as well as the sensitivity of costs to different aspects of the basic system, are also investigated.

Cost Summary

The following table summarizes the capital and operating cost estimates for the basic system:

Table 1: Cost Summary for the Basic System

Capital costs:		O&M:		
Plant	\$ 9.9M	Plant	\$1.0M/yr	2.5 ¢/kW·hr
Injection well	\$ 5.9M	Well field	\$0.6M/yr	1.5 ¢/kW·hr
Production wells (2)	\$10.8M			
Fracturing	\$ 4. M	Total	\$1.6M/yr	4.0 ¢/kW·hr
Water well	\$ 0.8M			
Total	\$31.4M (\$6200/kW _e installed)			

In arriving at the estimates in Table 1, no optimization for plant capacity has been performed. It is possible that a larger or smaller plant could result in reduced cost. The calculations and assumptions used to arrive at the above figures follow.

Primary Assumptions

The primary assumptions are

1. Two production wells and one injection well,
2. Binary power cycle with dry-cooling,
3. Plant availability is 90%,
4. Thermal-to-electric conversion efficiency is 17%,
5. Temperature of reservoir water at the inlet to the heat exchanger is 450°F (230°C),
6. Ambient air temperature is 80°F,
7. Pressure at the reservoir injection wellhead is 4000 psi,
8. Pressure at the reservoir production wellheads is 1500 psi,
9. Reservoir flow is 1000 gallons per minute (gpm),
10. Reservoir pump characteristics are
 - a. 0.80 pump efficiency and
 - b. 0.92 pump/motor efficiency,

11. Well depth is 13,100 ft (4000 m), and
12. No thermal depletion of the reservoir.

In order to achieve an inlet water temperature at the heat exchanger of 450°F (230°C) with a well depth of 13,100 ft (4000 m), an average geothermal gradient in excess of 60°C/km would be necessary.

Plant Thermodynamics

For dry cooling with an ambient air temperature of 80°F, the temperature of the working fluid leaving the condenser will be approximately 120°F and the temperature of the reservoir fluid leaving the heat exchanger will be about 140°F. Assuming no pressure drop across the heat exchanger, the enthalpy (h) at the inlet and outlet are

$$\begin{aligned} h(450^\circ\text{F}, 1500\text{psi}) &= 432.0 \text{ btu/lb} \quad (\text{all thermodynamic properties from Wark}) \\ h(140^\circ\text{F}, 1500\text{psi}) &= 111.7 \text{ btu/lb} \end{aligned}$$

This yields

$$\Delta h = 320.3 \text{ btu/lb of reservoir water}$$

Then the thermal recovery from the reservoir is

$$v(450^\circ\text{F}, 1500\text{psi}) = 0.01937 \text{ ft}^3/\text{lb}$$

$$\begin{aligned} P_t &= [320.3 \text{ btu/lb}] \{ (1000 \text{ gal/min}) (\text{min}/60 \text{ s}) \} / [(0.01937 \text{ ft}^3/\text{lb}) (7.48 \text{ gal/ft}^3)] \\ &= 36,800 \text{ btu/s} = 38.8 \text{ MW}_t \end{aligned}$$

At 17% thermal-to-electric conversion efficiency, the gross plant electrical output is

$$P_g = 0.17P_t = 6.6 \text{ MW}_g$$

Reservoir Pump Parasitic Losses

If head losses within the plant are ignored, the pump can be assumed to work between the pressure at the production wellheads, 1500 psi, and that at the injection wellhead, 4000 psi. For these working pressures, the required work rate to obtain a 1000-gpm flow rate is given by

$$\begin{aligned} W_p &= [(1000 \text{ gal/min}) / (7.48 \text{ gal/ft}^3)] \{ (4000 \text{ lb/in}^2 - 1500 \text{ lb/in}^2) (144 \text{ in}^2/\text{ft}^2) \} \\ &= 48 \times 10^6 \text{ ft} \cdot \text{lb/min} = 1460 \text{ hp} \end{aligned}$$

At a pump efficiency of 0.8, a pump rated at 1825 hp is needed. For a pump motor efficiency of 0.92, the pump parasitic losses will be

$$P_p = 1980 \text{ hp} = 1.5 \text{ MW}_p$$

Plant net electrical output is then 5.1 MW_g. The major in-plant parasitic loads, such as the condenser pumps, are accounted for in the thermal-to-electrical conversion efficiency. Plant lighting and miscellaneous power requirements could be an additional twenty-five to fifty kilowatt load; however, twenty-five to fifty kilowatts is smaller than the uncertainty in these calculations.

Plant Cost

The capital cost for a binary plant employing dry cooling is about \$1500/kW_g, and plant O&M will be from 10% to 15% of plant cost per year (Nichols). This gives plant capital and O&M costs of

Plant capital:	\$9.9M
Plant O&M:	\$0.99M to \$1.5M per year

It is uncertain how much maintenance would be required for the heat exchanger, but it should be equal to or less than that required for a hydrothermal binary plant. Also, this is a relatively small plant, thus it is not unreasonable that it would be highly automated, allowing unattended overnight operation. Then plant O&M is assumed to be near the lower end of the above bound: about \$1M/year. Based on net power of 5.1 MW, and 90% availability, plant O&M costs are estimated to be 2.5 ¢/kW·hr

Make-Up Water

The estimated water loss from an HDR reservoir is from 5% to 15%. For a 1000-gpm flow rate, the water losses would be from 50 gpm to 150 gpm. A single water well should be able to supply 300 gpm and, therefore, be adequate to supply make-up water. This water well is assumed to be drilled to 3000 ft at a cost of \$250/ft. The pump for the water well will cost in the neighborhood of \$60k. Then the capital cost for make-up water is

$$(3000 \text{ ft})(\$250/\text{ft}) + \$60,000 = \$810\text{k}$$

This estimate does not account for water rights. In many areas all water rights are sold. Thus, even after digging a well, water rights must be purchased before water can be consumed. The purchase price of water rights in the western U.S. can exceed the cost of purchasing municipal water in nearby communities.

Also, it is assumed that this water well will supply the water for fracturing the reservoir. However, it should be noted that for a twenty-million-gallon fracture, which is not unreasonable, a 300-gpm well will require a month and a half to produce the water for reservoir creation.

Reservoir Fracturing

In estimating the cost of building and operating an electrical generating station employing energy from HDR, probably the greatest uncertainty is in estimating the requirements for creation of the reservoir. For the purpose of estimating the cost of creating an HDR reservoir, the water volume and the pressure are needed.

One HDR reservoir for which fracturing data are available is at Fenton Hill, NM. Hydraulic fracturing of this reservoir was conducted from 1982 through 1984. The largest of these experiments was in December 1983 when 5.63 million gallons of water were pumped at 7000 psi (Duchane, 1991). The Fenton Hill reservoir has also been extended during experimental work.

The fluid volume of the Fenton Hill reservoir has been estimated at 2200 m³ from tracer tests (Robinson and Kruger). However, this is only 580,000 gallons, an order of magnitude less water than was pumped in the December 1983 fracture experiment alone. Therefore, it must be assumed that during fracture the reservoir is highly dilated and will hold significantly more water than during production.

Estimates of the volumetric extent of the Fenton Hill reservoir range from 2.9x10⁶ m³ to 28x10⁶ m³ of rock (Robinson and Kruger). The best estimate of the volumetric extent of the accessible reservoir is 16x10⁶ m³ (Duchane). This value corresponds roughly to the rock volume enclosed by two-thirds of the micro-seismic events that have been recorded during fracturing and operations at the site. The porosity of an HDR reservoir will vary with well-head pressure and with distance from the well-bore. Therefore, any single-valued estimate of porosity must represent an average. The porosity of the Fenton Hill reservoir is admittedly uncertain but has been estimated at 0.003 (Robinson and Kruger). Assuming an average porosity of 0.003 and a rock volume of 16x10⁶ m³ yields a total water volume of 48,000 m³ or about 13x10⁶ gallons. When compared to the known data and history of the Fenton Hill site, a water volume of 13x10⁶ gallons for creation of this reservoir in a single fracture event is not unreasonable. For this analysis, it is assumed that 13x10⁶ gallons pumped at 7000 psi are required to create a reservoir the size of that at Fenton Hill.

It is not at all certain that a pressure of 7000 psi is necessary for fracturing; 5000 psi may be adequate. Reduction of the fracturing pressure will reduce fracturing costs. The effect of variations in the cost of fracturing is discussed in a later section of this paper.

The pressure on the injection well at the Fenton Hill reservoir is limited to about 4000 psi to avoid reservoir expansion. This pressure limitation results in a flow limitation in the current two-well configuration of about 100 gpm. It has been estimated that a second production well at Fenton Hill could allow increasing the flow rate seven-fold. While it is not certain that the flow rate could be increased seven times, there is no doubt that a second production well would more than double the maximum achievable flow rate. Then a second production well at Fenton Hill would allow a flow rate somewhere between 200 gpm and 700 gpm. For the system being modeled here, somewhere between one and one-half and five times the flow rate possible with a second production well at Fenton Hill is required.

If it is assumed that the achievable flow rate increases linearly with reservoir size, a reservoir somewhere between one and a half and five times as large as the Fenton Hill reservoir is needed to obtain a flow rate of 1000 gpm in a system consisting of one injection well and two production wells. Then, assuming 13×10^6 gallons at 7000 psi are required to produce the Fenton Hill reservoir, somewhere between 19×10^6 gallons and 65×10^6 gallons of water at 7000 psi are required to achieve a reservoir capable of sustaining a flow rate of 1000 gpm.

In terms of the necessary heat capacity to support a power plant, an assumption of linearly increasing reservoir size is reasonable. However, as mentioned previously, flow is limited primarily by injection pressure, which, in turn is limited primarily by rock strength and in-situ stresses. So it is not certain that increasing reservoir size in itself will allow increased flow. An alternative assumption of a maximum obtainable flow capacity, thus requiring additional wells and reservoirs to achieve the total required flow rate, is discussed in a later section.

For 19×10^6 gallons, the energy requirements for fracturing are given by

$$(19 \times 10^6 \text{ gal})(\text{ft}^3/7.48 \text{ gal})(7000 \text{ lb/in}^2)(144 \text{ in}^2/\text{ft}^2) = 2.6 \times 10^{12} \text{ ft} \cdot \text{lb} \\ = 1.3 \times 10^6 \text{ hp} \cdot \text{hr}$$

At a rate of \$1.50/hp·hr, this operation would cost \$1.9M. A 65×10^6 -gal, 7000-psi fracture operation requires 4.4×10^6 hp·hr at a cost of \$6.6M. A cost of \$4M, approximately in the middle of the above two values, will be used.

Fracturing Summary

To summarize, in order to estimate the cost of creating the reservoir, the following assumptions were made:

1. Fracturing the Fenton Hill reservoir in one operation would require pumping 13×10^6 gallons of water at 7000 psi,
2. If a second production well were drilled at Fenton Hill, the maximum achievable flow rate would increase from 100 gpm to between 200 gpm and 700 gpm, and
3. The maximum achievable flow rate through a reservoir will increase linearly with reservoir volume.

Based on the above assumptions, it is estimated that between 19×10^6 gallons and 65×10^6 gallons of water, pumped at 7000 psi would be required for reservoir creation. At \$1.50/hp·hr, the cost of fracturing is estimated to be between \$1.9M and \$6.6M. An cost of \$4M is used in this analysis.

Well Costs

The drilling and well completion costs are based on a well depth of 13,100 ft (4000 m). When estimating drilling costs, the injection well was charged for mobilization, demobilization, and site costs. For the production wells, the only similar charges are those for moving the drill rig on site. It is assumed that the injection well can be drilled without directional control, however, charges for mud motors and directional control are included in the cost estimates for the production wells, since it is expected that these wells would need to be guided to intersect the fracture cloud. The estimated daily operating cost and casing schedule for well drilling and completion are given in the following tables:

Table 2: Day Rate

Rig rate	\$10,000
Fuel costs	0
Camp expense	\$500
Drilling supervision	\$1000
Mud logging	\$1000
Transportation	\$1200
Water	\$500
Miscellaneous	\$1000
Daily operating cost	\$15,200

Table 3: Casing Schedule

Depth	Hole Size	Casing Size
50 ft	48 in	42 in
300 ft	36 in	30 in
1500 ft	26 in	20 in
4500 ft	17 1/2 in	13 3/8-in liner
10,000 ft	12 1/4 in	9 5/8 in
13,100 ft	8 3/4 in	7-in liner

Based on the data in the above tables and the previous discussion, the drilling and completion costs are summarized in Table 4. The contingency cost given in Table 4 can be considered the best estimate, or expected cost, of drilling problems. Since the totals do not include contingency costs, they represent the expected cost for drilling and completion of trouble-free wells. Because of the expected geology in a region where HDR wells would be drilled, it may be possible to reduce the well costs by convincing the regulating agencies that many of the precautions required in oil, gas, and hydrothermal drilling are unnecessary. This might save as much as 10% of the well cost. The estimates in Table 4 allow for state and federal regulations regarding drilling safety and operations.

Table 4: Well Cost by Account

	Injection Well	Production Well
Mob, demob, and site	\$620k	\$140k
Operating cost	\$1763k	\$1710k
(Rig cost)	(\$1160k)	(\$1125k)
Mud cost	\$579k	\$457k
Bits and tools	\$792k	\$792k
Directional		\$132k
Logging	\$187k	\$187k
Casing	\$991k	\$991k
Cement	\$539k	\$539k
Blow-out preventer equipment	\$51k	\$53k
Wellhead equipment	\$90k	\$90k
Completion	\$120k	\$120k
Testing	\$200k	\$200k
Contingency	\$529k	\$513k
Total	\$5,932k	\$5,411k

Notes:

1. Operating cost includes rig cost
2. Totals do not include contingency cost

For well-field O&M, daily maintenance and operations will cost about \$200k/yr. This cost assumes one person's labor plus maintenance and repair contracts. Additionally, hydrothermal wells require work-over and clean-out every one to two years depending primarily on brine chemistry. It should be possible to maintain a certain amount of control over the chemistry in HDR wells, thus reducing the maintenance schedule when compared to hydrothermal wells. On this basis, it is assumed that each HDR well will need work-over every three years; thus the site average will be one well per year.

Clean-out and work-over will require a work-over rig for about 15 days at \$10k/day (\$150k). Mobilization and demobilization of the rig will cost another \$100k. Materials for work-over (wellhead, cement, casing, etc.) are estimated to cost between \$150k and \$500k. Using the lower bound for materials yields an estimate of \$400k for work-over. Combining work-over and daily maintenance, well field O&M is estimated to cost \$600k/yr. For a net 5.1-MW_e plant operating at 90% availability, this is about 1.5 ¢/kW-hr.

Cost Summary

A summary of the estimated capital and O&M costs for the basic HDR system are given in Table 5.

Table 5: Cost Summary for the Basic System

Capital costs:		O&M:		
Plant	\$ 9.9M	Plant	\$1.0M/yr	2.5 ¢/kW·hr
Injection well	\$ 5.9M	Well field	\$0.6M/yr	1.5 ¢/kW·hr
Production wells (2)	\$10.8M			
Fracturing	\$ 4. M	Total	\$1.6M/yr	4.0 ¢/kW·hr
Water well	\$ 0.8M			
Total	\$31.4M (\$6200/kW _e installed)			

Table 6 gives the capital recovery for three discount rates. The 4.6% discount rate was employed in the DOE technology characterization for HDR. For comparison, rates of 10%, and 15% are also included.

Table 6: Capital Recovery for \$31.4M Over 30 Years

Discount Rate	Capital Recovery (90% plant availability)	
4.6%	\$1.95M/yr	4.9 ¢/kW·hr
10%	\$3.33M/yr	8.3 ¢/kW·hr
15%	\$4.78M/yr	11.9 ¢/kW·hr

This completes the cost analysis for the basic plant. In the following sections, some of the assumptions made previously are examined, the sensitivity of the results to these assumptions is discussed, and, in some cases, the costs associated with alternative assumptions are estimated.

Thermal Depletion

It has been assumed that no thermal depletion of the reservoir will occur. This is not realistic; however, there are no data on which to make an informed estimate of thermal depletion for an HDR reservoir. In order to maintain full plant output, it may be necessary to drill new wells and/or fracture new rock one or more times over the life of the power plant. The capital costs associated with drilling three new wells and creating a new reservoir are given in Table 7.

Table 7: Capital Costs for New Wells and Reservoir

Injection Well	\$ 5.9M
Production Wells (2)	\$10.8M
Fracturing	\$ 4. M
Total	\$20.7M

Assuming the new wells and reservoir are needed after fifteen years, the cost, with 3.5% inflation, will be \$34.7M. The capital recovery requirements for a new reservoir at fifteen years depend on the discount rate. For the same three discount rates discussed previously, Table 8 gives the capital recovery for this thermal depletion scenario.

Table 8: Capital Recovery for New Wells and Reservoir After Fifteen Years

Discount Rate	Present Value	Capital Recovery	
4.6%	\$17.7M	\$1.10M/yr	2.7 ¢/kW·hr
10%	\$8.3M	\$0.88M/yr	2.2 ¢/kW·hr
15%	\$4.3M	\$0.65M/yr	1.6 ¢/kW·hr

This is not to imply that it is expected that three new wells and a new reservoir will be needed after fifteen years. There are a large number of possible approaches to compensating for any thermal depletion that may occur. For a given discount rate and a specific prediction of thermal depletion, an operational strategy to minimize costs can likely be determined.

Reservoir Pumping Costs

The requirement to pump water at high-pressure through the reservoir results in a significant cost. Besides the capital cost of a 2000-hp pump, the high-pressure requirements to dilate the reservoir require that the production and injection wellheads, as well as the connecting pipe, be rated for high pressure. Also, the reservoir side of the heat exchanger must contain high-pressure tubing.

All of the above requirements, due to high-pressure pumping, increase capital costs; however, there is another cost due to reservoir pumping requirements: the parasitic power losses. In the base case, the pump reduced the net plant output by 1.5 MW_e. This represents a fourth of the capacity of the plant. Reduction of the high-pressure pumping requirement could reduce levelized costs up to 25% through increased plant output alone.

Fracturing Costs

Perhaps the greatest uncertainty in the cost estimates are those associated with reservoir creation. As discussed previously, in the basic system an estimate of \$4M was used. However, this value is based on a rather crude estimate of the water volume necessary to create the Fenton Hill reservoir in a single operation and an admittedly questionable assumption of a linear relationship between reservoir volume and the maximum achievable flow rate. Table 9 shows the effect of variations in the cost of reservoir creation on capital costs.

Table 9: The Results of Different Reservoir Fracturing Costs

Fracture Cost	Capital Cost		Difference
\$1M	\$28.4M	\$5600/kW installed	- 10%
\$4M	\$31.4M	\$6200/kW installed	-
\$6M	\$33.4M	\$6600/kW installed	+ 6%

According to the data in Table 9, reducing the cost of fracturing the reservoir by 75% (from \$4M to \$1M) will reduce capital costs by 10%. A 50% increase in fracturing costs (from \$4M to \$6M) increases capital costs by 6%. From these data it appears that the effect of fracturing cost on project cost is not nearly as large as the uncertainty in the fracturing cost itself.

Flow Rate Uncertainty

In the basic system, it was assumed that the achievable flow rate increases linearly with reservoir volume. The only way that this assumption makes sense is if the reservoir volume is increased by increasing the length of the well bore exposed to the fracture cloud. However, it is by no means certain that this would be successful. It may be that rock strength and in-situ stresses will essentially determine the maximum possible flow rate regardless of reservoir size.

As discussed previously, a second production well at Fenton Hill would allow an increase in flow rate from the current 100 gpm to between 200 gpm and 700 gpm. If it is assumed that a second production well would result in a flow rate of 500 gpm, then two reservoirs the size of Fenton Hill, each with one injection well and two production wells, would be needed to supply 1000 gpm.

At a pressure of 7000 psi, the energy requirements for a 13x10⁶-gallon fracture operation are given by:

$$(13 \times 10^6 \text{ gal})(\text{ft}^3/7.48 \text{ gal})(7000 \text{ lb/in}^2)(144 \text{ in}^2/\text{ft}^2) = 1.8 \times 10^{12} \text{ ft} \cdot \text{lb} \\ = 880 \times 10^3 \text{ hp} \cdot \text{hr}$$

At a cost of \$1.50/hp-hr, each fracture operation would cost \$1.3M for a total fracture cost of \$2.6M.

Plant O&M would be no different for the dual-reservoir case than for the base case: \$1M/yr or about 2.5 ¢/kW-hr. However, well field O&M would be higher for the dual-reservoir case. As with the base case, it is assumed that daily maintenance and operations will cost about \$200k/yr. However, under the same rationale discussed previously, two wells per year would need work-over. This would require a work-over rig for about 30 days at \$10k/day (\$300k). Mobilization and demobilization will cost another \$100k and materials are estimated to cost about \$150k/well (\$300k). This yields a total of \$900k/yr for well field O&M. At a plant availability of 90%, this translates to about 2.2 ¢/kW-hr. The costs for the dual-reservoir case are summarized in Table 10.

Table 10: Cost Summary for Dual-Reservoir Case

Capital Costs:		O&M:		
Plant	\$ 9.9M	Plant	\$1.0M/yr	2.5 ¢/kW-hr
Injection wells (2)	\$11.4M	Well field	\$0.9M/yr	2.2 ¢/kW-hr
Production wells (4)	\$21.6M			
Fracturing (2)	\$ 2.6M	Total	\$1.9M/yr	4.7 ¢/kW-hr
Water well	\$ 0.8M			
Total	\$46.3M (\$9100/kW _e installed)			

In estimating well costs, mobilization and demobilization of the drill rig is charged to one injection well. The other injection well is charged only for moving the drill rig on site. Comparison of Table 10 with either Table 1 or Table 5 indicates that both the capital and the O&M costs for the dual-reservoir case are significantly higher than for the base case.

Conclusions

The cost of an HDR electrical generating system consisting of a single injection well, two production wells, and a dry-cooled binary power plant has been estimated. Also, the uncertainty and sensitivity of the cost of a number of aspects of this system have been discussed. These are summarized in the following table:

Table 11: Cost Summary

	Capital Cost	Difference	O&M Cost	Difference
Basic System	\$31.4M	-	4.0 ¢/kW-hr	-
Pumping Parasitic Losses	\$31.4M	*	3.1 ¢/kW-hr	- 23%
95% Plant Availability	\$31.4M	*	3.8 ¢/kW-hr	- 5%
Fracture Cost Uncertainty	\$28.4M - \$33.4M	- 5% to + 3%	4.0 ¢/kW-hr	-
Dual-Reservoir System	\$46.3M	+ 47%	4.7 ¢/kW-hr	+ 19%

While the second and third items in Table 11, pumping parasitics and plant availability, do not effect the total capital cost, they will reduce the cost per kilowatt-hour for capital recovery by the same percentages that they reduce O&M costs. Plant availability was included because there is some uncertainty in the value used. Hot-brine hydrothermal plants generally achieve availabilities significantly higher than 90%, sometimes producing over 100% of rated capacity for extended periods of time. There is no reason to believe that an HDR plant delivering baseload power should not do as well. Thus, the 90%-availability assumption may be conservative and the third line in Table 11 gives an indication of the effect on cost.

Technically, the greatest uncertainty in the development of the HDR resource for production of electricity is the reservoir; what flow rate can be achieved, what are the fracturing requirements, how large must the reservoir be, what are the thermal depletion characteristics, etc. However, the greatest proportion of the cost associated with production of electricity from HDR is not associated with the reservoir. Even at an estimate of \$4M for fracturing, this is still less than 13% of the total capital cost.

The greatest cost in an HDR project is drilling the wells. Well costs are estimated to account for more than 50% of the capital costs of the basic system and more than 70% of the capital costs of the dual-reservoir system; therefore, drilling is an attractive target for cost reduction. However, reducing drilling costs is not a simple task. People have been drilling holes in the ground to extract fluids for longer than a century; drilling is a mature industry. Also, the problem is not just the cost of making the hole. Inspection of Table 4 reveals that from 25% to 30% of the well costs are for materials used in completing the well: cement, casing, and wellhead. So, even if the holes are free, completion materials will still cost \$1.6M per well. Without the development of new completion methods, current completion practices significantly limit the cost reductions possible even with the development of a revolutionary drilling technology.

An indirect approach to reducing the significance of well costs would be to increase the productivity per well. Considering the increased cost of the dual-reservoir system, significant expenditures to avoid the necessity of a second reservoir can be justified. The flow rate in the basic system was assumed to be 1000 gpm using three wells. If it is possible to double the flow rate to 2000 gpm, the cost per installed kilowatt could be significantly reduced, even if fracturing costs also doubled. Since plant capital costs would also increase, doubling the flow rate would not reduce the installed cost by half, but initial calculations indicate that doubling the flow rate could reduce the installed cost per kilowatt by 25% to 35%.

Note: Work performed at Sandia National Laboratories is supported by the U.S. Department of Energy under contract DE-AC04-76DP00789

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POTPOURRI

**Chairperson: Gladys Hooper
DOE Geothermal Division**

POTPOURRI SESSION OVERVIEW

Gladys J. Hooper
U.S. Department of Energy
Washington, DC

Unlike most of the earlier sessions, which focused on a specific topic or research area, this session covered a diverse group of projects. The presentations ranged from an overview of the low-temperature resource assessment program (including geothermal heat pumps) to a review of bioprocessing techniques being used to remove undesirable elements from geothermal residual wastes. Presentation highlights are summarized below:

Low Temperature Assessment

The first speaker, Paul Lienau, of the Geo-Heat Center at the Oregon Institute of Technology presented the history, objectives, and key features of a new program to evaluate and use low- and moderate-temperature geothermal resources. He stated that the program involves a collaborative effort among a number of academic and state institutions working with potential direct-heat developers, as well as eastern institutions knowledgeable of geothermal heat pumps. He also stated that the program objective is aimed at facilitating the development of low- and moderate-temperature geothermal resources.

Near-Term Demand and Market-Side Analysis of Geothermal Electric Power

Brian Parsons of the National Renewable Energy Laboratory concentrated on highlights of an analysis being conducted by his planning group to evaluate the electric demand and market developments that will influence the development of new geothermal electric plants over the next 10-20 years. He concluded that the opportunity for increased geothermal electric development is not limited by either electric market demand or overall resource potential, but other competitive factors.

Biochemical Treatment of Geothermal Wastes

Eugene Premuzic of Brookhaven National Laboratory spoke of his research team's ongoing progress in using biotreatment techniques to reduce costs associated with handling geothermal byproduct materials. He stated that the low-cost, environmentally acceptable biotreatment process has shown in laboratory studies that 80% of the toxic materials can be removed in short periods of time (4 to 25 hours), thereby having the potential to cut waste disposal costs for some geothermal operations by as much as 50% or more.

Geothermal Brine Chemistry Model

John Weare of the University of California at San Diego provided an overview of some of the uses (e.g., scale and gas breakout control) of a chemical model being developed to improve the efficiency of geothermal operations. In addition to addressing the model capabilities and the quality of the modeling results, he provided several examples of ongoing efforts to make the model more user-friendly. For example, he stated that the model is now available in PC-versions and that two user workshops have been given to the geothermal community to demonstrate model uses and facilitate the exchange of information between the modeling group and industry.

Bonneville Power Administration Geothermal Activities

George Darr of the Bonneville Power Administration (BPA) presented an update on institutional issues that may affect geothermal development in the Pacific Northwest. Mr. Darr updated the group on the various environmental baseline studies that are ongoing in the area as a precursor to full-scale development of geothermal and other renewable resources. These studies are being conducted to ensure there is a strong atmosphere of environmental acceptability, in this scenic part of the nation, where environmental concerns are sometimes strong and where people have a historical tradition of working together to address such issues. Earlier in the day, David Lombard noted that the geothermal potential of the Pacific Northwest is huge because of the great abundance of geothermal resources there and the accelerating market demand.

LOW-TEMPERATURE RESOURCE ASSESSMENT PROGRAM

by

Paul J. Lienau
Geo-Heat Center
Oregon Institute of Technology

Howard Ross
University of Utah Research Institute

ABSTRACT

In Fiscal Year 1991, Congress appropriated money for the Department of Energy to begin a new program in the evaluation and use of low- and moderate-temperature geothermal resources. The objective of this program is to promote accelerated development of these resources to offset fossil-fuel use and help improve the environment. The program will consist of several components, including: (1) compilation of all available information on resource location and characteristics, with emphasis on resources located within 8 km (5 miles) of population centers; (2) development and testing of techniques to discover and evaluate low- and moderate-temperature geothermal resources; (3) technical assistance to potential developers of low and moderate-temperature geothermal resources; and (4) evaluation of the use of geothermal heat pumps in residential and commercial applications. Program participants will include the Geo-Heat Center at the Oregon Institute of Technology, the University of Utah Research Institute, the Idaho Water Resources Research Institute and agencies of state governments or Universities in most of the western states.

INTRODUCTION

Low-to-moderate temperature geothermal resources are widely distributed throughout the United States (Reed, 1983) and can provide a source of energy for many direct-heat applications. In contrast to other renewable resources, geothermal energy is not hindered by a cyclical output as in the case of wind and solar. It is a base load (constant output) resource the application of which does not require sophisticated storage strategies. Geothermal energy in the low temperature range can have a significant impact on U.S. energy consumption, especially with regard to space heating. Space heating in the 50° to 82°C (120° to 180°F) range is by far the largest single U.S. energy use, representing 45 percent of all energy use below 260°C (500°F). Matching geothermal resources to meet these space heating requirements would result in much better use of U.S. energy reserves and reduce emissions from fossil fuel.

Much of the recent interest in developing direct-heat resources may be attributed to a Department of Energy initiative, the State Coupled Program, which began in 1977. As a result of this program, geothermal resource maps were compiled and distributed for 18 western states. The maps, typically printed at a scale of 1:500,000, identify wells and springs with

anomalous temperatures, and were released from 1980 to 1983. These maps, and the data and reports upon which they were based, have been extremely useful to the more aggressive developers, and form an important starting point for the current update assessment study.

The Geo-Heat Center of Oregon Institute of Technology authorized a study of the collocation of geothermal resources and communities for eight western states (Allen, 1980). The criteria used in this study included incorporated cities located within 8 km (5 miles) of a thermal well or spring having a temperature of 50°C (122°F) or greater. This inventory identified a total of 1,277 hydrothermal sites within 8 km (5 miles) of 373 cities, having a combined population of 6,720,347 persons, in the eight states. The total heat for all cities, exclusive of industrial loads, was estimated at 140×10^{12} kJ/yr (133×10^{12} Btu/yr).

While the 1980 Allen study was quite instructive and arrived at impressive population and heat-load estimates, it was limited in scope to only eight states, and did not account for low-temperature uses for agriculture, greenhousing, or aquaculture. Also, it predated the publication of results from the DOE State Coupled Program. Clearly, the Allen study is outdated.

We believe a complete inventory of collocated resources and population centers will indicate a potential heat load for the western states (exclusive of industrial loads) more than 10 times the Allen estimates. It is apparent that geothermal energy could make a much more substantial contribution to our energy picture; but, the private sector needs the necessary information and stimulation.

LOW-TEMPERATURE PROGRAM

The program is a cooperative effort among a number of academic and state institutions working with potential direct-heat developers. The three principal institutions are the Geo-Heat Center at the Oregon Institute of Technology, the Idaho Water Resources Research Institute at the University of Idaho, and the Earth Science Laboratory of the University of Utah Research Institute. State Teams compiling data for ten states in the west are also participating. In addition, participation of eastern institutions knowledgeable in geothermal heat pumps is planned. The tasks for this project are discussed below.

Compilation of Data on Hydrothermal Resources

State geothermal resource teams will review and update their geothermal resource inventories which were completed as part of the USGS-DOE national assessment from 1977-1983. Each state will prepare a comprehensive digital database in table format and a resource map at a scale of 1:1,000,000. UURI and OIT will provide technical guidance and coordination, and UURI will complete 10 fluid chemistry analyses for each state. Table 1 identifies the state agencies and principal investigators involved with the project.

Table 1. State Resource Assessment Teams

State	Agency	Principal Investigator
California	Division of Mines and Geology	Leslie Youngs
Colorado	Colorado Geological Survey	James Cappa
Idaho	Idaho Water Resources Research Institute	Leland Mink
Montana	Bureau of Mines and Geology	Wayne Van Voast
New Mexico and Arizona	New Mexico State University - Southwest Technology Development Institute	James Witcher and Rudi Schoenmackers
Nevada	Bureau of Mines and Geology	Larry Garside
Oregon	Dept. of Geology and Mineral Industries	George Priest
Utah	Utah Geological Survey	Robert Blackett
Washington	Division of Geology and Earth Science	Eric Schuster

The compilations will include resources in the temperature range of 20° to 150°C (68° to 300°F) many of which have potential to supply energy to collocated cities within approximately 8 km (5 miles) of a resource as well as greenhouses, aquaculture, mining, and other process applications.

The State Teams, under subcontract to OIT and with guidance from UURI, are reviewing drilling records and other information to identify new resources and verify temperatures and flow rates of springs and wells which may have changed substantially since the previous statewide geothermal resource inventory. The databases will be organized into tables linked by common data-fields, using the preliminary database from the Utah Geological Survey

as a model for uniformity in presentation (Blackett, 1993). Information to be contained in the tables is listed below:

Table 1. Location: ID number, source name, county code, latitude and longitude.

Table 2. Description: ID number, source name, type of source, temperature (°C), flow rate (L/min), depth of wells (m), current resource use, and references to relevant studies (geology, geophysics, geochemistry, hydrology) completed for the site.

Table 3. Geochemistry: ID number, source name, pH, TDS, major cations, major anions, cation-anion balance, chemical species that may cause scale and corrosion products, and light stable isotopes.

Simultaneously, we will collect and interpret demographic and other data to evaluate potential heat loads, fossil-fuel displacement, utility electrical-demand reduction and load-leveling opportunities, and environmental benefits for potential geothermal direct-heat applications.

These two data sets, resource and demographic, will be jointly interpreted with the main objective of making a prioritized list of resources which have highest potential for economic development with significant benefit for in depth studies. Promising resources for near-term development will be studied in more detail when Phase 2 funding becomes available.

At the same time, we will undertake R&D on better cost effective methods for locating low- and moderate-temperature geothermal resources and on siting successful test and production wells. Part of this work will encompass development of better well-testing methods and better hydrologic models of these hydrothermal resources. These tasks are expected to pay off in further discoveries of resources and in better methods to evaluate reservoir production and ultimate-development capacity at an earlier stage in the development cycle than is possible now.

Geothermal Heat Pump Analysis and Use

We are collecting and interpreting information on the performance of residential and commercial installations of geothermal heat pumps (GHPs). This will yield information on: (1) the most effective and successful utility marketing and incentive programs to expand GHP markets; (2) the benefit to utilities from reduced peak demand and higher annual load factors; (3) barriers to market entry; (4) the potential total national energy savings contribution from GHPs; and (5) suitability of GHPs for northern climates. Energy-use patterns are being documented before and after installation of GHPs in typical

residential and commercial situations, along with energy savings and life-cycle costs.

Based on contacts with 36 utilities, they see geothermal heat pumps as a peak reducing demand side management (DSM) tool and many offer incentives of some kind. Incentive programs offered by utilities to customers include: rebates of \$125 to \$500 per ton of installed capacity, low cost loans, discounts on electric rates for the heat pump system, and in some cases they install ground coupled closed loops. In some cases, heat pumps are seen as a means of retaining customers with all-electric homes built in the 1960s to early 70s who are now tempted to switch to cheaper natural gas. Barriers to market entry of GHPs are higher initial costs (\$800 to \$1000/ton) than other HVAC systems due to incremental cost of the ground loop heat exchanger installation and a lack of an infrastructure of ground loop contractors and dealers. Where there are good contractors and inspections, customer satisfaction has been good.

A preliminary performance analysis has been evaluated for two ground-coupled heat pump (GCHP) residential systems in Minnesota from data obtained from United Power Association, Elk River, MN (Connett, 1993). Data was collected on an hourly basis, monitoring ground loop supply and return temperatures, outside air temperature, compressor power, circulating pump power, and water heater power.

The first home (260 m² or 2800 ft²) located in Stanchfield, MN was installed with a 4-ton heat pump using a vertical ground-coupling of five 45.7 m (150 ft) boreholes. Figure 1 shows a comparison of the geothermal heat pump with an air-source heat pump for a peak winter day when the outside temperature was at -28°C (-18°F). The geothermal heat pump had a 7.4 Kw lower peak demand and 5,294 Kwh lower annual heating and cooling energy than the air heat pump. The annual savings for the GHP was 11% for the cooling and 34% for the heating seasons compared to the air heat pump.

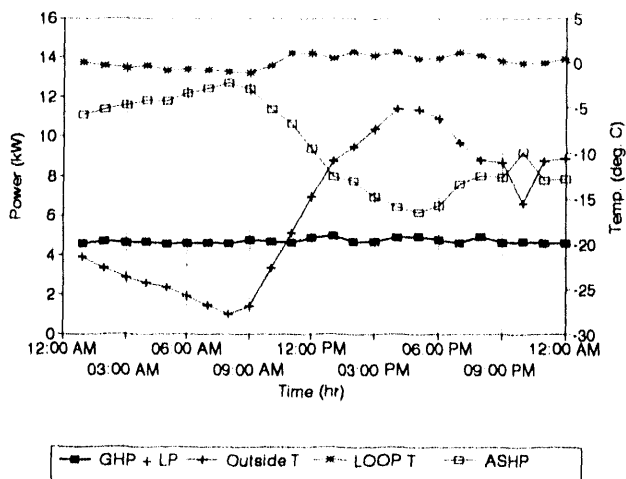


Figure 1. Demand comparison of a geothermal heat pump (vertical ground-coupled) with an air-source heat pump.

The second home (260 m² or 2800 ft²) located in Zimmerman, MN was installed with a 5-ton heat pump using a horizontal ground-coupling of 671 m (2200 ft) of pipe. The GHP had a 5.7 Kw lower peak demand than the air heat pump on the coldest winter day. Figure 2 shows a comparison of water temperatures in the loops for the vertical and horizontal configurations. A difference of about 6°C (10°F) in the winter and 11°C (20°F) in the summer will result in a better performance for the vertical ground-coupled heat pump.

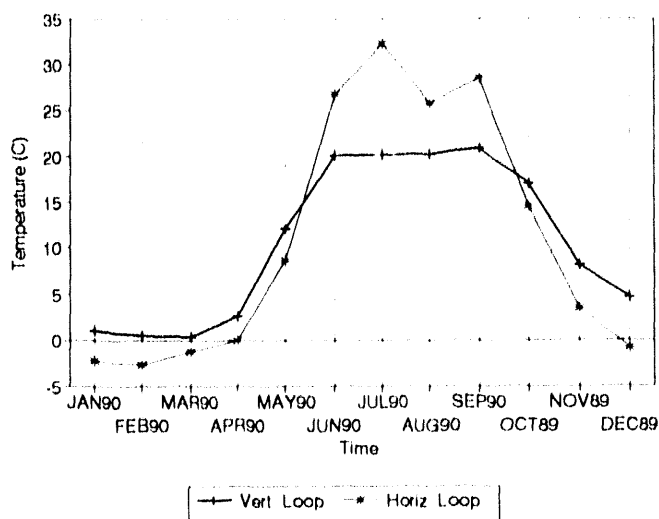


Figure 2. Loop supply temperature comparison for vertical and horizontal ground-coupled heat exchangers.

In the course of the above work, we will identify weaknesses in the technology and data base, with the objective of describing needed R&D that would accelerate GHP use.

Outreach and Public Education

All project personnel are working cooperatively and closely with state and local agencies, energy offices and other public entities. This network will bring information on geothermal resources and their uses to the public and to potential geothermal developers. We are also working closely with the Geothermal Resources Council, the National Geothermal Association, the Geothermal Education Office and other entities in the geothermal community. We are developing brochures on geothermal direct-heat, fact-sheets on GHPs and geothermal energy in general. We will also produce an informative video for general national distribution on geothermal energy and its advantages.

FUTURE PLANS

The state teams will complete their inventory, database listings, and resource occurrence maps in FY-93 and early FY-94. These will be reviewed and edited by UURI and OIT. OIT will complete the collocation study and with UURI and IWRI, will prioritize resources for more detailed study. The results will be reviewed by and discussed with the

appropriate state teams. UURI will complete fact sheets to inform Congress of the progress, and with OIT and IWRRI will solicit support for Phase 2 funding of additional states and detailed studies for the most promising resources for near-term development. We envision the present program to be the first part of an ongoing effort that will take possibly 5 years to complete.

Further information on this program can be obtained by contacting any of the authors, or Mr. Joel Renner, INEL, P.O. Box 1625-3830, Idaho Falls, ID 83415, or Mr. Marshall Reed or Mr. Lew Pratach, U.S. Department of Energy, 1000 Independence Avenue SW, Washington, D.C. 20585.

ACKNOWLEDGEMENT

This work was supported by the U.S. Department of Energy under EG&G Subcontract C92-120253. Such support does not constitute an endorsement by the Department of Energy of the views expressed herein.

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NEAR-TERM DEMAND AND MARKET ANALYSIS OF GEOTHERMAL ELECTRIC POWER

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SUMMARY

This paper covers the highlights of an analysis project addressing the electric demand and market developments that will influence the deployment of new U.S. geothermal electric plants over the next 10-20 years. I conclude that the opportunity for increased geothermal capacity installation is not limited by either electric market demand or overall resource potential. Instead, the installation rate of new geothermal power plants will be driven by the success of the technology in the new and evolving competitive marketplace.

Historically, high guaranteed power purchase rates were a key driver of geothermal development outside the Geysers region. However, these contract terms are no longer available. Electric demand growth rates are projected to be low, but there are significant uncertainties associated with these projections that could drive up the demand for new capacity. Hydrothermal resources are available, but a large portion of the potential is in unproven areas. Once resource uncertainty is addressed, a significant market opportunity exists in western states, beyond current industry plans.

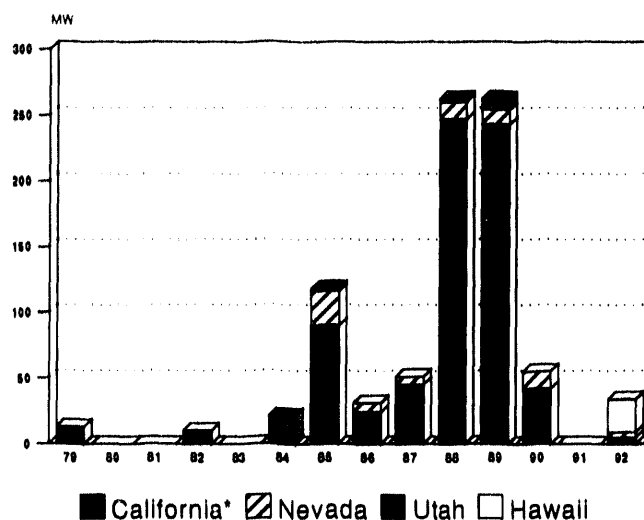
Past geothermal development has taken place in states dominated by private, investor-owned utilities (IOUs). The utility sector in states with resource potential but no current geothermal power plants is more diverse, with a large number of government-owned and government-financed public utilities. Important differences between private and public utilities, such as regulatory oversight, influence attitudes toward geothermal and are factors in ultimate market success.

Competitive bidding has become the primary mechanism for new utility acquisitions and power contracting. Renewable electric power technologies have not fared as well under bidding as under earlier acquisition procedures based on the Public Utility Regulatory Policies Act (PURPA); however, use of integrated resource planning, and particularly incorporation of externalities in acquisition processes, may help in the near future.

Lastly, a number of regulatory, project developer, and government opportunities for increased market deployment are listed.

HISTORIC DEVELOPMENT FRAMEWORK

Geothermal power in the United States has been dominated, in the total megawatt sense, by development in the Geysers resource area. This unique, low-cost, dry-steam resource has been fully exploited. However, additional development has continued at liquid dominated resources scattered throughout the West and Hawaii, as shown in Figure 1. In the 1970s and early 1980s, general private and public sector interest in geothermal energy led to intense applied research, on the part of both industry and governments, on ways to turn liquid-dominated hydrothermal resources into practical power sources. The timing of development outside the geysers area was mainly driven by regulatory developments (and to a lesser degree by tax incentives). In many states, implementation of PURPA in the early 1980s resulted in the availability of long-term contracts with stable, high payments for power. Contract availability and the high payment schedules were based on projections of capacity and energy shortfalls, and high fuel price escalation rates. In California, readily available 'Standard Offer' contracts were signed by a large number of developers. These contracts are no longer available, and the installation rate has fallen off substantially as a result.



*Figures include plants located in Nevada delivering power to California

Figure 1. Geothermal plant completions (outside geysers).

PROJECTIONS OF ELECTRIC POWER DEMAND

Future geothermal and other renewable electric power plant construction rates will be tied much more to the electric market than in the past. Resources must be cost-effective, and acquisition will be limited by the overall market need. The success of conservation efforts and a more moderately expanding economy have resulted in lower electric demand growth rates. Current projections are for around 1.5% to 2.5% annual growth.¹

Even though growth rate estimates are low, plans of western utilities for capacity additions fall short of projected needs by around 10 GW over the next 10 years, as shown in Table 1.² Much of this shortfall can be attributed to reliance on short lead-time gas-fired facilities, which can be developed as needs materialize. However, the gap between planned capacity and anticipated needs indicates market opportunities for all generation technologies, particularly in the Northwest and in California/southern Nevada. A number of factors could impact demand growth, including

- Success, reliability, and persistence of demand-side management (DSM) programs
- Bypass or self-generation by large customers as rates increase
- Additional requirements due to use of electric vehicles (e.g., Southern California).

DSM is being embraced by many utilities, and in many cases DSM is being relied on to meet the bulk of future needs. This situation introduces risk—utilities are essentially participants in a large-scale experiment in which the engineering and economic results over a long time frame are largely unknown. There is a large uncertainty associated with the success of DSM. Some utilities are expanding programs, but a number of utilities have cut back on projected savings from DSM, increasing their need for additional short lead-time supply-side resources.³

In addition to growth in demand, the market for new power plants is influenced by changing plans involving use of existing plants. Uncertainties are introduced on the supply side by the following:

- Full impacts of the 1990 Clean Air Act Amendments (CAAA)
- Effects of taxation and other government policies, for example, potential future global warming mitigation measures
- Drought and environmental factors associated with hydro systems
- Changes in repowering, retirement, and refurbishment schedules
- Additional transmission-facilitated north-south seasonal energy exchanges.

**Table 1. North American Electric Reliability Council
Regional Electric Projections**

NERC Subregions	Projected change from 1991-2001				
	Additional Peak Demand		Planned Capacity Additions		Unplanned Increments MW
	MW	Annual Growth	MW	Annual Growth	
NW Power Pool	8,878	1.5%	1,394	0.3%	7,484
Rocky Mountain	1,560	2.0%	1,704	2.0%	-144
Arizona-New Mexico	3,686	2.3%	2,280	1.5%	1,406
California-southern Nevada	9,712	1.6%	6,316	1.1%	3,396
Total: Western System Coordinating Council	21,100	1.7%	11,247	0.9%	9,853
Total Continental U.S.	110,228	1.8%	88,374	1.3%	21,854

Note: The peak demand for the Northwest Power Pool occurs during the winter, while the other subregions have maximum peaks in the summer. The Coordinating Council and U.S. totals are for the summer peak demand.

As an example, the prolonged drought in the Northwest has reduced revenues and increased costs, resulting in a drastic reduction in the financial reserves of the Bonneville Power Administration (BPA) (from \$1 billion to less than \$90 million (projected)).⁴ The drought has resulted in energy curtailments of around 555 MW of nonfirm energy.⁵ In addition, BPA hydro operational changes caused by measures designed to help migratory fish have resulted in the permanent loss of 300 MW (average) of firm capacity.⁶ These losses will have to be replaced by other resources.

Combining these supply and demand factors, I believe current projections for future resource needs are more likely to be on the low side than on the high side. Any additional needs open the market further.

RESOURCE ESTIMATES AND GEOTHERMAL DEVELOPMENT PLANS

Table 2 compares geothermal development projections with estimates of developable hydrothermal resource. The development plans reported by McClarty and Geyer,⁷ of just under 1000 MW by the close of the decade, are perhaps most reliable. Therefore, there is a large potential for increased development from both a resource and regional electric demand perspective. The two largest factors influencing development are how geothermal stacks up in the evolving competitive environment and the risk associated with developing new geothermal resource areas.

MARKET CHARACTERISTICS

Exploitation of the full market potential requires expanding geothermal deployment beyond existing markets of California and Nevada (Utah and Hawaii also have small installations). Success in the marketplace is tied to meeting the needs of utilities. Figure 2 shows that the power market in continental states with existing geothermal electric plants is dominated by IOUs. The power market in other western states with geothermal resource potential is much more diverse and includes a large number of public power agencies such as municipalities, rural electric associations (REAs), two federal power marketing administrations (BPA and Western Area Power Agency (WAPA)), and other public utility districts.¹¹

Table 3 compares general characteristics of IOUs and public utilities. These differences are important to developers and policy makers who are interested in promoting deployment of a technology. Public utility commissions (PUCs), or other equivalent state regulators, are the primary decision makers in IOU planning and acquisition processes. The procedures are formal and allow a large amount of public input. On the other hand, public power utilities usually are

Table 2. Comparison of Geothermal Development Projections and Resource Potential

Development Plans		
North American Electric Reliability Council (NERC) ² additions 1991-2001	475 MW	As reported by utilities to NERC
McClarty and Geyer ⁷ additions 1992-2000	846-906 MW	Compiled from industry plans, including planned, speculative, and offered capacity
Energy Information Administration (EIA) ⁸ additions 1990-2000	3700 MW	Based on a historic average installation rate per year
Resource Estimates		
Wright, ⁹ potential over next 10-20 years	4800 MW	Includes resource exploration and industry development factors
Petty et al. ¹⁰ for the EIA, 20-year potential for less than 5¢ cents/kWh	4300-8500 MW	Range a result of different technology development scenarios and whether more speculative unproven resources were included in the estimates

less formally controlled and processes usually are less involved.

Because of the regulated financial rate of return for IOU shareholders, IOUs are less likely to own and develop geothermal resources. IOUs are more likely to either directly purchase the power or to purchase hot water/steam from a field developer, thereby avoiding direct involvement in more risky resource

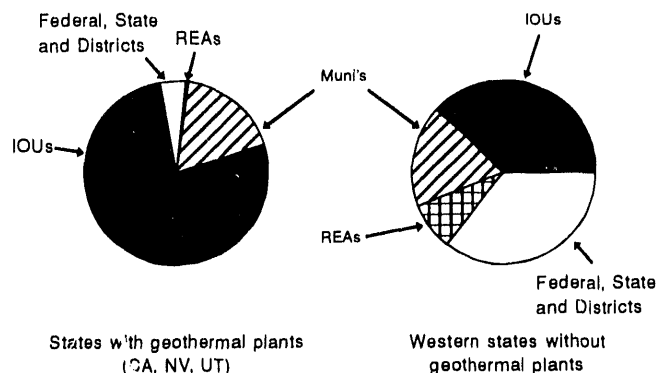


Figure 2. Breakdown of power sale by utility type (peak MW).

Table 3. Comparison of Investor-Owned and Public Utility Characteristics

Investor-Owned Utilities	Public Utilities
Rigid processes driven by state regulators (PUCs), less flexible	Locally governed by city government or customer groups
Higher avoided costs, more likely to explicitly incorporate noncost factors in evaluations	Have access to tax-free debt financing with lower interest rates; "preference" customers for federal hydro power
More customers and service territories (average size in 1000s of MW)	Generally smaller (average size in 100s of MW); less staff and expertise as a result
Regulated return, highly risk adverse	Attitude toward renewables more tied to corporate culture
Likely to own and operate conventional plants supplying a large portion of their need	May own generation but a large number purchase most of their power from other sources

exploration and field development. In addition, in California, IOUs are currently not allowed to own geothermal fields. Public utilities are more able to shoulder risk and are therefore more likely to develop, own, and operate geothermal power plants. Sales of power by a third party owner to public utilities could be more difficult since the utility's ability to use 100% tax-free debt financing, coupled with its first-in-line preference for cheap federal hydropower, have kept historic avoided costs low.

The power marketing administrations (PMAs) in the region, BPA and WAPA, were created to market power generated at federal hydro facilities. They also market power from some fossil plants in which the government has partial ownership or power rights. These marketing associations are quite progressive, but processes can be bureaucratic and slow. The Federal 1980 Northwest Planning Act gives BPA a regional planning mandate that obligates it to meet the future needs of its customers. This situation has led to a unique, centralized, regional planning mechanism that covers many public power utilities. WAPA does not have a planning mandate, but the Energy Policy Act of 1992 dictates that its utility customers will be required to file integrated resource plans starting in 1994. Changing or becoming involved in PMA processes is one possible mechanism for developers and policy makers to influence the public power market.

INTEGRATED RESOURCE PLANNING AND EXTERNALITIES

The use of integrated resource planning (IRP) as a framework for both utility planning and acquisition has been increasing nationwide. The following key

elements distinguish IRP from traditional utility planning:

- Considering conservation and other DSM programs as resources
- Including environmental, social, and other noncost factors ("externalities") in addition to direct economic costs
- Involving public participation (providing an opportunity to express support for renewables)
- Including uncertainty and risk analysis.

The broadening of decision criteria beyond direct cost is beneficial to geothermal and other renewables because they are generally more environmentally benign, reduce risk through elimination of dependence on historically unreliable fuel price projections, and provide other social benefits such as utilizing an indigenous resource and providing a local jobs base.

To a varying degree, nearly all states require IOUs to use IRP. However, nationwide, only 10% of publicly owned or financed utilities practice IRP.¹² In the West, where geothermal resources with electric generation potential exist, IRP by BPA has had a positive influence for renewables. The forthcoming requirement for use of IRP by WAPA customers, mentioned above, should have similar positive effects. Overall, the practice of IRP, while relatively new, has made an impact on utility planning decisions but has not resulted in revolutionary changes.

IRP is intended to be technology neutral. Its processes are relatively new, vary widely, and are still evolving. Renewable energy technology proponents need to become involved in IRP processes to articulate all beneficial attributes of their technologies. However, one of the most contentious parts of IRP is how to account for and weight noncost factors in resource evaluations.

"Externalities" evaluations are currently concentrating on the residual air emissions of utilities. Most states in the West have used qualitative externality evaluations. Only California and Nevada have monetized externality values.¹³

There are two methods for monetizing externality values: (1) control based and (2) damage based. Up to this point, all quantitative evaluations in the United States have used a control-based evaluation that looks at the costs of pollution control equipment or other mitigation measures (e.g., planting trees to absorb CO₂) for each pollutant. However, damage cost evaluation is more analytically correct because the intent is to account for actual deleterious effects

of a pollutant. For example, damage-based SO₂ costs would account for increased deterioration of buildings, fish population declines, and decreased forest productivity due to acid rain. Accurate and full determination of actual damages is difficult. The California Energy Commission has stated it will attempt to use actual damage cost determinations for externalities in the next biannual planning cycle.¹⁴

The wide range of values from states that have performed quantitative externality evaluations, as illustrated in Table 4, are due primarily to the fact that values vary greatly depending on evaluation methodology and to some extent that control costs are regional in nature.

Table 4. Externality Values

Fuel	Current range from states with established monetary externality adder values
Natural Gas	0.3-1.3¢/kWh
Coal	0.5-6.0¢/kWh

The valuation of CO₂ is a main driver in the variations; CO₂ values range from \$1/ton to \$23/ton. Widespread adoption of the higher externality values could have a profound influence on the resource selection process. Therefore, it is easy to understand why externality valuations are controversial and that such regulations are in a state of flux.

COMPETITIVE BIDDING

Historically under PURPA, utilities were required to accept power from qualifying facilities (QFs) and to pay a rate based on the "avoided cost" they would have incurred by generating the power themselves. High avoided costs and other favorable contract terms resulted in PURPA being overly successful. Policy makers anticipated 12 GW of QF capacity by 1995. However, actual installation reached 32 GW by 1991. Within this framework, renewables were quite successful; 40% of the QFs that came on-line in the 1980s were renewables based, and almost 3% were geothermal.

To solve issues associated with capacity allocation and avoided cost determination, utility acquisition processes have been moving toward competitive bidding. Under nationwide competitive bidding to date, only 12% of the capacity awards have been to renewable systems; 0.8% went to geothermal projects. The big winners are gas-fired projects.¹⁵ The primary reason is that renewable cost reductions and technology improvements have not kept pace with the rapid drop in fossil resource prices (driven by

current low natural gas prices). Even with the advent of IRP, bidding selection criteria tend to emphasize price and operational aspects, not environmental impacts, diversity, or fuel price and risk factors. However, geothermal bids have fared better than many other renewables, in general, because where the resource is favorable geothermal is cost-effective, a well-established technology, and not intermittent like solar and wind.

Another factor impacting the success of geothermal and other renewables is who is allowed to bid. Bid structures can be all-source, non-utility, QF only, or renewable only. The rationale for renewables-only bidding is that not all factors important to renewables can be incorporated in an all-source evaluation process. The recent set-asides in California and renewables-only request for proposals issued by Portland General Electric are examples.

MARKET DEVELOPMENT OPPORTUNITIES

During the course of this work, several regulatory, developer, and government opportunities for increased market development were identified and compiled. Not all the opportunities are addressed in this short paper, but the following list highlights opportunities in rough order of potential near-term impact on development.

Regulatory opportunities

- Encourage significant capacity set-asides or renewables-only bidding in the short term in lieu of full valuation of attributes
- Address disincentives like fuel-price pass-through provisions (with pass-through, the ratepayer shoulders the risk of future fuel price increases)
- Promote resource assessment to prove potential in new locations and recognize the value of resource proving (the BPA 30-MW pilot projects are examples)
- Encourage the use of externality values in setting actual power contract payment rates
- Encourage explicit consideration of more externality factors
- Encourage the use of externalities in resource scheduling (environmental dispatch).

Developer opportunities

- Add value through product differentiation (e.g., split energy and capacity or split summer and winter capacity sales between utilities with different needs)

- Discount rate arbitrage (use the difference between utility, financier, and private owner discount rates to structure a win-win-win payment structure)
- Couple geothermal with other resources for synergism (e.g., package base-load geothermal with a load shifting DSM program).

Government opportunities

- Enact tax incentives that would apply to IOUs (current geothermal investment tax credits are only available to private owners, and there are production payments authorized for public utilities)
- Exempt geothermal tax benefits from alternative minimum tax restrictions
- Create broad opportunities for decreased financing costs such as access to tax-exempt debt or loan guarantees
- Broaden the power marketing administration mandates for planning and acquisition.

CONCLUSIONS

The electric market and resource potential are not overly limiting to future geothermal power plant deployment. Significant power needs exist and may be larger than currently projected, and resource potential is much greater than planned development. However, there is a need to confirm the availability of geothermal resources to improve competitiveness.

Acquisition processes have changed, resulting in a new, more market-oriented regime for deployment. The market is more competitive and complex than in the past. There is a diversity in utility attitudes and motivations. Evolving factors like IRP and externalities will have an influence, but cost remains the main driver.

I hope this overview may be helpful in guiding developer, industry, and policy maker efforts to understand and affect key processes.

ACKNOWLEDGMENT

I would like to thank Drs. Ted Mock and Allan Jelacic of the DOE Geothermal Division for their sponsorship of this project and the opportunity to become involved in the geothermal program.

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BRINE (SOLUTION, SOLID, GAS PHASES) MODELING PROGRAM: ADVANCED TECHNOLOGY TO AID IN THE ECONOMICAL DEVELOPMENT OF GEOTHERMAL RESOURCES

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KEY WORDS

Brines, Gases, Computer Models, Reservoir, Scaling, Rock/Water Interactions, Simulation, Thermodynamic Data, pH, High Temperature, Breakout, Phase Transitions

ABSTRACT

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 easily accessible models will provide reliable predictions of the behavior of the 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 (see Table 1), it is necessary to have highly accurate models of the chemical behavior of the working fluids. Using recent developments in the physical chemistry of fluids and gases, we have shown that with proper attention to the parameterization we can develop models that accurately reproduce the measured laboratory behavior of brines, 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 (see below).

Table 1. USES OF A BRINE SIMULATION MODEL	
Exploration	• Predict Scale Formation • Predict Gas Behavior • Determine Formation Water Characteristics • Predict Recoverable Energy • Predict History and Evolution of Resource
Plant Design and Operation	• Predict Scale Formation • Predict Phase Separation • Simulate Chemical Treatments • Test Energy Optimization Strategies • Test Ways to Minimize Operations Costs • Support Laboratory Simulations
Waste Treatment	• Simulate Mineral Recovery Strategies • Predict Environmental Hazards • Simulate ReInjection Strategies

Our brine models handle the special problems of phase equilibrium predictions in complex mixtures, introduce a relatively low number of parameters and are highly accurate and flexible. Our gas modeling

approach utilizes a newly developed empirical equation which can reproduce PVT properties in both the liquid and gas phases, liquid/vapor coexistence and other useful thermodynamic functions.

As the models are developed, they are included in an user-friendly application package called GEOTHERM which can be loaded from diskettes to PCs or Mackintosh computers. Periodically, workshops are given in the use of these programs to treat problems of interest to the geothermal community. An instruction manual is available.

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 are very difficult to predict. However, if the system is near equilibrium they can be calculated from the free energy, G . This is commonly written in terms of the chemical potential, μ_i , of the species i as:

$$G = \sum_i \mu_i n_i$$

where n_i is the number of moles of i . For brines, the chemical potential of each species is a complex function of the concentration of all the species in a phase. It also depends on the temperature and weakly on the pressure. For gas phases, μ_i is a rapidly varying function of the pressure. By minimizing G subject to mass and charge balance constraints, the distribution of solids, gases and liquid phase species can be predicted.

We have developed highly accurate phenomenological equations giving the behavior of gas, liquid and solid phase chemical potentials. These equations are soundly based on theoretical results but contain a number of 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 brine behavior to high concentration and high temperature (0° - 250°C). (See Harvie and Weare, 1980; Harvie et al., 1984; Møller, 1988; Greenberg and Møller, 1989.) Our gas phase models accurately predict behavior in the system $\text{CH}_4\text{-CO}_2\text{-H}_2\text{O}$ system from 50 to 1000°C and from 0 to 1000 bars. (Duan, Møller, and Weare (1992a; 1992b)). *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. We believe that the GEOTHERM programs are the only models presently available that meet these demanding criteria.*

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 and gas breakout in production wells, throughout various brine flow and heat extraction systems and during reinjection procedures.

Parameterization of the $\text{CaCO}_3\text{-SiO}_2\text{-CaSO}_4\text{-NaCl-CO}_2\text{-H-H}_2\text{O}$ system and of the seawater system, $\text{Na-K-Ca-Mg-Cl-SO}_4\text{-H}_2\text{O}$, is complete to high temperature (0°C - 250°C) and to 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. A preliminary model of the important $\text{H}_2\text{S-H}_2\text{O}$ system has been prepared for the 0°C to 90°C temperature range (0 - 60 atm). When a model of the $\text{H}_2\text{S-NaCl-H}_2\text{O}$ system is complete to high temperature (T_{max} will depend on data availability) we will be able to begin the development of models of sulfide scale formation.

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. Therefore, our models 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.

Table 2. PROJECT PROGRESS: CAPABILITIES OF PRESENT MODELS
• Predict Behavior of Calcium Carbonate Scale Formation in NaCl and CaCl₂ Brines for T = 0° to 250°C (PC version available) • Predict Solubility of CO₂ and CH₄ in NaCl Brines for T = 0° to 250°C (PC version available) • Predict Solubility of Amorphous Silica Scale in Brines for T = 0° to 250°C • Predict Solubilities of Scaling Minerals (Gypsum, Anhydrite, etc.) to 250°C • Calculate Precipitation Characteristics of Rock-Water Systems Containing Na, K, Ca, Mg, Cl, and SO₄ for T = 0° to 250°C • Predict Onset of Two Phase Behavior (Gas Breakout) in NaCl Brines • Predict Solubility of Hydrogen Sulfide (H₂O-H₂S-HS⁻) System (0° - 90°C; 0 -60 atm) • Predict Partial Fugacity in Mixed Gas System (CO₂-CH₄-H₂O) T = 0° to 1000°C and P = 0 to 1000 bars • Predict Gas-Liquid Equilibrium in the CO₂ - CH₄ - H₂O System

Our equation of state for the CH₄ - CO₂ - H₂O system 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. We have shown that our new technology (equation of state and mixing rules) allows us to successfully model the behavior of gas-liquid systems of the compositions associated with geothermal operations as a function of temperature (0° to 1000°C) and pressure (0 to 1000 bars). This model can simulate both the single and two phase behavior of gas mixtures within experimental accuracy. We can use these models to improve predictions of gas breakout in highly pressurized formations. These models will also be used for predicting reservoir performance characteristics via fluid inclusion studies.

As an illustration of the application of the models, we consider an analysis of a geothermal well (W-235) in the Steamboat Springs geothermal resource. (This work was done in collaboration with Ted DeRocher, Yankee/Caithness.) The fluids in this system contain an average of 3183 ppm CO₂. Using the GEOFLUIDS gas solubility model in the GEOTHERM package, we can calculate the breakout pressure as a function of pressure. This is plotted in Fig. 1 below.

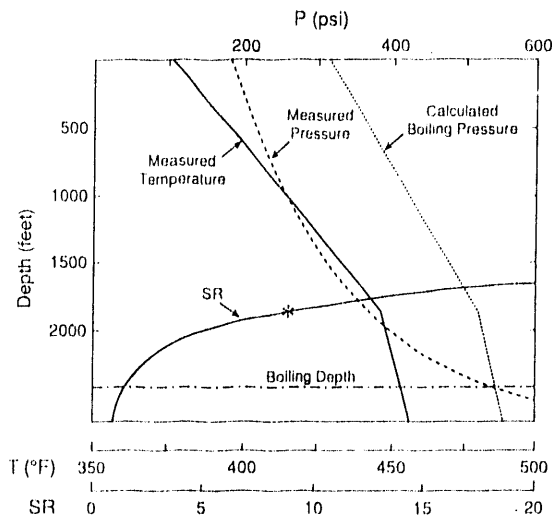


Fig. 1: Calculated scaling characteristics of Steamboat Springs Geothermal Well-235 (see text).

Plotted on the same figure are the measured temperature and pressure profiles for this well. When the curve giving the breakout pressure of the fluid crosses the well pressure curve, the working fluid will boil. Again using GEOFLUIDS, we can calculate the composition of the gas released in the boiling process. We find that it is very rich in CO₂ (roughly .3 mol fraction). With this loss of CO₂, the system rapidly supersaturates with respect to carbonate minerals. The saturation ratio of these minerals is calculated with TEQUIL, another program included in GEOTHERM. The results are also plotted in the figure. A mineral in equilibrium with the well water would have a saturation ratio very near 1.0. When saturation ratios reach 8 - 10, calcite scale forms. We see that scaling should occur in this well at approximately 1800 ft. This prediction is very close to the actual appearance of scale in the well (see asterisk in Fig. 1). Using the model, other important quantities such as the gas liquid ratio and the amount of scale can also be calculated.

Future Plans

Our goal is to complete a comprehensive brine model which will predict scaling (gypsum-anhydrite, carbonate, silica, metal sulfides) and acid-base characteristics in the system, H-Na-K-Ca-Mg-Al-Cl-HSO₄-SO₄-HS-HCO₃-CO₃-SiO₂, as a function of brine composition, ionic strength, pH, P_{CO2} and temperature (to 250°C). We plan to extend the carbonate scaling models into the carbonate-rich region (high pH) to 250°C as data allow. Inclusion of aluminum species in the models will greatly broaden their application to reservoir studies. Pressure effects on scale solubilities (to P = 400 bars and above, as data allow) will be included in the model. After the model is completed to 250°C, the model will be parameterized to predict the near critical behavior of brines.

We will continue to add important gases to the GEOFLUIDS programs. We have already initiated efforts to improve gas/liquid predictions in ternary and higher order systems.

We will continue to apply our models to geothermal problems and to promote the transfer of our technology to the geothermal energy community.

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GEOTHERMAL WASTE TREATMENT BIOTECHNOLOGY

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ABSTRACT

An ongoing R&D program at the Brookhaven National Laboratory (BNL) has identified technologies for a low cost, environmentally acceptable disposal of toxic geothermal residues. Laboratory work has shown that a biochemical process would meet the cost and requirements. In this work, microorganisms which can interact with toxic metals (including trace radionuclides) found in geothermal residual brine sludges and which can convert them into soluble species for subsequent reinjection or concentration have been identified. The biochemical activities of these organisms served as models for the development of technically and economically feasible detoxification processes leading to advanced biotechnology for geothermal waste treatment. Process variables have been identified and optimization studies have been carried out using a prototype laboratory scale pilot-plant for detoxification processing. A concurrent process for the concentration and recovery of valuable metals is also being developed.

In this process a better than 80% removal of toxic metals is achieved in short periods of time. The fast rates of metal removal, with residence time in the bioreactor of 4 to 25 hours, have been achieved at pH 1-2 and temperatures of 55-60°C. A secondary biochemical process for the removal of trace radionuclides, particularly radium is currently being developed and tested. A complimentary process for concentration of metals from the process by-products, i.e., the aqueous phase, produces a water effluent which meets drinking water standards.

BACKGROUND

Studies in this laboratory have shown that a technically feasible and environmentally acceptable biotechnology for detoxification of geothermal residual sludges depends on several parameters.¹⁻⁸ These include properties varying from reactor size and sludge loading to the chemical nature of salts and process temperature, all essential in the determination of cost-efficiency of the bioprocess(es) considered. The bioprocess investigated is based on biochemical solubilization of metals. The choice of a bioprocess was based on the following considerations. There are circumstances in which large quantities (i.e., tons) of a process end-product or by-product are produced containing small amounts (i.e., ppm) of materials which may be subject to environmental regulation and/or the materials are valuable, which would make their recovery advantageous. In such circumstances, conventional technologies for decontamination and/or recovery are by and large not suitable because of technical, economical, and environmental reasons. The disposal costs of such sludge are increasing and therefore adding to

the overall costs of geothermal power-production. For example, in 1985, the average cost of disposal for this type of sludge was two hundred US\$ per ton because it contained toxic metals (e.g., copper, arsenic, etc.) compared to seventy-five US\$ per ton for non-hazardous waste.⁹ In addition to the rise in disposal costs, the space for disposal is diminishing, therefore, application of a biotechnology for the treatment of geothermal residual sludges has economic and environmental advantages. Previous and ongoing studies have shown that there are at least ten key process variables which are essential in the determination of the cost-efficiency of the bioprocess(es) considered. Using these variables several reactor types have been compared, which included the following bioreactors and associated systems: (i) fluidized bed; (ii) agitated tank; (iii) continuous bioreactor system; (iv) counter-current process; (v) trickle bed; and (vi) tumbler mixers.

In addition, gravity flow vs. pump, materials, and corrosion aspects were and are currently being explored.

DEVELOPMENT OF A KINETIC MODEL

- o Comparative kinetic studies in which fluidized bed and agitated tank bioreactors were used, have shown that at 55°C the solubilization of metals from geothermal sludges follow similar kinetics.
- o Experimental data for a 25-h and 80-h treatment indicated that > 80% of the metals are removed in the first 25 h and the remaining low concentrations are removed at a slower rate over the following 40-h to 80-h.
- o Results from studies for different loading times have consistently shown that an efficient process at a 40% loading concentration of the geothermal sludge in the bioreactor can be achieved.
- o Essentially identical process efficiencies can be achieved with tank and fluidized bed type bioreactors.
- o Kinetic Model. To develop a kinetic model for metal solubilization rates, a tank bioreactor operating at 55°C and four different geothermal sludge concentrations were used.

Optimization of particular streams within the bioprocess, choice of bioreactors, construction materials, and other process variables, allow for additional savings in the overall process. Some of these savings will be discussed in this paper.

RESULTS AND DISCUSSION

Studies in which various sludge loadings have been considered have shown that an increase in the loadings of solids in the bioreactor will (i) decrease the consumption of bacterial culture (stream 2) (See Figure 1 for stream identification); (ii) decrease the flow rate at the reactor exit (stream 4); and (iii) decrease the consumption of calcium hydroxide (stream 8); and (iv) decrease the quantity of final fluid (stream 9). Thus, at 40% loading which appears to be a practical, working concentration, the flow rates for various streams are given in Table 1. In this particular scenario, microbial nutrients are in solution and are recyclable. Since they also represent inorganic salts found in the sludge, the use of indigenous salts with inorganic nutrient addition is being considered. While a number of bioreactors, mentioned in the introduction, are being considered, fluidized bed and agitated tank type bioreactors appear at the present time to be the most promising.

A fluidized bed bioreactor works on the principle that gas bubbles entering the bottom of a reactor can mix solid-liquid mixtures and disperse gas into the liquid media. Airlift bioreactors produce uniformly mixed fluids. However, given a 65% solids (by volume) or 2329 Kg/h sludge, a retention

Table 1
Biochemical Waste Treatment Plant Stream
Summary of Flow Rates at 40% Loading

Stream No.	Description	Flow Rate Kg/h	Amount of Solids %
1	Geothermal Sludge	2329	53.5
2	Bacterial Culture	1895	0
3	Filtrate, Recycle	1075	0
4	Reactor Exit	5299	23.5
5	Filter Cake	2329	53.5
6	Neutralization Drum Feed	1895	0
7	Water and Nutrients	-	0
8	Ca(OH) ₂	9.9	100
9	Reinjection Liquid	1790	0
10	Regulated Filter Cake	114	16
11	Neutralization	1905	1.0

time of 24-hours, the reactor would have to handle 144,000 liters of a 40% solids (w/v) sludge slurry. Costs of air compressors for a fluidized bed bioreactor, which can handle such quantities, come as high as 500,000 US\$ and up. The estimated cost of a bioreactor vessel itself is about 60,000 US\$, which is based on the cost for a vertical storage tank without provisions for jacketed heating, port-holes, and air compressor. The size of an air compressor can be reduced by supplementing the bioreactors supply gas flow with pressurized steam, a possibility that has to be further explored.

Biochemical Waste Treatment Plant Using Agitated Tank Bioreactor

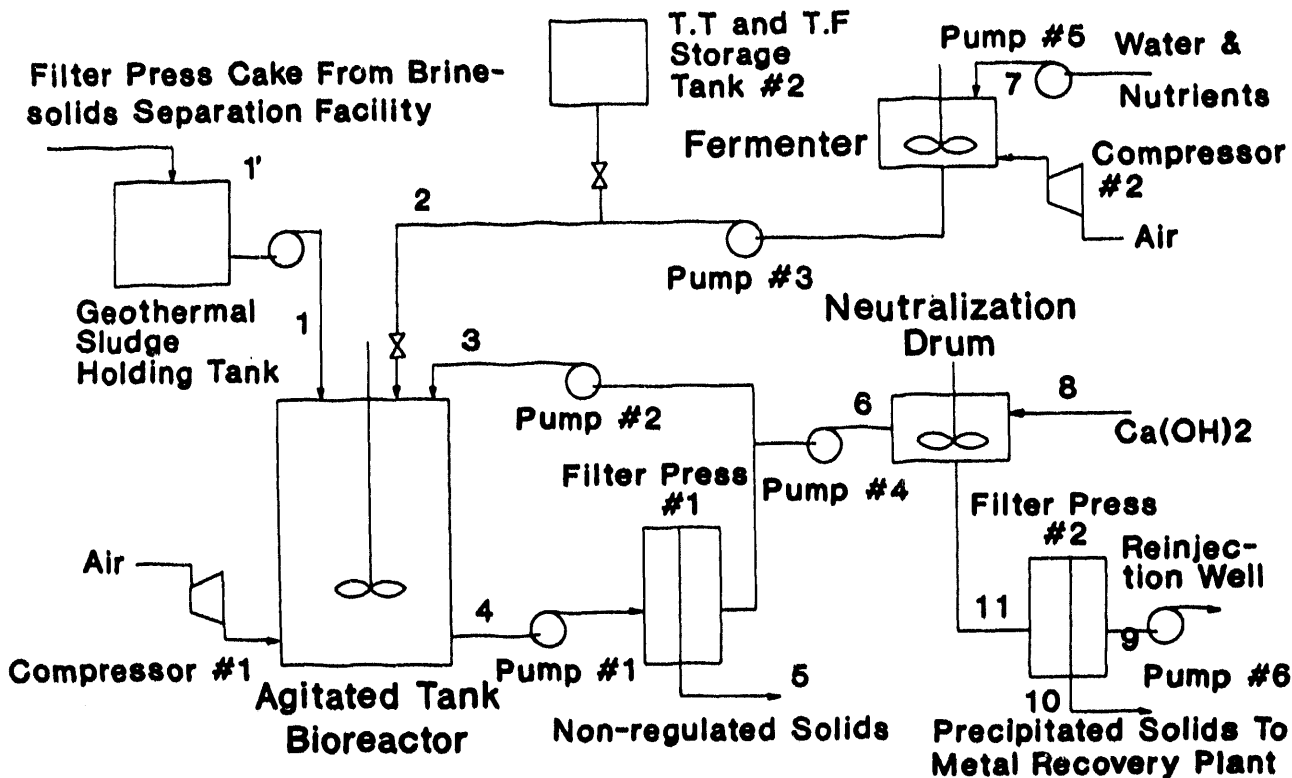


Figure 1

The operations of a fluidized bed bioreactor can also incorporate a scheme for recycling of bacteria. When sludge has been treated, a portion of the fluid can be discharged from the bioreactor. The other portion which contains live bacterial cultures can be retained in the bioreactor and fresh untreated sludge can be added to the bioreactor. The recycle option would reduce the cost of continuously growing new cultures of bacteria in a separate tank.

To increase the solubility of oxygen in water, and hopefully to increase the reaction rate, the total reactor operating pressure can be increased.^{10,11} On the other hand, the purchase cost of the bioreactor itself would increase due to an increase in the bioreactor wall thickness necessary to handle the higher pressure. On the other hand, the operating cost would decrease due to increased reaction rates or decreased retention time.

Agitated tank bioreactors use an impeller to mix the contents of a tank. The impeller creates turbulent flow in the tank, which mixes the solid-liquid-gas phases. In choosing an agitated tank bioreactor one has to consider which type of impeller to use, what kind of geometrically shaped tank to use, and how fast to mix the sludge slurries. Not all impeller-mixers are suitable for all types of mixing because different processes have different requirements for the kind of flow, the amount of power, and the amount of fluid shear.¹² A poor bioreactor design leads to inadequate solids suspensions, low heat transfer rates, and non-uniform gas concentrations in the liquid slurry. There are two types of impeller flows that characterize fluid mixing patterns, axial, and radial. Axial flow impellers that are top loaded circulate fluid in the vertical direction, while radial flow impellers circulate fluids horizontally towards the walls of the reactor vessel. While most industrial applications use radial flow turbines with auxiliary sparged gas, axial flow impellers are generally preferred for solids suspensions, although they cannot be used with bottom supplied gas because upward flow bubbles destroy axial flow patterns.¹² Pitched blades on impellers contribute to axial patterns, whereas flat blades contribute to radial patterns.

Cutting agitation costs means that over-mixing should be avoided by sizing and designing equipment to agitate only as much as is necessary for efficiency.¹³ When suspending fine solids, the mixer should provide high flow (pumping) capacity. When mixing gas and liquid, the mixer should provide high fluid shear stress for dispersion of bubbles. However, there are circumstances when a high flow and high shear cannot be fulfilled at the same time by the same impeller, therefore combined systems have to be considered.

Heat transfer parameters in an agitated bioreactor should be known beforehand. Factors that affect heat transfers are direct conversion of heat from agitator work, heat generation due to chemical reaction, tank diameter, liquid depth, number of baffles, heat surface (jacket or coils), type of flow (radial or axial), impeller diameter, number of impeller blades, blade geometry and pitch, impeller speed, impeller placement in tank (with respect to

heat surface), thermal conductivity of the fluid, thermal capacity of the fluid, and viscosity. Jacket heating is usually cheaper to construct and install in new vessels compared to internal coils which offer less heat transfer surface.¹⁴ Other aspects of design and construction should also be considered. For example, the impeller should be placed at the mid-point in a bioreactors to optimize heat transfer rates. However, that location is not ideal for solids suspension, where impellers are usually placed near the bottom, a location which has poor heat transfer rates.¹² In addition to heat consideration, types of impeller and size are also considered and optimized.

Bearing in mind the variables discussed in the preceding paragraphs, a working model of the bio-process was used for kinetics and cost evaluation studies shown in Figure 2. Based on the current experience, fluidized bed and agitated tank type bioreactors generate comparable results. Both reactor

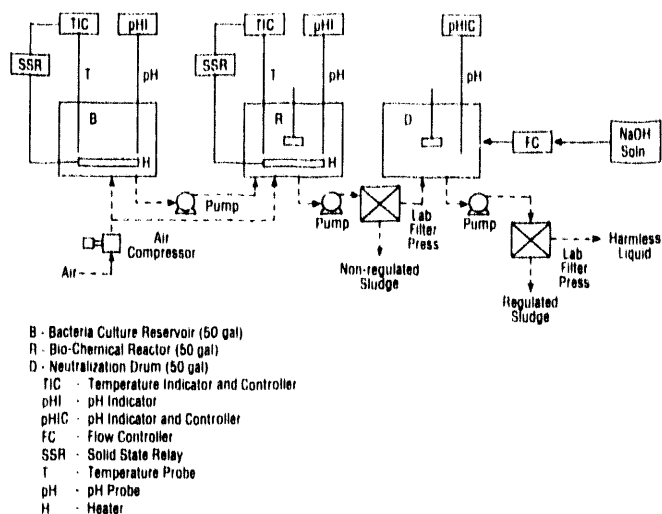


Figure 2. Pilot-plant for the biochemical processing of geothermal brine sludges.

types were tested for their usefulness and efficiency in a biochemical process for detoxification of geothermal residual sludges. Considering practical constraints of space availability, construction, and operating costs, a pilot plant has been constructed in which the agitated tank bioreactor was chosen as the operating unit. The pilot plant contains three fifty-gallon agitated tank bioreactors which serve as a bacterial culture reservoir, mixing and processing reactor, and a neutralization unit for concentration and subsequent metal and water recovery. Schematic diagram of the pilot-plant is shown in Figure 2. The present system is made of polyethylene and glass components which utilize commercially available pumps, filters, controllers, and other accessories without or with minor modifications. The system potential and variables essential to optimization (including modification) are currently being tested. The pilot plant has as yet to be integrated with a pre-biomass treatment facility and a post treatment metal recovery plant.

Multi-element analyses of solubilization rates by Induced Coupled-Mass Spectrometry (IC-MS) have consistently shown that during the initial phase of bioprocessing, ~80% of metals are transferred from the solid to liquid phase.¹³ Typical analytical results are given in Table 2. Examples of rates of

Table 2
Initial and Final Concentrations of Metals in
Bioprocessed Geothermal Sludge at 55°C and pH 1-2

Metal	Initial Conc. ppm	Final Conc. after the biotreatment	% Removal in 24/h
U	223.2	40.4	82
B	1356.6	461.4	66
Mn	4399.7	2172.1	51
Cu	688.8	103.6	85
Zn	1845	503	73
Rb	118	39	67

metal solubilization are given in Figures 3 for boron. Similar results were obtained with other metals including metals such as arsenic, mercury,

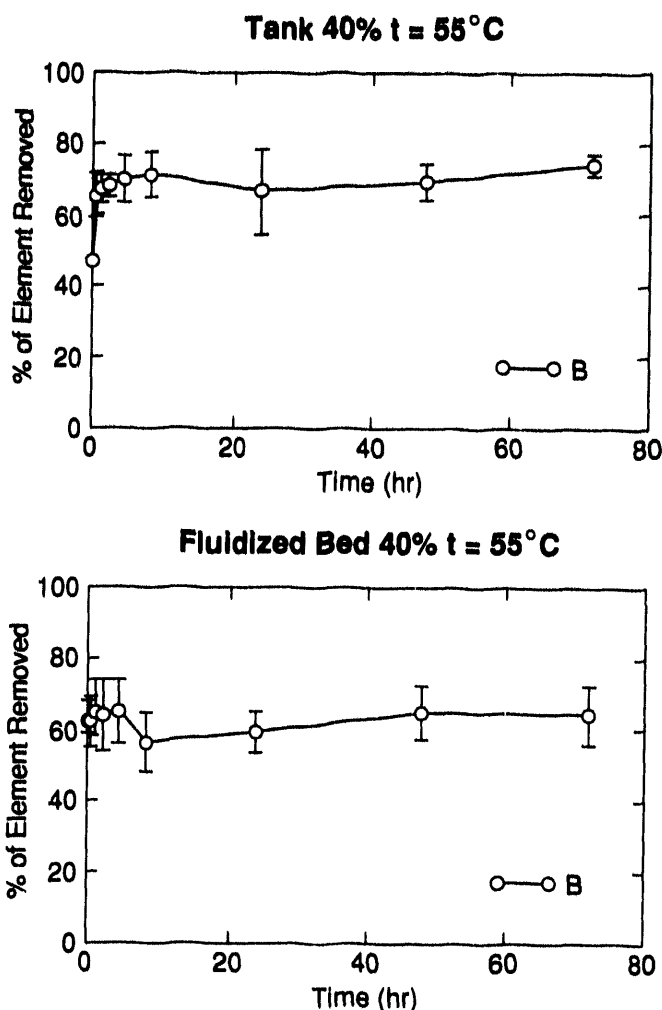


Figure 3. Rate of boron solubilization from geothermal residual sludges.

radium, thorium, uranium, etc., which are present in some types of geothermal sludges. In the examples given, two types of bioreactors, tank and fluidized bed bioreactors, were compared. The results show that the process efficiency is comparable for both types of bioreactors.

Based on the available data, a plant cost vs. waste disposal comparisons between a 1985 and a 1991 plant designed on the basis of the flow diagram in Figure 1, is given in Table 3. For the purpose of this comparison, the 1991 estimates for operating costs and amortization payments were used.

Table 3
Biochemical Treatment Plant Costs Vs. Costs of
Treated and Untreated Waste Disposal

Quantity of geothermal sludge to be treated: 2329 Kg/h		
Working hours per year: 8000 h		
Total capital cost + start up: \$4,209,000 US\$		
	1985	1991
Waste Disposal Cost:		
for non-regulated waste (US\$/ton)*	83	110
for regulated waste (US\$/ton)	220	550
Annual Total Expenses (US\$):		
untreated geothermal sludge disposed of directly	4,104,000	10,260,000
Geothermal Sludge Treated:		
by the biochemical process		
(non-regulated waste disposal cost)	1,539,000	2,052,000
Waste Concentrate (regulated disposal cost)	202,000	504,000
Operating Costs, etc.	1,396,000	1,396,000
Amortized Payment (fixed)	685,000	685,000

* metric ton (1000 kg).

An 80% reduction in the original concentration of the metals brings the material to be disposed of well within the range of non-hazardous waste. Thus, the biochemical process chosen represents about a 60-70% savings. It is to be understood, however, that the cost of disposal and long term liabilities are continuously increasing while the available space for disposal is diminishing. For example, at BNL disposal of a similar sludge cost 550 US\$ per metric ton in 1991. The corresponding non-regulated waste disposal cost was 110 US\$ per metric ton. If the sludge contains in addition to chromium and lead, say radium, then it has to be shipped at a cost of 400 US\$ per cubic foot or 14,000 US\$ per cubic meter. On the other hand, removal of the metals leaving radium alone produces waste costing 76 US\$ per cubic foot or 2,700 US\$ per cubic meter to dispose of, or 10,800 US\$ and 2,052 US\$ per ton respectively, representing a five-fold saving already achievable on a laboratory scale. For further optimization studies a kinetic model has been developed. Typical experimental and model results are shown in Figure 4. The results show a close agreement between the model and the experimental data.

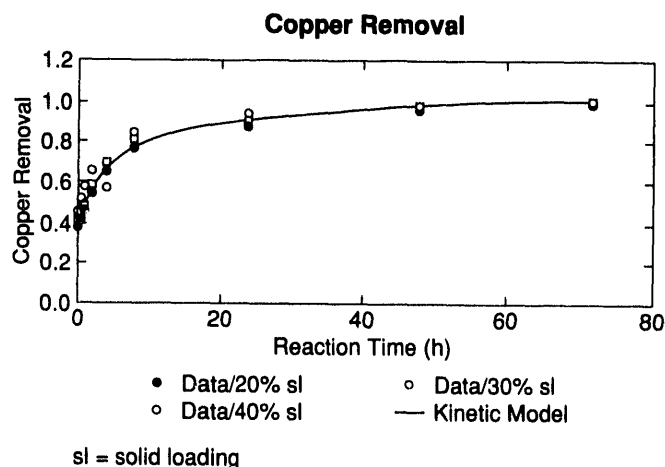


Figure 4.

Further, less soluble salts such as those of lead, bismuth, radium, and barium present in trace amounts are a special case to be considered. The radionuclides present are close to NORM levels which puts further requirements on the bioprocess as well as sampling and method of analyses. After regular biotreatment with the BNL system described in the previous paragraphs the geothermal material contains additional trace amounts of insoluble salts, such as those of radium and thorium. In order to meet a 5×10^{-12} Ci/g requirement, a secondary biotreatment is necessary. For this purpose a number of micro-organisms from the BNL collection were tested and several efficient candidates identified. Preliminary results are shown in Table 4. The final product from the detoxification of the sludge is an aqueous effluent.

Table 4
Biochemical Removal of Radium and Thorium from Geothermal Sludges Subjected to Secondary Biotreatment

	Ra-223	Ra-224 μ Ci/g	Ra-226	Th-232	Total Activity
Untreated (Total Sample)	2.63×10^{-5}	6.46×10^{-4}	2.8×10^{-4}	1.8×10^{-4}	2.82×10^{-3}
Treated with BNL MOs					
BNL-R ₁ -1	4.35×10^{-5}	6.75×10^{-4}	2.8×10^{-4}	1.8×10^{-4}	2.89×10^{-3}
BNL-R ₂ -2	3.3×10^{-5}	n.d.	n.d.	n.d.	1.31×10^{-3}
BNL-R ₃ -3	n.d.	n.d.	n.d.	n.d.	1.31×10^{-3}
BNL-R ₄ -4	n.d.	n.d.	n.d.	n.d.	1.27×10^{-3}

n.d. = below detectable limits

We are currently developing a detoxification process for this effluent. At the present time for the recovery of metals from the aqueous phase, we are using co-precipitation methods. For the metals tested the efficiency of recovering is remarkably high. The purity of water resulting after the treatment currently developed at BNL is indicated by preliminary results given in Table 5. The small volume

Table 5
Purification of the Aqueous Phase Generated During the Biochemical Processing of Geothermal Brines

Metal	Before Treatment (ppm)	After Treatment (ppm)	N.Y. State Drinking Water Standard (ppm)
Al	29	< 1.0	2.0
Cr	0.6	< 0.05	0.1
Mn	289	< 0.03	0.6
Ni	7.0	< 0.05	2.0
Cu	7.0	< 0.06	1.0
Zn	117	< 0.7	5.0
As	0.2	< 0.05	0.05
Ag	0.5	< 0.004	0.1
Cd	0.6	< 0.002	0.02
Ba	0.03	< 0.03	2.0
Hg	0.003	< 0.001	0.004
Pb	0.03	< 0.002	0.05

precipitate which is a by product of this step can be subjected to conventional metal recovery processes. It is also worthwhile to note that recovery of metals, including the recovery of valuable metals such as chromium, silver and platinum may, under some circumstances, be an attractive option. A combined sludge detoxification-metal recovery process will offset the overall costs, since detoxified sludge may be used for landfill and other purposes, while metal concentrates would yield marketable metals.

SUMMARY AND CONCLUSIONS

The geothermal residual sludge detoxification biotechnology R&D phase described in this work allows the following conclusions:

1. Fast detoxification rates are achievable.
2. Cost effective process(es) operate at elevated temperatures and acidic media.
3. Consistent results indicate that toxic metals are removed in the early phases of the treatment.
4. Forty percent sludge loadings can be achieved.
5. Four to ten hour cycles are achievable.
6. Removal of trace (close to NORM) radionuclides is also achievable.
7. The bioprocessed wastes can ultimately be disposed of as non-regulated wastes.

ACKNOWLEDGMENTS

This work has been supported by the U.S. Department of Energy, Department of Energy Conservation, Division of Geothermal Technology, under Contract No. AM-35-10. The authors wish to acknowledge the valuable help and assistance of L. Racaniello, BNL, for the development and maintenance of microbial cultures used in these studies. The authors also wish to acknowledge G.K. Ji, for analytical work performed in this program and Lung Pei Hu of Rensselaer Polytechnic Institute, who participated in the BNL summer educational program.

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1993 STATUS REPORT — THE BONNEVILLE POWER ADMINISTRATION'S GEOTHERMAL PROGRAM

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ABSTRACT

The Bonneville Power Administration's (BPA) Geothermal Program includes up to three demonstration (pilot) power projects that will initiate development of high-potential reservoirs in the Pacific Northwest. The program also includes activities that support the pilot projects and that encourage the use of the region's geothermal resources. Activities supporting the pilot projects include initiating environmental baseline monitoring programs and conducting environmental and economic impact studies. Research activities include efforts to better understand the cold water blanket phenomenon in the Cascades, a study to characterize the hydrothermal system in the Pueblo Valley, a geothermal exploration program in southeastern Oregon, and support for research to expand the use of slim-holes for resource confirmation.

Efforts to address institutional issues include support for the Regional Renewables Project, which will help Northwest environmentalists become more knowledgeable about the role of conservation and renewables in the region's energy picture. A guide to geothermal permitting and licensing was prepared to help developers and utilities find their way through the regulatory maze. A geothermal curriculum is being developed for grades 4 through 8 in the Oregon schools. Data on the location and operating experience of existing U.S. geothermal plants has been collected in a database. Market penetration of geothermal heat pumps is being encouraged through a demonstration project in Montana and by helping BPA customers prepare proposals for geothermal heat pump projects that can compete successfully in BPA power acquisitions.

Table 1. BPA Geothermal Program Activities, 1988-1993

ACTIVITY	CONTRACTOR	PRODUCT
Hydrologic Baseline Monitoring - Newberry Volcano	U.S. Geological Survey	Hydrologic, Water Quality, and Meteorological Data for Newberry Crater and Vicinity, Deschutes County, Oregon, 1992-92. USGS Open-File Report No. 93-xx
Hydrologic Baseline Program Design - Alvord KGRA	U.S. Geological Survey	In Progress
Hydrologic Baseline Program Design - Vale KGRA	U.S. Geological Survey	In Progress
Hydrologic Baseline Program Design - Medicine Lake	U.S. Geological Survey	In Progress
Environmental Baseline Program Design - Newberry	Ogden Environmental	Environmental Baseline Report (Pub. No. DOE/BP-29028-1), Mar. 1993
Economic Impact Study - Deschutes County	Oregon Dept. of Energy	Economic Impacts of Geothermal Development in Deschutes County, Oregon (Pub. No. DOE/BP-07129-1), Dec. 1991
Economic Impact Study - Harney County	Oregon Dept. of Energy	Economic Impacts of Geothermal Development in Harney County, Oregon (Pub. No. DOE/BP-07129-2), Dec. 1991
Economic Impact Study - Malheur County	Oregon Dept. of Energy	Economic Impacts of Geothermal Development in Malheur County, Oregon (Pub. No. DOE/BP-07129-3), Jan. 1993
Economic Impact Study - Whatcom County	Wash. State Energy Office	Economic Impacts of Geothermal Development in Whatcom County, Washington (Pub. No. DOE/BP-2013), July 1992
Economic Impact Study - Skamania County	Wash. State Energy Office	Economic Impacts of Geothermal Development in Skamania County, Washington (Pub. No. DOE/BP-2014), July 1992
Geothermal Impact Analysis - Newberry Volcano	Oregon Dept. of Energy	Newberry Volcano Geothermal Impact Analysis (Pub. No. DOE/BP-2142) June 1992
Geothermal Impact Analysis - Pueblo Valley	Oregon Dept. of Energy	Pueblo Valley, Oregon, Geothermal Impact Analysis (Pub. No. DOE/BP-2143) February 1993
Geothermal Impact Analysis - Bend Highlands	Oregon Dept. of Energy	Bend Highlands Geothermal Impact Analysis (Pub. No. DOE/BP-2141) May 1993
Optioning Geothermal Resources (Slim-Hole Project)	GeothermEx, Inc.	Purchasing Options on Geothermal Power Generated within the BPA Service Area (Unpublished Report) Sept. 1990
	GeothermEx, Inc.	Feasibility of Applying Slim-Hole Technology to Option Purchases (Unpublished Report) August 1991
	GeothermEx, Inc.	Computer Program Documentation for Geothermal Resource Assessment Software Package (Unpublished Report) April 1992
Geology and Geochemistry of the Alvord Valley Geothermal System	Portland State University	Hydrogeochemical Characterization of the Alvord Valley Geothermal Resources Area
Cold Water Blanket Study	Oregon Dept. of Geology	In Progress
Oregon Cascades Resource Assessment Update	Oregon Dept. of Geology	In Progress
Geothermal Exploration Program in SE Oregon	Oregon Dept. of Geology/ Portland State University	In Progress
Environmental Issues in Geothermal Development	Geothermal Resources Council	Environmental Issues in Geothermal Development (not yet published)
Regional Renewables Project	Northwest Power Planning Council	In Progress
Permitting Guides for Renewable Resource Developers	Washington State Energy Office	Geothermal: A Regulatory Guide to Leasing, Permitting, and Licensing in Idaho Montana, Oregon, and Washington (Pub. No. DOE/BP-00425-2), Oct. 1991
Geothermal Curriculum for Grades 4-8	Oregon Dept. of Energy	In Progress
Geothermal Power Plant Database	Oregon Dept. of Energy	Database Files and Annual Report
Missoula Geothermal Heat Pump Demonstration Project	Missoula Electric Cooperative	In Progress
Technical Support for Geothermal Heat Pump Billing Credit Projects	Oregon Dept. of Energy	In Progress

BACKGROUND

Geothermal is an environmentally desirable renewable resource that could contribute substantially to the Pacific Northwest's energy supply. Studies conducted by BPA and others show geothermal may be abundant in this region and has potential for being cost-effective in the near term (Bloomquist and others, 1985; Northwest Power Planning Council, 1991). To help initiate development at several high-temperature reservoirs — and to give utilities and the public the information they need to make informed decisions about issues related to development — BPA, in its 1990 Resource Program, offered to participate in up to three demonstration power projects. A number of studies and other activities have been done to support them.

BPA has also funded activities aimed at identifying new resources, solving technical problems related to resource development, and encouraging the use of low-temperature geothermal. This paper reports on the status of research and geothermal support activities undertaken during the last five years. These activities are summarized in Table 1.

GEOHERMAL PILOT PROJECTS

In July 1991, BPA issued a Request for Proposals announcing it would be willing to purchase up to 10 megawatts (MW) of output from each of three projects located in or near the BPA service territory. The resource had to be capable of supporting at least 100 MW of capacity, and the lease block had to be controlled by a single developer (unitized) or be suitable for unitization. There were a number of other threshold conditions, which are described in (Darr, 1993).

From the proposals received, projects at Newberry Volcano and Vale, Oregon, and Glass Mountain (Medicine Lake), California, were selected for contract negotiations. All three projects are approximately 30 MW in size

and are expected to achieve commercial operation in 1996. Their locations are shown in Figure 1.

Memoranda of Understanding signifying agreement on contract principles have been signed for the Newberry and Vale Projects, and the environmental review required by the National Environmental Policy Act is underway at Newberry. At the time of writing, agreement had not yet been reached on Medicine Lake.

PILOT PROJECT SUPPORT

Environmental Baselines

The regulations governing operations on Federal geothermal leases require the operator to collect at least one year of baseline environmental data prior to production. The purpose of the data is to characterize the existing environment so that impacts of development can be identified. Guidelines for acquiring baseline data are contained in Geothermal Resources Operation Order No. 4 (U.S. Geological Survey, 1975) and the Guidelines for Acquiring Environmental Baseline Data on Federal Geothermal Leases (U.S. Geological Survey, 1977). The baselines usually must include data on air quality, water quality, biology, noise, seismicity, and subsidence.

Early in the development of the geothermal confirmation program, we recognized that impacts on surface and ground water and other hydrologic features (such as hot springs) were likely to be an important issue in many areas. It was also apparent that one year of hydrologic data might be insufficient to adequately characterize the predevelopment hydrologic system. We did not want the pilot projects to be delayed if multiple years of data were deemed necessary by oversight agencies. We also wanted to be able to make informed judgments about possible environmental impacts of the projects. Collecting pre-development environmental data was considered so important that it was included in the Northwest Power Planning Council's Geothermal Confirmation Agenda (Northwest Power Planning Council, 1991).

Inspired by the hydrologic monitoring program at Long Valley Caldera, California (Farrar and Lyster, 1990), BPA — acting together with the Bureau of Land Management and the Forest Service — requested assistance from the Water Resources Division of the U.S. Geological Survey (USGS) in designing hydrologic monitoring networks at Newberry Volcano and the Alvord Known Geothermal Resource Area (KGRA). In 1991, the USGS performed a literature search and designed monitoring programs for both areas, and began collecting data at Newberry. Up to 45 parameters are being measured or sampled at about 20 sites (sites have been added or dropped since we started). The Forest Service began confounding the work at Newberry in 1992. Developers are expected to assume funding responsibility in 1994.

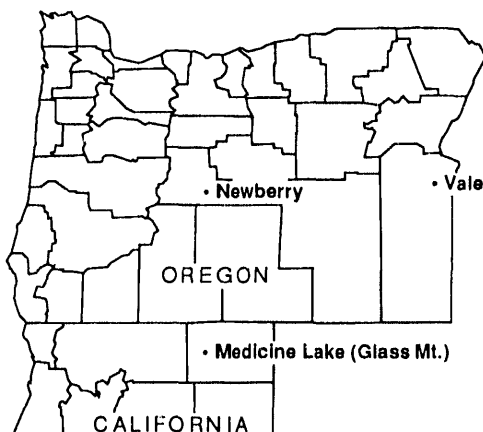


Figure 1. Pilot Project Locations

BPA focused on Newberry and the Alvord KGRA

because recent developer activity indicated we would probably see pilot project proposals at those sites. When no proposal was submitted for the Alvord, efforts were limited to developing monitoring recommendations that could be implemented in the future. In 1992, the USGS designed hydrologic monitoring programs at Vale and Medicine Lake. Reports on all four sites should be available by late 1993.

It appeared likely that adequate baselines for air quality and biology could also require more than one year of data collection. Even if it turned out that one year was adequate, designing monitoring programs in advance would help to identify problems and potential "show stoppers." The Forest Service and BPA therefore cofunded the design of air quality and water quality baselines at Newberry. We thought noise, seismicity, and subsidence were not likely to be major concerns at Newberry, or at least could be adequately addressed with one year of baseline data. Our contractor designed two program levels, one a broad-based program covering all of the sites likely to be developed, the second level only covering a specific site. The resulting report (Ogden Environmental, 1993), intended to identify issues and promote informed discussion (rather than prescribe the Newberry monitoring program), gave the agencies a number of useful insights into monitoring priorities.

Economic Impact Studies

Even a 25-MW geothermal project is likely to be among a county's largest revenue contributors. This was a conclusion reached in each of a series of economic impact studies performed for BPA by the Oregon Department of Energy (ODOE) and the Washington State Energy Office (WSEO). The studies estimate direct and induced economic impacts, as well as impacts on employment and public service requirements, of a hypothetical 100-MW geothermal power project development. The projects are assumed to be built in 25-MW increments, one per year for four years. The studies were done for Deschutes (Newberry Volcano, Bend Highlands), Harney (Alvord KGRA), and Malheur (Vale KGRA) Counties in Oregon, and for Skamania (Mt. Adams) and Whatcom (Mt. Baker) Counties in Washington. The locations of these counties are shown in Figure 2.

These reports have already been very useful to the pilot projects. For example, citizens in Bend, Oregon (near Newberry Volcano), are very concerned about impacts of rapid population growth in the area. Another concern is that reduced timber harvests in Federal forests, due to the spotted owl and other factors, may result in reduced county revenues. ODOE's Deschutes County study shows that geothermal development will generate about 100 short-term construction jobs and perhaps 20 permanent jobs, with much of the permanent work-force hired locally. Even a 25-MW project will probably be the largest property taxpayer in the county, and



Figure 1. Locations of Economic Impact Studies

half of Federal royalties on production will also go to the county. Thus, economic benefits will be large, but population growth and "boom-town" effects should be small. For most local residents, this is welcome news.

Geothermal Impact Analysis — Bend Highlands, Pueblo Valley, Newberry Volcano

In an effort to identify potential land use and other conflicts in areas judged promising for development, BPA funded geothermal impact studies by ODOE for Newberry Volcano, the Pueblo Valley (Alvord KGRA), and the Bend Highlands areas. ODOE also produced maps that facilitate analysis of these conflicts. Parameters analyzed include:

- Air quality
- Archaeological/Cultural/Historical resources
- Geological, volcanic, and hydrothermal features
- Hydrologic resources
- Recreational resources
- Visual resources
- Wildlife and plant resources

The studies discuss how land use conflicts could affect geothermal development and identify measures that may be used to mitigate these impacts. Data for the digitized maps were provided by the Forest Service and the Bureau of Land Management.

RESOURCE EXPLORATION AND CHARACTERIZATION

Assessment of the Feasibility of Applying Slim-Hole Technology to Option Purchases

In a typical exploration program, geological reconnaissance and geophysical techniques are used in conjunction with small diameter exploration wells ("slim-holes") to pinpoint sites for full-size production wells. Production wells typically cost one to two million dollars, and can cost much more. A slim-hole to the same depth costs about one-third to one-half as much. Usually, a reservoir is not considered "confirmed" for the purpose of obtaining financing or a power contract until long-term flow tests have been performed on production wells. Even if flow testing from a slim-hole is possible, the data obtained may be considered insufficiently reliable to evaluate the reservoir (Entingh and Petty, 1992).

Recognizing the potential cost savings from expanded use of slim holes, the University of Hawaii initiated a Scientific Observation Hole (SOH) slim-hole drilling program in an effort to confirm at least 500 MW of resources on the Big Island and Maui. This was needed to justify construction of a \$500 million underwater cable linking those islands to load centers on Oahu (Olson, 1988). The program included trying to develop techniques that would increase the extent to which slim-holes could be used to confirm resources.

Because the Pacific Northwest shares many of Hawaii's geothermal confirmation objectives, BPA and the Electric Power Research Institute (EPRI) cofunded studies that contributed to Hawaii's SOH project, took advantage of data developed through Hawaii's effort, and produced reports addressing specific BPA needs. One of these needs was information regarding the feasibility of purchasing options on geothermal power.

Utility planners in the Northwest have sought to reduce the lead time on power projects by performing as many pre-construction activities as possible, and then keeping the project "on-the-shelf" until needed. Project developers would be induced to do this through an option payment, and the concept is called "optioning." The idea seemed particularly applicable to geothermal development on Federal leases, especially if the environmental impact assessment for the initial development was sufficiently broad-based that subsequent projects could undergo a relatively short approval process. The environmental baseline programs described above were an outgrowth of trying to apply the optioning concept.

The University of Hawaii's consultant produced two reports for BPA. The first report examined the feasibility of purchasing options on geothermal resources (GeothermEx, 1990). The second report specified under what conditions slim-hole data could be used as the basis for an option purchase (GeothermEx, 1991). Studies funded

by EPRI developed methodology for applying probabilistic methods to slim-hole data to estimate reserves and quantify risks. A personal computer-based resource assessment package using these methods was also produced (GeothermEx, 1992).

Geology and Geochemistry of the Alvord Valley Geothermal System

The geothermal resource potential of the Alvord KGRA has been estimated to be about 66 to 91 MW for 30 years (Bloomquist and others, 1985; Brook and others, 1979). Environmental groups and others are concerned that geothermal development may affect the endangered Borax Lake chub, a fish species inhabiting a hot spring pool less than a mile from proposed exploration drilling. Before development can proceed, the relationship, if any, must be established between the hydrothermal system and the water feeding Borax Lake, or a monitoring program must be designed that adequately protects the chub. In an effort to better understand these systems, a number of studies have been done, including work by the Bureau of Land Management, the Nature Conservancy, the U.S. Fish and Wildlife Service, and the USGS hydrologic monitoring study noted above.

BPA also funded a study by Portland State University (PSU) that examined hydrologic and geochemical data in order to develop a conceptual model of the Alvord KGRA (Cummings and St. John, 1993). The study integrates geologic, geochemical, and isotopic data to estimate the temperature and extent of underlying reservoirs, evaluate reservoir rock types, define possible recharge zones, and determine if a hydrologic connection exists among Borax Lake, Alvord Hot Springs, and Mickey Hot Springs. Only preliminary results were available at the time of writing, but the final report should be done by mid-1993.

Cold Water Blanket Study

In the Cascades, ground water may mask signs of geothermal activity to several thousand feet (the "rain curtain" or "cold water blanket" phenomenon), and require deep drilling even for reconnaissance (Swanberg and others, 1988). Since the thickness of the cold water blanket cannot be predicted and has not been mapped, temperature gradient wells are often either deeper than necessary (and thus excessively expensive) or not deep enough (yielding inadequate data). Mapping and methods that aid in predicting the thickness of the blanket will decrease exploration costs and tend to stimulate geothermal development in the Cascades.

With BPA funding, the Oregon Department of Geology and Mineral Industries (DOGAMI) is performing a study that will analyze and summarize existing temperature and geologic data from exploration drilling and other sources. An attempt will be made to use this data to devise techniques for predicting the cold water blanket's thickness and for better estimating minimum drilling

depths needed to obtain necessary data. Results of this study are expected in mid to late 1993.

Oregon Cascades Resource Assessment Update

DOGAMI will also revise existing geothermal resource assessments for the Oregon Cascades. Efforts will concentrate on compiling temperature and thermal conductivity data for exploration wells drilled since the last assessment in 1985. New thermal conductivity data will be collected and tabulated where possible. The revised assessment is due in fall, 1993.

Geothermal Exploration Program in Southeastern Oregon

A joint effort headed by Michael Cummings at PSU and George Priest at DOGAMI will examine southeastern Oregon for undiscovered geothermal resources. The study area is shown in Figure 3. The project, which got under way in mid-1993, will use a recently developed statewide database of anomalously warm wells to search for blind geothermal systems (systems with no surface manifestations, such as hot springs) and to identify targets for field measurement of temperature gradient and/or water sampling. Quaternary faulting will be identified through aerial photography as a guide to exploration targets. Field sampling will include soil mercury surveys, water sampling, and analysis of soil and rock materials for the presence of hydrothermal alteration.

Digital maps will be produced which will summarize land availability (noting wilderness areas, wildlife refuges, etc.), heat flow, neotectonic features, and proximity to transmission lines. We expect the study to be completed in late 1994.

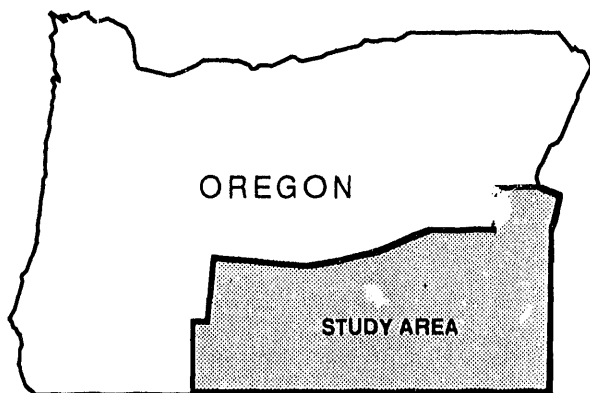


Figure 3. Study Area for Southeastern Oregon Geothermal Exploration Project

Environmental Issues in Geothermal Development Report

Long needed by the geothermal industry, this report will be an authoritative reference on the environmental impacts of geothermal development. Prepared — mostly with donated time — by experts in the industry, the report

will provide a concise introduction to geothermal technology and a balanced treatment of environmental impacts and available mitigation measures. The report is sponsored by the Geothermal Resources Council with funding from BPA, and should be available by fall 1993.

INSTITUTIONAL

Regional Renewables Project

The Northwest's long-standing energy surplus is gone, and utilities are acquiring additional power. Relatively little of this power is coming from renewable resources, partly because the environmental community resists resource development in valued scenic and recreational areas. Unfortunately, most renewables — particularly wind, solar, hydro, and geothermal — must be exploited where they are found, which is often in one of these areas. If we are to build a sustainable energy future based on the use of renewable resources, the environmental community needs a better understanding of energy issues. In particular, they need to understand the role of conservation and renewables in the region's energy picture, and to realize what the alternatives will be if they oppose all development. The Regional Renewables Project hopes to overcome some of this opposition and facilitate development of environmentally responsible renewable resources.

The project is being conducted by a consortium of Northwest environmental groups, lead by the Solar Energy Association of Oregon and the Northwest Conservation Act Coalition. The \$140,000 budget came from utilities, developers (including the California Energy Company), and institutions (including the Northwest Power Planning Council). The U.S. Department of Energy and BPA provided about half the funding. The following activities took place as part of the project:

1. Compile Information Packets. A Resource Handbook was compiled, containing information about the Northwest energy situation, conservation, wind, solar, and geothermal. Biomass and hydro were also covered, but they were not a focus of the project. The handbooks were distributed to environmental group members.
2. Conduct Individual Information Sessions with Participants. One-on-one meetings between resource experts and environmental group leaders were meant to initiate constructive dialogue in a non-adversarial setting.
3. Develop and Convene Participatory Workshops. A series of workshops were held in Seattle, Portland, Bozeman, Missoula, Boise, Bend, and Spokane. The workshops provided a concentrated introduction to conservation implementation issues and renewable

technology. Time was provided at each workshop for questions and discussion, again with the goal of promoting constructive dialogue.

4. Renewable Resources Conferences. All-day conferences were held in Seattle and Portland. Unlike the workshops, which were by invitation only and usually had 10 to 30 participants, the conferences were open to the public. They attracted 200 to 250 attendees at each site.
5. Site Visits. To give them a chance to see operating projects and thereby assess environmental impacts for themselves, two vanloads of environmental group leaders were taken to geothermal, wind, and solar sites in California and Nevada.
6. Development Criteria Workshop. A survey was taken to elicit from the environmental/public interest community their attitudes and concerns about renewable resource development. The survey was the basis for a development criteria workshop held in June at Carson Hot Springs, Washington. The workshop had not been held at the time of writing, but was expected to result in recommendations to decision-makers on development criteria. These criteria could include an assessment of what legal, regulatory, and other safeguards would be needed to protect against environmentally unsound development.

At this time, it is too early to judge the results of the project. At a minimum, it has resulted in an environmental community more knowledgeable about energy issues, and in a greater awareness among the developers and utilities who participated of the concerns of environmentalists.

Guide to Geothermal Leasing, Permitting, and Licensing in Idaho, Montana, Oregon, and Washington

The Washington State Energy Office — with assistance from state energy offices in Idaho, Montana, and Oregon — has written four guides to the Federal, state, and local permitting and licensing process in the four Northwest states for renewable resource power projects. One of the guides covers geothermal, and the others cover hydro, cogeneration, and wind and solar. The guides include tabular summaries of permit requirements, time lines for obtaining permits, flow charts of licensing processes, and agency addresses. A workshop devoted to geothermal permitting and licensing was held in Bend, Oregon, in November 1991. The guides are available (at no charge, presently) from BPA and the four state energy offices.

Geothermal Curriculum for Grades 4-8

With funding from BPA, ODOE is developing a geothermal energy curriculum and teaching materials for grades 4 through 8. After being tested, the curriculum will be distributed to teachers at one or more workshops to be held in summer 1994.

TECHNOLOGY TRACKING

Geothermal Power Plant Database

ODOE has compiled a database on operating geothermal power plants in the United States. It is described in detail in (Sifford, 1992). The database contains over 110 data fields, and currently covers 63 plants. Data is obtained through publications, other databases, questionnaires, and interviews with contractors and project managers. An annual report notes recent findings and trends.

GEOHERMAL HEAT PUMPS

Demonstration Project in Missoula, Montana

The goal of BPA's Resource Supply Expansion Program (RSEP) is to confirm the availability of conservation and renewable resources to meet future needs by conducting demonstration projects. The projects are to be collaborations among electric utilities and other interested parties. Although they predate RSEP, BPA's geothermal pilot projects are in the same spirit and share its goal.

As part of RSEP, BPA will cofund, along with the Missoula Electric Cooperative, the Missoula Montana Ground Source Heat Pump Demonstration Project. The project involves installing individual vertical closed-loop geothermal heat pump systems in 40 homes. Construction will take place during the 1993-94 construction season. All of the homes will be built to Long Term Super Good Cents building efficiency standards. In addition to the usual whole house kilowatt-hour (kWh) meter, 20 of the homes will be equipped with a heat pump kWh meter, a water heater kWh meter, water flow meters, and data acquisition equipment to measure heat transfer in water flows through their ground loop and desuperheater. The remaining 20 homes will have an additional kWh meter for the heat pump only. Data collected over a two-year period will be used for thermal analysis, cost-effectiveness analysis, and performance evaluation of the system.

Technical Support to Help BPA's Customers Develop Geothermal Heat Pump Projects

Billing credits were created by the Northwest Power Planning and Conservation Act of 1980 as a way to encourage BPA's utility customers to develop their own resources. Billing credits remove the disincentive of always being able to buy power more cheaply from BPA. A customer may receive a credit on its power bill ("billing credit") for the difference between BPA's wholesale power rate and the cost of power from the resource, up to

a prescribed limit. BPA periodically solicits billing credit proposals from customers as a way to "acquire" new resources. Both conservation and generation resources are eligible under these solicitations, and there are reasons to believe geothermal heat pump (GHP) projects could compete successfully.

ODOE will identify BPA customers in Oregon with high potential for developing cost-effective GHP projects. Feasibility studies will be done to find out under what circumstances GHP projects are feasible, and ODOE will identify and rank opportunities for implementing these projects through billing credits. If suitable projects are identified, BPA customers will be offered assistance in developing a billing credit proposal acceptable to BPA. If successful, this effort will encourage utility acceptance and market penetration of GHPs.

SUMMARY AND CONCLUSIONS

BPA's geothermal program includes efforts to identify and develop Northwest resources, both high and low temperature, and to improve technologies that promise benefits in the near term. We have worked to overcome institutional and public acceptance barriers through education and outreach projects, and to guard against environmental degradation by initiating environmental baseline monitoring efforts prior to development.

Future efforts will concentrate on ensuring the success of the pilot projects, on finding ways to make geothermal more competitive with other resources (by, for example, reducing capital costs and improving dispatchability), and increasing the use of low-temperature resources.

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SUMMARY

CLOSING REMARKS

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U.S. Department of Energy

As Geothermal Program Review XI draws to a close, we cannot help but be impressed by the advancements and accomplishments that have been reported. Even more, I am struck once again by the successful interaction of government, laboratories and industry. The format of this conference has mirrored the structure of the geothermal research and development (R&D) program itself -- side-by-side participation of industry and government in each technology area. Industry spokesmen have chaired the sessions, providing a unique perspective on the status of their specific areas for the benefit of all participants. In addition, Government and lab researchers have shared their industry-driven R&D objectives and activities.

Many of these reports described cooperative government/industry projects which currently account for almost 60 percent, or \$12 million, of the current DOE geothermal budget. These projects represent a significant increase in cost-shared projects. In fact, the geothermal community contributes (either in the form of monetary or in-kind contributions) an estimated \$3 for every federal dollar spent on cost-shared R&D.

We will continue to seek the valuable advice from industry, utilities, state agencies, universities, and laboratories when constructing the Division's Multi-Year Program Plans, which outline future program directions that integrate and address both the industry's and the Nation's priorities. In fiscal year 1994, the DOE Geothermal Division and the geothermal industry will begin a cost-shared exploration and drilling program focused on identifying new geothermal resources.

Efforts to provide an integrated exploration strategy to reduce risk and improve certainty in evaluating geothermal prospects will continue. A highlight of this year is a program to develop slim hole drilling technology for validating geothermal prospects. At the same time, we will continue to develop reservoir simulators that will aid operators in managing geothermal reservoirs. Advanced heat rejection schemes will be characterized to determine the performance and economic effects of recent technology improvements and environmental

considerations. We are also beginning a cooperative agreement with industry to demonstrate the economic benefits of improved electrical power generating systems for geothermal applications. The interest in economically utilizing low- to moderate-temperature geothermal resources is growing, both domestically and internationally. The interest in these types of resources is encouraged by the Energy Policy Act and owes its success to the many attributes geothermal has to offer, such as baseload power, modular and hybrid applications, demand side management options, minimal environmental impact, and reliability. It is manifested in plans for construction of 25 new geothermal plants between now and the year 2000 that will generate almost 700 MW of electric power and projections for rapid growth in geothermal heat pump installations.

Finally, the good word about geothermal is starting to be heard in Washington. But let's give credit where it belongs. Tsvi Meidav's distinctive voice and accent has become familiar on Capitol Hill and in DOE from the Secretary's suite to Dr. San Martin's office. Mike Wright, geothermal's best-selling author, has organized congressional and written sharp and persuasive white papers. And then, there is Tom Hinrichs of Magma Power and Tom Sparks and others at Unocal who have played significant roles in having Congress permanently extend the tax credits for geothermal, as well as solar energy. Last but not least is Dave Anderson, who as Executive Director of the National Geothermal Association, has tirelessly dedicated his time to promoting geothermal energy. Ted Mock is also on this list of champions.

Recently, both the National Geothermal Association and the Geothermal Resources Council established offices in Washington so that the geothermal industry can make a stronger presence there. This is a crucial year. I believe that this will be the year of decision...whether geothermal is marked as an essential, growing program of the future. If this is geothermal's year, we must aggressively tell others of our accomplishments and show the logic of our plans. Mike Wright recently remarked to me: "We have

win/win opportunities to offer" -- and clearly we do.

In summary, while the known, high quality geothermal reservoirs provide a major "here-and-now" benefit, the vast, undiscovered low-to-moderate temperature resource is a sleeping giant among renewable energy options. Working together, the geothermal partnership can awaken that giant to become the leading technology in fulfilling EPA's objectives for reducing the Nation's oil vulnerability and advancement of environmentally responsible energy technologies, and President Clinton's strategy of increasing the use of clean, economic renewable energy sources while building a solid competitive industrial foundation in this Nation.

Thank you for your contributions toward your goals and your participation in this review.

FINAL AGENDA

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U.S. DEPARTMENT OF ENERGY GEOTHERMAL PROGRAM REVIEW XI

"Geothermal Energy -- The Environmentally Responsible Energy Technology for the Nineties"

MONDAY (April 26)

7:00 pm Registration and Reception

TUESDAY (April 27)

8:00 am Registration and Continental Breakfast

SESSION 1: OVERVIEW

Chairperson: John E. Mock, Director, DOE Geothermal Division

9:00 am	DOE Welcome and Announcements	John E. Mock, Director, DOE Geothermal Division
9:10 am	Welcome Address	Terry Vaeth, Deputy Director, DOE San Francisco Operations Office
9:15 am	Edison QF Experience	Wayne Gould, Manager of QF Policy & Contract Development, Southern California Edison Company
9:45 am	Geothermal Power - How Does It Fit Into the National Energy Agenda?	Thomas C. Hinrichs, Vice President of Governmental Affairs, Magma Power Company
10:15 am	Break	
10:45 am	Overview Presentation on Department's Energy Efficiency & Renewable Energy Policy	Allan R. Hoffman, Associate Deputy Assistant Secretary, DOE Office of Utility Technologies
11:30 am	Geothermal Energy - The Environmentally Responsible Technology for the 90s: A Federal Perspective	John E. Mock, Director, DOE Geothermal Division
12:00 noon	NGA Luncheon: Renewable Energy Set-Asides	Norman Shumway, Commissioner, California Public Utilities Commission

SESSION 2: THE GEYSERS

Chairperson: Kathleen Eney, Pacific Gas & Electric Company

1:30 pm	Introduction	Kathleen Eney, Pacific Gas & Electric Company
1:40 pm	Overview	Phillip M. Wright, University of Utah Research Institute
1:55 pm	Geysers Reservoir Studies	Gudmundur Bodvarsson, Lawrence Berkeley Laboratory
2:20 pm	South East Geysers Injection and Reservoir Study	David Faulder, Idaho Engineering National Laboratory
2:45 pm	Seismic Monitoring at The Geysers	Ernie Majer, Lawrence Berkeley Laboratory
3:10 pm	Effects of Adsorption on Reservoir Performance at The Geysers	Roland Horne, Stanford University
3:35 pm	Break	

SESSION 3: EXPLORATION AND RESERVOIR CHARACTERIZATION

Chairperson: Dick Benoit, Oxbow Power Services, Inc.

4:00 pm	Introduction	Dick Benoit, Oxbow Power Services, Inc.
4:10 pm	Overview	Joel Renner, Idaho National Engineering Laboratory
4:25 pm	Lithology, Hydrothermal Alteration, and Magmatic Hydrothermal History of The Geysers Felsite	Jeffrey Hulen, University of Utah Research Institute
4:50 pm	Gas Geochemistry at The Geysers	Alfred Truesdell, Consultant to Lawrence Berkeley Laboratory
5:15 pm	Development of Conceptual Exploration Models Using Fluid Inclusions, Geochemistry, and Geologic Data	Joseph Moore, University of Utah Research Institute
5:40 pm	Adjourn for the Day	

WEDNESDAY (April 28)

7:30 am Continental Breakfast

SESSION 4: DRILLING

Chairperson: Jerry Hamblin, Unocal Geothermal Division

8:30 am	Introduction	Jerry Hamblin, Unocal Geothermal Division
8:40 am	Overview	James Dunn, Sandia National Laboratories
8:55 am	Status of Lost Circulation Research	David Glowka, Sandia National Laboratories
9:20 am	Memory Logging Tools	Peter Lysne, Sandia National Laboratories
9:45 am	Slimhole Drilling for Geothermal Exploration	John Finger, Sandia National Laboratories
10:10 am	Break	

SESSION 5: ENERGY CONVERSION

Chairperson: Donald Stock, Oxbow Power Corporation

10:30 am	Introduction	Donald Stock, Oxbow Power Corporation
10:40 am	Overview	David Lombard, DOE Geothermal Division
10:55 am	Overview of the Geothermal Energy Conversion Effort at NREL	John Anderson, National Renewable Energy Laboratory
11:20 am	Investigation of Condensation Behavior of Supersaturated Expansions	Greg Mines, Idaho National Engineering Laboratory
11:45 am	Geothermal Materials Development Activities	Lawrence Kukacka, Brookhaven National Laboratory
12:10 am	Lunch (not hosted)	

SESSION 6: ADVANCED SYSTEMS

Chairperson: Louis Capuano, ThermaSource Inc.

1:30 pm	Introduction	Louis Capuano, ThermaSource Inc.
1:40 pm	Overview	David Duchane, Los Alamos National Laboratory
1:55 pm	Fenton Hill Flow Test Results	Donald W. Brown, Los Alamos National Laboratory
2:20 pm	An Estimate of the Cost of Electric Production from Hot Dry Rock	Kenneth Pierce, Sandia National Laboratories
2:45 pm	Break	

SESSION 7: POTPOURRI

Chairperson: Gladys Hooper, DOE Geothermal Division

3:00 pm	Introduction	Gladys Hooper, DOE Geothermal Division
3:05 pm	Low-Temperature Assessment Program	Paul Lienau, Oregon Institute of Technology
3:20 pm	Near-Term Demand and Market-Side Analysis of Geothermal Electric Power	Brian Parsons, National Renewable Energy Laboratory
3:35 pm	Chemical Models for Optimizing Geothermal Energy Production	John Weare, University of California at San Diego
3:50 pm	Biochemical Processes for Geothermal Brines	Eugene Premuzic, Brookhaven National Laboratory
4:05 pm	BPA Geothermal Activities	George Darr, Bonnieville Power Administration

SESSION 8: SUMMARY

4:20 pm	Closing Remarks	Roland Kessler, DOE Office of Renewable Energy Conversion
4:35 pm	Conference Adjourns	

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