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U.S. Department of Energy

Proceedings
Geothermal Program Review XIV

Keeping Geothermal Energy Competitive in Foreign and Domestic Markets

April 8-10, 1996
Berkeley, California

Sponsored by:
U.S. Department of Energy
Assistant Secretary for Energy Efficiency and Renewable Energy
Office of Geothermal Technologies

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Preface

The U.S. Department of Energy's Office of Geothermal Technologies conducted its annual Program Review XIV in Berkeley, April 8-10, 1996. The geothermal community came together for an in-depth review of the federally-sponsored geothermal research and development program. This year's theme focussed on "Keeping Geothermal Energy Competitive in Foreign and Domestic Markets."

This annual conference is designed to promote technology transfer by bringing together DOE-sponsored researchers; utility representatives; geothermal developers; equipment and service suppliers; representatives from local, state, and federal agencies; and others with an interest in geothermal energy.

Program Review XIV consisted of eight sessions chaired by industry representatives. Introductory and overview remarks were presented during every session followed by detailed reports on specific DOE-funded research projects. The progress of R&D projects over the past year and plans for future activities were discussed. The government-industry partnership continues to strengthen -- its success, achievements over the past twenty years, and its future direction were highlighted throughout the conference.

The comments received from the conference evaluation forms are published in this year's proceedings. I thank all of you who took time to give us your thoughts and suggestions. Your comments will help make next year's program review even better.

I want to express my thanks to all who participated and contributed to the this year's successful Geothermal Program Review. I also wish to convey my appreciation to Princeton Economic Research, Inc. whose assistance and support in planning and implementing Geothermal Program Review XIV helped ensure its success.

Allan J. Jelacic, Director
Office of Geothermal Technologies
Energy Efficiency and Renewable Energy

Session 1:
Overview

Chairperson:

Allan J. Jelacic, Director
Office of Geothermal Technologies
U.S. Department of Energy

Opening Remarks

Allan Jelacic, Director
Office of Geothermal Technologies

Good morning, ladies and gentlemen. Welcome to the Department of Energy's 14th Annual Geothermal Program Review. I am pleased to see you all here bright and early this morning. I am Allan Jelacic, Director of the Office of Geothermal Technologies. The Geothermal Division no longer exist at DOE, it is now called the Office of Geothermal Technologies. Within that office we have some new programs. The traditional Geothermal Program is still there, but we also have the High-Temperature Superconductivity, the Energy Storage, and the Hydro Power Programs for the Department. This is what you may call reorganization. It seems that bureaucracy is like politics, it makes strange bed fellows.

We are going through some periods of substantial change at DOE -- reorganizations, downsizing. People are concerned about their jobs. There is always the threat of budget cuts, which are stronger this year than in recent years. And still the specter of the abolishment of the agency appears. These are troubling times for the government, but they are not nearly as troubling as the challenges that face the geothermal industry today.

For those of you in industry, you have to deal with weak domestic markets. There is not much call for new electric power out west, especially in California. You have pricing dominance by conventional technologies, notably natural gas, which you have to compete against head to head. There is a threat of PURPA reform that will take away some of the advantages that the Act gave. Then, of course, there is the restructuring of the utility industry, your primary customer. Also, there is the SO-4 cliff about which we have heard so much. Hopefully, that will just be a bump in the road and not really a precipitous cliff. Finally, there is the move overseas that the industry is undertaking, and maybe the grass is not so green over there after all. Only time will tell.

You have a number of difficult challenges ahead. We in the government are trying to be there to help you. I know that is an old joke, that we are here to help you, but we sincerely mean it. We would like to help in every way, and the best way we can help is through new technology that will help you meet the challenges that I have just outlined. This Program Review comes at a fitting time. Hopefully, over the next couple of days we will exchange information and provide you with some new useful tools that can enable you meet the challenges of the next three to five years. Certainly, if these challenges are not met, we face some real problems in the industry and there may not be an industry in five years. But, let us not look at the dark side. Let us look at the bright side.

This year's Program Review has some notable changes I would like to relate to you. We do listen to your comments, and we have taken those received from last year's Program Review to heart. As for meeting at Berkeley at the Marriott, a number of you expressed interest in meeting here. We are also planning to impart more information by providing more papers through concurrent sessions. That is a new twist that we are going to try this year and see if it works out. Please let us know if you agree that this is the appropriate way to go. We are implementing more interaction with the audience by providing for two open panel discussions: one on The Geysers and another on Cost Cutting. I think you will find the panel discussions very informative and you are invited to participate fully in these sessions. You also asked for more industry involvement, and we have done that by getting industry volunteers to chair sessions, give papers, and also to take an active roll in the panel discussions.

I think we are going to have a very fruitful two days ahead of us. I will kick it off by introducing our keynote speaker. I think most of you know Dr. Allan Hoffman who is acting as Deputy Assistant Secretary for Utility Technologies, directly under Christine Ervin, the Assistant Secretary for Energy Efficiency and Renewable Energy at DOE. Allan has a long and varied background. He is one of the few people I know who has experience in industry, academia, and government. He brings with him a considerable degree of experience and knowledge about how the government operates, has an appreciation for industry, and he understands research as well. I would like to introduce my boss Dr. Allan Hoffman.

Office of Utility Technologies Keynote Address

Dr. Allan Hoffman, Acting Deputy Assistant Secretary
Office of Utility Technologies

It is a pleasure to be here. I am really pleased to be able to address you this morning. I have been working hard on the relationship between our office and the geothermal industry as Allan Jelacic and his people have been doing. I think it has been a really good year for the relationship. There has been, I think, significantly improved communication between the DOE program and the geothermal industry. I know Allan joins me in the hope that next year will be an even better year for communication between our communities. What I would like to do this morning is try to look ahead and talk about some of the factors that I see shaping our energy future, and then talk about the role that I see for geothermal energy.

The first thing I want to note is that there are certain factors that are coming together to shape our energy future and that the 21st century is not very far away. Let me start with increasing environmental awareness. It is very clear that since the mid to late 60's, the environmental interest has been strong and growing in this country. We now see very strong evidence that other countries around the world are increasingly concerned about the environment as well. This is not a fad that is disappearing. It is something that is with us and it is getting stronger with time.

There are many new technology options available to us in the field of energy supply options with which you are mainly concerned. It is also true in information and telecommunication technology, which are going to be important for the future energy system. It is true in the area of materials, which affect so many of our activities.

A lot of the future shape of the energy systems of the world is affected by the growing energy demand, particularly in developing countries, where most of the demand will come from over the next several decades. This demand growth is going to be a very important factor in energy supply, environmental impact, and so on. One of these days, China will be putting out more CO_2 than the United States because of their increasing use of coal. There is a whole range of issues associated with energy security that we have to address in the future given the fact that most of the oil reserves in the world are tied up in the Persian Gulf.

Finally, there is a real movement toward increased business interest in the kind of technology with which we are concerned -- the set of renewable technologies. I was out recently at the SOLTECH meeting, which is a big meeting of the solar industry, and the most exciting thing to me was the fact that the utilities are finally beginning to see a way to make money using renewable energy. Once that happens, things begin to take off. I think there is a sea change in many ways, in the understanding that renewable energy can be big business and high profits, at least in the longer term.

The World Bank, which deals with developing countries, has estimated that over the next three to four decades demand for new electricity capacity in those countries alone is going to be on the order of 5 million megawatts. That is a big number. Total world capacity today is just under 3 million megawatts. So, even if they are off by a factor of two, that is still a lot of new generating capacity. If you start to put an average cost to that new capacity of $1,000 to $2,000 a kilowatt, which is a reasonable range, you realize that you are talking about $5 to $10 trillion. That is just the generating capacity, independent of the infrastructure that goes with it. You begin to understand why there is such intense international competition for these emerging markets in developing countries.

Countries like China and India are trying to improve the standard of living of their people. Together, they represent over 2 billion people. India in the next century will have more people than China, it already has a population of 900 million. Half the world will be basically tied up in these two countries and they are both major coal producers and users. If we do not want them to use their coal, which is going to be hard to stop by the way, we have to offer them some alternatives. I think that renewable technologies are an alternative that they are looking at very seriously. I must admit, though, that I am not optimistic about our ability to stop them from using their coal. I am not even sure we have the moral right to ask them not to use their coal since we used our coal and we are still using it to generate 55% of our electricity.

I have come to the conclusion in my own mind that we are not going to stop global climate change. We are going to adapt to global climate change. It is going to be a rather interesting experiment for the world to go through, but I do not see any other alternative right now. I hate to be pessimistic about it, but I just do not see how we are going to get China and India to stop using their coal reserves. China is the number one producer and user of coal in the world and India is probably number three or four. Latin America is also an increasingly important part of the energy picture. The world population is increasing. It is now probably about 5.7 billion people and is growing at about 1.6% a year and will not stabilize before the middle of the next century.

I have already mentioned that environmental awareness is not going away, it is growing. It is very clear that if the rest of the world powers up the way we did, the environmental impacts could be very, very serious. The picture I keep in my own mind is half a billion Chinese driving cars the way we drive cars. Think of the pressure on the oil supplies. Think of the environmental impacts. It is not a pretty picture. What it does offer is an opportunity to sell them vehicles that are not so polluting. Currently, there is a lot of work going on in the Department of Energy to develop advanced energy systems for cars that do not require the use of petroleum.

We have had a series of international conferences including the Rio Conference in 1992 and the Berlin Climate Conference in 1995. Clearly, the world is on a path toward reduced environmental impact and plans are already being developed for the post-2000 effort to reduce CO_2 concentration in the atmosphere. We can only hope to limit the increase. I do not think we can really reduce the amount in the near future.

What about nuclear power? It does not put CO_2 out into the atmosphere, which is absolutely true. But, when you consider nuclear power, you have to consider a whole range of social issues that come with it. In many developing countries, for example, there is no infrastructure that can accommodate nuclear power. You do not have the grid that can distribute power from a central location. The costs are high. The social issues have to be carefully considered.

What are other people saying about the energy situation as we look towards the 21st century? I think one of the most interesting quotes is from Chris Fay, Chairman and CEO of Shell UK Limited. Shell UK Limited has a very strong strategic planning operation. Shell Oil/Shell UK Limited was the group that anticipated the price rise of the 1970s. But more importantly, they predicted the price drop of oil in the 1980s, which very few people saw coming. They have gone from being a moderately profitable company to the most profitable corporation in the world, largely on their understanding of energy markets. Here is a statement of the CEO and Chairman of Shell that it is pretty powerful. It basically says that, "while fossil fuel supplies will continue to increase between now and the next century, they will peak out at some point and begin to diminish." They say this point is around the year 2030, at which time renewables will become increasingly the dominant energy source. This is an oil company with a good track record that is saying that renewables are going to be the future, given enough time. They are also beginning to buy some renewable energy companies and putting their money where their mouth is. I think that is a very significant statement. It is not something coming from an advocate, from an environmental group, or even from our own program. These are people who are hard-nosed and have to be hard-nosed to make a living.

Alan Greenspan points out that we have a trade deficit problem. It is $50 billion a year today. We import roughly half of our oil -- about 8½ billion barrels a day. That is $50 billion a year not going into our economy but going overseas to other people -- money that we can invest in activities here in the United States. What is really scary is that the number may double over the next ten years as we increase exports from the rest of the world. If we are going to increase exports, a lot of it is going to have to come from the Persian gulf.

Shell thinks that oil supply is going to peak out in the year 2030. A report that just came out about a week ago from the World Resources Institute and James J. MacKenzie, a very sound analyst who has been working in the transportation area for many years, estimates that we could have a peaking out of fossil supplies of oil between the years 2007 and 2019. While there is a lot of debate about this, I do not think it is that critical whether it is 2010, 2020, 2030 in the long run of history. The point is that the fossil fuel era is coming to an end and is going to be a blip on the time line of history. We have to look down the road at the long-term energy system that we are going to need for sustainable development. I am personally convinced that it is going to be a renewable future.

Why are people getting interested? I have already given you one set of numbers, $5 to $10 trillion, that should capture your attention. It sure is capturing the attention of governments all over the world who are helping their industries compete for this emerging market. Electricity is a big business. It is almost a trillion dollar annual business worldwide and about $200 billion a year in the United States. We sell about three trillion kilowatt-hours a year in this country at the present time. Take an average cost of about 7 cents a kilowatt-hour and you get $200 billion. It is big business around the world and is going to get a lot bigger.

An interesting development that we are beginning to see is typified by a statement by Jeff Eckels with Energy Works, a joint effort of the PacifiCorp Utility and Bechtel, the big international company with which most of you are very familiar. Jeff has said that "the market for human-scale energy systems, rather than gigantic projects, is enormous." You have two billion people in the world today who do not have a light bulb, who have no access to electricity. Many of these people can not be reached by traditional power lines. When the Bechtels and the PacifiCorps get together to start putting in smaller renewable systems, you know something is happening. The two billion people without electricity are joined by at least half a billion people who have very limited access to reliable electricity. Roughly half the world needs help in this area, if they are going to increase the quality of their lives.

There are a whole bunch of new energy technologies that are coming along. Geothermal is one of the renewable technologies. Clearly, there are other things that are being talked about. The advanced light-water reactors and fusion. I am probably not going to live long enough to see fusion. It would be nice, but I am not going to see it. Even if it is developed, who is going to be able to afford it -- not the developing countries because you cannot build it in small sizes. That is a problem. Maybe you can do it for urban areas.

Efficient gas turbines are a reality -- the real competition for renewables today. Nothing can compete with cheap natural gas today. That is just something that we have to accept. I personally think that natural gas will be the transition fuel to a renewable/hydrogen economy in the long run and they are natural partners in many ways. We need to do more about storage and we are beginning to develop some new storage techniques.

Hydrogen is going to be an important part of the future. It is a very flexible energy carrier. It can be used in transportation, homes, industries, and almost everywhere. It can be used to generate electricity in fuel cells. I personally think that hydrogen will be a very important part of the sustainable energy future. But, it is a long-term challenge. We have to learn how to produce hydrogen cheaply, learn how to store it economically and safely, and have to let the Hindenburg syndrome pass us by. Many people remember or know about the Hindenburg disaster. I personally would rather sit on a tank of hydrogen than on a tank of gasoline. I think there is greater danger in the gasoline. But, the mental image that most people have is of that dirigible going down in horrible flames in New Jersey in 1937. It is hard to shake that image.

As we look towards the 21st century, we have to recognize certain fundamental facts. One is that energy is fundamental to the welfare of modern nations. There is just no getting around that. You need energy that is accessible in terms of cost and reliability. You cannot get held up by other countries if you are going to have long-term stability and welfare in your country. The business-as-usual scenarios do not project well or safely into the future. You are not going to take the system we have today and make it the system of the middle of the next century. You are not going to have the supplies. You do not want the dependence upon the few areas of the world that are politically unstable. It does not allow us to take advantage of the market potential that is out there because other countries are going to be trying to sell renewable systems to the rest of the world.

I personally believe that renewable energy systems are going to be an important part of the economy in the United States in the next century. We are going to have to move into a sustainable society and the ingredients of that sustainable society, in large part, are going to be energy-driven. If we do not do things different than we have done them before, we are going to lose the economic potential out there, which is just massive. I just do not see business as usual answering our needs or the needs of the world. We have to provide options for people, for our children and grandchildren, and their children. I often say that I am in the options business. I am not in the financial community, but I am in the options business because I am helping to provide options for the people that are coming after us. They do not have to do it the way we did it. There are other ways to do it and renewable energy is an important part of that options package.

We are going to be moving inexorably toward increasing reliance on renewable energy. Hydrogen will emerge as an important energy carrier. I do not call it a fuel because it is a derived substance and, therefore, it is an energy carrier like electricity. It will be a natural complement to electricity as we move increasingly towards electrification. But, I really do believe it is going to take 50 to 100 years for this transition to occur. Most energy transitions take a long time. I see no reason why this one will not take a long time. I would like to try to expedite it as much as I can, but I think it is going to take time.

Today, we are in the early stages of a long-term transition. It is going to be chaotic and difficult, but we are beginning to move in that direction. Renewable energy will be an important part of that future for a lot of reasons with which you are familiar -- proven effectiveness and reliability. Your geothermal facilities are highly reliable. Wind machines today are 95 to 98% available, which is very different from what was true in the early to mid 1980's. With photovoltaic (PV) systems today, you can get a warranty on the module for 20 years, and they will probably be moving towards 30 years fairly soon. Biomass systems are finally going to be looked at seriously. There are a lot of markets that can be met or addressed reliably by renewables. In many situations they are already cost-competitive, especially in other places around the world where energy costs are not as low as they are today in the United States.

People in remote villages, say, in Africa spend a fair amount of money on kerosene to provide limited lighting for their huts. That money, if applied more effectively toward renewables, could give them a much improved standard of living. Just one 50-watt PV panel, for example, can provide the energy for a few lights and maybe a black-and-white television set. That gives you a lot of things. It gives you the opportunity to educate your children -- they can study at night. It gives you the opportunity to have a very low-level local industry that can perhaps provide some income. It provides birth control, which is a very important off-shoot of having light available at night. It involves the opportunity to communicate in ways that were not possible before. A lot of these developing countries are not going to put in telephone wires. They are going to go cellular and they are going to communicate without wires using satellites. They will be able to jump right over the kind of system we have in many ways.

Renewable technologies are distributed. They can be used in off-grid locations in many different ways. They can be combined if you want grid support or grid generation. They are going to be economically important because of the large markets that will create jobs for the United States. I want those to be American jobs, not jobs in other countries. They minimize our dependence upon unstable fuel supplies and certainly minimize the volatility of energy costs, because once you put your capital investment you basically do not have a fuel problem. We call this manufactured energy instead of fuel energy because you are basically paying for the capital.

With renewable technologies, you can reduce imports and environmental impacts as well as improve energy security by being less dependent upon other countries. There is a lot of money involved here, $50 to $100 billion of trade deficit because of oil. It is much better if spent in the United States. In addition, we have a real advantage. The American public strongly supports renewables. Polls that have been done over a number of years, whether by Republican pollsters, Democratic pollsters, or anybody else, all support the concept that people like efficiency and renewables. Those are their favorite energy forms. The American public would like to see the government support them more effectively, and are even willing to pay a little more to get energy from renewable sources. I think that is a very important factor that we have to take into account as we move into the future.

Where does geothermal fit in all this? I do not need to remind you that geothermal is a base load technology. It is one of the two renewable technologies that by itself is base load, the other being biomass. Hopefully, eventually all the renewables will be base load through the increased use of storage, but we are not yet there. There is a tremendous resource base around the world for geothermal, both in terms of hydrothermal resources and eventually in what has been up until now called Hot Dry Rock. I know there is a strong interest in changing the name and Enhanced Heat Recovery has been proposed as one.

Geothermal, if developed properly, can be an environmentally attractive technology. It does not have to put out H_2S into the environment, as so many people still think. You have to get that message out. You have made significant technical advances over the recent years. You have had a tripling of U.S. geothermal capacity since 1980. The cost of discovery of resources, of power plants, and peripheral equipment has come down in recent years, bringing the levelized cost of geothermal energy down into the range of 5 cents a kilowatt-hour. That is pretty good, but it is not good enough when you are competing against natural gas, which is producing power somewhere between 2 to 3 cents a kilowatt-hour. A year ago I saw spot prices for natural gas from Canada of less than a dollar a million Btu. That is just unreal, you just cannot do anything with that. Geothermal, as with all renewables, is a hedge against energy price volatility and fluctuation.

The U.S. industry is in a very good position to compete for the markets that are seen over the next decade. One estimate is a $20 billion market over the next 10 years. As Senator Hatfield acknowledged, we recently received $6 billion in contracts from the Philippines and Indonesia. That is very encouraging. U.S. industry is very strong in putting together and financing these projects, probably more than any other national group in the world. You have an unmatched track record for success in putting these projects in place, so you are in an excellent position to compete for these international markets.

We intend to work very closely with you to help ensure that you are a successful industry well into the 21st century. I recently learned about a World Bank Global Environmental Facility (GEF) grant to the Philippines to put in a geothermal project. What is intriguing about it is that they had planned to put in a fossil-fuel project, and, because of a little nagging perhaps from the Department, they looked at geothermal. Even though it was going to be somewhat more costly to put it in, they decided for environmental reasons to support the geothermal project. The $30 million investment by the World Bank and GEF is going to leverage a lot more money to the project, and we are really pleased about that. The World Bank, by the way, is finally getting serious about renewables and beginning to undertake a major Solar Initiative. The World Bank has a new president, James Wolfensohn, who really cares about renewables. I think we have a real opportunity to make the financial resources of the Bank available for renewable projects.

There is another aspect of geothermal, called geothermal heat pumps, in which we are very actively involved. Geothermal heat pumps are not deep geothermal obviously, but it is a very important technology. Most of the world, and most of the United States, knows about air-source heat pumps. Most of the United States probably does not like air-source heat pumps, because when the air temperature gets low they become electric heaters and do not offer any advantage. What if you put the heat exchanger in the ground? You have a constant surrounding temperature of 50° to 55°F all year around enabling you to use the ground both as a heat source and as a sink. Geothermal heat pumps give the customer probably the lowest-cost heating and cooling system available today on a life-cycle basis. Geothermal heat pumps also help utilities reduce peak loads in summer and winter. They are a very attractive option.

DOE is working with the electric utility industry on an initiative to increase the deployment of geothermal heat pumps. There is no question about their feasibility. The only question is the infrastructure that goes to put them in place and the up-front cost. So, we formed this initiative to increase the deployment rate from 40,000 a year, which is what it has been historically in the early 1990's, to 400,000 a year by the year 2000. This is an important part of the utility sector's Climate Challenge Program, which is their voluntary response to reducing greenhouse gas emissions. I think we can do it.

What is really going to be required here is innovation and financing. How do you finance something that has an up-front cost of a few thousand dollars more than a traditional system? It is really intriguing to see places like Detroit Edison and other utilities figuring that one out. I think it is a lesson for all of us that our technologies are getting good enough that the real issues are not going to be technological but financial. How do you get the money to people so they can put these systems in place? We are beginning to look at that financial question more and more in activities all over the world. I really think that is going to be the major barrier. Today's PV systems that you put out are pretty damn good for most places in the world. They are going to get better, no question about it. But the question is how you get the money in place to allow people to use them.

What does this all mean for the DOE geothermal program? We are going to continue our efforts to further reduce the cost. We have to reduce the cost of exploration, of drilling, of reservoir management, and conversion of the steam to electricity. What I expect is continued incremental progress in all of these areas as a result of our joint programs.

We are going to be helping the industry in identifying resources around the world. We have plans for the next year to work in Asia and Central America. We want to develop smaller power plants in demonstration projects. There is a lot of export potential for these small systems around the world. I recently had a very interesting conversation with some people from Indonesia. They have a large geothermal resource and a lot of places where small geothermal could be used effectively -- small geothermal being 100 kilowatts to maybe a megawatt.

We have gone through a lot in the last year on the Hot Dry Rock, or Enhanced Heat Recovery, Program. We worked very hard with the industry to look at where that program was and where we would like it to be. We have decided jointly to integrate it into the mainstream Geothermal Program. While we are closing down Fenton Hill, we do see Hot Dry Rock (or whatever you want to call it) as the long-term future of the geothermal industry. The resource is just immense, and is ubiquitous around the world. But, it is going to take time. We can learn a lot about Hot Dry Rock technology by working in traditional geothermal areas. So, we are going to move it more into the mainstream of the Geothermal Program as it exists today, but keep our eye on the long-term potential of Hot Dry Rock.

The budget is holding its own for geothermal. I do not think it is big enough. I would like to have more money in geothermal, but that is true of every budget category for which I am responsible. But, relatively speaking, geothermal is doing OK. The request for 1997 is $34.6 million and it looks like we should not have too much trouble achieving that level. I am really pleased about that and we will certainly try and get it up in the future.

In conclusion, let me just say a few things. There are a number of trends I mentioned that are converging, that are going to lead to greater use of renewable energy in the future. I think this is inevitable. I see people recognizing that you can make money on renewables and, therefore, business support is building as the opportunity becomes more apparent to people. We clearly have to make greater use of renewables if we are going to move towards a sustainable society. I do not see any alternative. I think geothermal technology will play a key role both in domestic and international energy markets. The geothermal industry/government partnership is going to get stronger in the years ahead and we look forward to working with you as we move towards the 21st century.

Improving the Competitive Position of Geothermal Energy

Thomas R. Mason, President and Chief Operating Officer
California Energy Company

I am here to tell you that the geothermal industry is alive and well in Omaha. I think a lot of the statistics we have just heard are certainly accurate reflections of what we would expect in the long-term scenario. Some of us, however, are focusing more on a shorter term, like this quarter, this year, and what is going to happen in 1997 rather than 2005, 2010 or beyond.

The domestic market is currently very difficult for geothermal with avoided cost at the bus bar based on today's natural gas prices. The avoided cost rate is low because it is established by the utilities, who want to pay non-utility competitors less for their generation, utility commission, who wants to see the benefits flow to the rate payer and the commission is supported by the Department of Rate-Payer Advocates, who would like to see the cost be lower. We have no leverage in this structure and we have not done as an effective job at arguing why it should be higher. As a result, the PURPA avoided cost that has been established is lower than what we would hope and expect would come out of the PURPA process as it was originally intended. We have also seen little in the way of externality revenues domestically, in spite of the fact that we hear that most people support renewables. That support has not been translated into increased payments for renewables.

I do not see compensation for the lower externality costs of geothermal happening any time soon. There has been a lot of talk. There has actually been some action with regard to externalities in that bills have been passed, but nothing has had any teeth in it that has resulted in increased revenue flow to producers of geothermal power.

The other thing that has not been considered well when we think "revenue" is the fact that indigenous resources have more value to the local people. For instance, in California you have an indigenous resource. Whether or not it is in the Imperial Valley, The Geysers, Coso, or wherever, you are drilling wells. You are spending a whole lot of money to produce a fuel source from California rather than buying fuel from Texas, New Mexico, Mexico or Canada. All taxes are being paid in California. All the benefits flowing to California are not in the calculation when you compare rates at the generator terminals. So, there are a number of things really not taken into account when people are making the decision, "Should we be buying geothermal power from inside California at this location, or should we be buying low cost power generated using the combustion of natural gas or coal, or nuclear from some other location outside of the region using fuel sources produced and benefiting other states and other countries?"

We do see those benefits considered when we get into the Philippines and Indonesia. If you look at the Philippines, one of the reasons that they see geothermal as being economically viable is their balance of trade. You might think they are just supporting the environment, but that is not really what is driving them. What is driving them is the fact that this makes sense to them from a balance of trade standpoint. If they were not using geothermal, they would be importing coal, oil, or something else, which will hurt their economy. They recognize the value of an indigenous resource. They do not in the State of California because we look at what is good for the whole country rather than what is good for the people of California and if one considers

Canadian imports, we don't ever consistently consider what is good for the country.

Figure 1. Desert Peak

Figure 1 shows Desert Peak. Desert Peak's contract with Sierra Pacific Power Company expired. We are currently getting short-run avoided cost there. We think we can find other, more attractive markets. We have not found them yet. Short-run avoided cost in the Sierra Pacific power system is 2.5 cents a kilowatt-hour. We continue to run this plant. We run it differently than we did when we got higher avoided cost -- we have to. We have to run it with less people. We have to run it with poorer availability. We have to look at the whole picture differently than we did before, but we are running and we are running profitably.

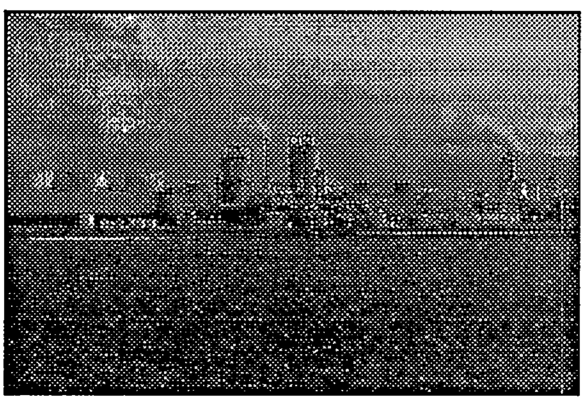

Figure 2. Vulcan And Hoch, Imperial Valley

Figure 2 shows you the Vulcan and Hoch facilities in the Imperial Valley. We have a project here in Vulcan that, just in February, went off the cliff. It is much nicer to get 12 cents a kilowatt-hour than it is to get 2.3 cents a kilowatt-hour for energy. A lot of the joy has gone out of the process. That does not mean that it is no longer profitable, but it is not as profitable as it was before, I can assure you. At that same time we are making money. We continue to run Vulcan and will continue to run the other projects as they go off the cliffs. My point is that the world is not coming to the end when rates fall off the cliffs.

Figure 3. Navy I at Coso

Figure 3 is a photo of Navy I at Coso. Navy I goes off the cliff in 1997. Our site cost of power production at Navy I is under a penny a kilowatt-hour. I assure you that getting 2.5 cents a kilowatt-hour for energy and another 2 cents for capacity will make sense for us to run the plant. If it costs you a penny and you are getting 4.5 cents, this is good. It is not as good as if you were getting 15, but it is still good. So, we will continue to run these projects. The world is looking very good.

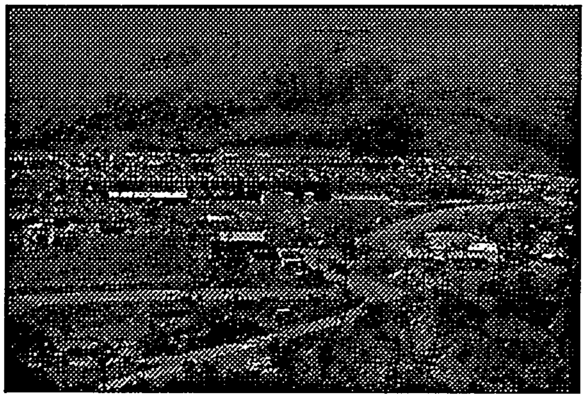

Figure 4. Upper Mahiao, Philippines

At the same time, we have some new projects coming on-line. Figure 4 is a photo of the Upper Mahiao project in the Philippines. It will come on-line before July. It will start to run sometime before May of this year and be commercial hopefully by July 1st. This project has huge binary heat exchangers which extend over 300 meters long. The facility has four General Electric noncondensing steam turbines and 13 Ormat binary systems, the OEC's. It produces about 119 megawatts net and is well along as you can see. Everything is going very well.

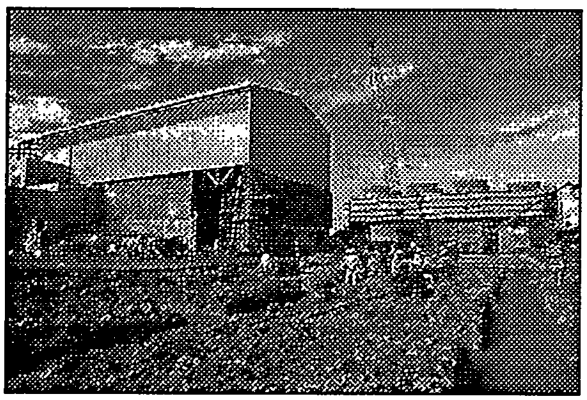

Figure 5. Malitbog, Philippines

Figure 5 shows a portion of the Malitbog project. This project is about 216 megawatts net. There are three flash units using Fuji turbines and the plant is being constructed by Sumitomo. The first phase of this three unit project is one unit which should be on-line this summer. The other two units will be on-line next summer. So, it is progressing nicely and will be operating shortly.

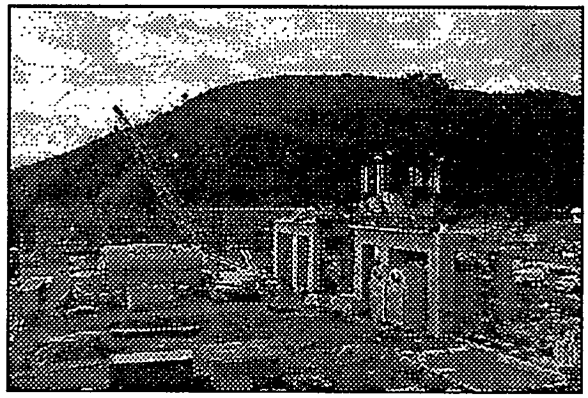

Figure 6. Mahanagdong , Philippines

Figure 6 shows the third Philippine project, the Mahanagdong project, which is under construction. It is an earlier phase project because it does not come on until July of 1997. It will be about 164 megawatts net. It is being constructed by CE Holt and Kiewit in a joint venture. In this project, we participate not only in the operation and ownership of the project, but also in the construction through the joint venture. Actually, when you get into Indonesia, the ownership and construction structure is such that we are almost indifferent as to whether or not profit occurs on the long-term operation of the project or as a result of the construction.

We have about 500 megawatts between the three projects in the Philippines.

Figure 7. Dieng, Indonesia

Figure 7 shows you one of the wells being drilled at Dieng in Indonesia. We have a number of wells that we drilled there. We started construction on our first 55 megawatt unit in Indonesia at Dieng, and it should be on-line around the end of 1997 or early 1998. The Indonesian opportunity is beginning to mushroom. The Dieng contract will allow us to sell up to 400 megawatts, depending on how much we can develop from this resource. We have similar 400 megawatt contracts with Patuha and Bali in Indonesia for a total of 1,200 megawatts that we can potentially develop.

In the Philippines we do not take responsibility for the wellfield operation, that is run by PNOC. In Indonesia we are drilling the wells and developing the wellfield, too. In Indonesia a megawatt of power represents substantially more dollars put to work than it is in the Philippines. However, you have the risk of wellfield development, exploration, and the kinds of risks that go with running a wellfield. We would prefer to do the Indonesian type operation over in the Philippines because, historically, we have always run our own field and it gives us some comfort to do so. When you are running a wellfield and you are trying to be competitive, you get some synergies because you have a labor resource that you can cross train. You can have some of the folks running the wellfield and running the plant. When you have them run by separate companies, some of the efficiencies that you can experience by combining the labor force are not available. So, when using the separate groups you end up with a somewhat less competitive and less efficient operation.

Lets talk for a moment about the installed cost of a plant.

As mentioned previously, one of the things we can do in the geothermal industry to control the cost, is to joint venture with your ownership partner for construction to make sure you are doing what you can to control the profitability of the contractor by making a good portion of that profitability yours.

Competition for the construction is something that you have to have to bring down costs. Even when we joint venture with ourselves, we try to use competition to the extent possible to bring down construction costs, and make sure that we do not get lazy. One of the concerns you have when you get involved in your own construction is that because it is captive you get complacent. Potentially, you lose the edge that you gain by being smarter. Having it be captive can actually hurt you because they know they have the business and they do not have to go out and compete. So, you have to make that construction joint venture go out and work to get the business, or you will not be as efficient as you might otherwise.

Some of the other things we do through our technical subsidiary, CE Holt, is to look at all of the alternatives available to us in the way of technology that may allow us to reduce our installation and/or operating costs.

We also have active cost reduction programs and have set up task forces to attack each problem that we have in the field. We try to bring that operating experience forward into the technological design of the new plants so we can continue to bring down long-term costs (long-term net present value). Sometimes it makes more sense to spend a little bit more money on the plant for the long-term benefits that result. If you can marry all of that thinking and weave it together in a way that you can really look at the long-term net present value, you optimize the value to the company.

There are a number of technological innovations that we have looked at and we have found some of them to be successful, and some not to be successful. You do not always win. But, I think we can continue to bring down costs.

We talked about revenues and what that means for us to be able to compete. We talked a little about plant costs and how we might try looking at that a little bit differently to bring down costs. Let's talk a little bit about operations. We are working very hard at the Imperial Valley to bring down costs and we are just starting operations in the Philippines. In six months to a year, we will start operations in Indonesia. When we first got involved at Coso, the costs were much higher than they needed to be. We found that we could operate with less people. We found different technologies and approaches to well maintenance, to abatement of H_2S gas, of managing our availability, of running our overhauls, and of doing everything. We took a fresh look -- throwing all the cards face up. We said, that is what we can do, this is what we cannot do, this is what they cost, and these are the technical risks comparing them to each other. We tried to figure out what is our least cost, most efficient way to move forward. It has worked for us.

One of the things we have found is that there has been an awful lot of people in our industry saying, and maybe this is universal, "it cannot be done". Time and time again we say, "let's try it". After they have done it for six months, they say, "that works". It has been proven time and time again, at least in our experience, that people can do more and be more efficient than they are today, if they are given some incentive and if they are encouraged and guided in that direction.

That is not always done without some pain. We have some instances of substantial work reductions in the not-too-far distant past in the Imperial Valley. A lot of good folks were laid off when I first got to Coso, and that does not come without some pain. But, we are not in the business of creating jobs. We are in the business of working for our shareholders, creating shareholder value, and of doing those hard things that have to be done. It is a whole lot more fun to be hiring people in the Philippines and Indonesia right now than it is to have to go into a place that has more people than it really needs to be profitable, and have to lay people off. These are tough decisions that we have to make when business is tough, but when avoided cost is 2 cents a kilowatt-hour, we need to get our cost as low as possible to ensure that we survive for the long-term future. We are doing the tough things and we are doing them, I think, quite well. I think we are making the hard decisions, and we are moving forward.

Reducing overhead expenses is one way that we can get at some of the operating costs. Other ways include decreasing labor costs, consolidating and standardizing purchasing, and utilizing cost-saving technology. Some reduction of overhead expenses has come, at least in our experience, through acquisitions and our ability to have a smaller group run more operations you can spread costs around over more folks. That certainly has brought down some of the costs.

Reducing management layers can lower overhead expenses. Other ways include consolidating and reducing management duplication and completing construction projects ahead of schedule. You have to do everything with a sense of urgency. We have to set schedules and meet them. We have to beat them if we can. The less time you are doing any of these things, the less labor and money you are using. You can move on and do something new. We work very hard to meet our schedules and be under budget.

Achieving outstanding safety records help us, not only because it increases our morale -- it means people are thinking about what they are doing and working smart in the operating organization, but it also substantially reduces our insurance costs. We just achieved over a year without a lost-time accident in the Imperial Valley. We have done that several times at Coso, but when we look at the combined Magma and UNOCAL safety records, we find that is the first time that the Imperial Valley has ever gone more than six months without a lost-time accident. These reduced insurance costs help bring down the cost of overhead.

Another way to reduce overhead costs is to assemble creative financing packages, which is something we certainly have been able to do.

To decrease labor costs, we have tried to consolidate job functions through cross training. When we first got to Coso, we had separate well operations and separate plant operations. The wellfield and plant operations as separate groups were combined into one through cross training. As a result, over time, we have been able to substantially bring down the number of people.

We are now working on improving our efficiency in the Imperial Valley. The wellfield and plant operations are not separate, but there are a lot of specialized activities. They are trying to train themselves to do several things so that you can eventually bring down the number of people. The site costs in the Imperial Valley are now below 2 cents. They were up to about 3.5 cents when we first got involved a little over a year ago. I do not think we will ever get as low as Coso. There are some special differences there with heavy total dissolved solids and other operating characteristics that we see in the Imperial Valley that are going to require more cost. However, I think we should get down to 1.5 cents/kWh to 1.25 cents/kWh, before we are done.

A way to reduce international project labor costs is to hire a local work force. It is much less costly to use Philippine Nationals than expatriates. It makes sense to have Philippine Nationals run their plants as quickly as we can get them trained and in a position to do that. These folks have good technical skills. They have not had the practical experience and training that we have here in the States, but they are coming up to speed very quickly. They have terrific attitudes and are enthusiastic about the work.

We have five expatriates in the Philippines associated with those three projects -- a general manager, three supervisors, and a maintenance manager. In two to three years -- as soon as we can find, train, and get comfortable with solid replacements -- we would like to pull those folks out of there and deploy them where they can start-up new operations, get systems organized, and create real value. While expatriate value is substantial in the start-up phase, as we leave them there, their value quickly diminishes.

Indonesia will be a little difference situation. Language differences exist. We do not have quite the same characteristics in the work force. Quite honestly, we just do not know as much about that work force yet because we have not started hiring. Until you start hiring, interviewing, and talking with people to determine their capabilities, it is very difficult to assess the situation. We think we will have good success in Indonesia and operate ultimately with a very limited expatriate staff.

In summary, we have reduced staff. It just makes sense. You cannot afford to have people on your staff that you do not need. You would rather be as lean as possible. At 12 cents a kilowatt-hour, you cannot afford even small lapses in availability. You need more people. However, when you start looking at 2 cents per kWh and you are producing a whole lot more energy than you need to make your full SO#4 contract capacity bonus, you can no longer afford that extra person for that extra little bit of availability.

Consolidating and standardizing purchasing has been extremely useful to us when we look at the domestic Imperial Valley and Coso operations. We have also now wrapped in our international operations. When you start looking at buying some of the wellfield products, pipe, drill strings, and other kinds of things, you have to learn to use your purchasing power as effectively as possible. None of that was really available before we were able to bring various facilities together through our good fortune. It leads to more efficient operation if you can consolidate and bring that purchasing power to the table.

There is no doubt that competitive bidding and stronger purchasing power leverage will bring down product prices, reduce our costs for the long run, and make the geothermal industry more competitive domestically. It also helps us internationally. Sharing information from the domestic to the international market helps to keep the international suppliers honest.

We have utilized cost-saving technology. We centralized some of our operations. We have used different kinds of alloys and cement-lined pipes to reduce overall maintenance costs in some of these systems. In the Imperial Valley, we implemented the pH modification process where it makes sense to do so. It does not make sense everywhere, but it does in some specific applications.

We know something about H_2S abatement systems. We have injected gas into the ground. We have run the Hondo chemical batch plants. We have run Sulferox systems. We have run LoCat systems. We know those systems at least as well today as the system manufacturers -- maybe a little better from the standpoint of what is really going on. Understanding those systems and knowing which way to move, given the constituencies of the geothermal fluid being produced in any location, is very helpful. Cost saving technology allows you to fully utilize available plants. While the incentive for very high availability diminishes after the cliffs, it is still there.

We have significantly reduced overhead costs by consolidating and centralizing management resulting a cost savings of more than $12 million -- that is just through the Magma acquisition. When we first got involved in CalEnergy in 1990, the overhead costs in San Francisco for that year were about $75 million. In 1991, we brought those down to about $13 million. When we got involved in the Magma acquisition, we reduced the overhead by about $12 million, $9 million in LaJolla and $3 million in the Imperial Valley. We talked about the importance of completing construction projects on time and within budget. The discipline was just not there to force these things to happen, to take them seriously, and to work with a sense of urgency. We have just tried to make sure the people understand how very important this is and make it reality. We discussed the benefits of full time safety with no lost-time accidents.

From a financial standpoint, it is worth noting that we were named as some of the Deals of the Year in both 1994 and 1995 by the Institutional Investor. We have certainly pulled together some very large financings. We have a creative, strong finance and solid legal organizations that makes those things happen, supported by solid technical and operating groups. Financing gets easier and easier as you build a reputation in the financial community of doing what you say you are going to do.

On the revenue side, we are facing difficulties in the U.S. We have not seen the avoided-cost support. From a rate standpoint, we have not seen the benefits for externalities. We have not seen the benefits for having an indigenous resource in some of these states.

From the plant-cost side, I think that we just have to continue to work harder, explore all the alternatives, and find the least cost way of producing power for any particular application, given a specific set of conditions of the geothermal fluid being produced. Is it dry? Is it wet? What kind of gases are involved? All of these will lead you to one conclusion or another depending on the technology. From the operating standpoint, there is just no magic. It is just hard work. Look at what you can do with less to bring costs down and continue to work at it.

The industry is healthy. It is doing well. Our earnings are looking good and I expect them to continue to look good. We will do new and more exciting things. We can use all the support from the government that they are willing to give us. I appreciate being asked to speak today. Thank you

Geothermal Energy -- Business Challenge and Technology Response

Darcel L. Hulse, Group Vice President Geothermal and Power Operations
Unocal Corporation

I am going to talk about the things we need to do to be successful and competitive in the new environment. I will be talking about the technological side of geothermal power. This is a subject of great importance to many of you who have invested much of your career in the science and technology that makes this industry work. We could talk about the philosophical side of technology and discuss the merit of basic versus applied research, or the differences between a mature technology and those low in the S-curve of learning. We could get into many philosophical discussions about research. I will leave these topics to those who are more qualified to address them than myself.

I would like to talk about another approach to geothermal research that I think is going to be key to success in the next 5 years. The key here is competition. We have made geothermal power a commercial reality by realizing the benefits of clean and efficient electric power from natural steam. We must now prove that this reliable power source that requires no fossil fuel, substantially reduces the release of harmful greenhouse gases, and competes with other energy sources on commercial terms anywhere in the world. This challenge will require:

- accurate identification of the barriers to success or identification of those things that must be done to assure success;

- innovative thinking, ingenuity to see the unseen, and the ideas and methods to meet these needs; and

- commitment to focus resources and personal talent on the issues of greatest importance.

This has been the hallmark of successful research all over the world. You must have heard that "desperation is the mother of invention". Let me give you an example from Unocal's oil and gas operations in Thailand. This operation is one of Unocal's largest, producing over 750 million cubic feet of gas per day and supplying about 25 percent of Thailand's commercial energy needs. This success has not always been a cheerful one as it is today. There were times when this project looked very hopeless. Despair set in and there was even a temptation to give up and walk away. Let me show you why.

Our initial gas discovery in the Gulf of Thailand was in 1972 at a field called Air One. We mapped the area using marine seismic technology of the time. The map showed a large closed anticline or fold in the subsurface, suggesting the presence of a very large gas field. Reserves were estimated to be about 1.5 trillion cubic feet of gas. The development contract was signed and drilling began. Development wells revealed that what had appeared to be a large gas field was actually a complex of small gas accumulations trapped behind faults in a structural low or syncline in the basin. The structure was so complex that our best geophysical technology at the time failed to properly resolve it. A large investment had already been made, contracts were signed and commitments were in place. Reserves were revised downwards to 423 billion cubic feet. The news was very discouraging and certainly destructive of project economics. It would make anyone just want to walk away from the project. We had made investments based on estimates of reserves, but once we accessed the resource we found a different picture.

I share this story to illustrate the role of motivation. There is certainly proper motivation when we face a challenge of this nature. You already know that the story ends on a positive note, but what you may not know is that a technological solution made things happen. New 3-D seismic technology accurately imaged faulting in the basin and identified some of the gas reservoir directly. Drillers learned to drill wells for 75 percent less the cost of wells in 1980. Wells that once required ten weeks to drill are now completed in less than ten days.

A development strategy that permits drilling of multiple reservoirs along foot walls in normal faults increased recoverable resources by 145 billion cubic feet. Reserves for Air One field are now estimated at more than 1.8 trillion cubic feet of gas, some 300 billion cubic feet above our original estimates. Technological advances turned a challenge, or I may say more accurately, turned a certain failure into a success that has made this resource very competitive. These are the same kinds of advances needed to increase the competitiveness of geothermal power in world energy markets -- technology to map the productive parts of hydrothermal systems and technology to increase the efficiency and reduce the cost of drilling in volcanic environments. The benefits from progress in these areas will increase geothermal power generation opportunities, new growth opportunities, and worldwide competitiveness for the U.S. geothermal industry. Let me show why these are critical needs of the industry.

In a typical geothermal project cycle, a geologist or engineer becomes aware of a resource that may have sufficient temperature and volume to generate electric power. This is followed by contracts for resource exploration and development as well as for the power sales agreement. When contracts are signed, a relatively small amount of money has been invested in the project. Thereafter, costs go up substantially. Exploration drilling alone will require several million dollars. If a resource is found, delineation drilling will require several millions more before the resource is proven. If all is successful, time will be required to design production systems, power plants, transmission systems, procure equipment, construct facilities, and drill development wells. There will be no positive cash flow nor return on investment until sometime after the project is completed and power sold to the local market. Consequently, investments made early in the process, for exploration and delineation drilling type activities, have an amplified impact on project economics. This is because of the long time interval between expenditures and recovery of costs. If costs are stranded and can not be recovered, then the project is bound to fail at some point. This is a risk we shoulder everyday in this business and a reality we have chosen to face. It is one of the reasons why we need to seriously think about the competitiveness of geothermal in the market place.

I will use a simple economic model to show where to focus our research efforts and where to appropriately apply them using the common business binocular of today. Where can we get the biggest bang for our research buck? The model is just a sample version and does not represent any Unocal geothermal project. The assumptions used include a two year exploration period before finding a field and starting development;

power plants would come online within three years; wells would cost $3 million dollars each, with probably 12 producers and 8 injectors for a hydrothermal system; the tax rate would be 38 percent; and the initial investment for a 110 megawatts plant, including financing and capital costs, would be about 250 million.

Since any model can be adjusted to reflect accurate numbers, we need to look for trends based on economic principles. Let us start by assuming a 15 percent real rate of return on the project, which will attract investors, and hold it constant. We will then vary one component at a time to see what happens to the various other factors. We begin by comparing price and well costs based on the earlier economic assumptions. In order for us to fully amortize our investments and maintain the 15 percent rate of return, our price must be 7 cents. If we focus only on drilling cost to bring the price down, we will need to reduce drilling costs by about 50 percent or drill wells for $1.5 million instead of the $3 million, and we reduce the price to 6 cents. Let us proceed with productivity, the cost per megawatt of the resource. The model estimates a productivity of 9.2 megawatts per well for a price of 7 cents. If we now enhance productivity by 50 percent to 18 megawatts per well, we reduce the price to 6 cents. And when considering plant costs, which are twice the cost of wells, to achieve the same reduction in price we will have to reduce plant costs by almost as much as well costs combined.

Therefore, a dollar early on in the project has much more significant impact than a dollar at the end of the project. The simple model demonstrates that if we reduce costs or use technology to reduce costs at the front end of the project, based on the time value of money one dollar saved at the front end is worth two dollars in the latter stages of the project. And this is just to give you some feel, so you have a clear understanding as to what we are trying to do.

If we set similar cost-reduction goals in a realistic market place, we would need to compete at 5.5 cents and not 7 cents. How could we do that? Let us try increasing productivity by 20 percent and reducing both drilling and plant costs by 20 percent. (Notice that combining the lower well cost and higher productivity gives an overall reduction that is less than the sum of the separate effects, because we will need fewer wells that are also cheaper.) But if we accomplish just these three things, it would suddenly make geothermal power competitive in the market place. We would reduce the cost per kilowatt-hour by about 1.42 cents, thus reducing the cost from 7 cents to 5.5 cents. This is just to show you what we need to be doing and focussing on in this business to make it competitive.

I think these technological solutions are achievable and let me tell you why. The needs we identified are not new in the geothermal industry. At this point, you may be asking the questions I asked our team. What are we going to do to improve fracture mapping and reduce drilling costs? And I asked that all the time.

We assigned some people to find answers and gave them the challenge to put some of this stuff together and make it all happen. I hope that there is a combination of effort that will make it happen. I can not answer specific questions as to how we make it happen, but we can make substantial progress in both of these areas.

Let us take fracture mapping. First, we are a relatively small industry working hard to control cost. We have not done sufficient basic research to understand the nature of permeability nor the geological control on the distribution of permeability in hydrothermal systems. This industry still does not know what fractures make contributions to permeability. We need to get to the point where we understand what makes the contributions to permeability. We know certain things that we would like to see, but we can not predict nor do we know exactly what contributes to permeability. This will require investments in coring and application of advanced technology to understand the origin and nature of permeability as well as the physical process that controls its development. If we can understand that, we will make this industry a lot more competitive. These basic studies should be done because they allow advances in drilling and well targeting similar to those achieved in Thailand. Understanding these systems may allow us to make effective use of new geophysical methods like acoustic fracture mapping, demonstrated by Los Alamos National Laboratories under DOE's Hot Dry Rock program. Some benefits we see out of that program may be the potential to map fractures and understand them.

Let us now take drilling. If we take a look at drilling in resource industries, you will find that there is often times wise improvements in drilling performance. From our Thailand experience, in 1980 wells were taking ten weeks to complete and today they are drilled in less than ten days. Not only has the time gone down, but if you reduce the rig time, the cost of the rig, all the manpower, and everything associated with that rig, our cost now is 75 percent less in Thailand than when we started. This is how we were able to make the project a success. I think we can make this same kind of dramatic improvement in the geothermal industry. During our continuous improvement efforts, 80 percent of the drilling cost reduction happened very rapidly with some breakthroughs in total effort. We need more of those kinds of breakthroughs in geothermal drilling to be more competitive.

Let us now look at some of the things that we are able to accomplish if we focus on drilling. I think we need to specifically focus on the technology of drilling in volcanic environments -- on the hostile conditions and problem formations that are for the most part unique to this business. We have seen how technical advances can bring large benefits. Let me describe one that many of you are already familiar with. In the 1980s, most geothermal developers drilled standard production wells, typically completed with 9 5/8" casings and 7" liners. At Unocal, we had engineers working on a wellbore simulator to improve our understanding of wellbore dynamics. Simulation results showed that the most important wellbore parameter controlling productivity was hole size. In some cases, predictions indicated that wells with standard completions and producing less than 5 megawatts could produce over 20 megawatts as big holes.

At our Salak project in Indonesia, the first four conventional producer wells had an average output of about 5 megawatts each. The next well, drilled using large bore technology, had a hole diameter of 13 5/8" and a 9 5/8" liner. Our big hole program focussed on achieving economic benefits from increased productivity as well as reducing drilling costs. By combining drilling costs and productivity, which are very important in your project, we have been able to reduce overall costs. The big hole made a large jump, but we have taken that cost and cut another 25 percent through recent improvements in drilling.

You can not make these improvements in drilling costs one well at a time scattered all over the world, doing research on individual wells. I have to tell you that you need a program with a laboratory where you can see the results of what happens from one well to the next and put it all together. That is what we need to do. Programs that drill one well in one part of the world and then in another part of the world to try to correlate what you have done will not give you the basic understanding of research that you need to make this kind of improvement happen. We need to find large drilling programs where we can put together and see the marked improvements over a period of time with the conditions that are known. You can not make progress if you have too many variables. This is the large step we have been able to make, continue to make, and need to make as an industry. This alone is not enough, we need to continue to reduce these costs at a substantial rate.

I have talked about the need for technology to impact the competitiveness of geothermal power in the worldwide markets. Which by the way, will also address the need for U.S. industry to be competitive in the worldwide economy. We have also talked about why there is reasonable expectation that sound research and development should bring substantial progress in meeting these needs.

Lastly, let us talk about focussing resources to achieve the greatest benefits. Most of us have been through an era of downsizing, right sizing, re-deployment, and so on. We realize that there are now more worthwhile and valuable projects out there than there are people and resources to apply to with. The temptation to try to do all of the projects at a reduced level of effort should be avoided. This would delay progress in all areas, delude the effectiveness of our people and capital, and cause the sponsors of research to loose interest in the technical program.

Another factor has to do with the federal budget process. As federal budget allocations are reduced, a larger share of the DOE geothermal program funds are committed to fixed costs or budgetary earmarks that do not permit application of funds to critical needs. This limits the ability of DOE management to make strategic decisions about program direction that can impact the worldwide competitiveness of geothermal power. What should work is for the geothermal program to be strategically focussed and given the resources and authority to conduct strategic research. Anything less will be a disservice to tax payers. The approach needs to be strategic and goals-defined -- such as reductions in a relative period of time. We need to focus time, talents, energy, and precious capital to accomplish those efforts. There needs to be strategic thinking in research, with the business need in mind.

I know that many have given careful considerable thought to strategy of research and the focusing of dollars and people for the maximum benefits. I hope that these programs will go forward and make a substantial contribution to improve the competitiveness of geothermal power and the U.S. geothermal industry.

I would like to thank you for the opportunity to raise my voice.

Maintaining a Competitive Geothermal Industry

V. P. Zodiaco, Executive Vice President
Oxbow Power Corporation

Good Morning. I am pleased to be here this morning to participate in this 14th review of geothermal programs.

I come to this geothermal business with over 30 years of experience in the power generation industry. I have earned my spurs (so to speak) in the electric utility, nuclear power, coal and the gas-fired cogeneration power businesses. I have been employed by Oxbow Power for the past seven years and for the past 18 months I have been based in Reno and responsible for the operation, maintenance and management of Oxbow's domestic power projects which include three geothermal and two gas-fired facilities.

The Oxbow Power Group (consisting principally of Oxbow Power Corporation, Oxbow Geothermal Corporation, Oxbow Power of Beowawe, Oxbow Power International and Oxbow Power Services, Inc.) is based in West Palm Beach, Florida, and has regional offices in Reno, Hong Kong and Manila to support on-line geothermal projects in Nevada, other domestic power projects and a geothermal plant under construction in the Philippines. Oxbow Power employs approximately 30 professionals in the development and management of power projects and over 100 supervisors and technicians in the operation and maintenance of power facilities. Current ownership in independent power projects total 340 MW in the United States and 47 MW under construction in the Philippines. Oxbow is currently negotiating additional projects in several Asian and Central American countries.

The power group's corporate mission is to develop, own and operate profitable and efficient power plants worldwide, using geothermal, and other technologies in an environmentally acceptable manner.

Commitment and Challenges

Oxbow's commitment to the development of new geothermal capacity is based on a firm belief in the many benefits of geothermal power generation which include:

- the local economic benefits and sustainability of the projects,
- the use of indigenous resources to displace imports of fuel,
- the wisdom and security of energy diversification,
- and the obvious environmental advantages of renewable over traditional energy sources.

These benefits are not restricted to domestic power planning but, are considered to have worldwide applicability as fundamental energy policy.

We are all well aware of the changes occurring or about to occur in the U.S. and worldwide electric power industries. These changes challenge us to be as efficient and as competitive as we can be. With those challenges in mind I'd like to focus my remarks this morning on Oxbow's perspective on creating a forward-looking, cooperative government-industry R&D program that will make U.S. geothermal technology competitive on the world market.

DOE's Role in Support of the Industry

Generally, Oxbow has looked to the federal government for leadership in establishing policy and lead efforts to level the competitive playing field in the electric power industry. We see the principal role of the federal government as establishing policy and the legal and regulatory environment conducive to the development of a U.S. energy industry which is secure, sustainable, environmentally responsible, safe and efficient.

However, there is a legitimate role for government in the support of technology development when such undertakings are beyond the capabilities of private enterprise or when the benefits of such undertakings achieve stated government objectives (such as national security). In the case of development of renewable energy technology the benefit is multi-faceted and widespread (in the form of national security, environmental protection <u>and</u> economic development). Further, the development of technology which can assure U.S. leadership and export sales abroad is a form of playing field leveling on an international scale.

The funding of R&D to secure these objectives has been a part of federal energy policy for my lifetime. It has taken the form of substantial direct investment in fuel and technology development in the coal, nuclear and petroleum industries, as well as the geothermal, solar, wind, and biomass fields. Given the manifold and broad-based benefits of renewable energy it is especially appropriate that our federal government play a significant role in support of R&D for renewable energy technology development.

It should go without saying, that in an atmosphere of budget deficits and competing uses for government funds it is urgent that dollars spent for geothermal R&D:

- focus on projects with the maximum leverage;
- lead to near term commercialization; and
- be efficiently spent.

Projects which aim to reduce drilling costs, increase the certainty of identifying commercial resource, improve the management of resource, improve power plant efficiency, and improve power project economics are projects with leverage.

Projects which focus n fundamental improvements of existing technologies have near term applicability.

Projects which are cost-shared and jointly managed have the maximum potential of applying dollars efficiently.

Oxbow-DOE Cost Shared Projects

Oxbow has a significant history of active support of DOE geothermal programs. This has taken the form of active participation in DOE workshops and Annual DOE Program Reviews over the years. This level of participation has included planning and critique of ongoing industry-DOE activities. We believe that this participation has helped formulate the direction of DOE funded research and development programs.

Over the years, Oxbow cost-shared programs are intended to demonstrate cost effective innovation in resource management and power production and to make these techniques available to the industry for world-wide application. Some examples of the benefits to industry from Oxbow participation in the DOE program include:

- The development of multiple tracers for reservoir analysis which was demonstrated with the Beowawe and Dixie Valley studies and have become routine in industry and research with newer tracers with detection at part per billion concentrations will soon be tested for refined reservoir analysis.

- The use of slim-holes as a cost effective evaluation tool to test heat flow in moderate depth volcanic environments was demonstrated within the thick volcanic sequence in the Santiam Pass.

- Current programs of reservoir fracture analysis and reservoir augmentation studies offer the promise of more efficient exploration and production.

These studies have met meaningful R&D objectives and provided mutual benefit both to Oxbow and to DOE funded research groups; Oxbow benefited from exposure to new technology and ideas which could or would not be pursued with internally generated funds. The DOE-funded research groups benefited through access to geologic environments which would be cost prohibitive for most R&D budgets and through access to the production and process problems associated with viable commercial energy projects.

This sharing of benefits is key to defining successful projects. From Oxbow's perspective, the gain from these programs has been real and the publication of the knowledge gained has presented an acceptable sharing of normally proprietary information for the benefit of the industry at large.

We are c
urrently conducting work preliminary to two negotiated programs and are seriously considering two additional programs that have been proposed to us by credible research institutions.

Future Direction for DOE Funded R&D

Competition both with fossil fuels, and with foreign-based companies on the international scene can only be accomplished by true efficiency in all aspects of our business. Goals should include:

1. **Development of effective exploration and drilling strategies and tools to either salvage dry holes or working models to improve the odds for success on subsequent wells.** While slim-hole programs have been effective in delineating areas of high heat flow, the problem of predicting permeable fracture systems at depth remains. Dry hole costs for wells which reach geologic targets only to find sub-commercial permeabilities or even a total lack of production capability in a known structural zone continues to be a major cost factor for many projects.

2. **Improvements in drilling hardware and techniques to bring drilling costs for geothermal wells into a more predicable and cost effective range.** The basic problems of effective penetration rates in the harsh geothermal environment and coping with lost circulation zones or sub-commercial water flows in this same environment remain as major contributors to drilling inefficiencies. We still have not bridged the gap between R&D efforts and commercialization in these areas. These uncertainties place large risk factors in our economic models for resource development and increase the difficulties of competing with lower cost traditional alternative energy sources.

3. **Energy conversion improvements.** While improvements in generation efficiencies at The Geysers over the past

three decades are notable, fully integrated efficient conversion of produced geothermal fluids to beneficial energy is missed in most geothermal projects and results in large project inefficiencies.

Topping and bottoming cycles need to be routinely integrated into the concept of geothermal development to prevent produced energy from being wasted by low efficiency conversion or re-injected back into the ground. Investigation of ultra-low flash technology is a step in this direction. Efficiency will be critical to being competitive in our industry. We simply cannot afford to put produced energy back into the ground.

Other efficiencies in plant design and operation can be achieved through a careful inventory of the design and operation of power plants over the life of a project. For example, traditional heat rejection systems are often designed and operated without consideration for lost BTU's in the energy conversion, without regard to lowering parasitic load and without regard to conservation of water which eventually becomes critical to maintaining reservoir performance. More efficient designs for new plants and retrofit of old plants need to better address such inefficiencies.

4. **The development of by-product and co-resident projects which enhance economic value for geothermal energy.** The concept of compatible uses associated with geothermal development deserves more consideration. Waste heat and solids contained in brine streams offer the opportunity for development which can add value to geothermal power development. Existing by-product recovery systems are often little more than environmentally acceptable waste disposal alternatives. The development of commercial products as a mitigation of silica scaling problems has been discussed but, never brought beyond pilot testing (which suggests that geothermal silica is a superior commercial product in comparison to traditional silica resources). The coupling of indigenous industry ranging from mineral extraction or agricultural to power generation facilities has become a rare reality despite the proximal location of these three industries.

The U.S. energy companies have maintained a market edge in the world over the past decades by innovative approaches to the problems od efficient production of electric power from fossil and nuclear fuels and in the design and operation of end use energy distribution systems for electrical power and liquid fuels. This edge was established and maintained by cooperation between industry and DOE its predecessor agency. Early geothermal development followed this same pattern; however, this innovative edge is rapidly being lost to smaller countries which recognize that strongly funded and innovative R&D programs directed to geothermal power generation is the key to not only efficient use of their own indigenous geothermal resources but, is also a major export edge in doing business in emerging energy markets throughout the world. Quality R&D programs focused on the efficient use and development of geothermal systems is moving countries such as Japan, Italy and New Zealand into leadership positions in development of geothermal resources within the Asian and Central American-South American markets.

The domestic geothermal industry was successful in past decades largely due to industry-government R&D cooperative efforts through ERDA and DOE. The evolved domestic industry has lost participation in the very programs which contributed to the success of the U.S. geothermal industry throughout the world. Arguments over the reasons for this decline in opportunity for co-operation are not particularly beneficial, formulating a forward looking formula for joint industry-DOE development and export of geothermal technology is an obligation of both industry and the federal DOE program.

Thank you for your attention.

Where is the Geothermal Program Heading?

Dr. Allan Jelacic, Director
Office of Geothermal Technologies

I would like to pick up on the theme I presented at last year's program review: "Where are we going in the R&D Program?" I will start by mentioning where we stand as an energy source. Geothermal is the largest energy resource in the United States. It dwarfs all other energy resources, comprising 40 percent of our resource base in this country. It is a huge resource. Recent studies have estimated that the total amount of oil in the world is only 2,000 billion barrels. We have 100 times as much energy locked up in geothermal energy in this country alone. And when looking at the world's geothermal resources, it is just astronomical. The problem, of course, is using that resource and getting that energy out for some productive purpose. The other attribute of geothermal energy is the fact that it is now a national resource. It is no more a regional resource or fixed to a certain part of the country. The advent of geothermal heat pump technology has brought some national stature for this energy resource.

So, what have we done so far? We have made some remarkable strides since the DOE R&D program started. Geothermal electric power generation has increased by a factor in excess of 5, direct use by a factor of 2, and geothermal heat pump installation by a factor of over 10. However, this represents two tenths of a quad in sharp contrast to a resource base of more than 1.5 million quads. We have a lot of room to bring geothermal to the market place. The only way that power is going to get to the market place is with industry involvement, but government can help as well.

We share a number of common goals with industry. Basically, both industry and government, whatever their purpose, want to make the best practical use of that huge geothermal resource base that I eluded to. We want to provide energy to consumers at affordable prices. And we want to enable our industry compete in the world market. These are all common goals that we both share. We have combined the goals of the R&D program into our mission statement, which states: "By working in partnership with industry and other stakeholders, we will develop and implement a balanced program of research and development to provide technology that will enable the geothermal industry to meet U.S. and world energy needs." To do this, we are gushing in what I am calling a new era of partnership.

As most of you know, we have worked in partnership with industry for many years. We have been sharing costs since the early days of this program in the late 1970s. What is different this time is the fact that we are partnering in program planning as well as in program implementation, and that process is already underway. This new partnership began last May when Secretary O'Leary met with industry leaders in Florence and, among other things, urged closer cooperation for the DOE program with our industry and with our customers. We pursued the new partnership within an hour of meeting with Secretary O'Leary. We had a separate meeting of industry representatives and ourselves after she left, and have since been pursuing the same. Last July, an industry-led workshop was convened to discuss technology improvements needed and to identify DOE's role in such pursuit. That was followed by another workshop, specifically related to the Hot Dry Rock program, which Mike Wright reported on yesterday at the GEA meeting. These workshops will continue this year with more discussions on various parts of the DOE program. There is a drilling workshop immediately after this particular program review, and others are scheduled in the coming months. There will also be additional follow up meetings in the future.

In line with the recommendations produced at the Hot Dry Rock workshop, we are proceeding with the close down of the Fenton Hill facility. Through the International Energy Agency (IEA), we are discussing international cooperation with other countries interested in hot dry rock technology. We are also having discussions with our GEA partners on setting up review panels that will oversee the future of the hot dry rock program.

In the area of program implementation, our R&D program was restructured in 1992 to develop a program that is more closely aligned to how industry evolves a project. Basically, finding a resource through exploration, accessing the resource through drilling, managing the resource through reservoir technology, and then putting the resource to some good use through conversion technology. We now we have a research program that is modeled after those four phases of project development.

Many of our research thrusts, if not most, have a fair amount of industry cost-shared involvement. Approximately half of our current budget is in cost-shared projects with industry and we are proud of that fact. It indicates that government money is being put to good use and furthering the technology in the near-term. There are also other opportunities coming up and currently ongoing for additional partnering and cost sharing. Industry coupled drilling was highly successful in the 1970s and early 1980s and we are currently planning to re-institute the program if there is sufficient interest in the future. There was an advanced drilling solicitation that just closed, looking for ideas to develop advanced and/or revolutionary drilling technologies. As Darcel pointed, drilling technology is key to keeping geothermal energy competitive. We also have a reservoir technology open solicitation, anyone can submit a proposal at anytime in the area of reservoir management and I believe exploration technology as well. In addition, we are looking for partners interested in testing supersaturated turbine expansions and newly developed coating materials. The new enhanced heat recovery aka hot dry rock program will also have a very sizable industry component. As I indicated earlier, we are still in the process of planning the program, but we see a great opportunity to work with industry.

And finally, there are the long standing organizations, the Geothermal Drilling Organization (GDO), the Geothermal Technology Organization (GTO), and the recent Geothermal Power Organization (GPO). These organizations were specifically created to encourage the early commercialization of new technologies coming out in those specific areas and to cost share a number of different projects.

You can not get away from one of my presentations without mention about the geothermal R&D budget. And I think there is some good news here. Our average budget over the 1992 to 1994 three year period has gone up. Our current budget is up from the average low- to mid-20s to the low 30's, and that is bucking a trend in Washington friends. We hope it continues. For FY 1997, the President's request is for $34.6 million, and it is going to require a lot of work to get it approved. If we succeed, that will become the largest geothermal budget since 1984. Hopefully, that number will hold and we can have enough resources to work with you all.

I think there is a bright future for geothermal. Even though the domestic market might be kind of flat, and we are sorry to see that, but overall, domestically and internationally, things are looking up for geothermal. We hope the trend will continue. So, as Allan Hoffman said earlier in his presentation, "Geothermal energy has a role in the sustainable energy future of the nation". And by working together, industry and government, we can achieve that fine goal.

Concurrent Session 2:

Exploration and Reservoir Technology

Chairperson:

Tsvi Meidav
Trans-Pacific Geothermal Corporation

INVESTIGATIONS OF FRACTURES IN HIGH-TEMPERATURE GEOTHERMAL SYSTEMS

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ABSTRACT

At ESRI we are using several approaches to the study of fractures in geothermal systems presently underway. Well exposed examples of faults are being mapped and sampled in order to provide input for numerical simulation of fluid flow along these features. Core from the Geysers geothermal system and Tiwi in the Philippines has been used to investigate the character of fracturing in compressional and extensional reservoirs. Geothermal fluid circulation is limited at depth by the transition from brittle to ductile behavior of rock. The potential for extracting heat from zones below present hydrothermal circulation depths should be considered in a program for Enhanced Heat Recovery.

INTRODUCTION

One finds general acceptance with the statement that high-temperature geothermal fluid production comes largely from permeable fractures. The term fractures is generally applied because the origin of the features are unknown, and without core or borehole images, is unknowable. In truth, the permeable fracture-controlled flow paths within an individual system may have different origins and orientations.

Some definitions are in order to avoid semantic gridlock. The American Geological Institute dictionary defines fracture as "a crack, joint, fault, or other break in rocks." It is, therefore, a general term and can be correctly applied when the investigator has no knowledge of the character of the feature. A joint is a fracture that has no displacement (Pollard and Aydin, 1988), while a fault is a fracture that does demonstrate offset.

This paper is a review of the investigations that are presently underway at ESRI to develop a better understanding of fractures within geothermal systems. Our studies are investigating fractures at scales that range from microscopic to regional. The pay off will be in exploration success, including fewer dry holes, and in more efficient utilization of the resource.

FAULT MODEL

Most geothermal production is directly associated with faults. These include specific faults such as the Negro Mag and Opal Mound faults at Roosevelt Hot Springs (Nielson et al., 1986), the Malpais fault at Beowawe (Sibbett, 1983) and faults mapped in the subsurface at Cerro Prieto (Halfman et al., 1984) among others. Faults are heterogeneous features, and we are studying selected examples to improve understanding of their geometry and permeability distribution. Fault zones may act as conduits, barriers, or combined conduit-barrier systems that enhance or impede fluid flow (Smith et al., 1990; Forster et al., 1994; Goddard and Evans, 1995). Fault zones are composed of distinct components; a fault core where most of the displacement is accommodated and an associated damage zone which is mechanically related to the growth of the fault zone (Sibson, 1977; Chester and Logan, 1986; Forster and Evans, 1991; Scholz and

Anders, 1994). The amount and distribution of each component controls fluid flow within and near the fault zone.

Insufficient information, particularly field-based data, are available to adequately characterize and compare architecture, permeability structure, fluid flow, and mechanical properties of fault zones found in different geologic environments. Fracture networks associated with fault zones, however, form important conduits for fluid flow that should be represented in predictive simulations of fluid flow in high temperature geothermal systems. Development of valid flow models is hindered by our inability to measure in-situ fault zone properties in a way that adequately characterizes the spatial and temporal variations in permeability, porosity, and storativity.

We have developed a conceptual fault zone model, based on detailed outcrop mapping, to aid in evaluating the physical properties of fault zones. This model provides a framework for determining spatial variability in fault zone architecture from field data and for incorporating physically-based geological information in mathematical models of fluid flow in faulted rocks. Our conceptual model for a fault zone is based on a synopsis of our own research and the work of other authors (Sibson, 1981; Chester and Logan, 1986; Parry and Bruhn, 1986; Scholz and Anders, 1994; Smith et al., 1990; Forster and Evans, 1991; Goddard and Evans, 1995).

Primary components of upper crustal fault zones (fault core, damage zone, and protolith) are shown in Figure 1. No scalar relationship is implied between the components, nor must all of the components be present in any given fault zone. Note that the fluid flow properties of a fault zone may change, thus the diagram represents only a single point in time. For example, the core may act as a conduit during deformation and as a barrier when open pore space is filled by mineral precipitation following deformation. Thus, it is important to specify the stage of fault evolution when forming a conceptual model for a particular fault zone.

The fault core is the structural, lithologic, and morphologic portion of a fault zone where most of the displacement is accommodated (Figure 1). Fault cores may include single slip surfaces, unconsolidated clay-rich gouge zones, brecciated and geochemically altered zones, or highly indurated, foliated ultracataclasite zones. Our field-based observations suggest that thickness variations, both down dip and along strike, combined with a distinctive internal structure and composition, play an important role in controlling the fluid flow properties of fault zone cores. Grain-size reduction and/or mineral precipitation generally yield fault cores with lower porosity and permeability than the adjacent protolith (e. g. Chester and Logan, 1986; Goddard and Evans, 1995). Permeability reduction leads to fault cores that act as barriers to fluid flow .

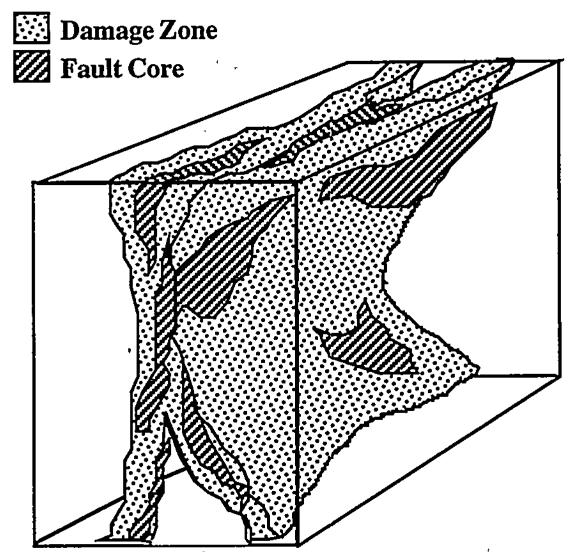

Figure 1: Conceptual model of the architecture of a fault zone with the protolith removed (after Chester and Logan, 1986; Smith et al., 1990).

A damaged zone (Figure 1) is the network of subsidiary structures that bound the fault core and may enhance fault zone permeability relative to the core and the undeformed protolith (Chester and Logan, 1986; Smith et al., 1990; Scholz and Anders, 1994; Goddard and Evans, 1995). Fault-related subsidiary structures in damage zones include small faults, veins, fractures, cleavage, and folds that cause heterogeneity and anisotropy in the permeability structure and elastic properties of the fault zone (Bruhn et al., 1994). Wide damage zones that indicate multiple episodes of slip may reflect the overprinting of successive deformation events.

The fault core and damaged zones shown in Figure 1 are surrounded by relatively undeformed protolith. This is the country rock where fault-related permeability structures are absent and both fluid flow and elastic properties of the rock reflect those of the unfaulted host rock. Fault zone architecture may ultimately reflect the degree to which the processes of strain localization verses strain distribution compete as the fault zone cuts different rock types in the protolith.

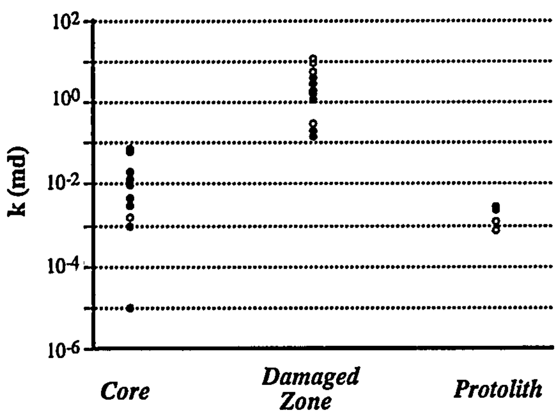

Figure 2: Permeability as a function of position in a fault zone (from Forster et al., 1994). Core diameters are indicated by filled circles (2.54 cm) and open circles (5.08 cm).

Field-based, laboratory, and numerical analysis of the microscopic and megascopic features of a thrust fault in northwestern Wyoming support our conceptual model for relating fault zone architecture to permeability structure (Forster and Evans, 1991; Forster et al. 1994). Thirty-one core samples were selected, at a variety of orientations with respect to the slip plane, to provide test results representing the primary fault components of a typical thrust fault in crystalline rock. The results of permeability (k) tests performed at an effective confining pressure (Peff) of about 4 MPa are shown in Figure 2 as a function of location within the fault zone. The higher k of the smaller protolith cores is attributed to the effects of weathering. Within each fault component a k range of 2 to 3 orders of magnitude was observed. In addition, the damaged zone appears to have a consistently higher k than that of the adjacent core and protolith. Overall, k values for fault rocks range over more than 6 orders of magnitude from less than 10-5 md to greater than 10 md.

The geometry and magnitude of permeability contrasts between the fault core and damage zone are primary controls on the barrier-conduit systematics of the fault zone. Fracture density in the fault core is usually significantly less than in the damage zone (Chester et al., 1993). Thus, the permeability of the fault core may be dominated by the grain-scale permeability of the fault rocks while the damage zone permeability is dominated by the hydraulic properties of the fracture network. The range of fault zone architectures observed in outcrop is illustrated in Figure 3. Each of the 4 end-member architectural styles is associated with a characteristic permeability structure. These include localized conduits, distributed conduits, localized barriers, and combined conduit-barriers.

Field work in Dixie Valley, Nevada has focused on detailed mapping of fracture networks found at two locations on the footwall of the Dixie Valley and Stillwater fault zones. These data have helped to revise our conceptual model of fault zone architecture (Figure 1) and yield constraints on ongoing efforts to simulate fluid flow within and near the fault zone. Contacts between fault core (identified as a distinctive breccia zone), damage zone, and protolith were mapped over a region extending over tens of square kilometers. Fracture data are tied together over several scales by centimeter-scale petrographic fracture analyses, meter-scale outcrop fracture analyses, and tens to hundreds of meters-scale fracture analyses using field mapping and low-elevation aerial photographs. In spite of the complicated fracture network found in this large fault zone,

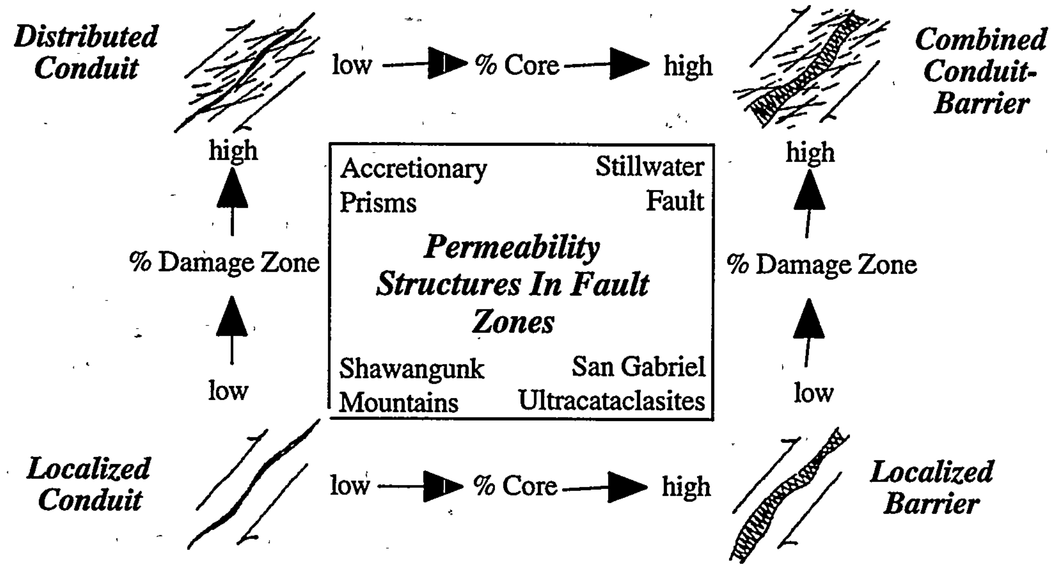

Figure 3: Conceptual scheme for fault-related fluid flow (from Caine, Evans and Forster, submitted to Geology, 1996).

distinct kinematically-related fracture sets can be identified. From these and the other fracture data, fracture permeability models are generated for each component of the fault zone. Laboratory testing provides a quantitative basis for estimating the matrix permeability of the faulted rocks. Overall, the fault zone likely acts as a combined conduit-barrier system.

We are integrating results of our outcrop studies with subsurface information collected at the Oxbow Geothermal Power Plant as a basis for simulating previous (Adams et al., 1989) and future tracer tests within a splay of the main Stillwater Fault Zone. The outcrop data provide an enhanced framework for interpolating the permeability structure encountered within the geothermal system. Simulations of high-temperature fluid flow and tracer transport within the fault zone are currently underway using TOUGH2 (Pruess, 1991). We intend to expand our outcrop-to-simulation studies to include other high-temperature geothermal reservoirs. Each study is expected to yield an entry in our "Fault Atlas" which will contain detailed descriptions of fault zone characteristics encountered in a range of host rocks, tectonic regimes, and geologic environments.

CORE STUDIES

We have had the opportunity to study several cores from geothermal reservoirs that further help determine the character of productive fractures. These studies have been completed at the Geysers using corehole SB-15-D (Hulen and Nielson, 1995) and at the Tiwi geothermal system in the Philippines (Nielson et al., 1996) using core from well Matalibong-25 (Mat-25). Of particular interest has been the statistical distribution of permeable features as well as their character.

The acquisition of continuous core from the upper part of The Geysers steam field in California has provided a great deal of new information from a field that has been in production for more than 30 years. Study of core has changed some of our concepts of the geometry of permeability control in the field. The Geysers is located in a compressional tectonic regime characterized by strike-slip faulting (McLaughlin et al., 1996). Faults are recognized in the SB-15-D core by the presence of slickensides on fault planes. These faults are best developed in argillite rather than the more competent graywacke. However, the graywacke next to the argillite will often be brecciated (Fig. 3A, Hulen and Nielson, 1995). This rheologic control on fracture formation has been noted by previous workers in The Geysers reservoir (Sternfeld, 1989; Nielson et al., 1991). The analysis of Hulen and Nielson (1995) shows that the slickensides have a predominantly low-angle orientation, indicating faulting in this part of the field was predominantly strike-slip. Note that strike-slip regimes are complex and develop complementary structures that include both normal and thrust faults as well as strike-slip offsets with displacements that are opposite to that of the overall system (Christie-Blick and Biddle, 1985). The core also demonstrated that the fractures are predominantly of high-angle orientation. This is contrary to the findings of some workers who concluded on the basis of the geometry of production from adjacent wells, that the controlling fractures were of low-angle orientation.

The Tiwi geothermal field on the southeastern coast of Luzon, The Philippines is a hot water-dominated field associated with an andesitic volcano, Mt. Malinao. Well Mat-25 was cored between depths of approximately 2500 and 8000 feet in the central part of the field (Nielson et al., 1996). Here again, production information had suggested that the permeability of the field was relatively flat and it was hypothesized to result from fluid flow along stratigraphic horizons (Gambill and Beraquit, 1993). The core, however, demonstrated that permeability was totally controlled by high-angle fractures. Often, the fractures contained abundant hydrothermal mineral phases, and it was not possible to determine their origin. Slickensided fault planes in the core indicated that the faulting was principally dip-slip, or normal. This was of interest in view of the proximity of the field to the Philippine fault, a major right-lateral strike-slip fault.

Figure 4 is a plot of the dip angle of open fractures in Mat-25 as a function of depth, and shows that these fractures, which we believe to be fluid conduits, are principally steeply dipping. Although there are some low-angle features, one must keep in mind that the probability of intersecting a low-angle feature with a high-angle hole is very large while the probability of intersecting a high-angle feature with a high-angle hole is very small (Barton and Zoback, 1992). One of the interesting aspects shown in Figure 4 is that the frequency of open fractures decreases toward the bottom of the well. This is also true for the frequency of sealed veins although it is not shown in this figure. We interpret that the lower limit of fluid circulation in this part of the reservoir results from this decrease in fracture intensity. This interpretation is supported by the depth limits of production from surrounding

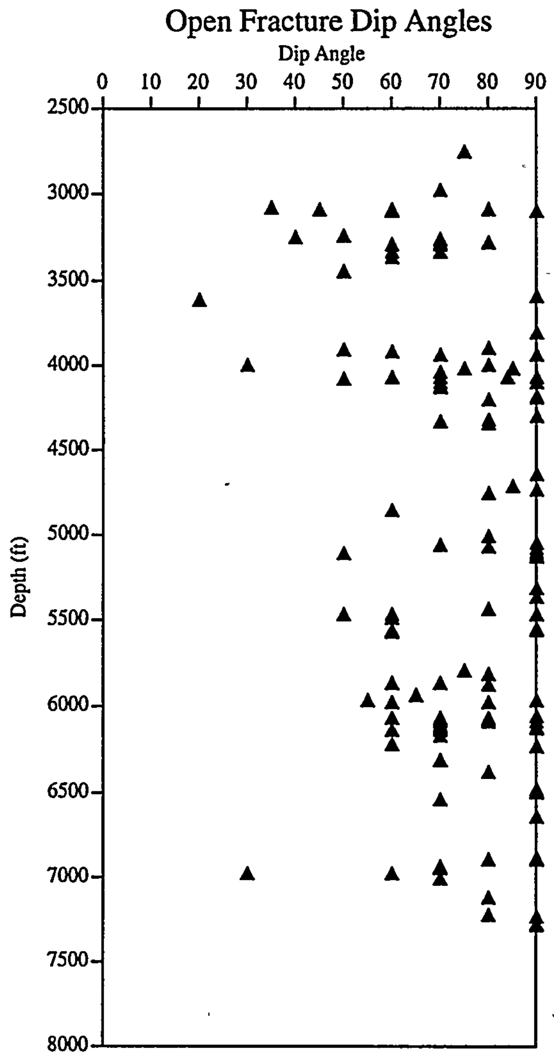

Figure 4. Dip angles of open fractures (a.) and veins (b.) in the Mat-25 core measured with respect to the cone axis. Frequency distribution of veins and open fractures (c.) is compiled on 100 foot intervals.

wells. The reason for the decrease in fracturing is not clear. Although the lower part of the well is in volcaniclastic sediments rather than the flows and lahars of the upper part of the hole, the rocks remain brittle and should sustain open fractures.

SYSTEM MODEL

Although we think of fractures as largely two-dimensional fluid flow paths, most high-temperature hydrothermal systems occupy a three-dimensional volume (Nielson, 1993). Reservoirs are made up of a series of interconnecting permeable channels. Systems have caps, created by either impermeable units or hydrothermal sealing of fractures. Systems also have sides and bottoms.

Nielson (1996) presented a system model for active high-temperature geothermal systems (Fig. 5) that pointed out the importance of the transition from brittle to ductile behavior of rock that probably defined the limit of fluid circulation in most high-temperature systems. The above discussions of fracture permeability have, of course, concentrated on the behavior of rock in the brittle zone. Much of a systems heat content and future development potential lies stratigraphically below and at temperatures greater than about 400 C, where rocks behave in a ductile fashion. The San Pompeo 2 well at Larderello has penetrated the ductile zone (Gianelli, 1994). The New Energy Industrial and Technology Development Organization (NEDO) of Japan has drilled a well to investigate the deeper parts of the Kakonda geothermal field (Yagi et al., 1995) and have measured temperatures that we interpret to show the well has penetrated the ductile regime. The recovery of heat from the deeper parts of geothermal systems is an important consideration for the future of the industry. Exposed analogs suggest that fracturing and ingress of meteoric fluids is a component of the natural evolution of a system. Acceleration of natural processes and economic heat recovery may be possible using deep injection, a process that could be termed Enhanced Heat Recovery (Nielson, 1996).

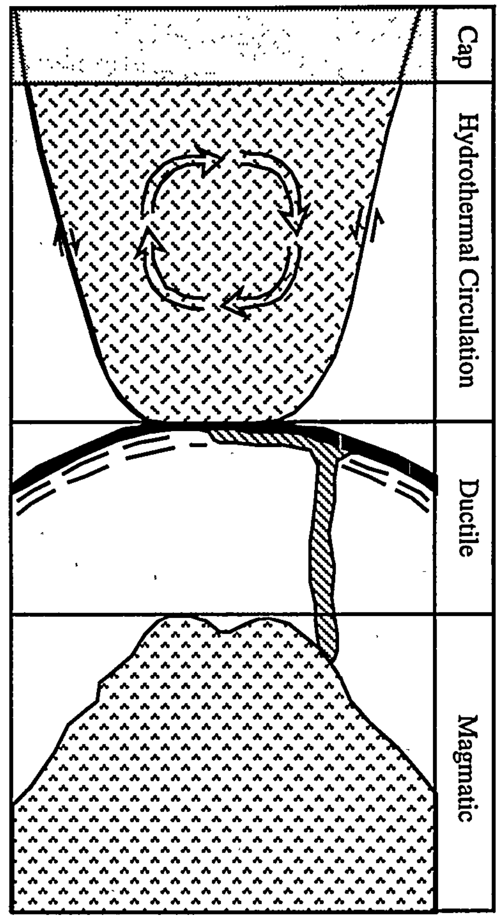

Figure 5. Schematic model for zonation within active hydrothermal system.

CONCLUSIONS

The research summarized here addressed the character of fractures at scales ranging from microscopic to regional. Studies of exposed fault zones are documenting their geometry and the variation of porosity and permeability. The results of this investigation are then being used to simulate fluid flow along these zones. Data from the Stillwater fault in Dixie Valley will allow comparison of these simulated results with tracer experiments being anticipated for that geothermal system. Studies of core from active geothermal reservoirs are also being used to define the origin of fractures from active systems. The SB-15-D core from The Geysers demonstrates the character of fracture formation in a strike-slip (compressional) tectonic regime. Core from the Tiwi geothermal system in the Philippines shows the character of fracture development in a normal fault (extensional) environment. Both of these cores have changed ideas of the orientation of fluid flow paths in these systems. Fractures form and remain open in the brittle zone. However, geothermal systems have bottoms that are generally typified by the change from brittle to ductile conditions. Research into the character of these zones suggests that fracturing is naturally superimposed on the deep parts of systems as they cool. Therefore, natural fracturing should provide the fluid pathways for heat extraction, or Enhanced Heat Recovery, using carefully planned programs of fluid injection.

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Integrated Exploration Tools

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PAPER NOT AVAILABLE

Reservoir Technology Research at the INEL

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Introduction

Reservoir engineering research at INEL was aimed at developing a better understanding of The Geysers and developing better tools with which to study flow in fractured geothermal reservoirs in general. Two specific topics were studied in the last year: matrix fracture interactions and decline curve analysis. A third project, revisiting the behavior of the "high-temperature reservoir" (HTR), was started near the end of 1995. These projects are being conducted in collaboration with other researchers and/or private industry. For example, our HTR studies are motivated in part because of new isotopic analyses conducted elsewhere (Walters et al., in preparation). The ultimate goal of these projects is to improve predictive capabilities and reservoir management practices and to extend the commercial life of The Geysers.

In addition to conducting engineering research for the Reservoir Technology Program, INEL also continued to assist the Geothermal Technology Organization (GTO) with the development and execution of cooperative research projects. In support of the overall mission of the Reservoir Technology program, INEL also entered into a broad program of subcontracts with industrial groups and universities. These programs support the Reservoir Technology mission by providing support for research topics considered particularly important by the geothermal industry. The GTO projects are summarized below.

Reservoir Engineering Studies

Matrix-Fracture Interactions in Dual Continua Simulators

Due in large part to complex fracture geometries, irregular fracture spacing, and lack of detailed information regarding contact areas between rock matrix and fracture, a Warren and Root (1963) dual continua approach is most frequently taken to describe storage and flow in fractured reservoirs. Interaction between the two is assumed to be linearly dependent on the pressure difference between the (numerical) grid block fracture pressure and average matrix pressure. This linear dependence, frequently referred to as the "pseudo steady-state assumption," is valid only at long time and for slightly compressible fluids. Work began in the last year to identify an improved matrix-fracture interaction term that removes these restrictions.

The most promising functional form identified thus far that describes the pressure in the matrix as a function of position is

$$P(\eta) = \overline{P} + (P_f - \overline{P})\, e^{(\eta - a)/D}$$

Only parallelepiped rock matrix blocks have been considered thus far; therefore, η is the distance from the centroid of the rock matrix (effectively a radial distance) and a is the effective radius of the matrix. P_f and $\overline{P}$ are the fracture and average matrix pressures, respectively. D is a characteristic distance associated with a change in pressure, and is related to the diffusivity of the medium and time by

$$D = \left[\frac{k\,t}{\varphi\,\mu\,c}\right]^{1/2}$$

This function has been tested against several analytical solutions. One such comparison, given in Figure 1, represents a step function change in pressure in the fracture, and the corresponding pressure transient in the rock matrix. The entire system is initially at a constant pressure of 1000 kPa. At $t = 0$, the fracture pressure is reduced to 100 kPa. Other data for the rock matrix are: $k = 10^{-16}$ m^2, $\varphi = 0.1$, $\mu = 10^{-3}$ Pa-s, and $c = 10^{-6}$ Pa^{-1}. The diffusivity is calculated as 10^{-6} m^2/s. The solutions shown in Figure 1 are truncated at $\eta/a = 0.9$, since we are primarily concerned with the pressure profile at the fracture-matrix interface (i.e., where the pressure gradient must be accurately resolved). This figure shows that excellent agreement is obtained with the test function on this particular problem. The largest errors near the interface occur at small times. Calculated pressure gradients at the fracture-matrix interface agree within about 25% at t = 10^4 seconds; in contrast, the pressure gradient calculated from the pseudo steady-state assumption is low by a factor of 40.

This function has been implemented in an existing dual continua simulator and is being tested and compared against fine-grid simulation. Additional testing is planned for single phase, slightly compressible, isothermal fluids before attempting to incorporate multi-phase simulations. For example, the functional form given above is known to be inaccurate for non-monotonic behavior at the fracture-matrix interface, and a correction term will be required. This project will continue through FY-96.

Fetkovich Analysis at The Geysers

Faulder (1996) shows that the Fetkovich (1980) type curve equations can be modified for use in vapor-dominated steam reservoirs. The dimensionless decline rate, q_{Dd}, is given in customary geothermal field units of mass flow as

$$q_{Dd} = \frac{\dot{m}(t)}{\dot{m}_I} = \frac{\dot{m}(t)}{\dfrac{kh}{1207}\left(\dfrac{\rho z}{p}\right)_{res} \dfrac{[m(p_I) - m(p_{wf})]}{\left[\ln\dfrac{r_e}{r_w} - \dfrac{1}{2} + s\right]}}$$

and the dimensionless decline time is

$$t_{Dd} = \frac{t_D}{\dfrac{1}{2}\left[\left(\dfrac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\dfrac{r_e}{r_w}\right) - \dfrac{1}{2}\right]}$$

where

$$t_D = \frac{k\,t}{\phi\,\mu\,c\,r_w^2}$$

These equations form the basis for applying the Fetkovich type curve technique to saturated steam in customary geothermal mass rate units. In applying this technique, mass production rate is plotted against production time on log-log paper. Faulder (1996) suggests using the method of Hinchman et al. (1987) to determine the onset of pseudo steady-state flow. That time corresponds to a t_{Dd} of 0.3 (Fetkovich, 1980), which identifies the match point $\dot{m}(t)/q_{Dd}$ for the analysis. Permeability-thickness is then calculated as

$$kh = 1207\left(\frac{\rho z}{p}\right)_{res} \frac{\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]}{[m(p_I) - m(p_{wf})]} \left(\frac{\dot{m}(t)}{q_{Dd}}\right)_{match\ pt}$$

The method was validated using numerical simulations of the rate-time response for a bounded, cylindrical, vapor-dominated reservoir (Faulder, 1996). Estimated kh values were within 16% of the input value.

This modified Fetkovich type curve analysis has been applied to 48 wells in the southeastern portion of The Geysers (Faulder, 1996). This area of The Geysers was also the subject of an extensive history match study, originally described by Faulder (1992). Results from this analysis will be implemented in that reservoir model to further reduce the degrees of freedom inherent in a modeling study. The frequency distribution of kh for the 48 wells in the study area is presented in Figure 2. Estimates of kh from this study range from 18,000 to 270,000 mD-ft and are in good agreement with other published estimates (e.g., Bodvarsson et al., 1989).

HTR Studies

We have recently renewed investigations into the formation of the HTR as observed in Northwest Geysers. Walters et al. (in preparation) show that isotopic signatures in Northwest Geysers indicate significant compartmentalization of the reservoir. While an HTR is observed in all compartments, isotopes and non-condensible gas concentrations vary significantly. Their analysis suggests that HTR characteristics may be sensitive to water throughput and recharge and communication across faults. Using the HTR model of Shook (1995) as a starting point, we have begun evaluating the effects of partially-communicating faults, the degree of venting, and the presence of non-condensible gases on formation of a HTR. This study will ultimately be used to evaluate the utility of reinjection into the HTR, as compared with reinjection into the "normal" reservoir.

Figure 1. Comparisons between analytical solutions and a test function for step change in fracture pressure at t=0. Differences are largest at small time. Solid lines are the analytical solutions.

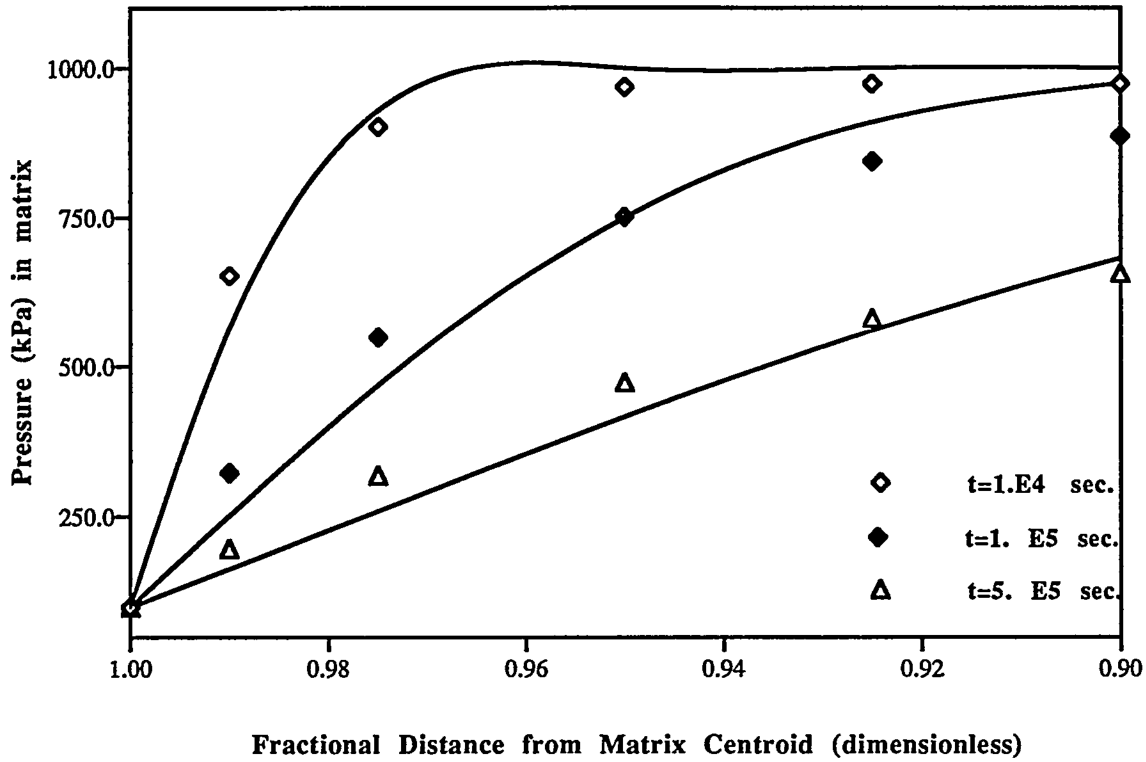
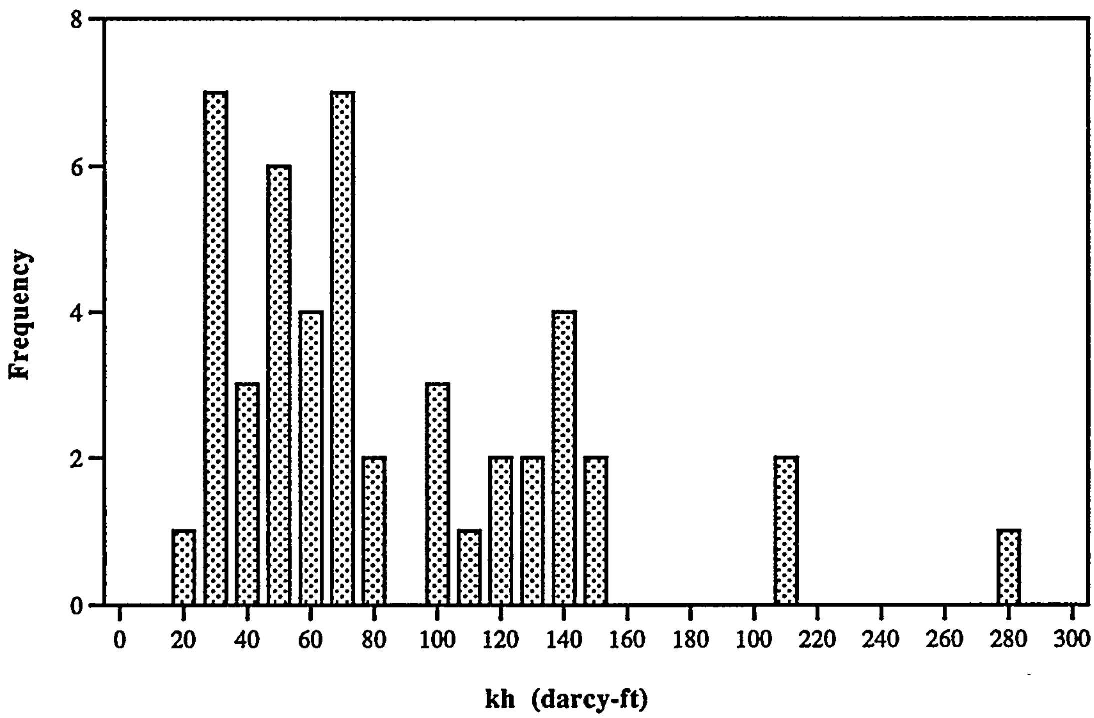


Figure 2. Frequency distribution for 48 wells in southeast Geysers study area. Data from Faulder (1996).



Reservoir Technology Support

INEL assisted the geothermal industry in forming a cooperative research organization, the GTO, and in developing an agreement with the U.S. Department of Energy (DOE) to perform cost-shared geothermal research. This agreement has provided a cornerstone for the cooperative research between the geothermal industry and DOE. The agreement specifies that technology development that has, in the short term, a high probability of yielding benefits in the areas of reservoir performance and energy conversion is available for cost-sharing. Since the inception of the DOE-GTO agreement in 1988, the INEL has facilitated the submittal and selection of GTO proposals, provided organizational support to GTO, and placed the subcontracts that have been necessary to accomplish the research. DOE Idaho Operations Office is now placing the necessary contracts. Three projects were underway during FY-95.

Seismologists at the University of North Carolina are completing a project characterizing subsurface fracture patterns and fracture density by analyzing shear-wave splitting. The study showed that the analysis is able to determine fracture orientation but not dip. Resolution of crack density is limited; however, analysis of a larger number of events may provide more precise identification of crack density. A final report to the participants is nearing completion. Preliminary results were reported by Lou and Rial (1994).

Researchers at the University of Kansas are completing a two-year project developing a structural model for the Coso and Argus ranges adjacent to the Coso geothermal field. The study will provide a better quantification of Basin and Range extension and its relationship to the eastern front of the Sierras. Early in FY-96, GTO approved an additional project by these researchers to study distal epiclastic and pyroclastic rocks in the Coso region. Their goal is to develop an analog model of geothermal systems associated with releasing bends of lateral fault systems.

Calpine, Northern California Power Agency, Pacific Gas & Electric, and Unocal have been conducting a long-term injection test in the Unit 18 area of The Geysers. Recently, the operators and DOE decided to move the test to the Units 7 and 8 area. This location may provide a unique opportunity to investigate the effect of injection into a high-chloride, high-temperature zone of The Geysers. Barker (this volume) discusses the Unit 18 test in more detail.

Late in FY-95, GTO and DOE also reached an agreement to develop a turbine-driven non-condensible gas compressor. The unit is being designed and built by Barber Nichols and will be installed at The Geysers in May 1996.

In addition to the GTO subcontracts, INEL also sponsored several other research projects covering a broad spectrum of research related to exploration and development of geothermal resources. These projects are summarized in Table 1.

Summary

Production decline curve analysis and reservoir simulation coupled with models of geothermal systems are important tools used to predict and manage reservoir performance. The results of our investigations of matrix-fracture interactions, decline curve analysis, and conceptual models of high-temperature, vapor-dominated reservoirs will be used in the following years to improve the ability of the geothermal community to manage the sustainable development of geothermal resources.

Acknowledgments

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Table 1. INEL FY-95 GTO Projects and Subcontracts

Subcontractor/Principal Investigator	Project Summary
Unocal Ed Voge	Geysers Long-Term Injection Test
University of North Carolina Min Lou and Jose Rial	Characterizing subsurface fracture patterns by analyzing shear-wave splitting
University of Kansas Douglas Walker and Eric Whitmarsh	Developing regional structural model for Coso geothermal area
Nevada Bureau of Mines Larry Garside	Archiving geothermal exploration data for Nevada.
New England Research Greg Boitnott	Laboratory measurements on reservoirs rocks from The Geysers
New Mexico Institute of Technology Larry Teufel and Her-Yuan Chen	Coupling variable-rate pulsing/interference testing techniques and tidal pressure changes to evaluate geothermal reservoirs.
Oregon Department of Geology and Mineral Industries Ian Madin	Reconnaissance of geothermal potential in southeastern Oregon.
S-Cubed Sabodh Garg and John Pritchett	Developing analog models of volcanics-hosted geothermal systems and studies of productivity of small diameter geothermal wells.
Southern Methodist University David Blackwell	Development of temperature and heat flow models for the central and eastern United States.
University of Nevada Lisa Shevnell and Ted DeRocher	Geochemical modeling at Nevada geothermal powerplants.
Virginia Polytechnic Institute and State University John Costain	Archiving geophysical data related to low-temperature geothermal systems in the eastern United States.
Mark Walters	Oxygen isotope systematics and evolution of the Northwest Geysers

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TRACER DEVELOPMENT AT ESRI

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ABSTRACT

At ESRI the Tracer Development Program is divided into three components: liquid-phase tracers, vapor-phase tracers, and pre-test modeling. The liquid-phase project has tested 40 aromatic acids and 10 fluorescent tracers for geothermal use. The vapor-phase project , which develops tracers for reservoirs such as The Geysers, is currently focused on testing SF_6 at high temperatures and examining HPLC methods for the sensitive analysis of alcohol tracers. The pre-test modeling component is exploring the feasibility of using simple numerical models to lower the cost of tracer tests by providing estimates of tracer quantities, flowpaths, and arrival times.

INTRODUCTION

Injection of geothermal fluid back into the reservoir is practiced throughout the world. The location of the injection well within the three-dimensional network of fractures that form the reservoir is critical to the successful exploitation of the field. A properly located well leads to higher power production from enhanced pressures, less reservoir scaling from boiling around the production wells, and little or no thermal breakthrough. An improperly sited well gives either no benefits or results in rapid thermal breakthrough and a decrease in power production.

Chemical tracers are used to evaluate the efficiency of injection. Prior to the tracer development project few tracers were available and their stability under geothermal conditions was unknown. The overall objective of the project is to identify and test compounds for use as geothermal tracers and to develop techniques for their use. These techniques include chemical analysis of the tracers and numerical modeling to optimize tracer tests and to interpret their results.

The components of the tracer development project are naturally divided into liquid-phase tracers, vapor-phase tracers, and pre-test modeling. In this paper we discuss each of these components and present some of our recent results.

LIQUID-PHASE TRACERS

The liquid-phase tracer program is driven by the need expressed by industry for tracers that can be analyzed on site, at extremely low concentrations, and with simple instrumentation. In accordance with this need our primary goal in the liquid-phase tracer program is to find and test fluorescent dyes because they are extremely sensitive and can be analyzed on site. In the past we have developed several aromatic acids that work well as tracers and can withstand higher temperatures than the dyes, but are harder to analyze on site (Adams et al., 1992).

To date we have completed work on the dyes fluorescein and rhodamine WT and can predict their decay rate in a geothermal reservoir at any given temperature. Our studies show that rhodamine WT is significantly less stable than fluorescein. Rhodamine WT should not be used above a temperature of approximately 200°C (Rose and Adams, 1994), while fluorescein can be used at temperatures of up to 260°C (Adams and Davis, 1991).

The blue dye amino G has been tested at various temperatures in our laboratory, and has a stability close to that of fluorescein. We hope to test amino G in the field this year. Field testing is an important component of our program, as exemplified by tinopal CBS. Tinopal CBS is another blue dye that was thermally stable in laboratory tests, but disappeared nearly completely when tested in the Beowawe geothermal field (Rose and Adams,

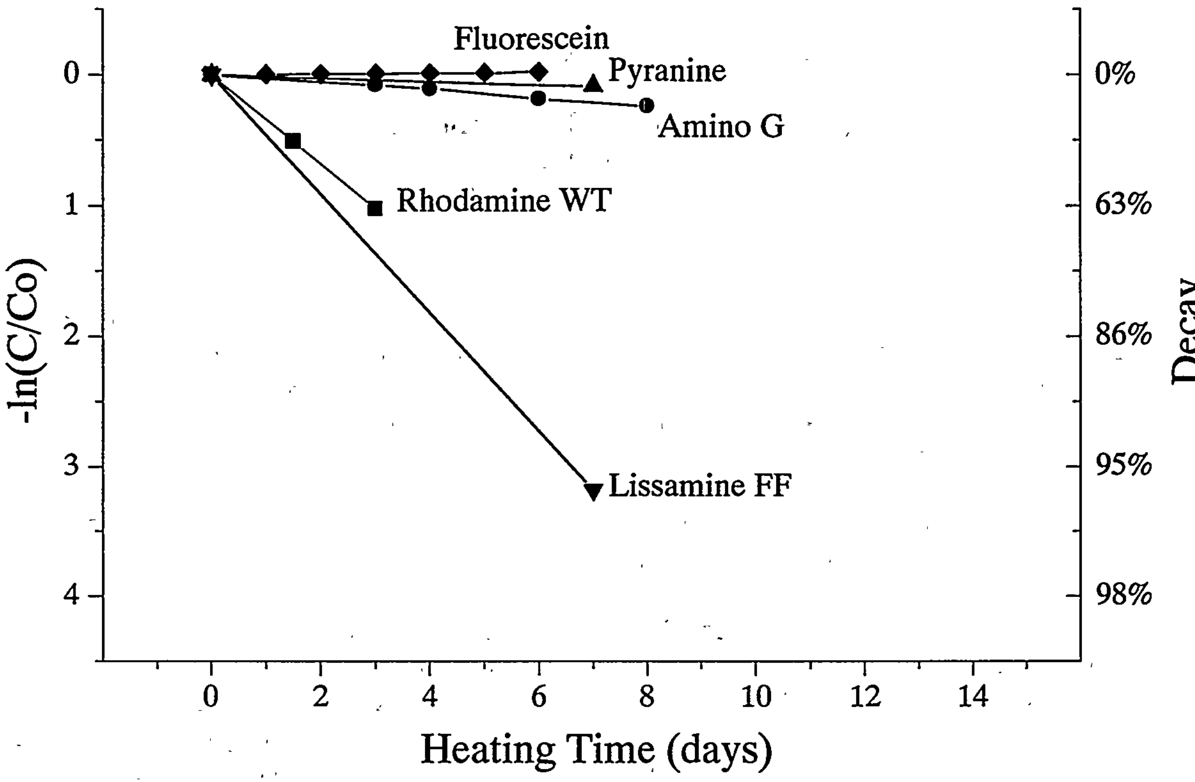

Figure 1. Decay of various fluorescent tracers with time at 215°C.

1995). The shape of the return curve indicates that adsorption caused tinopal's disappearance. We will test the adsorptive potential of tinopal and the other dyes on a specially equipped high pressure liquid chromatograph later this year.

The tracer that we are currently testing in the lab is pyranine. Pyranine is a green dye with a fluorescence and stability similar to that of fluorescein, but with a simpler molecular structure. The emission spectrum of pyranine shifts upward after heating, which requires that standards be heated before use. We are currently working out the analytic complications involved in the spectral shift, after which we will quantify its decay kinetics and test pyranine in a geothermal reservoir.

Figure 1 shows the relative decay rates at 215°C of some of the dyes that we have tested. At this temperature the half-life of fluorescein is one hundred times longer than that of rhodamine WT.

We have recently lowered the detection limit of the fluorescent dyes by a factor of one thousand by switching our analytic instrument from a filter fluorometer to a spectrofluorometer. This device is more selective than a filter fluorometer and extremely sensitive to fluorescence. It costs two to three times as much as a filter fluorometer, but it can be rented, is easy to use, and the analyses can be performed on site. Using a spectrofluorometer should reduce the cost of the tracers by a considerable amount because the quantity of tracer required is directly proportional to the detection limit.

VAPOR-PHASE TRACERS

Our vapor-phase tracer program was initiated when it became apparent that injection is crucial to a depleted reservoir. Very few tracers are available for use in vapor-dominated systems because of the phase transition between liquid injectate and steam production. We were very successful in introducing the use of chlorofluorocarbons tracers (Adams et al., 1991a, b; Beall et al., 1994), but these compounds have become difficult to obtain because of their ozone depletion potential. We

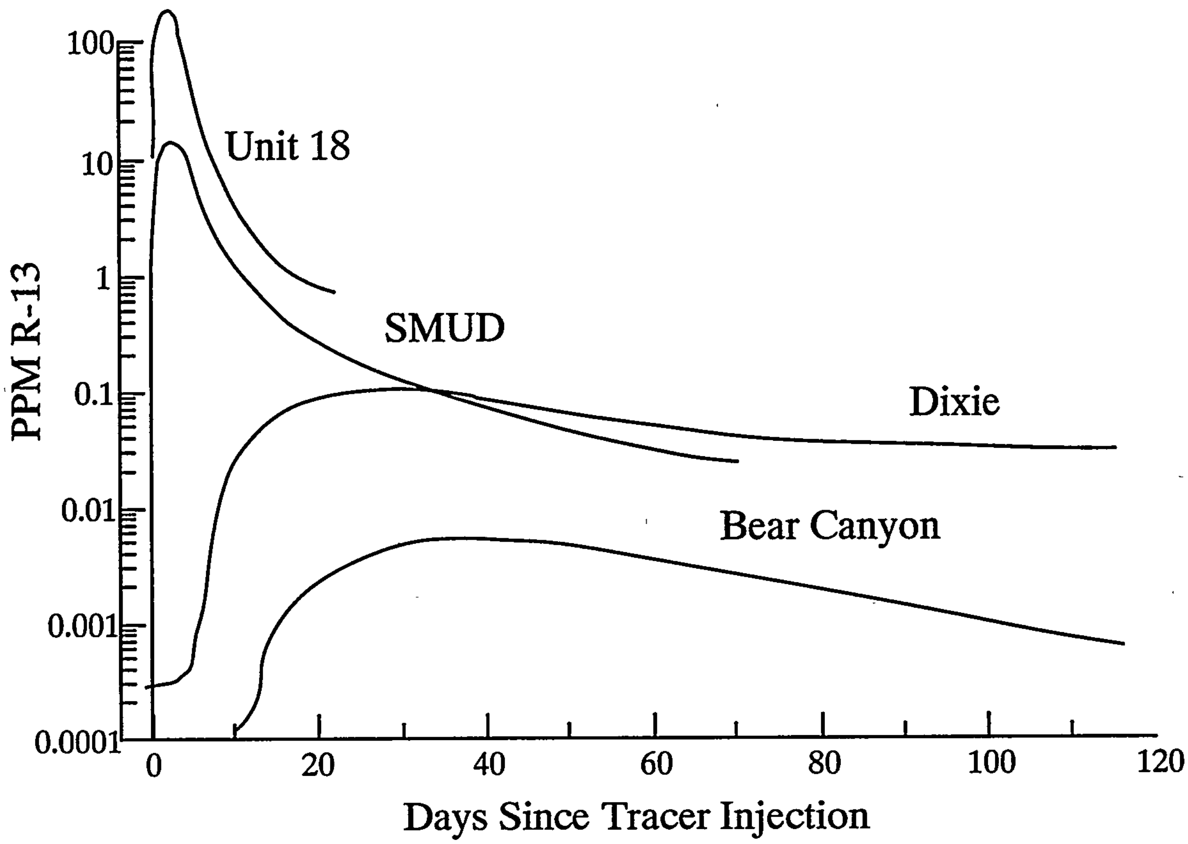

Figure 2. Return curves for three Geysers tracer (R-13) tests and one liquid-phase tracer (fluorescein)test. The differences in the curves are related to the length of the liquid-injectate flow path. The curves for the SMUD and Bear Canyon tracer tests are taken from Beall et al. (1994).

have been testing the current best choice, SF_6, in our laboratory and through literature searches. We have found that SF_6 is very stable. Our experiments, which are still in progress, indicate that SF_6 decays about 10% at 330°C. This means that it should be a virtually non-decaying tracer at the temperatures found in the normal Geysers reservoir.

Gaseous tracers were originally sought after for use in vapor-dominated systems such as The Geysers. However, they are equally useful in liquid-dominated systems. SF_6 has been successfully tested as a liquid-phase tracer at Rosemanowes quarry, England (Upstill-Goddard and Wilkins, 1995) and at the Wairakei, New Zealand geothermal system (Bixley et al., 1995). A highly detectable, gaseous tracer such as SF_6 should also be very useful in high salinity systems such as the Salton Sea, where it can be sampled from the steam line. Low-volatility tracers, which are sampled from the liquid line, are difficult to use in high-salinity systems because the high ion concentrations make quantification of the thermal stability difficult and because they interfere with analysis of the tracer. The main drawback to the use of gaseous tracers in liquid-dominated systems is that there must be no contact with steam in the subsurface. If this occurs the tracer will quantitatively fractionate to the steam phase.

Our current emphasis in the vapor-phase tracer development program is to test SF_6 at temperatures above 350°C to get better quantification of the reaction kinetics. We are also planning on optimizing the analytic method for low molecular weight alcohols, which we have shown to be potential tracers for The Geysers (Adams, 1995).

We have made significant progress in understanding the behavior of gas tracers in vapor-dominated systems. Figure 2 shows return curves from several tracer tests, plotted as the concentration in production steam versus the time since injection. Three of these curves are from different areas in the southern portion of The Geysers. The first, very spiky peak is from the Unit 18 test, which was jointly funded by the U. S. Dept. of Energy and industry (Voge et al., 1994). The second curve is from the SMUD Unit, and the third is from the Bear Canyon Unit. The last two are from tests conducted by Calpine Geothermal Corporation, and are taken from Beall et al. (1994). A return curve from the Dixie Valley DOE-industry cooperative tracer test is included for comparison. Dixie Valley is a liquid-dominated system. These three Geysers tests are shown because the different areas vary quite a bit in the amount of superheat. Unit 18 has produced for quite a while with no injection, and has high levels of superheat. SMUD has injection and a moderate level of superheat, and Bear Canyon has very little.

As shown in Figure 2, the three areas have obviously different return curves. At Unit 18 the tracer returned within one day of injection in some wells. At SMUD, the tracer showed up within 5 days, while at Bear Canyon it took one to two months to show up. At Dixie Valley, the liquid-dominated system, the tracer peaked at one month. These differences are related to the speed of boiling of the injectate coupled with the high volatility of the gas tracers. As soon as the injected water encounters a boiling zone, the tracer flashes off and follows the steam flow in the area. We have compared the gas tracer results with the isotopic and ammonia studies conducted by Joe Beall of Calpine (Beall, 1993), and also with the tritium tracer that was injected along with the gas tracers in the Unit 18 test. From this we have concluded that in moderate and low areas of superheat the gas tracer release is delayed long enough that it follows the main steam paths. At Unit 18, the injectate was boiled too early, as soon as it left the wellbore, and was released near steam paths that were not the same routes that the bulk of the injection-derived steam took. The similarity of the Dixie Valley and the Bear Canyon curves show that the gas tracer stayed in the injectate of the low-superheat area of Bear Canyon long enough to resemble a return curve from a liquid-dominated system.

The conclusion from this comparison is that gas tracers can be effectively used in areas of moderate to low superheat, but that they may be ineffective in areas where the superheat is high and boiling is rapid.

Another advance in understanding was made by trying to calculate the amount of boiling that occurred as the tracers were released in the injection plume during the Unit 18 test. Three tracers were used in this test, tritium and two vapor-phase tracers. The tritium concentrations were used to remove the effects of dilution along the flowpath. One can then cross-plot the concentrations of the two gas tracers and compare them to boiling models, as shown in Figure 3. In geochemistry there are three boiling models that are used, single-stage, multiple-stage, and continuous. The difference between these lies in the velocity of steam as it leaves the vicinity of the boiling front. Slow steam would match the single stage model because it allows complete equilibrium with all of the steam, and the continuous model works for extremely rapid steam transport with only instantaneous equilibrium. The multiple- stage model lies between these two extremes, and has adjustable parameters that account for just how fast the steam is being removed. The data from the Unit 18 test are plotted on Figure 3 as solid dots. The data only match the multiple-stage model. The cumulative steam fractions represented by the samples range from essentially zero to 2%.

This study is interesting from two aspects. The first is that we can show that the tracers were indeed released early in the boiling process, as we had hypothesized from the comparison of return curves. The second reflects on the interpretation of naturally occurring chemical species in geochemistry, in which the single-stage model is frequently used for boiling calculations. This is good news and bad news. The good news is that the slope is much closer to single-stage than to continuous boiling. The bad news is not terribly bad, its just that the range of compositions may require a multiple-stage model to accommodate them. The elongated range is often encountered in natural systems, for example in the isotopic data from the wellbore discharge of Ascension #1, a deep geothermal well on Ascension Island in the South Atlantic Ocean (Adams, 1996).

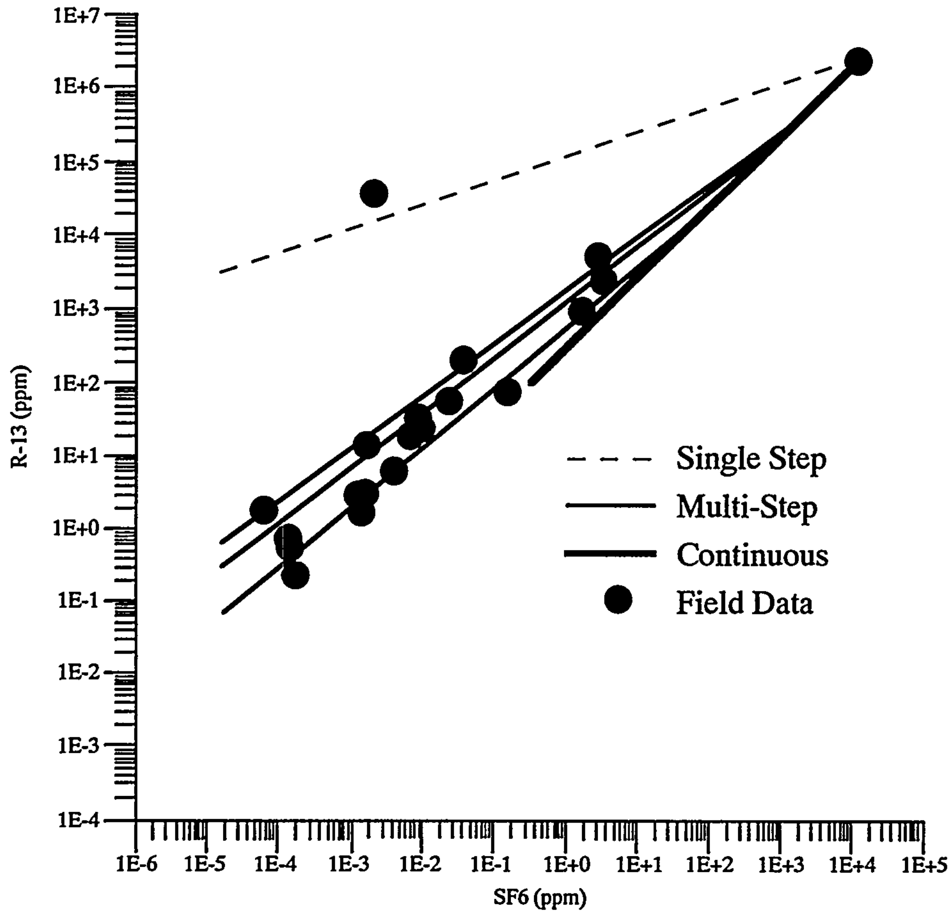

Figure 3. Tracer return data from the Unit 18 injection test. The lines show the closest fit of the single-step, multiple-step, and continuous boiling model.

PRE-TEST MODELING

Pre-test modeling using numerical reservoir simulators is a recent addition to the Tracer Development program. The reason that we have branched out to numerical modeling is that we believe it can help with some crucial decisions in tracer tests. These decisions are: how much tracer to inject, which production wells are most likely to show quick breakthrough, and how often to sample. Large quantities of tracers and frequent sampling of the production wells are expensive, but if you don't use enough tracer or sample too infrequently then you get a false negative and you have wasted all of the money and effort that you put into the test and have a false impression of the reservoir hydrology. We are using the simulators TOUGH2 (Preuss, 1991) or TETRAD (Vinsome and Shook, 1993), both of which have been adapted to geothermal work with funding from the Department of Energy.

FUTURE PLANS

Our future plans are to continue the research discussed above, and to test the concepts of our research topics in the field. At the present time we are preparing a simulation of the Dixie Valley liquid-dominated geothermal system as a tool to be used in planning a tracer test there. A previous test performed at Dixie Valley by the U. S. DOE and Oxbow Geothermal detected only one breakthrough because tracer technology and understanding were in their infancy. Although the one breakthrough that was detected was important in that it revealed a well that would eventually cool, the test did not reveal all of the injection-production flowpaths in the system. At the time a three month test and detection limits in the parts per billion range were considered satisfactory. Our simulations of Dixie Valley and the time lag of the reservoir chloride increases (Benoit, 1992) indicate that the upcoming test will need to be monitored for up to three years. In addition, we will be using a spectrofluorometer, which will lower the detection limits by a factor of 1000. The tracer dye fluorescein will be used because its properties are known, and the performance of the candidate tracer dye amino G will be evaluated by comparison with fluorescein. Thus, several components of our research will be included in the test. In addition, results from the Dixie Valley fault study groups at ESRI and the U. S. Geological Survey will be included in the conceptual model that the reservoir simulation is based on.

EFFECT OF TRACER RESEARCH ON OPERATING COST REDUCTION

The largest cost of a tracer test is the false negative, i.e., a tracer test is performed and no tracer is detected at the production wells because not enough tracer was used, the tracer decayed, or the test was not performed right. The research and development that ESRI has performed in the laboratory and in the field has provided data that has considerably reduced the number of false negatives.

We have developed organic tracers with no natural background that can be used instead of halides. This reduces the quantity needed, lowering material costs and avoiding the effects of high-density slugs, which may sink to the bottom of the reservoir instead of flowing to the production wells. Our work on detection limits has also reduced the amount of material required for a tracer test. A drop in detection limits of a thousand-fold, which is what we have accomplished with the fluorescent tracers, can theoretically lower the amount of dye tracer from 100 kilograms to a tenth of a kilogram, or, alternatively, 100 kilograms can be used with a large margin of error. The stability tests that we have performed on the organic tracers has indicated the maximum temperature at which each tracer can be used, avoiding negative tests in which the tracer decayed before it could reach the production wells. Our work on fluorescent tracers has enabled the operators to use several tracers simultaneously and still analyze the tracers on site.

Pre-test modeling impacts sampling in the same way that detection limits affect the tracer material cost. Targeting the probable wells and the injection velocities lowers the frequency of sampling, cutting manpower and analysis costs.

Our need to test the tracers in the field has resulted in several DOE-industry cost-shared tracer tests. Since we always use a known tracer in conjunction with the tracers that we are testing, this has lead to low-cost, high-quality tracer tests, good reservoir information, and published experience in tracer usage.

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ADVANCES IN THE TOUGH2 FAMILY OF GENERAL-PURPOSE RESERVOIR SIMULATORS

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ABSTRACT

TOUGH2 is a general-purpose fluid and heat flow simulator, with applications in geothermal reservoir engineering, nuclear waste disposal, and environmental contamination problems. This report summarizes recent developments which enhance the useability of the code, and provide a more accurate and comprehensive description of reservoir processes.

INTRODUCTION

Geothermal reservoir simulation is a mature technology which is now routinely used in the assessment, development, and management of geothermal resources (Bodvarsson et al., 1986). Advances continue to improve the description of reservoir processes, enhance the numerical efficiency for solving large problems on small computers, and generally increase the utility of reservoir simulators as practical engineering tools.

Research into mathematical modeling and numerical simulation of geothermal reservoir processes has been conducted at the Berkeley lab for almost twenty years. Since the late 1980s, mathematical modeling of fluid and heat flow has increasingly emphasized problems in nuclear waste disposal and environmental contamination. Geothermal reservoir simulation now benefits from advances made in these areas.

The general objective of our work is to improve the power and utility of geothermal reservoir simulation as a robust and practical engineering tool. By making state-of-the-art simulation capabilities widely available to the geothermal community, we hope to reduce uncertainties in geothermal reservoir delineation and evaluation. Specific goals include (i) more comprehensive and accurate description of reservoir processes, (ii) improved numerical algorithms, (iii) enhanced portability and ease of use of the simulator, (iv) development of novel applications of interest to the geothermal community, and (v) technology transfer and technical support for the TOUGH/MULKOM user community.

The TOUGH2 general-purpose simulator was released to the public in 1991 through the Department of Energy's software distribution center† (Pruess, 1991). Subsequently a large number of enhancements have been developed. Some of these have also been released, while others are undergoing beta-testing or are limited to in-house use at the present time (see Table 1). In this paper we focus on recent developments that are of interest to the geothermal community.

NEW RELEASES

Most of the computational work in a reservoir simulation arises in the solution of large sets of coupled linear equations. The 1991 release of TOUGH2 provided only one method for this task, namely, direct solution by sparse matrix methods. While this is a very stable and robust approach, storage requirements and numerical work increase rapidly with problem size and matrix bandwidth. The practical limit for 2-D problems is of the order of 2,000 grid blocks, while 3-D problems are limited to a few hundred grid blocks. To covercome these limitations, a set of three preconditioned conjugate gradient solvers was added to TOUGH2 (T2CG1; see Table 1). These solvers use iterative methods, whose computational work and memory requirements increase only slightly faster than linearly with problem size, making possible the solution of large 2-D and 3-D problems with of the order of 10,000 grid blocks. A technical report (Moridis and Pruess,

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Table 1. Summary of TOUGH2 enhancements. Status codes are: (PR) public release, (β) beta-testing underway, (i) in-house use only. Additional developments not shown in this table include coupling with a wellbore simulator (Hadgu et al., 1995), grid generation programs, and a number of utility routines for pre- and post-processing of data.

MODULE(status)	PURPOSE
T2CG1(PR)	preconditioned conjugate gradient solvers for simulation of large 2-D and 3-D problems with 10,000 grid blocks or more
TOUGH2 for PC(PR)	adaptation of TOUGH2 for Personal Computers (PC)
T2VOC(PR)	a module for 3-phase, 3-component flow of water, air, and a volatile organic compound (VOC)
ITOUGH2(β)	inverse modeling, allowing automatic model calibration (history matching), and process optimization, with applications to test design, reservoir management, and environmental remediation
T2DM(β)	strongly coupled flow and transport, with full hydrodynamic dispersion
EOS6(i)	fluid property module for water with silica dissolution and precipitation
EOS7(β)	fluid property module for mixtures of water, brine, and air
EOS7R(β)	fluid property module for water, brine, air, plus volatile tracers with optional parent - daughter chain decay
EOS8(β)	fluid property module for three-phase flow of water, non-condensible gas, and black oil
EOS9(β)	fluid property module for saturated/unsaturated flow according to Richards' equation (gas phase a passive bystander)
EWASG(i)	fluid property module for three-component two-phase mixtures of water, water-soluble salt, and non-condensible gas; includes salt dissolution and precipitation, and associated porosity and permeability change
ECH4(i)	fluid property module for water and methane
EGEL(β)	fluid property module for two-phase flow of an aqueous and a gas phase, where the aqueous phase may consist of a mixture of water and a gelling fluid
EOSNN(β)	fluid property module for three-phase flow of water, non-condensible gas, and a non-Newtonian fluid
EOS1G(β)	fluid property module for single-phase gas flow
MULH(i)	flow in strongly heterogeneous media (spatially correlated random permeability fields)
T2HYST(i)	hysteretic capillary pressure relationships

1995) presented detailed analysis of 16 fluid and heat flow problems, with as many as 20,000 coupled equations on different computer platforms (workstations, PCs, Macintosh).

TOUGH2 requires 64-bit arithmetic, while current workstations, PCs, and Macintoshes have 32-bit processors. FORTRAN compilers on workstations usually provide a "double precision" option which can generate a double-precision executable at compile time from single-precision code. Because such options have not been generally available on PCs and Macintoshes, we have created a version of TOUGH2 which is intrinsically double-precision. "TOUGH2 for PC" comes with a number of utility files and programs to facilitate implementation on these inexpensive and widely available machines (Antúnez et al., 1995). Flow problems with up to 800 grid blocks, 2,400 connections, and 3 equations per grid block can be solved with 4 Megabytes of RAM. Memory requirements for larger problems can be estimated by noting that the size of the largest arrays in TOUGH2 is proportional to

$$M = (NEL+2*NCON)*NEQ*NEQ \quad (1)$$

where NEL is the number of grid blocks (elements), NCON is the number of connections between them, and NEQ is the number of equations (mass and heat balances) per grid block. Accordingly, simulation of a problem with 8,000 grid blocks, 24,000 connections, and 2 equations per grid block would require approximately 18 MB of RAM.

T2VOC is a module recently released through ESTSC, which was primarily designed for environmental contamination problems involving volatile organic chemicals (VOCs; Falta et al., 1995). However, T2VOC retains the full two-phase coupled fluid and heat flow capabilities of geothermal modules of TOUGH2, so that it is applicable to the migration of volatile tracers in two-phase geothermal reservoirs.

INVERSE MODELING

An important new development is the ITOUGH2 code for "inverse" modeling (Finsterle, 1993; Finsterle and Pruess, 1995a, b; Finsterle et al., 1996). ITOUGH2 repeatedly calls the "normal" TOUGH2 code in an iterative process, automatically adjusting model parameters (such as reservoir permeability and porosity) to improve and optimize agreement between simulated results and field data. This overcomes the time- and labor-intensive tedium of traditional history matching (model calibration) through trial-and-error parameter adjustment "by hand." It also provides objective measures of "goodness of fit," such as error analysis and parameter sensitivities.

"Inverse" Modeling Process

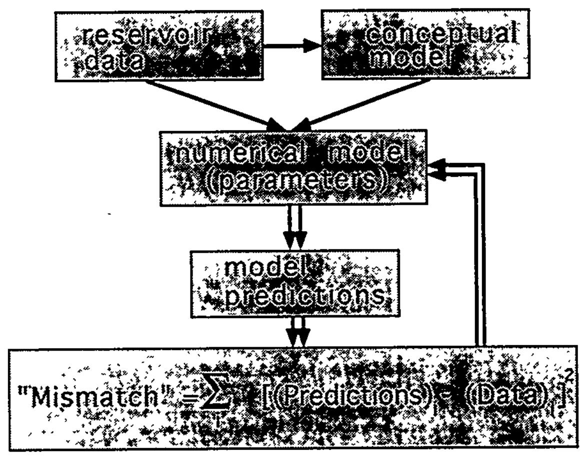

Figure 1. Schematic of the inverse modeling approach. The process of automatically re-adjusting model parameters (shown by double arrows) continues until model calibration (history match) is optimized.

The inverse modeling process is illustrated in Figure 1. "Hard" and "soft" data are used to first construct a conceptual model of the reservoir. This forms the basis for a numerical model which typically involves a number of unknown or poorly known parameters (e.g., permeability and porosity distributions, reservoir size and boundary conditions, etc.). Conventional "forward" reservoir simulation is then used to generate reservoir performance predictions. These predictions are compared with field data and, based on the observed mismatch, the parameters of the numerical model are automatically revised in a manner that will reduce the mismatch. The process of automated parameter revisions is continued, in an iterative way, until model calibration (history match) is optimized.

Figure 2 shows an example of an automatic history match that was obtained for a set of synthetic reservoir performance data which were generated with a TOUGH2 run. The reservoir is a five-spot production-injection system previously studied by Pruess and Wu (1993). Thermodynamic conditions are typical for deep zones of two-phase reservoirs. Random noise was added to the forward simulation data to simulate measurement errors. Automatic model calibration is seen to produce excellent agreement with the synthetic data. Model parameters were found to agree well with the specifications used in the forward runs.

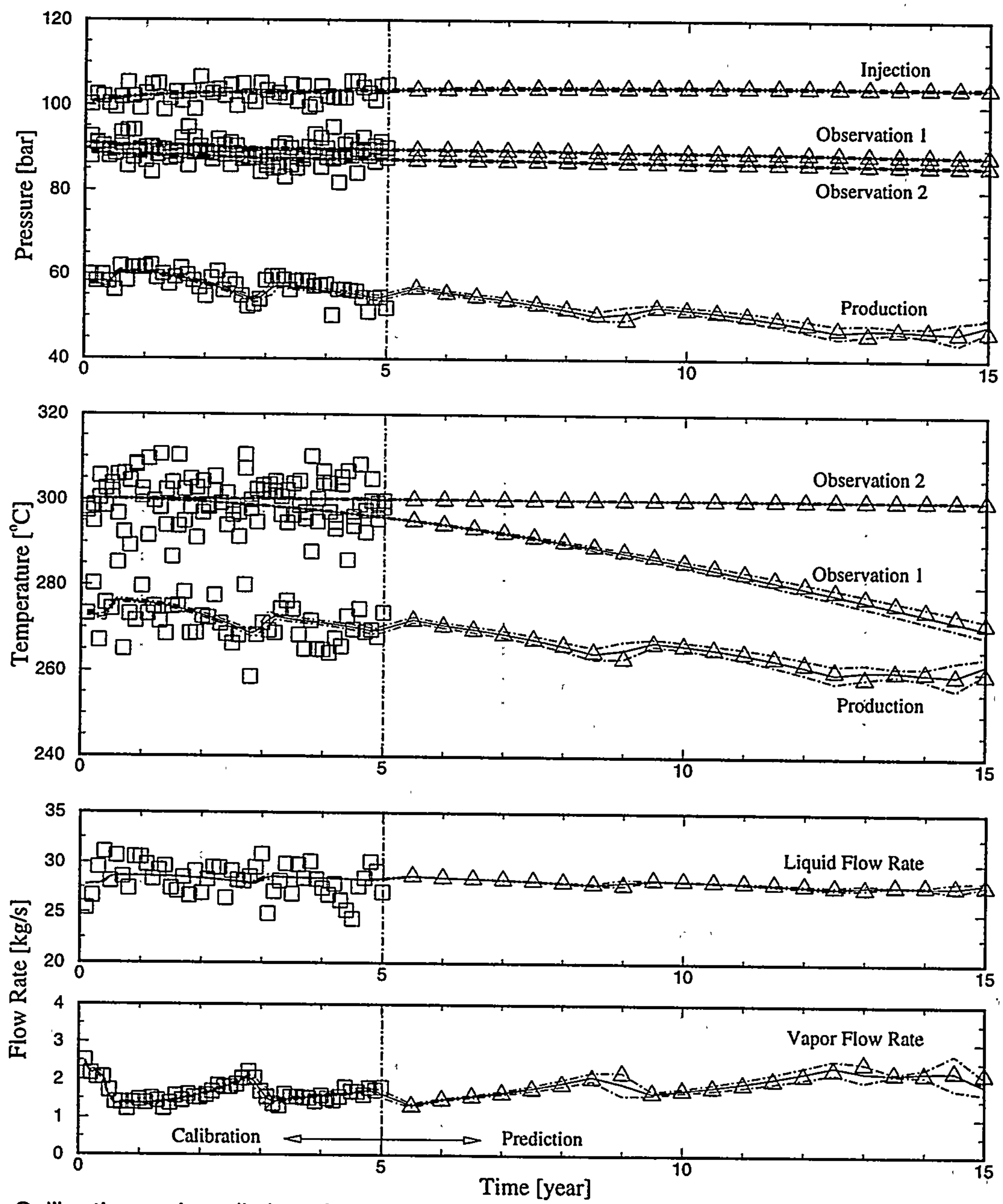

Figure 2. Calibration and prediction of pressures, temperatures, water and vapor flow rates. Squares are synthetic data points used for calibration. Triangles represent the true system response. Simulation results based on the estimated parameter set are shown as solid lines. Error bands (dash-dotted lines) are calculated using linear error propagation analysis (from Finsterle and Pruess, 1995).

ENHANCED PROCESS DESCRIPTION

Several new fluid property modules provide capabilities for handling saline fluids (Oldenburg et al., 1995; Battistelli et al. 1995a, b). EOS7 describes variable-salinity fluids as mixtures of water and NaCl brine, while EOS7R includes an additional capability for tracers with parent-daughter chain decay. These tracers can partition between aqueous and gas phases, and sorb on reservoir rocks.

While the description of saline fluids as water-brine mixtures is computationally very efficient, it is not applicable under conditions where solubility constraints may come into play, e.g., due to extensive boiling of a saline reservoir. This may give rise to precipitation and dissolution of salt which can be modeled with the EWASG module. EWASG keeps track of porosity and permeability changes when NaCl precipitates or dissolves. It also models vapor pressure-lowering effects from both fluid salinity and suction pressures (capillary and vapor adsorption effects). Several choices are available for the non-condensible gas (CO_2, air, CH_4, H_2, N_2), and changes in gas solubility with salinity are included ("salting out").

A capability for modeling mass transport by molecular diffusion and hydrodynamic dispersion has been developed (T2DM). At the present time, this is limited to two-dimensional reservoir domains with a rectangular grid structure. The strong coupling between mass transport and fluid flow, primarily due to the dependence of fluid density on salinity, was found to give rise to complex flow behavior (Oldenburg and Pruess, 1995). Dispersive behavior can also arise in the process of immiscible displacement of reservoir steam by injected water in heterogeneous fractures (Pruess, 1996a).

Another active area of simulator development and application relates to the multi-scale heterogeneities found in fractured reservoirs. Geostatistical methods are being used to generate spatially-correlated random fields which can represent aperture distributions in natural rough-walled rock fractures (module MULH; Pruess and Antunez, 1995). As an example, Figure 3 shows computer-generated permeability fields that were used to investigate fundamental issues relating to water injection into fractured vapor-dominated reservoirs such as The Geysers. An example of a simulated injection plume is shown in Figure 4 (Pruess, 1996b).

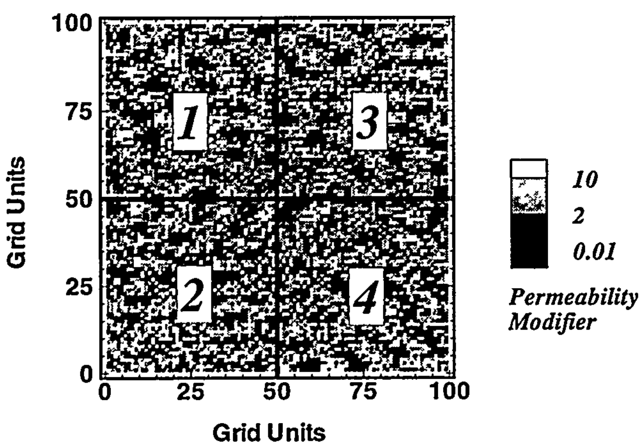

Figure 3. A spatially-correlated random field for representing heterogeneous fractures. Permeability modifiers in the four quadrants labeled 1 - 4 are used separately in numerical simulation experiments (from Pruess, 1996b).

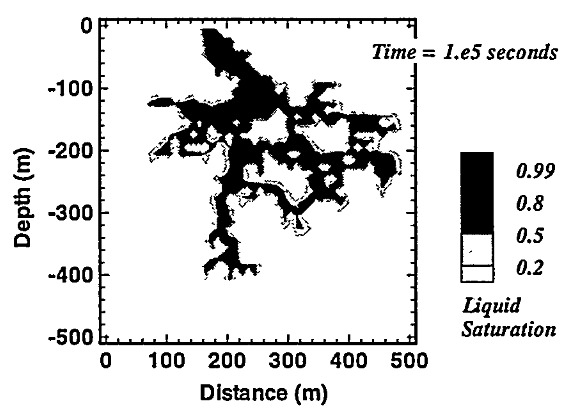

Figure 4. Simulated plume for injection at a rate of 10 kg/s over 10^5 seconds into a heterogeneous fractures, corresponding to the quadrant # 3 of the permeability field shown in Fig. 3 (from Pruess, 1996b).

TECHNOLOGY TRANSFER

The LBNL group serves as custodians of the TOUGH/MULKOM codes, and provides limited technical support to the user community which presently numbers approximately 150 organizations in 22 countries. Our general aim is to foster an open, interactive environment that can attract and induce other researchers to use, improve, and share codes for mutual benefit. We also encourage development of user support services and code enhancements in the private sector.

The TOUGH Workshop '95, held in March 1995 at LBNL, was attended by approximately 100 participants from 10 countries. The proceedings feature 53 technical papers in different areas, including geothermal reservoir engineering, oil and gas, nuclear waste isolation, environmental remediation, mining engineering, vadose zone hydrology, and simulation methods (Pruess, 1995).

Under a DOE-LBNL agreement with the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), DOGGR engineers are currently being trained in the use of TOUGH2-PC. The objective is to help DOGGR enhance their supervisory role of geothermal fields. A numerical model of the Heber geothermal field is being developed as part of this training (Antúnez et al., 1995; Boardman et al., 1996).

Prompted by the needs of DOE's civilian radioactive waste management program, TOUGH2 recently underwent qualification under a very strict QA (quality assurance) program. The QA report (Pruess et al., 1996) includes a summary of technical requirements and specifications of TOUGH2, a set of code verification problems, and a comprehensive bibliography (318 papers and reports) of TOUGH2-related developments and applications.

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OVERVIEW OF FUNDAMENTAL GEOCHEMISTRY BASIC RESEARCH AT THE OAK RIDGE NATIONAL LABORATORY

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ABSTRACT

Using unique facilities and expertise developed in the Geothermal Program and in projects supported by DOE's Office of Basic Energy Sciences, researchers in ORNL's Geochemistry and High Temperature Aqueous Chemistry groups are conducting detailed experimental studies of the physicochemical properties of the granite-melt-brine system; the sorption of water on rocks from steam-dominated reservoirs; the partitioning of salts and acid volatiles between brines and steam; the effects of salinity on hydrogen and oxygen isotope partitioning between brines, minerals, and steam; and the aqueous geochemistry of aluminum. These studies contribute in many ways to cost reductions and improved efficiency in the discovery, charac-terization, and production of energy from geothermal resources.

BACKGROUND

Over a period of several decades, under the direction of Dr. Robert E. Mesmer, the hydrothermal research program in ORNL's Chemical and Analytical Sciences Division has become recognized as one of the world's leading centers for experimental studies of the physicochemical properties of aqueous brines, chemical and light stable isotope exchange reactions in aqueous media, brine/steam/solid interactions, and silicate melt/brine interactions. The bulk of this research has been supported by the Chemical Sciences and the Engineering and Geosciences Divisions of DOE's Office of Basic Energy Sciences (BES). The Electric Power Research Institute (EPRI) also supports substantial research on basic solution chemistry applied to corrosion mitigation and performance improvements in power plant steam cycles.

Recognizing the relevance of this research in improving exploration and resource characterization, and in understanding geothermal system evolution, reservoir dynamics, and down-hole and in-plant corrosion, the Geothermal Division of DOE's Office of Energy Efficiency and Renewable Energy has for a number of years supported parallel studies of a fundamental nature, but addressing specific problems identified by the geothermal industry in its interactions with DOE. This symbiotic relationship between our basic and applied research projects results in substantial leveraging of applied program funds (Geothermal, EPRI) and ensures that the research performed is quantitative and definitive.

Currently the Geothermal Program at ORNL consists of five separate research projects, each of which is briefly summarized below. Space does not permit a complete bibliography of publications from this work, and so only a few of our key papers will be cited in each section.

RECENT ACTIVITIES

Thermodynamics and phase relations of synthetic granite melts and associated aqueous fluids We have recently initiated a study of the phase relations, water solubilities, and aqueous fluid compositions of melt-crystal-brine assemblages in the haplogranite system (albite-sanidine-quartz-water, or Na-K-Al-Si-O-H), widely regarded as an excellent analog for natural granites. The experiments are performed in precious-metal capsules in cold-seal pressure vessels and our unique hydrogen-service internally heated pressure vessel. A vacuum-manometric apparatus has been developed for measurement of the water content of saturated and unsaturated haplogranite melts. A new method has also been developed for monitoring the activity of water in equilibrium with unsaturated melts. Finally, we have developed a method that overcomes nearly all of the difficulties of determining the compositions of brines equilibrated with silicate melts (Anovitz et al., 1995; Blencoe and Anovitz, 1995).

With these new approaches, we are now actively investigating: a.) the phase boundaries of melt-crystal fields in haplogranite systems at 500-2500 bars, 680-1000°C; b.) the activity-composition relationships of water in haplogranite melts at 500-2500 bars, 680-1000°C; and c.) the K, Na, Al, Si, and Cl contents of alkali chloride brines in equilibrium with haplogranite melts.

We are also extending a thermodynamic model based upon earlier work in our BES program on the albite-water melts (Blencoe, 1992), which is qualitatively consistent with current models for water solubility in silicate melts as hydroxyl (OH) groups at very low total water, and as molecular water plus hydroxyl at higher water contents, to more complex systems. The equation is also consistent with all of the high quality phase-equilibrium, volumetric, and calorimetric data for high-temperature phases of the albite-water system. A comprehensive thermodynamic model for hydrous granitic magmas would facilitate the quantitative prediction of crystallization paths for the melts, which correlate with release of latent heat; estimating rates of heat loss from granitic intrusions; the pressure-temperature-composition conditions at which an aqueous fluid begins separating from a granitic magma;, and the chemical signature of magmatic fluid input into the superadjacent geothermal circulation system.

Measurements of water adsorption on the Geysers rocks (Gruszkiewicz et al., 1996). This is our newest project, in which we are using the unique capabilities of our high temperature isopiestic (equal vapor pressure) apparatus to measure the quantity of water retained by adsorption on the surfaces of rock samples taken from drill holes in The Geysers geothermal system. The impetus for this research is to enable modeling of the depletion of reservoir pressure in this and other steam-dominated geothermal fields, and to predict the effects of reinjection on reservoir pressures. Such models require a detailed knowledge of the fraction of water present as adsorbed layers and capillary condensates, relative to steam in pores, as well as the extent of hysteresis in the uptake versus release profiles of various rock types with changing reservoir pressure. The ultimate size of the economically extractable resource depends critically on these phenomena.

ORNL's isopiestic apparatus is the only one of its kind in the world that operates in the range of 100-250°C, spanning the average temperature (240°C) of the steam-dominated reservoir at The Geysers. The apparatus was developed and has been used for many years to determine the activity and osmotic coefficients of electrolyte solutions (NaCl, $CaCl_2$, etc.) over wide ranges of salinity. The apparatus consists of a large pressure vessel housing a copper block within which rest 20 platinum dishes, some of which contain standard titanium weights. The dishes can be simultaneously lifted and rotated at P and T, and each dish placed sequentially on an internal torsion beam balance for highly precise *in situ* total mass determination. The vapor pressure in the vessel is controlled within 5 mbar by injection or release of water, and the temperature is controlled within 0.1°C.

For this initial study, core samples from three wells in the producing steam reservoir of The Geysers (NEGU-17, 8530-8530.5 ft.; PRATI-STATE 12, 6261.7-6261.8 ft.; and MLM-3, 4336-4336.3 ft.) were crushed and sieved into three size fractions: coarse (2.00-4.25 mm), medium (0.355-2.00 mm), and fine (0-0.355 mm). All samples were dehydrated *in vacuo* at 200°C overnight at better than 0.5 mbar vacuum in the isopiestic vessel prior to the start of each adsorption/desorption isotherm. All samples

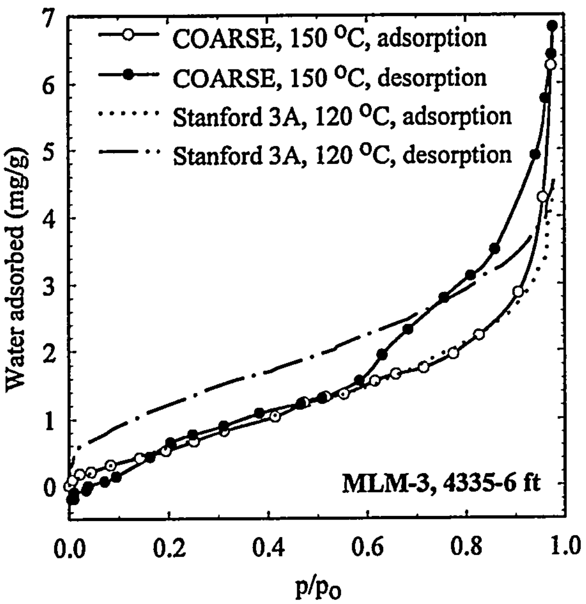

Figure 1. Milligrams of water adsorbed per gram of rock vs. ratio of vapor pressure to saturation pressure from a Geysers drill hole.

were studied in the same experiment, starting at 150°C, then moving to 200°C. The 250°C experiment is currently under way. At each temperature the amount of water adsorbed on the rock surface per unit gram of rock mass (mg/g) is reported relative to the ratio of vapor pressure to the vapor pressure of bulk pure water at that temperature (p/p_o).

Figure 1 shows a comparison of the adsorption/desporption behavior of the coarse fraction of MLM-3 at 150°C with the published results of the Stanford group (Satik and Horne, 1995) on a sample taken from the same well at a depth of 4335.1 ft., and studied at 120°C. It should be emphasized that mineral heterogeneities, differences in grain size (the Stanford group uses coarser material), temperature, etc. have not been normalized out in this comparison. It is a general observation in this study that, while the adsorption isotherms of all of our samples were found to be quite similar to each other and to roughly equivalent samples reported by the Stanford Group, our desorption isotherms for the coarse and medium fractions generally exhibit closed hysteresis loops (i.e. the sample returns to its starting weight by the end of the experiment), whereas the Stanford group reports open hysteresis loops in all cases (cf. Shang et al., 1995). A direct comparison of the two experimental methods with identical samples, to the extent that this is possible, might be desirable.

The hysteresis of our sample shown in Figure 1 is of the IUPAC H3 type possibly associated with slit-shaped pores in the adsorbent. The coarse and medium fractions of all three samples exhibited similar isotherms. Furthermore, the amount of water adsorbed at a particular value of p/p_o is roughly the same at 150 and 200°C. The fine grained fraction of all samples had *adsorption* isotherms at 150°C similar to the medium and coarse fractions, but the hysteresis on desorption was large and remained widely open, as shown in Figure 2. Furthermore, the adsorption isotherm at 200°C follows the 150°C desorption curve and shows even more hysteresis on desorption. This suggests an irreversible, temperature-dependent process of hydration of fresh surfaces exposed by fine crushing, which may involve the formation of hydrous minerals or surface OH groups at high p/p_o, which are very slow to break down during desorption.

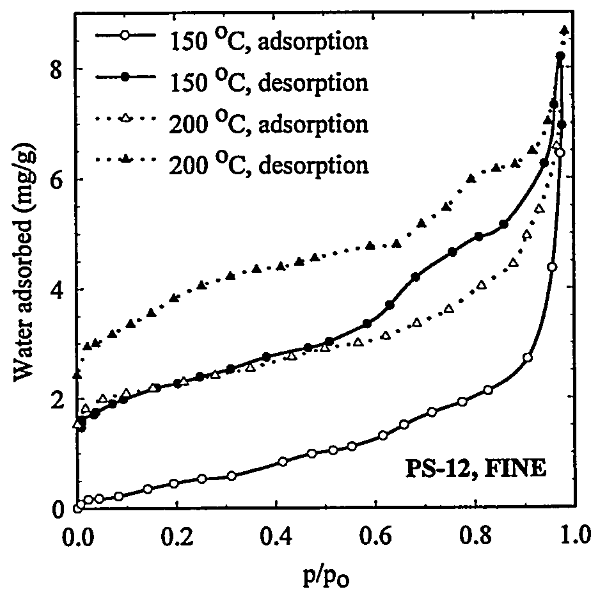

Figure 2. Adsorption/desorption behavior of a finely-crushed Geysers reservoir rock.

These preliminary results suggest that reservoir rocks which have been exposed to alteration for long periods of time should exhibit sorption isotherms similar to our sample MLM-3 in Figure 1, with little dependence on surface area, grain size or temperature, and this greatly simplifies the modeling of pressure changes in the unsaturated reservoir during production and reinjection. However, fracturing associated with reinjection, collapse during production, or earthquake activity, may expose fresh unaltered mineral surfaces which may irreversibly adsorb large amounts of water.

Volatility of HCl and the thermodynamics of brines during brine dryout (Simonson and Palmer, 1993; Palmer and Simonson, 1993; Simonson and Palmer, 1995). Some wells in the high temperature (>300°C), vapor-dominated resource at the Northwest Geysers have produced steam with high levels of chloride, greater than 100 ppm in some cases. This chloride-bearing steam is extremely corrosive to piping and well casings, leading in severe cases to loss of production within a few days. In order to mitigate this problem, it is first necessary to investigate the possible sources of corrosive steam components. We therefore designed a special liquid-vapor equilibration system which permits sampling of coexisting liquid and vapor at temperatures to 350°C without perturbing the phase compositions.

Earlier results from our research demonstrated that in order for steam to contain levels of HCl consistent with the excess chloride (relative to Na^+ and other common cations) observed in the Northwest Geysers, a coexisting brine with very low pH (<3) is required, which is inconsistent with the observed mineral assemblages in the reservoir rocks. Additional experiments demonstrated that the partitioning of NaCl into steam, even over very concentrated NaCl brines (to halite saturation and even to brine dryout) is significantly lower than that predicted from recently published equations of state for NaCl + H_2O. Additional experiments have been conducted with NaCl brines in contact with Geysers reservoir rocks, which indicate that the chloride content of coexisting steam is not significantly enhanced by fluid-rock interactions. Finally, experiments to 350°C with aqueous brines containing $MgCl_2$, $MgCl_2$ + NaCl, or $CaCl_2$ indicate that, while additional HCl in the steam is produced by hydrolysis of divalent cations in the brine, the total amounts of HCl generated are too small to account for the chloride levels observed in the Northwest Geysers steam.

High-chloride steam at The Geysers is often high in ammonia as well (to 1000 ppm). This field observation, coupled with experimental studies of NH_4Cl partitioning between liquid and vapor conducted in our EPRI-sponsored program, suggested a possible alternative. For a brine containing HCl, NH_3, NH_4Cl, and NaCl, all four solutes partition into the vapor, but NH_4Cl is much more volatile than NaCl, though less so than HCl. We have developed a model for the vapor phase composition coexisting with mixed brines in this system, which indicates that concentrations of chloride as NH_4Cl + HCl can easily exceed 100 ppm at temperatures above 300°C, even in equilibrium with brines having near-neutral pH (pH=5-6 at 300°C for a brine in this system coexisting with up to 100 ppm HCl + NH_4Cl, and 1000 ppm ammonia. Interestingly, in our experiments involving interaction of NaCl brines with Geysers rocks, the sampled steam contained significant concentrations of ammonia, even though the rock samples were pretreated with HCl, and the starting solutions contained no ammonia.

The model we have generated for the NH_3-NaCl-HCl-H_2O system also permits assessment of the efficiency of desuperheating, or injection of liquid water into superheated steam to lower its temperature and/or increase its pressure to the saturation point, as a means of stripping chloride from the steam. In Figure 3, F is the fraction of water as liquid in the steam by weight. The vertical axes are the chloride content of the steam and the pH of the liquid water at 200 and 275°C for an initial steam containing 70 ppm total chloride and 1000 ppm NH_3. As can be seen, at 200°C the chloride content of the steam drops to about 1 ppm when only 1% liquid water is present, while 10%

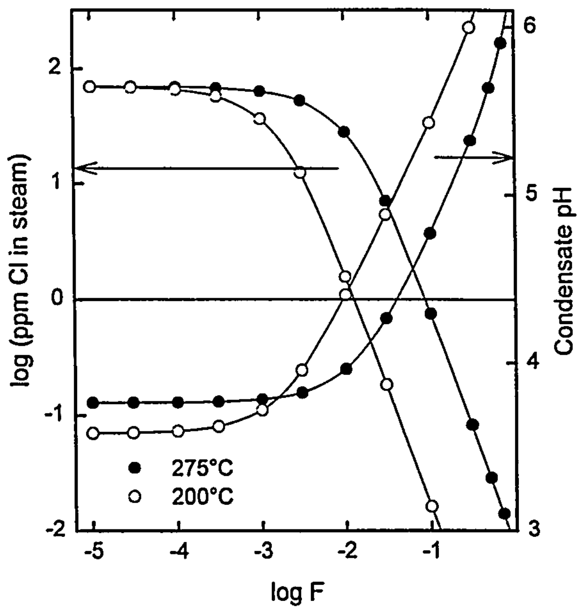

Figure 3. Chloride content in steam and the pH of an NH_4Cl+H_2O condensate as a function of fraction of water as condensate.

liquid water is required at 275°C. At both temperatures, however, the pH of the liquid remains relatively high, about 4.3 to 4.5.

Future research in this project will involve detailed modeling of chloride partitioning into steam from mixed salt brines. Experiments involving brine-solid interactions, including halite and Geysers reservoir rocks, will continue. We will also study corrosion problems in process units at Magma Power Company sites in the Salton Sea geothermal system, a hypersaline liquid system, and high chloride steam in two-phase wells at Los Azufres.

Salt effects on stable isotope partitioning between geothermal brines, steam, and minerals (Horita et al., 1993; Horita and Wesolowski, 1994; Horita et al., 1995). Hydrogen and oxygen isotope studies of produced water and steam at well heads, in hot springs and fluid inclusions, etc., are commonly utilized to constrain the sources of geothermal brines, reservoir temperatures, phase separation processes, and reinjection efficiencies. Our research in this project unambiguously demonstrates that solutes dissolved in water perturb the partitioning of hydrogen and oxygen isotopes between brines and coexisting phases (steam, minerals), that these salt effects are too large to be ignored in moderate to hypersaline systems, and that the effects are related simply and systematically to salt concentration and critical phenomena.

Using the same experimental apparatus as in the liquid-vapor solute partitioning studies above, as well as static systems with remotely-actuated valves, we have investigate the hydrogen and oxygen isotope compositions of water vapor in equilirium with brines in the system Na-K-Ca-Mg-Cl-SO_4-H_2O from 0 to 100°C for pure water, single salt, and mixed salt brines to 6 molal total salinity. The isotope salt effects on brine-steam partitioning of 0-6 molal NaCl have been studied to 350°C, 0-4 m $CaCl_2$ to 200°C, and 0-4 m KCl to 130°. Recently, we have begun measuring the effect of salinity on the partitioning of oxygen isotopes between NaCl brines and the minerals calcite and strontianite at 300 and 450°C, and the partitioning of hydrogen isotopes between NaCl and $MgCl_2$ brines and brucite at 200-450°C. The mineral-brine isotope salt effects are found to be exactly

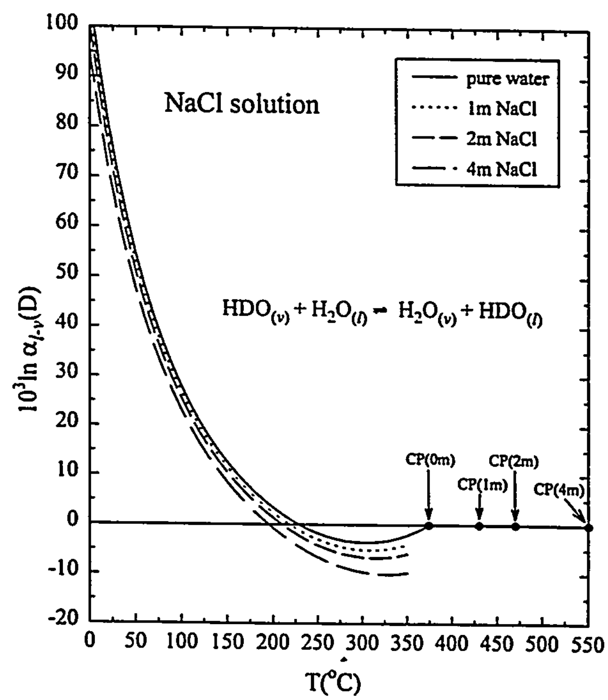

Figure 4. Equilibrium D/H fractionation factor (α) between coexisting water liquid and vapor as a function of temperature and NaCl content.

the same as the vapor-brine salt effects at equivalent temperatures and salinities, to 300°C.

Figure 4 illustrates the effect of 1, 2 and 4 molal NaCl on the equilibrium D/H fractionation factor (1000lnα) between water liquid and vapor from 0 to 350°C. It is apparent from this figure that the isotope salt effects are related to the increase in the critical temperature of the solutions with increasing salinity. Space does not permit a more detailed discussion of the experimental results, but our studies show that the salt effects, expressed as the log of the ratio of D/H or $^{18}O/^{16}O$ in the coexisting phases, are linearly related to salinity, are strong functions of both anion and cation charge and radii, and decrease with temperature to about 200°C, then increase to at least 350°C.

Figure 5 shows the change in estimated reservoir temperature from simultaneous measurements of the D/H and $^{18}O/^{16}O$ ratios of two-phase water and steam collected at the well head for pure liquid water versus 1, 2, and 4 molal NaCl brine. Errors of 50°C or more in the estimated reservoir temperature would result from neglect of the salt effect. Future studies in this project will include completion of liquid-vapor salt effect measurements on KCl, $MgCl_2$, $CaCl_2$, and Na_2SO_4 to 350°C, determination of the liquid/vapor salt effects of a few mixed salts to 350°C, and direct measurements of the brine-vapor and brine-mineral isotope partitioning in salt solutions to 500°C.

Geochemistry of Aluminum in high temperature brines (Palmer and Wesolowski, 1993; Wesolowski and Palmer, 1994) Aluminum is a major component of most geothermal reservoir rocks, and aluminosilcate transformations and dissolution/precipitation reactions often influence porosity and permeability changes in reservoirs, recharge zones, reinjection sites; and scale formation in production wells. At the start of this project some years ago, there was a major lack of reliable experimental data on the aqueous speciation of aluminum at both high and low temperatures, and various geochemical models predicted aluminum solubilities differing by

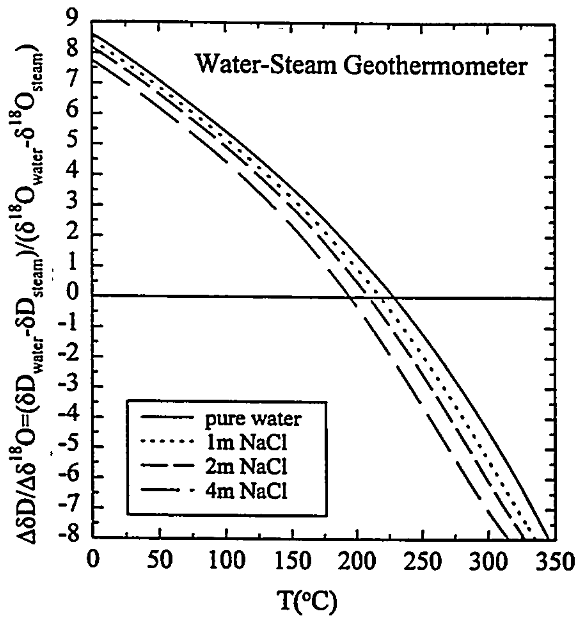

Figure 5. Downhole Temperature estimate from wellhead analysis of the oxygen and hydrogen isotopic compositions of steam and water separates as a function of NaCl content..

orders of magnitude for a given pH and temperature. Our previous research, which involved experimental studies of gibbsite, $Al(OH)_3$ solubility and potentiometric studies of the formation constants of aluminum hydrolysis species and complexes with organic ligands, presented in a five-part series in *Geochimica et Cosmochimica Acta,* has essentially eliminated uncertainty in the low temperature behavior (0-100°C) of aluminum, and has been widely adopted by the geochemical community as the definitive work on this subject (cf. Pokrovskii and Helgeson, 1995).

Our current studies involve measurements of the solubility of boehmite, AlOOH, in NaCl brines at 100-290°C, using a unique high temperature potentiometric cell designed for this project, which enables mineral solubility measurements to be made with continuous *in situ* pH monitoring, and periodic sampling for solution chemical analyses, in experiments lasting a month or more. These are the first such measurements ever made at elevated temperatures.

We have completed experiments in 0.03 molal NaCl at 101, 203 and 250°C, and in 0.1, 0.3 and 1.0 molal NaCl at 152, 203, and 250°C. Figure 6 shows results obtained at 203°C in 0.03 molal NaCl. The shape of the solubility curve is controlled by the relative stabilities of $Al(OH)_x^{3-x}$ species (x=0-4) as a function of pH, temperature, and ionic strength. As can be seen, at this low ionic strength we have obtained excellent agreement, at high pH where $Al(OH)_4^-$ is the dominant aluminum species in solution, with the recently-published results of Bourcier et al. (1993) and Castet et al. (1993), and good agreement with the latter study near the solubility minimum as well. However, the former study reported very much higher solubilities near the minimum, and is suspect.

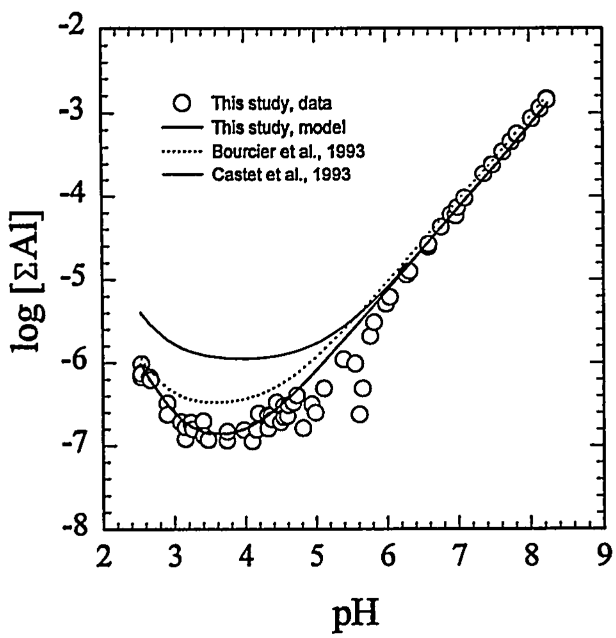

Figure 6. Solubility of boehmite, AlOOH, as function of pH at 203.2°C in 0.03 molal NaCl.

Note that there is a region of pH (ca. 5-6) where our results appear to be too low. This has been observed at other conditions as well, and indicates that in this region of pH, corresponding to the field of coexistence of $Al(OH)_4^-$ and the uncharged $Al(OH)_3$ species in solution, dissolution/precipitation reactions may be too sluggish to be studied in the time frame dictated by our approach. Our results at higher ionic strength are more difficult to compare with the literature data, until we have fully modeled the effect of salinity on aluminum speciation, and assessed the stability of $NaAl(OH)_4$ ion pairs in solution..

Future plans for this research include completion of boehmite solubility runs in 0.03 molal to 1.0 molal NaCl solutions, and some studies in which NaCl is titrated into solutions in equilibrium with boehmite at constant pH, with tetramethylammonium chloride as the ionic medium, which will enable us to directly determine the formation constants of $NaAl(OH)_4$ ion pairs, assuming that the much larger tetramethylammonium ion does not complex with the aluminate anion. We also intend to initiate a series of measurements of the reaction rates and equilibrium constants for silicate mineral hydrolysis reactions, such as the hydrolysis of potassic feldspar to muscovite plus quartz: 3Kspar + $2H^+ \Leftrightarrow$ Musc. + 6Qtz + $2K^+$; which plays a major role in controlling the pH of geothermal brines and may provide a source of corrosive HCl in coexisting steam.

FUTURE ACTIVITIES

We will continue our opportunistic approach of applying fundamental expertise and facilities developed in our BES programs to problems identified in consultation with the DOE Geothermal Program and the geothermal industry. Future studies may include studies of: the thermodynamics of more complex melt/brine systems, the kinetics of fluid/rock interactions, development of a linked chemical and stable isotope exchange model for fluid/rock interactions, and scaling and corrosion in high temperature brines.

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AN OVERVIEW OF THE CASE STUDIES OF THE COSO, ROOSEVELT HOT SPRINGS, AND SUMIKAWA GEOTHERMAL FIELDS

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ABSTRACT

A brief overview of the three case studies (Coso and Roosevelt Hot Springs, U.S.A.; Sumikawa, Japan) being performed as part of DOE's Reservoir Technology Program is provided in this paper. The principal goal of the Coso study is to provide a better understanding of the geologic development of the Coso Range. The Roosevelt Hot Springs and Sumikawa case studies will develop improved conceptual models of these fields based on the analyses of exploration and production data released by the field developers. Examples from the Roosevelt and Sumikawa Geothermal Fields are used to illustrate the utility of pressure interference tests for delineating the volume and permeability structure of a geothermal reservoir.

1. INTRODUCTION

A major purpose of reservoir engineering is to assess the quantity and quality (*i.e.*, heat content and chemical composition) of fluid that may be extracted from a geothermal reservoir. Reservoir assessment must of necessity start with the collection, analysis and interpretation of field data. This information is required to develop a physically viable conceptual model consisting of a well defined geometrical system with boundaries upon which appropriate thermal and hydrological conditions may be applied, an internal structure consistent with the local geology, and the physical and chemical properties of the associated rock and water. The conceptual model forms the basis for constructing a mathematical model which can provide quantitative estimates of the transport of heat and mass in the geothermal reservoir. The mathematical model is verified by comparing the theoretical predictions of surface heat flux, temperature and pressure distributions, *etc.* with available pre-exploitation and production related data. The verified model can then be used to predict future reservoir response under a variety of production scenarios.

Adequate field data are essential for developing a well constrained mathematical model of a geothermal field. Because of competition for project funds, it is usually not possible to collect a comprehensive reservoir data set. The field measurements program must be prioritized in relation to important reservoir parameters. In this context, case studies are of special interest. Case studies are needed to help formulate cost effective data collection and reservoir assessment strategies.

Starting in the mid-1970's, the U.S. Department of Energy (DOE) has supported work to collect and publish case histories of both U.S. and foreign geothermal fields. The DOE Geothermal Reservoir Engineering Program is currently sponsoring case studies of Coso (California), Roosevelt Hot Springs (Utah) and Sumikawa (Honshu, Japan) Geothermal Fields. Brief summaries of these three case studies, and current status of each, are given in Sections 2–4. A summary of the pressure interference data at Roosevelt Hot Springs is included in Section 3. The use of pressure interference data to characterize the permeability structure for the Sumikawa Geothermal Field is discussed in detail in Section 5.

2. COSO GEOTHERMAL FIELD, CALIFORNIA, U.S.A.

The Coso geothermal area is located in the Coso Range, Inyo County, California. The geothermal reservoir at Coso, developed by the California Energy Company, Inc. (CECI) and the U.S. Navy, is apparently related to a magmatic event that occurred less than 0.3 Ma (Feighner and Goldstein, 1990). The bedrock geology of the Coso Range is dominated by Mesozoic plutonic rocks containing pendants of Paleozoic/Mesozoic meta-sedimentary strata.

Since June 1994, J. D. Walker and R. S. Whitmarsh (Walker and Whitmarsh, 1996) at the University of Kansas have been carrying out a project titled, "Mapping and Geologic Interpretation in the Coso Geothermal Area". This work is jointly funded by the DOE and two member companies (CECI, and U.S. Navy's Geothermal Program Office) of the Geothermal Technology Organization (GTO).

The main aim of this study is to better understand the geologic development of the Coso Range. While the volcanic rocks younger than Miocene are somewhat understood, the older rocks, *i.e.* Mesozoic granitoids, are poorly characterized. Furthermore, the structural geology of the area is not well known. The technical objectives of the project include (1) identification of important geology features in the Coso Range, (2) determination of the relative timing of major faults and intrusive events in the Coso Range, and (3) partitioning of strain in the area between strike slip and normal faults active over the last 10 million years.

An improved understanding of the Coso geothermal area relative to major Pliocene to Recent faults in the area should be helpful in formulating the program for further exploration and/or step out drilling. Quantification of the amount of extension in the Coso Range may be useful in placing limits on the amount of heat flow in the area. Finally, an understanding of the position of the Coso Geothermal Field within the extensional regime of the Coso Range can aid in the development of exploration strategies for other areas within the Basin and Range province.

3. ROOSEVELT HOT SPRINGS GEOTHERMAL FIELD, UTAH, U.S.A.

Roosevelt Hot Springs Geothermal Field, located in southwestern Utah (Figure 1), is the oldest producing geothermal field in the Basin and Range Province. The successful discovery well, RHSU 3-1, was drilled in April 1975. A 20 MWe power plant was commissioned in May 1984. Idaho National Engineering Laboratory (INEL), in cooperation with CECI and Earth Sciences and Resources Institute of the University of Utah (UUESRI), initiated in 1994 a project to conduct a case study of the Roosevelt Hot Springs geothermal system. CECI, the operator of the field, has made available an extensive data set, including data from three long-term flow tests conducted prior to the start of exploitation and the complete exploitation production history. The INEL/CECI/UUESRI project is intended to provide an evaluation of the utility of reservoir engineering techniques in early assessment of the production characteristics of the geothermal reservoir (Faulder, 1995).

The case study will involve examination and analysis of geologic, geochemical, geophysical and reservoir engineering data. A final conceptual model will be developed incorporating the results of these studies. It is expected that completion of this work will lead to (1) an improved model of a Basin and Range liquid-dominated reservoir and its response to exploitation, (2) an enhanced understanding of the long-term behavior of a fractured granitic reservoir, and (3) an assessment of the usefulness of different types of data and techniques for evaluating geothermal resources.

Prior to the plant start-up in May 1984, three long-term flow tests (LTFT) were conducted in the period 1977 to 1983. LTFT #1 was performed from October 7, 1977 to May 31, 1978 using a single production well (RHSU 54-3) and three observation wells (RHSU 3-1, RHSU13-10 and RHSU25-15). The well locations are shown in Figure 1. The liquid portion of the discharge from RHSU54-3 was reinjected into a well (RHSU82-33) located outside the reservoir. The flow rate and observation well pressure histories are shown in Figures 2 and 3, respectively. Faulder (1994) has analyzed the observed pressure response. Based on his analyses, the primary reservoir fluid volume at Roosevelt Hot Springs, ignoring the role of aquifer influx, is estimated to be ~ 20 billion barrels (3×10^9 m^3). If aquifer influx is assumed, the primary reservoir volume becomes ~ 7 billion barrels (~ 10^9 m^3). The study by Faulder (1994) illustrates the utility of pressure interference tests for characterizing the geothermal reservoir.

4. SUMIKAWA GEOTHERMAL FIELD, HONSHU, JAPAN

The Sumikawa Geothermal Field is located in the Hachimantai volcanic area in northern Honshu, Japan, about 1.5 kilometers to the west of Ohnuma

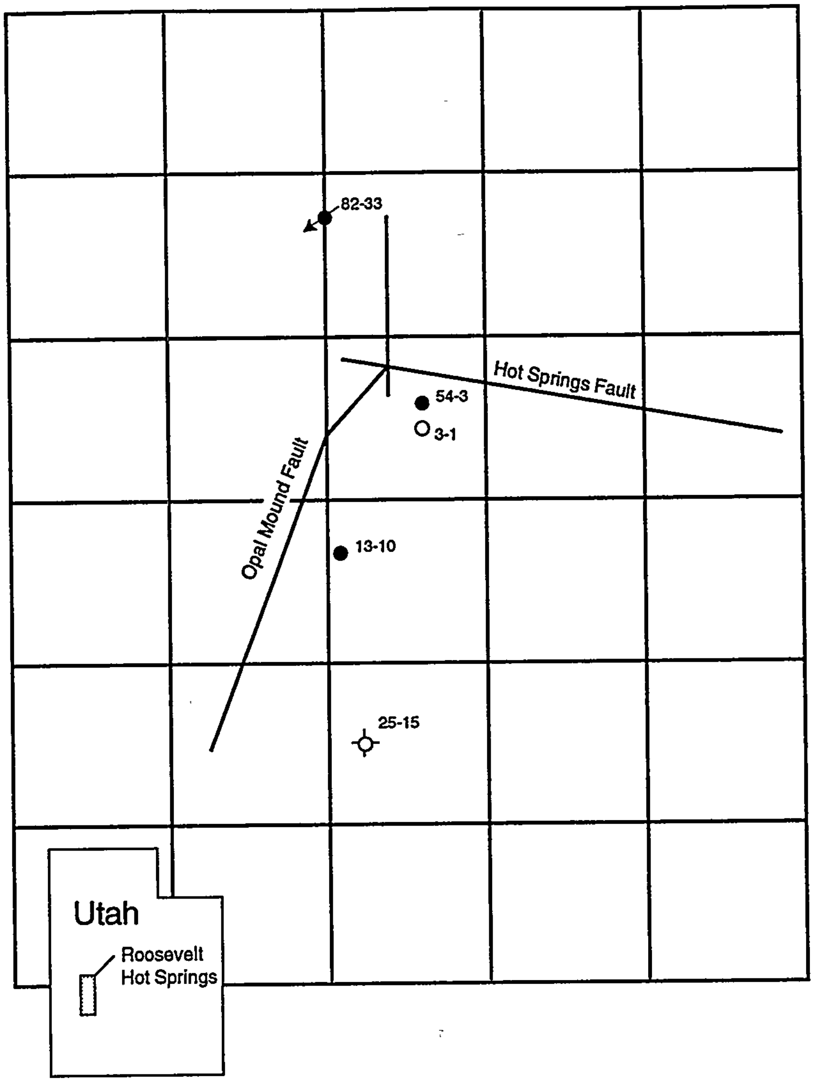

Figure 1. Locations of Production (54-3), Injection (82-33), and Observation (3-1, 13-10, 25-15) wells during Long-Term Flow Test #1, Roosevelt Hot Springs Geothermal Field, Utah. Adapted from Faulder (1994).

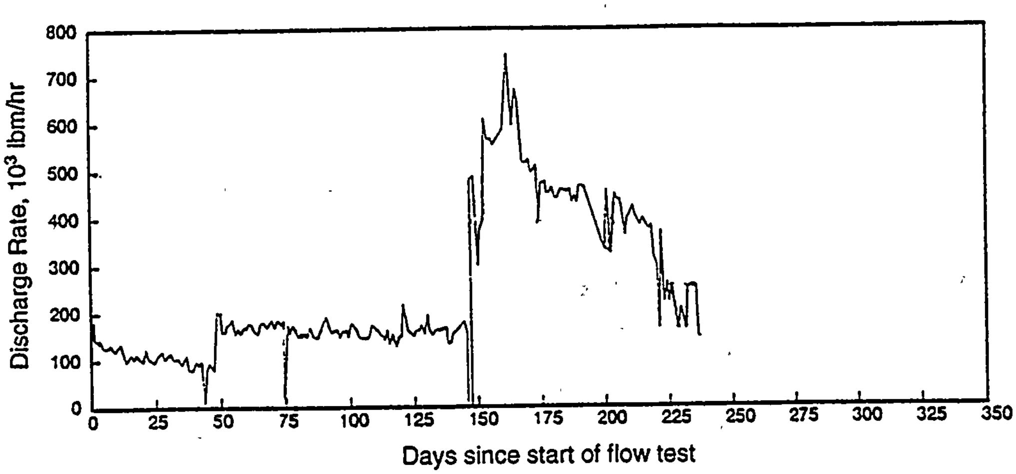

Figure 2. Flowrate history of RHSU54-3. Adapted from Faulder (1994).

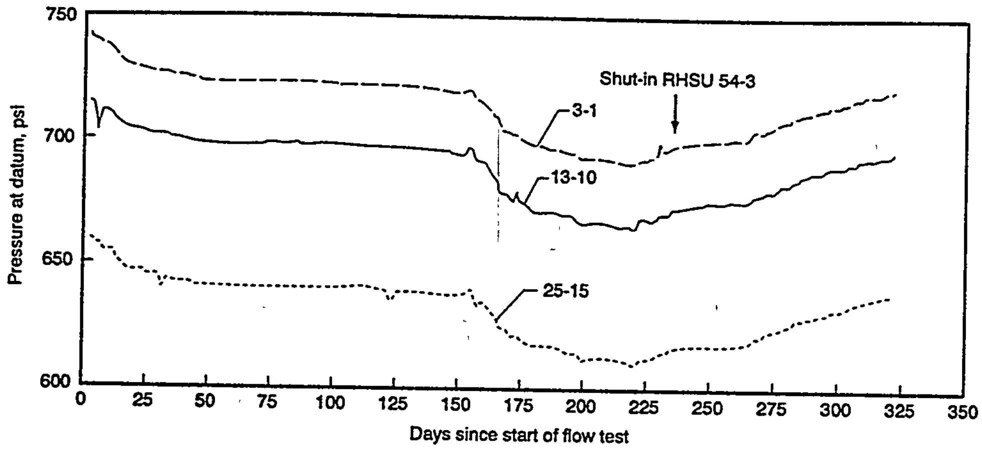

Figure 3. Observation well pressure response, Long-Term Flow Test # 1. Adapted from Faulder (1994).

geothermal power station operated by Mitsubishi Materials Corporation (MMC). The Hachimantai area also includes the Matsukawa and Kakkonda Geothermal Fields. An extensive well drilling and testing program was initiated in the Sumikawa area in 1981 with the spudding of boreholes S-1 and S-2 by MMC and the Mitsubishi Gas Chemical Corporation (MGC). The New Energy and Industrial Technology Development Organization (NEDO) became involved in the field characterization effort with the drilling of borehole N59-SN-5 in 1984–1985. During the years 1986–1990, under NEDO sponsorship, S-Cubed carried out reservoir engineering studies of the Sumikawa Geothermal Field. The field characterization program at Sumikawa was successfully concluded in 1990 with a decision to build a 50 MWe power plant. The Sumikawa geothermal power plant was commissioned in early 1995.

In 1993, S-Cubed—under a contract with the U.S. Department of Energy (DOE)/Sandia National Laboratories (Sandia)—approached MMC for release of their proprietary data from the Sumikawa Geothermal Field for use in a case study of a high-temperature, fractured, volcanic geothermal field. As a result of these negotiations, MMC gave permission to S-Cubed to use pertinent Sumikawa data obtained prior to 1990. The principal objectives of this study of the Sumikawa Geothermal Field are as follows:

- Document and evaluate the use of drilling logs, surface and downhole geophysical measurements, chemical analyses and pressure transient data for reservoir assessment purposes.

- Evaluate the feasibility of predicting the discharge characteristics of large-diameter production wells on the basis of test data from slim holes.

- Demonstrate the usefulness of a map-oriented geothermal database for interpretation of exploration data and analysis of exploration strategies and reservoir information.

To provide convenient access to the Sumikawa data base, the pertinent Sumikawa data are being incorporated into S-Cubed's Geothermal Reservoir Data Management System (GEOSYS). GEOSYS (Stevens *et al.*, 1992) is an interactive, graphical, map-oriented computer system used to store, display and analyze large volumes of geothermal reservoir engineering data. GEOSYS consists of a set of independent, integrated modules that analyze and display geographical data, subsurface cross sections, well structure, well logs, and chemical and production data. GEOSYS runs on Unix workstations using the X Window System. More information about GEOSYS is available on the World Wide Web at http://www.scubed.com:8001/products/GEOSYS.html.

Production and injection data from slim holes and large-diameter wells at the Sumikawa Geothermal Field were analyzed to determine the effect of wellbore diameter on (1) the productivity/ injectivity index, and (2) on the discharge rate (Garg and Combs, 1995). The injectivity indices for Sumikawa boreholes do not depend on borehole diameter in any systematic manner; furthermore, the productivity indices (for boreholes with liquid feeds) are more or less equal to the injectivity indices. For boreholes with liquid feed zones, discharge rates scale with diameter according to a relationship previously presented by Pritchett (1993). Pritchett's scaling rule does not appear to apply to discharge data from boreholes with two-phase feed zones; however, discharge characteristics of slim holes with two-phase feed zones can be used to infer production rates from large-diameter wells.

The reservoir fluids at Sumikawa are mainly of the Na-Cl type with a near neutral pH. Acidic fluids have been encountered only infrequently at Sumikawa. Drilling along the flanks of young volcanoes (*e.g.*, Mt. Yake at Sumikawa, see Figure 4) can be expected to result in encounters with acidic zones. The ongoing examination of geochemical data for the Sumikawa Geothermal Field should be useful in deriving a better understanding of acidic zones in high-temperature, fractured, volcanic geothermal fields.

MMC has carried out a series of pressure transient (both single well drawdown/buildup and multiple well pressure interference tests) tests at the Sumikawa Geothermal Field. These test data are invaluable for determining the permeability structure at Sumikawa. As an example, identification of the "altered andesite" formation as a high permeability reservoir is in large part based on two pressure interference tests between boreholes S-4 and KY-1 (see Figure 4 for borehole locations). An interpretation of these pressure interference tests is described in Section 5.

5. PRESSURE INTERFERENCE TESTS FOR SUMIKAWA WELLS S-4 AND KY-1

A north-south geologic section along wells S-4 and KY-1 is shown in Figures 4 and 5. The major formations in order of increasing depth are (1) surficial andesite tuffs, lavas and pyroclastics (ST formation), (2) lake sediments (LS formation), (3) Pliocene dacites and tuffs (DA formation), (4) interbedded Miocene dacitic volcanic rocks and black shales (MV or marine/volcanic complex), (5) altered and fractured andesites (AA formation) and (6) crystalline intrusive rocks (GR formation).

Slim hole KY-1 is cased and cemented to 1001 meters depth (–10 m ASL); uncemented slotted liner is present from that point to 1604 meters depth (–613 m ASL). Only two mud loss zones were encountered in the uncemented part of the hole; at –169 m ASL (MV formation) and at –571 m ASL (AA formation). Well S-4 was drilled vertically to a total depth of 1552 m ASL (–445 m ASL); the bottom of the 7-inch casing was set at 1071 meters (36 m ASL), and an open hole completion was used below this depth. The major feedpoint for well S-4 is located at –413 m ASL in the "altered andesite" formation. The horizontal distance between S-4 and KY-1 is about 1176 meters. It is highly likely that S-4 and KY-1 communicate with each other through the "altered andesites".

In the fall of 1986, well S-4 was discharged for approximately three months (September 2, 1986 to November 29, 1986); separated water from the S-4 discharge was injected into nearby relatively shallow slim hole S-2 (feedzone depth = 131 m ASL). Four observation boreholes (O-5T, S-3, KY-1 and SD-1) were equipped with capillary-tube pressure gauges. No pressure signal attributable to the discharge (or injection) of well S-4 (slim hole S-2) was seen in boreholes O-5T, S-3 and SD-1. On the other hand, a clear response associated with the discharge of S-4 was recorded in KY-1; the pressure in KY-1 started to decline within a couple of hours after the initiation of discharge from well S-4 (Figure 6). Because of the low vertical permeability of the black shales, it is unlikely that injection into S-2 is in any way responsible for the observed pressure signal in KY-1.

Starting at 19:00 hours on May 16, 1989, cold river water was intermittently injected into well S-4 until 14:00 hours on May 19, 1989. Borehole KY-1 was equipped with a capillary-tube type pressure gauge during the latter injection test. KY-1 responded within a couple of hours to each change in injection rate (Figure 7).

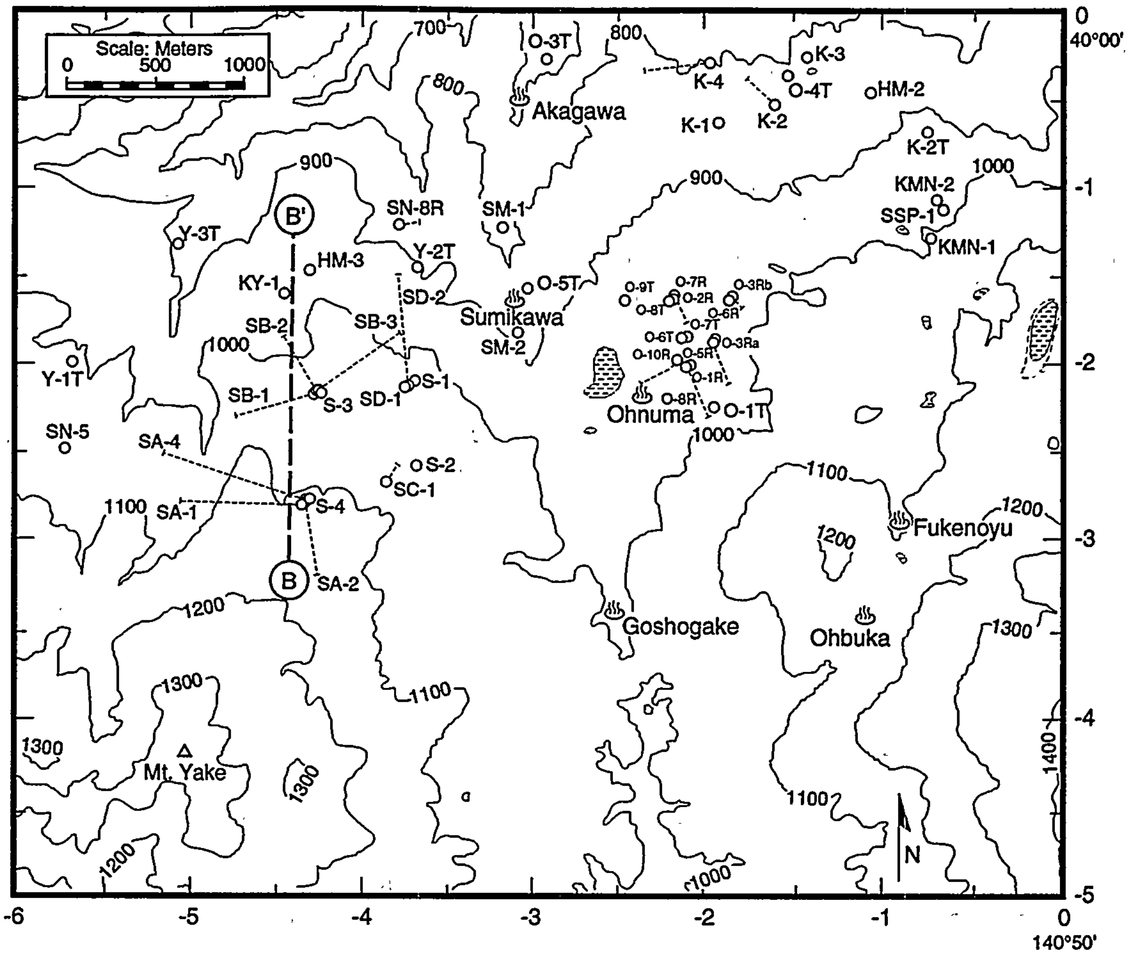

Figure 4. The Sumikawa/Ohnuma area, showing locations of boreholes and cross-section B–B′. The origin of the local co-ordinate system is 40°N latitude and 140°50′ E longitude.

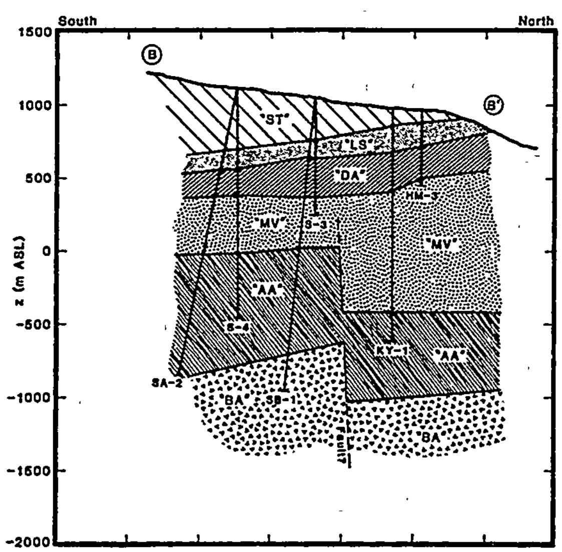

Figure 5. North-south B–B′ (total length = 3.5 km) geological cross-section through the Sumikawa area.

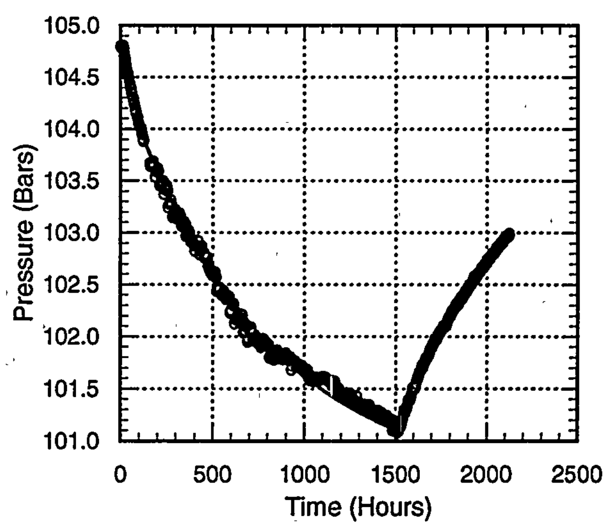

Figure 6. Comparison between measured (o) and computed (–) pressures in KY-1 during the 1986 test. All times are in hours since 00:00 hours LT on September 2, 1986.

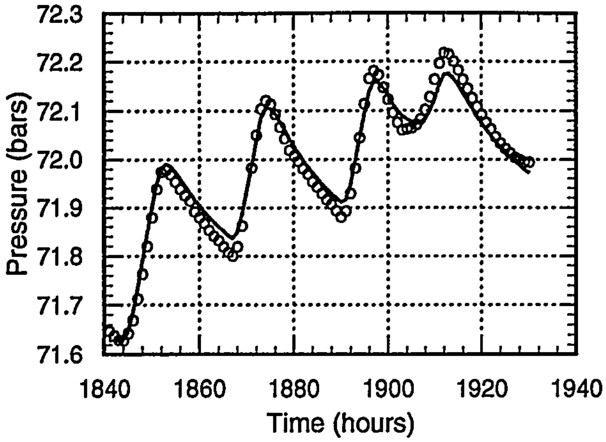

Figure 7. Comparison between measured (o) and computed (–) pressures in N60-KY-1 during the 1989 test. All times are in hours since 00:00 hours LT on March 1, 1989.

Garg and Owusu (1996) used the line source solution to model both the 1986 and 1989 tests. Both S-4 and KY-1 are assumed to fully penetrate an infinite reservoir. The 1989 test data can be fitted adequately without invoking the existence of any boundaries. The unknown reservoir parameters kh and φch were varied to obtain the best possible match between the measured and computed pressures. The final model parameters are:

$$kh = 15.6\ (\pm 0.8)\ \text{darcy-m}$$
$$\varphi ch = 8.2\ (\pm 0.3) \times 10^{-9}\ \text{m/Pa}$$

During the 1986 production test, a small two-phase region was created in the immediate vicinity of well S-4. The observation borehole KY-1, however, remained in the single-phase (liquid) part of the reservoir. Garg and Pritchett (1988) discuss methods for analyzing pressure interference data from a hot water geothermal reservoir which evolves into a two-phase system as a result of fluid production. According to Garg and Pritchett (1988), single-phase solutions may be applied for interference test interpretation provided that the discharge rate history used in the analysis is suitably modified to reflect the influence of the two-phase zone. The "effective discharge rate" for use in analysis is only a fraction of the actual (or measured) discharge rate. Except for the early part of the flow test, the "effective discharge rate" history for the 1986 test cannot be determined from the available data. To assess the impact of uncertainties in the "effective discharge rate" history: Garg and Owusu (1996) considered a series of five plausible "effective discharge rate" histories. Analyses by Garg and Owusu (1996) indicate that the aquifer penetrated by S-4 and KY-1 is bound by impermeable boundaries to the east, the west and the north; to the south, a constant pressure boundary terminates the aquifer.

The formation parameters inferred for the various cases are listed in Table 1. The formation permeability-thickness and storage parameters do not differ significantly (an exception is kh value for case 4) from case-to-case. Unfortunately, the inferred distances to different boundaries vary significantly between the different cases. While the formation permeability thickness and storage are well constrained from both the 1986 and 1989 tests, the distances to the various boundaries (or even the presence of boundaries) are much less certain.

A structural interpretation for the "altered andesite" reservoir at Sumikawa is shown in Figure 8. Above the "altered andesite" layer lies a thick formation consisting of alternating marine sediments and dacite volcanic flows; because of the presence of shales, it is likely that the average vertical permeability is rather low. Below the andesite layer, a crystalline granitic layer ("granodiorite" formation) is to be found. Since no pressure interference has been observed between S-4, and wells completed in the "granodiorite" layer, it is likely that the "granodiorite" formation has poor vertical permeability.

The thickness of the andesite layer sandwiched between the "marine/volcanic complex" and the "granodiorite" formations is about 500 meters. The "granodiorite" formation appears to rise abruptly ~ 0.7 km west of well S-4; this geologic discontinuity probably constitutes the western boundary of the permeable channel. The east-west extent of the permeable channel is about 4 km.

The presence of an impermeable boundary to the north of KY-1 is implied by the results of the analyses shown in Table 1. The distance to this northern boundary is of the order of 1 km north of slim hole KY-1. The northern boundary is probably associated with the dacitic dike outcropping along the Kumazawa river.

Table 1. Formation parameters inferred using different "effective discharge rate" histories for well S-4 (1986 test).

	Case 1	Case 2	Case 3	Case 4	Case 5
Permeability-thickness *kh* (darcy-m)	13.5	13.5	13.5	9.7	13.8
φch storage (m/Pa)	8.1×10^{-9}	8.7×10^{-9}	8.5×10^{-9}	8.2×10^{-9}	8.0×10^{-9}
Distance to western impermeable boundary (km west of KY-1)	1.77	2.08	4.31	10.0	1.88
Distance to eastern impermeable boundary (km east of KY-1)	2.00	2.32	1.87	1.61	2.06
Distance to northern impermeable boundary (km north of KY-1)	1.19	1.55	0.95	1.07	1.61
Distance to southern constant pressure boundary (km south of KY-1)	9.43	6.87	10.1	No boundary	10.5

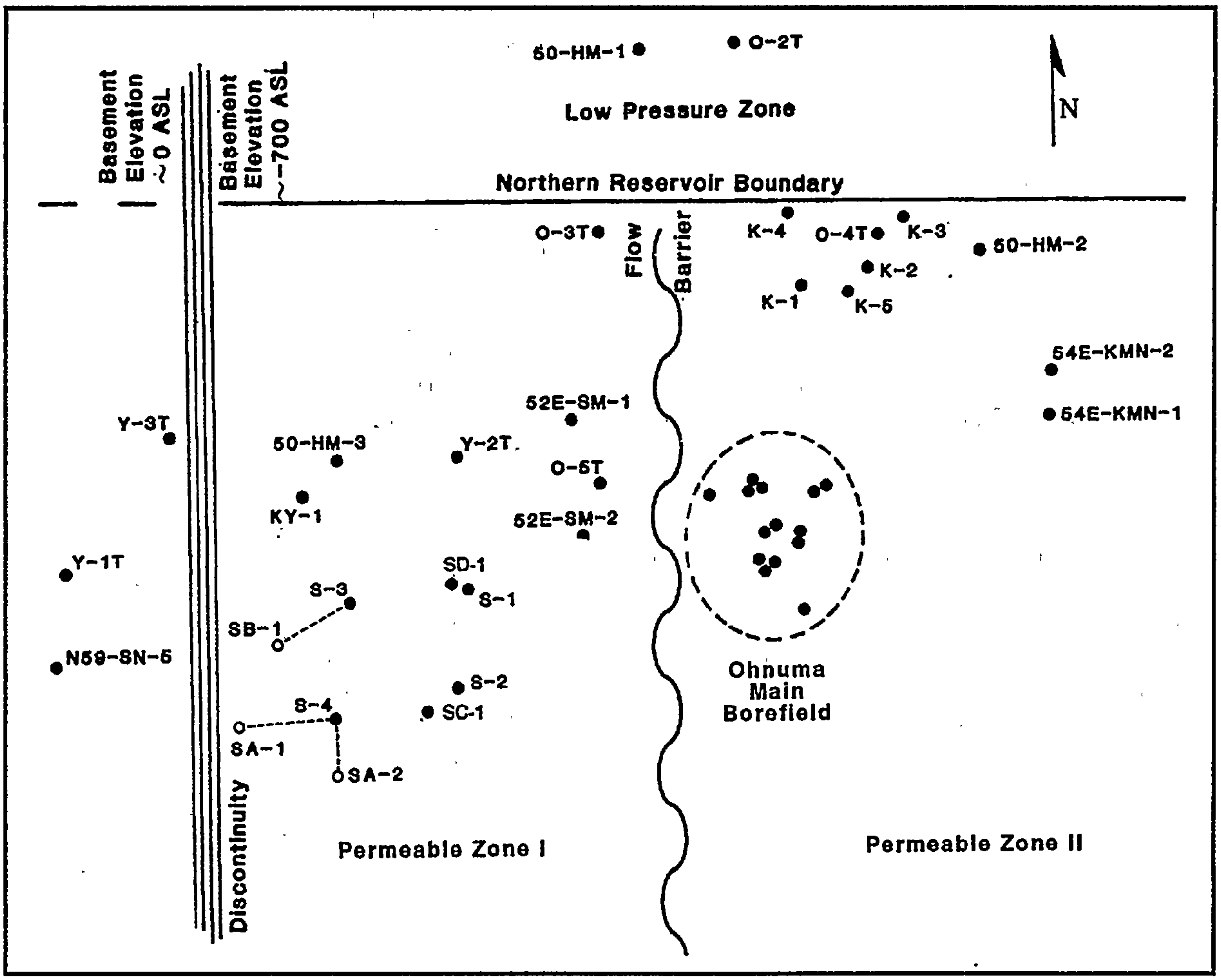

Figure 8. Estimated locations according to Garg and Owusu (1996) of deep permeable channels in Sumikawa/Ohnuma area.

Analyses of 1986 test data suggest the presence of a constant-pressure boundary to the south of well S-4. It is, however, unlikely that this boundary is located as far south (*i.e.,* 6 to 10 km south of well S-4) as that implied by the results given in Table 1. The explanation for this peculiar result is intrinsic in the linear character of the flow model. More specifically, it was assumed that the reservoir contains single-phase liquid. In reality, two-phase conditions prevail under undisturbed conditions a short distance (~ 1 km) south of well S-4. This suggests that the actual location of the constant pressure southern boundary is quite close to well S-4.

6. CONCLUSIONS

The determination of key reservoir parameters requires a spectrum of geological, geophysical, drilling, geochemical, geohydrological and well testing data. For purposes of planning cost-effective field measurements programs, it is useful to review specific case histories. Although the scope, objectives and details of the three case studies described herein are different, the availability of these case studies should be useful in designing reservoir assessment programs for other geothermal reservoirs. Examples from both the Roosevelt Hot Springs and Sumikawa Geothermal Fields illustrate the use of pressure interference tests for determining the volume and the permeability structure of a geothermal field.

7. ACKNOWLEDGMENT

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FOCUS OF THE HOT DRY ROCK PROGRAM AFTER RESTRUCTURING

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ABSTRACT

Since the early 1970's, the technology for extracting useful amounts of geothermal energy from hot dry rock (HDR) has developed from the conceptual stage to a demonstration of the technical feasibility of routine production of high-grade geothermal energy from HDR. On the basis of extremely promising flow-test results at the Fenton Hill, NM HDR test facility, the USDOE issued a solicitation in late 1994 seeking industrial partners to construct and operate a plant to produce and market energy derived from an HDR resource. Although bids were received and a DOE-appointed technical review committee recommended the project go forward, the solicitation was withdrawn in October 1995. At the same time, the DOE directed the Fenton Hill facility be completely decommissioned and announced a restructuring of the US HDR program.

In December 1995 a geothermal industry panel commissioned by the Geothermal Division of the DOE reviewed the HDR program. Although the industry group made a number of general recommendations, it deferred specific program actions to future deliberations. The DOE is now considering convening two groups to address the future of HDR. A panel working under the auspices of the National Academy of Sciences (NAS) would conduct an in-depth review of HDR and outline a visionary path to the eventual implementation of HDR technology. A second group, representing geothermal stakeholders, would provide advice and guidance to the DOE on the implementation of specific HDR projects to assure that HDR technology, while moving toward the vision developed by the NAS panel, at the same time contributed to achieving the near-term goals of the conventional geothermal industry.

A multi-faceted HDR program will be required if both the expressed national goal of worldwide leadership in the development, application, and export of sustainable, environmentally attractive, and economically competitive energy systems, and the more expedient goals of the geothermal industry are to be achieved. It is suggested that a restructured HDR program should have components that involve industry-coupled projects to apply HDR-developed technologies to the improvement of hydrothermal productivity, a search for niche opportunities for immediate HDR deployment, and an increased level of participation in foreign HDR projects.

INTRODUCTION

In 1970, researchers from the Los Alamos National Laboratory filed for a US Patent on a process employing hydraulic fracturing to extract heat from a dry geothermal reservoir (Potter et al 1974) The concepts outlined in that patent application formed the basis for the United States HDR Program formally initiated in 1974, and for subsequent work on the extraction of energy from HDR in England, Japan, the European Community, and a number of other countries around the world.

Since its inception, HDR work in this country has been sponsored by the USDOE and its predecessor agencies. Domestic HDR research and development work has been conducted primarily under the direction of the Los Alamos National Laboratory, with most field experiments carried out at the HDR test site at Fenton Hill in the Jemez Mountains of northern New Mexico. Under an International Energy Agreement, Japan and Germany participated in the development of the Fenton Hill HDR facility from 1980 to 1986, contributing both financing and technical personnel to the HDR project.

BACKGROUND

After a few tentative heat flow and hydraulic fracturing experiments, the development of the world's first HDR system began at Fenton Hill in 1974. A small reservoir was created by hydraulic fracturing in granitic rock at a depth of about 9,850 ft and a temperature of 365°F. This reservoir, together with the two wellbores penetrating it, formed the Phase I HDR system. The Phase I system was evaluated in a series of flow experiments between 1978-1980 (Dash et al 1981). These tests demonstrated the scientific feasibility of extracting heat from engineered geothermal reservoirs.

In 1980, work was begun on a much larger, deeper, and hotter, Phase II HDR reservoir. It was not until 1986, that the Phase II system was completed and initially flow tested (Dash 1989). Since that time, the Phase II reservoir has been subjected to extensive evaluation under both static and flow conditions. It is undoubtedly the most-characterized and best-understood, fully-engineered geothermal reservoir in the world. The Phase II reservoir is centered at a depth of about 11,400 ft in rock at a temperature of 420-460°F. Seismic, hydraulic, tracer, and geometric measurements indicate that the Phase II reservoir has a flow-connected volume of 200-800 million cubic feet (on the order of 50 to 200 times the volume of the Phase I reservoir).

Between 1987 and 1991, a permanent surface plant was constructed at Fenton Hill and mated to the Phase II wellbores (Ponden 1991). The complete Phase II system today consists of a highly automated, closed loop in which the same water can be continuously recirculated. Thermal energy is absorbed from the hot rock during each pass through the reservoir and then rejected via an air-cooled heat exchanger at the surface. A high pressure injection pump provides the sole motive force for the operation.

A series of flow tests of the Phase II HDR system was conducted between 1992 and 1995 (Brown 1996, Brown 1993). Under the steady-state conditions maintained during most of the testing, the injection pressure was typically held at about 3,960 psi, the highest level that could be maintained without causing an increase in the reservoir volume. This pressure was high enough so that the injected water could be returned to the surface at backpressures as high 2,200 psi without large reductions in the rate of production. A few of the tests involved operation under cyclic conditions during which the injection and production conditions were intentionally varied to demonstrate that the output of an HDR reservoir could rapidly adjusted to meet changing demands for power.

Both the steady-state and cyclic production testing programs were highly successful. Approximately 100 billion BTU's of thermal energy was extracted from the Phase II reservoir during a total of about 11 months of steady-state circulation over a span of 4 years. Although small changes in the temperature distribution were noted in the open-hole production interval at the bottom of the production wellbore, no decline was observed in the temperature of the fluid produced at the surface. Cyclic testing demonstrated that energy production could be increased by about 60% from a baseline level within a period of only 2-3 minutes, held at that elevated level for 4 hours, and then be rapidly reduced back to the baseline output for the remainder of a 24-hour repetitive production cycle. Obviously, many other cyclic production schedules might be employed in the operation of an HDR facility to obtain the maximum economic return, but limited project resources did not permit further evaluation of this energy production strategy.

The flow testing series provided solid evidence that water loss need not be a serious problem in the operation of HDR reservoirs. Water consumption declined directly as a function of the time the system was held at operating pressure, reaching a level of only 7% of the injected volume on a trend line that indicated an eventual decline to 2-3% or even less. Dissolved solids remained at low levels and the circulating fluid picked up essentially no suspended solids. Because the HDR plant was fully-automated, all the flow testing was conducted with a minimum of manpower. The site was typically run unmanned at night.

With encouraging flow test results in hand, the DOE issued a solicitation in December 1994 seeking an industrial partner to develop a facility to produce and market energy from an HDR resource. Bids were received from several organizations. In late June 1995, a technical review committee appointed by the DOE selected a winning bidder and recommended that the project go forward. Several months later, in October 1995, the DOE canceled the solicitation, stating that it would continue to pursue research and development on HDR but not commercialization at this time. Concurrently, a directive was issued to decommission the Fenton Hill site. Restructuring of the HDR Program is now in progress.

A RESTRUCTURED HDR PROGRAM

The announcement that the HDR Program would be restructured was first made by Karl Rabago, then DOE Deputy Assistant Secretary for Utility Technologies, in a speech at the opening of the Geothermal Resources Council meeting in Reno, Nevada on October 8, 1995. While that speech made the intent to restructure the HDR Program clear, it was vague on the goals and direction of the restructuring. A subsequent memo from the DOE Geothermal Division to the Department's Albuquerque Operations Office offered a little more insight into the future of the HDR program, stating:

> "Rather than pursue a commercialization goal, the Department will refocus the Geothermal Hot Dry Rock Program to work with industry and other interested parties to resolve the key technical issues. Los Alamos National Laboratory (LANL) is expected to play a continuing role in technology development."

The above statement makes two major assertions: 1) The HDR program will be refocused to work more closely with industry and other interested parties and, 2) Los Alamos National Laboratory will continue to play a role in HDR development. The "key technical issues" referred to in the memo have not yet been explicitly identified. Apparently, one of the first tasks under the restructured HDR program will be for the DOE Geothermal Division, industry, and other interested parties to delineate these key technical issues and formulate a plan to address them.

Initial Steps in Restructuring the HDR Program: In December 1995, the Geothermal Energy Association (GEA), at the direction of the DOE Geothermal Division, convened a geothermal industry panel to make recommendations on the future course of HDR research and development. The panel first engaged experts from the US geothermal industry, the national laboratories, other government agencies and foreign HDR programs in discussions of the status of HDR technology. It then met in executive session to develop a set of "industry" recommendations on the future course of HDR in the US These recommendations were immediately presented in preliminary form to Allan Hoffman, DOE Acting Deputy Assistant Secretary for the Office of Utility Technologies.

In a report that so far has appeared only in "draft" form, but the essence of which was printed in a recent Geothermal Resources Council Bulletin, that group affirmed the importance of HDR to the future of the geothermal industry, suggested that HDR technology should be integrated into the conventional geothermal industry, and proposed that the acronym "HDR" be replaced with a new term that would encompass all geothermal resources requiring artificial measures beyond current technology to achieve commercial heat extraction. They did not, however, offer any suggestions as to what the new term should be. The group also made the following specific recommendations:

- Unify management of all geothermal R&D programs and include HDR elements within the unified program.
- Convene a panel to formulate short- and long term geothermal R&D goals, including the long-term commercialization of HDR.
- Establish a peer-review committee to evaluate the current status of the US HDR Program, publish its findings, and implement technology transfer to move HDR technology into the geothermal mainstream.
- Mothball the Fenton Hill site.
- Coordinate US geothermal R&D efforts with HDR programs in other countries.

Impending Restructuring Activities: The GEA panel offered some broad directions but few specifics in regard to the future course of HDR research and development. While the panel endorsed a much closer tie of HDR work to the goals of the hydrothermal industry, it gave no indications of exactly how to accomplish this. With this background, the DOE Geothermal Division now appears to be considering a dual approach to restructuring the HDR Program that will move toward the vision of the United States as a "worldwide leader in the development, application, and export of sustainable, environmentally attractive, and economically competitive energy systems" as expressed in the DOE's strategic plan of April 1994, while at the same time addressing the more immediate concerns of the conventional geothermal industry. Two complementary groups are being considered to help set the course of future HDR work. One panel, under the auspices of the National Academy of Sciences, would review the status of HDR technology in depth and provide a visionary outline of a path to eventual HDR implementation. The second group, more geothermal industry oriented, would address HDR in the context of its relationship to the conventional geothermal industry.

A National Academy of Sciences Review of HDR: A review of HDR by a National Academy of Sciences (NAS) panel may the single most important factor in establishing a reinvigorated HDR Program. An NAS review would certainly be widely recognized as authoritative, independent, and unbiased. Hopefully, the result of an NAS review of HDR would be a realistic assessment of the current state of HDR technology and a visionary plan to make HDR and the full range of geothermal resources, a key component of the clean energy supply the world will need in the 21st century.

An NAS review could bring national stature to geothermal energy by focusing the attention of DOE upper management, other government agencies, wide segments of the energy and environmental communities, and the public at large, on HDR and geothermal energy in general. In this way, the review could help provide wider appreciation of the current contributions of geothermal energy to the nation's clean energy goals. Furthermore, recognition of HDR as a ubiquitous resource of national importance with a proven potential for deployment, would foster the increased public support for geothermal energy that will be essential if federal financial assistance to geothermal development is to be maintained in these times of shrinking national budgets.

A Geothermal Industry Review Board for HDR: The function of the geothermal industry review board will be to work closely with the DOE to define the specifics of the HDR Program. The board will assure that HDR is integrated into the mainstream of the geothermal research program, develop or endorse projects that apply HDR technology to the improvement of hydrothermal productivity, and advise the DOE on the direction of HDR work, especially in the near-term. Hopefully the membership of the board will be drawn from the full spectrum of geothermal stakeholding organizations. Ideally, the geothermal industry HDR review board will be an ongoing entity that will first provide input to the NAS panel and then work with the DOE Geothermal Division to implement the NAS vision for HDR in a manner compatible with the aims of the geothermal industry. While the industry board may be charged with developing and prioritizing HDR projects, the DOE, acting as the agent of the US taxpayer, must make the final programmatic decisions in the face of budgetary limitations and broad departmental renewable energy goals.

OPTIONS FOR A RESTRUCTURED HDR PROGRAM

The most important restructuring challenge is to formulate an HDR program that more closely allies the goals of HDR with the needs of the private geothermal industry, while at the same time holding to the central promise of HDR technology. That promise - transforming geothermal energy from its current perceived status as a localized resource with limited potential to that of a widely recognized world-class energy resource that will be one of the important contributors to providing the 21st century world with clean energy available virtually everywhere - must be met if the geothermal industry is to prosper and grow in the long run.

In order to reconcile the national HDR goals with the immediate interests of the conventional geothermal industry, a multi-faceted HDR effort will be required that: 1) applies HDR technology to the solution of near-term hydrothermal problems, 2) capitalizes on special opportunities to develop HDR technology in projects complimentary to hydrothermal technology, and 3) promotes international cooperation both to maximize the effectiveness of HDR research and development work underway in a number of countries around the world, and to assure US leadership in HDR development and marketing in countries that are just beginning to explore the potential of HDR as an indigenous energy resource. Each of these potential facets of a restructured HDR Program is discussed in more detail below.

Industry-Coupled HDR Technology Applications: Cooperative Projects which apply HDR technology and expertise to the solution of hydrothermal problems and increase the productivity of hydrothermal or quasi-hydrothermal (hot wet rock) reservoirs have the potential to provide almost immediate benefits to the geothermal industry. During more than 20 years of work on HDR, unique capabilities in drilling, hydraulic fracturing, fracture location and characterization, reservoir engineering, logging tool design and application, fluid injection, and reservoir modeling have been developed. In some instances, especially in regard to drilling and logging-tool development, significant technology transfer has occurred via the service companies that have at times been involved in the HDR project. However, in other areas such as reservoir engineering, fracture mapping and characterization, reservoir modeling, and fluid injection, there has as yet been little effective technology transfer to the hydrothermal industry

One aspect of a restructured HDR program might therefore be the development of industry-coupled projects to apply HDR reservoir mapping and fracture location techniques to the identification and location of fractures in hydrothermal fields. The information thereby generated could reduce the incidence of drilling "dry holes" and thereby markedly lessen field development costs. A second joint project might entail applying HDR expertise in injection and stimulation to make existing dry holes at hydrothermal sites productive and/or to develop engineered reinjection plans that would ensure that reinjected fluid (or supplementary injected fluid such as that to be delivered via the Geysers/Clearlake pipeline) is most effectively utilized to enhance energy production. Yet a third application of HDR technology might involve the application of HDR reservoir models to hydrothermal situations, particularly those concerned with reinjection or pressure maintenance and fluid production problems, in order to better understand how to limit declines in reservoir productivity.

The project areas described above are presented from an HDR perspective. Undoubtedly, industry engineers and scientists could modify them to most effectively meet the current hydrothermal research and development needs. Obviously, any of these projects are worth pursuing only if they have the solid support of one or more industrial organizations and can potentially contribute to improving the technical competence and competitive status of the US geothermal industry.

HDR Niche Development Projects: Cooperative projects which bring HDR technology to bear on hydrothermal problems will result in immediate useful applications of HDR technology, but this approach will not move geothermal energy toward the national stature needed to assure continued support from the federal government and the taxpaying public. In order to accomplish the latter goal, we must continue to pursue the development of HDR processes that can be implemented in those non-hydrothermal regions that underlay the vast majority of the US.

With the closure of Fenton Hill, a highly visible effort to advance heat mining technology in its widest sense - as a means of tapping the ubiquitous HDR resource - becomes more important than ever. This effort must include a continued search for a new site that can provide opportunities for field work in an HDR environment.

The knowledge base accumulated during work at Fenton Hill can be applied to develop a new HDR site that may have practical as well as research and development applications. In view of the depressed price for electric power generation in the US, any such domestic HDR site must fit into either an especially attractive electricity niche (due to advantageous resource characteristics or local economic factors that lead to high electricity prices) or be located where these is an opportunity for a direct use application of the HDR energy. Direct use opportunities should be carefully evaluated and developed, as appropriate, in cooperation with private industry as well as state and local government entities that may have an interest in energy or economic development. Given the current bleak outlook for the electricity market in those parts of the US where hydrothermal resources are found, niche applications of HDR may at present represent one of the few opportunities for additional domestic geothermal development. Finding a niche for HDR in today's highly competitive energy marketplace is a challenging task but, for all of the above reasons, it must be pursued if HDR and, indeed, the geothermal industry itself, is to have any chance of being a significant factor in the US energy picture of the future.

Increased International HDR Activities: HDR research and development has had an international flavor almost since its inception. The high point of international cooperation was reached during the period from 1980 to 1986 when Japan and Germany participated both financially and technically in the work to develop the large HDR reservoir at Fenton Hill. The international contacts made during those years have led to continued international cooperation in the form of periodic personnel exchanges and international meetings. For example, the 3rd International HDR Forum to be held in May 1996, at Santa Fe, NM, will bring together dozens of HDR workers from both Europe, Japan, and elsewhere to exchange information with their US colleagues and explore ways to work more closely together.

At present, US leadership in HDR technology is recognized worldwide, but with the closure of the only domestic HDR field site, that leadership role is likely to be assumed by Japan or the European Community. The US is thus likely to move from the position of serving as a primary source of new technical information and ideas for the international HDR community to one of heavy reliance on foreign HDR work to supplement a downsized HDR development program. In this light, increased international cooperation becomes an imperative for the domestic HDR program.

Efforts to increase international cooperation in geothermal energy via a new International Energy Agreement (IEA) have been underway for some time. The Japanese have taken the lead in the area of HDR and are proposing their New Energy and Industrial Development Organization (NEDO) be the operating agent for all HDR work conducted under the auspices of the IEA. Four project areas have been suggested for joint work. These include HDR economics, applications of hydrothermal technologies to HDR development, coordination of data acquisition and processing developments, and joint development of reservoir assessment technologies.

Although the US is in the process of passing the mantle of leadership in HDR to nations that are more aggressively pursuing the technology, a window of opportunity remains to work with nations that now have fledgling HDR efforts. At present, engineers and scientists from these countries typically turn to US HDR experts for background information and initial guidance. As these nations develop field programs, the drilling, wellbore services, and other industry-based work may accrue to US companies if a relationship with the US HDR research community has been established. In fact, providing technical support today for these blossoming HDR projects may be the only means of assuring US participation in the international HDR energy market that could develop by the early years of the next century.

SUMMARY

Work at the Fenton Hill test site in northern New Mexico has taken HDR from the purely conceptual stage through a demonstration of the technical viability of exploiting this ubiquitous geothermal resource. The USDOE is now in the process of closing Fenton Hill and restructuring the HDR program to more closely align it with the immediate goals of the US geothermal industry. The industry, through the GEA, recently affirmed the importance of HDR. At the same time, the GEA made number of general restructuring recommendations, but deferred the formulation of specific actions to future deliberations. The DOE is now considering a dual approach to restructuring the HDR program, under which a National Academy of Sciences panel would review HDR technology and develop a visionary path to HDR implementation, while a geothermal industry board would provide more immediate guidance to the DOE in regard to the implementation of specific HDR projects.

It is suggested that a restructured HDR program should have three essential elements: 1) Industry coupled projects that apply HDR technology to the solution of near-term hydrothermal problems, 2) projects that maintain the validity of geothermal energy as a national resource by moving toward development of the water-deficient geothermal resources found throughout the nation, and 3) increased participation in international HDR activities. Taken together, these elements must meet the domestic geothermal industry needs of today while assuring that the US will have a significant role in the HDR world of tomorrow.

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Concurrent Session 3:
Energy Conversion

Chairperson:

Ken Nichols
Barber Nichols, Inc.

Overview of the Energy Conversion Program

Raymond LaSala
Program Manager, Office of Geothermal Technologies

I wish we had time to cover all of the DOE-sponsored energy conversion and materials projects in detail, but we don't. Instead, let me take a few minutes to bring you up to date on several items that will not be discussed elsewhere in this session.

First, we still have a cooperative Agreement with Exergy, Inc. to demonstrate a 12.4 MW Kalina cycle power plant at Steamboat, Nevada; but the project remains stalled by the lack of a power purchase agreement, a problem that I am sure many of you can appreciate. I hope we can get this project back on track by the time of the next annual meeting of the Geothermal Resources Council in late September.

A second project of ours is facing the same difficulty: our Lee Hot Spring (Nevada) 5 MW project which was awarded to Earth Power Resources.

Luckily, sale of power is not an issue in the "Low-Temperature Flash" demonstration being conducted by Oxbow Geothermal and Barber-Nichols at Dixie Valley. Oxbow is presently conducting tests to determine the level of scale formation associated with flashing of brine to sub-atmospheric pressures. At the same time, Dames and Moore is preparing an environmental assessment for the project. We should have the results of this study in the next few weeks, after which Barber-Nichols can begin design of the sub-atmospheric flash plant in earnest.

Finally, I would like to remind all of you that the Geothermal Power Organization will meet later this afternoon, immediately following this session. This should be an exciting meeting because at long last we have an organizational structure and funding for cost-shared collaborative projects. I would like to have several such projects established by the end of September and therefore encourage you to come with ideas. See you there.

With that, I would like to turn the program back over to Ken Nichols so that we can get on with the technical presentations. Thank you.

Corrosion and Scale Resistant Materials R&D

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ABSTRACT

The Geothermal Materials Program is structured to help meet the U. S. Department of Energy (DOE) performance goals for geothermal energy and reflects the R&D priorities established by the industry. Corrosion, scale deposition, well completion, and lost circulation are all high priority topics, and materials solutions to these problems must become available if the geothermal industry is to remain competitive in foreign and domestic markets. Excellent progress is being made on the first three topics, but work on advanced cementitious muds for lost-circulation control was suspended in FY 1994 due to budget constraints. Fiscal year 1995 and 1996 accomplishments in the development of lightweight CO_2-resistant cements for well completions; corrosion resistant, thermally conductive polymer matrix composites for heat exchange applications; and metallic, polymer and ceramic-based corrosion protective coatings are given in this paper. The results from laboratory and field evaluations, performed in conjunction with the geothermal industry, are given.

INTRODUCTION

If the U. S. geothermal industry is to remain competitive in foreign and domestic energy markets, significant technological improvements must be made. These needs were reflected in a keynote address given at the 1995 Annual Meeting of the Geothermal Resources Council by Mr. Karl Rábago, then Deputy Assistant Secretary for Utilities Technology, U. S. DOE. In his address, Mr. Rábago presented a list of five DOE performance goals for geothermal energy. One was to reduce drilling costs by 30% by the year 2005 and another was to improve energy conversion efficiency 10 to 20% by the year 2000.[1] The attainment of these goals is highly dependent upon the successful development of low cost corrosion and scale-resistant materials of construction.

The importance of materials R&D to the geothermal industry was also detailed in their recent review of major R&D topics in the DOE/Geothermal Division budget.[2] The industrial panel which consisted of representatives of geothermal developers, utilities and their consultants and contractors assigned a very high priority to corrosion and scaling control. Well completion and lost-circulation control R&D also received high priorities but at levels below corrosion and scaling. These priorities have been acknowledged by DOE and they are being addressed in the Geothermal Materials Program that is conducted at Brookhaven National Laboratory (BNL). The work consists of laboratory scale and field testing efforts, the latter performed as cost-shared activities with industry and other national laboratories.

In FY 1995, the Geothermal Materials Program consisted of four activities which are all continuing in FY 1996. These are titled 1) advanced high temperature CO_2-resistant lightweight cements, 2) thermally conductive composites, 3) corrosion mitigation at The Geysers, and 4) advanced coating materials evaluations. Descriptions and a summary of the results from each of these activities are given below.

RESULTS

1. Advanced CO_2-Resistant, Lightweight Cements

Improvements in the durability of lightweight well completion materials are needed. One problem that can severely limit well life, and has increased costs and environmental concerns, is cement deterioration due to alkali metal catalyzed reactions between CO_2-containing brines and the calcium silicate hydrate (CSH) compounds and calcium hydroxide present in conventional well cements. In the former, reactions between Na and K in the brines and CSH phases lead to the formation of substituted CSH compounds such as pectolite and reyerite, both of which are susceptible to carbonation. Leaching of the resulting $CaCO_3$ and $Ca(HCO_3)_2$ leads to rapid reductions in strength, increased permeability, and corrosion on the outside surfaces of the well casing. Cement failures attributed to CO_2 are occurring in less than 5 yr, and in one case, resulted in a collapsed well casing within 90 days. Solving these materials problems which could seriously constrain the development of the world's geothermal resources, is the goal of this activity. Design criteria for the cements are as follows:

- Slurry density, approximately 1.3 g/cc.
- Pumpability, 4 hr at 100°C.
- Carbonation rate, <5% after 1 yr in brine at 300°C containing 500 ppm CO_2.
- Compressive strength, >5 MPa at 24 hr age.
- Bond strength to steel, >0.07 MPa.
- Water permeability, <0.1 m Darcy.

Successful attainment of these objectives will result in:

- Decreased costs for well completions due to reductions in lost-circulation control episodes.
- Increased well life to >20 yr.
- Reduced environmental concerns regarding blow-outs.
- Permit development of higher temperature, higher CO_2 content brines.

Approach

The activity 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 I consists of fundamental work to synthesize non-portland cement-based materials and to elucidate the interactions that occur between them and a number of lightweight inorganic and organic 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 CO_2-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.

Status

Cost-shared R&D between BNL, Halliburton Services and Unocal was continued. The results confirmed that materials that yield a cementing matrix produced by acid-base reactions between calcium aluminate cements and phosphate-containing compounds can be mixed with lightweight fillers to produce pumpable slurries with densities as low as ~1.1 g/cc.[3,4] Upon curing for 20 hr in hydrothermal environments up to 300°C, high strength (>58 MPa), durable and CO_2- resistant cement pastes are produced. Measurements of the $CaCO_3$ concentrations after autoclave exposure to a 0.05M Na_2CO_3 solution at 250°C for 120 days indicated values generally of <0.4 wt%. A conventional portland cement-based well completion material will form approximately 10 wt % $CaCO_3$ after only 7 days exposure to the same environment. Upon laboratory exposure to extremely harsh conditions (>1.5% CO_2, 300°C), slight carbonation-induced decomposition of some calcium phosphate cements was noted. It was also determined that the rate of carbonation obtained upon exposure to hot water containing CO_2 gas is essentially the same as that in Na_2CO_3- laden hot water. Experimentally, it is easier and safer to use the latter.

The incorporation of inorganic and organic microsphere fillers into the calcium phosphate cement matrix (CPC) produces a lightweight, moderate strength and highly durable cement.

Aluminosilicate-based hollow microspheres, with a density of 0.67 g/cc and a particle size of 75 to 200 μm, produced a low slurry density of approximately 1.3 g/cc and a compressive strength greater than 6.89 MPa. The slurry did not segregate after storage for 24 hr at 25°C due to chemical interactions between the microspheres and the cementing matrix formulation.

Although the calcium phosphate cements are extremely resistant to carbonation at CO_2 concentrations up to those present in geothermal fluids currently of interest, care must be taken to insure that reactions with filler materials are not induced. For example, data from well tests performed at a depth of 2440 meters on lightweight cements containing glass and ceramic microspheres indicated that both of these inorganic-based microspheres reacted chemically with the cement hydrates. These reactions resulted in the formation of numerous microcracks and subsequent strength loss. The fluid temperature and pressure for these tests were 257°C and 16.3 MPa, respectively. BNL laboratory data confirmed these downhole results. In the BNL studies, lightweight calcium phosphate cements containing mullite microspheres exhibited 70% reductions in strength after 6 mo autoclave exposure to a 0.05 M Na_2CO_3 solution at 250°C. The rate of strength reduction can be reduced by changing the surface to volume ratio of the microspheres.

Chemically inert organic-type microspheres were found to be promising fillers for use with calcium phosphate cements to produce lightweight, CO_2-resistant cements. As an example, slurries containing hollow acrylonitrile microspheres had a density of 1 g/cc and produced a cured cement which upon autoclave exposure at 250°C for 6 mo. retained 73% of its initial strength. The effects of high pressure on the microspheres is yet to be studied.

More recent BNL studies have identified blast furnace slag and class F flyash combinations as promising cementing material additives. Since they both are industrial by-products, they are inexpensive. They are also highly reactive with $(NaPO_3)_n$ solutions and exhibit rapid hydration rates. Preliminary BNL studies using high alumina cement/blended class F flyash cement mixtures modified with $(NaPO_3)_n$ solutions produced cements with compressive strengths >27 MPa after curing for 7 days at 300°C . The cost of a lightweight formulation is estimated to be 33 cents/kg, 70% lower than one derived from $(NaPO_3)_n$ modified high alumina cement lightweight slurries.

The resistance of these cements to carbonation is being determined. In these tests, samples cured for one day in deionized water at 300°C were then exposed to a 4.0 wt% Na_2CO_3 solution at the same temperature. For comparison purposes, conventional cement systems consisting of 45 wt% class G cement, 20 wt% silica flour, and 35 wt% water were also exposed. After 28 days in this highly concentrated CO_2 environment (15,700ppm), there were no signs of alkali carbonation-caused damage. In fact, the compressive strength of the specimens tends to increase with exposure. In contrast, the compressive strength of the conventional class G cement decreased with exposure time, thereby indicating that the conventional cement is susceptible to carbonation-related degradation. These tests are continuing.

2. Thermally Conductive Composites

The economic utilization of binary working fluids in geothermal energy conversion cycles operating in the 150° to 200°C temperature range would dramatically increase the size of the exploitable hydrothermal resource. Therefore, a key objective of the GD Conversion Technology Task is to reduce the cost of power from a binary plant through improvements in efficiency and in O&M cost components. A significant item of cost in a binary plant is the shell and tube heat exchangers, primarily due to the necessity of using high alloy steel tubing to prevent corrosion. Even then, excessive fouling prevents the economic use of binary processes with hypersaline brines. Both problems could possibly be solved with the development of a thin, scale resistant, thermally conductive polymer matrix composite which could be used as a liner on low cost mild steel tubing. Cost effective utilization of bottoming cycles in flash processes as a means of increasing energy conversion efficiency will also become possible. To meet these needs, a material with the following characteristics is desired:

- Heat transfer and fluid-flow characteristics similar to those of AL-6XN tubing.

- Fouling coefficient <50% of AL-6XN.
- Cost not more than twice that of mild steel.

Successful attainment of these objectives is expected to result in the following:

- Electric generation capacities in geothermal flash processes could be improved by 10% with the availability of cost-effective materials for use in bottoming cycle heat exchangers.

- Low temperature geothermal resources that are currently uneconomical will become more attractive for development, thereby greatly enhancing the exploitable geothermal reserves.

- Increased plant utilization factors due to reduced scale deposition and decreased quantities of waste sludge for disposal will result from the use of binary processes with hypersaline brines.

The work is being performed as a collaborative effort between BNL, NREL and private industry. 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. Post-field test evaluations are also performed at BNL.

Engineering analyses and heat transfer tests are conducted by NREL. The work includes measurements of heat transfer and fouling coefficients, cost estimates, and the management of field testing. NREL also coordinates technology transfer activities.

A geothermal company provides the field test site, operating personnel and ancillary equipment. Tests in an environment typical of that in a bottoming cycle application in a flash process are being performed. Design and economic studies are then conducted by a heat exchanger manufacturer.

Status

In FY 1995, BNL completed the post-test analysis of polymer concrete lined (PCL) and AL-6XN control tubing after completion of a 75 day field test exposure to flowing hypersaline brine under heat exchange conditions. In separate tasks, NREL evaluated the fouling and heat transfer characteristics and arranged for the performance of design studies and economic estimates. These NREL tasks are documented separately.

The BNL results from post-field test evaluations performed on four 3-meter sections of PCL tubes and on equal length sections of AL-6XN tubes that were cut from the 6-meter tubes are summarized below:

- After 75 days of exposure, the PCL and AL-6XN tubes were both found to contain a layer of scale ~3.2 mm in thickness. In general, the deposition of scale in the tubes was found to increase as the temperature of the brine stream decreased. Measurements also indicated that the deposition of scale on the PCL tubes was, on average, ~8.5 percent greater than that deposited on the AL-6XN tubes. This was probably due to the fact that the scale adhered more readily to the surface of the PC liner than to the AL-6XN.

- Visual and radiographic examinations of the PC liners indicated that the liners were still securely bonded to the tubing, and there was no evidence of any voids or delaminations between the liner and the tubing.

- Shear bond strength test results indicated that the bond between the liner and the carbon steel tubing had not deteriorated as a result of the exposure tests. After 75 days of exposure, the PCL had an average bond strength of 8 MPa, compared to an average control value of 7.9 MPa. A visual examination of the interior surface of the tubes after the liners had been pushed out indicated that there was no apparent evidence of corrosion at the interface between the liner and the tubing.

- Test results indicated that the bond of the scale to the surface of the liner was almost as high as the bond of the liner to the tubing. The average shear bond strength of the scale to the PC liner was 7.8 MPa.

- The average strength of the bond between the scale and the AL-6XN tubes was measured to be 1.2 MPa. A visual examination of the interior surface of the tubes after the scale had been pushed out indicated that there was no apparent evidence of corrosion at the interface between the scale and the AL-6XN tubing.

In conclusion, the results of the post-field test evaluation indicated that the PCL tubes were in good condition, and that they performed as well as the AL-6XN tubing. Plans for a field test in FY 1996 are being formulated. In this work, the effectiveness of organic additives as a method for reducing scale accumulation on the PCL surface will be determined. In addition, tubing samples are being provided to a heat exchanger manufacturer for use in studies to define methods for the joining of tubes to tube sheets in shell and tube heat exchangers. They are also estimating materials and manufacturing costs.

3. <u>Corrosion Mitigation at The Geysers</u>

Increased HCl concentrations in the steam condensate produced from geothermal wells in some portions of The Geysers have resulted in severe corrosion problems in the upper regions of the well casing where condensation may occur, in steam collection piping, and on turbine blades and rotors. Geothermal fields in other countries have reported HCl production after many years of operation, and it is expected that HCl will cause problems in other U.S. fields. In addition, before dry cooling towers can economically be used as a means of conserving water needed for reinjection, low cost corrosion protective systems for use on structural components must be identified. Solving these materials problems is the objective of this activity.

The technical 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.

Attainment of the project objectives will result in the following:

- Wells that presently cannot be operated due to excessive maintenance costs or environmental/safety concerns may be restarted.
- Service life expectancies of fluid production, transmission and electric generation components will be increased.
- Cost-effective methods for water conservation will be available, thereby resulting in reservoir life extensions due to increased fluid reinjection.

The approach being used to meet the project objectives is to optimize polymer, polymer cement composite and pre-ceramic formulations, previously developed under GD sponsorship, for specific end-use applications at The Geysers. Potentially suitable advanced alloys and ceramics are also evaluated. 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.

The Project consists of three phases:

Phase 1 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.

<u>Status</u>

As of March 1996, a series of field tests of coating systems for well casing had been completed with the Central California Power Agency (CCPA), and evaluations of pipeline and dry cooling tower coatings were ongoing with the Northern California

Power Agency (NCPA) and Pacific Gas and Electric (PG&E), respectively. In addition, laboratory work directed towards other components, such as rotor housings, was underway. Details for these activities are summarized below.

Turbine Components

Flame spray-applied coatings on five metal substrates of compositions representing those currently used in turbines by PG&E at The Geysers are being evaluated. Components of interest are wheel pieces, buckets, diaphragm bodies and diaphragm partitions. New materials and specimens cut from parts removed from turbines used at The Geysers are included in the test matrix. Data from the latter will yield insite regarding the performance that may be expected when coatings are field applied to the components during routine maintenance operations.

Work to evaluate flame spray variables for polyphenylene sulfide (PPS) and other high temperature polymeric coatings is being conducted as part of a cost-shared effort with the Materials Sciences Department at The State University of New York at Stony Brook. Experiments to determine the optimum PPS particle size for spraying and to evaluate application techniques are underway. The work to date has shown that PPS can be sprayed with a butane torch, flame spray torch and plasma. Parameters such as substrate preheat temperature, flame temperature and particle size are being evaluated. Based on the results obtained, it appears that high quality coatings suitable for demonstration are achievable. One major stumbling block has been the particle size of the PPS feedstock. A size distribution between 50 and 100 microns appears necessary, and this has been obtained by laboriously grinding larger particles. A major supplier of PPS resins is cooperating with us in our attempt to obtain larger quantities of properly sized material. Once received, coating of the PG&E turbine component samples will commence.

Laboratory evaluations of PPS coatings dip-applied to cold rolled steel and aluminum substrates were started. It was determined that coating thicknesses of >0.12 mm are needed to achieve long-term corrosion protection. With steel, it was determined that the formation of water insoluble FeS and ZnS reaction products at the PPS/steel interface enhances bonding and durability. These compounds are produced by interactions during the application process between S originating from the PPS and Fe in the steel.

A moderate rate of oxidation of the sulfide in PPS was found to play a key role in insuring that PPS coatings protect aluminum in wet, low pH environments. The formation of a discontinuous, intermediate layer of $Al_2(SO_4)_3$ as the interfacial reaction product between Al_2O_3 at the top surface of aluminum and the oxidized PPS enhances the bond strength at this interface.

Nickel aluminide alloys and advanced engineering ceramics such as TiC, TiN, Cr_7C_3, Al_2O_3, and their combined phases are also being evaluated. The former are known to exhibit corrosion resistance at room temperature typically 2 to 3 orders of magnitude better than cold-rolled steel. However, there are no data for low pH hydrothermal environments. The alloys exhibit excellent wear resistance and surface hardness, and the thermal conductivity is similar to that of stainless steel. Unfortunately the material cost is about ten times greater than that of mild steel, thereby probably limiting its potential use in geothermal systems to cladding applications. Autoclave testing in low pH brine at 300°C is planned.

Very thin (micron range) ceramic coatings applied to low cost steel and aluminum have also been introduced into the test program. The coatings can be applied using plasma, chemical vapor deposition (CVD) and physical vapor deposition (PVD) techniques. The plasma technology is relatively simple, it can be applied in the field, and there are no substrate dimension size or coating thickness limitations. Therefore, the on-site internal coating of transmission piping, heat exchanger tubes and turbine rotor housings appears feasible.

The CVD and PVD technologies utilize heated reaction vessels which contain the precursor gas and vapor phases. Currently their use is limited to substrate dimensions up to 50-cm diameter and 122-cm length. These techniques will be investigated for use with turbine blades since they yield uniform, very hard (Vicker Hardness, >8GPa) and dense coating films. Commercial firms interested in participating in these studies by providing test coupons have already been identified.

Dry Cooling Tower Components

Prototype sections of polymer coated finned-tube heat exchanger tubing were placed into test by PG&E at The Geysers in June 1994. In the test environment, the corrosion rate of carbon steel is approximately 15 mpy. Aluminum corrodes at a lesser but unacceptable rate. Two metal systems, aluminum fins on stainless steel tubing and electrogalvanized steel on carbon steel tubing are being evaluated. Polyphenylene sulfide (PPS) and vinyl ester resin - trimethylolpropane trimethacrylate applied to surface modified and "as-received" metal surfaces were used for corrosion protection. Visual inspections were made after approximately 2, 5, and 10 mo, and no signs of blistering, chalking or delamination were apparent on any of the coated samples. All of the samples were reported to be in an "as new" condition. These tests are continuing.

Piping Systems

In March 1992, two polymer cement (PC) lined 30-cm diameter pipe tees were installed by NCPA in a steam transmission line where the conditions are as follows: flow rate 13,640 kg/hr, temperature 173°C and pressure 0.83 MPa. Both tees were visually inspected after approximately 12 mo exposure. At that time, some fine cracks and small regions of disbondment of the liner were noted, but in general both tees were in good condition. Therefore, the test was resumed and it has continued without interruption for a total exposure time of 47 mo as of March 1996. Since filters located downstream of the tees which are monitored routinely have not collected any pieces of the PC liner, it is expected that no gross erosion or delamination has occurred. At the next plant shutdown, both tees will be removed for examination.

4. Advanced Coating Materials Evaluations

Since the general utilization of high alloy steels is cost prohibitive for most geothermal plants, current practice is to attempt to minimize corrosion and the scale deposition rate by plant design and subsequent operation that may not be optimum for energy conversion and fluid injection. For example, it is well known that lowering the pH of hypersaline brines can significantly reduce silica scale deposition. This would allow greater temperature differentials across the heat exchangers, reduce plant size and complexity by elimination of the clarifiers, and decrease the amount of potentially toxic waste sludges that must be disposed of at ever increasing costs. Unfortunately, the lowering pH option is constrained by increased corrosion problems which can only be solved by the use of prohibitively expensive construction materials. Low cost, acid resistant and hydrothermally stable coating systems that can be used for new plant construction and for the retrofit of existing plants are needed.

Portland cement-based materials are sometimes used as liners on brine piping systems, but the alkaline nature of the cements prevents their use with acidic fluids. Other conventional protective barrier materials such as epoxies, polyesters and acrylics, or metallic claddings, are limited by the thermal and/or hydrolytic stability of the plastics, and the costs for the latter.

This activity was started in FY 1995 and is being performed as a cooperative cost-shared effort with geothermal energy firms.

The technical objective is to develop and field test low cost, acid resistant and hydrothermally stable corrosion protective coating systems that can be used for the retrofit of existing plants and for new plant construction. If successful, the activity will result in the following:

- Significant reductions in plant construction costs and complexity by elimination of the need for clarifiers.
- Increased electric generation efficiency and plant utilization factors.
- Enhanced environmental acceptance due to reductions in solid waste generation rates.

Approach

The project objectives are being met by the performance of a multi-phase effort that is cost-shared with geothermal energy and/or other industrial partners. In Phase 1, specific coating needs are identified and performance specifications defined. Phase 2 consists of the selection of potential candidate polymer and composite systems developed in other program tasks, and optimization of them for the specified end-use application. Field testing of coupon size samples will also be conducted in this phase of the effort. Contingent upon these results, Phase 3 will identify potential commercial sources and development partners for the technology. Field testing of coated prototype and full-scale process components at the Salton Sea KGRA and other locations will be conducted in Phase 4. Contingent upon these results, Phase 5 will consist of economic studies and the completion of technology transfer.

Status

A cost-shared effort with industry for the testing of advanced coating systems at one or more of their plants was initiated.

In preliminary tests to determine the technical feasibility of using flame spray techniques as a means for applying polyaryl-type polymer coatings, metal coupons representing piping and turbine housing materials were supplied to the Flame Spray Laboratory operated by the Materials Sciences Department at the State University of NY at Stony Brook (SUNY-SB). Two polymers, polyphenylene sulfide (PPS) and polyphenyletheretherketone (PEEK) are being used in these initial tests. Experiments to determine the optimum PPS particle size for spraying and to evaluate application techniques are underway. The work to date has shown that PPS can be sprayed with a butane torch, flame spray torch and plasma. Parameters such as substrate preheat temperature, flame temperature and particle size are being evaluated. Based on the results obtained, it appears that high quality coatings suitable for demonstration are achievable.

Work to prepare coated pipe sections for field testing commenced. Four 60-cm lengths of 25-cm diam carbon steel pipe will be used in these tests. One of the pipe sections contains a welded joint so that the ability to protect welds from corrosion can be ascertained. At BNL it is planned to dip-coat one section with PPS and another with PEEK. At SUNY-SB, PPS will be applied on two sections including the welded one. Flame spray technology will be used.

CONCLUSIONS

The Geothermal Materials Program continues to make contributions to the control of corrosion and scaling in geothermal processes, thereby helping to meet DOE/GD and industry identified goals and priorities. Significant advances have been made in the areas of lightweight CO_2-resistant cements, thermally conductive composites and corrosion-resistant coatings.

With respect to well completion materials, phosphate-modified calcium aluminate compounds yield high strength, CO_2-resistant cements that are pumpable over a wide range of temperatures. The incorporation of hollow microsphere fillers into this matrix produces a lightweight cement slurry which cures to yield strength and durability properties suitable for well completions. As an example, the inclusion of chemically inert acrylonitrile polymer microspheres produced a slurry with a density of 1 g/cc. After autoclave exposure to a 0.05M Na_2CO_3 solution at 250°C for 6 mo, the cement retained 73% of its initial strength.

Compared to the above cement formulations, cost reductions of ~70% can be made by blending Class F flyash with the calcium aluminate cement. This formulation is also resistant to CO_2 attack. After 28 days in a 4.0 wt% Na_2CO_3 environment (15,700 ppm CO_2) at 300°C, no signs of alkali carbonation caused damage were apparent.

The field testing in flowing hypersaline brine under heat exchange conditions of PCL that was applied to carbon steel tubing verified the hydrothermal stability and corrosion protective capabilities of the liner. Heat transfer and fouling coefficients similar to those for the high alloy steel (AL-6XN) control tubes were measured. It can also be concluded from these results that the high temperature polymer used as a matrix for the PCL is an excellent candidate for use as a corrosion-resistant coating for transmission piping and other process components.

Methods for the field application of polymeric and ceramic coatings to geothermal process components are being evaluated. It was demonstrated that high quality PPS coating can be produced using flame spray techniques. Work on all of these activities will be continued in FY 1996 and into FY 1997. Further needs as identified by industry will also be incorporated into the FY 1997 program.

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Next Generation Geothermal Power Plant Study

Mai Hattar
C.E. Holt Company

PLEASE REFER TO:

Next Generation Geothermal Power Plants

EPRI Project WO3656-01
Final Report
September 1995

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Turbocompressors for Noncondensible Gases

Ken Nichols
Barber-Nichols, Inc.

PAPER NOT AVAILABLE

OPERATION OF MAMMOTH PACIFIC'S MP1-100 TURBINE WITH METASTABLE, SUPERSATURATED EXPANSIONS

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ABSTRACT

The Idaho National Engineering Laboratory's Heat Cycle Research project continues to develop a technology base that will permit increased use of moderate-temperature hydrothermal resources to generate electrical power. Project investigations have confirmed the viability of technologies that allow the binary power cycle performance to approach practical thermodynamic maximums. One of the concepts under investigation is the use of metastable, supersaturated turbine expansions. These expansions support a supersaturated working fluid vapor; at equilibrium conditions, liquid condensate would be present during the turbine expansion process. Studies suggest that if these expansions do not adversely affect the turbine performance, up to 8 to 10% more power could be produced from a given geothermal fluid. Determining the impact of these expansions on turbine performance is the focus of the project investigations being reported. This work is supported by the U.S. Department of Energy, Assistant Secretary for Energy Efficiency and Renewable Energy, under DOE Idaho Operations Office contract DE-AC07-94ID13223.

BACKGROUND

The primary object of the Idaho National Engineering Laboratory's (INEL's) Heat Cycle Research project is to develop technologies that result in the greater use of moderate-temperature geothermal resources for the production of electrical power. Project investigations have identified cycles whose performance approach thermodynamic maximums established by practical equipment constraints or operating limits.[1-3] Field investigations have validated the adequacy of the engineering technologies necessary to incorporate these concepts into the design and operation of a binary power plant.

INEL's Heat Cycle Research project is currently examining the potential improvements in performance achieved when metastable, supersaturated vapor expansions are allowed in the binary cycle turbine. During these turbine expansions, the working fluid expands into the equilibrium two-phase region. If the fluid is brought to equilibrium at that point, liquid condensate would be present. The formation of the condensate is not an instantaneous process; it requires the chance grouping of molecules or it requires nucleation sites for the drops to form. Because of the delay in condensate formation, the vapor is referred to as supersaturated. The turbine expansion is considered to be a metastable process.

Expansion of a vapor into the equilibrium, two-phase region in a turbine is not unique. In condensing steam turbines, the Wilson Line estimates the extent to which the expansion can proceed while maintaining a supersaturated vapor (no condensation). The condensation behavior of the hydrocarbon fluids of interest for binary cycles is not expected to be the same as that of steam. An isobutane working fluid or a mixture of isobutane and a heavier, minor component provides the highest cycle performance for the resource temperatures of interest. Isobutane, as well as the mixtures, has a retrograde dew point curve on a temperature-entropy (T-S) diagram. In contrast to steam, these fluids tend to become drier or more superheated as they expand.

A supercritical binary cycle is schematically shown on the T-S plot in Figure 1. In this cycle, the working fluid is first preheated and vaporized at a pressure above its critical pressure. In a conventional cycle, the working fluid is superheated before entering the turbine to ensure that the expansion process in the turbine (represented in Figure 1 by point 3 to point 4) will remain completely outside the two-phase region. Demuth[4] suggests that a modified cycle where the ideal turbine expansion process passes through the two-phase region (represented by the process from point 3' to point 5) could proceed without adversely affecting turbine performance. After a theoretical examination of the condensation behavior of the hydrocarbon working fluids in these expansions, Demuth concludes that droplets might not form. If droplets did form, they initially would be very small and tend to evaporate as the expansion proceeded.

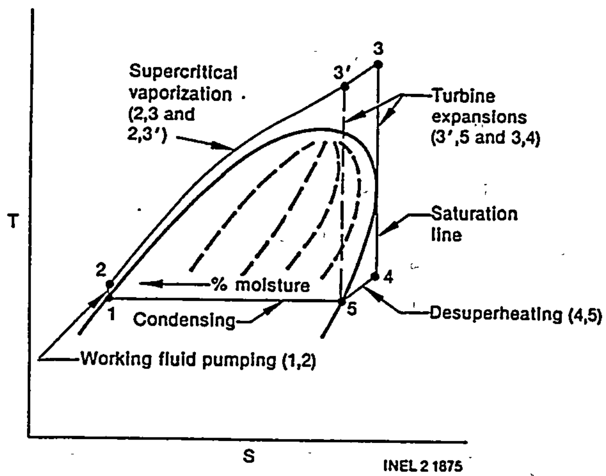

Figure 1: Binary Cycle Showing Two Types of Turbine Expansions

During the metastable expansions in a steam turbine, the two-phase region is entered near the end of the expansion process (the final turbine stage). In contrast, the proposed metastable expansions with the isobutane working fluid enters the two-phase region much sooner in the expansion process (see Figure 1). Depending upon if and when condensation occurs, droplets may be entrained in the vapor as it enters the turbine rotor. If the droplets are present at the rotor inlet, there is a higher potential for degradation in performance and erosion of the rotor and vanes (nozzles).

If it could be confirmed that these expansions did not impact turbine performance, an additional cycle performance improvement of up to 10% could be realized.

HCRF FIELD INVESTIGATIONS

To determine the impact of these expansions on the performance of a binary cycle turbine, the project conducted a series of field investigations at the INEL's Heat Cycle Research Facility (HCRF) located in California's Imperial Valley. During the first phase of these investigations, the condensation behavior of these metastable expansions was examined with a converging-diverging nozzle. In the second phase of these investigations, turbines were tested to determine the degree to which the expansions could enter the two-phase region (the level of supersaturation) before affecting the turbine performance.

The two-dimensional, converging-diverging nozzle expansions simulated an isentropic process in a turbine. Different nozzle inlet conditions were examined to determine those conditions that resulted in condensate forming during the expansion. A window on the nozzle allowed the expansion process to be monitored. A laser-based droplet-detection system was used to identify the onset of condensate formation and to size the droplets that formed.[5] The nozzle inlet pressure was varied from 550 to 650 psia (above the isobutane critical pressure). By changing the nozzle inlet temperature at a fixed inlet pressure, the degree of supersaturation in the expansion was varied. Testing was conducted with an isobutane working fluid, as well as an isobutane-hexane mixture.

The nozzle testing confirmed that these metastable expansions initially support a supersaturated vapor without condensate formation.[6,7] It was possible to delay the onset of condensate formation in the nozzle until a maximum equilibrium moisture level of 6 to 7% was reached (at equilibrium, 6 to 7% of the fluid would be liquid). At the onset of condensate formation, the droplets initially evaporated as the fluid expanded. As the inlet conditions were varied to further increase the equilibrium moisture level, the condensate that formed did not evaporate. The laser, droplet-detection system proved to be very effective in identifying the onset of condensate formation and its location along the expansion path. The results of the testing to size the droplets that formed were inconclusive.

During the second phase of the HCRF investigations, an axial-flow, impulse turbine and a radial-inflow, reaction turbine were installed and tested. Barber-Nichols, Inc., provided the axial-flow turbine, generator, load bank, and associated control equipment. The turbine had a nominal power output of ~40 horsepower. Rotoflow Corporation provided the radial-inflow turbine. In conducting the turbine tests, the inlet and exhaust pressures were constant test conditions. The turbine inlet temperature was varied to obtain the desired levels of supersaturation or equilibrium moisture levels in the expansion process. The turbine tests were primarily conducted at an inlet pressure of 600 psia with an isobutane working fluid. Limited testing was also conducted at an inlet pressure of 550 psia, as well as with an isobutane-hexane mixture.

The testing with the turbines confirmed that their performance was not impacted at inlet conditions supporting a supersaturated vapor in the nozzle investigations.[7] The impulse turbine performance was not affected until the conditions leaving the turbine (actual) were within the two-phase region (the expansion would have a maximum equilibrium moisture content of ~25%). The radial-inflow turbine performance was not impacted until an isentropic expansion from the turbine inlet to the exhaust pressure was within the two-phase region (i.e., the turbine inlet entropy was less than the dew point entropy at the exhaust pressure). If the fluid expanding through the turbine had been brought to equilibrium, it would have had a maximum moisture content of ~13%. At the corresponding inlet conditions in the nozzle, the condensate forming would not have evaporated.

At the conclusion of the testing, neither the performance of the impulse turbine nor the radial-inflow turbine appeared to be adversely affected by their operation with the metastable expansions. Neither turbine operated for more than a couple hundred hours. The post-test examination of the turbines was inconclusive as to whether the expansions resulted in any erosion damage to internal components.

MAMMOTH INVESTIGATIONS

At the conclusion of the HCRF investigations, investigators had shown that the metastable expansions could proceed without adversely affecting turbine performance. However, investigators had not resolved whether the performance could be maintained over the expected life of a commercial turbine. (Over time, the presence of condensate could damage the component surfaces exposed to the expanding vapor.) With the closure of the HCRF, it became necessary to find an alternate facility where a turbine could be operated with the metastable expansions for an extended period. With the assistance of Rotoflow Corporation and C.E. Holt Company, the project reached an agreement with Mammoth Pacific Limited Partnership (MPLP) to continue the metastable expansion investigations at one of MPLP's commercial facilities near Mammoth Lakes, California. At this location, MPLP operates three power plants, with a total design capacity of ~40 $ME_{(e)}$. All three are binary plants using an isobutane working fluid. MPLP proposed conducting this investigation at the Unit 100 of the MP1 plant (MP1-100).

As part of the agreement with MPLP, the project assumed the risk of potential damage to the turbine rotor and vanes by purchasing these components for installation before operating with the metastable expansions. The use of new components also allowed the project to establish their pretest condition. MPLP agreed to install the components and operate the plant at the inlet conditions selected for a minimum of 6 months. MPLP would provide project requested operational data during this period.

Before installing the new components in MP1-100's turbine, the project first evaluated whether it was feasible to operate at the Mammoth facility with the metastable expansions. The HCRF testing was conducted exclusively at supercritical pressures. The Mammoth facilities were designed and operated with a subcritical turbine inlet pressure. The Mammoth facilities produce electrical power for commercial sale; they are not designed for research activities.

After evaluating the performance of the MP1-100 facility over a range of different operating parameters, the project concluded that it would be possible to operate the facility with the metastable expansions, though the inlet pressure would be below the critical pressure of the isobutane working fluid. A mutual decision was made to continue with extended operation investigation, with the following conditions:

- The new turbine rotor and set of vanes were to be the same as the existing design.
- The operation with the metastable expansions would have minimal impact on the power produced by MPLP's facilities at Mammoth.
- The turbine would operate at as high an inlet pressure as possible.
- The turbine would operate with 1 to 2°F of superheat at the inlet.
- During abnormal periods of operation, MPLP could adjust the turbine inlet conditions as it considered necessary.
- The turbine could be operated at the project's requested conditions during the period between October 1995 and June 1996. At the end of May 1996, a mutual decision would be made whether to continue the investigations.

The new turbine components were obtained from Rotoflow and installed in November 1995. Before installation, the component surfaces that would be exposed to the expanding vapor were photographed to establish the pretest condition. After installation of the new components, the turbine operated for ~140 hours at the nominal conditions to establish a baseline performance with completely dry expansions. During this baseline period, the turbine efficiency varied between 70 and 85% with changes in the ambient air temperature. The brine utilization varied from ~5.7 w-hr/lb_{gf} (watt-hr per pound of geothermal fluid) at an air temperature of 32°F to ~3.2 w-hr/lb_{gf} at 64°F.

The baseline period was used to define the inlet pressure condition for the operation with the metastable expansions. This was accomplished by conducting a series of tests where the turbine vanes were sequentially closed in 5% increments, throttling flow, and raising the turbine inlet pressure. The effect of throttling with the vanes on the turbine inlet pressure and turbine efficiency is shown in Figure 2. At the nominal turbine operating conditions, the turbine inlet pressure was ~275 psia. The desired minimum pressure for the extended period of operation was 450 psia. To achieve this pressure, the vanes would have to be closed to between 40 and 50% open. Although this resulted in a significant degradation in the turbine efficiency, the brine utilization during this series of tests did not change significantly. The decrease in efficiency was offset by an increase in the isentropic enthalpy change (the potential work across the turbine) and a decrease in the brine flow requirement. Since excess brine from MP1-100 could be diverted to one of the other facilities and increase its power production, it appeared that the pressure of 450 psia could be attained without adversely affecting the total power output from MPLP's facilities.

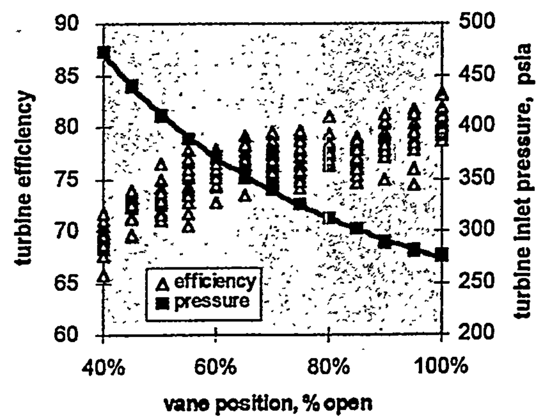

Figure 2: Effect of Vane Position on MP1-100 Turbine Performance

The range of turbine efficiencies in Figure 2 for a given fixed vane position reflects the variation in the measured isobutane flow rates. The turbine efficiencies presented in this paper are the actual turbine work divided by the isentropic enthalpy change between the inlet conditions and the exhaust pressure. Except where indicated, the actual turbine work is obtained by dividing the generator power, with adjustments for generator inefficiency and gearbox losses, by the measured isobutane flow rate. At MP1-100, there are variations in the measured isobutane flow rate of ~5 to 10%. Because there are not similar variations in the other measured parameters in the isobutane system, it is suspected that the fluctuations in the measured flow rate are inherent to the measurement and are not actually occurring. To offset the fluctuation in the measured flow, the value recorded hourly was an average of multiple readings.

On November 13, 1995, the turbine inlet conditions at MP1-100 were adjusted to a pressure of ~450 psia and a superheat level to 2°F. These conditions were attained at a turbine vane position of ~45% open. At these inlet conditions, the maximum equilibrium moisture during the turbine expansion was ~1 to 2%. During the operation of MP1-100 at these inlet conditions, the turbine vanes were maintained at this fixed position. The brine flow rate held at a constant value. The isobutane flow rate was used to adjust the level of superheat at the turbine inlet. Turbine performance was monitored hourly. As shown in Figure 3, over the first 100 hours of operation there was no discernible degradation in turbine performance. The turbine efficiency varied from ~65 to ~75%

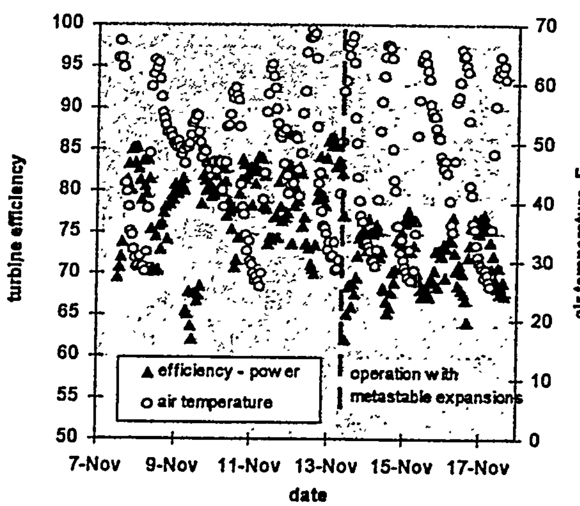

Figure 3: Performance of MP1-100 Turbine at Start of Operation with Metastable Expansions

as the ambient air temperature changed. The performance of the plant (in terms of the amount of power produced from the brine flow utilized) was not affected by operating at the modified inlet conditions. During the first 100 hours of operation, the brine utilization varied from ~5.9 w-hr/lb_{gf} at an air temperature of 32°F to ~3.6 w-hr/lb_{gf} at a temperature of 64°F. These values were similar to those at the baseline conditions.

The MP1-100 turbine has operated with the modified inlet conditions since November. The turbine inlet conditions during this period are shown in both Figures 4 and 5. Figure 4 is a temperature-entropy (T-S) plot showing the nominal range of turbine inlet conditions (before operation with the metastable expansions), a daily operating point during the metastable expansion investigation, and the saturation curve for the isobutane working fluid. The turbines at the Mammoth facilities are nominally operated at inlet conditions that are approximately at an entropy of S=1.190 btu/lb-R (as defined by the NIST12 property codes). The operation at these inlet conditions ensures the expansions occur completely outside the two-phase region, as well as provide sufficient superheat to ensure there is no liquid entrained in the vapor leaving the boiler.

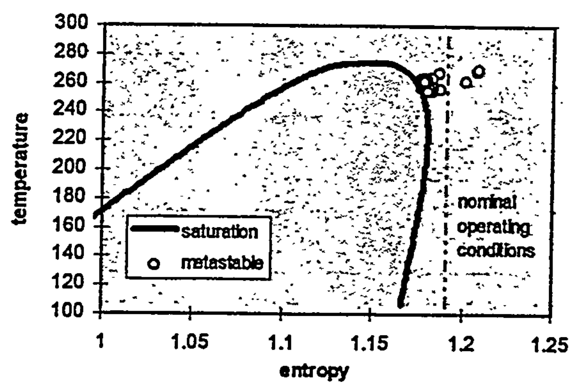

Figure 4: MP1-100 Operation Conditions on Isobutane T-S Diagram

In Figure 5, the turbine inlet entropy is shown as a function of time over the period the turbine has operated with the metastable expansions. As indicated in this figure, the inlet conditions were revised after ~1270 hours. On January 5, 1996, the turbine inlet pressure was increased to ~465 psia with inlet superheat levels of 1°±0.5°F. Before this revision of the inlet conditions, there was a trend toward an increasing turbine inlet entropy (decreasing level of supersaturation). [At inlet entropies above the maximum dew point entropy (S=1.1806 with the NIST code), the turbine expansion occurs completely outside of the two-phase region.] The turbine inlet entropy increased because the turbine inlet pressure had decreased (the inlet superheat was maintained at ~2°F). Changes in pressure were noted after periods of atypical operation in response to activities at Mammoth's other plants or to curtailments in power production imposed by the utility. Although the turbine vanes were returned to the indicated value of 45% open after these periods of abnormal operation, the inlet pressure would be at different values, depending upon whether the vanes were opened or closed to reach the set value.

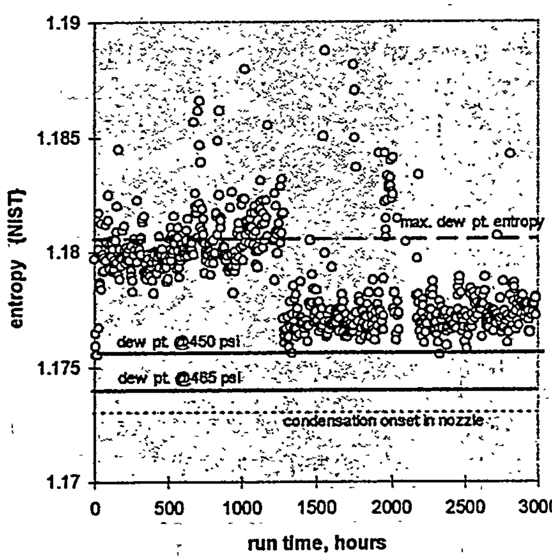

Figure 5: MP1-100 Turbine Inlet Conditions during Operation with Metastable Expansions

When the turbine inlet conditions were revised in January, the mode of operation was also changed. Along with reducing the amount of superheat at the inlet, MPLP was asked to use the turbine vanes to maintain the inlet pressure at 465 ±5 psia. The turbine was operated with the total isobutane flow rate available (maximum pump capacity); small adjustments were made with the brine flow to adjust the level of superheat. As indicated in Figure 5, the turbine inlet entropy (and the level of supersaturation) has remained relatively constant since January. At the revised inlet conditions, the equilibrium moisture level in the expanding vapor is ~3 to 4%. Based upon the nozzle investigation where the equilibrium moisture level reached 6 to 7% before condensate formed, the MP1-100 turbine is being operated at conditions supporting a supersaturated vapor.

The performance of the MP1-100 turbine through mid-March of 1996 is shown in Figure 6. Efficiency determined from both the generator power measurement and the measured turbine inlet and exhaust pressures and temperatures are plotted with time. The efficiencies determined by both methods are in agreement. The data indicate that there has been no degradation in turbine performance with time while operating with these metastable expansions. The modification of the turbine inlet conditions in January resulted in no appreciable change in the turbine performance.

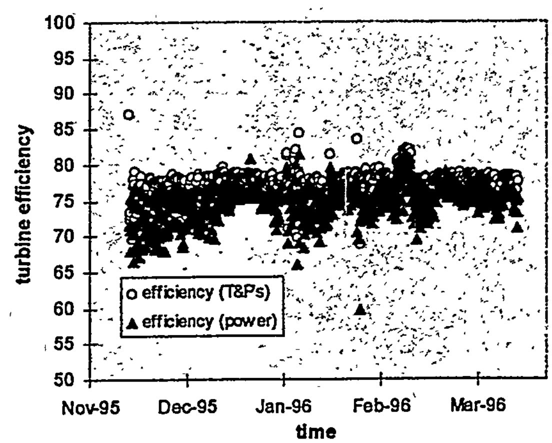

Figure 6: MP1-100 Turbine Efficiency during Operation with Metastable Expansions

The observed variation in the turbine efficiency with the ambient air temperature (condensing/exhaust pressure), raised some question that the cooler ambient air temperatures during the winter may have masked a degradation in the turbine performance. In Figure 7, the turbine performance is plotted as a function of the ambient air temperature for each month, as well as during the period when the baseline performance was established. These data show there has been no degradation in performance through mid-March. At similar air temperatures, the turbine efficiency in March was essentially the same as it was in November at the start of the investigation.

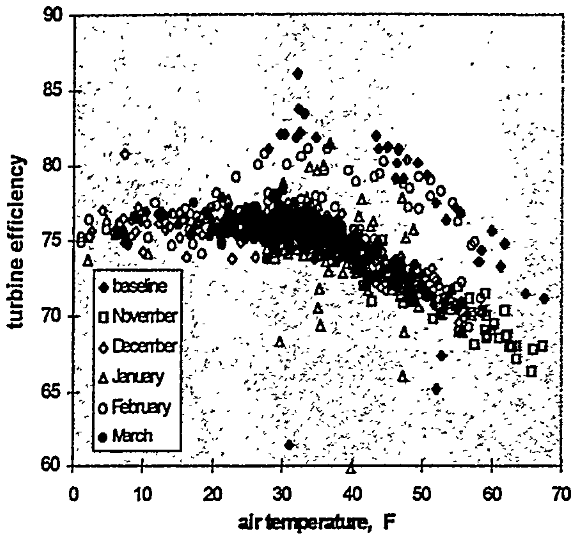

Figure 7: Effect of Ambient Conditions on MP1-100 Turbine Performance

A condition of the agreement with MPLP was that the investigation with the metastable expansions have minimal impact on the power production. In Figure 8, the brine utilization for the MP1-100 facility is plotted as a function of the air temperature for the different periods of operation during this investigation. The data show that it has been possible to maintain the brine utilization at values similar to the baseline cycle performance with the metastable expansions, even though the turbine efficiency was 6 to 9 percentage points lower. The data in Figure 8 show that the brine utilization improved during the January to March period. Although this improvement is real, it cannot be attributed to the operation with the metastable expansions. It is the result of a more optimum configuration of the flow through the heat exchangers that was made in February 1996.

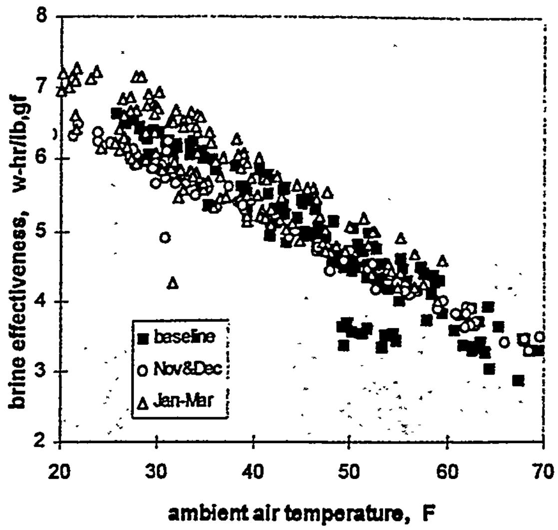

Figure 8: Effect of Ambient Conditions on MP1-100 Plant Performance

SUMMARY

The turbine at MPLP's MP1-100 plant has operated since November 1995 at inlet conditions supporting a supersaturated vapor (as indicated by the HCRF nozzle tests) without any measured degradation in performance with time. To operate the turbine at inlet pressures that would produce these metastable expansions, it was necessary to throttle the isobutane flow with the turbine vanes. A degradation in turbine efficiency was associated with throttling with the vanes, independent of operation with the metastable expansions. Despite the decrease in turbine efficiency, there was not a corresponding degradation cycle performance (in terms of the power produced from a given flow of brine). If the turbine rotor and vanes had been sized to maintain efficiency at the reduced isobutane flows, the cycle performance could have increased by up to ~10% at the turbine inlet conditions providing the metastable expansions.

The constraints imposed by the facility's fixed equipment configuration and the need to minimize the impact on plant performance has dictated that the turbine be operated at subcritical inlet pressures with ~1°F of superheat at its inlet. These constraints have limited the level of supersaturation attained in the vapor as it is expanded through the turbine. As the ambient air temperatures increase (raising the condensing pressure) in the spring, it may be possible to further raise the turbine inlet pressure without additional throttling with the turbine vanes. This may allow further modification of the inlet conditions to increase the level of supersaturation in the turbine expansions and not adversely affect MPLP's power production.

The MP1-100 turbine will continue to be operated with the metastable expansions through May 1996. The agreement between INEL and MPLP provides for the suspension or termination of the investigation then at the request of either party. (This provision provides MPLP the flexibility to adjust its operations as necessary during the summer when maximum revenues are obtained for the power produced.) If the operation of the turbine with the expansions proceeds without interruption, MPLP will continue to provide the project operating data. If the test is suspended, it is anticipated that it will resume in the fall of 1996. With the decision to terminate the investigation, a nondestructive examination of the turbine rotor and vanes will be made. This examination will be made at the first shutdown of the turbine for maintenance following the decision to conclude the test. In the event of a turbine failure, the turbine components will be removed and examined to evaluate the contribution of the operation with the metastable expansions to the failure.

If the MP1-100 turbine continues to operate with no degradation in performance through the end of May 1996, the project will explore the possibility of expanding these investigations to other facilities.

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VALUE ANALYSIS OF ADVANCED HEAT REJECTION SYSTEMS FOR GEOTHERMAL POWER PLANTS

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ABSTRACT

A computer model is developed to evaluate the performance of the binary geothermal power plants (Organic Rankine Cycles) with various heat rejection systems and their impact on the levelized cost of electricity.

KEYWORDS

Heat Rejection, Organic Rankine Cycles, LEC, Computer Model

INTRODUCTION

Researchers at the National Renewable Energy Laboratory (NREL) have developed a computer model to evaluate the performance of the geothermal power plants with various heat rejection systems and their impact on the levelized cost of electricity (LEC). The computer model developed in this work is capable of simulating the operation of a geothermal power plant which consists mainly of an Organic Rankine Cycle (binary plants) with different types of working fluids such as pure hydrocarbons and some binary mixtures of the most promising combinations of hydrocarbons. The computer model performs the cycle analysis and component sizing for binary systems with various heat rejection systems. A spread sheet is then used to carry on the economic data calculation and analysis. The value analysis technique used in this work is the method described by Demuth and whitbeck (1982). In this method, the impact of a new system on LEC is calculated based on an incremental technique which determines the change in the cost of producing electricity between a baseline configuration and another configuration expressed as a fractional change. The cycle analysis computer program accepts five different heat rejection models. The following configurations are now operational in the computer program: 1)Air-cooled condenser, 2)Shell-and-tube (surface) condenser with evaporative cooling tower, 3)Shell-and-tube (surface) condenser with the cooling water first cooled in an air-cooled exchanger and then in an evaporative cooling tower, 4)Parallel configuration of 1 and 2, 5)Series configuration of 1 and 2 (air-cooled condenser at the hot end). The program operates in two modes: "design mode" in which all components are sized for a particular set of design parameters such as pinch points, and "operational mode" in which the component hardware is fixed and the cycle state points change to accommodate a different set of ambient conditions.

TYPES OF SYSTEMS ANALYZED

Figures 1 shows the type of binary cycle system which can be analyzed by the computer program. Figure 1 shows a simple Rankine cycle, which may be a boiling cycle or a supercritical cycle depending on the heater pressure. This paper will emphasize the work with the unrecuperated cycle. Studies at a later time

time will investigate the recuperated cycle.

Five different heat rejection systems can presently be analyzed by the computer program. First, and perhaps the simplest system, consists of an air-cooled condenser. This is, at the present time, the most prevalent heat rejection system for binary geothermal plants. The advantages of this system are its simplicity and lack of a requirement for water. The primary disadvantage of this system may be a high condensing temperature produced when ambient temperatures are high (Summer and daytime). This system will be referred to in the remainder of the report as Case 1. The second most prevalent type of heat rejection, Case 2, is a totally evaporatively cooled system. The working fluid from the turbine or recuperator is condensed in a shell-and-tube (surface) condenser with cooling water on the other side of the exchanger. Case 3 is one of three hybrid systems using both evaporative and dry cooling. This may be thought of as an extension of Case 2 in which the cooling water from the condenser first passes through an air-cooler and then through the evaporative tower of Case 2. Case 4 is the second hybrid arrangement. Here, the working fluid is split as it leaves the turbine (or the recuperator) and part is sent through a standard air-cooled condenser (similar to the one in Case 1) and the remainder is sent through a shell-and-tube (surface) condenser with cooling water cooled in an evaporative tower (as in Case 2). For this arrangement, the flow split may be varied in response to varying ambient conditions to optimize the system performance. Case 5 is the other hybrid arrangement. Here, all of the turbine exhaust goes through an air-cooled condenser. Then, the uncondensed portion goes through a shell and tube condenser with the cooling water evaporatively cooled. If the working fluid is a pure substance, the liquid which is condensed in the air-cooled condenser will bypass the second condenser. If the working fluid is a mixture, this choice is more difficult. Bypassing the partially condensed liquid will result in worse performance than if the phases can be intimately mixed in the second condenser. However, this may be difficult to do. Further investigation of this problem will be considered at a later date.

COMPUTER PROGRAM FOR CYCLE ANALYSIS AND COMPONENT SIZING

This section discusses the computer program developed to predict the performance and size the major components of the baseline and modified systems. The computer program provides two options: a "design" option, which sizes the various components for a given cycle and an "off-design performance" option, which takes the hardware from a design run and determines its performance under different ambient conditions.

Method of Solution

The computer program determines the Rankine cycle for a prescribed set of initial conditions. The first pass through the program is a "design" run. Given the design constraints, the program determines the equipment necessary to meet the constraints. The output of this program consists of the plant performance and an estimate of the sizing of the major components.

The "off-design performance" option takes the size parameters for the heater, turbine and heat rejection components and with the new ambient conditions varies pinch points and flow ratios until the size parameters are sufficiently close to the set values. This iteration assumes that the heater pressure remains constant and that the working fluid to coolant flow rates remain the same. (This means that the working fluid flow rate is fixed by the turbine while the coolant flow rates are the same as in the "design" case and the condenser pinch point, cooling tower approach and geofluid flow rate can vary.)

Baseline Binary System

Four plants were considered to span the low temperature region for small binary plants. Geofluid inlet temperatures of 220 and 280 F were used where the geofluid might come directly from a low temperature resource or it might come from the exhaust of a high temperature plant. For the cases of a bottoming cycle, geofluid from a high temperature plant, the geofluid reinjection temperature was restricted to 190 F to minimize silica deposition. For the low temperature resources, no outlet limit was applied. To incorporate reliable data into the computer simulations, NREL used a database obtained from an industry partner (Barber-Nichols) on design and cost information of these systems for both air cooled and water-cooled evaporative heat rejection systems. Using Barber-Nichols data base, the performance and cost data for these systems were evaluated and utilized as baseline for the computer program. Using "rules of thumb" and case studies, optimum systems were determined. Isobutane was used in these binary cycles.

APPLICATION OF THE VALUE ANALYSIS TOOL AND COMPUTER MODEL

The use of lighter hydrocarbons have been recommended for geothermal binary plants with low resource temperatures. To explore this recommendation and to illustrate the use of the computer model developed here, the replacement of isobutane in the baseline power plant with propane for the 280 F resource with no geofluid reinjection temperature limit was studied. This example will demonstrate that the value analysis method and the computer model can be used to minimize the LEC by changing the basic design parameters of the cycle, *e.g.*, the pinch points in the heat exchangers and condensing pressure.

Figure 2 shows a composite of the optimization choices with the new working fluid. The fractional changes in the LEC are with respect to the isobutane baseline described earlier. The highest curve is for a heater pressure of 500 psia. This is higher than the 313 psia pressure in the baseline case. No account was taken of the impact of this higher pressure on cost of piping and heater because the piping. fittings and valves will be of the same class of service and that any increase in cost of the heat exchanger shell will be negligible for this change in pressure. The 500 psia heater pressure did not produce a decrease in LEC over the baseline value. Increasing the heater pressure to 600 psia did result in a decrease in LEC for condensing pressures below 94 F. A brief study of the heater pinch point using 4 and 6 F indicated little difference with the larger pinch point giving the lower LEC. The optimum condensing temperature was 85 F with a 600 psia heater pressure and a 6 F heater pinch point. The resultant decrease in LEC was almost 4% below that of the baseline cycle.

Figure 3 indicates the differences in net geofluid effectiveness (Net W h/lb_m of geofluid). The increase in net geofluid effectiveness for all of the propane cycles is 20 to 30% above that of the baseline system. This means that the power plant will use 20 to 30% less geofluid to produce the same amount of new electrical energy and deplete the reservoir at a much lower rate. One might expect this large improvement in performance to be reflected in a larger decreased energy cost. Field costs were only 15 to 25% of the LEC for the baseline cases considered here. Classically, for larger plants this number is near 50% which would result in a much greater impact on LEC. It is planned in future work to consider larger size plants. This may result in a stronger preference for propane over isobutane in this type of application.

CONCLUSIONS

A computer model was developed to evaluate the performance of the binary geothermal power plants (Organic Rankine Cycles) with various heat rejection systems and their impact on the levelized cost of electricity. The computer model is capable of simulating the operation of an Organic Rankine Cycle with different types of working fluids such as pure hydrocarbons and some binary mixtures of the most promising combinations of hydrocarbons. The computer model performs the cycle analysis and component sizing for binary systems with various heat rejection systems. A spread sheet is then used to carry on the economic data calculation and analysis. The method of computing the LEC is an incremental method to determine the percentage change from a base case. The cycle analysis computer program accepts five different heat rejection models. The program operates in two modes: "design" mode, and "off-design performance" mode in which the component hardware is fixed and the cycle state points change to accommodate a different set of ambient conditions.

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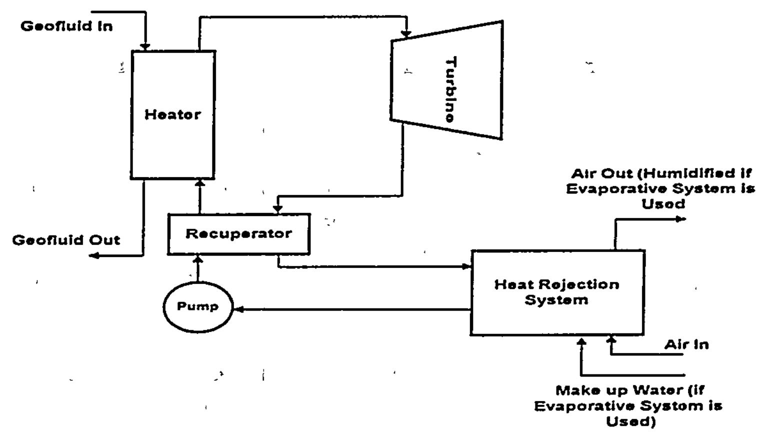

Fig. 1 Simple Organic Rankine Cycle

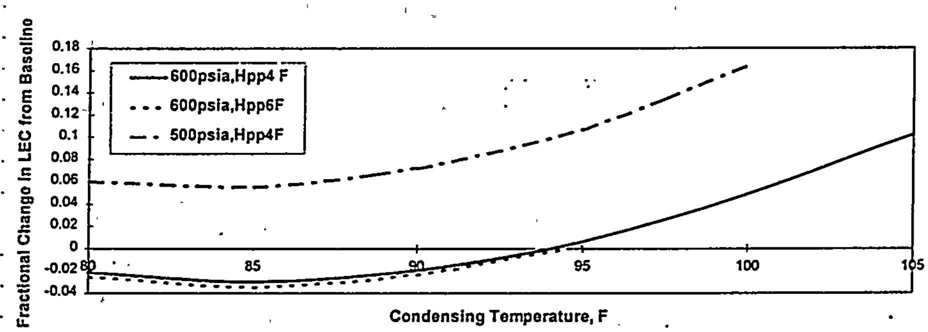

Fig. 2 LEC for Propane cycle compared to the Baseline Isobutane cycle

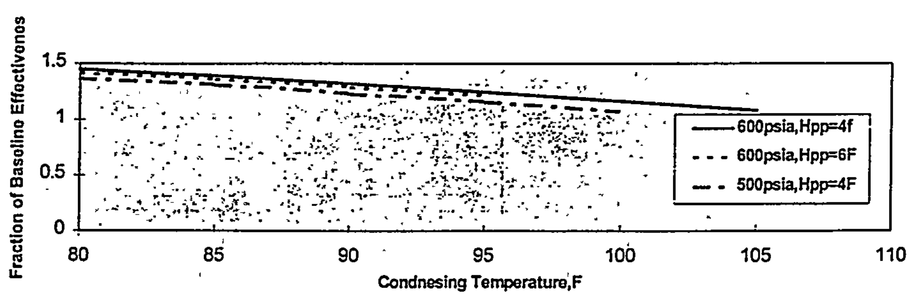

Fig 3. Net Effectiveness for a 280 F resource using Propane

DEMONSTRATION OF A BIPHASE TOPPING TURBINE

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ABSTRACT

A wellhead power plant with a Biphase rotary separator turbine is being constructed at Cerro Prieto, Mexico. The Model 30RSB Biphase turbine is a production design with improved performance and reduced cost, resulting from development projects, and proven by demonstration operation under this Department of Energy program at Coso Hot Springs, CA.

The Model 30RSB Biphase turbine is sized for application as a topping turbine for use at most geothermal projects worldwide that have medium to high pressure resources. The first unit will increase the electricity production due to the given well flow by more than 40%. This major improvement in utilization of the resource leads to significant reduction in geothermal power costs, which is the goal of this DOE meeting.

Cost savings have been realized for this turbine by means of a standardized design, by innovative ceramic bearings, and by simplification of the rotating elements. Improved performance by the use of steam blades was proven by the sub-scale tests. Analysis shows that the addition of a backpressure steam turbine significantly improves power output on high enthalpy wells.

Design and projected performance of the initial wellhead plant are reported.

BACKGROUND

The rotary separator turbine was invented in 1975[1]. This turbine, the Biphase turbine, generates power from mixtures of gas and liquid. For geothermal flash steam power plants, application of the Biphase turbine to the wellhead flow can generate power from the available two-phase energy otherwise dissipated in frictional heating in the flash process. The Biphase topping turbine or the flash separator supply steam to a central steam power plant.

Analysis relied heavily on design of two-phase nozzles. Machine tests showed the practicability of liquid/gas separation on a rotating drum, production of power from the rotating element, and recovery of liquid under pressure by means of a diffuser.

Early versions of the Biphase turbine, applied to geothermal brine, converted pressure and temperature energy (enthalpy) in the fluid to kinetic energy by accelerating the fluid in the nozzles. The kinetic energy in the liquid was converted to shaft power on the rotating drum, but the kinetic energy in the separated steam was not converted. Nevertheless, a 1600 kW Biphase turbine operating at Roosevelt Hot Springs for 4000 hours demonstrated a 20% increase in power output above the single flash steam system[2].

In order to utilize the steam kinetic energy, an advanced Biphase turbine was developed which included a single stage of steam blades operating in the separated steam. For a low quality, high pressure, water-steam mixture the addition of steam blading increased the turbine output power by 75%.

By using a single rotor, the advanced turbine achieved simplified mechanical elements. Innovations in bearings and seals were adopted.

To demonstrate the applicability of the single rotor with steam blades to geothermal power production, a program was proposed to operate a sub-scale unit on a geothermal well and to determine steam blade performance. This demonstration would be followed by the design, fabrication and operation of a full size commercial unit in an existing geothermal flash steam power plant.

The proposal was accepted by the U.S. Department of Energy. The project was joined by the

California Energy Commission. The sub-scale test site was provided by the California Energy Company. The installation site for the commercial Biphase plant was provided by the Comisión Federal de Electricidad.

PROJECT DESCRIPTION

The project for commercial demonstration of the advanced Biphase turbine is being conducted in two phases:

Phase 1 is the demonstration of the sub-scale unit under realistic field conditions. The 12-inch Biphase unit, Model 12RSB, which included steam blades, was equipped with nozzles sized for the low pressure fluid at Coso Hot Springs. The portable system was operated for three periods with high, medium, and low enthalpy at a range of speed, pressure, flow, and steam quality. The results were used to evaluate performance of the steam energy conversion as well as durability and performance when operated at the geothermal well.

Phase 2 is the design and operation of a full size (megawatt class) advanced Biphase turbine. Review of worldwide applications resulted in selection of a rotor size of 30 inches for universal application, with interchangeable nozzles for different field conditions. System designs include a backpressure steam turbine stage for very high well pressures. The completed power plant will be installed on a well at the Cerro Prieto geothermal field. Operation is scheduled to start in the Fall of 1996. Separated steam will be sent to the existing CP1 Power Plant. The Biphase turbine will be oeprated for two years to evaluate performance and reliability. Power produced will be supplied to the commercial grid of Comisión Federal de Electricidad.

Phase 2 includes analysis of applications at geothermal fields throughout the world together with economic analyses to determine if a viable American business for domestic and export will develop. The Application and Economic study results showed that the Biphase topping power plants, costing \$500 to \$750 per kW, can be built and operated at a profit in Mexico, the Philippines, and Indonesia. This export market is estimated at 977 MW by the year 2003.

SUB-SCALE BIPHASE TURBINE

The sub-scale Biphase turbine with steam blades was fabricated for an in-house program using pure steam. The turbine Model 12RSB was equipped with 10 new nozzles sized for the Coso well conditions. The control system was revised for semiautomatic operation, simulating future full automatic operation. The turbine and all accessories were mounted in a highway trailer, with controls in a separate trailer.

The Model 12RSB Biphase turbine was disassembled for inspection after 720 hours operation at Coso. The rotor is pictured in Figure 1. Two of the ten nozzles are shown to illustrate the angle of impingement on the inner rim of the wheel. The stationary liquid diffuser is mounted on the opposite side of the wheel.

The Model 12RSB Biphase turbine incorporated most of the essential features of the full size commercial turbine for the project. The main limitation for the Phase 1 demonstration was the low pressure of the geothermal well which was available at Coso. The maximum well pressure was only 100 psia compared to the original design pressure of 400 psia for the sub-scale turbine and 800+ psia for the full size turbine. The low pressure available limited the nozzle efficiency and flowrate (and hence, power output). However, analysis of the off-design performance was made which agreed well with measured results, confirming the utility of the analytical codes.

SUB-SCALE TEST RESULTS

The turbine efficiency defined as (*gross shaft power*) divided by (*isentropic enthalpy difference from inlet to exit*) is shown in Figure 2. Efficiency increases from about 10% of the lowest enthalpy to 46% for the highest enthalpy. These values were obtained for very low values of the ratio of blade speed to jet speed (typically 0.18 to 0.25). The optimum steam blade efficiency occurs at a value of 0.5.

The results validate the nozzle code and rotor performance codes over a wide range of operating conditions. The close agreement of the steam blade performance and previously demonstrated agreement of the two-phase nozzle code and rotor performance at design conditions validate their use to design the full size Biphase turbine and to predict performance.

30RSB TURBINE DESIGN ADAPTABILITY

The full size Biphase turbine has been designed to be adaptable to a wide range of geothermal well conditions. This feature of adaptability is provided by making contour changes to three independent components within the turbine. These components are: 1) the two-phase flow nozzle inserts, 2) the single stage of impulse steam blades and 3) the output liquid diffuser. Altering the design of these three components provides the adaptability of the 30RSB turbine to the range of wellhead conditions shown in Table 1. These conditions are found in the productive liquid-dominated fields worldwide.

Table 1 - Range of 30RSB Operating Conditions

Wellhead Enthalpy	350 to 1000 Btu/lbm
Wellhead Pressures	100 to 1000 psia
Total Flowrates	0.05 to 1.0 MM lbm/hr
Steam Output Pressures	50 to 450 psia
30RSB Output Power	0.5 to 4 MW
30RSB & Back Pressure Turbine Power	1.0 to 12 MW

This adaptability feature also provides the ability to modify an existing machine to meet major resource changes within the above ranges. The Biphase turbine is relatively insensitive to small changes in resource parameters, and ordinarily no hardware changes will be required. Moderate changes can be accommodated by rework or replacement of nozzles, and the machine design is especially made to expedite field nozzle interchange. Significant resource changes may require rework of steam blades by changing blade length.

ROTARY SEPARATOR TURBINE IMPROVEMENTS

The design of the 30RST turbine incorporates major design improvement from prior commercial RST turbine designs to improve the performance, reliability and reduce costs. These are summarized in Table 2. With the exception of bearings and seals, the design improvements were demonstrated during Phase 1 of this program by their application to the sub-scale 12RSB.

Table 2 - 30RSB Design Features

1. Single rotor design.
2. Increased power output from integral steam blade stage.
3. Silicon carbide bearings - water lubricated.
4. Seal arrangement to prevent geothermal process fluids from entering seals or bearings.
5. Cost savings from reduction in overall rotor size from 54 to 30 inches.
6. Improved liquid turbine efficiency by increasing the number of nozzles from 4 to 8.

The single rotor design represents a major reduction in cost and complexity from the prior three-rotor design previously demonstrated in the Roosevelt Hot Springs test turbine. The single rotor design permits the addition of a single stage of steam impulse blades to the rotor disc which more than doubles the turbine output power. The single rotor design replaces the three, cantilevered shaft and bearing assemblies in the prior design with one simpler and less costly trunion shaft design. This design provides a much improved dynamic stability of the rotor.

The rotor bearing and seal assembly used previously was an oil lubricated babbit type bearing with labyrinth seals. The present design replaces these with water-lubricated silicon carbide bearings and low leakage face seals. The replacement of the conventional lubricating oil with water lubrication provides a simplification from elimination of logistic problems associated with lube oil and the handling of contaminated used oil. The major benefit derived from the change from oil to water lubricated bearings is to prevent the leakage of geothermal process fluids (steam or liquid) into the shaft seals. This is accomplished by maintaining the bearing cavity pressurized with the lubricating water flow at a pressure typically 25 psi above the process pressure of 425 psia, within the turbine case. This low pressure differential of 25 psi across the face seal results in little or no leakage of clean water into the geothermal process. The important aspect of this design is that it eliminates the potentially damaging situation of silica scale deposition within the seal if process geothermal steam is permitted to flow into the seal.

30RSB TURBINE DESIGN

The rotary separator turbine which embodies the design simplifications described above is the 30RSB. A cross-section of the 30RSB is shown in Figure 3.

Well mixed two-phase flow enters one of two inlets. 1, An internal splitter, 2, divides the flow into four equal streams, each feeding a two-phase nozzle. 3, The two-phase nozzle is formed by a contoured insert which can be removed and replaced through an external port, 4. The flow is accelerated in the nozzle, forming a two-phase jet, 5, which is separated on the rotary separator surface, 6.

The separated liquid, 7, is slowed to the velocity of the separator by frictional forces, converting the momentum to torque. The liquid subsequently flows through holes, 8, in the separator disc to the opposite side where it enters a diffuser, 9. The flow is decelerated to convert the remaining velocity head to pressure and exits through a port, 10, in the casing.

The separated steam, 11, flows through axial impulse blades, 12, converting the steam kinetic energy to power. Steam subsequently exits through the steam port, 13.

The Biphase 30RSB has conventional face type seal with a clean water purge to eliminate scaling. Tilting pad bearings are used to provide the straddle mounted rotor with the required stiffness.

The operating speed is 3600 rpm enabling direct drive of the generator. The first critical is at 4500 rpm, a 20% margin above the operating speed.

The rotor and blades are manufactured from HY 80, an alloy used for previous Biphase geothermal units. Previous experience with brine velocities of 400 feet per second showed that alloy to be resistant to both corrosion and erosion.

30RSB GEOTHERMAL TEST SITE DESCRIPTION

The site selected for the full size turbine is Cerro Prieto Well Number 103, which supplies steam to the 180 MW Cerro Prieto 1 power plant installation. The Cerro Prieto geothermal field is located in Mexico, approximately 25 miles southwest of Calexico and Mexicali. The total power produced at the field is 620 MW. The Comisión Federal de Electricidad, owner and operator, is cooperating in this program.

Figure 4 schematically shows the present operating conditions for well 103 as the design basis for the 30RSB turbine.

The well currently is operated at a wellhead pressure of 755 psia. At this pressure a flowrate of 312,000 lb/h is produced with a steam fraction of 45%. The flow is flashed to 126 psia to produce steam. The steam is utilized by the Cerro Prieto turbines to produce power. At the current steam rate of 24 lb/kWh the steam from this well produced 7410 kW.

Figure 5 schematically shows the addition of the 30RSB power train to the Cerro Prieto well 103. The normal power train consists of the 30RSB turbine which is directly coupled to a 3600 rpm 5 MW synchronous generator. The generator is also connected to a two-stage, backpressure steam turbine. Because of the availability of an existing backpressure steam turbine-generator, the plan is to use separate turbine-generator skids for the 30RSB and backpressure turbine for the first application to well 103. Table 3 gives design parameters.

The total power output from the Biphase system is estimated to be 4353 kW (shaft). A 4% design margin gives a final predicted electrical output of 4180 kWe. The steam produced will generate an additional 6610 kW in the central steam turbine giving a total power output from the well of 10,790 kW. Thus, addition of the Biphase system at this site increases the power production from the chosen well by 45%.

Table 3 - Design Parameters for Biphase Power System for Cerro Prieto Well No. 103

Biphase Turbine	
Inlet Pressure	755 psia
Inlet Flowrate	312,480 lb/h
Inlet Steam Fraction	0.455
Biphase Exit Pressure	424 psia
Rotor Diameter	30 inches
Rotor Speed	3600
Output Power	1135 kW (shaft)
Steam Turbine	
Inlet Pressure	416 psia
Inlet Flowrate	149,700 lb/h
Inlet Steam Fraction	1.00
Exit Pressure	126 psia
Output Power	3218 kW (Shaft)
Total Generator Power from Biphase Plant	4180 kWe (electrical)

Note: Minor adjustment of these parameters, as compared to the paper in Geothermal Program Review XIII, is due to adjusted values of well pressure and flow.

Figure 6 is the general arrangement of the dual skid configuration on the platform of well 103. Major equipment consists of the two turbine skids, two enclosed skid mounted rooms for control and electrical equipment, and an auxiliary separator.

PERFORMANCE VARIATION WITH GEOTHERMAL RESOURCE VARIATION

The two-phase nozzle design code and the Biphase turbine performance code were used to estimate the system performance over a range of resource conditions. The power increase for a single stage flash geothermal turbine with the addition of a 30RSB power train including backpressure steam turbine is shown in Figure 7 for geothermal wellhead enthalpies from 400 to 900 Btu/lbm. These data show for very high well pressures of 900 psia the percentage power increase rises from 23% at an enthalpy of 550 Btu/lbm to 40% at an enthalpy of 900 Btu/lbm. The data show similar results for well pressures of 100, 300 and 600 psia.

The variation of 30RSB system power and total power including a condensing turbine over the same range of variables is shown in Figure 8 for one or more wells with a total flow of one million lbm/h. At the highest well pressure curve of 900 psia the power of 30RSB turbine system is 14.1 MW. This power total consists of 3.9 MW from the 30RSB and 10.3 MW from the backpressure turbine. The second set of data labeled Total Power represents the additional power from a condensing steam turbine with efficiency of 77% and condensing pressure of 1.5 psia. For the enthalpy of 950 Btu/lbm and wellhead pressure of 900 psia, the total power is 49 MW of which 28% is obtained from 30RSB power train.

CONCLUSIONS

The production Model 30RSB Biphase turbine, together with a wellhead system including a backpressure steam turbine, provides a topping power plant which can be built and operated at a profit in existing and future geothermal projects. Total cost of the Biphase power plant is $500 to $750 per kW.

The power resulting from the well flow from well 103 at Cerro Prieto, supplying steam to central plant CP1, is increased by more than 40% by the addition of the Biphase topping plant.

Application of ceramic bearings, lubricated by water, can result in major simplification of Biphase and geothermal turbines.

The single rotor Biphase production design with integrated steam blades represents a major equipment cost reduction and performance improvement.

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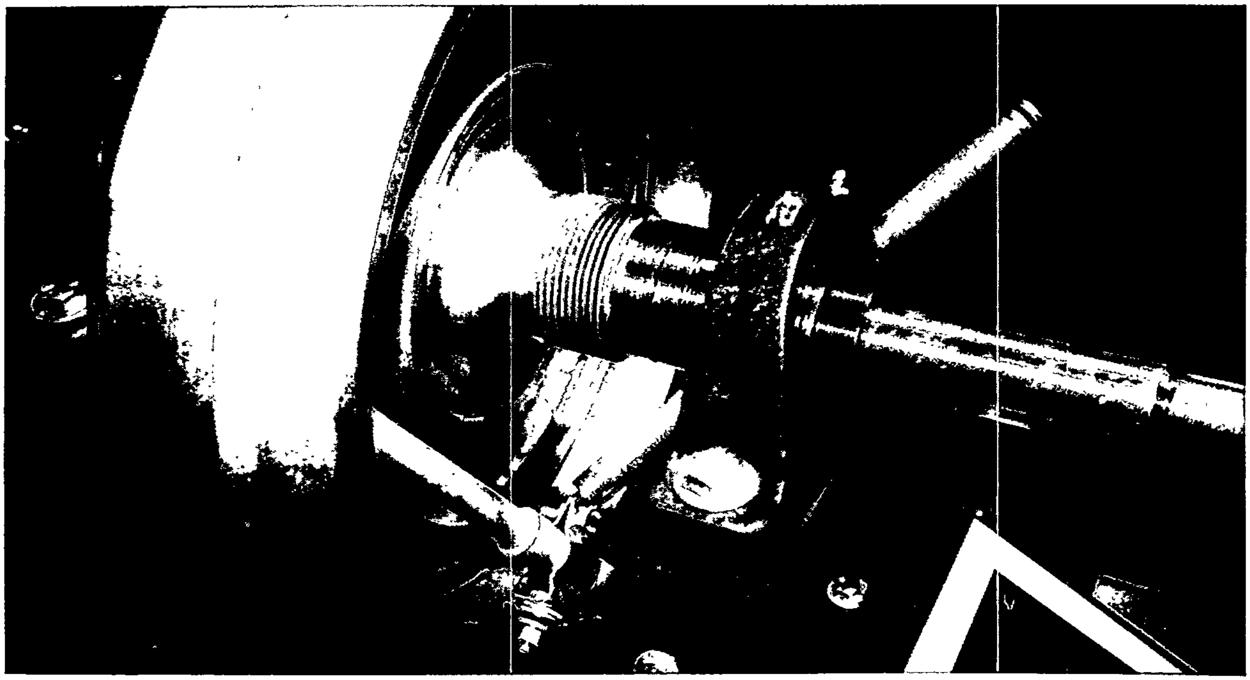

Figure 1. Model 12RSB Rotor after 720 Hours Operation

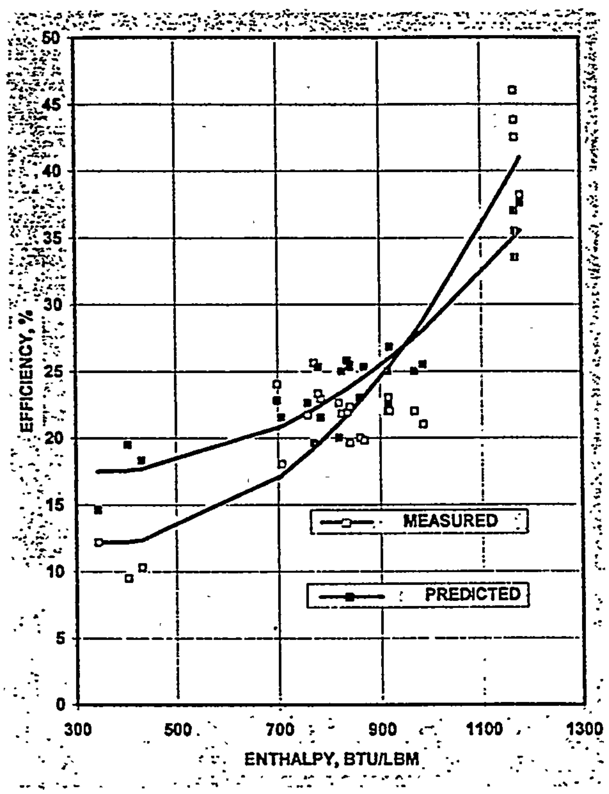

Figure 2. Measured and Predicted Efficiency

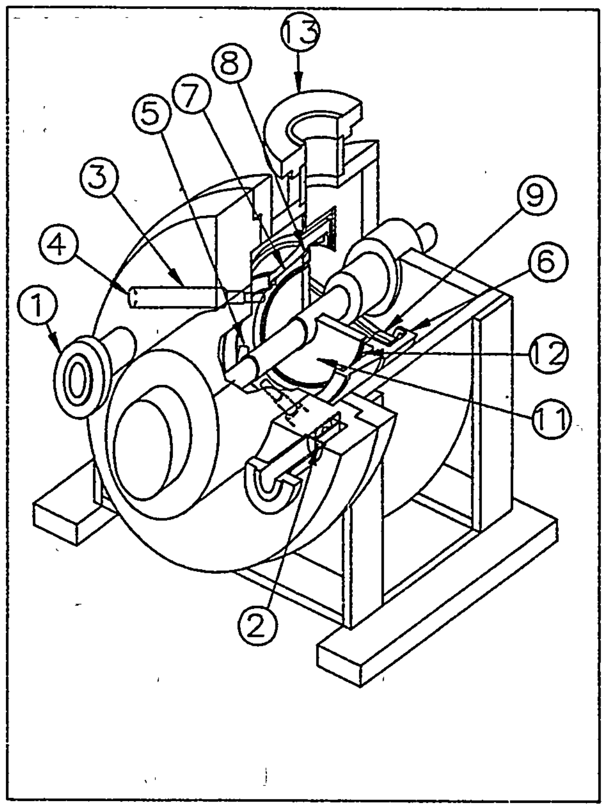

Figure 3. 30RSB Turbine Isometric

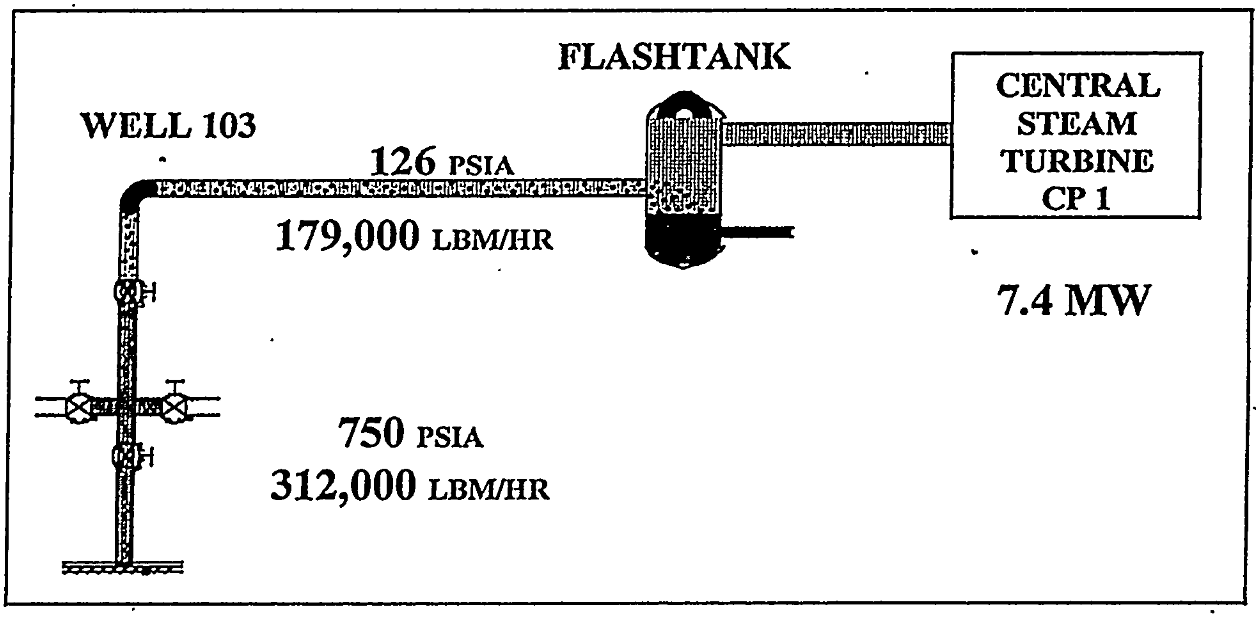

Figure 4. Schematic of Present Well 103 Conditions

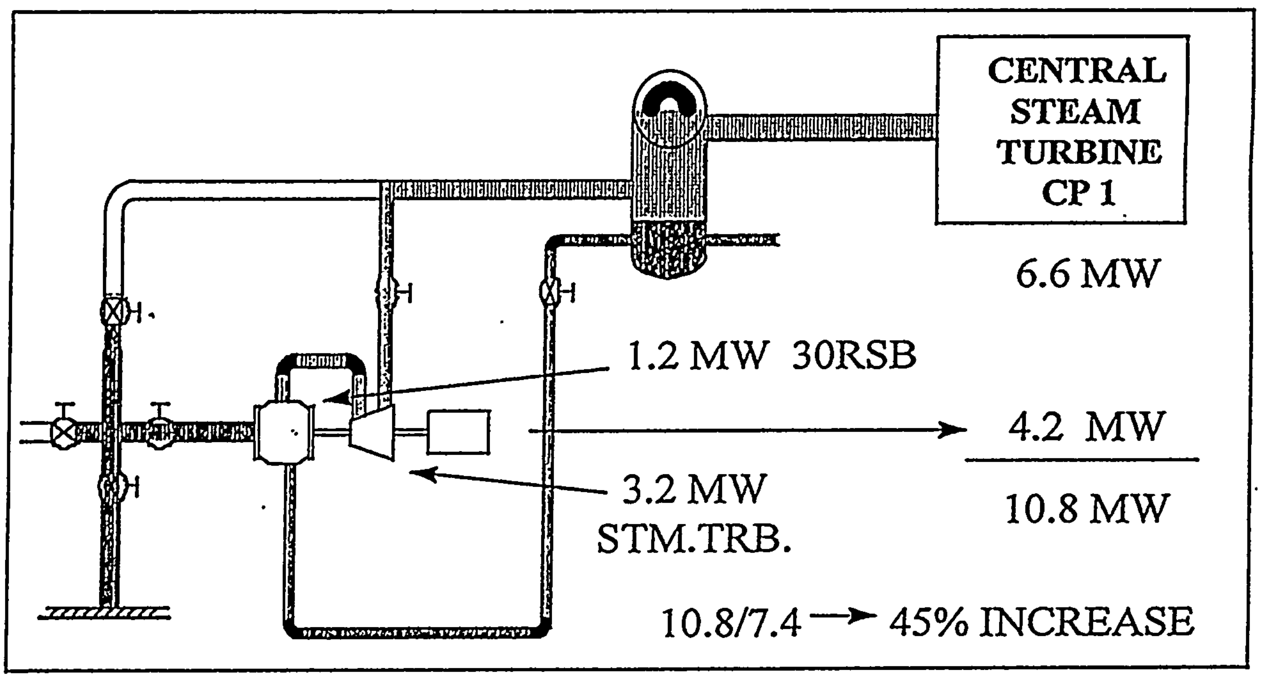

Figure 5. 30RSB Addition to Well 103

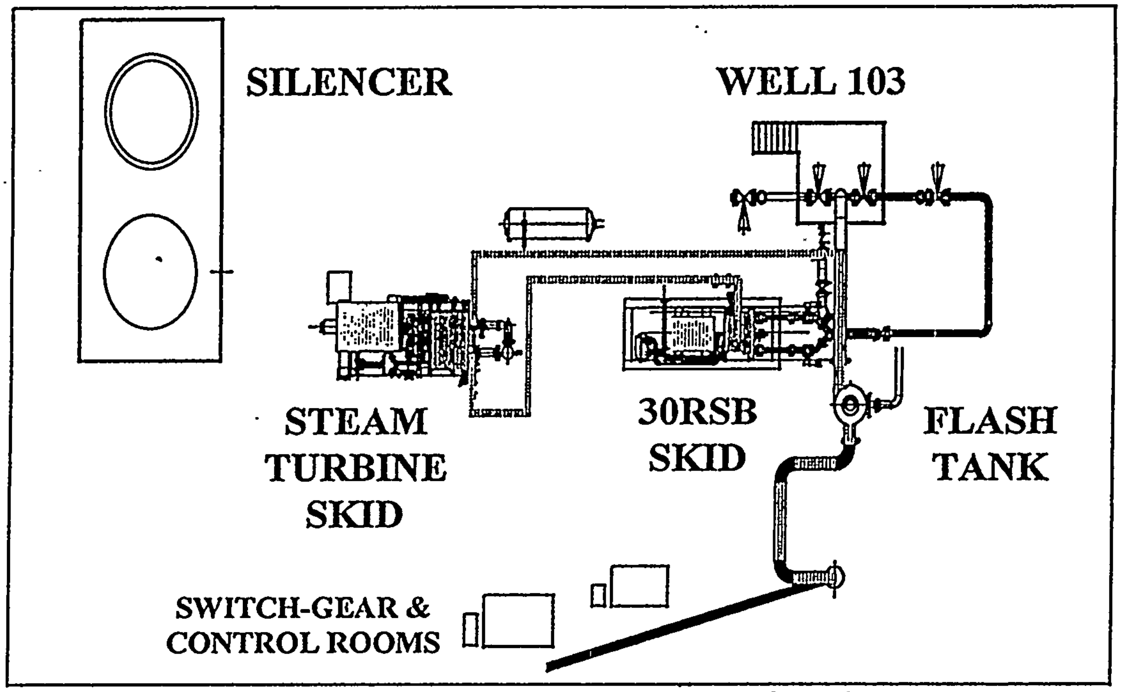

Figure 6 30RSB Dual Skid Plot Plan

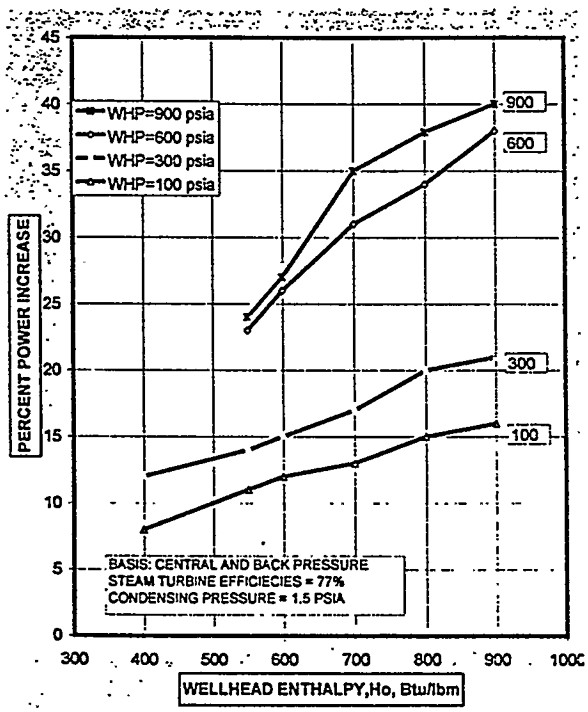

Figure 7. 30RSB Potential Power Increase

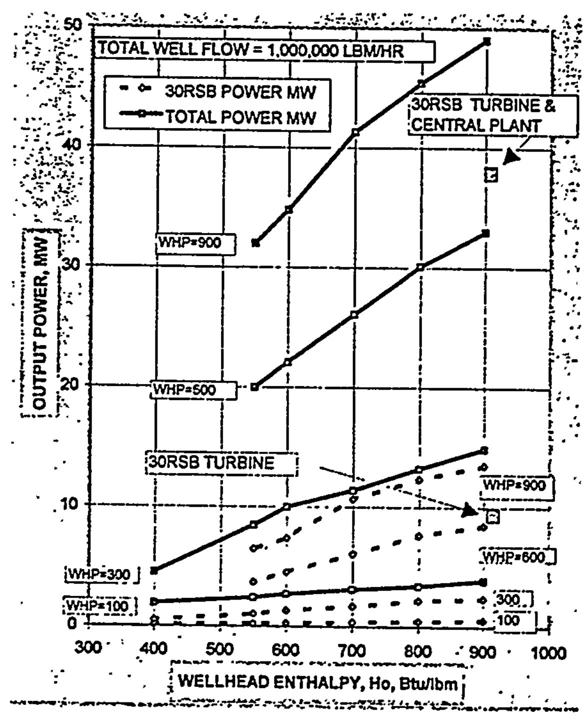

Figure 8. 30RSB System Power Output

RECENT ADVANCES IN BIOCHEMICAL TECHNOLOGY FOR THE PROCESSING OF GEOTHERMAL BYPRODUCTS

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ABSTRACT

Based on Laboratory studies, the biochemical technology for the treatment of brines and sludges that are generated in the production of electric power from geothermal resources is promising, cost-efficient, and environmentally acceptable. In terms of scaled-up field applications, the new technology depends on the chemistry of the resources which influence the choice of plant designs and operating strategies. The latter have to be flexible and adaptable to variables such as high and low salinities, temperatures, quantities of geothermal materials to be processed and the chemical properties of brines and by-products. These variables are of critical and economic importance in areas such as the Geysers and the Salton Sea type resources. In addition to power production, the economic benefits which may be derived from geothermal brines and sludges, now disposed of as wastes, are attractive. This is particularly so, since the emerging biochemical technology is inexpensive and can be integrated with other processing options which convert residual materials into commercially useful products.

In a joint effort between industrial collaborators and BNL, several engineered processes for the treatment of secondary and other by-products generated in the power production from geothermal resources are being tested. In terms of field applications, there are several options. Some of these options will be presented and discussed.

BACKGROUND

Extensive studies leading to the development of biochemical technology for the treatment of geothermal sludges and brines have shown (1-4) that the emerging technology is cost-efficient and environmentally acceptable. Concurrently, the studies have also shown that a number of process variables have to be taken into consideration in the design and engineering of the total process as well as in the cost analysis. The parameters which have to be considered include rates on input, volume, batch, or continuous processing, residence times, recycling of biocatalysts; corrosion and the chemical characteristics of the incoming materials as well as those of end products. In a typical full design for processing of large input of (~1 ton/h) filtered sludge, shown in Figure 1, the supply of biocatalysts and the treatment of produced waters become determining factors. Thus, experimental data (e.g. 1) have shown that a significant cost-reduction can be achieved by recycling of the biocatalysts and changing the ratios of the biocatalyst mix. Other options have also become apparent during the studies. These include metals and salt recovery possibilities as well as strategies which would lead ultimately to the utilization of the sludge from which toxic and valuable metals have been removed. To facilitate optimization studies and explore alternative strategies, a laboratory scale batch process is being used. Typical scenario for the batch process is shown in Figure 2. In this scenario, streams A and B are combined for metal recovery, where stream A is derived from the plant and stream B is derived from the biochemical reactor via stream 9 in which the solids are removed and the filtrate stored in tank B. In the earlier versions, the filtrate which contains toxic and valuable metals was neutralized with calcium hydroxide and the precipitate filtered and the aqueous phase reinjected. There are disadvantages to this approach. Precipitate in stream 14, although greatly reduced in volume, compared to that generated in stream 10, will still have to be disposed of. Maintaining an appropriate anionic and cationic concentration allows to pool stream 11 from the holding tank B with stream A with the full elimination of all the steps beyond B. The sterilizers used in the preparation of biocatalysts are inexpensive commercially available units, normally used in water treatment processes and are needed only prior to the mixing of biocatalysts and are not needed in downstream applications of the biocatalyst mix. Other options, such as the recovery of select metals, production of potash and further treatment of the purified filter cake are also possible and the cost-efficiency of such scenarios has already been discussed elsewhere (4). As mentioned earlier, further adaptations of the system are possible and will be discussed briefly in the next section.

RECENT ACTIVITIES

A fully developed process, including all the processing options and alternatives, is summarized in Figure 3. This scenario assumes use of brines with high concentrations of dissolved solids at elevated temperatures and relatively fast flow rates. Current R&D addresses these options and in the following discussion, the filter cake option will be considered first. Assuming a production of filter cake at a rate of over a ton per hour, as shown in the scenario given in Figure 1, a substantial annual yield of this material is realized. If the chemical and physical properties of this material can be manipulated, then formulation of a new product might be feasible. Analysis of this material indicated that with some additional treatment, the bulk of the material in the filter cake can be converted into a paper and/or paint filler(5) and become a commercially attractive product, an avenue which we are currently exploring jointly with our industrial colleagues. Typical analysis of the filter cake produced by the process shown in Figure 1, is given in Figure 4. After additional treatment, the material is depigmented, leaving predominantly high quality silicates.

Further modification of the total process allowed it to be applied to a different type of a sludge. In a joint venture in the form of a "Collaborative Research and Development Agreement" (CRADA) between CET Environmental Services, Inc. and BNL and other arrangements between CET and PG&E, the modified BNL process is being tested for the treatment of the slurry generated in the hydrogen sulfide abatement technology. In this application, one has to consider only two metals, arsenic and mercury and a non-metal, sulfur. As shown in Figure 5, there are two treatment options available. One involves an initial sulfur extraction followed by the biochemical processing of the residue and the other the direct biochemical treatment of the slurry. The rates of the metal removal in either of the options are given in Figure 6. Scenario 2 involves a solvent extraction step to isolate a high quality sulfur. Because of environmental considerations, Scenario 1 is the process of choice and is now being fully explored. For this purpose, CET Environmental Services, Inc. has designed a process, diagramatically shown in Figure 7. In this process, the sludge from a settling tank is mixed with prepared biocatalysts in bioreactor 1 for the first treatment, followed by a shorter treatment in bioreactor 2. After separation, the aqueous extract meets the analytical and regulatory requirements and is reinjected. The residue is arsenic and mercury free, predominantly sulfur of a lower commercial grade. Optimization of this process is currently in progress.

CONCLUSIONS

1. New biochemical technology for the treatment of different residues derived in the production of geothermal power is versatile and cost-efficient.

2. Collaboration with industry, particularly CET Environmental Services, PG&E, and CALEN is active and efficient which makes

possible a full development and field applications of the new technology.

ACKNOWLEDGMENTS

This work has been supported by the U.S. Department of Energy, Office of Conservation and Renewable Energy, Geothermal Technology Division, Washington, DC under Contract No. AM-35-10 and by Brookhaven National Laboratory with the U.S. Department of Energy under Contract No. DE-AC02-76CH00016. We also wish to express our gratitude to W.M. Zhou, J. Yablon, and Y. Lin for technical assistance and Ms. Gladys Hooper, the U.S. DOE program manager, for continuous interest and encouragement.

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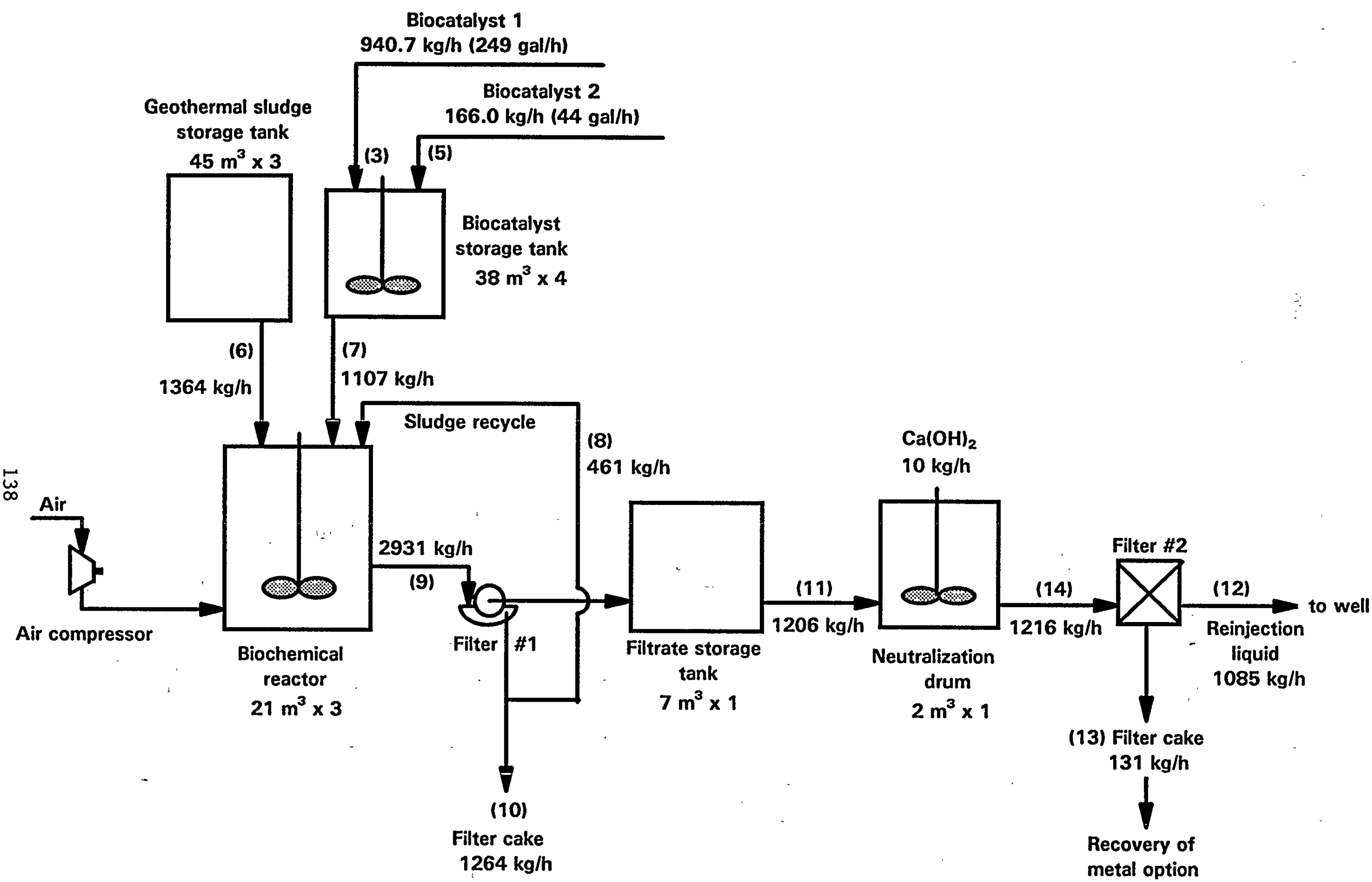


Figure 1. The biochemical process for geothermal sludge (3000 lb/h flux, BC1:BC2 = 85%:15%)

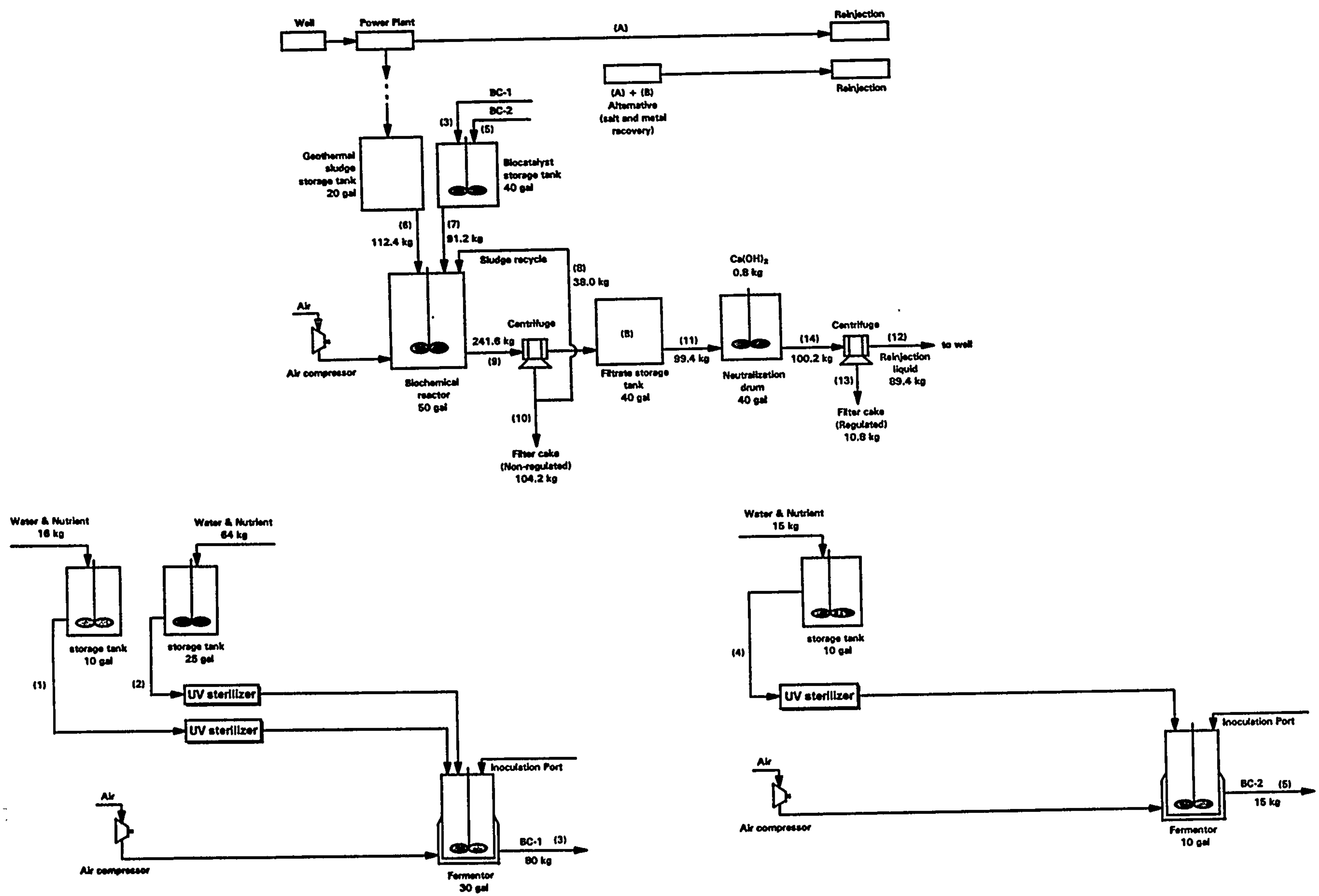


Figure 2. Laboratory batch process for the production of biocatalysts and the treatment of sludges and brines

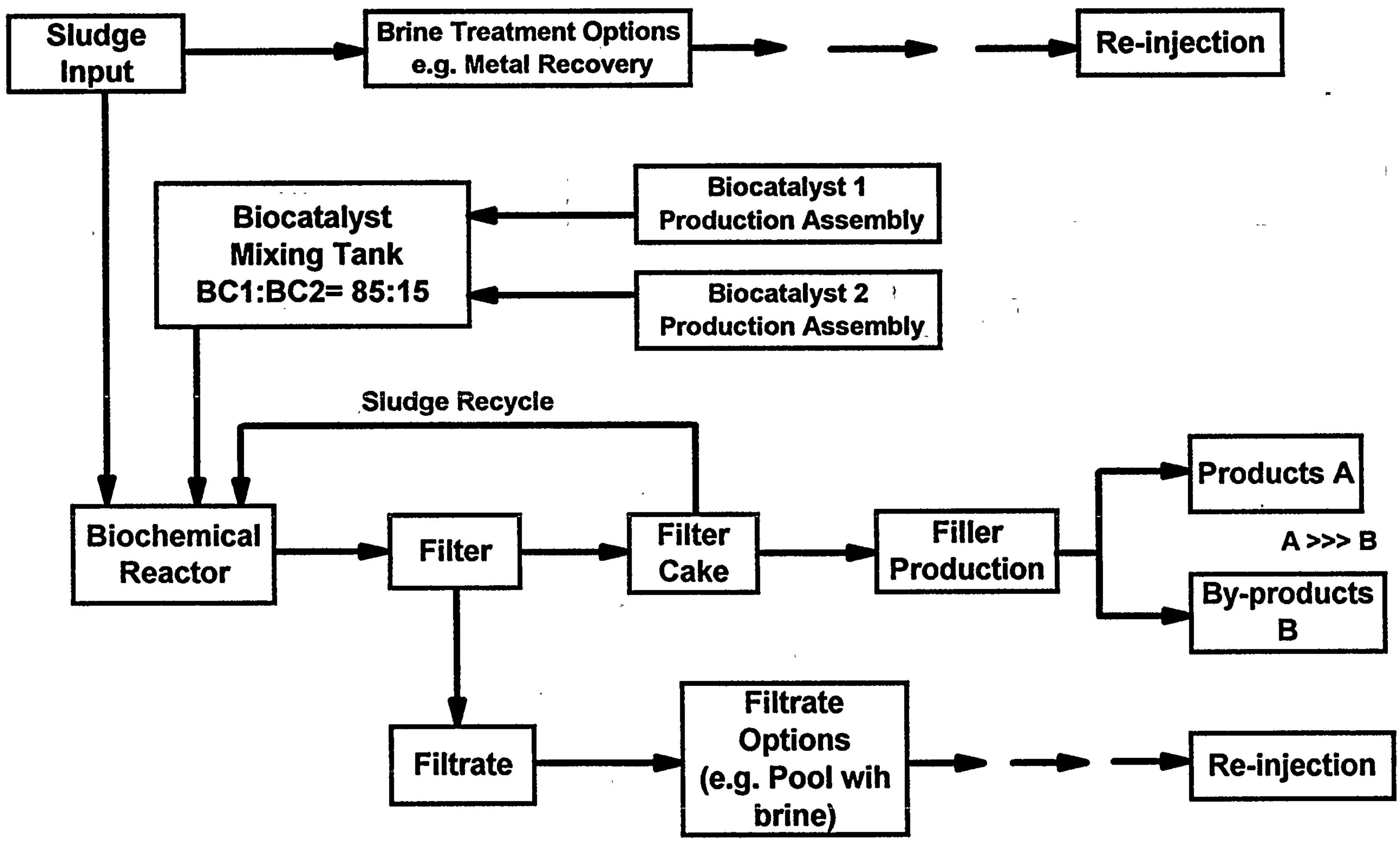
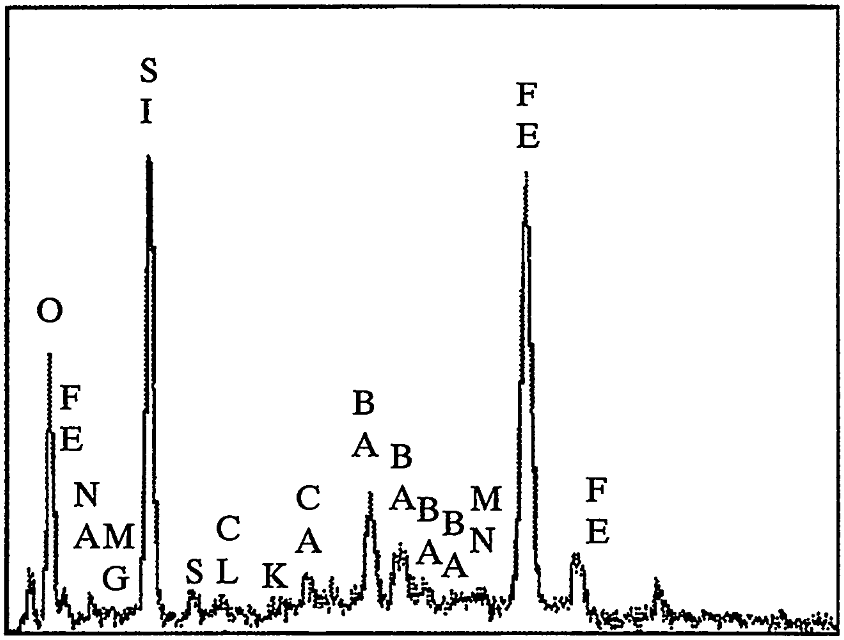


Figure 3. Total processing of geothermal sludges and brines

Untreated



Treated

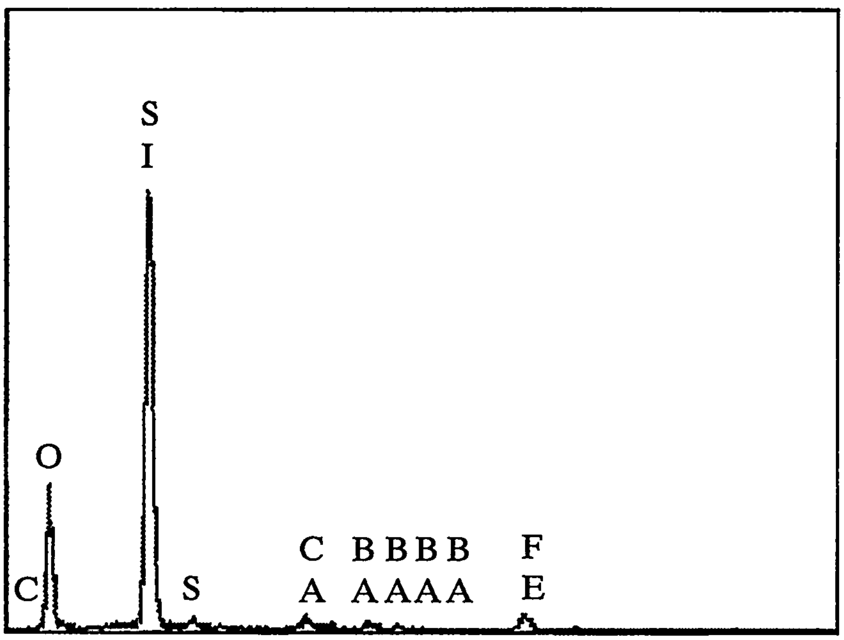


Figure 4. Energy Dispersive Spectroscopy (EDS) x-ray analysis of processed geothermal residues

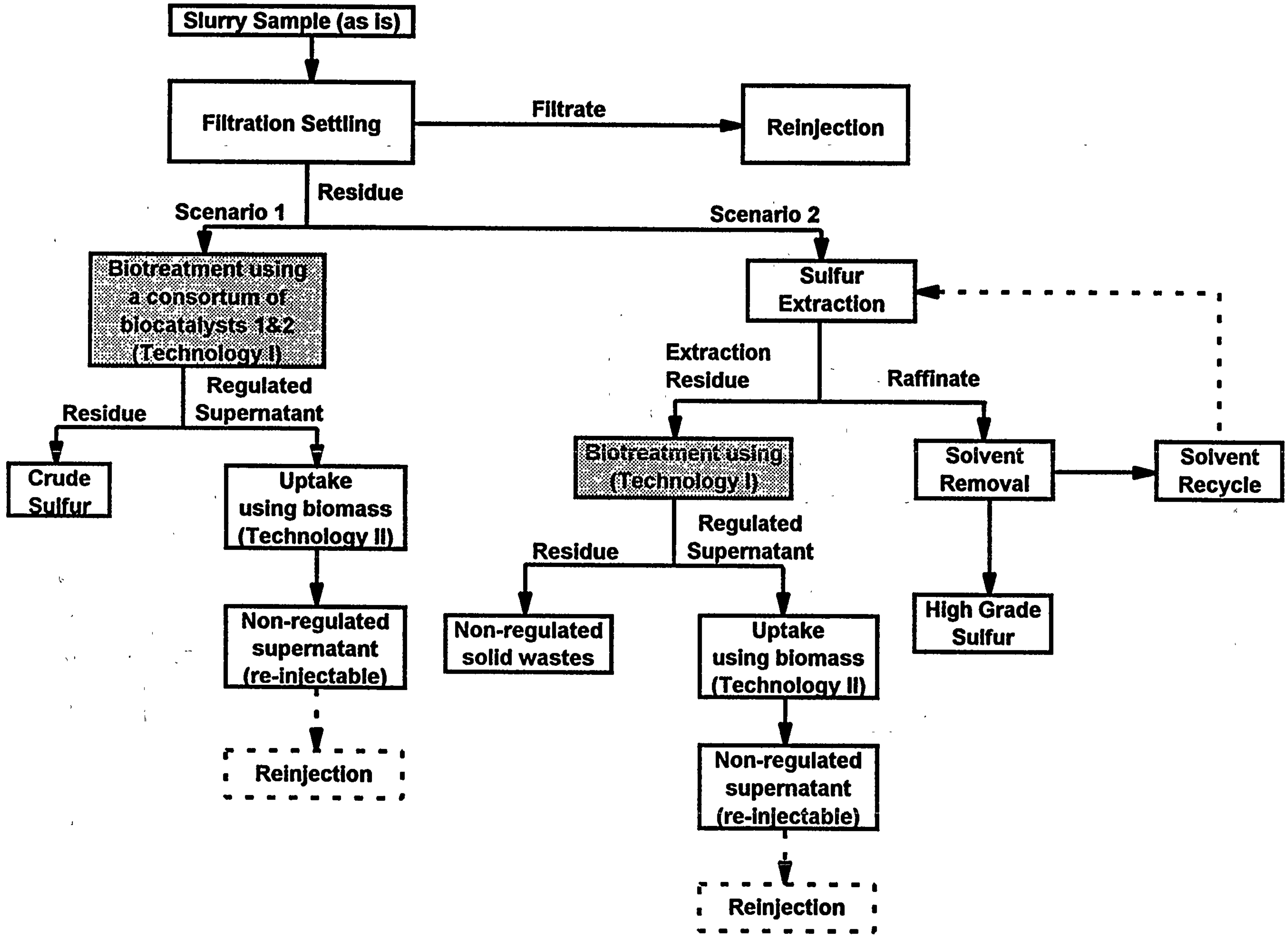
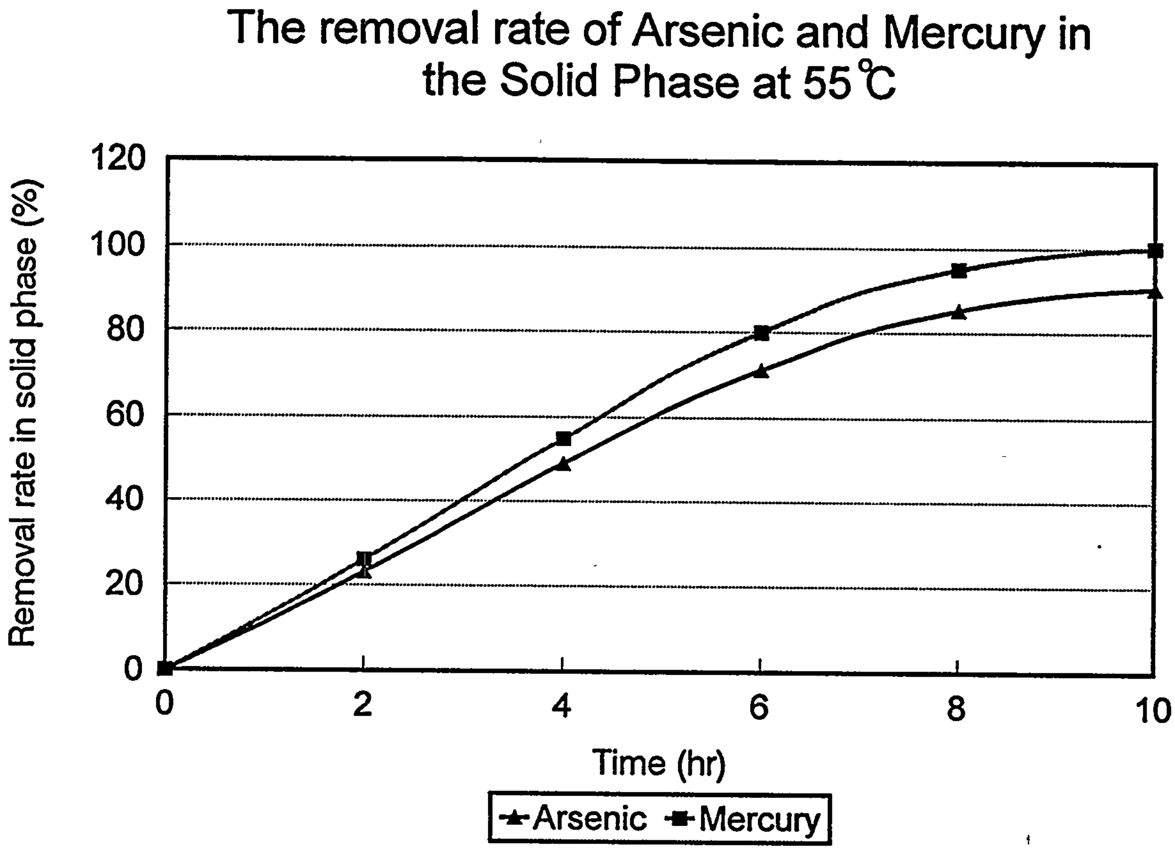


Figure 5. Proposed scheme for the treatment of geothermal waste slurry (CET/P.G.&E./BNL)



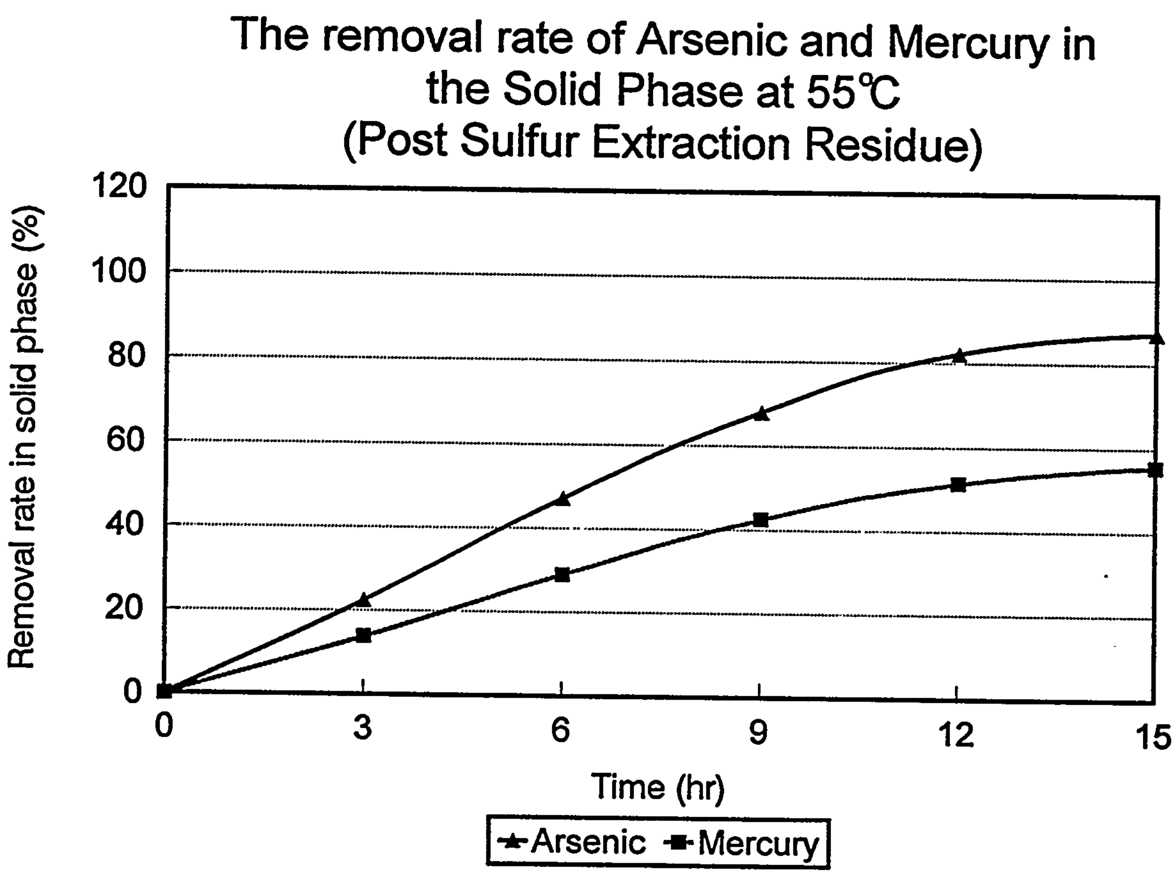


Figure 6. Rates of arsenic and mercury removal

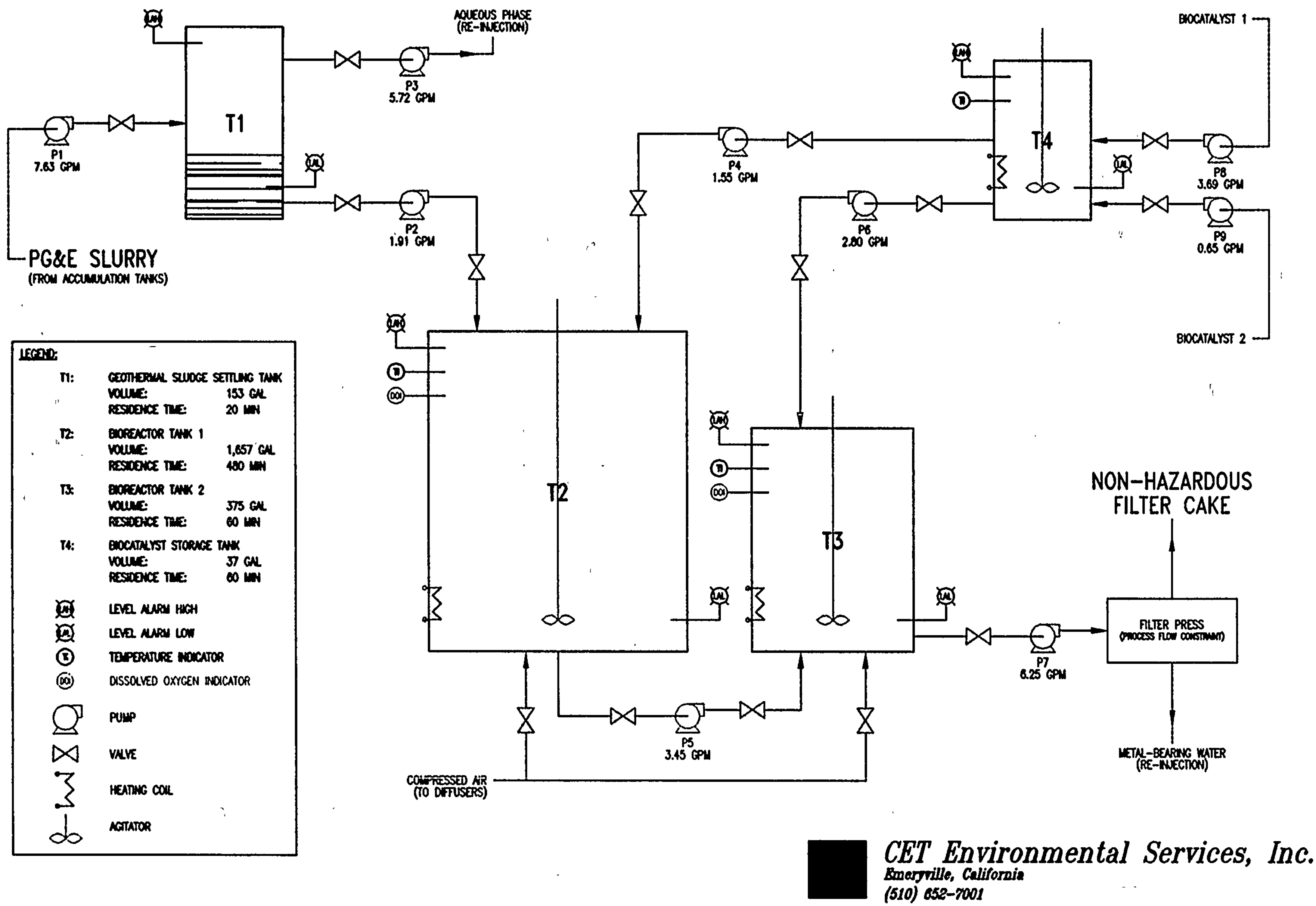


Figure 7. Basic process flow diagram. Bioremediation of geothermal sludges

CHEMICAL MODELS FOR OPTIMIZING GEOTHERMAL ENERGY PRODUCTION

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ABSTRACT

The progress of our chemical modeling program is described. This year's improvements include the development of an enthalpy model for geothermal brines and their coexisting vapor phases. This model may be used to estimate working energy content, liquid/steam ratios, etc. In addition we have developed methods of simulation of geothermal fluids from first principles that promise to supplement experimental data. Examples of the remarkable agreement between theory and experiment for ternary systems are presented here. Significant improvements in our ability to visualize the output of our application software were initiated. These programs will allow the geothermal engineer to rapidly interpret the composition and phase information from model calculations. We also have continued the development of more user friendly interfaces for our geothermal application software. Improvements include an improved method of saving prior calculations and improvements in user options.

PROJECT OBJECTIVES

To improve the productivity and efficiency of geothermal operations and exploration by providing user friendly computer models of the thermochemical and thermophysical properties of geothermal reservoir and brines and their associated noncondensible gases and solid phases. These easy to use models provide operators, engineers and consultants with the ability to enhance operation by adjusting process variables, to rapidly analyze potential problems and to develop strategies for their abatement. Our project also includes efforts to increase communication with the geothermal community, to improve technology transfer and to increase the relevance of the models to the problems of the industry.

TEQUIL application package: This series of computer programs will include variable temperature ($T < 250°C$) solubility models of geothermal brine components at liquid densities. Reservoir/brine interactions, scaling and gas-breakout as well as mixing, pH, reinjection compatibilities, spent brine storage effects, etc., can be calculated using this package.

GEOFLUID application package: This series of computer programs will include models for calculation of the PVT properties and vapor/liquid equilibria from subcritical to supercritical temperatures and pressures. Both experimental data and results of molecular dynamics simulations are used to develop a reliable and very general data base for these models. Application of these programs include: gas breakout, fluid inclusion studies of reservoir evolution, and the solubility of gases.

GEOHEAT application package: This series of computer programs will include specific heat and enthalpy calculations for complex liquid/gas mixtures. It will allow the rapid calculation of gas breakout, liquid/vapor ratios, available heat, etc.

GEOPHASE application package: This package (initiated recently) will provide visualization capabilities to aid in the interpretation of complex gas/liquid/solid phase relations.

Reliable summary of data sets for brine/solid/gas species: Our chemical modeling methods include the correlation and evaluation of many data sets. In this process the reliability of a particular data base is determined by comparison with results of other measurements.

APPROACH

In order to have the predictability required for geothermal applications, highly accurate models of the chemical behavior and physical properties of the resource formation and working fluid and their interaction are necessary. Using recent developments in the chemistry of fluids and gases and with careful attention to parameterization, we have developed models that accurately reproduce measured chemical behavior of brines, solubility and liquid/vapor coexistence, and heat content of both liquids and gases. (see Harvie et. al. (1984), Weare (1987), Møller (1988), Greenberg and Moller (1989), Duan et. al. (1992 a,b)). The models have been applied to well determined production situations with remarkable success.

Our research program also includes a continuing effort to develop new phenomenological expressions which will more succinctly summarize the thermodynamic behavior of solids, liquids and vapors. As new models are developed, they are included in test versions of user friendly software packages, called TEQUIL, GEOFLUID and GEOHEAT (not yet distributed). These can be loaded from diskettes to PC's or Macintosh computers. A continuing effort is made to determine the needs of the geothermal community and to build appropriate software. Periodically, workshops are given on the use of these programs to treat problems of geothermal interest.

HIGHLIGHTS OF THE MOST RECENT RESULTS

Modeling of the Enthalpy of Geothermal Fluids for a Large T-P-X Range: Quantitative estimation of heat transfer in geothermal energy extraction requires the knowledge of fluid and gas enthalpy as a function of temperature, pressure and composition. Unfortunately, few enthalpy data are available for mixed geothermal systems. Only pure water has a relatively complete data base. For this reason, geologists and geothermal engineers use the pure water steam table when enthalpy or other related properties are required. However, in most settings the fluids contain substantial amounts of gases, such as CO_2, CH_4, H_2S, H_2O, O_2, and N_2 (Lyon, 1974, Ellis, 1977). Mahon and Finlayson (1972) reported high CO_2 concentrations in the total discharge from a number of drill holes in the Broadlands Geothermal fields, New Zealand. Submarine hydrothermal systems contain appreciable amounts of CH_4, CO_2 and other gases (Kim, 1983). The presence of gases can substantially alter the manner in which convective fluids transfer heat.

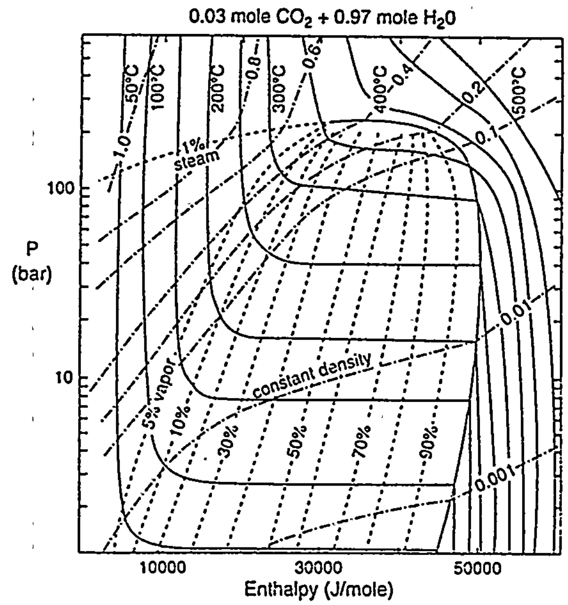

Figure 1. Enthalpy pressure temperature steam ratio diagram for the CO_2–H_2O system

We have developed a model calculating enthalpy of geological fluids composed of H_2O, CO_2, CH_4, N_2, H_2S, O_2, H_2, CO, HCl and possible additional gases from the subcritical two phase region up to 2000

°C and 30 kbar (possibly up to 3000 °C and 300 kbar), with an accuracy close to that of the experiments. This model uses canonical partition functions to calculate the enthalpy of ideal gases as a function of temperature, and equations of state (EOS) to calculate the departure of real systems from the ideal gas state. The largest deviation from experimental data is about 0.4 kJ/mole for temperatures below 1000 °C. For temperatures above 1000 °C, the error may be less than 1 kJ/mole. An example of a calculated enthalpy pressure diagram is given in Figure 1. As far as we know, this is the first model able to calculate mixed system enthalpies. This model can be used in the study of various thermal processes associated with power production. For example, it can be used to estimate steam ratios in gas breakout, density of fluids, and available heat.

Reliable Simulation of Phase Equilibria in Complex Systems: In many operations the efficient production of geothermal power is intimately affected by the phase equilibria of the working fluid, e.g., gas breakout, scale formation, etc. Traditionally, phase equilibria are studied by experiments. However, to obtain phase equilibrium data for the range of intensive variables that are common to geothermal problems would require a very large experimental effort. Recently, using the Monte Carlo Gibbs ensemble method, we have been able to simulate phase equilibria in the system CO_2–CH_4–N_2. This method is direct and intuitive. Both the equilibrium composition and mole volume (or density) can be obtained simultaneously. We found that latent heat can also be reliably predicted by this method. Compared to other approaches (such as the grand canonical ensemble method), the Gibbs ensemble is more direct. *A priori* knowledge of phase relations is helpful but not necessary. Comparison of the simulated results with experimental data indicates that the equilibrium compositions and mole volumes are predicted with an accuracy close to that of experiments. An example of one such calculation is given in Figure 2. The simulation has advantages over both experiments and equations of state (EOS) such as the popular Peng-Robinson EOS (1976) and Lee-Kesler EOS (1975). In comparison with EOS, our simulations with fewer adjustable parameters are more accurate for a larger temperature and pressure range. We believe this method has great potential in the study of geothermal fluid chemistry.

Modeling of the Thermodynamic Properties of Supercritical Fluid Mixtures: The pressure-volume-temperature-composition (PVTX) properties of natural fluids composed of pure members or mixtures of the system, H_2O–CO_2–CH_4–N_2–H_2S–CO–Ar–He–H_2 and O_2, are very important in the study of various geochemical systems. Almost all thermodynamic properties can be derived from these PVTX relations. Although many experimental PVTX data sets have been published, these cover only a small range.

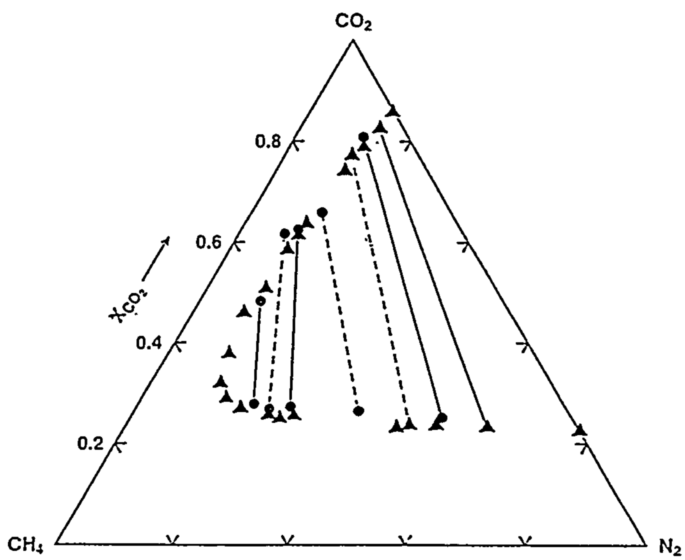

Figure 2. Fluid compositions in the N_2–CH_4–CO_2 system.

In order to bridge between the various TVPX ranges of experiments, many equations of state (EOS) have been proposed. However, any given EOS can cover only a small part of the variable space with an accuracy close to that of the experimental data.

Based on molecular simulation, we have developed a representation of the system which is much more accurate, and covers a much larger part of TVPX space than any previous EOS for supercritical fluids. This phenomenology contains only two parameters for each pure component and two additional parameters for each binary mixture. No higher order parameters are needed for more complicated mixture systems. The two mixing parameters can be eliminated for non-aqueous mixtures with a slight loss of accuracy in both total mole volume and in the excess volume. Comparison with a large amount of experimental PVTX data in pure systems (including H_2O) and for mixtures in the systems, H_2O–CO_2–N_2–CH_4 and N_2–CO_2–CH_4, results in an average error of 1.6% in density. Comparisons with commonly used EOS for supercritical fluids shows that the simulation results of this study cover far larger intensive parameter range with the required accuracy. We believe that it is accurate from just above critical temperatures to 2000 °K and from 0 to 25,000 bar or higher with an average error in density of less than 2% for both pure members and mixtures in the system H_2O–CO_2–CH_4–N_2–CO–H_2–O_2–H_2S–Ar. Comparison with published data suggests that this EOS is approximately correct up to 300,000 bar and 2800 °K.

Liquid Density Brines: Testing of the solubility predictions for the variable temperature model for the seawater (Na–K–Ca–Mg–Cl–SO_4–H_2O) system was continued this year. Most of the 39 salts included in the model are single (e.g., bischofite: $MgCl_2 \bullet 6H_2O$) or double (e.g., carnallite: $KCl \bullet MgCl_2 \bullet 6H_2O$) salts and therefore can be parameterized from correlation with binary and ternary salt solution data. However, two triple salts, polyhalite ($K_2SO_4 \bullet MgSO_4 \bullet 2CaSO_4 \bullet 2H_2O$) and kainite ($4KCl \bullet 4MgSO_4 \bullet 11H_2O$) are also included in the system. Parameterization of the chemical potential of these salts requires data in quaternary or higher systems.

Recently Ziegenbalg et. al. (1991) investigated solid-liquid phase equilibria in the quinary Na–K–Mg–Cl–SO_4–H_2O system over the 90 to 149 °C temperature range. Remarkable agreement for the four salt coexistences as a function of temperature was found. Model predictions of the solution compositions also compare well with other quinary data. Isothermal phase diagrams comparing model calculations with data in the seawater system have been prepared for publication. Model predictions of the solubility of the scale forming mineral anhydrite ($CASO_4$) in Ca–Mg–Cl–SO_4–H_2O solutions are compared with the data in Table (1). The agreement is excellent.

Temp.	[$MgCl_2$]	[$CaSO_4$]
250°C	.0328 *m*	.00166 *m* (.00187)
"	.0965	.00394 (.00391)
"	.1631	.00610 (.00568)
"	.2956	.01024 (.00909)
300°C	.0328	.00091 (.00127)
"	.0982	.00300 (.00294)
"	.161	.00502 (.00456)
"	.2956	.00948 (.00792)

Table 1: Anhydrite solubility in $MgCl_2$ solutions. Comparisons of model predictions and data at 250 °C and 300 °C (data in parentheses).

The polythermal representation of the saturated phases in the seawater system have proven useful in many applications. These diagrams delineate the stability fields of the phases in a brine system as a function of temperature and ion concentration. Polythermal diagrams from 0 to 250 °C of the solid phases in the ternary systems containing magnesium have been constructed. For the most part these diagrams show remarkable consistency with the experimental data.

User Interfaces: Our efforts to make the programs more user friendly by improving the graphical user interfaces on the Macintosh's and PC's are continuing. The following new features have been added in response to feedback from researchers who have been using our programs: (1) Options for scaling brine mixtures: A user may now select scaling parameters by changing values listed in fields in a user interface window. Thus, they may, for example, choose the proportion with which to mix two brines or select an evaporation rate. (2) Centigrade and Fahrenheit temperature units may be chosen from a pull down menu. (3) Concentration units may be chosen from a pull down menu. Currently, molality and PPM (parts per million) are supported. (4) Input file storage and retrieval options have been included. In our prior interface the user starting the TEQUIL interface had to re-enter all the composition data and the calculation options. The SAVE field on the user interface may now be selected, thereby saving their composition data and all other options (temperature, step direction, etc.) that they have chosen to a file of their choice. Later they may retrieve their data by choosing the RESTORE field and entering the file name. (5) New options giving model flexibility have been added. Previously, TEQUIL only read the file "tequil.dat" which contained the Pitzer parameters, and "input.dat" which contained pure phase data. Now, the TEQUIL user interface program reads a file that contains a list of files that define the model: the name of the Fortran executable, the names of the parameter files and the name of a description file that tells the user what components make up the model, what temperature range it covers.

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1995, TECHNOLOGY TRANSFER	
CONTACTS	**DESCRIPTION**
BATTELLE NATIONAL LABORATORY	Simulation methods (S. Xanthansias, X. Long visit UC)
BRGM (Orleans, France)	Request publications (C. Fonillac)
CEN. REC. SYNTH., CHIM. MINERAUX (Orleans, FR)	Request publications (B. Sailer)
CNR-IAIF, Physics (Italy)	Request publications (S.L. Fornili)
CRREL (US ARMY CORPS)	Gypsum/Anhydrite predictions (M. Giles)
ETH ZURICH INSTITUTE FUR MINERALOGIE UND PETROGRAPHIE	Request publications (T. Drisner)
FEDERAL CENTER (Denver)	Request publications (M. Lewan)
GEORGIA INSTITUTE TECHNOLOGY	Request publications (P. Dove)
GEOTHERM EX, INC.	TEQUIL to calculate calcite saturation (C. Klein)
GSF (Germany) INSTITUT FUR TIEFLAGERUNG	Check salt mine solution data with several models Dr. H.J. Herbert visit UCSD
INDIANA UNIVERSITY	Request publications (A. Schedi)
INEL	GEOFLUID used to analyze field pressure data
"	M. Shook visit UCSD to discuss flow models
INRA (Nantes, France)	Request publications (B. Lerous)
INSTITUT DER UN. FREIBURG (Germany)	Request publications (M. Rahn, Buches)
INSTITUTO INVEST. ELECTRICAS (Mexico)	Request GEOFLUID
KINGSTON UNIVERSITY (Surrey, UK)	Request publications (Clemens)
KIST (Korean Inst. Sci. Tech.)	Discuss modeling technology (S-W Park)
LAB. ENVIRONMENT ET MINEROLURGIE (France)	Request publications (L.J. Michot)
LONG ISLAND UNIVERSITY	Request Publications (A. Siegel)
LOS ALAMOS NATIONAL LABORATORY	TEQUIL, GEOFLUID: chemistry of Hot Dry Rock resource
"	T. Callahan visit UCSD
LAWRENCE LIVERMORE LABORATORY	Request MAC executable for Centris, HMW code
"	TEQUIL, HMW compared with other models (Dale Jones)
NATIONAL GEOPHYS. RES. INST. (INDIA)	Request publications (G. Parthasarathy)
OAK RIDGE NATIONAL LAB.	Discuss collaboration and data (Dr. M. Simmonson)
"	Request NHC, GEOFLUID
OXBOW GEOTHERMAL	Assessment of injection chemical problems (Dixie Valley)
PEKING UNIVERSITY (China)	Request publications (Y. Zeng)
PENNSYLVANIA STATE UNIVERSITY	Request publications (W.B. White)
POTASH CORP. SASKATCHEWAN, CANADA	Model for potash recovery delivered
SINICA CHINA GEOLOGICAL INST. (Taiwan)	Request NHC, GEOFLUID
STOCKHOLM UNIVERSITY (Sweden)	Request publications (A. Rupprecht)
TECHNISCHE UN. BERGAKADEMIE (Freiburg, Germany)	Request publications (W. Voight)
U.C., SANTA BARBARA	Request publications (F. Spera)
UNIVERSIDA OVIEDO (Ovieda, Spain)	Request publications (L.G. Corretoe)
U. COMPLUTENESE (Madrid, Spain)	Request publications (J.N. Delgado)
UNIVERSITE LAUSANNE	Request publications (Z. Sharp)
UNIVERSITY MIAMI	Request publications (F. Millero)
UNIVERSITY MICHIGAN	Request publications (V.C. Hover; S.E. Kesler)
UNIVERSITY NANJING (China)	Request GEOFLUID and NHC programs
"	Collaboration
UNIVERSITY OKLAHOMA	Request publications (D. London)
UNIVERSITY RHODE ISLAND	Request publications (J.G. Schilling)
UNIVERSITY TENNESSEE	Request publications (P.T. Cummings)
UNIVERSITY TURKU (Finland)	Request Publications (F. Scharlin)
UNIVERSITY UTAH RESEARCH INSTITUTE	Request publications (P. Wannamaker)
US GEOLOGICAL SURVEY	Request NHC program, publications (T. Gerlach, I-M Chou)
"	Request publications (T. Gerlach)
VIRGINIA POLYTECHNICAL INSTITUTE	Assist them in setting up NHC program
"	Request publications (M. Vityk, F. Harrison)
YANKEE/CAITHNESS	Assist them with TEQUIL

Concurrent Session 4:
The Geysers

Chairperson:

Steven L. Enedy
Northern California Power Agency

GEOLOGIC RESEARCH AT THE GEYSERS

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ABSTRACT

Geologic research at The Geysers vapor-dominated geothermal field during the past year has yielded new information on the nature of steam-reservoir porosity and permeability; the origin of the caprock; mechanisms of lateral sealing; the evolution of The Geysers hydrothermal system; and specific reservoir controls in and immediately above "the felsite", an hypabyssal, batholith-sized pluton largely responsible for The Geysers' existence. Our research has shown that (1) fluid conduits above the felsite may be dominantly vuggy, high-angle hydrothermal veins; (2) latest-stage hydrothermal calcite in such veins may seal them at the margins of the steam reservoir; mixed-layer clays are probably the corresponding seals in the caprock; (3) steam entries in the felsite are concentrated along the top of the youngest intrusive phase in the pluton — a 1 m.y.-old granodiorite; (4) steam entries in the felsite show a negative correlation with massive borosilicate enrichments.

INTRODUCTION

The governing goal of ESRI's geologic research effort at The Geysers steam field, northwest-central California (Fig. 1) is enabling its geothermal operators to better understand the highly complex, vapor-dominated system they exploit. The geology of The Geysers is fundamental to this understanding; the fields's rocks and porosity networks are its first-order controls. The more we know about these controls, the more accurately can indigenous reserves be calculated, and the more effectively can injection strategies be designed for maximum yield. Our work this year has involved: (1) Petrographic, mineralogic, and stable-isotopic analysis of hot but non-productive geothermal wells drilled beyond the field's presently defined borders; (2) baseline geologic characterization of

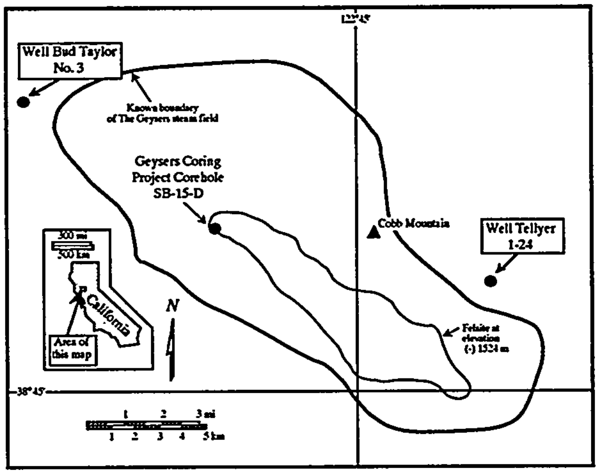

Figure 1. Location map

drill core from The Geysers Coring Project; and (3) completion of data acquisition and analysis for The Geysers felsite mapping project. One of us (JNM) has also been working closely with consultant Mark A. Walters to characterize whole-rock ^{18}O distributions and their implications in the northwestern portion of the steam field. We briefly discuss progress in each of these endeavors except the last in the text which follows.

PERIPHERAL, NON-PRODUCTIVE, STEAM-EXPLORATION BOREHOLES

Deep geothermal wells drilled beyond the currently defined margins of The Geysers geothermal system to date have been hot (>200°C) but non-productive, yet many penetrate the same metaclastic rocks that host the bulk of the steam reservoir. To begin investigating this discrepancy, we have completed a detailed petrographic, mineralogic, and oxygen-isotopic investigation of drill cuttings from two such "dry holes" — Sunoco's Bud Taylor No. 3 just northwest of the field, and MCR's Tellyer 1-24 to the east (Fig. 1). Both wells were drilled to depths in excess of 3000 m in similar rock sequences, and although non-productive encountered temperatures in excess of 200°C in the late Mesozoic, Franciscan- Assemblage metamorphic rocks which they penetrated.

The rocks of Bud Taylor No. 3 differ little from their regional counterparts outside the steam field. The penetrated argillites and metagraywackes contain abundant metamorphic calcite and pumpellyite to total depth; these phases are virtually absent from similar rocks in the steam field proper. Although the Bud Taylor rocks are very hot, temperature logs reveal a purely conductive geothermal gradient. We conclude that these rocks did not receive the permeability-enhancing "ground preparation", including hydrothermal fracturing and carbonate-dissolution, experienced by otherwise similar steam-reservoir rocks (Hulen and Moore, 1995)

By contrast with those in Bud Taylor No. 3, the rocks of non-productive Tellyer 1-24 (Figs. 1 and 2) are nearly identical to those penetrated by nearby producing steam wells to the west — all have been extensively altered and mineralized by the hot-water system which immediately preceded formation of the modern steam field (McLaughlin et al., 1983; Moore and Gunderson, 1995). Whole-rock oxygen-isotopic ratios reflect this fluid-rock interaction — del^{18}O values systematically decrease downhole with approach to felsic intrusive rocks below 3200 m (Fig. 2). The critical difference between the rocks of 1-24 and those of nearby steam wells is that otherwise open veins in the former contain abundant, late-stage, hydrothermal calcite. We believe that this calcite "chokes off" what would otherwise be productive steam channels. This late vein calcite could be an important lateral permeability barrier around the entire steam reservoir (Hulen and Moore, 1995).

THE GEYSERS CORING PROJECT

The Geysers Coring Project (GCP; Hulen et al., 1995), a DOE-Industry collaborative venture, was conceived and undertaken principally to improve understanding of The Geysers' porosity and permeability controls and fluid-saturation characteristics. The drilling phase of the project recovered 237 m of continuous core from the uppermost part of the steam reservoir and its immediately overlying caprock. This footage nearly triples the total amount of core now available for study from The Geysers. Detailed research projects on the core by collaborating investigators from around the country are in progress to determine the nature of fluid-storing and transmitting open spaces; lithologic and mineralogic controls on reservoir vs caprock development in similar rock sequences; physical properties of reservoir rocks which might assist their remote geophysical characterization; the tectonic-hydrothermal history of this part of The Geysers; and the degree to which specially preserved cores remain saturated with indigenous reservoir fluid. Preliminary results of these studies have been published in various journals, and were presented at a researchers' meeting chaired by JBH and held in conjunction with this program review at Lawrence Berkeley Laboratory. At this meeting, plans were made to assemble the research summaries as papers in a special issue of the journal "Geothermics".

Our baseline characterization of core from GCP corehole SB-15-D has provided valuable new insight into the steam-reservoir/caprock transition zone and the nature of porosity and permeability throughout The Geysers field. For one thing, we now know that the difference between the relatively tight caprock and the uppermost steam reservoir in otherwise similar rocks in this sector of the field is in the type and abundance of clay in young hydrothermal veins.

These veins, commonly vuggy and high-angle, were formed by the hot-water system antecedent to the steam field. They contain a wide variety of hydrothermal phases, including wairakite, adularia, and bladed calcite (Fig. 3). The veins are superficially similar throughout the entire length of core, but there are critical differences related to the caprock/reservoir transition. For one thing, deeper veins, in the reservoir, contain epidote along with more abundant wairakite and adularia; shallower, caprock veins are deficient in calc-silicates, but contain abundant, expandable, mixed-layer illite/smectite and chlorite/smectite (Fig. 3). We believe that the these swelling clays, deposited at strategic locations, prevent otherwise permeable veins from acting as fluid conduits. Devoid of these clays, similar, deeper veins in the steam

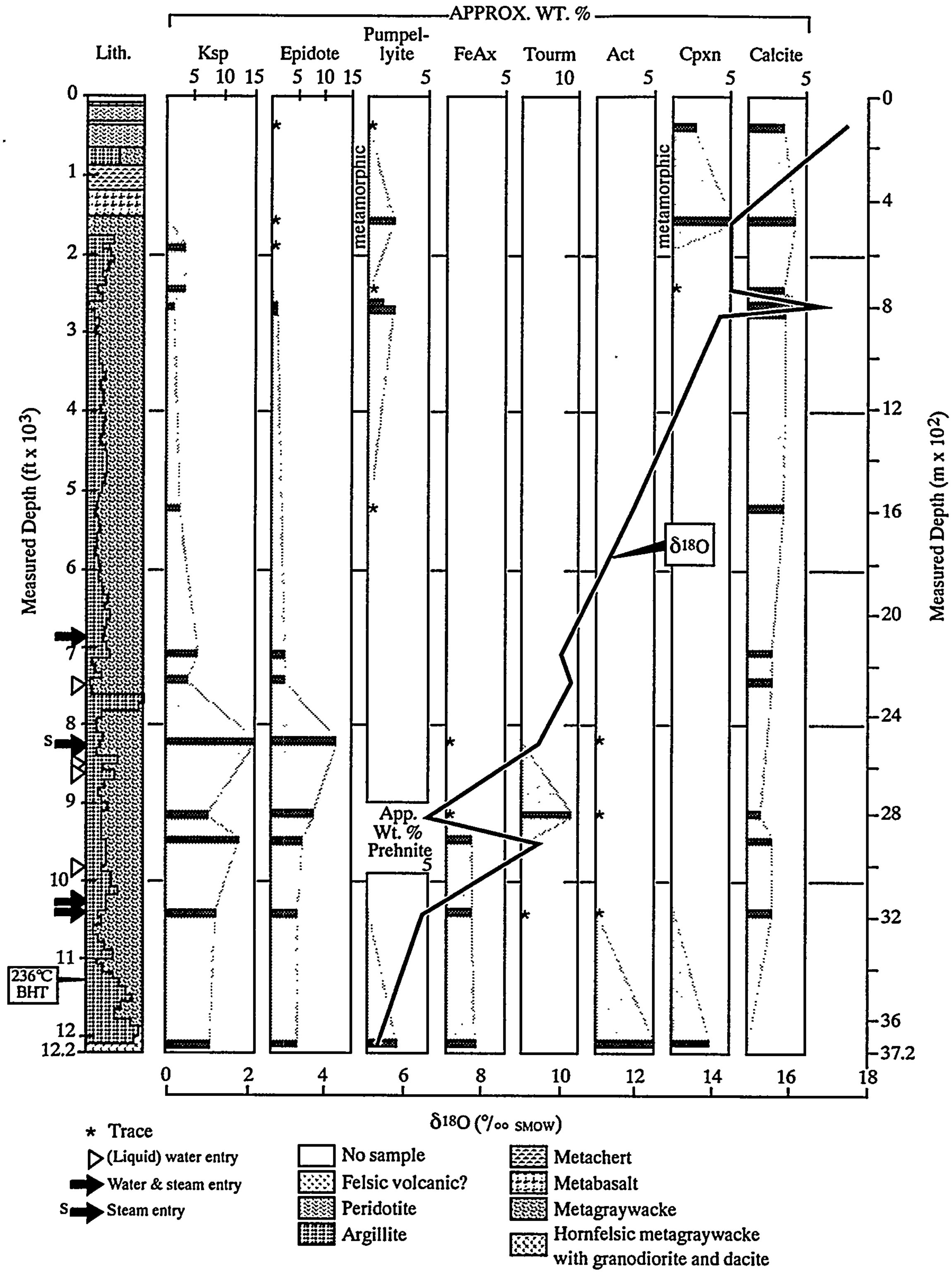

Figure 2. Well Tellyer 1-24: Whole-rock $\delta^{18}O$ values vs downhole distributions of various secondary minerals. Lith. = Lithology. Ksp = Potassium feldspar. FeAx = Ferroaxinite. Tourm = Tourmaline. Act = Actinolite. Cpx = Clinopyroxene. BHT = Bottom-hole temperature.

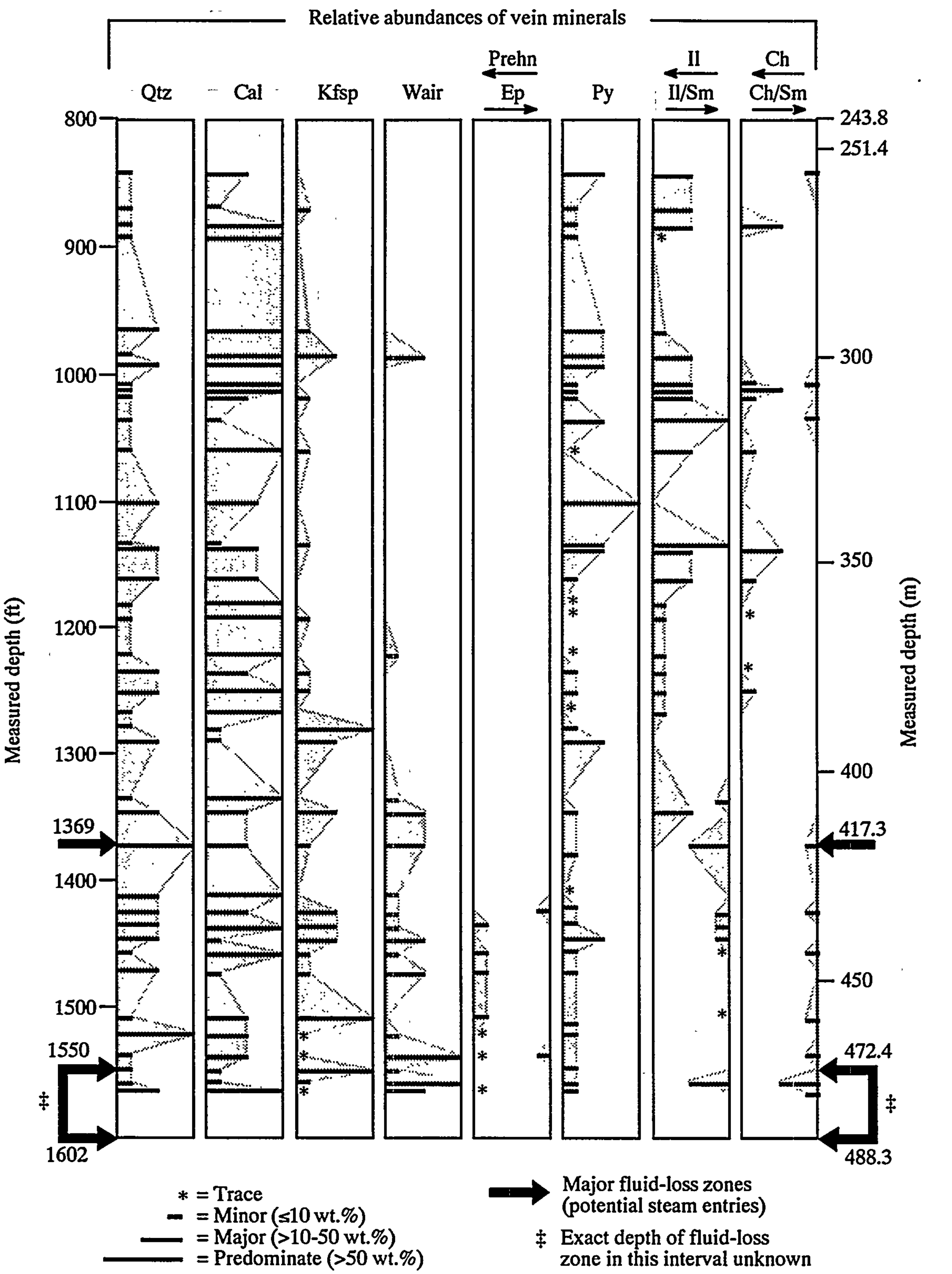

Figure 3. Downhole mineralogy and vertical mineral zoning of selected, representative, Geysers hydrothermal veins in core from corehole SB-15-D. Qtz - quartz; Cal - calcite; Kfsp - potassium feldspar (adularia); Vair - wairakite; Prehn - prehnite; Ep - epidote; Py - pyrite; Il - illite; Il/Sm - mixed layer illite/smectite; Ch chlorite; Ch/Sm - mixed layer chlorite/smectite.

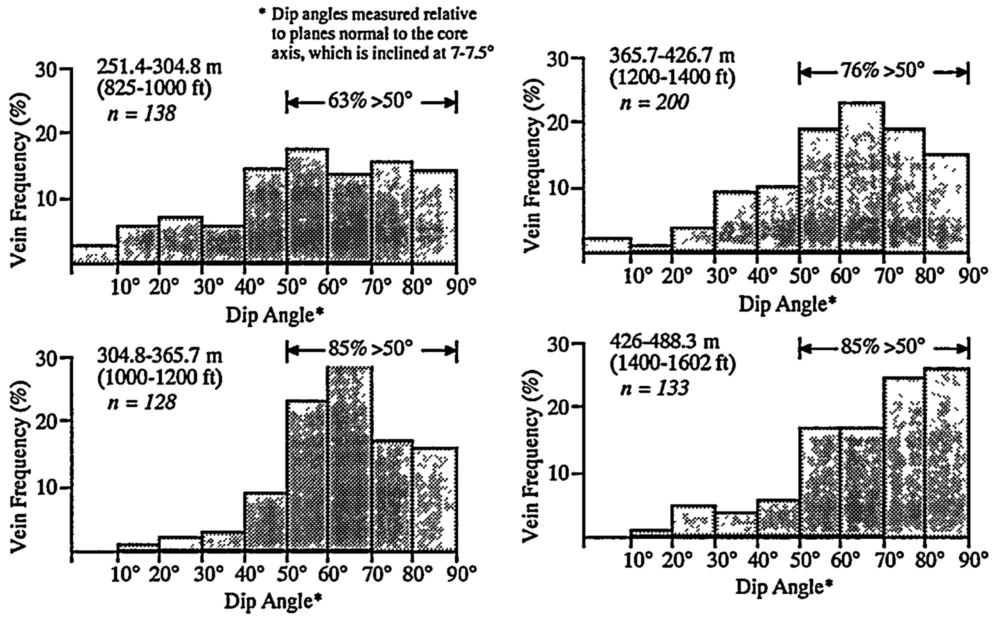

Figure 4A. Dip-angle distributions for Geysers hydrothermal veins in core from successively deeper intervals of corehole SB-15-D. Note predominance of high-angle veins in all intervals.

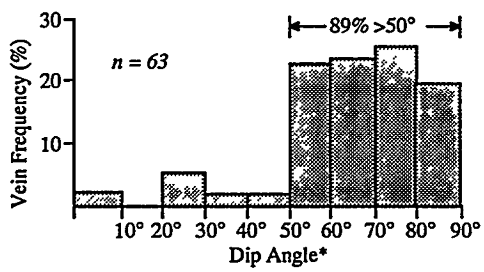

Figure 4B. Dip-angle distributions for all SB-15-D Geysers hydrothermal veins with vuggy porosity.

reservoir provide excellent fluid passageways (Hulen and Nielson, 1995a; 1995b).

Another intriguing finding from our baseline geologic characterization of the SB-15-D core: Both past (now sealed) and present (open, vuggy) fluid channels — the Geysers hydrothermal veins — are clearly high-angle features (Fig. 4; Hulen and Nielson, 1995b). This fact apparently conflicts with the findings of Beall and Box (1989) and Thompson and Gunderson (1989), who presented convincing evidence that steam-bearing fractures in reservoir metagraywacke at The Geysers were principally lower-angle features. A possible explanation for this discrepancy is that SB-15-D, drilled into a shallow "bubble" at the the top of the reservoir (e.g. Gunderson, 1990) is not fully representative of the reservoir. Still, many of the other Geysers metagraywacke cores archived at ESRI do host relatively high-angle hydrothermal veins. We believe strongly that another corehole, drilled deeper into the reservoir, would allow more definitive direct characterization of these open veins and other critical elements of the field's permeability network.

One of us (JBH) is also collaborating with Peter Persoff of Lawrence Berkeley Laboratory in the detailed hydrologic characterization of representative core plugs from SB-15-D (Persoff and Hulen, 1996); and with Greg Boitnott of New England Research (see Boitnott and Boyd, 1996) in an attempt to correlate measured permeabilities and electrical and acoustic properties of selected cores with corresponding mineralogical and textural parameters. In the first study, it was demonstrated that unless disrupted by megascopically invisible microfractures, 1 X 2" metagraywacke core plugs were virtually impermeable, on the order of a few tens of nanodarcies. The second study is still in progress, but it can be reported here that there are obvious mineralogic reasons for observed differences in the measured sonic and resistivity values.

THE GEYSERS FELSITE MAPPING PROJECT

This long-term project has been devoted to mapping rock types, alteration, mineralization, and metamorphism of The Geysers felsite and its hornfelsic halo. It has involved detailed petrographic analysis of 1200 grain-mount thin sections of air-drilled cuttings and 50 thin sections of felsite cores retrieved from various portions of The Geysers steam reservoir. Supplemental techniques employed in the study include oxygen-isotope analysis; whole-rock geochemistry (including trace elements); X-ray diffraction, scanning electron microscopy; and electron microprobe analysis of individual primary and secondary phases in the pluton. The data-acquisition and interpretation phase of the project is now complete.

The felsite, coaxial with and intimately related to The Geysers steam field (Fig. 1; Hulen and Nielson, 1993), was first identified by Unocal Corporation's Alex Schriener and Gene Suemnicht (1981). Samples from most of this igneous intrusion are small-diameter drill cuttings, so the pluton has traditionally been viewed as monolithologic. As a result of our studies, we now know that the felsite actually consists of at least three major intrusive phases. There are also several large and compositionally varied dikes above the main pluton which are almost certainly genetically related to the main mass of the felsite.

The three main phases of the felsite are an older granite and probably coeval microgranite porphyry and a younger granodiorite. The older intrusives, dated by Dalrymple (1992) at >1.3-1.4 Ma, predate the overlying Cobb Mountain volcanic center, but the granodiorite, which Pulka (1991) dated at about 1 Ma, is the same age as the the Cobb Mountain dacite. The dacite and granodiorite are also extremely similar chemically, even their rare-earth-element concentrations. We believe strongly that the dacite and granodiorite are intrusive-extrusive equivalents.

Based on the distributions of igneous rock types, key secondary minerals (for example, tourmaline and ferroaxinite),and major steam entries, the granodiorite among all three intrusive phases appears to have been the major influence in formation of The Geysers hydrothermal system. Intensely mineralized portions of the pluton and its overlying contact-metamorphic halo show no correlation with the configurations of the earlier granite and microgranite porphyry. They are clearly related to the granodiorite, particularly those portions of this intrusive which reached the highest elevations. Moreover, major steam entries are concentrated along and just above the top of the granodiorite.

Surprisingly, these steam entries show a negative correlation with intensity of mineralization in the felsite. In many epithermal and mesothermal mineral deposits, clearly formed by ancient geothermal systems, there is clear evidence that veins and mineralized breccia bodies were repeatedly used as major fluid-flow conduits; they are also zones of weakness most liable to rebreak (with consequent permeability enhancement) when subjected to renewed stresses, either tectonic or hydrothermal in origin. Many banded epithermal veins, in fact, show evidence of hundreds of mineralizing epidodes, bearing witness to repeatedly vigorous fluid flow along the same channels. This does not seem to have been the case in The Geysers felsite.

We know from scattered cores and from secondary-mineral textures in cuttings (e.g. free, euhedral crystals) that the mineralization in the felsite is in fact dominantly open-space filling. In numerous wells, this mineralization, mostly tourmaline and ferroaxinite, accounts for more than 30% of the rock for tens of meters downhole. We suspect that these intensely mineralized zones may be fully-sealed magmatic-hydrothermal breccia bodies. Whatever their origin, however, they are no longer the permeable conduits they clearly once were. In our felsite-study wells, very few steam entries occur in these zones; however, many are found in felsite with secondary-mineral contents of <1%.

The relationships noted above would seem to have important implications for, among other things, the design of injection strategies for optimum placement of injectate deep into the pluton. Injection into nonmineralized zones along the top of the granodiorite might be expected to yield the best results.

These and other critical aspects of the felsite have been plotted on a series of strategically positioned level maps and cross-sections through the igneous body. These maps and cross sections should shortly be available for distribution. Manuscripts summarizing the felsite research project are in the final stages of preparation

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Microearthquake Source Mechanism Studies at The Geysers Geothermal Field

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ABSTRACT

Source mechanisms of 1697 microearthquakes at the Northwest Geysers, and 985 microearthquakes at the Southeast Geysers geothermal fields are investigated using a moment tensor formulation. P- and S-wave amplitudes and polarities are utilized to estimate the full, second-order moment tensor, which is then decomposed into isotropic, double-couple, and compensated linear vector dipole components. The moment tensor principal axes are used to infer the directions of principal stress associated with the double-couple component of the source mechanism. Most of the events can be modeled as primarily double-couple; however, a small but significant isotropic component, which can be either positive or negative, is also needed to explain the observed waveforms. In the SE Geysers, events with positive isotropic components and events with negative isotropic components both occur in areas of steam extraction and in areas of fluid injection. In the NW Geysers, however, events with a positive isotropic component occur mainly in the area of fluid injection. In both the SE and NW Geysers, principal axes of moment tensors with negative isotropic components are roughly aligned with the regional stress field, while those of moment tensors with positive isotropic components differ significantly from the regional stress field. This suggests that two differing inducing mechanisms are required: negative-type events involve local stress perturbations that are small compared to the regional stress, while positive-type events involve stress perturbations which locally dominate over the regional stress.

INTRODUCTION

Many investigators have demonstrated that steam extraction and fluid injection are associated with microearthquake (MEQ) activity at the Geysers, California, geothermal field (e.g., Eberhart-Phillips and Oppenheimer, 1984; Stark, 1992). However, until recently few detailed studies of the nature of the mechanisms have been carried out. Seismic waveforms contain information about the characteristics of the source which generated them. If this information can be extracted it can be used to infer properties of the earthquake source and thus provide constraints on possible inducing mechanisms.

In this paper we discuss moment tensors obtained from inversion of MEQ waveform data recorded at the Southeast (SE) and Northwest (NW) Geysers geothermal areas by the high-resolution seismic networks operated by Lawrence Berkeley National Laboratory (Berkeley Lab) and the Coldwater Creek Geothermal Company (now CCPA) (Figure 1). The network in the SE Geysers consists of 13 high-frequency (4.5 Hz), digital (480 samples), three-component, telemetered stations deployed on the surface in portions of the Calpine, Unocal-NEC-Thermal (U-N-T), and Northern California Power Agency (NCPA) leases. The network in the NW Geysers is a 16-station borehole array of three-component geophones (4.5 Hz), digital at 400 samples/sec, and telemetered to a central site.

One of the main objectives of Berkeley Lab's program at the Geysers is to assess the utility of MEQ monitoring as a reservoir management tool. Discrimination of the mechanisms of these events may aid in the interpretation of MEQ occurrence patterns and their significance to reservoir processes and conditions of interest to reservoir managers. Better understanding of the types of failure deduced from source mechanism studies, and their relations to production parameters, should also lead to a better understanding of the effects of injection and withdrawal.

Moment tensors contain information regarding the possible orientations of principal stresses involved in an event nucleation. They also provide a measure of how well a particular event can be modeled by shear displacement, or whether a more complicated source model is required. Non-shear earthquake mechanisms have been reported in geothermal and volcanic areas in recent years (e.g., Julian et al, 1993; Shimizu et al, 1987). Seismic P-wave radiation patterns from these areas appear to indicate that positive or negative volumetric change is involved in the source process of many of these events. We compare our results to these, and to other previous studies of earthquake source mechanisms at the Geysers, and investigate evidence for non-shear source processes.

METHOD

The displacement at a seismic source can be represented as a set of forces and force couples, which are sufficient to cause the seismic wave displacements observed at a receiver at some distance from the source. The seismic moment tensor represents the moments of these so-called "equivalent body forces." By making the assumption that the source can be approximated as a point in time and space, the moment tensor reduces to a symmetric, rank 2 tensor and therefore contains six independent elements.

It is possible to compute the equivalent body forces and resulting moment tensor for any arbitrary source model, and, conversely, it is also possible to estimate the moment tensor of an actual source by solving the following set of equations:

$$u_i = G_{ij} m_j$$

where u, i=1-n, are the n observations of the P- and S-wave pulse amplitudes of all waveforms recorded at all receivers for one event; m, j=1-6, are the six independent elements of the moment tensor; and G_{ij}, derivatives of the Green's functions for the appropriate source-receiver paths (Stump and Johnson, 1977). To compute m_j, we must first calculate Green's functions from the estimated path properties such as seismic velocity and attenuation. Surface effects are also included. Errors in our computed moment tensors will reflect errors in these quantities, which are also affected by mislocations of hypocenters, as well as observational errors in determining accurate waveform amplitudes. Because our instruments record ground velocity, which is the time derivative of ground displacement, we obtain displacement amplitudes by integrating over the width of the recorded P- and S-wave pulses.

The eigenvalues and eigenvectors of the moment tensor describe the magnitude and orientation, respectively, of the equivalent body forces. We identify the eigenvector corresponding to the minimum eigenvalue as the "compression," or "P" axis, and the eigenvector corresponding to the maximum eigenvalue as the "tension," or "T" axis. For a double-couple source (a double-couple is the body-force equivalent for a shear displacement), the P and T axes bisect the quadrants of the focal sphere (a small imaginary sphere centered on the source) corresponding to areas of downward and upward P-wave first arrivals. The well-known fault-plane solution method utilizes this concept by tracing polarities of first motions back to their positions on the focal sphere, and then separating them into quadrants defined by nodal planes (the slip plane and the auxiliary plane). The P and T axes are then determined as the poles which bisect these quadrants. Our moment tensor approach improves upon this method by utilizing the amplitude as well as the polarity of both P- and S-wave pulses, and by allowing models other than double-couple ones to be considered.

The eigenvalues of the moment tensor are used to decompose the solution into isotropic, double-couple, and compensated linear vector dipole (clvd) components. For a purely isotropic source (i.e., an explosion or implosion), all three eigenvalues of the moment tensor are equal. For a purely double-couple source (i.e., a shear displacement), one eigenvalue is zero, and the other two are of equal magnitude and opposite sign. For a clvd (representing an opening or closing in one direction accompanied by corresponding closing or opening in orthogonal directions so that there is no net volume change), two of the eigenvalues are equal to each other and to 1/2 the third. We consider that the source could be composed of a combination of any of these three source models, and "decompose" our moment tensor solution into the relative contributions of each.

An example of a moment tensor solution for an event recorded by our network in the SE Geysers is shown in Figure 2. Orientations of P, T, and I ("intermediate") axes (the eigenvectors) are plotted on a lower-hemisphere equal-area projection of the focal sphere. The stippled area represents the area of upward first motions that are predicted by the computed moment tensor. The dipping planes represent nodal planes for the double-couple component of the source. The departure of the stippled area from the quadrants defined by these planes is a measure of the departure of the moment tensor from a pure double-couple.

The moment tensor decomposition result for this example is shown on the ternary diagram in Figure 2. The apexes of the triangle represent the end-member models. The diagram shows that this event can be modeled as predominantly double-couple, with some isotropic component and some clvd component. The sign of the isotropic component is negative (i.e., $\lambda_1 + \lambda_2 + \lambda_3 < 0$, where the λ's are the moment tensor eigenvalues), which, if real, would indicate a small volume decrease in the source region accompanying this event. The orientations of the P and T axes indicate a predominantly strike-slip-type mechanism for this event's double-couple, or shear displacement, component. The example has a moment-magnitude (Mw), of approximately 2.1, which is a large event for the SE Geysers.

SE GEYSERS RESULTS

Hypocenters of 1605 events in 1994 were determined from hand-picked P- and S-wave arrival times. Uncertainties in the locations are estimated to be less than 200 m. A three-dimensional P- and S-wave velocity model, derived from a subset of the data using the joint hypocenter-velocity inversion method of Thurber (1983) as modified by Michellini and McEvilly (1991) was used. Event epicenters are shown in Figure 3; and the vertical distribution of seismicity is shown on the north-south depth sections in Figure 4. Figure 3b shows the locations of injection wells in the UNT, NCPA, and Calpine lease areas, and the approximate area of steam extraction in the Calpine lease area.

The plots show that the MEQs tend to occur in spatial clusters, as well as in more diffuse patterns. Comparison of Figures 3a and 3b shows that few events occur in areas where steam extraction or fluid injection are absent; however, not all injection areas and not all steam extraction areas have associated seismicity. For example, no MEQs were detected near the Calpine injection well at 1,803,000 E, 400,000 N (Figure 3). Likewise, very few events are detected in the area of steam extraction on the northeast edge of Calpine's portion of the reservoir. It appears that fluid injection and/or steam extraction is a necessary, but not sufficient condition to induce MEQs at the SE Geysers.

The base of the seismicity zone varies from -1 to -2 km msl (2 to 3 km below the surface), and appears to be roughly coincident with the base of the current producing zone (Kirkpatrick et al, 1995). Localized MEQ "stringers", however, do extend below the maximum depth to which producing wells are drilled in several areas. This could reflect preferential fluid flow in the vertical over the lateral directions, as also postulated by Stark (1992), and supported by the fracture model developed by Beall and Box (1991). Their work suggested the existence of zones of many, small, randomly-oriented horizontal and low-angle fractures, cut by fewer, larger, high-angle fractures which extend to an unknown depth, and in some cases, correlate with mapped surface faults.

Moment tensor inversions were performed on the waveforms from these events; solutions for 985 events were obtained. Because a higher signal-to-noise ratio is required for accurate P- and S-wave pulse amplitude determination than for arrival time determination, and because 6 observations are required for moment tensor inversion, while only 4 for hypocentral inversion, moment tensors could not be calculated for all located events.

Moment Tensor Decomposition:

Decomposition of the moment tensors (Figure 5) showed that some could be modeled as predominately double-couple events and that over half (approximately 53%) of the events had double-couple components comprising over 50% of their moment tensor solution. In contrast, few events, if any could be modeled as predominantly isotropic, excluding purely explosive or implosive source processes. The isotropic component is not insignificant, however, as it is present in the moment tensors in percentages up to approximately 30%. This result is quite robust, occurring even when only the most well-constrained moment tensor solutions are considered (those having the highest number of observations and the most complete coverage of the focal sphere). Errors in velocity structure or hypocentral locations can introduce errors in the decomposition of the computed moment tensor (O'Connell and Johnson, 1988); however, because volumetric changes might be expected in areas where large amounts of fluids and gases are being injected and withdrawn, we will cautiously assume that the results are significant and proceed to investigate the implications.

Of the 985 moment tensor solutions, 556 have positive isotropic components, while 429 have isotropic components which are negative (56% and 44%, respectively). The pattern of moment tensor decomposition shown in Figure 5 also suggests that a positive volumetric component (upper triangle) is slightly more predominant overall than a negative component (lower triangle). Although this appears to be a small difference and may be due to methodological inadequacies, it is consistent with the observations of Julian et al. (1993), who found evidence for significant numbers of non-shear earthquake source mechanisms at the central Geysers using P-wave polarity data. They found that, of the events which could not be fit to a double-couple model, most had predominantly compressional first arrivals, indicating a positive volumetric component, while only a few had predominantly dilitational first arrivals. These results are intriguing because the Geysers is undergoing lateral contraction and vertical subsidence in response to reservoir depletion (Denlinger et al., 1981). If, as ours and Julian et al.'s results indicate, positive volumetric strain predominates over negative volumetric strain in the MEQ sources, then most of the field-wide negative volumetric change must be a product of aseismic processes.

Volumetric components to earthquake source mechanisms at the Southeast Geysers are feasible because large amounts of steam are being extracted from the reservoir, and large amounts of fluids are being injected into the reservoir. It might be expected that positive isotropic source mechanisms would occur predominantly in areas of fluid injection, and negative isotropic mechanisms in extraction areas. However, comparison of Figures 6a and 6b with Figure 3b shows that this is not the case. Both positive and negative isotropic moment tensor components occur in both injection and extraction areas. The ratio of positive to negative components varies in the injection areas; for example, near the NCPA injector Q-2, the ratio is 68% to 32%, while in the DV-11 area the ratio is similar to that in the field as a whole (56% to 44%). No injection areas show substantially higher percentages of negatively isotropic events, however.

Moment Tensor Principal Axes:

The orientations of the P and T axes of the 985 moment tensors obtained for the SE Geysers are shown in Figure 7a. These axes can be thought of as representing principal stress axes for the part of the source modeled as a double-couple.

A consistent pattern in the orientations of the axes is not evident in Figure 7a. The orientations correspond to shear slip of both strike-slip and normal type, with few thrust-type mechanisms. The results are similar to those obtained by Oppenheimer (1986), who determined fault plane solutions using P-wave polarities for 210 events in the central Geysers. Our solutions depart from his in the more variable orientation of the T axes. The T axes determined by Oppenheimer were mostly restricted to W-E and WNW-ESE directions, roughly coincident with the direction of maximum tensional stress of approximately N70°W and horizontal, derived from analysis of regional events outside the Geysers (Bufe et al, 1981). Bufe's analysis also indicated a horizontal, maximum compressional stress orientation of N20°E, which reflects the dominant regional strike-slip mode of faulting.

If the events at the SE Geysers were caused by these regional stresses, it would be expected that all the P and T moment tensor axes would cluster around these orientations, which is not the case. However, when the event moment tensors are separated according to whether their isotropic component is positive or negative, a regional tectonic signature is seen for the double-couple component of moment tensors having a negative isotropic component (i.e., the principal axes do cluster around the regional stress axes) (Figure 7b). The double-couple component of moment tensors whose isotropic component is positive, however, is seen to reflect predominantly normal-type modes of failure, with vertical P axes and horizontal T axes of variable azimuthal orientation (Figure 7c).

This relationship between the sign of the isotropic component of a moment tensor (indicating a small component of positive or negative volumetric change in the event rupture process) and the orientation of P and T axes associated with the double-couple component of the moment tensor (indicating simultaneous shear displacement) has strong implications for the mechanisms inducing these events. It suggests that two differing mechanisms may be involved in MEQ generation at the SE Geysers. The mechanism causing events with a negative volumetric component must involve changes in the local stress state which reduce the local stresses opposing the regional stress and allow the material to respond seismically to the regional tectonic stress. Similarly, the mechanism causing events with a positive volumetric component must involve local perturbations in the stress field which dominate over the regional.

NW GEYSERS RESULTS

The seismicity at the NW Geysers geothermal area is shown in a plan view and an east-west cross section in Figure 8. The seismic network and geothermal wells are also shown. (Geothermal wells exist south of 38.83° latitude but are not shown.) The events were processed in a similar manner to the SE Geysers events. Hand-picked P- and S-wave arrival time data were used along with a 3-D velocity model to obtain accurate locations. The P- and S-wave amplitudes were then processed to obtain moment tensor solutions.

The hypocenters shown in Figure 8 are coded according to the characteristics of their isotropic component. The circles represent MEQs with high positive isotropic components (defined as greater than 20%). The squares represent MEQs with high negative isotropic components (less than -20%). These values are interpreted as indicating opening and closing components, respectively, to these MEQ sources. Events with isotropic components between -20% and 20% are shown as crosses.

The event cluster centered at approximately -122.827°, 38.824° (Figure 8) is centered around the bottom of the only injection well in the CCPA lease active at the time. About 45% of these events had high positive isotropic components to their moment tensors, while only 4% had high negative isotropic components. Overall, 80% of these injection-associated events had positive isotropic components, and 20% had negative isotropic components. The principal axes of the positive-type events indicate mostly normal-fault-type mechanisms for the double-couple and CLVD components of their moment tensors (the P-axis vertical and the T-axis horizontal), a result similar to that found for the positive-type events at the SE Geysers. The events with negative isotropic components have principal axes indicating strike-slip-type behavior, also similar to the SE Geysers. The least principal stress axis is rotated slightly from the regional orientation, which may indicate that the injection activity has perturbed the regional stress direction slightly.

Outside the injection area, 27% of the events had high positive isotropic components, and only 16% had a high negative isotropic component. Most of these events with high negative isotropic components occurred in the SE portion of the study area (Figure 8a), and were deeper than the other events (Figure 8b).

DISCUSSION

Mechanisms to account for seismicity induced by geothermal exploitation activities have been discussed by many investigators. Majer and McEvilly (1979) considered stress perturbations caused by mass injection and withdrawal, and Denlinger et al (1981) proposed thermal contraction due to reservoir cooling. Allis (1982) presented a mechanism whereby aseismic slip was converted to stick-slip behavior through an increase in the coefficient of friction along fractures due to deposition of exsolved silica, and Stark (1992) concluded that a reduction in effective normal stress due to fluid injection could result in MEQ generation.

More specific consideration of possible inducing mechanisms is needed to account for the crack or cavity opening and closing that is suggested by the positive and negative isotropic components of the moment tensor results. Crack or cavity opening could be caused by increased extensional stress caused by thermal contraction of the rock matrix, local increases in pore pressure due to injected fluid, or to a sudden local increase in pore pressure caused by the flashing of superheated water to steam. Closing could be caused by fluid pressure decreases within preexisting fractures or cavities due to withdrawal of steam ("fracture deflation"). It has also been proposed that localized injectate flashing could cause increasing pressure on adjacent, preexisting fractures, thereby inducing closing-type events.

The results discussed in the previous section provide constraints on which, if any, of these inducing mechanisms are valid. The candidate model must account for the following observations:

1) Fluid injection and/or steam withdrawal are necessary, but not sufficient conditions to cause MEQs at The Geysers.

2) Almost half the events at the SE Geysers cannot be modeled with a predominantly double-couple source mechanism.

3) Most event mechanisms indicate a small but significant component of volumetric strain.

4) Event moment tensors can have either a positive or a negative volumetric component, and both types are found in all parts of the seismically active area. Positive-type events occur in slightly higher numbers than negative-type events, and occur in higher ratios around some, but not all, injection wells.

5) The orientations of the principal axes of the moment tensors of events with negative volumetric components at the SE Geysers approximately coincide with those of the regional tectonic stress.

6) The orientations of the principal axes of the moment tensors of events with positive volumetric components at both the NW and SE Geysers are consistent with a normal-faulting-type mechanism and are not consistent with the regional tectonic stress.

At this time, for the following reasons, we believe that the flashing of superheated water to steam is the most feasible mechanism to explain the occurrence of the events with positive volumetric components. Water is present in the reservoir as both injectate and as a naturally-occurring component of the mixed vapor/fluid reservoir. Thus, as observed, positive-type events would not be restricted to injection areas, although they could be expected to occur there with greater number. It also could account for the absence of MEQs from some areas of injection and extraction: if the reservoir pressure is high enough, water present in the system will not flash to steam. Only after the pressure drops to some threshold value will conditions allow flashing and consequent seismic activity. If the magnitude of the tensional stresses generated by flashing were much larger than the magnitude of the regional tensional stresses, and less than the overburden pressure, then the observed, variable, horizontal orientations of the T axes, and the vertical orientation of the P axes would result. Conversely, if thermal contraction due to cooling by injected fluid caused the positive-type events, they might be predicted to occur in all injection areas, which is not observed. Additionally, the presence of positive-type events at large lateral distances from injection wells probably could not be accounted for.

While the flashing of water to steam might cause the positive-type mechanism as described above, it has also been suggested that it might simultaneously cause an increase in compressive stress on a nearby, preexisting fracture, leading to the nucleation of a closing-, or negative-type event. This type of event could also reflect simple fracture deflation due to withdrawal of fluids or gases. It is unclear, however, how these mechanisms account for the dominance of the regional stress regime in the negative-type events, shown by the orientations of the moment tensor P and T axes. The mechanism proposed by Allis (1982) of the exsolution of dissolved silica onto fracture surfaces might account for this regional tectonic signature to these events, because it involves only an increase in the effective strength of the material which then allows it to respond seismically to the regional stress. This process might also be enhanced by cooling due to fluid injection, and to lowering pressures caused by steam extraction.

FUTURE WORK

The conclusions derived from the analysis of the moment tensor solutions from The Geysers field considered as a whole provide a framework for evaluating seismicity and source mechanisms in individual areas of the field.

Future work will focus on detailed analysis of MEQ activity in specific areas of fluid injection and steam extraction. Available information on injection and production rates, values of temperature and pressure, fracture patterns, and other reservoir parameters will be incorporated. We hope the results will further constrain ideas of MEQ inducing mechanisms, contribute to the understanding of the effects of injection and extraction, and ultimately provide useful information to SE Geysers reservoir managers.

ACKNOWLEDGMENTS

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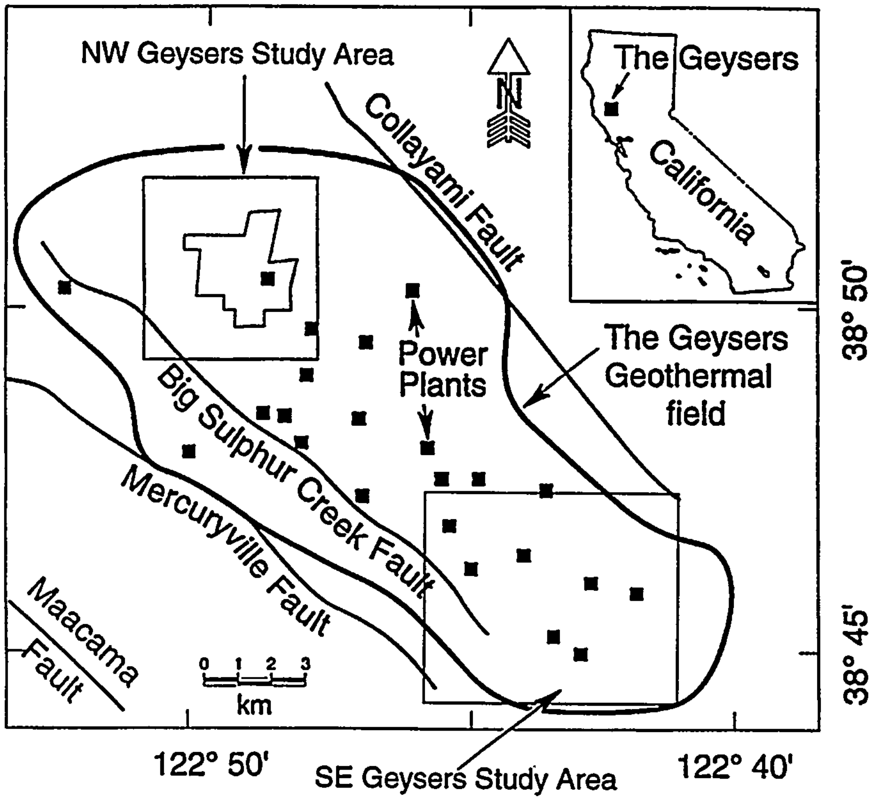
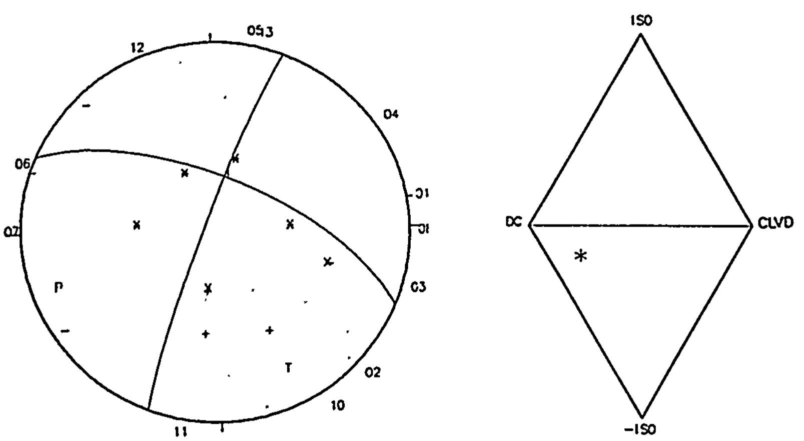


Figure 1. Location of stations in the Lawrence Berkeley National Laboratory (LBL) MEQ network at the Southeast Geysers, California.



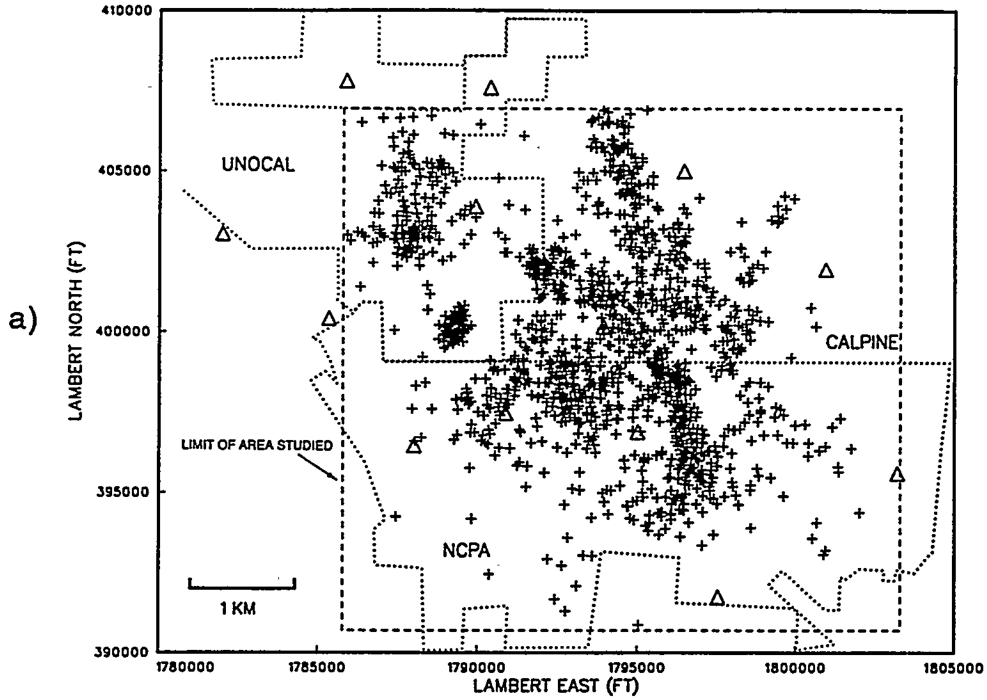
N	EVALUE
1	0.8912E-01
2	-0.1143E-01
3	-0.1450E+00

DECOMPOSITION OF MOMENT TENSOR

TYPE	MOMENT DYNE-CM	PORTION %
ISO	-0.2245E+19	15.48
DC	-0.1006E+20	69.33
CLVD	-0.2203E+19	15.19

Mo 0.1450E+20 . Mw 2.07

Figure 2. Example moment tensor solution output.



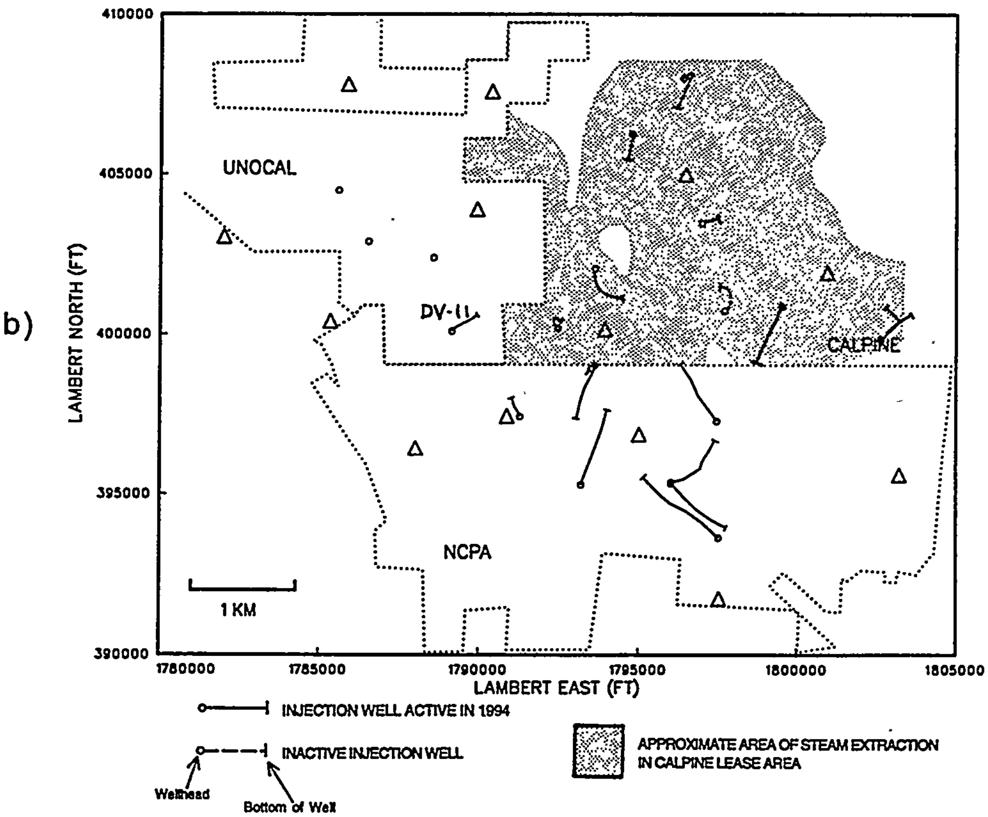


Figure 3. a) Plan view of the 1605 MEQ hypocenters located by the LBL SE Geysers seismic network in 1994. b) Injection wells and approximate area of steam extraction. Well bore traces not available for the injection wells in the Unocal lease area, except for DV-11. Data on extent of steam extraction area not yet available for the Unocal and NCPA lease areas.

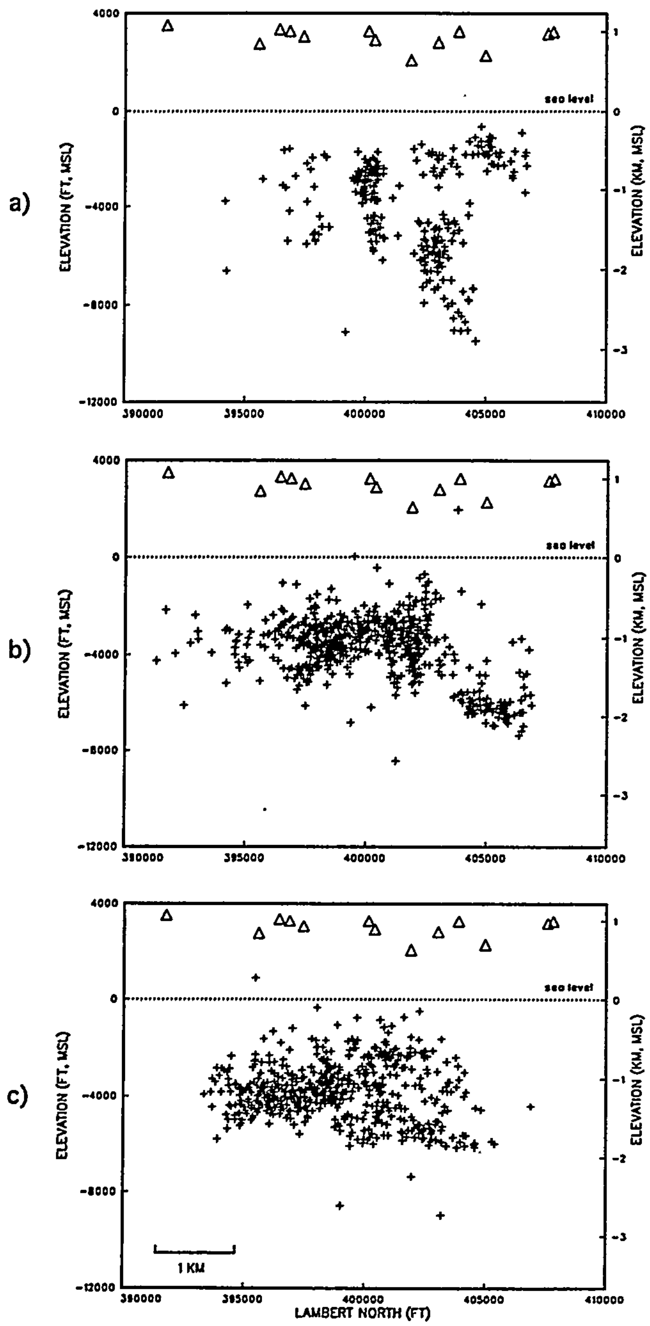


Figure 4. Series of north-south vertical sections of MEQ hypocentral locations. View looking to west; section a) shows events with Lambert east coordinate 1785000 to 1790000; section b) 1790000 to 1795000; and section c) 1795000 to 1800000.

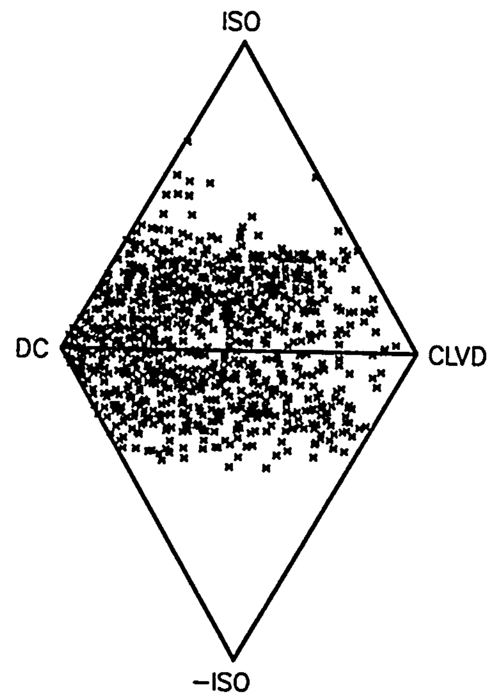


Figure 5. Ternary diagram showing decomposition of the 985 event moment tensors into isotropic (ISO), double-couple (DC), and compensated linear vector dipole (CLVD) components. Moment tensors plotted in the upper triangle have positive isotropic components; those in the lower triangle have negative isotropic components.

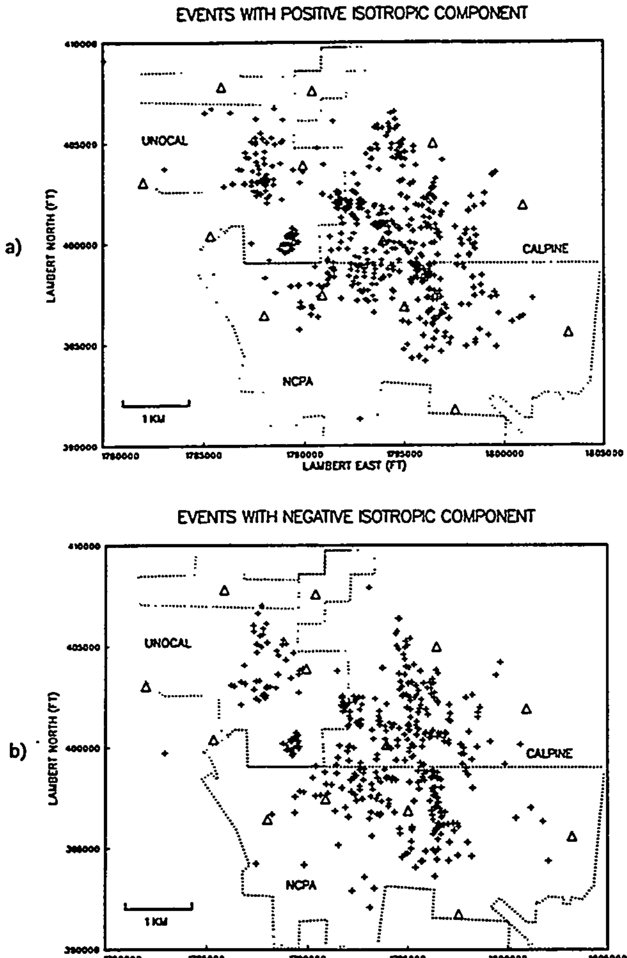


Figure 6. a) Locations of MEQs having positive isotropic moment tensor components (events plotted in upper triangle in Figure 5). b) Locations of MEQs having negative isotropic moment tensor components (events plotted in lower triangle in Figure 5).

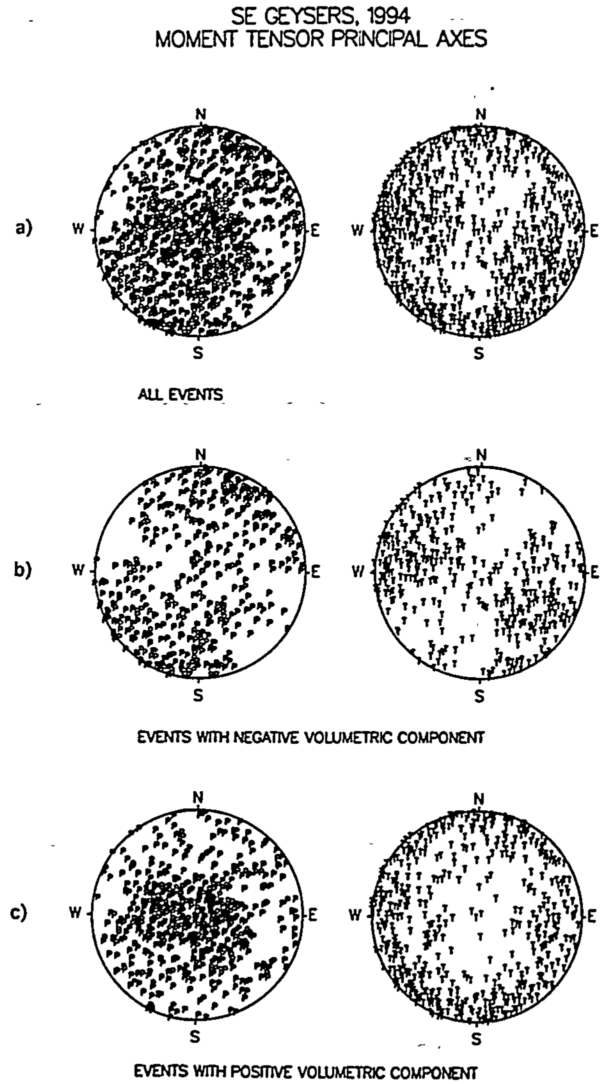


Figure 7. Moment tensor principal axes. a) All 985 events. b) The 429 events with negative isotropic moment tensor components. c) the 556 events with positive isotropic moment tensor components.

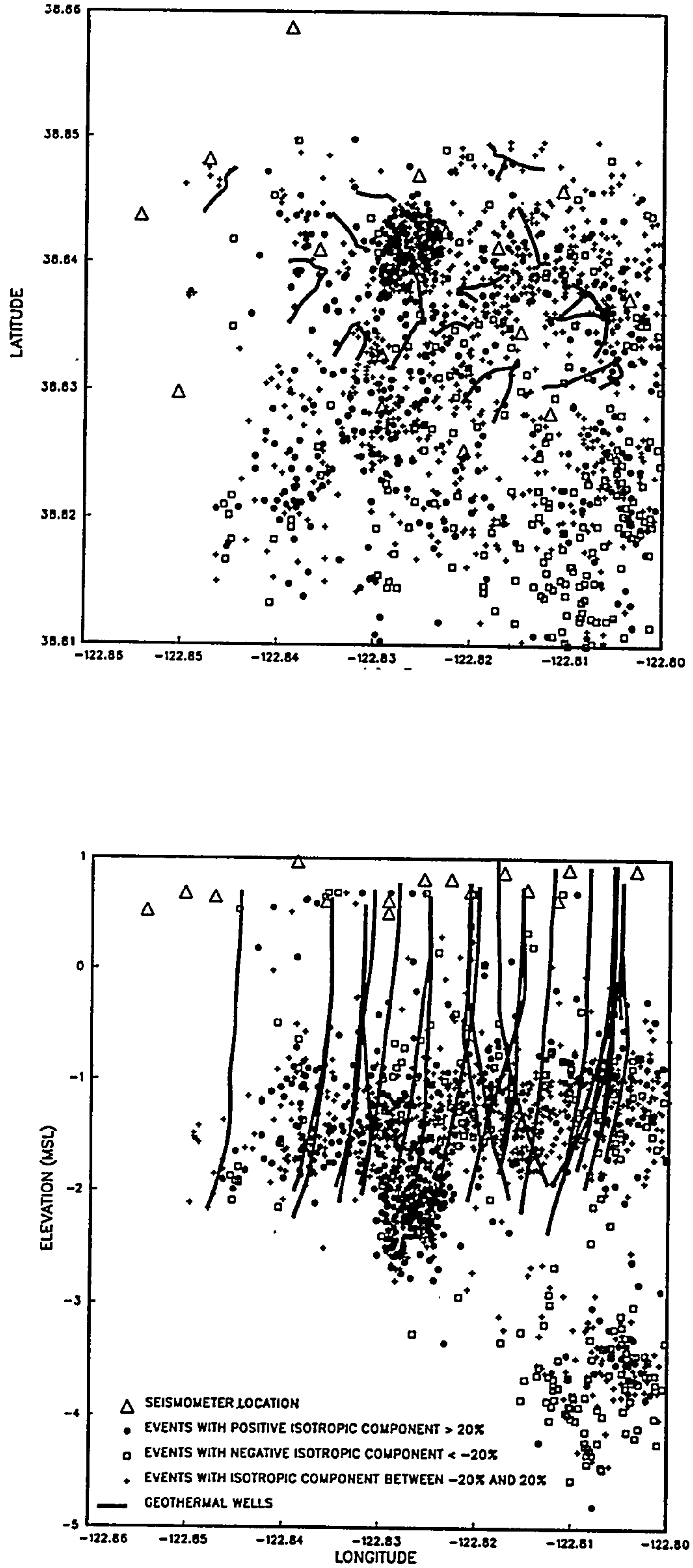


Figure 8. a) Plan view of MEQ hypocenters located by the LBL/CCPA NW Geysers seismic network in 1994. b) Hypocenters projected onto East-West plane.

EFFECTS OF ADSORPTION AND CAPILLARITY ON INJECTION IN VAPOR-DOMINATED GEOTHERMAL RESERVOIRS

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INTRODUCTION

One major motivation for the study of the effects of adsorption in geothermal reservoirs is the phenomenon known as "The Geysers Paradox". Data from The Geysers field suggest that some water must be stored in the reservoir in a condensed phase even though the prevailing reservoir pressure and temperature dictate superheated conditions.

Physical adsorption of steam onto rocks and the thermodynamics of curved interfaces prevailing in the pore spaces of the rock matrix can explain the apparent paradox. These mechanisms make it possible for water and steam to coexist in conditions we normally refer to as "superheated" based on our concept of flat interface thermodynamics (e.g., the Steam Table).

Studies in the past have shown that the performance of a vapor-dominated geothermal reservoir can be strongly effected by adsorption. The adsorbed condensed phase represents most of the fluid mass in the reservoir. Thus, it sustains production beyond what might be expected for a reservoir filled only with vapor (Horne, et al., 1995).

Furthermore, the effectiveness of water injection to sustain production of a vapor-dominated reservoir may also be affected by adsorption. Understanding how adsorption and capillary forces affect water injection is particularly relevant at this time because of the plans to increase water injection into The Geysers. Although water injection has been ongoing for many years, injection rates will increase significantly when water from Lake County, and possibly the city of Santa Rosa, becomes available for injection. The performance of the reservoir under this new condition is a subject of very active study.

Numerical simulation is an effective method to forecast the performance of a geothermal reservoir. Until recently however, simulators have used flat interface thermodynamics to define the phase of the reservoir. Development of new simulation codes has incorporated the effects of adsorption and curved interface thermodynamics. This study makes use of these 'new' simulators to investigate of the effects of adsorption and capillary forces on water injection into vapor-dominated geothermal reservoirs.

THEORY

Physical adsorption is the phenomenon by which molecules of steam adhere to the surfaces of a porous medium. This phenomenon is caused mainly by Van der Waals forces. Desorption is the opposite of adsorption; it occurs when the adsorbed phase vaporizes due to pressure reduction (Horne, et al., 1995). When sufficient deposition has taken place, a capillary interface may form and deposition due to capillary condensation becomes more significant. The transition from adsorption to capillary condensation is continuous.

In addition to mass storage, adsorption affects other aspects of geothermal exploitation. The surface between the vapor and the liquid phases in a porous medium is not flat. It is a well-recognized phenomenon that the vapor pressure above the curved surface of a liquid is a function of the curvature of the liquid-vapor interface. Thus, curved interface thermodynamics is more appropriate than flat interface thermodynamics. The curvature of the surface gives rise to vapor pressure lowering (VPL), thus allowing liquid and vapor to coexist in equilibrium at pressures that are less than the saturation pressure.

Sorption (adsorption and desorption) and capillary condensation are affected by temperature. The general behavior is that the amount of the adsorbed phase increases as the temperature increases, and vice versa (Shang, et al., 1993). In experiments performed at Stanford University, the amount of steam condensing onto rocks is measured as a function of the relative vapor pressure (p_v/p_{sat}). This relationship, which is measured at a specific temperature, is called an adsorption isotherm. The desorption isotherm is measured when the process is reversed and the condensed phase vaporizes as the pressure is reduced.

Experiments show that adsorption and desorption are not reversible processes. Measurements of adsorption and desorption isotherms clearly hysteresis. Rock heterogeneity effects on capillary condensation and irreversible changes in the rock pore structure during adsorption are the likely causes of this hysteresis (Shang, et al., 1993). Because of this, the adsorption isotherm is different from the desorption isotherm.

IMPLEMENTATION

There are two main schools of thought about the implementation of curved interface thermodynamics in reservoir simulation. One focuses on capillary pressure while the other focuses on adsorbed mass in reservoir rocks.

The focus on capillary pressure follows the work of Calhoun, et al. (1949). Experimental studies were conducted to measure vapor pressure lowering and capillary retention of water in porous solid. The primary principle used is described by Kelvin equation:

$$p_c = -RT\rho_l\,(1/M_W)\ln(p_{sat}/p_v)$$

where R is the universal gas constant, T is absolute temperature, ρ_l is water density, M_W is the water molecular weight, p_{sat} is the equilibrium vapor pressure (from the Steam Table) and p_v is the lowered vapor pressure. In the original formulation, 'p_c' denotes the capillary pressure. In recent literature (Pruess, et al., 1992), suction pressure (p_{suc}) is defined as numerically equal to p_c but has a negative sign. The term 'suction pressure' is preferred because it is recognized that the phenomenon being observed involves not only capillarity but also adsorption. The suction pressure is the same mechanism that promotes imbibition of water into the pores of dry rocks.

Works by Pruess and O'Sullivan (1992) and Shook (1994) follow this line of thought and are now being implemented on the simulators TOUGH2 (Lawrence Berkeley National Laboratory), STAR (S-Cubed), and TETRAD Version 12 (also known as ASTRO).

The simulator TETRAD was used in this study. TETRAD is a commercial simulator that has been modified to account for VPL. Version 12 of the code uses the generalized VPL algorithm developed in the Idaho National Engineering Laboratory (Shook, 1993). This algorithm follows-up on an earlier work by Holt and Pingol (1992) to modify the standard steam tables to account for VPL.

The alternative approach follows the work of Hsieh and Ramey (1978). It focuses on the measurement of the amount of adsorbed mass in reservoir rocks. If the dominant mechanism for liquid storage is adsorption, then measurement of sorption isotherms of water on reservoir rocks is deemed necessary.

Experimental data suggest that sorption isotherms follow a Langmuir-type behavior, as described by a modified form of the Langmuir equation:

$$X = d\,\{\,c\,(p_v/p_{sat})\,/\,(1+(c-1)(p_v/p_{sat}))\,\}$$

where the parameters 'd' and 'c' represent the magnitude and the curvature of the adsorption isotherm (Horne, et al., 1995). The parameter 'X' is the mass adsorbed per unit mass of rock. The quantity (p_v/p_{sat}) is often denoted by the symbol β, referred to as the relative vapor-pressure or the VPL factor. The isotherm that describes the relationship between sorption and relative vapor-pressure accounts for both adsorption and capillary condensation (Figure 1). Work on this approach is being spearheaded by the Stanford Geothermal Program (work synopsis given by Horne, et al. (1995)).

The implementation of this approach into a numerical simulator was accomplished in GSS (Geothermal Sorption Simulator), a simulator recently developed in Stanford University. GSS was especially developed to take into account adsorption and curved interface thermodynamics (Lim, 1995).

USING TETRAD

The data required to incorporate VPL in numerical simulations is either a p_c vs. S_l (liquid saturation) relationship or the X vs. β isotherm. TETRAD requires a p_c vs. S_l relationship (Figure 2) while GSS requires an X vs. β isotherm (Figure 1).

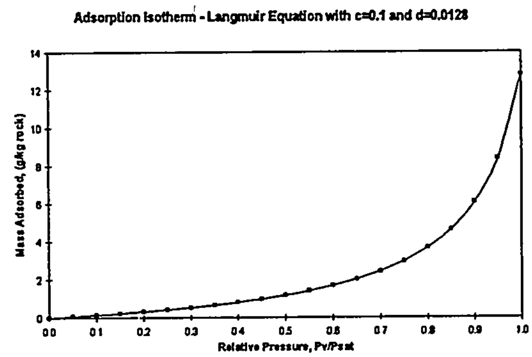

Figure 1: Typical Geysers adsorption isotherm.

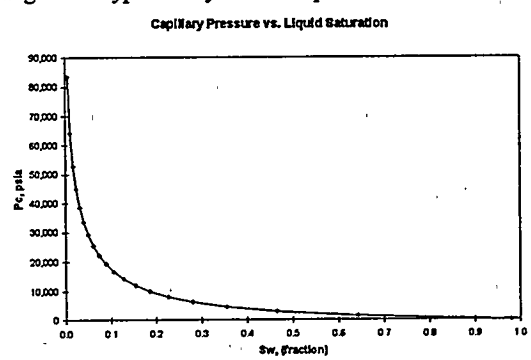

Figure 2: Same adsorption isotherm in Figure 1 converted to p_c versus S_l relationship.

The two sets of data are equivalent and conversion from one to the other is done through the Kelvin equation and an intermediate relation for X vs. S_l. This relation is given by the following equation:

$$S_l = [(1-\phi)/\phi]\ (\rho_r/\rho_l)\ X$$

where ϕ is the rock matrix porosity and ρ_r is the rock grain density.

The resulting p_c vs. S_l relationship can be approximated by the Van Genuchten equation. This equation is expressed as follows:

$$p_c = p_o\ [\ S_{ef}^{-1/\lambda} - 1]^{1-\lambda}$$

where $S_{ef} = (S_l - S_{lr})/(1-S_{lr})$ is the normalized (effective) liquid saturation. The term 'S_{lr}' is the residual liquid saturation (Pruess, et al., 1992).

Neither the Langmuir isotherm nor the Van Genuchten equation can represent the empirical data over the entire range of relative pressure. The Langmuir equation breaks down over the range where the capillary condensation is dominant (e.g. $\beta > 0.9$). On the other hand, Van Genuchten equation breaks down when water saturation is low (e.g., $S_l < 0.1$) where the adsorption effect is dominant. Because of this, even if a simulator has the capability of using data in the form of a parametric equation, it is also important to have the ability to use data in tabular form. TETRAD has this capability.

The simplest way to enter a p_c vs. S_l relationship into TETRAD is by using analytical functions of relative permeability and capillary pressure as a function of liquid saturation. However, the built-in analytical expression for capillary pressure,

$$p_c = a\ [1 - S_l]^b$$

where 'a' and 'b' are fitting parameters, is insufficient to represent the converted adsorption data. The Van Genuchten expression is also available but was not used in this study. Instead, tabular input of relative permeability and capillary pressure relations were used.

One weakness of TETRAD is its inability to adjust the p_c vs. S_l relationship as the reservoir temperature changes in response to exploitation. This is only possible if the built-in analytical expression for capillary pressure is used. This means that the p_c vs. S_l relationship used in this study remains constant even when parts of the reservoir are cooled by production and water injection.

Another weakness of TETRAD is its inability to handle the adsorption/desorption hysteresis (Figure 3). Although any number of sorption isotherms or p_c vs. S_l relationships can be assigned to different matrix blocks, only one sorption isotherm or p_c vs. S_l relationship can be specified for a particular gridblock. The matrix gridblock may undergo both adsorption and desorption in response to injection and production operations.

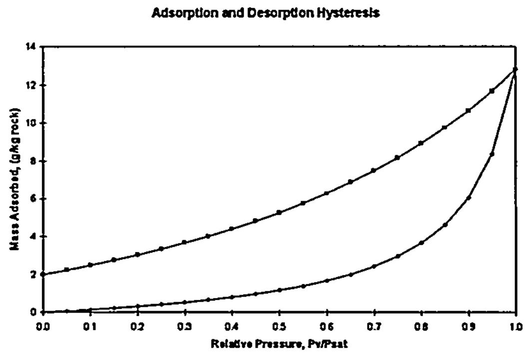

Figure 3: Example of adsorption and desorption isotherms hysteresis.

THE RESERVOIR MODELS

Two vapor-dominated reservoir models (with simple geometry) were developed to investigate the effects of adsorption and capillarity on injection. The geometry of these models is illustrated in Figure 4 and Figure 5. The basic properties used in both models are listed in Table 1. The relative permeability function used allows steam as the only mobile phase at the given initial water saturation (S_w is 30%); water becomes mobile when S_w is greater than 35%. Adsorption properties are patterned after those typically observed in The Geysers (Figures 1 and 2).

The model shown in Figure 4 is comprised of a horizontal layer 1,000 feet long, 200 feet wide, and 100 feet thick. A uniform Cartesian grid with a total of 5 gridblocks was used. The porosity, permeability, sorption properties, and capillarity are uniform for all gridblocks. Initial thermodynamic state (pressure, temperature, and saturation) is also uniform. An injection well and a production well are located on the opposite ends.

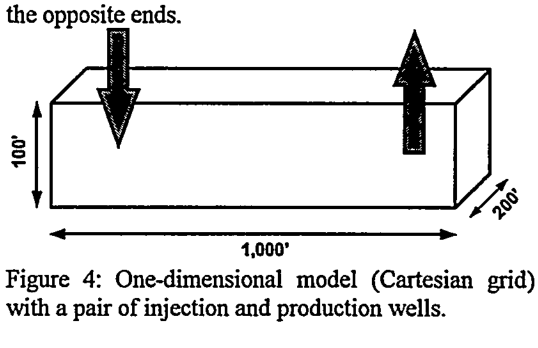

Figure 4: One-dimensional model (Cartesian grid) with a pair of injection and production wells.

The second model shown in Figure 5 uses a uniform radial grid. The model is horizontal, 100 feet thick, and 1,000 feet in diameter. This model uses the same properties used in the Cartesian model. However, in this case the production and injection wells are both located on the center gridblock.

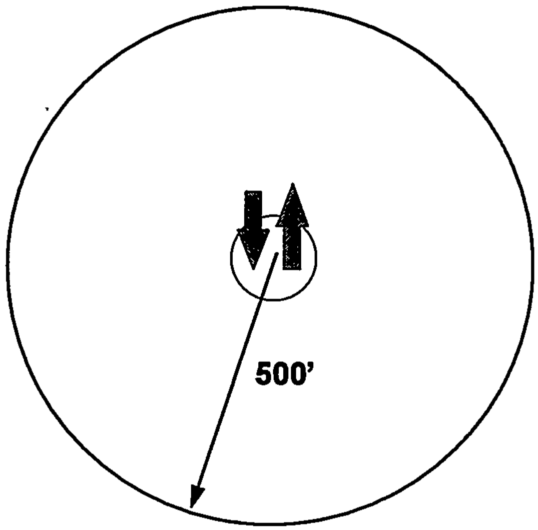

Figure 5: Horizontal two-dimensional model (radial grid) with a pair of production and injection wells located at the center.

The two models are essentially 'closed tanks'. The model boundaries are closed to mass and heat flows. The only way mass and energy can flow in and out of the systems are though the wells

Model Properties

Porosity	**5%**
Permeability	**20 md**
Initial S_w	**30%**
Pressure	**400 psia**
Temperature	**Evaluated**

Table 1: Properties of the Cartesian and radial model.

For clarity, the "reservoir pressure" of 400 psia shown in the table above is equal to the pressure of the vapor phase. Note that the reservoir temperature needs to be evaluated based on the given reservoir pressure and the prevailing phase saturation in the reservoir. At the given initial condition wherein S_w is 30% the appropriate reservoir temperature is about 465°F. If we are using flat interface thermodynamics, the appropriate temperature would have been 445°F.

In a conventional sense the models we are using are superheated by about 20°F at the initial condition.

EFFECTS OF INJECTION

Working with the one-dimensional Cartesian model, we investigated the effects of water injection into a vapor-dominated reservoir when adsorption and vapor pressure lowering are considered. We compared the predicted behavior to the case when adsorption and VPL are ignored.

We perturbed the reservoir by injecting cold water (90 °F). Figure 6 below shows that 20 lbs/h of water is injected during the first 10,000 days. After injecting water, the field was shut-in and the reservoir allowed to equilibrate.

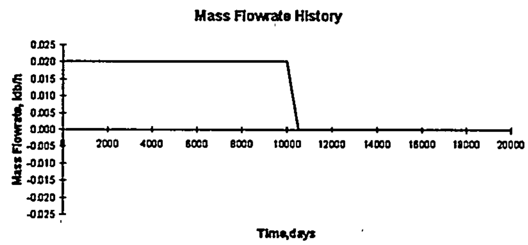

Figure 6: Constant water injection for 10,000 days for the one-dimensional Cartesian model.

Figures 7, 8, and 9 contrast the behavior of the reservoir if it is modeled with and without adsorption and vapor pressure lowering. Shown in these plots are the reservoir pressure, reservoir temperature, and phase saturation measured in the injection gridblock.

Figure 7 shows the reservoir pressure through time. With no adsorption the pressure measured in the injection gridblock is observed to decline. With adsorption the opposite effect is observed. Instead of declining, the pressure is observed to rise in response to injection.

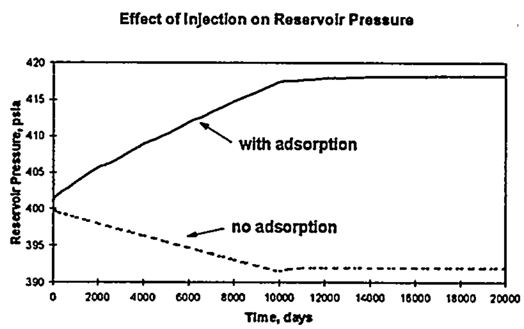

Figure 7: Pressure behaviors of the injection gridblock.

Figure 8 shows the reservoir temperature through time. As mentioned earlier, the use of pressure as the independent parameter to specify the thermodynamic state of the reservoir result in different temperatures for models with and without vapor pressure lowering. Without adsorption, the reservoir temperature is about 445 °F; this is the saturation temperature at 400 psia if the vapor/liquid interface is flat. With VPL, 400 psia actually corresponds to a lowered vapor pressure across a curved vapor/liquid interface. With the water saturation initially at 30%, the given adsorption isotherm dictates the appropriate reservoir temperature to be about 465 °F. Thus, in terms of initial energy in-place the models with and without adsorption are not equivalent. The differences are not limited to the heat in-place but also on the temperature variation of each gridblocks. Without adsorption, temperature declines monotonically for all gridblocks. With adsorption, gridblocks adjacent to the injection gridblock initially exhibit increases in temperature before starting to decline (not shown in Figure 8).

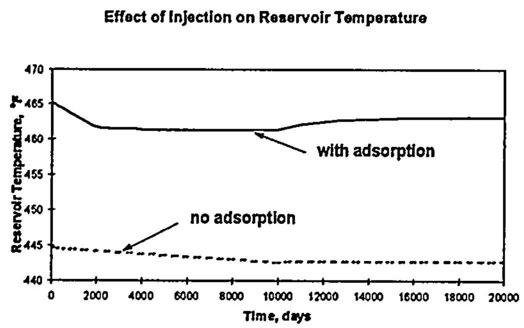

Figure 8: Temperature behaviors of the injection gridblock.

Figure 9 shows the vapor saturation of the injection gridblock through time. The difference between the curves (with and without adsorption) can be attributed to the differences in the pressure and temperature profiles.

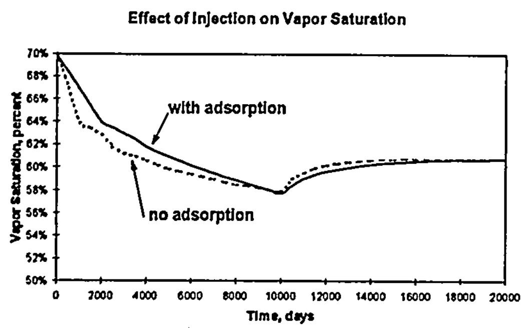

Figure 9: Vapor saturation behaviors of the injection gridblocks.

The next step was to use the two-dimensional radial model to investigate the behavior of the reservoir when we try to produce the injected water. To do this, we impose adsorption and vapor pressure lowering on the model. During water injection, the reservoir pressure is raised above the initial reservoir pressure. After terminating injection, the production well was opened. Production is constrained such that the maximum production rate does not exceed the injection rate and the well is able to produce only down to the point when the reservoir pressure is restored to its initial value.

Figure 10 below shows the reservoir pressure throughout the 30,000 days simulation period. There was constant rate injection from 5,000 to 10,000 days. The production well is opened beginning at 15,000 days. The well is allowed to produce as long as it can sustain production based on the given constraints.

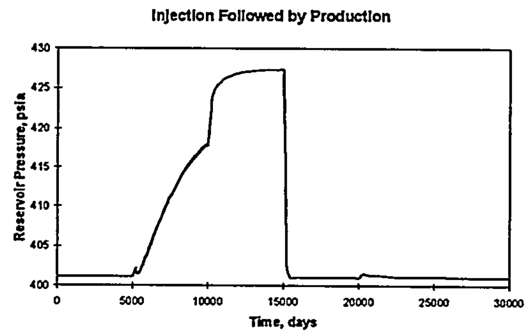

Figure 10: Pressure behavior of the central block in response to injection followed by production.

Figure 11 shows the resulting mass flowrate history of the model. We used a sign convention such that injection is denoted by a positive mass flow while production is denoted by negative mass flow. It is apparent from the plot below that the production rate declines rapidly in response to the decline of the reservoir pressure.

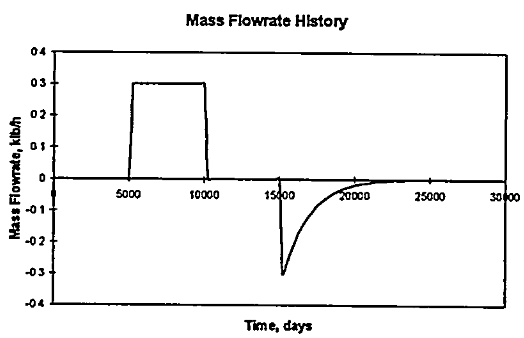

Figure 11: Injection and production rate history.

Figure 12 shows the same information as the previous plot but in terms of cumulative production and injection through time. The total mass injected into the reservoir is 36 Mlbs. The total mass produced afterwards is about 13.82 Mlbs. The total mass produced amounts to only 38.4% of the mass injected. The mass difference of over 22 Mlbs is retained in the reservoir and will be produced only if the reservoir pressure is allowed to decline below 400 psia.

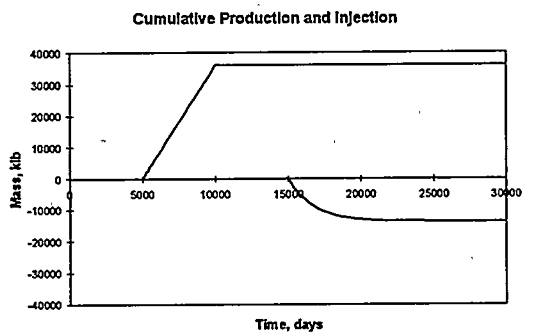

Figure 12: Cumulative masses produced and injected.

DISCUSSION OF RESULTS

One of the most revealing result of this study is the interdependence of pressure, temperature, and saturation within the environment of a geothermal reservoir. With flat interface thermodynamics, water saturation in the rock matrix is a quantity that is independent of pressure and temperature for a system in saturation condition. Because saturation is one of the major unknown quantities in reservoir modeling, its arbitrariness gave it a reputation as a "calibrating" parameter. However, this is not the case with curved interface thermodynamics. If the measured reservoir pressure and temperature are close to saturation condition, this implies that VPL is negligible and a high liquid saturation is appropriate. On the other hand, if a substantial vapor pressure lowering (i.e., superheating) is observed, liquid saturation must be small and it can be evaluated if the sorption properties of the reservoir rocks are known.

Adsorption and desorption hysteresis is a major issue that needs to be addressed. Sorption experiments in Stanford University using cores from The Geysers show that the adsorption and desorption isotherms can be very different. For reservoirs with low liquid saturation, the hysteresis can cause water to be retained in the rock matrix instead of becoming available for production. This will have a big impact when predicting the effects of injection. In the preceding simulations, although it was assumed that adsorption and desorption follow the same isotherm, it was already apparent that the water retention property of the reservoir rock is significant. It is apparent that water injection causes localized increase in reservoir pressure, thus promoting adsorption rather than production of the injected water. If an actual desorption isotherm was used, water retention will be further increased, therefore resulting to an even lower mass recovery from injection operations.

Capillary force is a major factor affecting the propagation of injectate into the reservoir. The high magnitude of suction pressure (in the order of 10^4 psia) of rocks with low water saturation will cause injectate to be imbibed into the rock matrix, away from the high permeability fractures. If injection is targeted in depleted areas with high degree of superheat, imbibition of water into the rocks may minimize the detrimental effects to production that is associated with injection breakthrough. When injecting water, heat transfer limitation is always the biggest issue. If injectate can be sucked away from the high permeability flow channels (fractures), it will facilitate the development of a sustainable injection program.

The next step in this continuing study is to optimize water injection programs into vapor-dominated geothermal reservoirs. The parameters that will be considered include the following: injection rates; depths of injection relative to production; location of injection based on well patterns; and, location of injection using the thermodynamic state (i.e., degree of superheat) of an area as the main criteria.

CONCLUSIONS

This study shows that adsorption and capillary forces are major factors governing the behavior of a vapor-dominated geothermal reservoirs. These mechanisms affect both the resource size estimation and the production performance of the field.

The effectiveness of water injection programs to sustain the geothermal field's productivity is affected by adsorption and capillary forces. Water injection into vapor-dominated reservoirs cause reservoir pressure to increase. Although this improves well productivity, it also increases water retention in the reservoir.

Geothermal reservoir simulators that use curved interface thermodynamics are now available. The hysteresis and temperature dependence of sorption and capillary properties are issues that still need to be addressed. These processes should be incorporated in future codes of geothermal reservoir simulators.

ACKNOWLEDGEMENT

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Injection Tests in the Southeast and Central Geysers

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PAPER NOT AVAILABLE

S.E. GEYSERS EFFLUENT PIPELINE PROJECT

TURNING COMMUNITY WASTES INTO SUSTAINABLE ENERGY

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Energy and Resource Manager
Lake County, California Sanitation District

On October 6, 1995, a unique public/private partnership of local, state, federal, and corporate stakeholders started construction of the world's first wastewater-to-electricity system in Lake County, California. A rare example of a genuinely "sustainable" energy system, three Lake County communities will recycle their wastewater effluent through the Geysers geothermal steamfield to produce enough power to meet their electricity needs for decades to come. Known as the Southeast Geysers Effluent Pipeline Project, this $45 million effort has become a national model of geothermal resource management distinguished by the following accomplishments:

- Turning the rhetoric of sustainability into functional infrastructure that sustains electric generation with a combination of community wastes and geothermal energy.

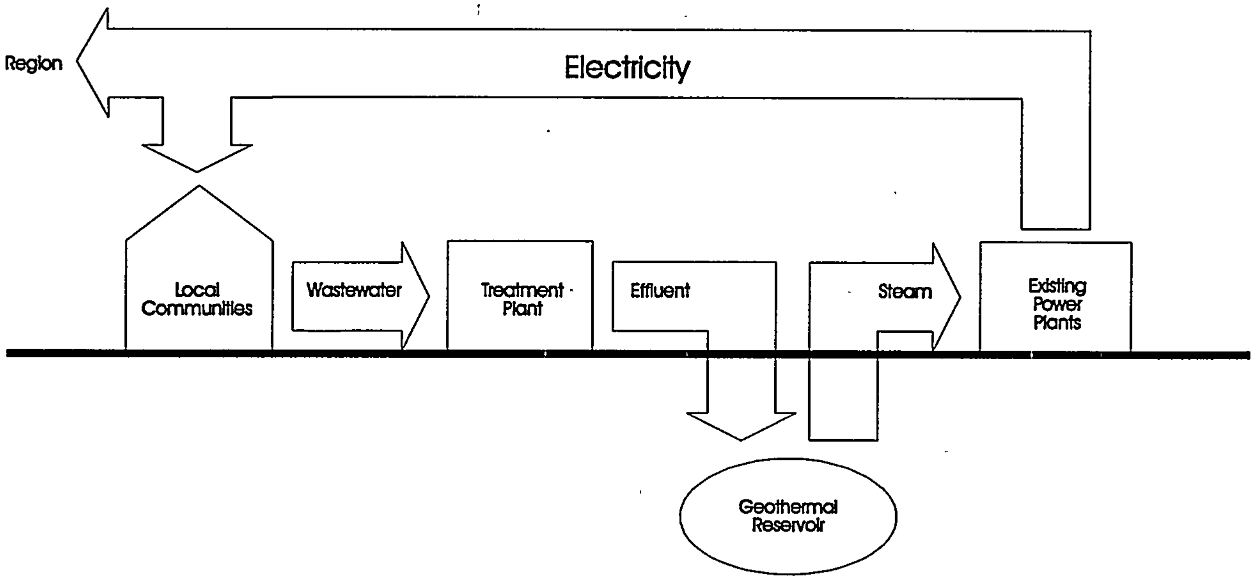
- Creating an inclusive partnership of eleven public and private stakeholders to undertake the project.

- Integrating the project's environmental review with its engineering design to avoid rather than mitigate impacts.

- Using consensus decision-making among stakeholders during project development to insure eventual support for implementation.

When construction is completed in 1997, the project will begin an expected 25-year operating life that will provide the Lake County communities with not only all of their electricity needs, but also sufficient wastewater disposal capacity to accommodate regional growth to 2022.

PROJECT CONCEPT



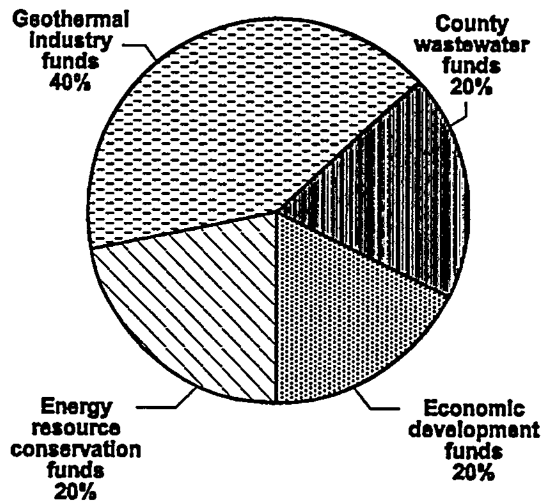
Project History and Development Process

Lake County, California, with a population of 58,000 persons, is situated approximately 100 miles north of San Francisco. Like many rural areas, its growth has strained its public infrastructure, including wastewater systems. Since the 1980s the communities of Clearlake & Lower Lake have been subject to state-ordered upgrades in wastewater treatment facilities. Finding environmentally-acceptable and affordable solutions for these requirements has not been easy, with several years spent evaluating alternative treatment and disposal scenarios.

At the same time in the 1980s, the region's geothermal power industry began to experience productivity declines in the Geysers steamfield. Power plant steam usage was exceeding the steamfield's natural recharge capacity and electricity production was falling dramatically. The geothermal heat source remained constant, but injection of additional water was needed to convey the geothermal heat to steam production wells. After surveying the region for potential water sources it became apparent to both the County and geothermal industry that wastewater injection could satisfy two needs at once: first, as an environmentally-superior wastewater disposal method; and second, as a continuous supply of power plant "fuel" that could sustain a critical part of the local economy and an environmentally-superior method of electric generation.

Despite the risks and unknowns of the idea, by 1991 a group of key stakeholders were willing to pursue an investigation of its feasibility. This core group included the Lake County Sanitation District, Northern California Power Agency, Calpine Corporation, Unocal Corporation, Pacific Gas and Electric Company, and the U.S. Department of Energy. The group's efforts evolved into four separate tracks of work:

CONSTRUCTION COST SHARES



- Technical. A series of geothermal reservoir analyses and pipeline engineering studies examined reservoir impacts, and multiple pipeline alignments and operating strategies. These were completed during 1992-94.

- Environmental. Concurrent with design studies, a consolidated EIR/EIS was prepared for CEQA and NEPA compliance. The EIR/EIS was completed, without any appeals, in October, 1994.

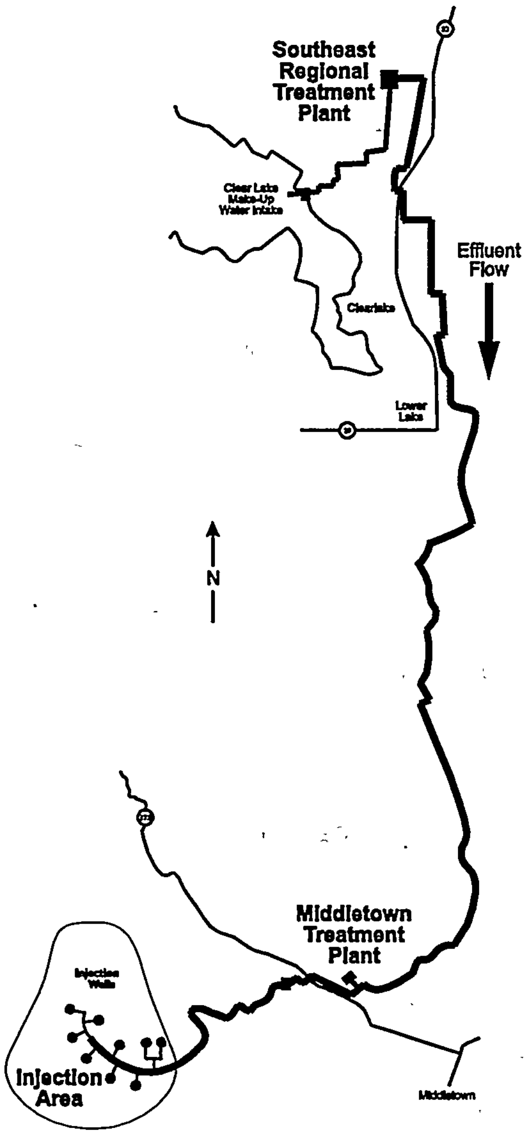
- Legal. The stakeholders spent three years negotiating a construction finance agreement and a 25-year operating agreement. These were signed in August, 1995.

- Financial. Equivalent time was devoted to raising construction funds from stakeholders proportionate to their affected interests. Approximately 95% of the $45 million construction budget has been raised to date.

As finally designed, the project consists of a 29-mile, 20-inch diameter pipeline that will carry up to 7.8 million gallons per day of treated wastewater effluent to the Geysers, where the effluent will be injected to depths of approximately 8,000 feet. Depending upon steam recovery rates for the injected effluent, the project is expected to produce up to 70 megawatts of generating capacity at six existing geothermal power plants in the Geysers. This will equate to as much as 625,000 megawatt-hours annually of clean, low-cost geothermal electricity that is enough for not only the 18,000 residents of Clearlake, Lower Lake, and Middletown, but also thousands of other California electric consumers.

Keys to Success Thus Far

The project reached a milestone on October 6, 1995, when ground was officially broken for its construction at the Southeast Regional Treatment Plant in Clearlake. The factors that enabled this significant project milestone include:



PIPELINE ROUTE

- The powerful logic of sustaining a community need (electricity) with a continuously-available community waste (effluent) by replenishing a geothermal resource.

- An inclusive partnership of stakeholders that was broad enough to insure that all affected interests were represented.

- Stakeholders willing to commit themselves to consensus decision-making, and the trust and respect for each other that such a commitment implies.

- Getting people to think in long rather than short-range terms, with success measured in decades rather than years.

- Using environmental determinants to guide project development. The project's overriding attention to the environment has produced an absolutely clean record of no delays or appeals of any kind related to environmental issues.

The potential for using these techniques to convert community liabilities into sustainable assets is not dependent upon conditions unique to Lake County. Although Lake County is fortunate to have the Geysers nearby for effluent injection, other communities are finding comparable opportunities. Seattle, for example, is using its effluent as heat pump source fluid for space conditioning industrial buildings along its outfall pipeline. Tucson, Arizona reclaims and distributes its effluent for landscape irrigation. The common thread among these and similar efforts nationwide is a recognition that environmental quality and economic progress are not mutually exclusive, but can be mutually supportive components of a sustainable future. With the assistance of USDOE, Lake County and its industrial partners are now building that kind of a future.

PG&E'S GEYSERS' POWER PLANT IMPROVEMENTS - PAST, PRESENT, AND FUTURE

by
Paul Louden, PG&E Geysers
Carl Paquin, PG&E Research and Development Department
Walter Southall, PG&E Geysers

ABSTRACT

Geothermal power plant retrofits can improve plant efficiency, reduce operations and maintenance costs, as well as increase plant availability. All geothermal power producers must find new ways to become more competitive as the electric power industry becomes deregulated. To survive and thrive in the competitive power generation market, geothermal plant operators must continually look for economic power plant upgrades that reduce the cost of production and improve availability. This paper describes past and present power plant retrofits as well as shows how further research can help future plant improvements.

Past power plant retrofits at Pacific Gas and Electric Company's Geysers Power Plants include innovative H_2S burners that reduced chemical costs and a turbine jack-shaft that improved unit efficiency. Other important retrofits that dramatically reduced turbine forced outage and repair costs were turbine blade and nozzle changes, turbine weld repairs, and steam desuperheating.

Power plant retrofits in progress now at The Geysers include turbine steam path modifications and a high speed turbo-compressor to improve power plant efficiency. In addition, advanced direct contact condenser modifications will improve turbine efficiency and dramatically reduce H_2S abatement costs. A new turbine rotor with titanium blading will eliminate stress corrosion cracking in the rotor disks which further improves unit efficiency since steam desuperheating will no longer be necessary.

More government and industry research is needed to develop and demonstrate new technologies that will help geothermal power remain competitive. For example, another method of preventing stress corrosion cracking of older turbine rotors is needed instead of steam desuperheating. Researchers need to find lower cost methods of dealing with hydrogen sulfide emissions and hazardous waste disposal. Hydrogen sulfide burner waste heat energy recovery could increase power production by several megawatts. And finally, economical sources of water for injection into the reservoir are needed to sustain The Geysers, the flagship of US geothermal power.

BACKGROUND

Pacific Gas and Electric Company (PG&E) operates fourteen units at The Geysers, in Northern California, where superheated steam powers low pressure turbine - generators. PG&E's units have a combined capacity of about 1250 MW but actually generate approximately 800 MW due to the steam field pressure decline. Most of the heat remains in the reservoir rock but about half of the water has been used up for steam production. Studies and construction of a water pipeline are in progress to help mitigate the steam field pressure decline. However, we must continually look for ways to improve economic power production of this valuable natural resource.

Geothermal power plant energy conversion improvements must face the hard realities of competition. Deregulation of California's electric power generation industry forces all power producers to closely analyze the costs and benefits of power plant retrofits in the emerging competitive power industry. Geothermal power from The Geysers must compete with low cost, usually abundant hydro power as well as fossil fired power generation fueled by low cost natural gas. Therefore, Geysers' power plant improvements must deliver strong financial benefits, providing an investment payback generally within three years.

PG&E, the Department of Energy (DOE), the steam suppliers, geothermal equipment manufacturers, and consultants have studied power plant improvements that improve efficiency, lower auxiliary power losses, reduce emissions, or reduce operating and maintenance costs. This paper reviews several power plant improvements that have occurred in the past, describes work that is currently in progress, and identifies opportunities for further power plant improvement research.

PAST POWER PLANT RETROFITS

Hydrogen sulfide burners: Geysers' operating permits require that hydrogen sulfide (H_2S) emissions be abated. Over the past ten years, H_2S burners have been retrofitted in the abatement systems at Units 5, 6, 7, 8, 11, and 12. These units have direct contact condensers where about half of the H_2S gas is removed from the condenser with the non-condensable gases while the remaining H_2S gas is absorbed in the circulating water where it is treated using iron chelate. The H_2S burner is a refractory lined vessel where air is added and the H_2S ignited so that it is oxidized, forming SO_2 and H_2O. The hot flue gases are quenched with circulating water and scrubbed with an alkaline solution to convert the SO_2 to SO_3. This solution is then returned to the circulating water to work with the iron chelate and oxygen to form thiosulfate. Thiosulfate is a soluble compound that is environmentally safe and can be disposed of or injected back into the reservoir.

Before these units were retrofitted with burners, the H_2S in the non-condensable gas was scrubbed in the after condenser where caustic was added to absorb the H_2S gas into the circulating water. More iron chelate was added to the circulating water to absorb this H_2S. The burner retrofits cut costly iron chelate usage at these units by half and reduced costly cooling tower sludge removal and disposal, for a combined saving of over $10 million a year.

Turbine jack-shaft: As the geothermal steam field pressure and flow decline over time, there is less available energy to produce electric generation. This results in a steam path that is less efficient than originally designed. From a reservoir perspective, the remedial action is to match the new steam delivery characteristics with the appropriate steam path geometry. The first such modification that had the greatest benefit to cost ratio was to reconfigure two of the dual turbine rotor generating units into single turbine generating units. This modification is done by replacing one of the turbine rotors with a drive shaft. This raises the steam delivery pressure flow relationship closer to design by sending full steam flow to the remaining turbine rotor. The long term benefit is higher energy conversion efficiency and reduced steam reservoir pressure and flow decline rates.

Turbine blade and nozzle changes: In the 1970s and 1980s, PG&E's geothermal turbines experienced numerous second stage turbine blade failures that forced many units out of service for costly overhaul. The blades usually failed in the vane area, with the crack often initiating at a small pit. Initially, the cause of failure was believed to be corrosion or stress corrosion cracking (SCC) of the high alloy turbine blades in the very corrosive geothermal steam. Turbine blades should last 10 to 20 years, however many second stage blades failed after only a few years of service. Occasionally a blade would fail after only a few weeks or months of operation!

Blade vibration research and testing by PG&E researchers and plant engineers eventually identified the problem as blade group resonance. The nozzle passing frequency was too close to a tangential mode of the second stage blade groups. The dynamic steam forces from the upstream nozzles excited the blades into resonance, resulting in rapid fatigue failures. PG&E researchers and plant engineers successfully demonstrated that using titanium shroud bands or replacing the second stage blades with integrally shrouded titanium blades moved the blade resonance and improved damping. The turbine manufacturer also redesigned the diaphragms with fewer nozzles to move the nozzle passing frequency far away from the blade resonant frequencies. Eliminating blade failures dramatically reduced maintenance costs and improved plant availability.

Stress corrosion cracking and steam desuperheating: Routine inspections of the turbine rotor uncovered SCC in the second stage turbine shaft to disk radius and in the disks at the blade hook areas. Turbine disk SCC never caused an in-service rotor failure, but several rotors with severe SCC had to be taken completely out of service. Replacing these rotors with high alloy SCC resistant materials is prohibitively expensive, costing about two million for the rotor and an additional million to install new turbine blades. PG&E and ABB researched and successfully demonstrated rotor weld repair methods whereby the SCC damaged area of the disk was first removed and then rebuilt with successive weld passes of SCC resistant 12 chrome material. Next, the newly formed rotor disk was heat treated and then machined with new blade hooks. After re-blading and balancing, the repaired rotors were returned to service.

To prevent SCC at other turbine stages, the steam is now desuperheated to remove corrosive chemicals from the steam. To desuperheat the steam, water is sprayed into the steam lines to bring the steam to saturated conditions, approximately 80 psig and 300 F. The corrosive chemicals are quickly absorbed by the moisture which is separated from the steam, drained from the steam line, diluted, and reinjected back into the Geysers reservoir. The "cleaned" desuperheated steam continues to the power plant and into the steam turbines without causing SCC. Although desuperheating decreases power production by approximately 20 MW for all of PG&E's units, desuperheating is effective at preventing SCC and has eliminated costly rotor repairs and associated outage costs.

CURRENT POWER PLANT RETROFITS

Unit 13 steam path: The original steam path at Geysers Unit 13 has had a history of rotating blade and nozzle failures. Also, the Unit 13 steam path was the not suited to the steam reservoir's current pressure and flow delivery relationship. A new steam path is currently being installed that will result in a 12 MW increase in generation and will mitigate the reliability issues.

The increase in generation is achieved by matching the current available energy of the steam with the appropriate steam path geometry and by installing a steam path capable of being operated in superheated steam without SCC. The last stage blade length was increased from 16.5 inches to 23 inches which accounts for approximately 8 MW of the generation increase. SCC resistance capability is achieved through the use of 12 chrome steel materials for the rotor and a rotor design having lower stress levels. Turbine disk stresses at the third stage were lowered by the use of titanium blading. These material changes allow the use of superheated steam without rotor SCC concerns and accounts for approximately 4 MW of the generation increase.

The new steam path was specifically designed for the steam conditions at Geysers Unit 13. This specific design may or may not be suitable at another geothermal location. However, other geothermal operators at The Geysers are also planning similar steam path upgrades. In addition to the available energy issue, the other consideration used to specify the steam path is the designed stress levels in the turbine rotor and rotating blade hook fit. This is important so as to reduce any potential for SCC. In this case, the region where the potential for SCC is the highest is at the third stage where the steam begins to first form condensation. Due to the stresses in the rotor hook fits in this area and the corrosive steam, the use of titanium rotating blading is appropriate to reduce the blade weight by about a third. The lighter weight of this material over conventional 12 chrome blade material allowed the rotor hook stress levels to be below the threshold for SCC.

In summation, the steam path geometry should be sized for the current and forecasted steam field delivery capability. This will maximize generation through use of all of the available energy in the steam. The turbine rotor and blade material should be considered along with the stresses to minimize SCC risks.

Unit 11 advanced direct contact condenser: The National Renewable Energy

Laboratory (NREL), funded by DOE, and PG&E are working together to develop and demonstrate novel advanced direct condenser technology at Unit 11. Currently, circulating water falls through perforated trays inside the Unit 11 condenser which create droplets that absorb heat from the incoming steam. About half of the H_2S entrained in the steam is absorbed in the condensate, the other half is removed with the non-condensable gases.

NREL developed computer thermal and chemical performance models of "structured packing". Structured packing is a commercially available material that resembles a honeycomb and provides a large surface area for heat transfer. The NREL design divides the direct contact condenser into two different flow areas: a co-current section and a counter-current section. In the co-current section of the condenser, steam flows downward through the packing along with the cooling water. Near the bottom of the condenser, but above the liquid condensate, the steam that has not yet condensed turns and flows upward through the counter-current section of the condenser while the cooling water flows downward.

The depth of the packing in the co-current section and counter-current section are optimized to minimize absorption of H_2S into the circulating water. The depth of the structured packing in the co-current section is designed to keep the partial pressure of H_2S low relative to the steam which greatly reduces the H_2S absorbed by the circulating water. The reduction of H_2S in the circulating water is expected to reduce the use of costly iron chelate by about $380K per year.

A second benefit comes from the large surface areas of the packing which improve heat transfer from the steam to circulating water. Improved heat transfer reduces condenser pressure and reduces steam carry over with the non-condensable gases. Reduced condenser backpressure will increase turbine power output by approximately 2 MW.

Unit 11 turbo compressor: DOE, Barber-Nichols, PG&E, and UNOCAL are funding the research and demonstration of a high speed turbo compressor for inter-condenser gas removal. The Barber-Nichols turbo compressor will be installed in the summer of 1996. The single stage axial flow turbine is driven by main steam and will exhaust to the main turbine steam seal system. The single stage radial flow compressor will compress non-condensable gases from the inter condensers, move this gas to a gas cooler which then flows to the H_2S burner system. The turbo-compressor rides on water lubricated bearings, which eliminate the need for costly oil lubrication and shaft sealing often required by vacuum pumps.

The turbo-compressor only uses about 30% of the steam required of a final stage jet venturi ejector system, saving 1. 2 MW at the current main steam pressure of about 65 psig. However, as the local steam field pressure declines to below 50 psig, the benefits of the turbo-compressor relative to conventional final stage jet venturi ejectors become significant. Final stage jet venturi ejectors require main steam pressure of at least 50 psig otherwise their performance seriously degrades. To maintain 50 psig main steam pressure, the turbine throttle valves must be partially closed which reduces power production and increases throttling losses. The turbo-compressor is designed to operate efficiently over a wide range of steam pressures thus avoiding several megawatts of power production losses.

FUTURE POWER PLANT RETROFIT RESEARCH OPPORTUNITIES

Alternatives to desuperheating: Steam desuperheating at The Geysers successfully eliminated steam turbine SCC but at the cost of about 20 MW of energy otherwise available for power production. Further research is needed to (a) develop dynamic steam chemistry models of the steam as it flows through the turbine to identify the corrosive elements that cause SCC, (b) demonstrate alternatives to desuperheating that will remove the corrosive chemicals from the steam, (c) research low cost rotor modifications that will lower the stresses in the turbine disks, and (d) develop flexible but durable coatings that will protect the turbine disks from SCC.

Real time H_2S emissions monitoring: Currently each power plant's H_2S emissions are measured monthly to assure permit compliance. Measurements are performed on top of each cooling tower using an H_2S monitor with data recorded during a manual multi-point traverse of several fan stacks. Over the years several attempts have been made to design a continuous emissions stack monitor using manifold arrangements or multiple stack sampling ports. These systems have been unsuccessful because of the corrosive and water saturated environment.

Real time H_2S stack emission would provide several benefits including assistance with air quality H_2S compliance and monitoring. The biggest potential dollar savings would be optimization of chemical usage, primarily iron chelate. Iron chelate is added to the circulating water to react with dissolved H_2S to form elemental sulfur.

H_2S fluctuations in the incoming main steam require most plants to target iron feed to obtain 75% of allowable emissions. Accurate real time stack emission monitoring would allow lower iron chelate concentrations to obtain 90% of allowable emissions. This 15% improvement would result in an annual iron chelate saving of about $300K.

Reduction of mercury in sulfur: The Geysers area was once heavily mined for mercury. Mercury is also prevalent in the geothermal steam supplied to several of the plants. Mercury vapors combine with H_2S to form an insoluble compound, mercury sulfide. In the abatement of H_2S this mercury sulfide creates a problem at Stretford abated units.

The Stretford H_2S abatements process uses a vanadium solution to absorb these sour gases in an alkaline solution. H_2S is then oxidized by vanadium forming small particles of sulfur which are floated to the surface using air. The sulfur along with some of the vanadium solution is then skimmed off and sent to a vacuum filter where water sprays wash out most of the vanadium solution. The sulfur cake is then slurried with water and pumped through a steam supplied heat exchanger where it is melted and discharged to a decanter. The decanter separates the water from the sulfur and the sulfur is held in an insulated steam traced storage tank until tested for mercury levels.

If mercury concentrations in the molten sulfur are under the 20 PPM regulatory limit, the sulfur is trucked to a processor who prills the sulfur into pellet beads used by other industries. If mercury is over the allowable limits the entire sulfur load is disposed of as hazardous waste. Approximately 20 percent of the sulfur or 500 tons annually is disposed as hazardous waste, costing over $100,000.

One technology for removal of mercury vapor comes from the natural gas industry and is currently being used at other geothermal facilities. The mercury vapor is passed through a filtering vessel filled with a bed of sulfur and/or activated charcoal. We are currently exploring this option for our plants with mercury problems. Another technology being explored by Brookhaven National Laboratory is biological treatment of the sulfur to remove mercury.

Research would be helpful in determining other possible methods or processes to remove mercury in the steam supply, in the sour gas supplied to the Stretford process, and/or from contaminated sulfur. Other possible areas to explore include identifying and evaluating both existing and new mercury removal mediums. This effort would benefit both the geothermal and natural gas industries by providing solutions to reduce environmental and safety concerns, as well as reducing hazardous waste and disposal costs.

H_2S burner energy recovery: The H_2S burners generate heat that is absorbed by the circulating water. Assuming only 30 percent of the available energy can be recovered, the energy available varies from about 0.5 MW at Unit 12 to 2.5 MW available at Unit 11. The high temperature burner exhaust gases are quite corrosive, providing a significant engineering challenge to recover this energy economically.

Find more water: As everyone knows, The Geysers is running out of water. Over 90 percent of the heat remains in the rock but about half of the water has been used for power production. Finding water for reservoir injection is the key issue facing The Geysers; the power plants must have steam to produce power! Rain water injection and power plant cycling have reduced the steam decline from the predicted 8 percent rate to 3 percent last year.

A $34 M Lake County treated waste water pipeline is under construction which will bring water for injection to help mitigate the steam decline by an estimated 50 to 75 MW. Innovative funding solutions made this pipeline a reality. Additional creative financial and technical solutions of this kind are needed. The City of Santa Rosa has a similar waste water disposal problem but the cost of bringing the waste water to The Geysers is estimated at $180M. Research is needed to find innovative means of funding this pipeline as well as find technical solutions to reduce the construction and operating costs. The volume of water available from Santa Rosa could result in well over 300 MW of energy, enough to sustain The Geysers at current generation levels!

CONCLUSION

Past power plant retrofits have dramatically reduced the operating and maintenance costs. The H_2S burners cut iron chelate costs by half and reduced cooling tower sludge removal and disposal costs. The jack shaft modification removes a rotor but improves the efficiency of the unit. Using titanium blades, redesigning the second stage blades, and changing the number of nozzles moved the blade group resonant frequency far enough away from the nozzle passing frequency so that costly second stage blade failures are only a bad memory. Rotor weld repair technology demonstration avoided the replacement of costly turbine rotors. Steam desuperheating removes corrosive chemicals from the main steam so that SCC is no longer a problem.

Current power plant retrofits such as the new Unit 13 rotor and steam path will improve turbine efficiency and eliminate rotor SCC without desuperheating. The turbo-compressor will improve condenser gas removal efficiency and allow future unit operation at main steam pressures below 50 psig without main steam throttling. Demonstration of NREL's advanced direct contact condenser modeling technology at Unit 11 will improve condenser performance, improve power production, and dramatically reduce H_2S abatement costs. These successful projects evolved from technology development and sound engineering that required a significant commitment of people and funding by PG&E, steam suppliers, manufacturers, industry, and DOE.

Future power plant retrofit research and demonstration are essential to the survival of geothermal power in the competitive electric generation industry. Research is needed to eliminate steam desuperheating to recover an estimated 20 MW of energy. Several more megawatts of heat energy is available at the H_2S burners, but economical heat recovery from the corrosive gases will be a challenge. Additional research is needed to improve H_2S emission monitoring and develop technologies to reduce hazardous waste disposal costs. And finally, finding innovative and economical methods of bringing water to The Geysers for reinjection could sustain and renew this valuable energy resource.

PG&E, DOE, steam suppliers, industry, and manufacturers must continue to work together to research, develop, and demonstrate improved energy conversion technologies. Continued cooperative technology development is key to improving conversion efficiency, improving plant availability, and reducing operating and maintenance costs at The Geysers as well as flash steam power plants throughout the US. In addition, development and demonstration of these advanced technologies by US firms provides proven technologies that US firms can market throughout the world.

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PANEL DISCUSSION:

Lessons Learned at The Geysers and the Next Steps

Opening Remarks by Marcelo Lippmann

During the last part of this morning session, we will be discussing joint DOE-industry research and development efforts on The Geysers geothermal field. I have asked five panelists to oversee discussions, three from industry and two from DOE- supported research organizations. They are Paul Hirtz from ThermoChem Inc., Keshav Goyal from Calpine Corporation, Ben Barker from Unocal Corporation Geothermal, Jeff Hulen from the Earth Sciences and Research Institute (ESRI) of the University of Utah, and Collin Williams from the Geological Survey (USGS).

As was mentioned earlier during this meeting, up to now DOE has spent about $12.2 million in Geysers research-related projects and another $7 million for the Lake County pipeline. On the other hand, industry has spent large amounts of money to keep The Geysers project going.

The discussions will be based on the personal experiences of the Panel members, on what we heard today as well as in previous meetings, and on what we read in the Research Program Update that was distributed as part of the registration package. On the basis of what we learned, we will attempt to identify the joint DOE-Industry Geysers research that should be done in the future.

Ben Barker, Unocal

Fortunately, The Geysers is such a complex and evolving system that you can say almost anything about it and sooner or later you would be right in some part of it. Just by way of background, I started working on The Geysers first in 1978 and spent about five years there. I then went away for about five years and came back again. The Geysers was not exactly a new field at that point. It had certainly changed a lot in the five years. I came back around the time of the start of California Energy Commission's investigations and the early discussions about the Lake County pipeline.

The last seven years has been an interesting time. Marcelo asked us to say something about what we have learned and what we, I guess by contrast, still need to learn. I think one of the things that is pretty obvious from all of the presentations is that injection is still the single dominant topic when you talk about The Geysers. Virtually everything relates to injection in one way or another. So, let us look back and ask what we know about injection?

We know some fairly elementary things like reservoir superheat favors boiling. It seems sort of obvious that the hotter and dryer the reservoir, but it took a while to get the evidence of proof, that in fact you can extract boiling water at a commercial rate and get real production benefit from it. We know that you can develop pressure support and Roland this morning showed an example of why that is an important observation. This observation, in fact, means something about the fundamental physics of the reservoir, which is different from the conventional physics as built into most reservoir simulators. It tells that we need to learn a lot more about how to deal with reservoir simulators. We have learned that chloride production can be reduced, or is somehow reduced by injection. We have learned that microseismicity happens. And we have learned that you can use tracers, especially tritium, to do long-term, long-distance mapping of hydraulic connectivity, or however you want to describe it, in a lateral sense. Those are things that I think you can put up on one side of the board and say we know those things and proceed to ask what do we not know?

Well, we do not know why or quite how microseismicity happens. We can not analytically tie the observations that we are capable of making with considerable precision to the hydraulic phenomenon that we are most concerned about when it comes to managing injection in production. We do not know how to predict the optimal rate of injection in an area. With 20 or actually close to 30 years of large-scale injection experience, injection is still a matter of trial and error. Part of that problem relates to another thing that we do not know, which is how to map permeability. I can almost say that we can not map it at all, but that is not true. What we can not do is map permeability and define fractures in 3D. We can record steam entries, but The Geysers being a vapor-dominated system has not lent itself to a lot of reflection seismic work and things of that sort used in the oil and gas industry. So there is another area of mapping of permeability and fractures that we do not know.

Finally, we do not know how to get vertically distinguishable chemical measurements. There is ongoing DOE-sponsored work on downhole sampling. This work needs to continue, because right now we only get vertically averaged samples for sampling at the well head. There is a lot of vertical definition in The Geysers reservoir, which is tremendously thick, that we can untangle.

These are some of the things that we do not know, and I would submit that these are all pieces of a puzzle that all relate in one way or another to injection. They all have to do with how injection is ultimately going to effect production and all the other areas we focus on our research work.

Keshav Goyal, Calpine Corporation

Ben has given a pretty nice review as to what we know and what we don't about The Geysers reservoir. I shall take you back to the days when we started reading in the newspapers that The Geysers was running out of steam. Starting there, I will cover the lessons learned since and where we need to go. I will mostly be talking about The Geysers Unit 13 area because DOE sponsored tests have been conducted in its vicinity. Unit 13 is the largest geothermal unit in the world (140 MW). However, we may not be able to say that in the future because we are installing a new 102 MW capacity rotor in this unit.

The Unit 13 area, especially its southwest corner (Figure 1), is the lowest pressure area where most of the injection has been taking place. This view graph (Figure 2), is very old and is taken from a paper which I presented at Stanford in 1990. This view graph depicts the results of a comprehensive study of one unit area over a 10 year production period. Previously, studies concentrated mostly on the decline behavior of one well here and one well there. In this study, I took all the original 20 production wells from this unit and developed their production behavioral pattern. Initially, the decline rate of these wells was high followed by a moderation during 1983-84. After that, the decline rate increased to 9% in the next two years and then tripled to 28.6% during 1987-88. During this highest decline period, Unit 13 was losing about 5 MW per month. With that kind of loss, there was no way to keep drilling makeup wells to counter it. We had to do several things to reduce the decline. What was done from then until now is described in an article, prepared for The Geysers Geothermal Association (GGA), that appeared in the Geothermal Resources Council (GRC) Bulletin of January 1995. The steps taken include:

- A hiatus in makeup well drilling by most of the operators in The Geysers.

- Injection relocation in search of better injection results rather than just a site for dumping water.

- Starting of joint injection projects with and without DOE sponsored programs. These include a joint project with NCPA and one DOE sponsored project in the Unit 18 area.

- Development of tracers suitable for The Geysers field through a DOE-sponsored program.

- Conducting tracers tests to find the path of the injected water.

- Quantifying injection benefits by analyzing production and chemical data, as to how much steam we are getting back, if any.

- Developing remedies to counter adverse injection impact. We have found that injection has both positive as well as negative impacts. There are some injection created problems, too.

- Constructing a Geysers model, for unit areas as well as for the whole wellfield, to predict future reservoir performance. The entire wellfield model for The Geysers was constructed under the direction of the Technical Advisory Committee formed by the California Energy Commission. The modeling of our Unit 13 area was also done separately by Dave Faulder of Idaho National Energy Laboratory.

- Developing plans to construct a dam and/or bring in more water to inject into The Geysers field. The dam alternative has been dropped but the injection pipeline from the city of Clearlake to The Geysers is becoming a reality.

Now I will talk about The Geysers current performance. I took the steam production data from 1990 through 1994 from the 1994 California Division of Oil, Gas and Geothermal Resources report. The plot of the data (Figure 3) suggests an exponential decline rate of only 4.4 percent. Compared to those days when The Geysers was running out of steam, the present decline rate is quite low. This suggests that the above steps taken by the operators at The Geysers have been successful in arresting the decline rate.

Since the start-up of Unit 13, most of the injected water in this area went below 6000 feet into two deep wells located to the north (Figure 1). In late 1989, we started injecting into a well CA 956A-1 located in the southwest of the unit. We monitored surrounding production wells for their flow rates which were found to be increasing for the first few months. Production well CA 958-14 displayed the highest increase and turned out to be a star performer.

The normalized flow rate data of all 12 surrounding wells is shown on this view graph (Figure 4). As you can see, since we started injection, the high decline rates which were on the order of 20 percent have now been reduced to 10.5 percent. The cumulative recovery provided by injection in three years was 61 percent or a generation gain of about 10 MW per year as indicated by the hatched area (Figure 4).

For the star well CA 958-14, as shown in this view graph, initial decline was 18 percent. It was followed by an increase of 30 to 40 thousand pounds per hour of steam flow rate in just 4 months, or an increase of a couple of megawatts (Figures 5 and 6). For the next three years the decline rate for this well remained at a lower rate of 10 percent. Even after injection for four years in CA 956A-1, the superheat in the star well (CA 958-14) was pretty high, more than 60°F. At that point, we thought of reducing the superheat by converting another nearby production well (CA 956A-2) to an injection well.

The steam entries at the bottom of the second proposed injection well were plugged before the start up of the injection. By converting CA 956A-2 into an injection well towards the end of 1993, we got a 40 thousand pounds per hour of flow increase in CA 958-14 which was pretty good for a while (Figure 6). However, the flow rate dropped drastically during 1994. We tried to clean the well and ended up losing tools in the hole. We ran P/T/S surveys and found water entering the well at 5,280 feet. The steam flow continued to decline for the next two years. At that time, we decided to stop injection into CA 956A-2. Now the challenge is to clean the star well (CA 958-14) and get back its original steam production.

The next view graph shows temperature and superheat variations in the star well (CA 958-14) since 1992 (Figure 7). After the start of injection into CA 956A-1 (Figure 1), the temperature in CA 958-14 maintained an increasing trend. However, following the injection into CA 956A-2, the temperature in CA 958-14 declined sharply (Figure 7). We attempted to regain the temperature by reducing injection rates from 600 to 300 gpm, but to no avail. The lower injection rate helped for a while by keeping high wellhead temperature during the second half of 1994 but the temperature exhibited a sharp decline in 1995. Having found that even a 300 gpm rate of injection was detrimental to temperature and flow rate, we stopped injection into CA 956A-2 towards the end of 1995. The temperature has since gone up. However, it is still about 30°F lower than what it used to be before the start of injection into CA 956A-2.

In conclusion, we have come a long way. The overall decline rate of The Geysers is much lower now. In the Unit 13 area, the decline rate of 30 percent has reduced to less than 10 percent. Injection is beneficial but not without cost. Hereafter, the key is to identify an effective injection strategy to counter the problem of water breakthrough and scale deposits in the wellbore and in the formation.

For future research, injection modelling similar to that done by Dave Faulder but also including the chemical effects will be helpful. With R-13 out of favor, an identification of a new cost effective vapor tracer will also be helpful.

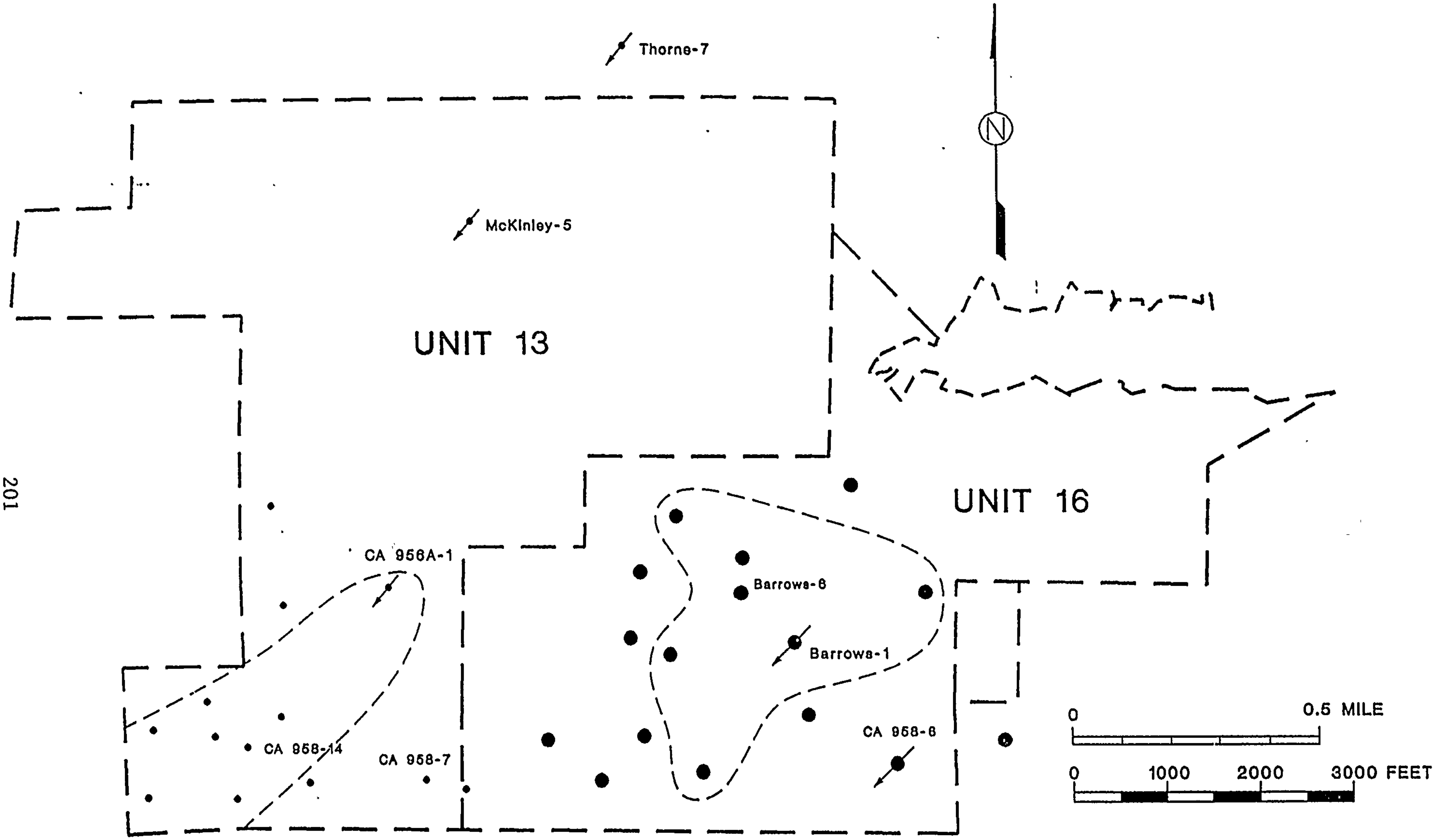
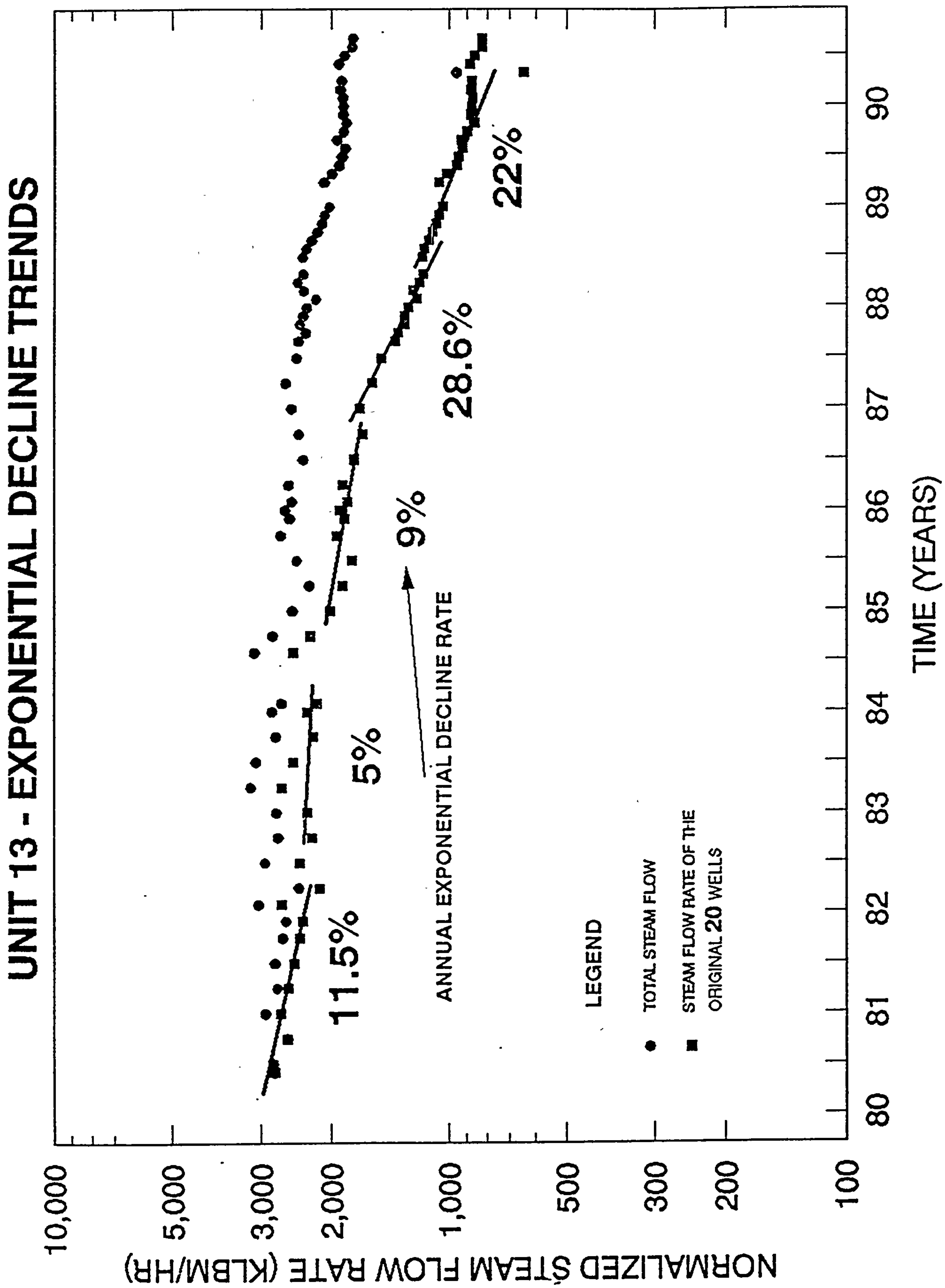


FIGURE 1: Study Area in Units 13 and 16



UNIT 13 - EXPONENTIAL DECLINE TRENDS
NORMALIZED STEAM FLOW RATE (KLBM/HR)
10,000
5,000
3,000
2,000
1,000
500
300
200
100
TIME (YEARS)
80
81
82
83
84
85
86
87
88
89
90
11.5%
5%
9%
28.6%
22%
ANNUAL EXPONENTIAL DECLINE RATE
LEGEND
TOTAL STEAM FLOW
STEAM FLOW RATE OF THE ORIGINAL 20 WELLS

FIGURE 2

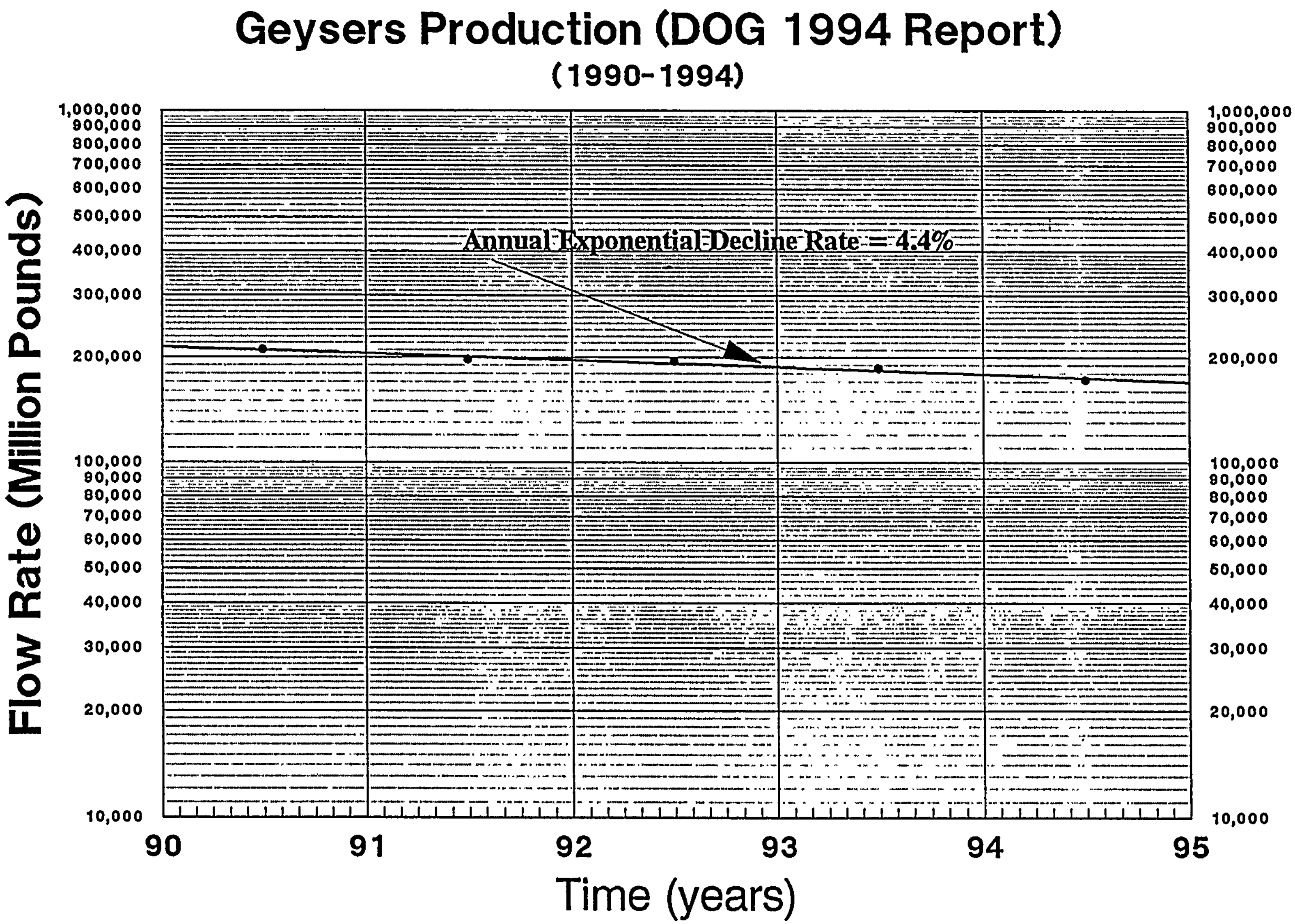


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FIGURE 3

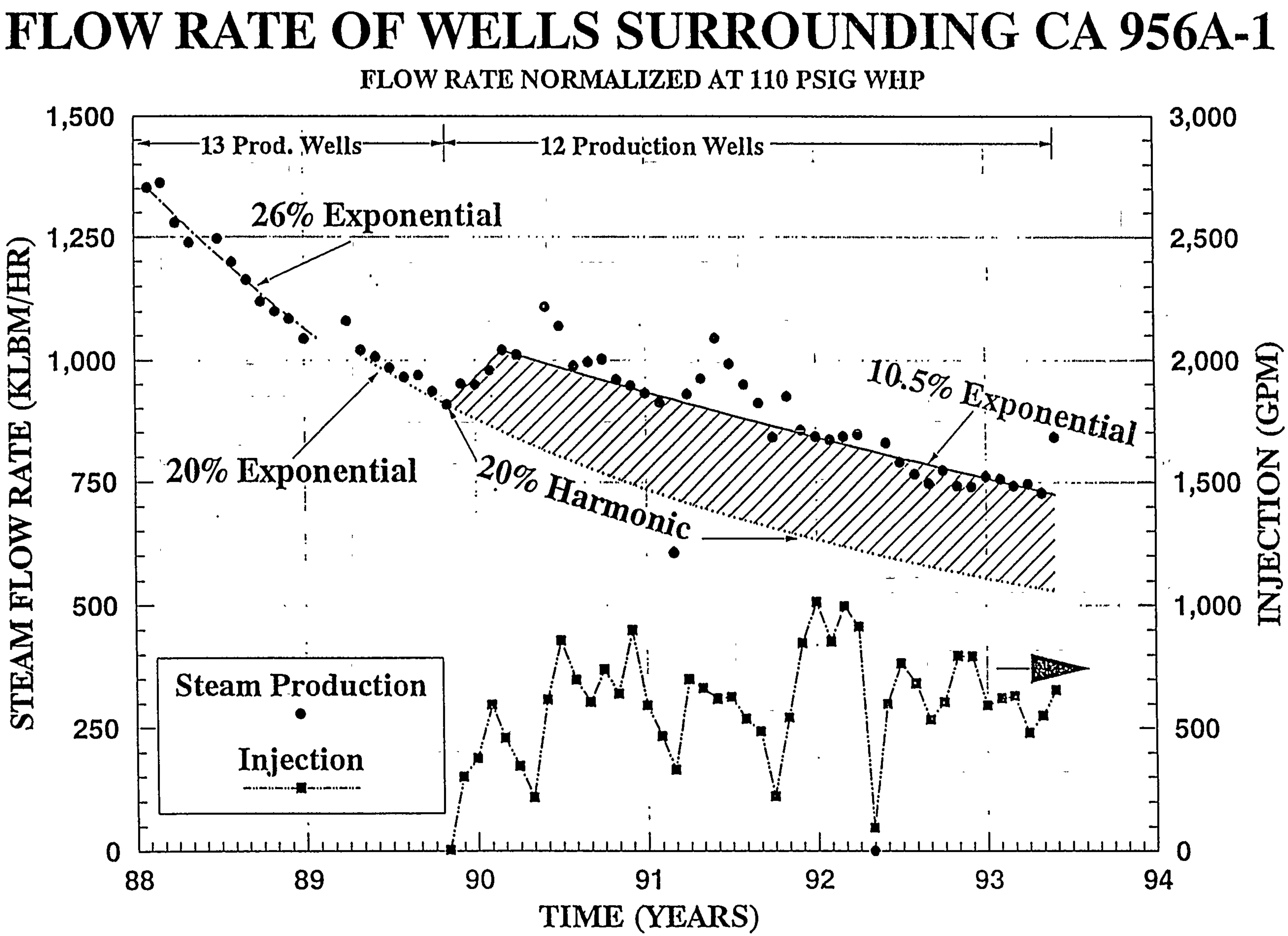


Fig.4: Effect of Injection into CA 956A-1 on some surrounding Prod. Wells

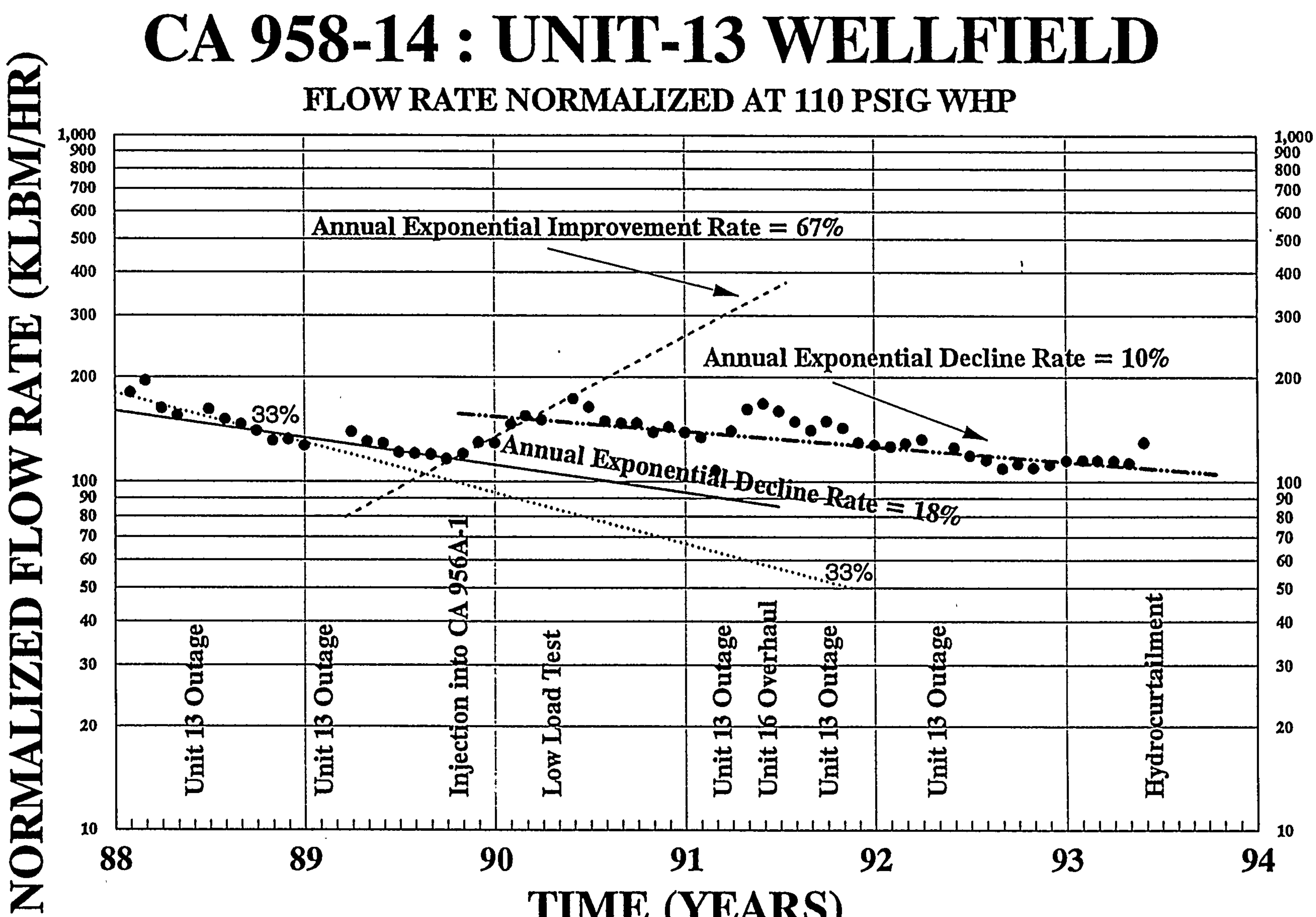
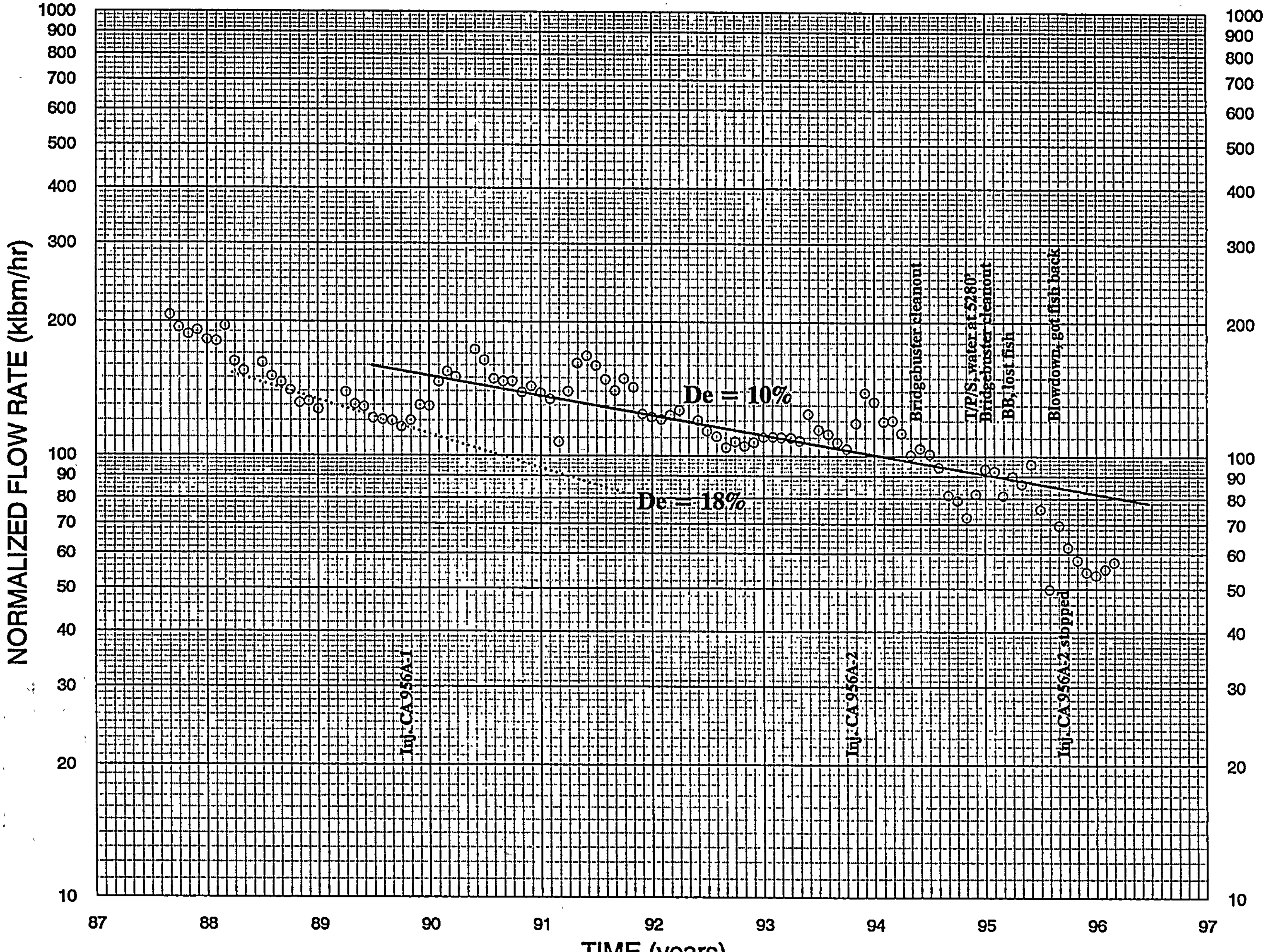


Figure 5: Changes in Decline Rates of CA958-14 Due to Injection into CA956A-1

NORMALIZED FLOW at 110 PSIG vs TIME, CA 958-14



h:\deliv\u13\drw\logflow\1-958-14.drw

FIGURE 6

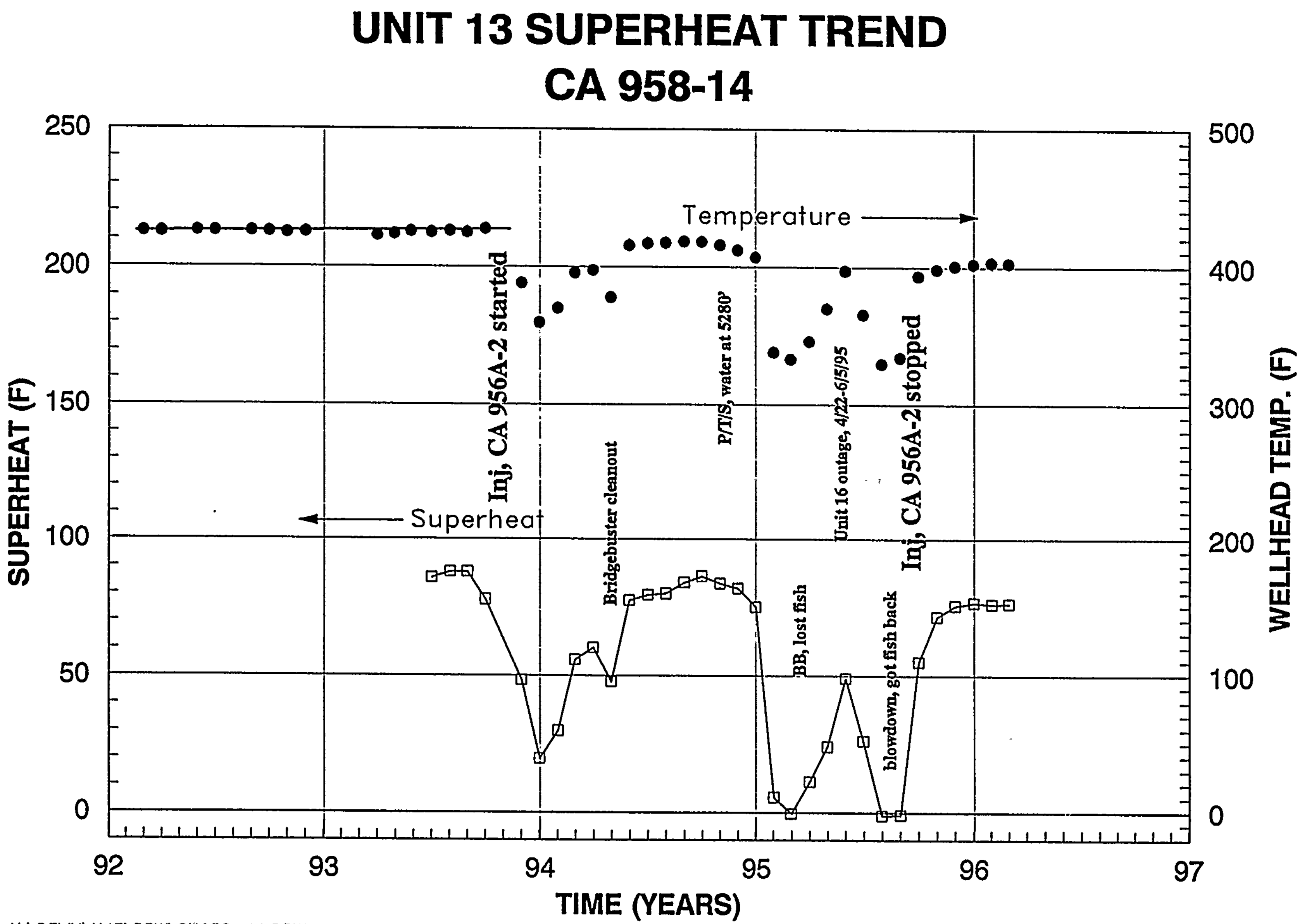


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FIGURE 7

Paul Hirtz, ThermoChem

My company has been working with the geothermal industry at The Geysers for about 14 years as a private consulting and testing laboratory. We have been involved in projects such as injection recovery monitoring, HCl corrosion mitigation, and geochemical analysis of fluids at The Geysers. We are also actively involved in Indonesia, the Philippines, and Japan. We have participated in several GTO funded projects at The Geysers mostly related to injection monitoring. We have also participated, of course, in numerous DOE workshops and the program reviews.

Marcelo has asked me to comment on my impressions of the DOE's research performed at The Geysers. Based upon that, my first impression of the DOE-funded research projects is that they usually do address the current concerns of industry in general and I think they are on target with that. However, there is often a lack of direct connection between the researchers and the industry end users, especially for the long-term basic research projects. This can lead to inappropriate research directions and, of course, inefficiencies in the general research process. I think it is critical that the DOE researchers and industry end users maintain close communication during research efforts so that a usable product is developed. Some examples of things that I have experienced with some of the DOE projects include:

- Tracers for The Geysers -- during initial development some of the tracers were tested under laboratory conditions that unmatched actual reservoir conditions. The tracers being developed had really no hope of being used as viable tracers due to problems with the solubility of the tracer or analytical detection. In this case, these problems were identified early on and corrected. Not much time was spent developing these chemicals for use as tracers. Some of the compounds were completely insoluble in water and could never have been used as a tracer, for instance.

- Vapor-Phase Bottom Hole Sampler for The Geysers -- a fair amount of time and money was spent developing the sampler and testing it on Unocal leases. During these tests, we basically found that there were some inherent design problems with the sampler that probably could have been easily identified by industry review early on in the development process.

- HCl production at The Geysers -- research has resulted in some brine partition models that would require impossibly high amounts of halite deposition in the fractures, near the wellbore or in the wellbore. This could have been easily discussed with the researchers and have them concentrate on some other facets of that generation mechanism. HCl research that was performed and continues to be performed describes mitigation measures that actually have been in use by the industry at The Geysers for a number of years now. However, they are described as if they are unique developments of the research effort. This is basic research that I think is critical but it needs to be closely coupled with what is actually happening with the industry up at The Geysers.

I think the solution is, you know of course, just closer communication between researchers and the industry end users. Probably just a phone call, E-mails, even informal meetings would be sufficient to alleviate some of these problems. I think we need this direct feedback component to make sure that this research does meet the needs of industry directly. I do not think the communication problem is only the fault or the responsibility of DOE and the researchers. Industry is often apathetic towards the overall research projects, they do not always take an active roll. I think if industry wants a usable final product they have to get involved in the development process. One mechanism that works apparently fairly well is the GTO-funded projects. These projects do not seem to suffer from the above-mentioned problems because they are jointly funded by industry and DOE. They have very specific goals, clear time tables, and there is often good communication between all the participants. I would recommend the GTO mechanism as one of the more important ways to get some of these short-term problems solved at The Geysers.

Some of the technology development that I think is still desperately needed includes:

- Reservoir tracers that have similar or uniform partitioning between steam and liquid. A number of years have been spent developing tracers. We have had some interesting and important tests performed. However, we basically do not have a chemical tracer that can be used at The Geysers to trace the flow path of injectate in the vapor-dominated system. We have freons which are now prohibitively expensive and we have SF6 which does not seem to trace the flow path of the injectate effectively. Operators are back to using tritium again, which is expensive and has, of course, environmental, health, and safety concerns. There are some viable tracers out there and we need to speed up the effort in developing those.

- Dry steam HCl mitigation to remove hydrogen chloride from the steam without condensing it. We loose at least 20 megawatts, maybe 25 megawatts overall, at The Geysers for using steam wash systems to remove chloride. Steam washing is very effective in mitigating corrosion but we also loose quite a bit of energy, which makes it economically inefficient. Dry scrubbing processes would conserve steam and increase megawatt output.

- The downhole sampler to get vertical profiling of chloride among other chemicals in the well. We need to know what the actual HCl concentration is in the deep reservoir. This would also be important to validate some of the models that are being performed in the national labs. It will provide data about the true chloride coming from the deep zones rather than just the average concentration at the wellhead. I think that downhole samplers would also be very useful for monitoring injection recovery during tracer tests to see from which zones inside the well the tracer is being recovered. Currently available downhole samplers are just not applicable for The Geysers, we need some specific development for that purpose.

I think just these projects alone could be easily handled through the GTO process, some of them may be already in the works, but that would be my recommendation.

Collin Williams, U.S. Geological Survey

I will first provide a brief summary to bring people up to date on where we have been at the USGS. Much of our research is not supported by DOE. However, we have received DOE support for the most important Geysers critical research and I think this sets the direction of future collaboration. Basically, some of the projects funded primarily by DOE and also by internal USGS funding have focused on geochemical studies. These include measurements of elemental and isotopic compositions of various gases and fluids both at The Geysers and the wider Clear Lake region by Kathy Janik and Jake Lowenstern in collaboration with Fraser Goff of Los Alamos. Brent Dalrymple started a project on felsite dating to try and figure out the timing of intrusion of this body with recent magmatic activity and whether it could be correlated to make any sense in some of the models. This in recognition of magmatic activity as being the source of heat in the high temperature reservoir. Brent has left the Survey since, but Mark Lanphere is trying to continue on with that work. I have been working in a study to investigate spatial and temporal variations in heat flow at The Geysers, particularly in the northwest portion. This perhaps could contribute to the idea that there might have been a recent heating event that led to the formation of the high-temperature reservoir. More recently, we have been focusing on the variations of thermal properties with temperature and pressure in Geysers rocks. I have been working with John Sass to really try and get a handle on how well we can measure thermal variations at these temperatures and pressures and working with Geyser's corehole samples as a part of that.

Completely external to DOE-funded projects, however, there have been many internally funded USGS projects. Often these tend to be primarily regional projects such as those for The Geysers and the Clear Lake region. Some of these projects, if properly directed, could be of great interest in the short-term and focused on the field. In particular, I want to show an example of some seismic tomography studies that just came out in the Geophysical Research Letters by Bruce Julian and his cohorts, very similar to what Ernie Major was showing earlier. This was a study in the central Geysers primarily using some IRIS and PASCAL instruments and the Unocal network. It gives a very similar sort of picture with cross sections of at sea level and at a depth of one kilometer, variations in deep Vp and Vs, and a consistent low in the middle of The Geysers. The interesting thing that Julian and his people were able to do is look at this over a period of a few years and essentially map changes, in this case, reductions in Vp and Vs in parts of the field. This is almost certainly related to pressure changes and phase changes as saturation state changes within the reservoir. These kinds of techniques are beginning to provide, I think, the opportunities at a fairly fine scale to look at these vertical and spatial variations of what is happening within the reservoir both in terms of production and also injection. This will also be very important in the future.

Another example of regional sorts of studies that can be important in the field-specific sense is a new aeromagnetic survey that was collected in The Geysers and Clear Lake region. Patrick has the original maps where we actually see things. Most of the features are large-scale regional tectonic in character. They do not have much to do with the Geysers except in the general sense of how The Geysers got to be The Geysers. What is interesting in this survey is that for the first time, as I pointed out, this small anomaly is related to deformation of rocks overlying The Geysers felsite. And so, for the first time, we can counter the story that we always had both in the Survey and elsewhere that you could not say much about the detailed structure of the subsurface in The Geysers reservoir from surface geophysical techniques. It turns out that we are finally breaking through that barrier, that maybe we can map out beyond the depth of which we can penetrate the felsite or the felsite's metamorphic halo with some surface and near-surface geophysical techniques.

And finally, Bob Fournier and Jim Bisehoff have been working on studies of calcium and water and generation of low-pH HCl during boiling, i.e., when crossing through lower pressure at a temperature of 400°C. This gets back to the HCl problem, exactly what the source of it is and what kind of experiments can be done under realistic conditions to understand its generation. This paves the way for planning injection strategies that can mitigate HCl problems.

The key to all this, from the Survey's point of view, is to focus more on industry collaborative work and DOE lab collaborative work. We do not want to compete with the DOE labs, but we want to be able to be complimentary to their efforts. And, as far as the future is concerned, everybody is focusing on trying to maintain production levels with injection and we should also be focused on anything that we can do in a field-specific sense to assist with that effort. I would take one slight exception to something Steve Enedy said earlier, which has to do with the short-term. In the next ten years or so, we are looking at really a next generation system. Injection is going to be a much higher percentage of production than it ever has been. In other areas of the field wellhead pressures are going to be very low. It is really, in many ways, a substantially different system and different problems will come up. We should start thinking about some of the difficulties that we can anticipate down the road in the early part of the 21st century that can be dealt with if we start the research right now. And that is all I have to say.

Jeff Hulen, ESRI

During the past few years, as a result of DOE-industry collaborative research endeavors, there have been all sorts of significant accomplishments, I think. Certainly, to list them all would take far more than my allotted 7 minutes. I will select some of those which I feel have been the most significant and branch out from there to suggest possible avenues for future research.

But the first point to make really in all this, and it is really a reiteration of what several other speakers have said in prior presentations, is that injection has definitely been proven a viable method for increasing production and, therefore, the overall field longevity. Reservoir models have certainly been refined as a result of this collaborative research. We now know a lot more about porosity and permeability in The Geysers resource. As an example, something that Unocal was onto sometime ago, we have been able to prove fairly conclusively that in the greywacke-hosted portion of The Geysers reservoir much of the porosity is due to dissolution of metamorphic calcite. We know a lot more about the nature of indigenous reserves in The Geysers and how much is left as a result of experiments carried out by Unocal's Eric Whitjack and our DOE collaborative SB-15-D coring project. The origin of acids and non-condensable gases and steam have been homed in on to a greater extent. Mark Walter's work in the northwest Geysers is beginning to show that non-condensable gases can indeed emanate from unflushed, basically, Franciscan metamorphic assemblages. We know a lot more about the magmatic hydrothermal history of The Geysers, and in knowing that hydrothermal history we can perhaps pick places for more efficient production.

The felsite has now been mapped. This used to be considered a fairly homogeneous igneous batholithic blob in the sub-surface. We now know, as I mentioned in a prior presentation, that it is actually a fairly complex composite igneous body and that certain phases of the pluton actually show some relationship with the distribution of steam entries in the sub-surface. Shown on the slide, on the far left, is a granite from a Unocal well in the central Geysers. This is a very much different appearing mafic grandiorite from a Calpine well in the eastern portion of The Geysers. We certainly know a great deal more about the geochemical and isotopic evolution of the field at this point largely through the efforts of Joe Moore. His work with fluid inclusions, micro-thermometry, and stable isotope systematics in collaboration with a number of us and other colleagues in the industry has really pinned down on just how this great resource has gotten to its present vapor-dominated state.

Well, what approaches have been particularly effective in carrying out this research program? I heard earlier that communication between industry and DOE researchers might be a bit of a problem. I think that the industry-DOE working groups that Mike Wright convened to focus in on specific problems in The Geysers and on industries specific needs were a very effective means of establishing dialog between industry and individual researchers. That approach, I think, should be continued.

We have proven that scientific coring, diamond coring in The Geysers, is a very viable research and exploration tool. Some years ago, it was just considered an impossibility that diamond coring could actually even work in an under-pressured, vapor-dominated system like The Geysers. But, our SP-15-D coring project, a DOE collaborative endeavor involving a team of collaborating investigators from around the country, has homed in on new information about porosity, permeability, fluid saturation and on the structural, thermal, and chemical evolution of The Geysers field as a whole. Certainly, tracer-controlled injection tests have been very effective in defining fluid flow pathways in the subsurface and in characterizing other properties such as fluid saturation and certain boiling parameters. For the future, we still need to expand our knowledge of reservoir parameters. This is needed for maximizing forecasts of steam supply and quality well into the future. Particularly, since injection is going to be such an important part of The Geysers' future. We can accomplish this utilizing among many other methods a continued tracer-controlled injection testing. Injection really works and production can be significantly increased.

I think there is a need for deeper scientific coring efforts at The Geysers, not only in the normal graywacke-hosted portion of the reservoir that we tested with SP-15-D, but also perhaps into the high-temperature reservoir and the felsite. A point that Dennis Nielson has been making effectively, I think, is that we need to run imaging logs for these scientific core holes. This will enable us not only retrieve the solid core to have a hands-on experience with, but to characterize features such as fractures and hydrothermal alterations as well as orientations of porosity and permeability in the core. This information will be critical for designing the most effective injection strategies for the future. Thank you very much.

OPEN DISCUSSION:

Marshall Reed: What was the funding level for the USGS efforts with The Geysers research. We put in about $12.5 million dollars in a five-year research project from the Department of Energy and I would like to get some handle for what the USGS component was since 1990?

Collin Williams: It is difficult for me to come up with an exact number. But I would just simply say that the support from people like Kathy Janick, myself, and Brett Sterrumple including the occasional support from people like Bob Fournier and others is in the neighborhood of, I would say, approximately a million dollars a year. Therefore, I would say something in the order of at least $5 million since 1990, primarily in salaries and overhead expenses, possibly lower than that. It depends on where you draw the line between The Geysers and Geysers-Clear Lake regional studies.

Karsten Pruess: Over the years there have been many contacts and cooperation with Italian researchers at Larderello. Much of this was inaugurated through DOE initiatives but there have also been strong contacts directly between companies here and in Italy. I am wondering whether this cooperation is continuing? Should more be done? Has this been useful?

Marcelo Lippmann: Ben, has Unocal continued its informal contacts with ENEL, the Italian utility?

Ben Barker: I am not personally involved in that. My understanding is there has been an ongoing but relatively infrequent sort of contact. It certainly is not anything on the level of the DOE battalion work that was going on back in the 70's or anything of that sort.

Marcelo Lippmann: What I understand, and maybe Marshall can correct me, the agreement between DOE and the Italian group ENEL is still active, but it is not being funded. However, companies and investigators from different laboratories still maintain informal contacts with their Italians colleagues. The first question is whether or not the collaborative effort should increase. If so, is there any possibility of getting support for these activities? One of the objectives of these efforts would be to obtain data and experience from the Italian vapor-dominated systems that could be applied to The Geysers.

Marshall Reed: The cooperation between the U.S. Department of Energy and the Italian ENEL electric utility has been very spotty. Back when our research program in The Geysers began about 1990, we tried to strengthen the US-Italian work and held several seminars, both here and Italy. We had a strong component of the U.S. industry including companies from The Geysers involved in this. We were constantly asking for feedback from the industry as to what they thought the value of this work was. After the last visit from the Italians to the Geysers, around 1992 or 1993, the feedback that I got from The Geysers operating companies was that they really did not get that much from the Italian cooperation. The Italian ENEL structure was too confining, there was no free exchange of information, there were no wide-ranging discussions, that the Italians were very conservative, and that they wanted everything written in a formal paper and reviewed by their bureaucracy. This cycle impeded the free exchange of information.

With that kind of response from the U.S. industry, we have let things die down. There is very little activity with the ENEL now. Specific questions have been brought up by Geysers operators and Joel Renner, Mike Shook, and others have been assigned to go over to Italy and talk to the ENEL people on those specific questions and that was about it. That is what I consider a very low level of activity.

Marcelo Lippmann: Are there any other comments for the panel or the audience about what should be done in the future?

Don DePaolo: I was wondering why two of you mentioned tracers as being a problem. I was very impressed by the tracer data you showed from the stabilized isotopes. I was wondering why you do not consider stable isotopes to be almost adequate tracers for tracing injection?

(Jeff Hulen?): Because of the direct injection of condensates now, we no longer are enriching the condensate with stable isotopes as much, so that method of tracing is going away. Many of the power plants directly inject the hot well condensate rather than concentrate it through the cooling tower. So, that is a big problem, we need other artificial tracers.

(Don DePaolo?): So, it has been good in the past?

(Jeff Hulen?): It has been good, but it is no longer available. There are some other natural tracers like ammonia that have been effective, but what we really need are artificial tracers that we can add to the system.

Closing Remarks by Marcelo Lippmann

From what we heard during this hour, DOE and Industry should continue their joint efforts on The Geysers in the following areas:

- Injection
- Tracers
- Downhole fluid samplers
- Methods to determine the 3-D distribution of porosity, permeability, and fractures distribution in the reservoir
- HCl research to determine its origins and how to mitigate its effects
- Coring of deeper reservoir regions
- Imaging logs.

The important message, and something that was brought up by Mike Wright yesterday, is that there should be more timlier interactions between researchers from industry and DOE-sponsored groups. This agrees with one of the suggestions made that the DOE-Industry Geysers Research Working Groups created about four years ago, should be reactivated in the near future.

Finally, I want to thank all the Panel members and the audience for their invaluable comments and suggestions.

Concurrent Session 5:
Drilling

Chairperson:

Louis E. Capuano, Jr.
ThermaSource, Inc.

GEOTHERMAL DRILLING RESEARCH OVERVIEW

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ABSTRACT

Sandia conducts a comprehensive geothermal drilling research program for the U.S. Department of Energy. The program currently consists of eight program areas: lost circulation technology; advanced synthetic-diamond drill bit technology, high-temperature logging technology; acoustic technology; slimhole drilling technology; drilling systems studies; Geothermal Drilling Organization projects; and geothermal heat pump technology. This paper provides justification and describes the projects underway in each program area.

INTRODUCTION

The cost of geothermal energy must be reduced in order for this clean and reliable resource to expand beyond its current market in the United States. One significant area where costs could be reduced with improved technology is in drilling geothermal wellbores. Because of the high temperatures, hard rock, and fractured formations usually encountered in geothermal drilling, the cost of a typical geothermal well is roughly twice that of a petroleum well drilled to the same depth. The well field accounts for about 35-50% of the cost of a geothermal power project, and drilling costs are accrued early in the project, making their impact particularly significant. Advanced technology development and technology transfer has the potential for reducing geothermal drilling costs by at least 30%.

Because of this potential, the U.S. Department of Energy sponsors a comprehensive geothermal drilling research and development program at Sandia National Laboratories. The program contains a mixture of short-, medium-, and long-range projects aimed at developing new technology and transferring this technology, as well as technology developed by other drilling industries such as petroleum and minerals, to the geothermal industry. Past significant successes of this program include: advancement of polycrystalline diamond (PDC) drill bits; development of high-temperature drilling muds; development of high-temperature elastomers for downhole motors; and development of a thermal simulator for predicting downhole temperatures while drilling. The current drilling research program is described below.

DESCRIPTION OF THE PROGRAM

The current program consists of eight program areas:

- *Lost Circulation Technology;*
- *Advanced Synthetic-Diamond Drill Bit Technology;*
- *High-Temperature Logging Technology;*
- *Acoustic Technology;*
- *Slimhole Drilling Technology;*
- *Drilling Systems Studies;*
- *Geothermal Drilling Organization Projects; and*
- *Geothermal Heat Pump Technology.*

Each of these program areas is described below.

Lost Circulation Technology

Lost circulation is the loss of drilling fluids from the wellbore to the surrounding rock formation. This is a significant problem because it leads to wellbore instability, stuck drill pipe, inadequate casing cementing, and increased costs. Lost circulation accounts for about 10-20% of the total costs for a typical geothermal well. The objective of the lost circulation technology program at Sandia is to develop technology for diagnosing and treating lost circulation zones in order to reduce drilling costs by at least 10%.

Rolling Float Meter

The rolling float meter is a device developed at Sandia for measuring the outflow rate of drilling fluid from a wellbore during the drilling process (Glowka *et al*, 1992). Accurate measurement allows the rate of loss into the formation to be determined, which can provide information related to the location and severity of the loss zone and help the driller determine when and how the loss zone should be treated.

Sandia first field tested this meter in 1991 and has been in the process of improving its performance and transferring the technology to industry since then. We have recently completed the design of the second-generation rolling float meter, which has improved accuracy and is more rugged. We are currently working with several industry partners, CalEnergy, Epoch Well Logging, and Tecton Geologic, to demonstrate the proper use and utility of the meter in the field.

Acoustic Doppler Meter

The acoustic Doppler meter is a device for measuring the inflow rate of drilling fluid to a wellbore during the drilling process. Although Doppler flow meters have been commercially available for over twenty years, it was only recently that Peek Measurements, Inc., developed a Doppler meter capable of rejecting drilling rig noise and thereby providing accurate measurements of fluid flow rates in that environment. Accurate measurements are essential for comparison with outflow rates in order to accurately diagnose lost circulation problems.

Sandia is working with Peek Measurements and several geothermal industry partners, CalEnergy, Epoch Well Logging, and Tecton Geologic, to evaluate the use of the improved Doppler flow meters in geothermal drilling. Results to date indicate that the meter has a significant potential in this industry (Whitlow *et al*, 1996).

Expert System

With the development and use of accurate methods for measuring drilling fluid inflow and outflow rates, it is possible to develop a software package that monitors the flow rates, detects circulation problems, alerts the driller of the problems, and provides assistance to the driller in correcting the problems. Such a system, known as an expert system, is currently under development as a Geothermal Drilling Organization (GDO) project (more about the GDO in a later section).

The system is being developed by Tracor, Inc. under contract to Sandia, building on their existing expert system for detecting and treating gas kicks in petroleum wells. CalEnergy is participating in the project by providing field data for validating the software package.

Drillable Straddle Packer

The drillable straddle packer is a low-cost, drillable packer assembly developed at Sandia for isolating lost circulation zones and improving the efficiency of cementing operations for lost circulation plugging (Glowka, 1995). Such zonal isolation is necessary in large-diameter wellbores when a loss zone is off bottom because of the tendency of cement to channel through the drilling fluid to the bottom of the wellbore, thereby increasing the number of cement plugs that must be set before sufficient cement flows into the loss zone to plug it. The drillable straddle packer accomplishes zonal isolation with a low-pressure, dual-packer assembly that is inflated with cement, forces cement into the loss zone, and is left downhole to be drilled out when the cement sets.

Significant effort was spent in the laboratory developing and testing with water the various components of the drillable straddle packer, including the fiberglass-fabric packers bags, the packer shroud deployment mechanism, and the grapple mechanism for remotely detaching the packer assembly from the bottom of the drillstring. A recent test of the packer at full-scale flow rates with cement in the Engineered-Lithology Test Facility (see next section) was successful. This test provided an intermediate step between lab tests with water and field tests with cement. It will be used as a demonstration of the packer's capabilities in convincing a geothermal operator to field test the packer.

Engineered-Lithology Test Facility

The ELTF is an outdoor test facility at Sandia for conducting large-scale experiments related to lost circulation control and other below-ground testing where the capability for emplacing a known lithology, conducting a test, and excavating the lithology to evaluate the results is needed (Glowka, 1995). The ELTF consists of a 15-ft X 15-ft X 15-ft concrete structure in which, for example, alternating layers of gravel and clay can be emplaced to simulate permeable and impermeable rock zones, respectively. Pipes penetrating the vertical walls connect the permeable gravel zones to an external plumbing system through which fluid can be pumped in various configurations. Sections of concrete pipe stacked vertically and spaced apart at the gravel zones simulate a wellbore with fractures connecting to the permeable zones.

In the three ELTF tests conducted to date, three horizontal gravel layers were emplaced, with the bottom layer simulating additional, closed wellbore volume, the middle layer simulating a loss zone, and the upper layer simulating a production zone. Two tests were conducted with an open-end drill pipe positioned at the loss zone, and cement was pumped into the wellbore in a manner similar to that used in conventional lost circulation zone treatments in geothermal drilling. These tests showed that the cement flowed down into the lower gravel zone before it flowed into the loss zone.

In the third ELTF test, a drillable straddle packer assembly was emplaced in the wellbore, straddling the middle gravel layer. As the cement was pumped, it inflated the packer bags and flowed into the middle gravel layer. Thermistors emplaced in all three gravel layers to measure cement exotherm temperatures indicated that the packer assembly was effective in isolating the loss zone and forcing all of the cement into that zone. At the time this paper was prepared, the facility had not yet been excavated to confirm this.

Cementitious LCM Field Evaluation

Halliburton Services has developed a new cementitious lost circulation material (CLCM) that could replace the conventional Portland cement currently used to treat lost circulation zones encountered in geothermal drilling. The CLCM has the advantages of faster setting and better chemical compatibility with bentonite drilling fluids, thereby potentially reducing loss-zone treatment costs.

Field testing of the CLCM has been undertaken as a GDO project, with participation by Halliburton, CalEnergy, and Sandia. Halliburton is providing the research and development of the CLCM, CalEnergy is providing the use of wells in which to test it, and Sandia is providing surface instrumentation (rolling float meters and Doppler flow meters), downhole logging (televiewer and temperature), and coordination support of the field tests.

Two field tests have been conducted thus far. In the first tests at the Coso geothermal field, the CLCM was effective in plugging small fractures but not large ones. Halliburton concluded that this was a problem with viscosity control and worked to improve the product. The second field test, at the Newberry geothermal field, did not encounter any loss zones where use of the CLCM would have been appropriate. We are currently awaiting the availability of another well at Coso for further field testing of this material.

Advanced Synthetic-Diamond Drill Bits

PDC bits have had a significant impact on the petroleum drilling industry because of the large increases in penetration rates and bit life that can be achieved in soft and medium-hard formations over those of roller cone bits. PDC bits are currently not successful in hard-rock drilling, however, because of thermally accelerated wear and impact damage that occurs when drilling rocks with compressive strengths greater than about 20,000 psi. The objective of the advanced synthetic-diamond drill bit program at Sandia is to extend the benefits of PDC and other synthetic-diamond drill bits to harder rock applications, such as geothermal drilling.

This program currently consists of four cost-shared projects with industry. Brief descriptions of these projects are given below. More detailed descriptions are given in a companion paper in these proceedings (Glowka, 1996).

Claw-Cutter Optimization

This joint project with Dennis Tool Co. is optimizing the design of PDC claw cutters. These cutters differ from conventional PDC cutters in that the tungsten carbide substrate on which the synthetic-diamond layer is sintered is machined with grooves prior to the sintering process. This results in diamond-filled grooves that become "claws" along the cutter wearflat that concentrate stress on the rock surface and improve cutter effectiveness. Under this project, the number, width, depth, and spacing of these claws are being optimized with numerical stress modeling and cutter wear testing.

Track-Set Optimization

This joint project with Security DBS is developing design information for optimizing Track-Set PDC bits. These bits differ from conventional PDC bits in that the cutters are more widely spaced in the radial direction, resulting in deeper tracks in the rock in which the individual cutters run. This "locks" each cutter in place and prevents or significantly reduces lateral bit vibration, which can lead to cutter damage. Under this project, linear single-cutter tests are being conducted to provide design information on the optimal spacing of cutters for Track-Set bits.

TSP Bit Optimization

This joint project with Maurer Engineering and SlimDril International is optimizing the design of thermally stable polycrystalline (TSP) diamond bits for hard rock drilling. TSP cutters differ from conventional PDC cutters in that the cobalt used in the diamond sintering process is subsequently chemically leached from the diamond structure. This improves the thermal stability of the diamond layer and thereby the drillability of hard rock under certain conditions. Under this project, cutter wear testing is being conducted to identify the TSP cutter shapes that are most effective in drilling hard rock.

Impregnated-Diamond Bit Optimization

This joint project with Hughes Christensen Co. is optimizing the design of impregnated diamond drill bits for hard rock applications. This type of bit consists of small natural or synthetic diamonds imbedded in a tungsten carbide substrate. As the tungsten carbide wears, it exposes new diamonds, which cut the rock until they fracture or fall out of the substrate. Further wear then exposes new diamonds, and the process continues until the bit is consumed. Under this project, bit design parameters are being optimized, such as tungsten carbide grade, diamond grade, diamond size, and diamond concentration.

Cutter Wear Test Facility Development

Sandia has developed a unique laboratory test facility for wear testing synthetic-diamond and other drag-type rock cutters. This facility, the CWTF, consists of a small drill rig that utilizes a three-cutter core bit in which test cutters can be used under highly controlled conditions to determine relative wear rates compared to baseline wear rates of conventional PDC cutters. A 3-ft X 3-ft X 3-ft rock sample, usually Sierra White Granite, is placed on an air pallet that allows the rock to be easily moved between holes. This allows up to 85 holes to be drilled in each rock sample. The facility can be operated in either a constant penetration-rate or constant weight-on-test-cutter mode. Multiple slip rings allow data measured at the test cutter, such as cutting forces and temperatures, to be taken off the rotating drill string.

Development of this facility is now complete, and baseline wear rate data are now being established. This facility will be used in several of the ongoing synthetic-diamond cutter studies as well as in future studies on advanced cutter materials.

High-Temperature Logging Technology

Knowledge of geothermal reservoir conditions is essential to their proper development and operation. Because of the extremely high temperatures and corrosive fluids that can be encountered in these reservoirs, conventional logging tools used by the petroleum industry cannot be used. Even expensive, multi-conductor wirelines are susceptible to rapid degradation and add to the high cost of logging geothermal reservoirs. The objective of the high-temperature logging technology program at Sandia is to develop dewared memory logging tools that can be run on inexpensive slicklines (i.e., no conductors) and survive downhole temperatures long enough to obtain the needed data.

The logging technology program currently consists of three projects. Brief descriptions of these projects are given below. More detailed descriptions are given in a companion paper in these proceedings (Normann *et al*, 1996).

Temperature/Pressure Memory Tool

The temperature/pressure memory tool is a dewared tool developed at Sandia that can be run on either slicklines or conventional multi-conductor wirelines. It employs a RTD temperature probe with a resolution of +/-0.005°C and an accuracy of +/-0.3°C, traceable to NIST standards. The pressure transducer is a quartz crystal oscillator with a resolution of 0.01 psi and an accuracy of 0.1 psi, also traceable to NIST standards.

The tool is 6 ft long, 2 inches in diameter, and is enclosed in a stainless steel dewar that permits operation at 400°C for 10 hours. It is capable of storing up to 3000 each pressure and temperature data points that can be downloaded to a computer at the surface with a Windows-based program.

More than 30 downhole logs in geothermal wells have been successfully run with this tool. We are currently seeking technology transfer opportunities to make the tool available to the geothermal industry on a routine basis.

Downhole Steam Sampler

The downhole steam sampler is a tool developed at Sandia for obtaining uncontaminated steam samples from any location within a geothermal well. Developed primarily for use at The Geysers, the tool operates on a slick line and is capable of downhole operation at 400°C for 10 hours. The tool is 6 ft long, 2 inches in diameter, and employs a commercially available stainless-steel valve and eutectic material for condensing and capturing up to 50 ml of condensed steam downhole.

The steam sampler has been successfully tested at the surface on a geothermal well at The Geysers. We are currently seeking the opportunity to test the tool downhole.

Spectral Gamma Memory Tool

The spectral gamma memory tool is a dewared tool developed at Sandia for detecting trace radioactive elements that often plate out on fracture surfaces in geothermal wells. The tool is therefore useful in fracture detection. It is 10 ft long, 2 inches in diameter, and employs a sodium iodide spectral gamma detector. The tool has been successfully tested at The Geysers, where it revealed increased levels of potassium at a loss zone.

Acoustic Technology

Transmitting data from downhole to the surface is a problem in any type of wellbore. Wires are often difficult or impossible to emplace and are subject to degradation and breakage. The objective of the acoustic technology program at Sandia is to develop data transmission systems for various applications using acoustic technology, where sound waves transmitted up a steel pipe or shaft carry the needed information. There are currently three acoustic technology projects underway.

Core-Tube Latching Detector

The core-tube latching detector is a device developed at Sandia for detecting when a core tube used in wireline coring has landed downhole at the bit. Proceeding with drilling before the core tube has landed can cause significant problems, including jamming of the core and the need to trip the drillstring to correct the problem. Similarly, waiting extra time for the core tube to land because of uncertainties in the fall rate of the tube down the drillstring wastes time. Accurate detection of the core tube's landing could therefore same time and money in drilling geothermal exploratory holes with wireline-coring rigs.

The core-tube latching detector consists of a sensitive accelerometer mounted on the top drive, noise-filtering circuitry, and a set of noise-canceling headphones. In operation, the driller wears the headphones as the core tube falls and listens for the characteristic sound as it lands at the bit. The noise-canceling headphones eliminate most of the environmental rig noise, and the noise-filtering circuitry isolates the sound of the core-tube landing.

Development of a prototype latching detector has been completed, and field tests with Tonto Drilling, the industry partner on this project, are scheduled for the summer of 1996.

Wireless Telemetry System

The wireless telemetry system is a hardware and software system for oil production applications that is under development by Sandia and its industry partner, Baker Oil Tools. This tool transmits downhole pressure and temperature data to the surface via acoustic waves traveling up the production tubing. This system will replace wires that are currently used to power the downhole system and transmit the data uphole. These wires are subject to costly emplacement and breakage. Although the system is most immediately useful for producing oil wells, with temperature upgrading it also has a significant potential for use in the geothermal industry.

The system consists of a battery-operated downhole device for coding the data and generating the sound waves, a surface accelerometer for receiving the data, and data acquisition hardware and software for decoding the sound waves. The low-power downhole components are designed for a six-month life. The system is still under development. Prototype tests are planned for the fall of 1996.

Line-Shaft-Pump Position Detector

The line-shaft-pump position detector is a device under development by Sandia and its industry partner, Johnston Pumps. It detects the relative position of the rotor and stator in line-shaft pumps used in geothermal wells. Current practice is to provide large clearances between these pump components so that when the pump begins to operate, causing differential thermal expansion between the production tubing and the pump drive shaft, there is sufficient play to prevent the rotor from interfering with the stator. A technique for detecting the relative position of these components while the pump is running will allow the position to be continuously adjusted, thereby permitting smaller clearances to be employed and resulting in smaller and more efficient pumps.

The position detector under development consists of a very simple downhole device for generating a sound wave whose frequency is a function of the relative rotor/stator position, a surface accelerometer for detecting the sound wave that travels up the drive shaft, and data acquisition hardware and software for decoding the sound waves. This project has only recently been initiated and is still in the design stage.

Slimhole Drilling Technology

Geothermal exploration has traditionally entailed the drilling of large-diameter (production-sized) wellbores for production testing in order to prove a resource. Given that production-sized wellbores typically cost over $2 million, a more cost-effective means for proving a viable geothermal reservoir is to drill smaller-diameter (slimhole) wells that can be produced to obtain reservoir data. If a resource is proven and financing for a geothermal project can be secured, then production-sized wellbores can be drilled to actually recover the geothermal energy. Although this approach seems apparent, there has been some skepticism in the geothermal industry and among financiers that viable reservoir production data can be obtained from slimholes.

The objective of the slimhole drilling program at Sandia is thus twofold: 1) to prove that viable reservoir production data can indeed be obtained with slimholes; and 2) to develop improved slimhole drilling technology in order to reduce geothermal exploration costs by 25%. A summary of this program is provided below. A more detailed description is given in a companion paper in these proceedings (Finger, 1996).

Steamboat Hills, NV, Slimhole

A 4,000-ft exploratory slimhole (3.9-inch diameter) was drilled in the Steamboat Hills geothermal field near Reno, NV, in July-September, 1993, in cooperation with Far West Capital. Four series of production and injection tests were conducted while taking downhole and surface data, such as temperatures, pressures, and flow rates. Continuous core with a detailed log were taken, and borehole televiewer images were obtained in the upper 500 ft.

The reservoir data obtained in these tests showed the reservoir to be of essentially infinite productivity. This agrees with data obtained from full-sized production and injection wells in the same field. A detailed report was written that summarizes this data and includes daily drilling reports and a detailed narrative of the drilling and testing operations (Finger *et al*, 1994).

Vale, OR, Slimhole

In April-May, 1995, a 5,826-ft exploratory slimhole (3.85-inch diameter) was drilled in the Vale Known Geothermal Resource Area near Vale, OR, in cooperation with Trans-Pacific Geothermal Corporation. Several temperature logs and injection tests were conducted. Over 2,700 ft of continuous core were obtained; the top portion of the well was drilled with conventional rotary drilling techniques to reduce cost.

The test results indicated an extremely low formation permeability. Consequently, it was concluded that the reservoir is very tight and is unlikely to be an effective, developable, geothermal resource. This conclusion agreed with that drawn from a nearby large-diameter wellbore, which cost 39% more on a cost/ft basis than the slimhole. A detailed report was written that summarizes this data and includes daily drilling reports and a detailed narrative of the drilling and testing operations (Finger *et al,* 1996).

Newberry, OR, Slimhole

A 4,500+ ft exploratory slimhole (3.85-inch diameter) was drilled in cooperation with CalEnergy in the Newberry Known Geothermal Area near Bend, OR, in July-November, 1995. Several temperature logs and injection tests were conducted. Over 4,000 ft of continuous core were obtained; the top portion of the well was drilled with conventional rotary drilling techniques to reduce cost.

Test results from this well have not yet been released due to the proprietary nature of the field and CalEnergy's operations there. Appropriate data will, however, be released within two years, and a detailed report will be written.

Drilling Technology Demonstrations

In addition to demonstrating the capability for obtaining viable reservoir data from slimholes, the drilling conducted thus far under this program by Sandia has demonstrated the utility and advantages of using cost-saving technologies not usually employed by the geothermal drilling industry.

The use of magnetic flow meters and acoustic Doppler flow meters to measure inflow and outflow rates from wells during drilling was demonstrated and shown to be of significant benefit. Slimhole borehole televiewer logs were run that demonstrated the benefits of that technology in orienting the core and measuring the direction and dip of producing fractures.

High-temperature downhole instrumentation developed at Sandia was used to obtain downhole temperatures and pressures during injection and production tests, and advanced surface flow meters were used to augment the conventional surface equipment normally used to test well productivity. Finally, numerous examples of cost-saving techniques were demonstrated by Sandia during the drilling and plugging of these slimholes.

Evaluation of Japanese Slimhole Data

Under contract to Sandia, S-Cubed is evaluating production data from numerous slimholes and production-sized wellbores in several Japanese geothermal fields. The goal of this evaluation is to test the viability of reservoir data determined from slimhole production tests. Wellbore discharge and injection data have been characterized for wells in liquid-feedzone reservoirs at the Oguni, Sumikawa, and Takigama fields, where the reservoir pressure is sufficient to maintain the produced fluid in a liquid state at the feedzone of the well. Reservoir and wellbore flow models were used to analyze these data. It was shown that reservoir characteristics and production rates in such reservoirs can indeed be predicted using the slimhole data (Garg *et al*, 1995).

Work is now underway at S-Cubed to collect and analyze data from the Kirishima reservoir, where high temperatures and limited permeability cause *in situ* boiling. Wellbore modeling and data analysis of such flows are significantly more complex than in liquid-feedzone reservoirs.

Drilling Systems Studies

In order to ensure that Sandia is addressing the proper technology needs of the geothermal drilling industry, we are conducting several engineering systems studies of drilling and other well-related activities. The objective of these studies is to identify areas where improved technology or procedures would reduce costs. These results will be used to re-direct our R&D program to have maximum impact.

Hydrothermal Well Systems Study

The purpose of this study is to update the 1981 systems study conducted by Sandia and Livesay Consultants that presented a detailed analysis of the costs of drilling and completing geothermal wells (Carson *et al*, 1983). That study compiled the costs from eight geothermal fields in the U.S. and generated a computer-simulation-based model for each field that allowed sensitivities to variations in relevant parameters to be determined. This enabled the cost reductions due to various assumed technology improvements, such as increased penetration rates and bit life and reduced lost circulation costs, to be assessed for the various reservoirs. The results have guided Sandia's geothermal drilling R&D program over the past 15 years.

The planned update will include life-cycle costs of geothermal wells in addition to updated drilling technology. This will allow effects such as using more corrosion-resistant casing materials, for example, to be weighed against the costs of using conventional materials and replacing wellbores more frequently. This study update has only recently been initiated and will take approximately one year to complete.

Advanced Drilling Systems Study

This recently-completed study by Sandia and Livesay Consultants addressed the costs of novel drilling techniques that have been proposed in the past (Pierce *et al*, 1996). This study, conducted in support of the DOE's National Advanced Drilling and Excavation Technology (NADET) program, determined the drill rig, drilling procedures, and supporting requirements for ten different novel techniques. The study derived penetration rate improvements that would be necessary with each of these systems in order for them to compete with conventional drilling techniques. The results are useful as a guide for the type of advanced drilling research that has the most potential.

GHP Drilling Systems Study

This study was recently initiated to study the cost and technology elements associated with drilling boreholes and installing heat exchangers for geothermal heat pumps (see later section for a more complete description of GHP research at Sandia). This study is collecting data on drilling and heat exchanger operations in order to identify problems and costs. An economic model will be built that allows parametric analysis to be done in order to identify which technology or procedural improvements could have the greatest impact on heat exchanger installation costs. These results will be used to guide future R&D in this area.

Geothermal Drilling Organization Projects

The GDO is an organization consisting of 17 member companies and national laboratories that collaborate on short-term, industry-driven, cost-shared projects involving improved geothermal drilling technology. Sandia coordinates the GDO projects, provides DOE's cost-shared funding to the entities performing the research, and in some cases performs some of the work, often participating in field tests. A number of projects have been completed by this organization over the past 14 years. Recently completed and ongoing projects are listed below. Space limitations do not allow more detailed description of these projects.

- *High-Temperature Drill Pipe Protectors* - Joint project with Regal Inernational, Brookhaven National Laboratory, and Unocal.

- *Rotating Head Seal* - Joint project with Smith International and Unocal.

- *Retrievable Whipstock* - Joint project with Smith International and Unocal.

- *Downhole Air Motor* - Joint project with Baker Hughes Inteq and Unocal.

- *Cementitious LCM Field Evaluation* - Joint project with Halliburton Services and CalEnergy.

- *Downhole Mud Hammer* - Joint project with Novatek, Unocal, and CalEnergy.

- *Expert System for Lost Circulation Control* - Joint project with Tracor, Inc., and CalEnergy.

Geothermal Heat Pump Technology

Geothermal heat pumps utilize the low-temperature geothermal energy found near the surface of the ground almost worldwide. In support of DOE's goal of increasing the number of GHP installations in the U.S. from 40,000/year to 400,000/year by the year 2002, Sandia is conducting research and development in three areas.

GHP System Performance Measurements

In order to properly market GHPs, viable demonstration projects and system performance measurement projects are needed for locations nationwide. Sandia is involved in a number of such projects in several locations, including:

- Dyess Air Force Base - demonstration project;
- Fort Hood Army Base - performance measurement project;
- Selfridge Air National Guard Base - performance measurement project;
- Fort Polk Army Base - performance measurement project;
- Patuxent River Naval Air Station - performance measurement project;
- Stockton College - performance measurements project; and
- Sandia National Laboartories - performance measurement projects.

Some of these projects involve the use of cost-shared funds from the Department of Defense. Data obtained from these projects has and will be made available to the public (Phetteplace and Sullivan, 1996; and Martinez *et al*, 1996).

GHP Drilling Systems Study

This project was described in a previous section.

Replaceable-Cutter PDC Bit

A joint project with Dennis Tool Co. was recently initiated to develop a low-cost, replaceable-cutter PDC bit for GHP drilling. Such a bit would make the high-penetration-rate and long-bit-life advantages of PDC bits available to the GHP industry, allowing drilling costs to be signifcantly reduced in some rock formations. Such bits would employ low-cost, used PDC cutters reclaimed by Dennis Tool Co. from petroleum PDC bits. A technique developed by Sandia for mechanically clamping these cutters to a bit body will permit replacement of worn or broken cutters in the field by the driller. This project is still in the design phase.

CONCLUSIONS

A large number of geothermal drilling technology development projects are currently underway at Sandia in eight program areas. In light of a renewed emphasis by DOE on providing immediate assistance to the geothermal industry in reducing costs, we are currently re-examining the program and will re-direct it to provide more immediate results. Discussions with the geothermal industry will be an integral part of this re-direction effort.

ACKNOWLEDGEMENTS

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UPDATE ON SLIMHOLE DRILLING

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ABSTRACT

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

BACKGROUND

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

Drilling costs associated with exploration and reservoir assessment are a major factor affecting future geothermal development. Slimhole drilling has been shown to reduce oil and gas exploration costs by 25 to 75%, but the more hostile conditions for geothermal resources present technology challenges which must be solved before the cost impact there can be thoroughly evaluated.[1] Once demonstrated, slimhole drilling technology will have application to geothermal exploration and reservoir assessment in both the U. S. and international markets.

RECENT ACTIVITIES

Sandia examined the basic feasibility of slimhole exploration with in-house analysis, field experiments on existing geothermal coreholes, and collection of an extensive data set from comparable drilling in Japan. We then negotiated an agreement with Far West Capital, which operates the Steamboat Hills geothermal field, to drill and test an exploratory slimhole on their lease. The principal objectives for the slimhole were development of slimhole testing methods, comparison of slimhole data with that from adjacent production-size wells, and definition of possible higher-temperature production zones lying deeper than the existing wells. This work has been reported in detail[2].

Sandia has contracted with S-Cubed to conduct extensive collection and analysis of data from Japanese slimholes and production wells in common reservoirs. Results from two geothermal fields support a correlation in productivity between different-sized holes[3]; this work is being extended to another, higher-temperature field in Japan.

Two industry cost-shared exploratory slimholes were drilled during 1995. The first was in the Vale Known Geothermal Resource Area (KGRA) in eastern Oregon; the second was on the north-west flank of Newberry Caldera, approximately 20 miles south of Bend, Oregon.

NEWBERRY EXPLORATORY SLIMHOLE

As part of an attempt to evaluate the commercial potential of a location within the Newberry

KGRA, CE Exploration (CEE), a subsidiary of California Energy Company, Inc., drilled two slimholes in the projected reservoir area. One hole was drilled entirely by CEE, the other was cost-shared with Sandia. Both holes were drilled with a Longyear minerals-type core rig. The cost-shared hole reached a depth well below 4500' in a drilling operation which lasted just over 100 days, including continuous coring to TD, directional drilling, and testing. Precise depths, temperatures, and gradients for this hole are proprietary at this time, but both slimholes predicted temperature gradients at depth which were later realized in nearby production-size wells.

VALE EXPLORATORY SLIMHOLE

In cooperation with Trans-Pacific Geothermal Corporation, another slimhole was drilled in the Vale KGRA in eastern Oregon. In addition to possible discovery of a new geothermal resource, this situation offered an opportunity for direct cost comparison between the slimhole and a conventionally-drilled exploration well approximately two miles away. TGC drilled this previous well in early 1994, and it was completed to roughly the same depth as that planned for the slimhole.

The principal objectives for this project were the following: development of slimhole drilling and testing methods; cost comparison with a recent, nearby; conventionally-drilled exploratory well; comparison of reservoir and performance data from this well with that from subsequent production-size wells; and evaluation of commercial geothermal potential at this location. Since both formation temperatures (see Figure 1) and permeability (less than 1 Da-ft) were lower than expected, it is unlikely that commercial development will take place in this location. The drilling and testing, however, were successful in showing that slimholes are informative and cost effective.

To meet our testing and data collection goals for this well, it was designed to meet the following criteria:

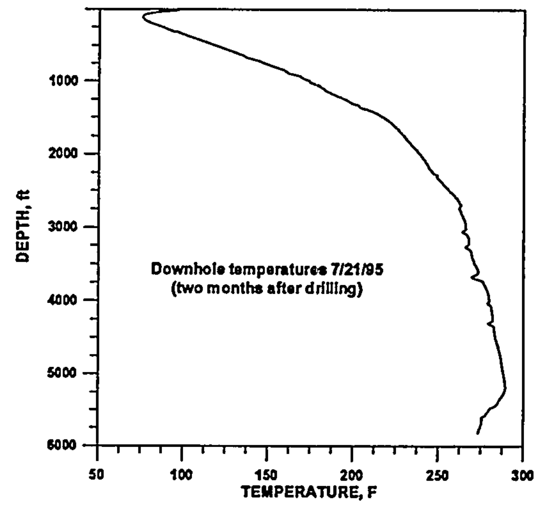

Figure 1 - Temperature in Vale Exploratory Slimhole

- Drill to TD at minimum cost consistent with necessary testing.
- Obtain a competent cement job on all casing, to allow extended production testing.
- Maintain HQ (3.85") hole diameter as deep as possible, to allow setting packers for isolation of possible production/injection zones.

The well design (Figure 2) has 7" casing to 510' and 4-1/2" casing to 3111 feet. The drilling program used a Tonto UDR-5000 core rig with conventional rotary tools to drill the top 3112 feet of hole; minerals-type coring tools were then used to core the interval of interest from casing shoe to TD. This approach combined the cost savings of a slimhole drill rig, doing fast rotary drilling in the upper part of the hole, with the scientific and reservoir data obtained from core in the potential production zone.

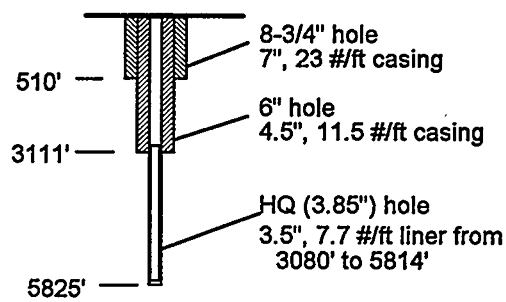

Figure 2 - TGC 61-10 Design

Drilling was relatively continuous, with all testing (other than temperature logs) reserved until hole completion at 5825 feet. The following tests were performed at TD: injection tests into the complete open-hole section, with pressure shut-in data; bailing from the bottom 500' of the hole, which was isolated with an inflatable packer, and then measuring temperature change in that section; repeated temperature logs in the hole, following well completion with a 3-1/2" liner from 3080' to 5814'.

Numerous temperature logs were taken with Sandia's platinum-resistance-thermometer (PRT) tool which, along with a Sandia logging truck, remained on-site for the entire project. This instrument uses a simple resistance bridge, with changes in resistance measured from the surface through a four-conductor cable. Since there are no downhole electronics, temperature drift with time is negligible and the PRT temperature measurements were considered the reference standard for these tests. Static temperature logs (no flow in hole) were done with this tool when coring operations were suspended for bit trips, rig maintenance, or other time intervals that would permit the hole to equilibrate with the static temperature gradient.

After the hole reached TD, a pressure-temperature storage, or "memory", tool was also used to compare temperature data with that previously taken by the PRT tool and to collect downhole pressure data during the injection and shut-in tests. This tool, part of Sandia's on-going program in Instrumentation Development[4], has a Dewar flask around an electronic memory which stores data (approximately 3,000 data points total capacity) that can later be downloaded into a laptop computer. This tool's primary advantage is its ease of operation, since it can be run into the hole on the rig's wireline and specialized logging trucks are not required. As an experiment, the tool was also run into the hole inside a core-barrel "cage" while tripping the drillstring and gave good results.

A major objective of the slimhole program is to demonstrate not only that the smaller wells give sufficient data to evaluate a reservoir, but that they do it more cheaply than conventionally-drilled large holes. The Vale slimhole presented an ideal situation for cost comparison because a rotary-drilled exploration hole had been completed less than two miles away, to approximately the same depth, in February 1994. The table at the end of this paper gives a breakdown of costs for both wells, and helps to define where major cost differences occur.

DISCUSSION

There are several points to note in the cost comparison:

- Even though charges by the drilling contractor were greater for the slimhole than for the A-Alt hole, lower ancillary costs for the slimhole made the total project much cheaper. Part of the greater rig cost was caused by the longer time required for the slimhole, and the remainder is due to the rig day-rates. It is not obvious that the core rig for the slimhole ($4990/day plus $5-$9/foot) should be more expensive than the rotary rig for A-Alt ($5640/day), but day-rates for drill rigs obey the same principles of supply and demand as other commodities. At the time A-Alt was drilled, rotary rigs were available in abundance and consequently were bid at relatively low prices, while core rigs, mostly employed by the minerals industry, were in short supply when bids for the TGC 61-10 slimhole were solicited.
- The only aspect of the earlier well which made it inherently more expensive was the directionally drilled interval. Beside the explicit costs of directional tools and services, there may have been additional rig days and bit costs, but even after deducting these items, there are clear savings for the smaller hole.
- The drilling-fluids expense for the slimhole was slightly greater than for A-Alt, but it was inflated by the complete loss of circulation in the lower part of the hole. This meant that we were continually pumping 10 to 15

gpm of mud down the hole for the last 20 days of drilling. A slimhole which did not lose total returns would have a much smaller mud cost.

- Even though more than half the total footage was rotary-drilled, the smaller bits used in the rotary section and the less expensive core bits in the cored section greatly reduced the cost of bits and tools. In the cored section, the simplified BHA also eliminated the cost of stabilizers and drill collars.
- Smaller sizes of the rig, pad, and sump reduced rig mobilization and site construction costs.
- A mud logging service company was only used for the rotary section of the hole, although we did continue to rent their H_2S monitors for the duration of the project. Once core was being retrieved, cuttings analysis was no longer required. Similarly, contract drilling supervision was only used during rotary drilling. While outside consultation was useful for design of bit hydraulics and BHA programs, these activities are considerably simplified in core drilling and the drillers are accustomed to making these choices independently.
- Smaller casing sizes, with correspondingly smaller cement volumes, were less expensive for the slimhole. Normally, there would be even more of a cost advantage to the smaller hole, but the 6" hole was washed-out over several intervals, requiring more cement for the 4-1/2" casing than originally estimated. Washed-out intervals may have been caused by excessive bit hydraulics, designed in an effort to increase drilling performance. If this was the case, then the trade-off with a $66,000 cement job was not cost-effective.

CONCLUSIONS

Although the Vale slimhole was geologically informative and the drilling went well, it was, unfortunately, drilled in a location which holds little promise for commercial geothermal development. Still, several useful conclusions can be drawn from this project.

- Drilling this hole to the same depth as a nearby rotary hole provided information of the same quality at substantially lower cost.
- With some refinement of techniques (hydraulics, etc.) used in the rotary part of the hole, cost savings could have been even greater.
- Total well cost is sensitive to the ratio of rotary-drilled interval to core-drilled interval. For example, see the table below. If rotary drilling had only gone to 2000', then the extra

Type of drilling	Hole advance ft/day	Avg cost, $/day	Avg cost per foot
Rotary	289	14,408	$50
Coring	129	10,573	$82

  1100' feet of coring would have increased the total cost by approximately $32/foot for that interval. (These costs-per-foot are much lower than shown in Table 1 because they include only cost during drilling; i.e., no casing, cement, site preparation or other non-drilling costs.)
- Given the availability of a storage-type logging tool, the method of taking a temperature log with the tool in a core barrel while tripping pipe has several advantages. It takes almost no extra rig time, it happens when the hole has not seen circulation for a period of several hours, and it is extremely safe (for the logging tool) compared to running the tool in an open hole, which might be fractured, caving, or sloughing.
- If a hole has several intervals which appear (from core examination) to have high permeability, then an inflatable packer is useful in evaluating these intervals individually. If significant lost circulation has been treated by pumping LCM, which may have plugged some of the fractures, then swabbing the hole can relieve this situation and give a better indication of that interval's true permeability. To do this, a specifically designed swabbing tool would have been more effective than the make-shift one used on this hole.

Drilling is cheaper for slimholes than for production wells because the rigs, crews, locations, and drilling fluid requirements are all smaller; because site preparation and road construction in remote areas is significantly reduced, up to and including the use of helicopter-portable rigs; and because the very fine cuttings and removing a substantial part of the hole volume in the form of core mean that it isn't necessary to repair lost-circulation zones before drilling ahead.

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

RECOMMENDED FUTURE WORK

Since all our slimhole operations to date have supported the validity of slimhole drilling as a lower-cost exploration technique, we should seek other opportunities for cost-shared projects in geothermal reservoirs where subsequent production wells will give comparisons between slimhole tests and production data. This would be part of a general effort to do exploratory drilling and testing in reservoirs with different flow characteristics, and to compare those results with production wells in the new reservoirs.

A consequence of moving to other types of reservoirs will be the increasing need for flow modeling capability, especially in terms of coupling a reservoir simulator to a wellbore simulator. Although little modeling was done for this well testing, it will be important to simulate the flow from the reservoir into and up the wellbore when working in a reservoir where production tests can be done.

The pressure-temperature log taken while tripping drill pipe with the memory tool in a core barrel was successful, having as a principal defect the necessity for hand entry of drill pipe length during the trip. A simple drill-pipe-length encoder should be developed to expand the opportunities for this type of logging on core rigs. An encoder would produce time-depth data which could be merged with the logging tool's time-pressure/temperature data to generate a curve of depth versus pressure and temperature.

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Well Name:	**A-Alt**	**TGC 61-10**
Depth	5757'	5825'
Completion	14" line pipe to 62' 9-5/8" casing to 506' 7" casing to 3010' 5" slotted liner, 2902'-5723'	10" line pipe to 29' 7" casing to 510' 4-1/2" casing to 3111' 3-1/2" H-rod, 3080'-5814'
Rig days	31 + 5 standby	40

WELL	A-Alt	TGC 61-10
Rig Charges (day rate, footage, crew per-diem)	184,955	254,837
Rig mobilization and de-mob	87,860	43,560
Site construction and maintenance	57,700	29,998
Mud logging	26,040	13,490
Bits and downhole tools	67,279	27,978
Directional	37,374	0
Fishing	3,200	1,695
Rentals	28,090	20,182
Fuel and water	10,350	5,570
Drilling fluids	48,421	48,468
Casing, casing crews, and cement	172,817	107,076
Logging	58,376	14,929
Trucking and additional labor	36,723	12,895
Equipment maintenance	11,530	1,260
Drilling engineering	56,940	13,790
Wellhead and miscellaneous	32,670	42,555
TOTAL	920,325	638,334
Cost per foot (*excluding* directional costs)	$153	$110

DEVELOPMENT OF ADVANCED SYNTHETIC-DIAMOND DRILL BITS FOR HARD-ROCK DRILLING

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ABSTRACT

Cooperative research is currently underway among five drill bit companies and Sandia National Laboratories to improve synthetic-diamond drill bits for hard-rock applications. This work, sponsored by the U.S. Department of Energy and the individual bit companies, is aimed at improving performance and bit life in harder rock than has previously been possible to drill effectively with synthetic-diamond drill bits. The goal is to extend to harder rocks the economic advantages seen in using synthetic-diamond drill bits in soft and medium rock formations. Four projects are being conducted under this research program. Each project is investigating a different area of synthetic-diamond bit technology that builds on the current technology base and market interests of the individual companies involved.

INTRODUCTION

If the survivability of PDC and other synthetic-diamond drill bits could be improved for hard-rock conditions, the more efficient cutting mechanisms inherent to such bits could be used to advantage in reducing drilling costs. Because drilling costs, in general, are very high in hard rocks, the incentive to improve the technology is great. Reduced hard-rock drilling costs would increase the United States' energy supply by making both geothermal resources and deep oil and gas more economical to access.

DESCRIPTION OF THE PROGRAM

The Advanced Synthetic-Diamond Drill Bit Program currently consists of the following projects. These projects have been described in detail in Glowka and Schafer (1993) and Schafer and Glowka (1994).

- *Optimization of PDC Claw Cutters with Dennis Tool Company*

The objective of this cooperative project is to maximize the benefit of the claws and minimize overall and localized cutter stresses in PDC claw cutters (see Delwiche et al. (1992) for a description of claw cutters). Numerical modeling of various claw geometries is being conducted to calculate thermal and mechanical stresses under typical operating conditions. Single-cutter wear tests are also being conducted with various claw geometries in order to rank the wear resistance of the geometries and verify the numerical results. Dennis Tool Company is designing and manufacturing the cutters for this project. Sandia is performing the numerical analysis and single-cutter testing. Sandia is also providing DOE funding to Dennis Tool Company on a cost-shared basis.

- *Optimization of Track-Set Bits with Security DBS*

The objective of this cooperative project is to maximize the cutter tracking effect, minimize bit vibration and wobble, and maintain rapid rock penetration with Track-Set bits (see Weaver (1993) for a description of Track-Set bits). Single-cutter testing is being conducted by Sandia to provide quantitative cutter performance characteristics to guide bit design. Security DBS is incorporating these cutting parameters into computer software that will be used to design Track-Set bits. Sandia is also providing DOE funding to Security DBS on a cost-shared basis.

- *Advanced TSP Drill Bit Development with Maurer Engineering and Slimdril International*

The objective of this cooperative project is to maximize thermally stable polycrystalline (TSP) diamond bit performance and identify optimal cutter configurations and bit design guidelines for hard-rock applications (see Cohen et al. (1993) for a description of Maurer's past work on TSP bits). Sandia is wear-testing single TSP cutters of various shapes and sizes to provide ranking with respect to wear and impact-damage resistance. Sandia is also providing DOE funding to Maurer Engineering/Slimhole International on a cost-shared basis. Maurer Engineering and Slimhole International are manufacturing and testing TSP bits with various cutter configurations to identify optimal cutter placement guidelines and to confirm the single-cutter wear test results. DeBeers and General Electric are providing TSP test cutters at no cost.

- *Optimization of Impregnated-Diamond Drill Bits with Hughes Christensen Company*

The objective of this cooperative project is to increase penetration rates with impregnated-diamond bits while maintaining impact and wear resistance in hard-rock applications. Hughes Christensen is conducting drilling tests with various diamond and matrix designs, evaluating a proprietary diamond coating technology that aids diamond retention in the matrix, and developing mechanistic models of the impregnated-diamond rock-cutting process. Hughes Christensen is contracting with Dr. Fred Appl to perform the model development. Sandia is providing DOE funding to Hughes Christensen on a cost-shared basis.

• *Other Participants*

Amoco Production Research is under contract with Sandia to provide drilling time at their Catoosa Test Facility in order to field test bits developed under this program. The facility contains access to over 2,000 feet of well-documented lithologies that contain hard rock intervals and transition zones from soft to hard rock.

There were initially eight participating bit companies in this program. Due to corporate restructuring and consolidation, the number of participating companies is now five, as outlined above. In addition, two original participants in the program, Smith International and Magadiamond, have undergone corporate restructuring that did not leave them with adequate resources to continue participation in the program. Consequently, their cooperative project on fundamental bit failure and rock cutting mechanisms in hard rock has been eliminated from the program.

PROJECT RESULTS TO DATE

The program outlined above has been underway for two years. This section presents the progress made in the various projects thus far.

Optimization of PDC Claw Cutters

Numerical Stress Modeling

Thermal and mechanical stress modeling has been conducted for nine claw cutter configurations. A typical configuration is shown in Figure 1. An advanced automated mesh generation capability developed at Sandia was used to construct the numerical models. Each finite-element model consists of over 16,000 elements. Seen in this figure are the claw-cutter design parameters that were changed for the various configurations: diamond layer thickness; tungsten carbide groove depth; groove width; distance between grooves; and number of grooves. By calculating stresses for various combinations of these parameters, equations can be derived that allow interpolation of stresses for parameter values that lie within the bounds of those used in the numerical calculations. The thermal and mechanical conditions for which the calculations were made were chosen as typical of challenging,

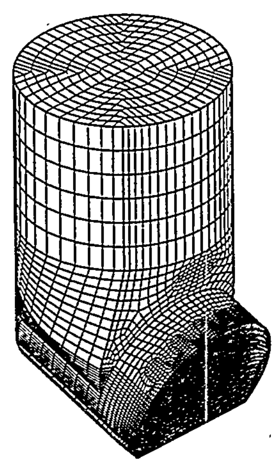

Figure 1 - Typical claw-cutter finite-element mesh.

hard-rock drilling. They are based on previous Sandia work by Glowka and Stone (1985, 1986) and recent experience with single-cutter testing.

The thermal stress analysis has been completed. Although the results are complex and difficult to convey in a summary article such as this, it is possible to present some general conclusions. Table I shows the maximum computed Von Mises stress for each of the selected claw cutter configurations. Note that the configurations with the thinnest diamond layers have the highest calculated thermal stress. This is a reasonable conclusion based on the fact that the thermal stresses are primarily a product of the thermal gradients in the cutter and the differential thermal expansion between the tungsten carbide and the diamond structure. The effects of the other design parameters are more complex and will require further study to fully explain.

TABLE I
COMPUTED MAXIMUM CLAW CUTTER THERMAL STRESSES

Configuration	Diamond Thickness, in	Groove Depth, in	Groove Width, in	Dist. Between Grooves, in	No. of Grooves	Maximum Stress, ksi
1	0.020	0.060	0.039	0.039	6	21.6
2	0.005	0.020	0.039	0.020	8	37.4
3	0.040	0.100	0.039	0.071	4	24.8
4	0.005	0.100	0.020	0.040	8	31.1
5	0.060	0.060	0.020	0.020	12	17.7
6	0.020	0.020	0.020	0.087	4	22.7
7	0.040	0.020	0.078	0.039	4	19.2
8	0.020	0.100	0.102	0.020	4	19.1
9	0.005	0.060	0.102	0.102	2	38.5

Before a claw cutter configuration can be selected based on stress, it will be necessary to complete the mechanical stress analysis. The principle of superposition can then be used to combine the thermal and mechanical stress results to determine the total stress field for each cutter configuration. Equations can then be developed that describe the effects of the various design parameters on cutter stresses.

Single-Cutter Wear Testing

In order to perform wear-testing of PDC claw cutters, a test procedure was developed using the vertical lathe shown in Figure 2. A large 3 ft X 3 ft X 3 ft block of Sierra White Granite was mounted on the rotary table. A triaxial dynamometer mounted on the traveling head was fitted with the test cutter. The traveling head moved at a fixed radial speed across the top surface of the rock as the rock was rotated. The cutter therefore made tightly wound spiral cuts across the top surface of the rock while triaxial cutter forces were measured. A vertical, 2.5-inch diameter hole was drilled in the center of the rock prior to the tests in order to remove that portion of the rock that would have required operating the cutter in a very tight radius. Also, the outside corners of the rock were removed prior to each pass with a different cutter in order to prevent the test cutter from having to perform interrupted cuts. Water was directed through a 0.25-inch nozzle at the cutter/rock interface at a rate of 0.08 gpm in order to wet the rock surface and control dust.

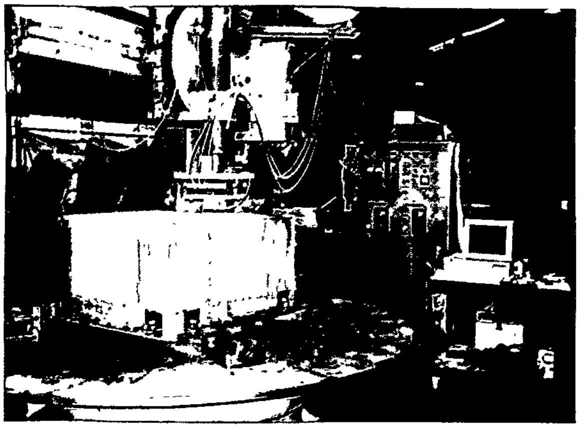

Figure 2 - Vertical lathe set-up used to wear-test single PDC and TSP cutters.

A nominal vertical depth of cut of 0.060 inches and a radial feed of 0.080 inches/revolution were adopted as standard cutting conditions. These conditions resulted in rock removal rates typical of those for a PDC cutter on a bit drilling at 30 ft/hr. Each pass of the cutter over the rock surface represented about 1000 ft of linear cutting, sufficient to cause a measurable amount of cutter wear with each pass. The cutter wearflat dimensions (length, width, and area) were measured after each pass using a video-microscope measurement system.

Baseline cutter wear rates were established with conventional, 1/2-inch, chamfered PDC cutter compacts (GE model 2741). Data were obtained at two different rotary table speeds, 10 and 20 RPM. Because the rotary speed was held constant for a given test, the linear speed of the cutter varied from a maximum along the outer radius of the rock to a minimum near the center of the rock. The linear speed of the cutter thus varied from 1.3 to 18.8 ft/sec at 10 RPM and 2.6 to 37.7 ft/sec at 20 RPM. In order to ensure that the cutter wear results were not cutter-dependent, each of the two cutter compacts were tested both at the lower and higher rotary speeds, with the compact being rotated 180° in the cutter holder between tests. Miniature (0.010-inch diameter) thermocouples were mounted in the compacts through an electro-discharge-machined (EDM) hole drilled through the back of the compact up to, but not through, the diamond layer. The EDM hole was oriented such that the wearflat would actually wear into the thermocouple at some point during the wear process.

Results of these baseline tests with the conventional PDC compacts are shown in Figures 3 and 4. Figure 3 shows the cutter wear volume as a function of cutting distance, with the total cutting distance representing 10-15 passes of the cutter over the rock surface. Testing for each cutter was terminated when the wearflat reached the point that the cutter penetrating (vertical) force exceeded 1000 lb, the

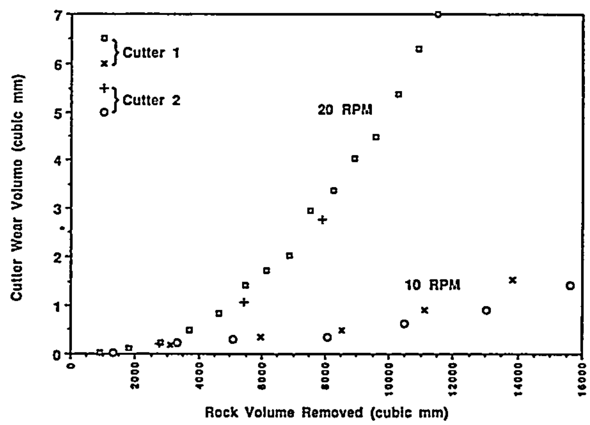

Figure 3 - Conventional PDC cutter wear rates measured on the vertical lathe in Sierra White Granite at two rotary speeds.

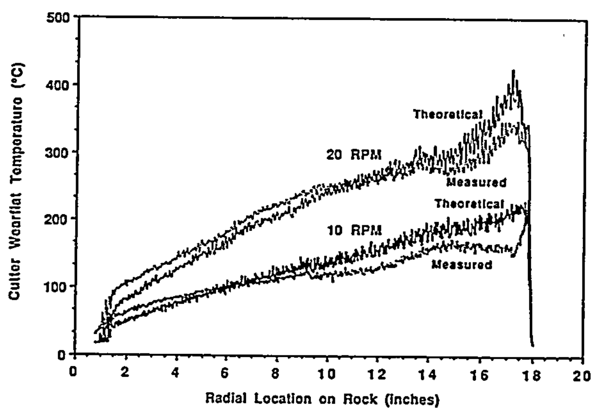

Figure 4 - Theoretical and measured cutter wearflat temperatures for conventional PDC cutters in Sierra White Granite.

maximum safe force for the vertical lathe. It is seen for a given rotary table speed that the results are highly repeatable and that the effect of rotary speed is profound. Wear rates at the higher rotary speed are about 10 times higher than wear rates at the lower rotary speed. Figure 4 suggests the probable cause for this phenomenon.

In Figure 4, the cutter wearflat temperatures are plotted for the pass just before the wearflat reached the thermocouple and destroyed it. In addition to the experimental data, the theoretical wearflat temperatures are plotted based on the measured cutter forces and speeds and a temperature model previously developed by Glowka and Stone (1985). Several points can be made from these results. First, there is excellent agreement between the measured and calculated wearflat temperatures. Second, the cutter temperatures depend on the cutter's radial position on the rock and thus its linear speed. Third, the cutter temperatures are significantly higher at 20 RPM than at 10 RPM. This is the probable cause for the accelerated wear rates experienced at the higher rotary speed. This conclusion agrees with the theory proposed by Glowka and Stone (1986) that thermally accelerated cutter wear occurs when wearflat temperatures exceed 350°C.

Cutter Wear Facility Development

Considerable time was spent in developing the wear test procedures described above with the vertical lathe. Although the procedures were found capable of developing significant, repeatable wearflats, several deficiencies in the method were identified that caused us to question the technique. These include the following:

1) The linear speed effect described above and the inability to maintain a constant linear speed added a degree of uncertainty to the results because it is possible that various cutter configurations would exhibit different critical temperatures above which thermally accelerated wear occurs. This would have made it difficult to ensure that experimental cutters were being operated below their critical temperatures without performing tests at multiple rotary table speeds with each cutter configuration.

2) Although quite stiff, the vertical lathe did exhibit enough flexibility at high penetrating forces to make it difficult to maintain a constant depth of cut between one pass and the next pass as the cutter wore. Depths of cut typically varied by 10-30%, which was deemed unacceptable for comparative wear testing.

3) It was not possible in these tests to hydraulically cool the cutter to the same degree as on a bit drilling with drilling mud. Although a low-pressure water jet was directed at the cutter, the jet neither enveloped the cutter not impacted it with velocities typical of those encountered downhole in actual drilling.

4) The character of the cutter interaction simulated in these tests was not similar enough to that experienced on a real bit to convince us that the measured wear rates could be used to quantitatively predict wear downhole on a real bit.

Because of these deficiencies, we embarked on the development of the Cutter Wear Test Facility (CWTF) shown schematically in Figure 5. This facility is basically a small rotary drilling machine that can be used to efficiently drill approximately one hundred 3-inch diameter holes in a single 3 ft X 3 ft X 3 ft block of rock. The rock block is mounted on an air caster to enable it to be easily moved laterally between holes.

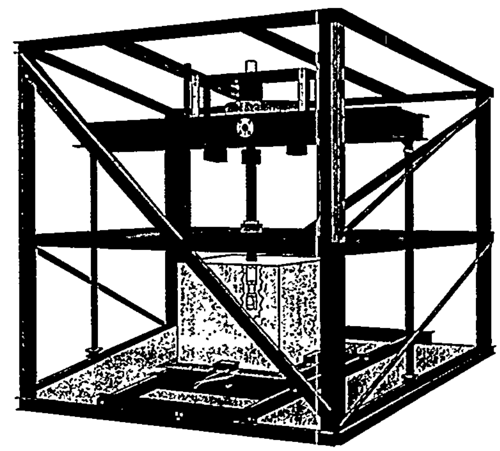

Figure 5 - Cutter Wear Test Facility under development.

The drill bit consists of three cutters and is similar to a core bit, with the test cutter situated radially between the inner and outer trim cutters at a radius of 1 inch. The test cutter thereby experiences cutter interaction similar to that on a full-face bit. The bit was designed and laterally balanced using Sandia's PDCWEAR code; see Glowka (1987, 1989a, 1989b).

The test cutter is mounted on a block instrumented with strain gages to allow triaxial cutter forces to be measured. All three cutters on the bit can also be fitted with one or more thermocouples to measure cutter temperatures. Slip rings are used to bring the strain gage signals and thermocouple signals off the rotary drill stem. Water or other liquids are used to cool the cutters and remove rock cuttings from the hole.

The machine is operable to 500 RPM to permit duplication of linear speeds typical of those seen near the gage of an 8-3/4 inch bit at 60 RPM. A weight-on-bit capability of 6,000 lb allows up to 2000 lb of penetrating force to be imposed on the test cutter. The maximum penetration rate is 160 ft/hr. The machine can be operated in two modes, constant penetration rate or constant weight-on-bit.

Construction of the machine is complete, and testing of standard PDC and claw cutters has begun.

Optimization of Track-Set PDC Bits

Linear single-cutter tests are underway using the horizontal milling machine shown in Figure 6. In these tests, a rock sample (typically 22 inches long X 10 inches wide X 4 inches tall) is placed on the translating table. A triaxial dynamometer is mounted to the fixed head and fitted with the test cutter. Linear cuts are performed at a fixed cutting speed of 2.4 inches/second, the table's maximum speed. This arrangement is the same as that used to study cutter interaction for conventional PDC bits by Glowka (1987, 1989a, 1989b). With these tests, the linear cuts are not long enough to cause measurable cutter wear over any given pass, even in hard, abrasive rock.

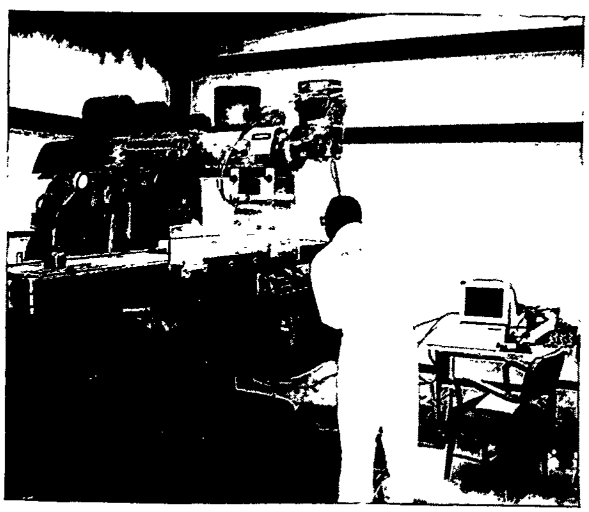

Figure 6 - Horizontal milling machine used to perform instrumented, linear, single-cutter tests for Track-Set bit design.

In this study, cutter interaction patterns typical of those that occur with Track-Set bits are being evaluated. Two such patterns for which data have been obtained are shown in Figure 7. In the engagement-angle tests, successive cuts are made at a constant depth of cut in the same track (or groove), thereby increasing the total groove depth (and thus engagement angle) with each pass. These tests are important in determining the effect of the groove depth on cutter forces as a function of the depth of cut (i.e., penetration per revolution). In the restoration-force tests, a cutter is displaced laterally with respect to an existing groove. This provides data on the lateral restoration force available to return a cutter to its running track when lateral bit vibration or wobble occurs. Data for both of these cutter interaction patterns were obtained with a sharp, 1/2-inch, chamfered PDC cutter at a 20° backrake for three rock types: Sierra White Granite, Tennessee Marble, and Berea Sandstone.

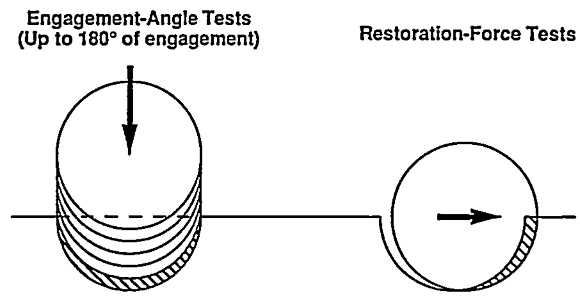

Figure 7 - Cutter-interaction patterns being evaluated in single-cutter tests for Track-Set bits.

Engagement-angle data are shown in Figures 8 and 9 for Sierra White Granite. Plotted here are penetrating (vertical) and drag (horizontal) forces as functions of the total groove depth and incremental depth of cut. Note that the forces seem to approach an asymptote as total groove depth increases. This is reasonable because of the shape of a round cutter. As the groove depth approaches a value equal to the compact radius times the cosine of the backrake angle (i.e., 0.24 inches), the engagement angle between the cutter and the rock approaches 180° and the circumferential contact length between the cutter and the rock approaches its maximum (one-half the circumference of the round compact).

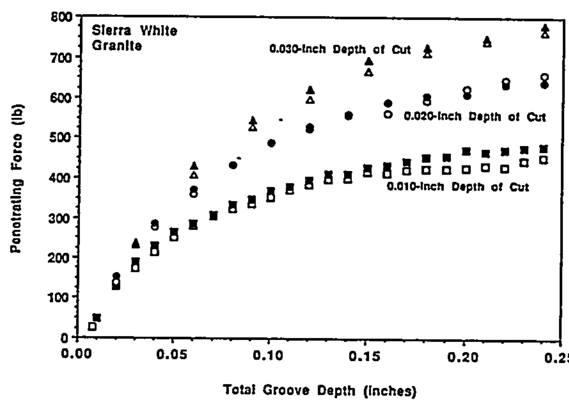

Figure 8 - Measured penetrating forces in single-cutter, engagement-angle tests in Sierra White Granite.

Typical restoration-force data are shown in Figure 10. Seen here are the lateral cutter forces measured as a function of the total groove depth and the lateral

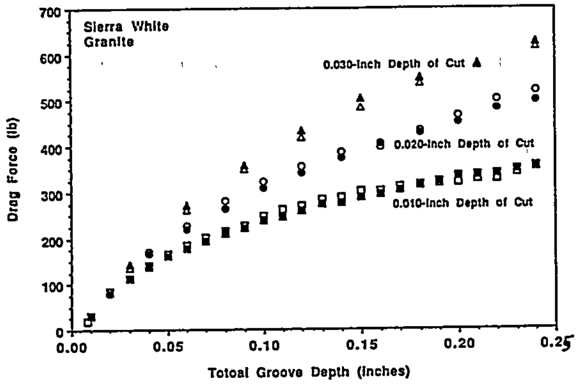

Figure 9 - Measured drag forces in single-cutter, engagement-angle tests in Sierra White Granite.

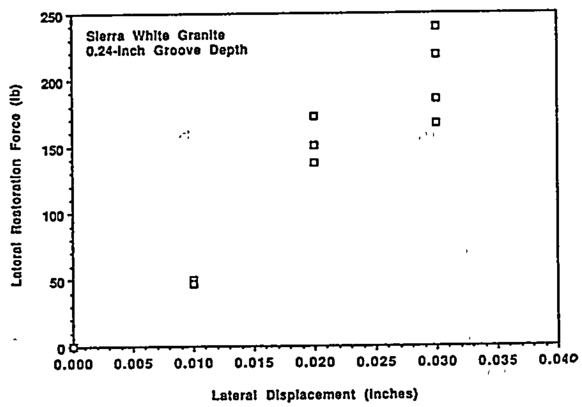

Figure 10 - Measured lateral restoration forces in single-cutter tests in Sierra White Granite.

displacement imposed on the cutter with respect to the groove centerline. Note that very small lateral displacements result in relatively high lateral forces. This confirms that with hard rock, significant restoration forces are available to push the cutters back into their tracks if bit vibration or wobble occurs.

Similar results to those described above were obtained with Tennessee Marble and Berea Sandstone. The force levels were, of course, found to be lower with these rock types, consistent with their lower compressive strengths. Measured compressive strengths for the three rock types were reported by Glowka (1987, 1989a) to be: 7,100 psi for Berea Sandstone; 17,800 psi for Tennessee Marble; and 21,500 psi for Sierra White Granite.

Security DBS is currently analyzing the single-cutter data so that it can be used to improve the force-balancing software they use to design PDC bits. This will make the software more directly applicable to the design of Track-Set bits.

Optimization of TSP Bits

The vertical-lathe cutter wear test procedure described previously was used to measure wear rates for several different TSP cutter configurations. The profiles of these configurations are shown in Figure 11. With the exception of the TSP disk configuration (not shown), these cutters were significantly smaller than typical PDC cutters, only 5-7 mm across. Consequently, the nominal depth of cut was reduced to 0.015 inches and the radial feed rate was reduced to 0.023 inches/revolution for tests with these configurations.

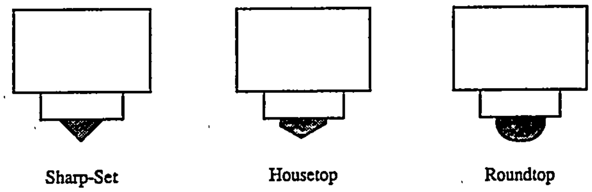

Figure 11 - Profiles of TSP cutters used in single-cutter wear tests. (TSP disk cutter not shown.)

The TSP disk cutter, on the other hand, was the same shape (round profile) and size (1/2-inch diameter) as a conventional PDC cutter. Also with this configuration, the TSP diamond was bonded to a thin (0.030 inch thick) wafer of tungsten carbide for support. In this case, the same nominal 0.060-inch depth of cut and 0.080-inch/rev feed rate were used as for the standard PDC cutters, allowing a direct comparison of wear rates to be made. All tests were performed in Sierra White Granite with a rotary table speed of 20 RPM.

Results for the small TSP cutter configurations are shown in Figure 12. Note that the housetop configuration experienced the lowest wear rates, followed by the 7-mm sharp-set, the GE silver top, and the roundtop configurations. These results cannot be compared with those of the conventional PDC cutters because of the significant size

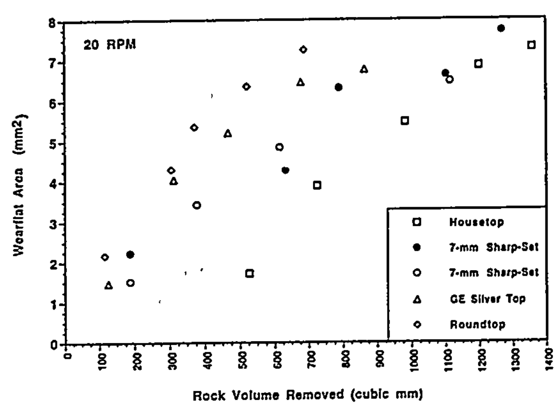

Figure 12 - Measured cutter wearflat areas for various small (5-7 mm) TSP cutters in Sierra White Granite.

differences and the different depths of cut and radial feed rates used.

Results for the TSP disk cutters are shown in Figure 13, where the wear rates are compared with those of the conventional PDC cutters. Note that the results were repeatable and that the TSP disk cutters wore at only about 15-20% of the wear rate of the PDC cutters. In fact, the TSP disk cutters at 20 RPM wore at almost the same low rate as the PDC cutters at 10 RPM (see Figure 3), indicating that the TSP disk cutters were not subject to the same thermal-wear threshold that the PDC cutters demonstrate.

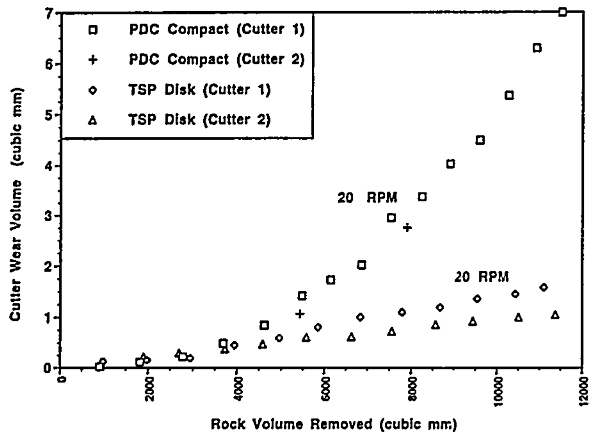

Figure 13 - Measured cutter wear rates of conventional PDC and TSP disk cutters in Sierra White Granite.

The TSP disk cutter tests were terminated when the wearflats reached the point that cutter forces were high enough to fracture the cutters, including the tungsten carbide backup wafer. Nevertheless, these results are exceedingly promising. Thicker tungsten carbide backup wafers may allow the cutters to withstand higher forces and, therefore, larger wearflat areas before fracturing. This type of experimental TSP cutter shows significant potential for improving synthetic-diamond bit life in hard-rock drilling.

Optimization of Impregnated-Diamond Bits

A large number of laboratory drilling tests have been conducted in several rock types with various impregnated-diamond core bit designs (2-3/8 inch OD X 1-1/2 inch ID). An existing laboratory drilling machine was modified to increase its rotary speed capability to 1000 RPM. Weight-on-bit and drilling torque were measured for a variety of constant penetration rates and rotary speeds. A stereo microscope and scanning electron microscope (SEM) were used to examine experimental bits to study diamond distributions and wear patterns. A coordinate measuring machine (CMM) was used to measure bit wear and diamond exposures after drilling.

A baseline bit design was selected with nominal bit design parameters, including: diamond grade of SDA 100; diamond sizes of 25/30 and 35/40 mesh; diamond concentration of 100 (25% by volume); and matrix type 617. After establishing bit wear rates with the baseline design, changes were made in each of these design parameters to determine the effects of the changes on bit wear. Typical bit wear results are presented in Figure 14 for several of these design parameter changes. These results are the total wear of the bit in the axial direction after drilling 120 inches in each of three hard, abrasive rock types at a rotary speed of 750 RPM and a penetration rate of 20 ft/hr. Note the profound effect that changes in the design parameters can have on measured bit wear. These results are being used to determine the optimal design parameters with respect to bit performance and cost.

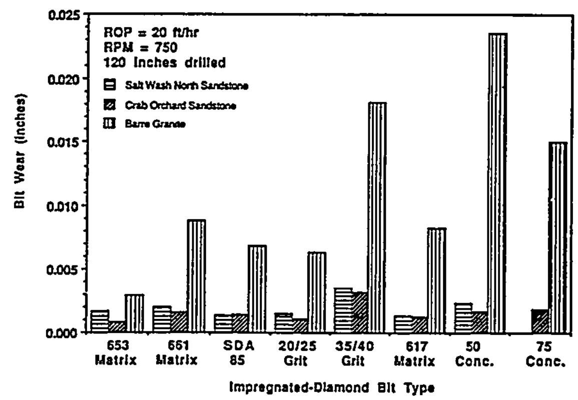

Figure 14 - Measured bit wear for various impregnated-diamond bit designs in three hard, abrasive rock types.

Mechanistic modeling of the impregnated-diamond cutting process is aimed at optimizing the matrix wear rate in various types of hard rock. Matrix wear must be rapid enough to provide adequate diamond exposure but not rapid enough to cause diamonds to be dislodged prematurely. It is therefore critical to understand the effects on matrix wear of several important parameters, such as: the distribution of penetrating stresses between the matrix and the diamond, which is a function of the diamond exposure and concentration; the relative hardness of the matrix and rock chips; the size of the rock chips; and the local velocity of the matrix, which is a function of the bit diameter and rotary speed. A model has been developed and compared with the experimental drilling results to define the relative wear resistance for various matrix types.

The model also allows prediction of important drilling parameters for a given bit design. Shown in Figure 15 is a comparison of the measured weight-on bit for the baseline bit design with that predicted by the model. Although the model does contain empirically-derived parameters, the excellent comparison with the experimental bit performance indicates that the model correctly simulates the essential cutting mechanisms involved. With further development and verification, the model should be useful in guiding the optimization of impregnated-diamond drill bit designs for any selected rock type.

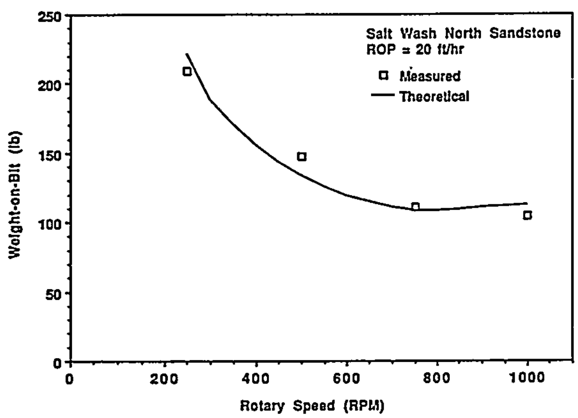

Figure 15 - Comparison of measured drilling performance with that predicted by the model developed for impregnated-diamond drill bits.

CONCLUSIONS

Steady progress has been made thus far in DOE's Advanced Synthetic-Diamond Drill Bit Program. Synthetic-diamond bit technology is already at a mature state, so major advances will not come easily. Furthermore, relatively modest funding levels for this program imply that progress will not be rapid. The work underway in the various projects is considered to be more evolutionary than revolutionary, with the intent of steadily improving bit performance and increasing the rock strengths that can be effectively drilled with synthetic-diamond drill bits. Nevertheless, the impact of such developments could be quite significant in that resources could be reached that are not economically accessible today.

ACKNOWLEDGEMENTS

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National Advanced Drilling and Excavation Technologies Program and Institute

Abstract

The National Advanced Drilling and Excavation Technologies (NADET) program has been established to facilitate cooperative, substantial, R&D programs necessary for the competitive survival of many basic industries dependent upon these technologies. Geothermal power generation is one such industry, where drilling costs must be substantially reduced. The Geothermal Energy Division of DOE has provided seed money to begin operations, but a broad support base from other sources must be established for the NADET program to continue. The NADET Institute at MIT has been established to administer the program. A series of workshops is underway to introduce the NADET program to industry and to gather information on needs and opportunities. An RFP has been issued seeking advanced drilling concepts applicable to geothermal drilling, with first round funding expected in July, 1996. A national facility for drilling and excavation research and demonstration has been established at the Nevada Test Site, with drilling and excavation R&D activities to be managed by NADET Institute. Work continues to secure broad support for a multi-industry program.

Background

As noted in the invitation to this Program Review XIV, significant reductions in geothermal power costs are needed to bring about a resurgence in geothermal power projects within the U.S. Prominent among the costs are those associated with drilling. The National Advanced Drilling and Excavation Technologies (NADET) program has been established to provide a means to undertake the sustained programs that will be necessary to bring about significant reductions in drilling costs. The geothermal power industry, on its own, is not sufficient at this time to support such a program. The same is true of other industries dependent upon drilling and excavation technologies hence the need for collaborative action. The NADET Institute at the Massachusetts Institute of Technology will administer the program, while coordinating a host of separately funded projects that can benefit, and benefit from, broadly cooperative and integrated development of advanced technologies. Since July, 1995, the NADET Institute has been engaged in a variety of efforts, including the first round of support for research programs.

Request for Proposals

NADET Institute issued its first Request for Proposals on March 1, 1996, seeking proposals for broadly defined advances in geothermal drilling technologies. The request was publicized in the Commerce Business Daily, by direct mail to the NADET mailing list and via press release to 140 media outlets.

A copy of the RFP is attached as Appendix A. The request is deliberately broad at this stage in order to stimulate a wide sampling of new ideas. In keeping with this initially wide search, a two-stage proposal procedure has been adopted. The initial response, due April 8, 1996, is limited to a 5-page prospectus or "pre-proposal," briefly defining the proposed project. From there a coherent initial program in keeping with available funding will be defined, and formal proposals will be invited from those within that program. With roughly one million dollars available for research, formal proposals will be invited for two to three times the number of projects that can be supported.

From the proposer's viewpoint, the limited pre-proposal format avoids the necessity of preparing an elaborate proposal until the proposed project is found to be relevant. From the NADET viewpoint, this approach should bring in a wide range of ideas which, if not relevant at this early stage, may be relevant in future projects as the NADET program grows in both scope and budget. This two-step format has been very favorably received by all who have called to inquire about the relevance of their ideas within the general RFP statement.

This first RFP is of course directed to projects which will be of benefit to geothermal drilling. But it is the basic premise of the NADET program that, with proper coordination, these will be of interest for many other applications. Preliminary indications point to a very broad range of interests among prospective proposers. NADET Institute expects a wide range of innovation, from concepts clearly of little significant promise to others offering the prospect of truly revolutionary advance.

Final definition of the RFP was preceded by a meeting with geothermal industry representatives in San Francisco on January 19, 1996. With ten industry members in attendance, this meeting substantially influenced the scope and sense of the NADET RFP. Starting with a NADET-proposed dual interest in advanced (i.e. lower cost) drilling technology and "smart drilling" systems, this group suggested, in view of the limited available funding, that the initial program focus only on advanced drilling. Further, the group converged on a statement of purpose for this initial program. Both key suggestions were incorporated in the final RFP. At the conclusion of its effort the group endorsed the concept of a permanent geothermal industry advisory committee to serve future NADET Institute planning. Those present volunteered to serve on such a committee and other members will be sought. It seems appropriate that other such advisory committees be formed to represent other industries as the NADET program grows.

Final selection of projects warranting formal proposals will be made at a meeting of all proposal reviewers in San Francisco on May 3. With a rapid turnaround of pre-proposals, final selection of funded projects is expected in July.

Startup Activities

The NADET Institute structure is headed by an Operating Committee made up largely of industry members, and is lead by an industry chairman. The committee has met twice and is scheduled to meet four times each year. Presently composed of sixteen members, additional members in several key areas will be added.

Startup has also involved a continuing series of workshops to introduce the NADET program to industry and to solicit advice and guidance in program planning. The first, on Advanced Mining Technology, was held at the Colorado School of Mines on October 5-6, 1995. It was attended by thirty-two participants from industry, academia, and government agencies. In the face of the recent demise of the Bureau of Mines, a speaker from that organization summed up the conclusion of the workshop: Development of new, lower cost, environmentally friendly mining methods must continue.

The second workshop focused on geothermal drilling. It was held in Reno on October 10 and 12, 1995 in conjunction with the Annual Meeting of the Geothermal Resources Council. A preliminary introduction to NADET was held on the evening of the 10th, while a day-long technical workshop was held on the 12th. The workshop was attended by forty participants, mostly from industry. The discussions contributed significantly to the definition of research goals and opportunities in geothermal drilling and significantly shaped the current RFP.

At present, three more workshops are scheduled as follows:

April 25, 1996: Tunneling Workshop, covering both large and micro tunneling, held in Washington, D.C. in cooperation with the North American Tunneling '96 Conference, April 21-24.

May 1-2, 1996: Sensing Workshop, covering a wide range of position and other sensing needs and opportunities, held in Keystone, Colorado in cooperation with the Symposium on the Application of Geophysics to Engineering and Environmental Problems of the Environmental and Engineering Geophysical Society on April 28-May 1.

May 15, 1996: Oil and Gas Drilling Workshop, held in Houston preceding a Drilling Engineering Association meeting on May 16.

In addition, an Environmental Drilling Workshop is tentatively scheduled for late Spring.

As may be seen, workshops are often coordinated with other closely related meetings for the convenience of those who may wish to attend both. In addition to NADET's own mailing list, cooperating agencies provide assistance in assembling additional mailing lists of those directly interested in the subject of the workshop. For example, 400 additional names have been provided for direct mail invitations to the tunneling workshop.

Outreach

NADET Institute has prepared a new brochure describing both the broad NADET program and the role of the Institute within that program. It has been distributed to the NADET mailing list, and to those who call for information, and it is distributed at various meetings. A media package containing a greater sampling of NADET information and activities is in preparation. The NADET mailing list has tripled in the last year and now includes about 940 individuals and organizations.

NADET Institute has assumed editorial responsibilities for the NADET News and the next issue is nearing completion and will be published in late April, with a newly-designed format. Articles are now in preparation for future issues and additional suggestions or contributions are welcomed.

National Drilling and Excavation Test Site - NeTI

Researchers and developers in the drilling and excavation field, ranging from theoretical rock mechanics to massive equipment design, have long sought a national test site to facilitate research, testing, and demonstration. Such a facility is now being created at the Nevada Test Site (NTS). NTS is now managed by Bechtel-Nevada, with the mission to maintain a nuclear bomb test capability in the event the nation finds it necessary to return to such testing in the future. To help defray the costs of maintaining the facilities, equipment and work force, the Nevada Testing Institute (NeTI) has been established. NeTI is a not for profit corporation, providing commercial access to a comprehensive research, development, and demonstration facility for researchers and developers around the world. Facilities and personnel for drilling and excavation work and for explosive research (including explosive simulation of earthquakes) will be provided.

Drilling and excavation work at NeTI will be managed by NADET Institute, while explosive research will be managed by Stanford Research Institute. In keeping with the basic NADET concept, the test site will offer opportunities for cooperative testing and for "piggy-backing" of projects not otherwise possible. Participation in the management of this operation will add significantly to the credibility of the NADET Institute.

Formal announcement of the Nevada Testing Institute took place in a Las Vegas press conference on March 18. Early indications of world-wide interest in the facility are encouraging.

Conclusion

It is necessary, even from the single-industry viewpoint of geothermal power, that the NADET Institute support base be broadened, both for the additional funding that is clearly necessary, and for the technological benefits that will accrue from cooperative, inter-industry sharing of thinking and opportunities. At the recent ASME Energy Week program and exposition in Houston, an oil industry spokesman outlined the industry's R&D direction in terms of three new views:

- New technology is more critical than it has been to survive in world competition.
- The oil and gas industry must look outside this industry for new ideas and talent.
- The industry must look to collaborative research in support of the industry as a whole rather than to independent research in support of separate proprietary advantage.

These comments clearly support the format and intent of the NADET program. The NADET program is indeed industry driven. It should ultimately be largely industry supported, but the present status of industry -supported advanced research (to say nothing of inter-industry collaborative R&D) is such that government support will be required to establish the feasibility of collaboration, and to sustain core projects necessary for substantial advances. Securing significant new federal support for inter-agency cooperative R&D is, however, rather difficult in the face of greatly reduced federal research budgets. NADET Institute will vigorously seek a broader funding base, but it seems clear that some demonstration of technical merit, and some industry support of the cooperative format will be necessary before significant inter-agency funding can be expected. Broad R&D support from a variety of sources is as essential to the geothermal energy industry's future in this country as it is to the NADET Institute's survival.

NADET INSTITUTE REQUEST FOR PROPOSALS

The National Advanced Drilling and Excavation Technologies (NADET) Institute announces solicitation of prospectuses for advanced drilling technologies with primary interest in concepts relevant to geothermal drilling. NADET Institute is a research and development consortium supported by government and private funds that is administered by the Massachusetts Institute of Technology (MIT). Initial funding for NADET research has been provided by the Geothermal Energy Division of the U.S. Department of Energy. In order to exploit abundant geothermal energy resources, it will be necessary to reduce substantially geothermal well drilling costs.

The ultimate goal of this advanced drilling program is to reduce all drilling and excavation costs by 50 percent or more. That very ambitious goal cannot be achieved in a short time or by a narrowly focused program. While this solicitation focuses on relevance to geothermal drilling, clearly, advances in this area will be of benefit to many other drilling activities. This solicitation is intended to be the opening round in a multifaceted and sustained effort that, with funding from a wide variety of sources, can indeed achieve its goal of reduced drilling and excavation costs.

Present geothermal practices typically employ holes ranging in diameter from about 26 inches at the surface to 6 inches at depth, with depths from 5,000 to 10,000 feet. Hard rock (relative to oil-bearing formations) is typical, and fractured rock is often encountered. Bottom-hole temperatures typically range from 150°C to 350°C. Future operations may go to much greater depths and exploit higher temperatures, if enabling technologies can be developed.

Although geothermal drilling now uses drilling technologies and equipment adapted from the oil and gas drilling industry, at least six factors distinguish geothermal drilling and contribute to its higher cost. They are:

- harder rock or interbedded hard and soft rock,
- higher temperatures,
- more frequent lost circulation,
- increased corrosion and erosion of components,
- larger hole diameters, and
- remote, inaccessible drill sites

Drilling cost reduction within the range typical of geothermal drilling conditions is a function of many variables in addition to the instantaneous rate of penetration as determined by the drilling element. Thus, responses may address any or all of the above listed factors, singly or in combination. In any case, however, proposed work must be viewed within the context of a complete drilling system.

This solicitation seeks innovative, even revolutionary, approaches to the reduction of drilling costs. With limited initial funding and with the objective of identifying innovative approaches, a two-stage proposal response will be used. This announcement solicits brief, five-page (double-spaced, 12 pt. font) *prospectuses* consistent with the ultimate goal of drilling cost reduction. These prospectuses will be promptly evaluated by a review panel of technical experts, and a lesser number of full proposals will be invited in keeping with available funds and the development of an effective initial program. Approximately $1 million dollars is expected to be available for first year programs and, depending upon proposal quality, six to ten grants are anticipated.

This announcement solicits prospectuses from individuals, universities, corporations, government, national, and private laboratories and other qualified entities. Prospectuses must be received at the NADET Institute by 5:00 pm EST, on Monday, April 8. They will be promptly screened and invitations to submit full proposals will be issued to those projects that appear best suited to program goals. We will notify all submitters as to the status of their prospectus when the review process is complete. However, no review comments will be made available. Grants are expected to be awarded in July, 1996.

Both short- and long-range projects may be proposed, but the availability of funding beyond the initial grant cannot be guaranteed at this time. Joint proposals and cost-shared projects are encouraged, but a single principal investigator should be identified for overall contractual responsibility.

Each prospectus should include, within the five-page double-spaced limitation, the following material:

- title and description of the proposed work,
- a brief description of the total system within which the proposed concept will function, although it is not necessary to propose work on an entire drilling system,
- an estimate of the project budget on an annual basis, including any cost sharing from other sources,
- an indication of the potential cost/benefit of a successful concept,
- the name, address, telephone, fax and e-mail of a contact person, and
- very brief credentials of the proposed principal investigator and any other key personnel

In addition to the availability of funding, continuation of projects beyond the first year will depend upon first-year progress of each project. Reimbursement for cost overruns will not be available.

First-year deliverables include a complete technical report and participation in an advanced drilling symposium scheduled for July, 1997. The report should include a thorough evaluation of the concept's potential, an outline of the remaining program and cost to bring it to commercial fruition, and an indication of additional parties, if any, interested in participating in commercial development.

Information and descriptions contained in the prospectuses will remain confidential.

For further information, please contact the NADET office by phone at (617) 253-5782, by e-mail at nadet@mit.edu or by mail at the address below. Please be advised that only procedural questions can be answered by the NADET office. No additional technical information beyond this solicitation will be made available.

To submit a prospectus, please send five copies to:

US Mail: The NADET Institute
MIT E40-481
77 Massachusetts Avenue
Cambridge, MA 02139

Overnight: The NADET Institute
MIT Energy Lab, E40-481
One Amherst Street
Cambridge, MA 02139

Submittal by fax or e-mail is not allowed.

ADVANCED DRILLING SYSTEMS

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This paper discusses the methods and results of a study of advanced drilling systems sponsored jointly by the Department of Energy Geothermal Division and the Natural Gas Technology Branch, Morgantown Energy Technology Center[1].

A number of problems common to several concepts, as well as current rotary technology, are identified. Conditions under which novel cutting techniques can reduce drilling costs are discussed. Finally, the results of analyses of several advanced concepts are presented.

Introduction

Drilling is widespread in oil, gas, geothermal, minerals, water well, and mining industries. Worldwide expenditures in oil and gas drilling approach $75 billion per year. Lower cost wells could make it economically viable to exploit low yield and depleted oil and gas reservoirs. Drilling and well completion account for 25% to 50% of the cost of producing power from geothermal energy. Reduced drilling costs will reduce the cost of electricity produced from geothermal resources.

Attempts to improve or replace rotary drilling technology date back at least to the 1930's. Many novel and even exotic concepts were examined in the 1960's and 1970's and there has been some continuing effort through the 1980's. Much of this effort is documented in two books by Bill Maurer: *Novel Drilling Techniques* (1968) and *Advanced Drilling Techniques* (1980).

Undoubtedly, there are concepts for advanced drilling systems that have yet to be studied. However, the breadth and depth of previous efforts in this area almost guarantee that any new efforts will at least initially build on an idea or a variation of an idea that has already been investigated. Therefore, a review of previous efforts, coupled with a characterization of viable advanced drilling systems and the current state of technology as it applies to those systems, provides the basis for this study.

A Systems Approach

Nearly all studies of advanced drilling systems concentrate on methods of reducing rock. There is often little or no discussion of how these methods would fit into the full system necessary to drill, maintain, and complete a well. Unless the entire system is considered, much effort and money could be spent improving specific aspects of drilling technology only to discover that other facets of the problem prevent successful deployment of the system. Consequently, this study has not just investigated novel methods for reducing rock, but has examined all aspects of drilling systems necessary to drill and maintain a wellbore.

Basic Drilling Functions

- Energy transmission to the system-rock interface
- Rock reduction
- Debris removal
- Borehole maintenance while drilling
- Well control
- Preservation of the borehole

The six functions listed above must be performed by all drilling systems. The last factor

[1] Work performed at Sandia National Laboratories is supported by the U.S. Department of Energy under contract DE-AC04-94AL8500.

is not a necessary function in the sense that a well could be drilled without completion. However, completion is considered a basic function because (1) it is necessary for a well to be of any use and (2) it is a significant part of the cost of a well.

In addition to the drilling functions, all systems must operate under a number of technical requirements and institutional constraints including those in the following table.

System Constraints

- Environmental impact
- Operational safety
- Government regulations
- Directional drilling and control
- Sensing and communication

While we have generally classified drilling systems according to cutting mechanism, we have analyzed these systems according to how they perform the basic drilling functions given previously under the constraints listed above.

The table at right lists the concepts and systems that have been studied. This list evolved to cover the range from current technology, through ongoing efforts in drilling research, to highly speculative concepts. Included are cutting mechanisms that induce stress mechanically, hydraulically, and thermally.

Most, if not all, of the concepts listed will be familiar to anyone who has followed the efforts in the development of novel drilling systems. The only concept less than twenty years old is the pulsed-laser water-jet which has been proposed and investigated by PowerPulse Systems of Lakewood, CO (ref 3).

Many of the concepts are currently being studied or developed. Both Baker-Hughes and Fracmaster are developing coiled-tubing rigs (ref 4). FlowDril in Kent, WA (ref 5), Maurer Engineering in Houston, TX (ref 6), and TeleJet Technologies in Dallas, TX (refs 7 and 8) are in various stages of development of jet-assisted systems. Tround International of Washington, DC, has an operational projectile-assisted drilling system (refs 9 and 10). Tetra Corporation in Albuquerque, NM, is studying the use of spark discharge for reducing rock (ref 11).

Novatek in Provo, UT, has an operational mud hammer (ref 12). Researchers at MIT Energy Lab and at Los Alamos National Laboratory (LANL) have continued to study thermal spallation (ref 13). Worldrill has applied for a European patent on a device to reduce the number of conduits needed in thermal spallation (ref 14). LANL also has a program studying the use of a rock melting system for environmental drilling (ref 15).

Systems and Concepts

- Conventional rotary technology
- Coiled tubing drill rig
- Rotary-assist:
  - → Jet-assist
  - → Projectile-assist
  - → Thermal-assist (microwave)
- Mud hammer
- Thermal spallation
- Jet drilling
- Spark drill
- Explosive drill
- Rock melters:
  - → Electric heater
  - → Laser thermal
  - → E-beam
  - → Plasma arc
- Pulsed-laser water-jet

Methodology

The initial phase of this study consisted of general information and data gathering. During this time, we established an initial set of concepts and identified individuals and organizations involved with each concept.

We developed descriptions based on the six drilling functions and completed system layouts. Based on the layouts, we defined equipment and material requirements and began to identify the strengths and weaknesses of each system.

We initiated a series of technical discussions with individuals both currently and previously involved in drilling research. We engaged in two types of discussions:

- General discussions where we presented the project organization, direction, and goals and invited comments and criticisms; and

- Discussions of technical details concerning current and past research efforts on specific concepts and systems.

Throughout the study we collected cost and performance data not only on advanced drilling systems, but also on conventional rotary technology. We developed a number of models and analysis routines relating cost to performance requirements and used these models to compare each system to current technology.

Operating Costs

There are many ways to assess the viability of advanced drilling concepts. Instead of concentrating only on technical feasibility we also estimated the capital and operating costs of advanced systems. Due to excess equipment and low demand, rig rates today are artificially low. Thus, it was necessary to estimate the costs of a conventional rotary drilling system built from all new equipment and materials as a basis for equitable comparisons to the expected costs of advanced systems. Using these cost estimates, we calculated the performance required for the advanced systems to be economically competitive with conventional rotary drilling.

We estimate that it would cost over nine-million dollars to build and field an 18,000-foot conventional rig from all new equipment and materials. The rental rate for this rig alone would be about $12,900 per day. There would be an additional $6,200 per day in operator-incurred drill-site charges for a total daily rate of $19,100. Current daily rates for an 18,000-foot rig are about $13,200 ($7,000 rig rate plus $6,200 additional drilling costs to the operator). We estimated performance requirements for advanced systems competing both with existing rigs and with newly-built rigs which are more expensive but represent the future market.

Performance Requirements

Performance assessment for most advanced concepts is difficult. The technical maturity varies dramatically from concept to concept. Data for some systems include field tests, while other systems have not progressed beyond bench tests, and still others have yet to be tested as a system in any format. It is neither easy nor accurate to extrapolate expected performance characteristics from such data.

Instead of estimating performance capabilities, we estimated performance requirements. These requirements are based on the necessary penetration rate and life such that the advanced technology will cost no more than conventional rotary technology over a specific drilling interval.

The drilling interval chosen is a 12 ¼-inch hole from 4,000 feet to 8,000 feet, completed with 9 ⅝-inch casing. We considered three general rock types defined as soft (IADC Series 51x and 52x), medium (IADC Series 53x through 61x), and hard (IADC Series 62x through 74x). The penetration rates and bit lives assumed for current technology in each of these formations are given in the following table.

Estimated Rotary Bit Performance

	ROP	Life
Soft	40 fph	90 hr
Medium	15 fph	90 hr
Hard	7 fph	90 hr

In estimating interval costs, we included time and materials associated with drilling, hole conditioning, logging, casing, cement, testing, and well control. Under the requirement that the advanced technology cost no more than current rotary drilling, the result is minimum rate-of-penetration as a function of equipment life.

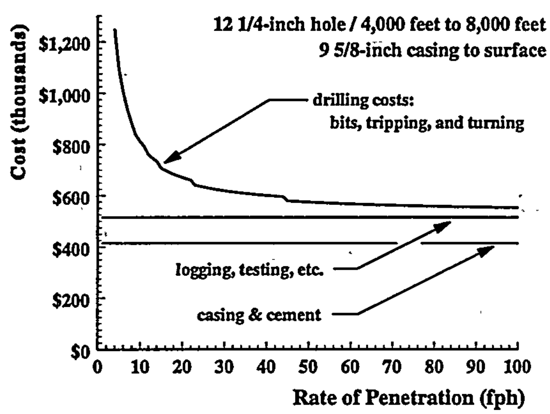
Most of the concepts we considered could be introduced to drilling either as rental tools or as capital equipment. To evaluate the concepts for either contingency required a method of estimating rental rates. We used a cash flow analysis that considered interest rate, capital investment, repair costs, mean-time-between-repair, expected life, idle time (time not on the meter), operational overhead, and profit margin. The rental rate was estimated under the requirement that income cover costs over the life of the tool. Profit margin was included as a percentage of costs and stand-by charges were estimated to cover capital expenses only.

Based on the methodology and the assumptions discussed in the previous paragraphs, the table at the end of this paper summarizes the estimated performance requirements. Data have been published to indicate that at least four concepts are capable of meeting these requirements: jet-assisted and projectile-assisted drilling, mud hammers, and thermal spallation.

Conventional Rotary Performance

We developed performance requirements for various systems and concepts under the constraint that drilling with these systems cost no more than drilling with conventional rotary technology. It is also informative to examine the performance of conventional drilling technology.

The breakout of the costs incurred in completing the defined interval with conventional technology is illustrated in the following figure.



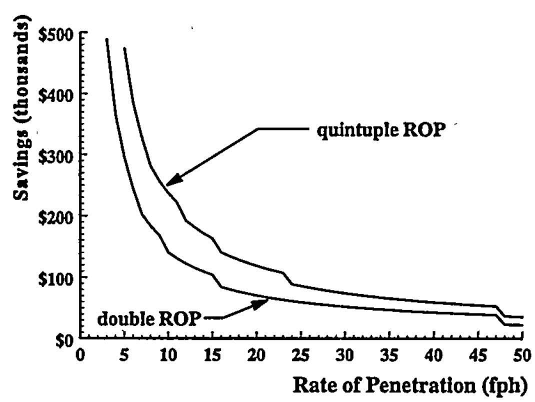
Interval Costs with Conventional Rotary Technology

The end-of-interval costs (i.e. casing, cement, logging, testing, etc.) do not vary with penetration rate. However, the costs of drilling (bits, tripping, and turning on bottom) vary significantly with penetration rate. Most of the systems and concepts we investigated would affect the costs of drilling.

Costs and Possible Savings

The performance requirements were developed under the constraint that the advanced technology cost no more than current technology in completing the defined interval. Another approach would be to estimate savings given a particular improvement in penetration rate.

In most cases, merely matching current performance would be insufficient for a system to achieve commercial success. A system would need to surpass current performance in order to earn acceptance in the drilling industry. Based on the same 4,000-foot drilling interval used previously, the following figure shows savings in dollars that could be realized if the penetration rate is doubled or quintupled while all other factors are held constant.



Possible Savings Through Improved Performance

As an example of how to interpret this figure, consider the possible savings at an ROP of 20 fph. This figure indicates that doubling the ROP would result in savings of about $70,000, while quintupling the ROP would yield savings on the order of $120,000.

The possible savings increases significantly as penetration rates decrease below fifteen feet-per-hour. This region is a particularly attractive target for systems whose primary advantage is to increase the rate of penetration.

Based on the previous figures and discussion, the greatest opportunity for reducing costs through improved rock cutting techniques is in hard-rock drilling. That has been the experience of people who have attempted to market new techniques for cutting rock.

Common Problems

We took a systems approach to avoid overlooking some facet of the problem that would prevent successful deployment of a system; however, there has been another consequence of the systems approach: we identified a number of common problems that run across multiple systems. The solution to one of these problems could advance the viability of all the systems cross-cut by that problem. These common problems include the following:

- Multi-channel conduit,
- Electric conductor downhole,
- Maintenance of the borehole gage,
- Control of stand-off distance,
- Trajectory control,
- Well control and wellbore stability in the absence of liquids,
- Reduced effectiveness with depth, and
- The size of the surface system.

Multi-Channel Conduit

A number of the systems under consideration require multiple conduits for the transmission of different fluids and/or electrical energy. Multi-conduit pipe can be manufactured. FlowDril used dual-wall pipe for their system and TeleJet Technologies has designed multi-conduit pipe for the MultiCon™ system. Low-pressure, concentric drill pipe is available commercially in the U.S. When compared to standard drill pipe, it is generally heavy, expensive, and difficult to handle.

Electrical Transmission

A number of systems would benefit from cheap and reliable methods to transmit electricity to the drill head. This is especially true for high-energy systems. Even rotary technology would benefit from such a development. A power cable would allow the use of electric motors, actuators, and control systems. The development of fast, reliable telemetry would allow not only the use of current downhole sensors such as pressure, temperature, and formation evaluation tools, but also the development and use of systems to evaluate the condition of the bit and BHA, to detect kicks almost instantaneously, and to provide data for real-time analyses of downhole conditions.

Borehole Gage

Maintenance of borehole gage and trajectory is a concern for nearly all of the system concepts that are not rotary hybrids. For a given set of conditions, the diameter of the hole created with high-pressure jets and thermal systems will depend largely on the advance rate of the drilling head. There is a minimum hole diameter needed for running casing. Above this minimum, though, excessive variation can cause problems when cementing the casing.

Control of Stand-Off Distance

The efficiency of most systems that do not maintain direct contact with the rock is dependent on stand-off distance. A simple solution is a mechanical probe, but some systems may require a more elaborate mechanism. It is not clear that a universal stand-off control system, cross-cutting several systems, can be developed.

Trajectory Control

For most cutting mechanisms including rotary drilling, the direction of advance is determined largely by the direction of the face of the drilling head. For many systems that are not rotary hybrids, a simple bow-spring or rolling support may be adequate for vertical drilling. However, a more sophisticated thruster-director may be advantageous for directional drilling and may be necessary for highly deviated and horizontal drilling.

Well Control and Wellbore Stability

A number of the concepts investigated cannot operate under a full column of liquid. While cuttings can be removed with air, the absence of drilling mud greatly inhibits the ability to control formation fluids. Also, the contributions of drilling muds to wellbore stability through static pressure and chemical additives are lost. The applicability of any system that cannot operate in the presence of drilling mud is diminished.

Since most formations drill faster with less wellbore pressure, a quick way to increase penetration rate with rotary technology is to lighten the drilling mud even to the point of drilling underbalanced. Improvement of methods to control formation fluids and maintain borehole stability while drilling underbalanced could significantly increase penetration rate and reduce drilling time.

Reduced Effectiveness with Depth

As with rotary drilling, several of the advanced concepts have demonstrated reduced cutting effectiveness with depth. Although this effect may not be universal, it is common enough to suggest that there is still a need for better understanding of depth and fluid pressure effects on rock properties as they apply to drilling.

More importantly, these experiences imply that a first step in the development of any new drilling system should be to test the performance of the concept at depth. Existing facilities can independently simulate pore pressure, rock stress, and borehole fluid pressure at depth. Unconventional rock-cutting concepts should be tested at one of these facilities prior to the expenditure of significant resources on system development.

Size of the Surface System

The investment necessary to build a land-based rig capable of drilling to 18,000 feet from all new materials and equipment is over nine-million dollars with the vast majority of this expenditure in the surface system. The size, cost, and complexity of the rig's surface system is little affected by the way we cut rock.

The sizes and specifications for the mast, substructure, and drawworks are determined by the need to handle casing. The requirements of the mud pumps, pits, and mud-cleaning equipment are determined by the size of the cuttings and the rate at which they are produced.

About the only equipment that depends on how we cut rock is the bottom hole assembly. It is doubtful that any novel rock cutting mechanism will cost less than drill collars, stabilizers, and bits. Overall, it is unlikely that significant savings in materials and equipment can be achieved by simply changing the way we cut rock.

Similar conclusions are reached when daily operational costs are considered. The numbers and skills of the crew are determined by the surface equipment. Rig insurance is determined by capital investment; liability insurance and workman's compensation costs are proportional to payroll. While we are turning on bottom, the power delivered to the rotary table or top drive is generally less than 30% of the total power usage on the rig. And, in any event, all rock-cutting mechanisms require energy delivery in some form.

Reduction of drilling costs can occur only by changing the nature of the drilling system or by increasing the rate of penetration. Neither capital investment nor daily operational costs are significantly affected by the way we cut rock. Any increase in capital or operating costs must be offset by a commensurate increase in penetration rate. Unconventional rock-cutting mechanisms can reduce costs only if they can increase the ROP.

Summary

The authors wish to thank the sponsors for their support throughout this study. This paper has presented an overview of the methods and a summary of results of a study of advanced drilling systems. Much greater detail will be included in the final report, *Advanced Drilling Systems Study*, SAND95-0331.

A number of problems common to several advanced concepts, as well as current rotary technology, have been identified. Solution to one of these problems could help multiple systems.

The surface system dominates the capital investment in drilling systems. New rock cutting techniques can do little to influence the size of this investment, so these mechanisms must out-perform conventional rotary technology in order to reduce well costs. The greatest opportunities for reducing costs through improved rock cutting techniques are in formations that limit current rotary technology to penetration rates below about fifteen feet-per-hour.

Analyses of advanced cutting concepts indicate that many can be competitive if they increase penetration rate by factors ranging from just over one to about five. Based on published data, this performance is within reach of some systems, particularly mud hammers, jet-assisted and projectile-assisted drilling, and thermal spallation.

We hope that these efforts will be of use to project managers and policy makers in making decisions concerning the expenditure of resources for the development of drilling systems.

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Summary of ROP Requirements			
	Soft	Medium	Hard
Fully integrated coiled-tubing rig	1.5 - 3.5	1.4 - 2.3	1.4 - 2.1
Jet-assist			
Surface pressure generation	> 3.4	2.2 - 5.0	1.9 - 3.4
Positive-displacement DHP	1.7 - 2.0	1.6 - 1.9	1.6 - 1.9
Centrifugal DHP	1.6 - 1.8	1.5 - 1.7	1.5 - 1.7
Projectile-assist	2.2 - 3.2	2.0 - 2.5	1.9 - 2.3
Microwave-assist	?	?	?
Mud hammer	1.4 - 1.6	1.3 - 1.5	1.3 - 1.5
Thermal spallation			
Downhole separation	1.1 - 1.4	1.1 - 1.3	1.1 - 1.2
Spark drill	?	?	?
Explosive drill	?	?	?
Pulse laser-water jet (3,500-hr life)	~ 2.5	~ 1.7	~ 1.5
Rock melters	?	?	?

Notes:

1. The values are the necessary increase in ROP when compared to a conventional rotary system operating at a total drill-site cost of $13,200/day.
2. The ranges were generated by varying the cost estimates for the advanced technologies by ±25%.
3. A question mark, "?", indicates insufficient data and information to complete the analysis of performance requirements.

Development and Field Use of a Memory-Based Pressure/Temperature Logging Tool for the Geothermal Industry

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Geothermal Research Department
and
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Department of Geological Sciences

Abstract

A memory-based logging tool for pressure and temperature measurements has been developed for the geothermal industry. This tool is low in cost, easy to field, and is calibrated for high accuracy. Uses of the logging data are explored for tracking reservoir conditions, logging-while-drilling, and lithology. Well temperature gradients at 0.001°C/m are measured and found repeatable, giving evidence for detection of changing lithology.

Introduction

Sandia has designed and produced three prototype memory logging tools for geothermal applications. To date, each tool has been calibrated and used at least once to log a geothermal exploration or production well. The three tools are Pressure/Temperature, Spectral Gamma, and Steam Sampler.

A geochemical sample taken by the steam sampler from a Geyser production well was proven valid by laboratory analysis. In future applications, geochemical samples could be taken from differing well production zones. Zones producing high levels of caustic fluids could be sealed off, greatly increasing plant service life.

The spectral gamma tool was used in a well at the geysers after coring was completed. The spectrum revealed increased levels of potassium (K40) at areas of loss circulation.

Potassium along with uranium and thorium are naturally occurring radioactive materials found in nature. The occurrence of these elements provides insight to the wellbore lithology, even through steel casings.

The Pressure/Temperature tool was the first tool prototyped and has seen the most field testing. This tool is the primary subject of this report.

Pressure/Temperature prototype tools have been built, calibrated, and tested in both geothermal slim hole exploration wells and larger production wells. The prototypes demonstrated high dependability, logging seven different wells last year for more than thirty logging runs without failure or loss of data. The prototypes have been flown via commercial air as normal baggage ready for logging from various platforms as large drilling rigs, small tailored slick line systems, or conventional logging trucks. Figure 1 shows the tool and support equipment ready for travel.

The next step in the Sandia process is to demonstrate the usefulness of memory logging tools for pressure/temperature measurements to the geothermal industry. There are two categories of tool uses from differing industrial consumers. The plant operator/owner needs to track changes in reservoir conditions as resources are utilized over the life of power production. This application requires calibrated instruments giving accurate measurements year after year. The exploration customer needs cost-effective logging. Logging requires high reliability, ruggedness, and fast logging rates to minimize drilling down time. Both customers need to better understand that information can be discerned from well temperature and pressure measurements.

To better utilize temperature measurements, a cooperative effort was undertaken with Dr. David Blackwell of Southern Methodist

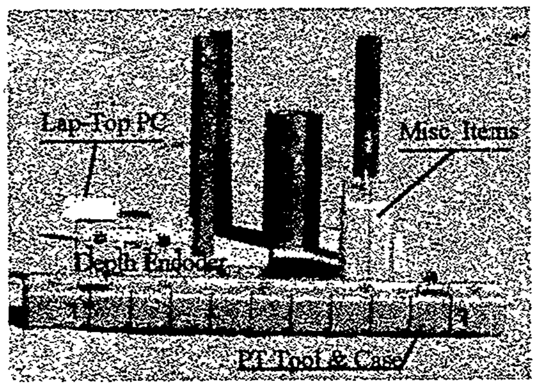

Figure 1. Complete travel package ready to log at a well. The components are:Lap-Top PC, Depth Encoder, PT Tool & Case, & Case of Misc. Items.

University, (SMU). The thrust of this work is to extend temperature logs for well temperature gradient measurements. Temperature gradients provide insight to well lithology, flow zones, and possibly other well conditions. An overview of the gradient process calculation, measured results, noise problems, and proposed solutions are given.

Specifications

Table 1 is a list of tool specifications. In general, the tool is a microprocessor-based memory tool. It operates within a dewar flask powered by either common 3V camera style batteries or 200°C rated lithium cells from Battery Engineering Inc, Hyde Park, MA.

The specifications of Table 1 were taken from the prototype tool used for logging in 1995. Small changes to the tool electronics were completed early in 1996 and will improve several of the specifications. The main changes are increasing the sample rate, sampling temperature and pressure simultaneously, and increasing the maximum number of data points. These changes will improve dynamic temperature measurements for faster logging rates, more accurate temperature gradients, and tracking well temperature changes during flow testing.

Table 1. List of Specifications

Accuracy Temperature	±0.3°C
Resolution Temperature	±0.005°C
Temperature Range	0-500°C
Accuracy Pressure	0.1psia
Resolution Pressure	0.01psi
Pressure Range	0-6000psia
Temp. Response, τ	0.206 Sec^{-1}
Max. Sample Rate	8 Sec/Sample
Maximum # of Points	3000 each P/T
Dewar Construction	Stainless Steel
Tool Diameter	50mm
Tool Length	1.9m
Batteries Cost	5 cells-$30 or $150*
Approximate Cost	$15K
Software	IBM Compatible
Depth Encoder	Programmable, ac/dc with real-time readout, Depth & Rate

**High Temperature 200°C batteries.*

The temperature response specification of 0.206 s^{-1} is a measure of the tool dynamic temperature response to a step input. This value was taken from tests conducted in the lab using the complete tool assembly and two tanks of water, one near freezing, the other slightly heated. The response is useful in determining maximum logging rates for temperature correction. The logger can correct some of the ill effects of logging at high rates. Conaway, (1977) used Eq. 1 for correcting temperature lags caused by logging rates and changing temperature gradients.

$$T = T_m + (1/\tau)*DT_m/dt, \quad (1)$$

Where T is the actual temprature, T_m is the measured temperature, and τ is the temperature response.

Applications

Fly-In, Shut-In, Pressure Testing

In the course of drilling a geothermal slimhole exploration well near Vale, OR the drilling personnel wanted to evaluate formation permeability. The core samples looked promising. A pressure shut-in test for estimating the transmissivity (permeability-depth product) was requested. The pressure tool was held stationary in the well just above the flow zone. The flow zone was inferred from prior temperature logs of the well. Using drilling pumps, a hydrostatic head was built up and then allowed to fall

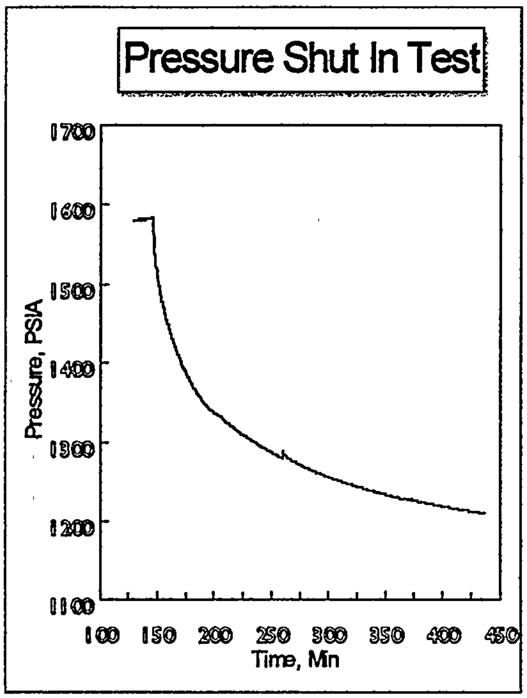

Figure 2. Pressure Shut In Test for Permeability.

off. The pressure seen by the tool also fell, see Figure 2, as the wellbore fluid moved into the formation.

The rate at which the pressure falls is indicative of the transmissivity of the formation. The estimate of transmissivity for this data was 0.077 Da-m or 0.253 Da-ft.

This test is more interesting than just the pressure data. The logging tool, encoder, and PC had been flown to the site along with two Sandia personnel only the day before. The tool was lowered into the well not by a logging truck but via the slick line on the drill rig. Another facet to this test was the first use of computer logic inside the tool to self initiate data collection.

The tool was programmed to start taking data when the external pressure readings exceeded 50 psi. This allowed the tool to be ready whenever the drilling crew was ready. The tool could wait almost indefinitely without impacting other ongoing drilling processes and simply start taking data when submerged.

A number of other logging runs were conducted in such a manner, including a well temperature response log.

"Opportunity-Knocking" Temperature Test

The use of drilling muds while drilling causes the formation to cool. When the drilling fluid flow stops, the formation begins to recover.

By having a memory tool available on the drilling platform, opportunities arise when the drilling is stopped and a measure of temperature rise can be made. These opportunities arise from a number of common situations such as servicing the engines, waiting for a change of drilling instructions, or mud pump breakage. Figure 3 shows the recovering of a well while the drilling was stopped. Again, the tool was lowered into the well by the drilling crew using the rigging on the platform. The tool remained at the point of interest for several hours. By solving for τ and then 'a' in Eq2. an estimate of maximum recovery temperature can be calculated.

$$Temp = a*(1 - e^{-t*\tau}), \quad (2)$$

Where Temp = Maximum temperature 'a' as t approaches ∞.

After a five-hour log the well temperature had reached 102.4°C. The calculated maximum temperature from Eq. 2 was 105.8°C for this well at this depth.

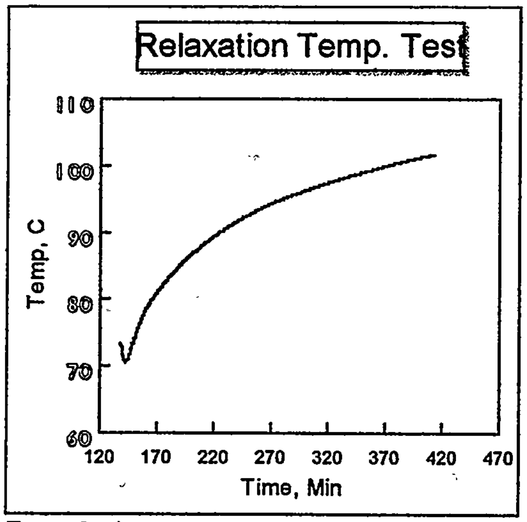

Figure 3. A momentary stoppage is time enough to measure well temperature recovery.

As a result of these successful logs off of the drilling platform, the geologist asked if he might own such a tool. This thinking leads to new markets for low-cost memory tools. The drilling site geologist or drilling platform owner could own their own logging tools. This methodology greatly reduces the logging cost and could give drilling companies and/or field geologists new facets for increasingly competitive markets.

Advancing Temperature Gradient Measurements

Low-cost, high-precision memory temperature tools are opening the door to improved well characterization. Continuous temperature logs produce detailed temperature data with characteristics unique to the well.

Characteristics suggest production zones, lost-circulation zones, changes in lithology, steam-liquid interfaces, ect. Some characteristics are easiest seen if the log is performed while drilling. Characteristics of

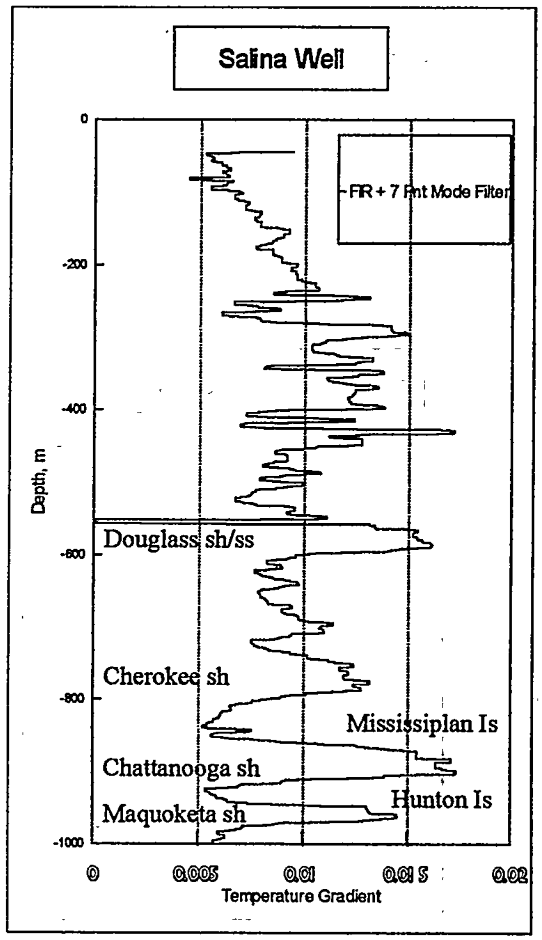

Figure 4. Temperature gradient mapping changing lithology.

lost-circulation zones from newly drilled exploration wells are viewed as candidates for fluid or steam production, Lysne (1994). Other characteristics appear after the well has stabilized at temperature. Temperature gradients give insight to changing lithology similar to gamma and sonic logs, Blackwell and Steele, (1989).

In cooperative temperature logging with Dr. David Blackwell at SMU, the Sandia pressure/temperature tool and other temperature well logging tools were used to make comparative measurements of well temperature gradients. Two SMU students, Ken Wisian and Dr. Stefano Bellani, performed the logging using a slick line trailer. This simple logging system in conjunction with the use of memory tools allows for inexpensive well logging.

The first test well was a 1050 m well near Salina, KS. This well was drilled in 1980 by the USGS as a disposal test hole. The well is fully cased in steel and had been undisturbed since 1981. The lithology of the well is known and documented.

Figure 4 shows the results of the Salina well temperature gradient log. Gradients ranging from 0.005°C/Ft to 0.015°C/Ft clearly show changing lithology. Major lithology formations are labeled. Lithologies increasing the temperature gradient are labeled to the left and lithologies reducing the gradient are to the right. These differing temperature gradients are primarily due to differing heat conductivity of the formation.

Temperature gradient information for detecting lithology is only useful at hundredths of a degree Celsius and below range. At these low levels many sources of noise corrupt the measurement. (electronic noise, convection cells, system nonlineararity, logging speed errors, and others). These noise errors are exasperated by the gradient calculation from the two measured variables T and D as shown Eq. 3.

$$\text{Gradient } n = (T_{mn+1}-T_{mn-1})/(D_{mn+1}-D_{mn-1}), \quad (3)$$

Where n is an index for measured points, T_m and D_m are measured values at index n for temperature and depth.

Some filtering was performed on the data shown in Figure 4. The filtering does not add information to the data, but makes it easier for the user to see signal structures. The filtering in this case was a two-step process. First, a linear finite impulse response (FIR) filter used on the temperature readings to improve measurement lineararity. After the gradient calculation of Eq. 3, the temperature gradient is filled with shot-like noise, resulting from the division of two measurements. The second step removes shot noise by using a nonlinear seven-point median filter. The FIR and median filters are easily implemented in Microsoft Excel or Lotus 123. For copies of these algorithms contact either of the Sandia authors.

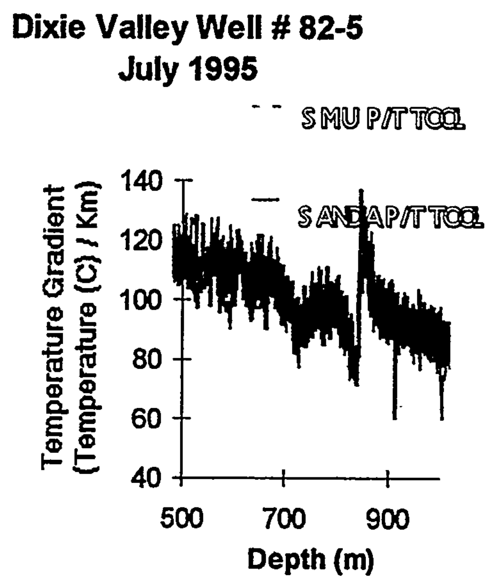

Figure 5. Temperature Gradients from two different logging tools showing signal similarities.

After the success in Kansas, other geothermal wells were logged. Less is known about these wells and their temperature gradients. To separate repeatable well characteristic signatures from non-recurring noise, wells were often logged twice using different instrumentation. This situation will change after developing signal processing algorithms for separating noise from useful information.

An example of surprising data similarities can be seen in Figure 5. Both tools follow the same general temperature gradients. Note the signature between 700 and 870 m. This variance is believed to be caused by cold water flowing around the casing. However, temperature tools are designed to make accurate absolute temperature measurements for comparing well temperatures, not **dynamic** temperature gradients inside the well. By examining differing well temperature responses and knowing the measurement system characteristics, a strategy to optimize well temperature logging for dynamic temperature measurement will develop new uses of the information.

Future of Memory Tools

The future of memory tools starts with informing the geothermal community of their ease of use and effectiveness of operation. The present circumstances of competitive markets and lower profits force operators into a conservative corner. In the short term, it is less risky to perform business as usual.

To overcome this thinking, geothermal logging instrumentation must be proven in the field by field personnel. The benefits of such instrumentation must be learned first hand. For the temperature/pressure tool it must detect loss circulation, flow zones, declining reservoir resources before loss of power production, and so on. Practical examples of useful pressure/temperature measurements can be found in technical literature. What is now needed is getting geothermal logging instrumentation into the hands of field operators.

Once these uses are realized, the tools must be calibrated to give consistent results. Logging processes must be simplified to the point that almost any on-site personnel can perform the log. Without consistent results the information may do more harm than good.

All Sandia tools are calibrated using calibration procedures approved by the calibration standards lab at Sandia. SMU and Sandia are working to expand uses of pressure/temperature data. Small changes in the temperature gradient provide clues to lithology and well characteristics.

Acknowledgment

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Session 6:

Direct Use and Geothermal Heat Pumps

Chairperson:

David Anderson
Geothermal Resources Council

A CAPITAL COST COMPARISON OF COMMERCIAL GROUND-SOURCE HEAT PUMP SYSTEMS

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Geo-Heat Center
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ABSTRACT

The ground-source heat pump industry is focusing a great deal of effort on reducing system first cost. For the most part, this effort has been directed at ground-coupled systems. This paper explores two other ground-source system types (hybrid and groundwater) and compares their costs to ground-coupled systems. Costs were developed for the three system types over a range of soil temperatures, well depths, building load characteristics and other parameters. Results show that reductions in capital cost of 20 to 80% can be achieved with hybrid and groundwater systems compared to ground-coupled systems.

GSHP DESIGN CONSIDERATIONS

Unitary ground-source heat pump systems for commercial buildings can be installed in a variety of configurations. The oldest and, until recently, most widely used approach was the groundwater system. In this design (Figure 1), groundwater from a well or wells is delivered to a heat exchanger installed in the heat pump loop. After passing through the heat exchanger (where it absorbs heat from or delivers heat to the loop), the groundwater is disposed of on the surface or in an injection well. The use of an injection well is desirable in order to conserve the groundwater resource.

A second and increasingly popular design is the ground-coupled heat pump system. In this approach (Figure 2), a closed loop of buried piping is connected to the building loop. For most larger commercial applications, the buried piping is installed in a grid of vertical boreholes 100 to 300 ft deep. Heat pump loop water is circulated through the buried piping network absorbing heat from or delivering heat to the soil. The quantity of buried piping varies with climate, soil properties and building characteristics, but is generally in the range of 150 to 250 ft (of borehole) per ton of system capacity. Borehole length requirements are almost always dictated by heat rejection (cooling mode) duty for commercial buildings.

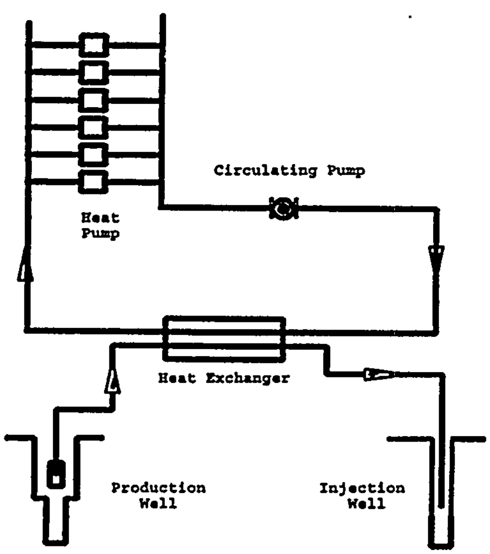

Figure 1. Groundwater heat pump system.

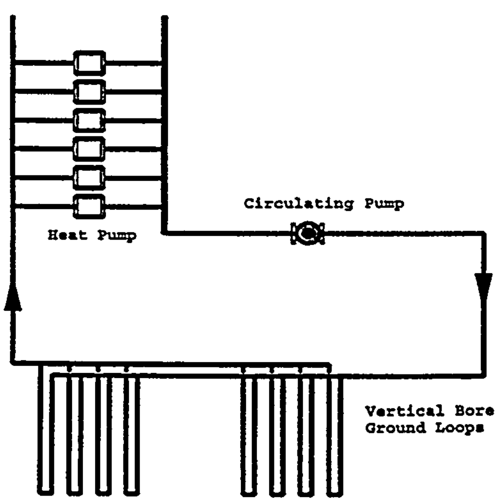

Figure 2. Ground-coupled heat pump system.

A third design for ground-source systems in commercial buildings is the "hybrid" system. This approach (Figure 3) may also be considered a variation of the ground-coupled design. Due to the high cost associated with installing a ground loop to meet the peak cooling load, the hybrid system includes a cooling tower. The use of the tower allows the designer to size the ground loop for the heating load and use it in combination with the tower to meet the peak cooling load. The tower preserves some of the energy efficiency of the system, but reduces the capital cost associated with the ground loop installation.

In addition to the three designs discussed above, ground source systems can also be installed using lake water, standing column wells and horizontal ground coupled approaches. This article focuses on the three former schemes due to their wider use and broad potential application.

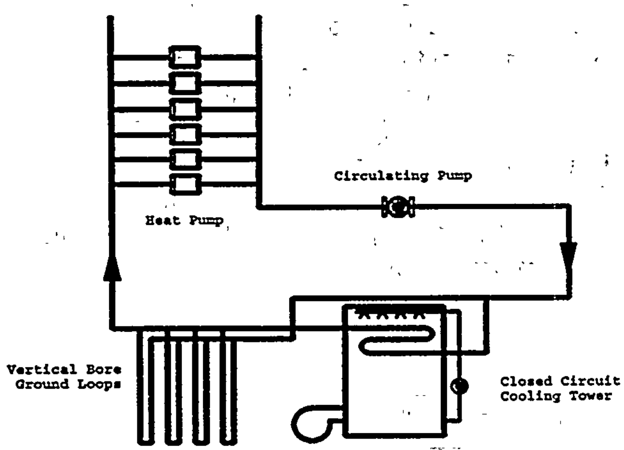

Figure 3. Hybrid ground-coupled heat pump system.

The purpose of this article is to compare capital costs associated with the three designs. Specifically, the costs considered are those associated with the heat source/heat sink or ground source portion of the system. In order to standardize the heat rejection over the three designs, it was assumed that the heat pump loop would operate at a temperature range of 85° (to the heat pumps) to 95° (from the heat pumps) under peak conditions. The assumption of constant loop temperature conditions for all three permits an apples-to-apples comparison of the alternatives.

The following items are included in the costs calculated in this article.

Groundwater system:
- Production well (or wells)
- Production well pump test
- Production well pump
- Well pump variable-speed drive
- Buried piping (wells to building)
- Heat exchanger
- Heat exchanger controls
- Injection well
- Injection well test
- 15% contingency factor

Ground-coupled system:
- Vertical borehole
- Loop installation
- Header piping and installation

Hybrid system:
- Vertical boreholes
- Loop installation
- Header piping and installation
- Closed circuit cooling tower
- Tower pad
- Tower piping
- 15% contingency (on tower and accessories)

Commercial building is a term which can cover a very broad spectrum of sizes from a few hundred square feet to several million square feet. The range selected for this article includes system sizes from 50 to 500 tons. Using an average value of 300 ft^2 per ton, this translates into a building area range of 15,000 to 150,000 ft^2. Buildings in this size range comprise the bulk of the commercial building stock in the United States.

In order for the results to be as broadly applicable as possible, cost calculations were made for a wide variety of soil (or groundwater) temperatures, well depths (groundwater), loop lengths (ground coupled) and tower/loop ratios (hybrid system).

It is common in the ground-source heat pump industry to refer to costs for the ground source portion of the system on a cost per ton basis. In keeping with this practice, most cost data presented for this article is expressed in terms of cost per ton. It is important to note, however, that the cost per ton refers to the actual load imposed on the ground source portion of the system. This is not the same as the installed capacity of the equipment. Due to load diversity, the peak load imposed upon the heat rejection equipment is always less than the total installed capacity. The load used for cost calculations in this article is frequently referred to by engineers as the block load.

RESULTS

Costs were developed for three groundwater/soil temperatures 50°, 60° and 70°F representing northern, central and southern climates. For brevity, only the results for the 60° cases are presented. These costs address only the groundwater portion of the system.

Figure 4 presents the results for the 60°F groundwater case assuming the use of a single production/injection well pair to serve the system. The four curves shown indicate costs (in $/ton) for four different groundwater well depths: 200, 400, 600 and 800 feet. In all cases, the values shown include costs for the production wells, well flow testing, production well pump, pump variable-speed drive, buried piping for transport

Groundwater System Cost
1 Well - 60 F Water

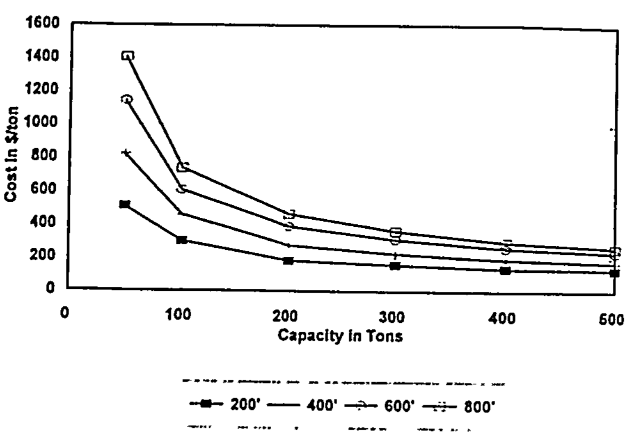

Figure 4.

of the groundwater to the building, heat exchanger to isolate the groundwater from the building loop, heat exchanger controls, injection well, injection well flow testing, and a 15% contingency factor. As indicated, the depth requirement for the wells has a substantial impact upon the installed cost. In addition, the unit cost for small systems (50 - 100 tons) is often higher by a factor of 3 compared to costs for larger systems (300 - 500 tons).

In many cases, a single production/injection well pair may not be capable of producing (or injecting) the required system flow rate. To address this situation, costs were calculated for systems using 2 production wells and 2 injection wells. In addition to the wells, adjustments were also made in well pump, piping, and testing costs to accommodate the installation of the additional wells. Figure 5 presents these costs for 200 and 600 foot well depths and system sizes of 100 to 500 tons.

Groundwater System Cost
2 Well - 60 F Water

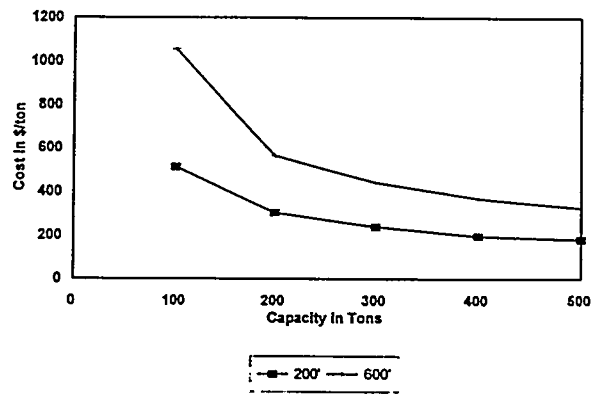

Figure 5.

For ground-coupled systems, actual project costs rather than calculations were used. Costs for these systems are a function of two values--the number of feet of borehole necessary per ton of heat rejection, and the cost per foot for completing the vertical bore and installing the piping. For purposes of this article, the values of 150 feet per ton for 50°F soil, 200 feet per ton for 60°F soil, and 250 feet per ton for 70°F soil have been used. To arrive at a cost per ton, a value of $5 per foot of bore has been used. Although some recent projects have been the beneficiary of costs as low as $3.75 per foot and one as low as $3 per foot, many areas of the country are still reporting costs of as much as $15 per foot.

Hybrid systems include both a ground loop and a cooling tower. The ground loop is sized to meet the heating load and, it along with the tower, is used to meet the cooling heat rejection load. As a result, hybrid system costs are a combination of ground loop costs and cooling tower costs. Using the $5 per foot value for the hybrid ground loop portion and vendor quotes for the cooling tower, Figure 6 shows the cost per ton for the hybrid system based on 60°F soil temperature. Hybrid system costs were also developed for 50° and 70°F soil. The four curves shown for the hybrid system reflect costs for different ratios of heating loop length versus cooling loop length. As indicated, hybrid systems enjoy more favorable economics as the heating ground loop length decreases as percentage of the cooling ground loop length requirement. This is because the cost per ton of the cooling tower is less than the cost per ton of the ground loop.

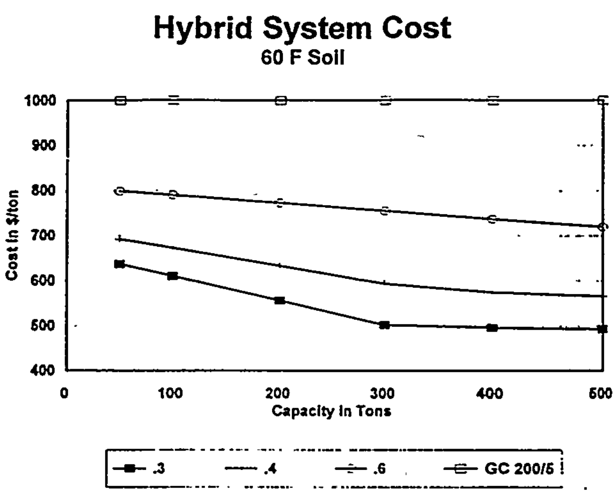

Figure 6.

Generally, the hybrid system is attractive in situations where ground loop costs per ton are high, and where the heating loop length requirement is low relative to the cooling loop length requirement.

Figure 7 presents a comparison of the three types of systems for 60°F soil. The ground-coupled system cost line is based upon $5 per foot and 200 ft per ton ($1000 per ton). The two hybrid system curves are based upon loop length ratios (heating ÷ cooling) of 0.30 and 0.40 evaluated in this article. These are the most favorable conditions for hybrid systems. The two groundwater curves are based upon 200 ft wells and one production/injection well pair (lower curve) and two production/injection well pairs (upper curve). Again, these are the most favorable conditions calculated for groundwater systems in this article. It is clear that, based on these conditions, the groundwater system enjoys substantial capital cost advantage over the remaining two systems over the entire range of capacity covered.

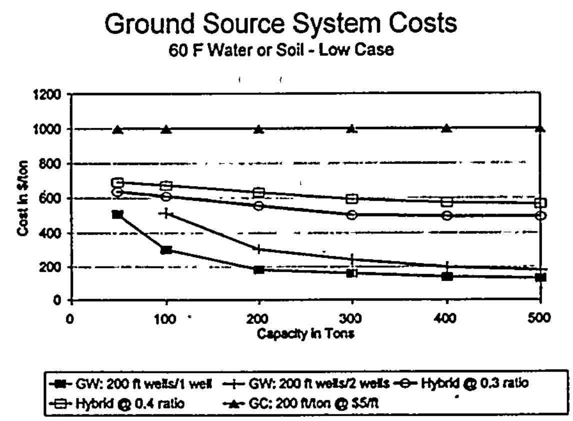

Figure 7.

Figure 8 presents additional data for the 60°F soil case. Again, the ground-coupled line is based on 200 ft per ton and $5 per foot. The two hybrid system curves are based upon loop

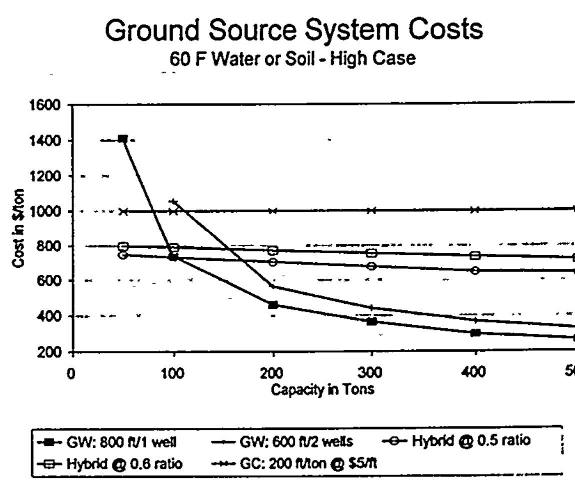

Figure 8.

length ratios of 0.50 (lower) and 0.60 (upper). These are the least favorable conditions for the hybrid systems covered in this article. The two curves for the groundwater system are based upon a single production/injection well pair at 800 foot depth (lower curve) and two production/injection well pairs at a 600 foot depth. These are the least favorable conditions for the groundwater system cover in this article.

As indicated at system capacities of 100 - 175 tons and above, the groundwater system has the capital cost advantage over hybrid and ground-coupled systems. Below this range, the hybrid system is the most attractive. It is only under conditions of less than 100 tons with well depths of 800 feet, that the groundwater system capital cost exceeds that of the ground-coupled system. To emphasize the cost advantage of the ground-water system for large heat pumps, Figures 9 and 10 portray the cost comparisons for the three systems in a bar graph format. The graphs are based on groundwater systems with 400 ft production and injection wells, hybrid system at a loop length ratio of .30, and ground-coupled system at 200 ft/ton and $5.00 per foot.

This article addresses only system capital cost. In the process of system selection, other issues should be considered as well. These would include operating costs such as electricity for pumps and fans, water treatment costs (tower) and regulatory issues with respect to groundwater. As a result, system capital cost provides only a portion of the information required for informed decision making.

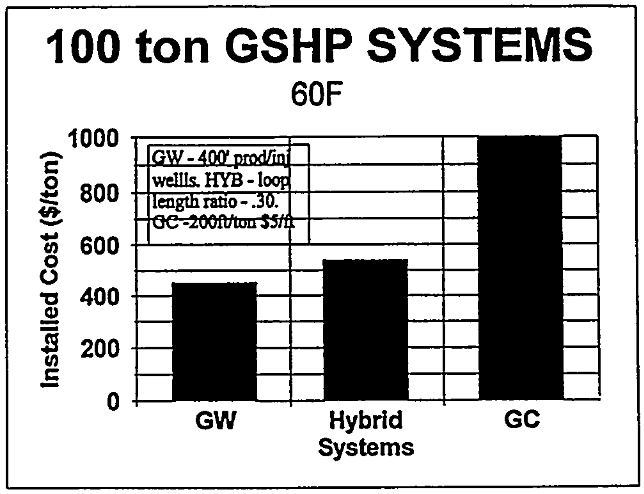

Figure 9.

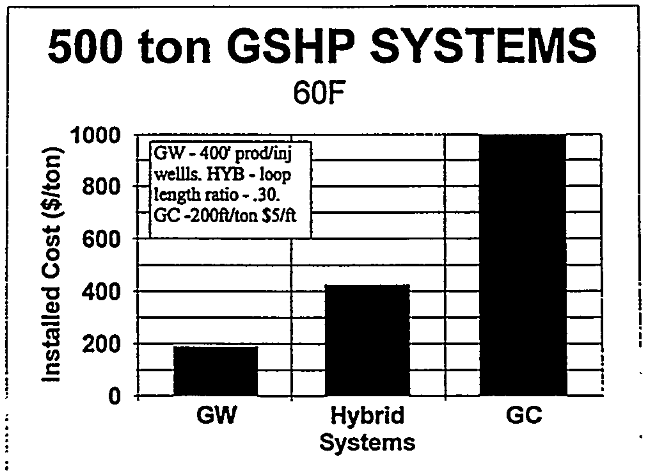

Figure 10.

Geothermal Heat Pump Consortium

Paul Liepe
Geothermal Heat Pump Consortium

PAPER NOT AVAILABLE

Session 7:

Cutting Costs Panel Discussion

Moderator:

Phillip Michael Wright
Earth Sciences and Resources Institute
University of Utah

Introduction

Mike Wright, Moderator
Earth Sciences and Resources Institute

We have a distinguished panel that most of you recognize. What we want to do for a couple of hours this afternoon is to explore how we can cut costs off everything we do in geothermal development. From initial concept to finally putting power online, any cost we can cut results in a drop in the power price that we have to charge and makes us more competitive. We are in a very competitive world, we have heard a lot about that. While we now are not the lowest cost energy producer, we are not too far out of the picture. We are not out in left field.

I was impressed when Darcel Hulse showed the results of some modeling that Unocal had done. His results indicate that if we can achieve reasonable cost reduction, say 20 percent in some of the steps in geothermal development, it will have a very significant effect on the bottom line. He talked about achieving cost reduction through development of better technology. Tom Mason talked about how CalEnergy has been able to get their costs down through combining management functions and creative financing of business options, certainly a legitimate way to approach cost cutting, too. Tom cited O&M costs of less than 2 cents per kilowatt-hour, which is pretty good. Some of the latest bids for geothermal power in the California BRPU, which were never signed, indicated that new geothermal power can be put online in the range of 4.5 to 6.5 cents per kilowatt-hour. We are not too far out of being competitive and having a market here in the United States. Among the renewables, our chief competitor is wind. If we are able to get adoption of a portfolio standard here in California, which would require a certain percentage of new generation resources to come from renewables, our competition will be wind. We are pretty darn competitive now, but we still need to concentrate on lowering our costs.

Cost reduction is the focus of this session. I would like to introduce the panel, which includes Jerry Huttrer, Louis Capuano, Mohinder Gulati, and Tim Hollingshead. Ken Nichols has very kindly consented to sit on this panel. I asked him to join the panel about half an hour ago. Dan Schochet, for whom Ken has sat in, is out of the country on business and has sent his regrets. I will ask the panel members to talk about cost reduction, by emphasizing the improvements that can be done on the technology.

Let us start with panel member's statements followed by lively discussions. Please put on your thinking caps and participate in this discussion. We will see if we can get some good ideas on the table.

Exploration Cost-Cutting

Jerry Huttrer, President
Geothermal Management Company

I have played around with geothermal since 1970, I guess that is some 25 or 26 years, primarily in the exploration end of matters. There has been a certain amount of project development involved in the last 10 or 15 years. When I started to think about this topic of cost cutting, one of the things that came to my mind is a television ad that most of you have probably seen. I will not mention the company name, but they show very flashy pictures of various products that are for sale on the market and they say "we do not make such and such, we make it better." You may have seen those ads. That kind of a statement in my opinion, applies to the exploration phase of geothermal projects.

Exploration itself is a critical and vital phase of the whole operation, but we do not make the product. We do not do the drilling that brings fluid to the surface nor do we manufacture the power plant that turns out kilowatt-hours. We do sort of an intangible task that is critical, but we do not make the product. I still adhere to the boiler-burner-plumbing analogy for geothermal. I would like to point out that we have two basic missions in life as explorationists. In our geothermal exploration life, we are hunting for one or both of two things, heat and permeability. The reservoir delineation comes at a little later date. Our objective in life is to find hot spots, or even better, hot wet spots. The basic disciplines that we use can be boiled down to geology, geochemistry, and geophysics. You can make an argument that there are some other disciplines such as geobotany coming in, and used from time to time. I guess I can not deny that, but the three basic ones, I still believe, are geology, geochemistry and geophysics.

Despite many attempts, geologic mapping has not changed a whole lot over the centuries, but we have some new tools. I would like to highlight a few of the tools that I think we are using, or should be using, and that the DOE R&D program might consider emphasizing in future iterations. Aside from walking through the fields and doing reconnaissance and detailed mapping, satellite imagery has improved a great deal in the last few years. That allows us to do more things. We are using satellite imagery on a large scale. We also have spy photography that can detect a cigarette from an altitude of ten miles. If you can detect the heat from a cigarette from ten miles away, we ought to make some kind of use from it. We should revisit the optimal use of satellite imagery.

We could save some cost in normal field mapping through the use of Global Positioning Systems as well as Geographic Information Systems. We can learn a lot from the mineral industry as well as the oil and gas industry. We should be coordinating with them to optimize the efficiency with which we undertake the task we have been doing for years. I think there is a database being accumulated now that I read about in the Federal Geothermal Research Program Update included in the registration package. This database is gathering geologic, geochemical, and all sorts of geoscientific data available from other geothermal areas throughout the world. We now have 23 countries producing 7,000 megawatts from a fair number of fields. If we continue to compile a detailed a database that each one of us can access either through the Internet or through personal communication, it is going to be a beneficial cost cutting exercise.

In the area of geology, it seems to me that we have not optimally accessed the data available through copper and other mining exercises around the world. I think you all agree that those porphyry deposits and a lot of other mineral deposits represent fossil geothermal systems. There is information to be had right there. These represent cakes that have already been sliced open. In many cases, you have to open pits where you can go in and look at your hydrothermal systems. In other cases, they are still a little bit more obscure, but you can have drilling data that should be accessed and studied. We should learn from the amazing amount of work the mineral people have done to understand alterations, fractures, and permeability patterns. I do not know if they are ahead of us or not, but at least we should talk to each other.

When it comes to geochemistry, I certainly applaud the work that Joe Moore and others are doing on fluid inclusions. Likewise, I applaud the work on geothermometry that the Geological Survey has always been a leader in. I think that perhaps we ought to try to go a little bit further in gas geochemistry. The efforts made by the Italians and others in gas geochemistry and geothermometry could be improved to help us get to the bottom line and understand our systems a little bit faster. The idea of doing a little more thorough resource characterization in the early stages using geochemistry should be pushed as well. I do not want to slight any geochemist in the audience since there are some amazing deductions that have already come out of your work. But I think there is still room for improvement, at least in characterizing and coming up with ballpark ideas that would help us in exploration.

Geophysics is probably the most important indirect technique that we use in exploration. I do not have to tell this choir what they are. We can go from magnetics to resistivity techniques of many different styles. Lately, there have been real improvements in seismic techniques. I applaud the tomography efforts that are being made, and we have to use these methods to try to characterize and map fracture patterns. Whether we do it directly using borehole televiewers, or find other new methods, we will obviously need to be able to get permeability and map fractures. We will also need to understand the difference between tight and loose fractures. All this leads me to conclude that the costs of exploration are unlikely to drop significantly. Except by making little efficiencies or shortening the amount of time we take to do certain processes, I do not see us making any cheaper investigations. We will probably reduce costs down-stream of exploration, even if some of the exploration investigations cost a little bit more.

Compared to the cost of a dry hole, the cost of exploration is a drop in the bucket. I think the future objective of geothermal exploration needs to focus on increasing the ratio of successful holes to dry holes, from its current 1 in 3 to 1 in 5 range, up to 1 in 2. If we can do that, we can save a heck of a lot of money in the long run. I think this needs to be our main objective. We need to improve our methods and utilize all that science can give us right now to search for and find heat, especially in blind situations. We need to focus on finding permeability using geophysical techniques, not so much geochemical.

I think that the objective of the whole exercise is to use drilling techniques less. As a result, we can cut down the number of holes needed to achieve the same exploration objectives.

Drilling Cost-Cutting

Louis E. Capuano, Jr., President
ThermaSource, Inc.

I have been in the geothermal business since 1973, that is about 23 years. I am not as old as Jerry obviously. It is kind of logical that I follow Jerry in the exploration when talking about cost reduction. If he did not reduce his cost, then maybe I can do better on mine. I am a firm believer, and Jerry was correct at the conclusion of his talk, that if we spend more money on targeting wells then the success ratio will be better. If my success ratio is better, the cost of development or exploration comes down. Overall, we then have a better and more viable project.

It was quite apparent from Darcel Hulse's talk yesterday that all aspects of a project must be streamlined to make it viable and commercial. Certainly the drilling aspect, many times blamed as being the highest cost component of a geothermal project and hard to reduce, must be streamlined. From what Darcel said, he would like to see a 50 percent reduction in the cost of drilling. I can always drill the second well cheaper. The first exploratory well is usually the most expensive, because I really do not know what to look for. I am not sure whether the exploration techniques used are adequate for finding the right formations that support production. I will have to build a drilling program that is flexible enough to be able to accomplish all those goals.

Therefore, rather than an enormous reduction in drilling costs, I would much rather maximize production from wells. In other words, pursue things like what Darcel was talking about yesterday regarding big hole completion. Big hole completion has the ability to maximize production from one well, but it is a rare reservoir that can support a big well. Multi-leg completion is another way of maximizing production, or side tracking wells until we find production. We can no longer leave wells dry. We need to maximize production from each hole. We have to keep re-drilling until we find and define the resource, so that subsequent wells can be drilled more accurately.

These days, there is a lot of ongoing research on directional drilling. Can we target the well properly? Can we hit the target we are looking for? Consequently, it comes back to Jerry. What is the target? How defined is that target? Darcel does not advocate a big hole for exploration. During exploration, you are looking for the resource. You can drill a small well fast, to quickly assess the area and define the region. Once you define the resource, you can then select the drilling program for a big hole, a two- or three-legged hole, or whatever. The well must meet maximum conformance standards when completed. It comes back to the old age "you make it all you can make it." You might want to get it as big as you can get it and not drill more wells, reducing the overall cost of the project. If you have twenty wells capable of producing 5 megawatts each, you get 100 megawatts. But if you have 5 wells capable of producing 20 megawatts each, you reduce the cost of drilling and pipelines as well as the overall project cost. These are the kinds of things that we need to look at.

In the drilling field, we constantly look for ways to reduce cost. The way to reduce cost is by increasing penetration rates. How many days are you going to spend over one hole? If one were to look at the cost estimate for a well, it is divided into basic categories. The largest amount of money is spent on tangibles, the casing and the wellhead. Unless it is an exotic casing, such as for some of the Imperial Valley wells, there is not much room for cost reduction with a standard casing. It is just a factor of how many feet we are going to run. And by multiplying depth in feet times cost of casing per foot we get the tangible cost right away.

The next most expensive item on the cost estimate is the rig. In the early 1980s, during the boom days of drilling, a rig was running for about $10,000 to $12,000 a day. Nowadays, rigs run for anywhere from $5,000 to $7,000, and the small rigs run at almost the same price as the big ones. We basically pay for labor. Rigging companies are not making any money on the investments of the metal, the iron that they have out there in the field. A new rig has not been built in the United States in the last 10 years and we are gradually using up the inventories. When a drilling contractor offers to come out and drill a well, he is offering to bring a rig capable of drilling to 15,000 feet for about $6,000 a day. He might have 10 men out there and he pays for fuel. There is not a lot of cost that can be reduced on the day rate. What can be reduced is the number of days spent on the hole.

The next big item on the cost estimate is location cost. Half the time, we do not drill next to a road but in remote areas: mountains, desserts, and rugged terrains. We have to build roads, the site, and everything else for the first well. All that adds a big component to the well cost. We then look at the basic components that add up to the cost of the well, bits and drilling tools. Many companies are working on new bit designs that can achieve higher penetration rates with better longevity to reduce the time on location. Unlike drilling for oil and gas, we cement a well from the bottom of the casing to the top. In many cases, this cement has to be placed just right or we lose circulation, which may be reason for losing a well. Unless well-cemented, the pockets of voids between the casing and formation will be detrimental for long-term production. Cementing is not something we can cut corners on.

The drilling medium in geothermal drilling is characterized by lost circulation episodes. Lost circulation is the "nature of the beast" caused by the sub-hydrostatic nature of the resource. That is different from oil and gas resources. We need to drill through with a better system to avert facing lost circulation episodes, by either using air, aerated water, or aerated mud. The drilling engineer has a unique problem in being able to complete a well in a reduced number of days, at a reduced cost, and yet expect it to last 30 years.

Finally, the last big factor is directional drilling. If we can successfully directionally drill four or five wells from the same pad, rather than drill at different locations, we minimize the cost of pipelines as well as site and access costs. As mentioned earlier, these items constitute a big component of the cost of a well.

We now see where cost reductions can come from. These are better achieved by reducing the number of days spent on one location or site, rather than by cutting the costs of casings or that of cementing. A good knowledge of the resource and knowing where to penetrate facilitates cost reduction. Familiarity with the location where we are drilling is equally important. If I know where to drill, I can select the ideal casing size and depth. Similarly, I can design hole size and multiple legs, to maximize well production. This is the way to reduce cost in geothermal drilling operations.

Reservoir Management Cost-Cutting

Mohinder S. Gulati, Chief Engineer
Unocal Geothermal Operations

The title of my contribution is called Cost Cutting in Reservoir Management. When I read that title, my first reaction was "I hope they do not cut any cost in reservoir management." We are the least expensive guys on the team. In a typical 110-megawatt new development, you can assume the cost to be about $250 million, including the power plant. The total number of exploration, development, production, and injection wells required is about 24 to 25, with close to $75 million right there. The reservoir engineering group may run a few surveys and some simulation studies for about $1 million per year. We are not the problem area.

I would like to put this problem in a different perspective, maybe by treating the alternatives like the two faces of the same coin. Instead of cutting cost, let us focus on improving the well performance, or alternatively, make geothermal more competitive. This is where the reservoir engineer or geoscientist can make a lot of contribution. When we talk about improving the well, two items come to mind: reducing the cycle time and reducing the cost. Cost reduction entails the cost of doing everything, the cost of every component that makes the $250 million, 110-megawatt development.

Yesterday, we saw how cycle time can be significant. What CalEnergy did in terms of cost reduction, from the beginning of exploration to power online, was really remarkable. I think they brought their plants online in probably 3 years time. If we can bring power online in 5 years we are doing good, anything more than 5 years really penalizes us. You can look at the value in terms of net present value at a certain rate of return or discount rate.

Alternatively, for a given rate of return, what is the selling price of kilowatt-hours? This is really the way to look at it because we are being governed by our competition, coal and gas. By just looking at its fuel cost, gas today is roughly 2 cents per kilowatt-hour, or about $2 per million Btu. And that sort of sets the tone for geothermal. It is tough to compete with gas, so we have to look at the market place where geothermal can compete. Obviously, geothermal competes well in areas where there is no gas or where there is no pipeline to bring gas.

From a resource management standpoint, we have to prove resources early to reduce the cycle time. At The Geysers, if we completed a power plant from proposal to power online in seven years, we used to have the luxury to be very happy. There are seven components in that chain where we did not have much control, like getting the blessing of California Energy Commission. Fortunately, the market place has moved outside of California or outside the U.S., where the Energy Commission does not dictate the terms.

As reservoir engineers, we need to prove bigger resources in a reasonable and small amount of time. To make a decent rate of return on investment, 330 megawatts is generally considered a minimum. If you have just a 110-megawatt power plant in a remote location, the overheads really do not justify even starting the project.

Louis eloquently expressed the drilling components. I just want to make a point that there are two components of drilling cost. First, the mechanical component in terms of rates of penetration. The second and more important, is the geoscientific component that involves the targeting of wells. The California Division of Oil and Gas maintains certain statistics which show the success ratio of oil and gas wells in the state. These success ratios are on the order of 95 to 98 percent for many years, with very little variation from one basin to another.

From our experiences at The Geysers, where we have several hundred development wells, our success ratio was on the order of 65 percent when counting the successful penetrations divided by the total penetration. If we start drilling to make a well a success, we would wind up spending a bundle of money drilling in two or three directions. Counting all those legs, the successful wells were only 65 percent over a ten year track period. We need to improve our success ratios in development wells. Exploratory wells are generally disposable wells, we do not end up using them for production or injection other than for monitoring purposes. But development wells can be optimized to maximize our index of dollars per megawatt, rather than dollars per foot. One way to improve this is to map our permeability highways better.

I want to briefly elaborate on the cycle time again. We not only have to pay attention to the total time period between exploration and power online, for which five years is a decent time, but we need to really target the total capital expenditures which come early in the game plan rather than the ones that come later. The capital expenditures that come early in the game plan consist of exploratory and development drilling. The ones that come later are associated with surface facilities and, lastly or concurrently, the power plant. The longer the capital dollars sit and wait, the more expensive they are. By running a simple calculation you will arrive at a similar conclusion, that one dollar saved in drilling cost is equivalent to two dollars saved in the power plant. The power plant dollars are spent later while the drilling dollars are spent early in the life of the project. The drilling dollars sit for a longer time period without producing any revenues, whereas the power plant dollars do not sit very long before they start making revenues. So, again that brings the burden back to Louis Capuano to cut down the drilling cost.

As reservoir engineers, I think our technology has come along very well and we need to keep doing what we do. We probably need more aggressive resource management, looking for changes in pressure, temperature, enthalpy, and salinity not only on the X and Y directions but also in the Z direction. That is the direction which we most often do not pay much attention to even though the resources have a Z direction. We will need to interpret all the changes and make them part of our ongoing conceptual model of the reservoir. The model does not necessarily have to be made with the help of high speed computers. Those are more useful for simulation, or as an easy and more accurate way to test our conceptual model. All the changes that we monitor as a function of time need to quickly go into changing or updating our conceptual model, which can then be evaluated with the help of high speed computers.

The things that have helped us in the recent past include instrumentation, particularly the temperature-pressure-spinner surveys. We can now measure the rate at which fluid is entering or exiting a well in real time, using spinner surveys. From the surface, we can see what the tool is sensing at the bottom of the hole. Our technology has come a long way in terms of simulation. The simulators being used today are wonderful, aided by high speed and inexpensive computers that we have access to. Those are all the tools at the hands of reservoir engineers. And of course, those are the guys, I hope, that help make the decisions in terms of reducing the cycle time and proving the resource.

Operation and Maintenance Cost-Cutting

Timothy W. Hollingshead, Technical Services Manager
Pacific Gas & Electric Company

I guess my challenge for this afternoon is to try and figure out how to blame Louis for maintenance and operations (M&O) costs. I appreciate the opportunity to speak to this group this afternoon. If you folks know anything, you know that old maintenance guys like to talk. One of the things I like to talk a lot about is this industry. M&O cost cutting -- it seems to be a fairly innocuous title that conjures up a notion of running around looking for a place here and there to save a buck. Well, I am here today to tell you that its pure bull. What I am talking here folks is survival -- plain, pure, simple survival. From the geothermal industry point of view, I am looking at a world full of terrorists. Everyone here today has someone working on ways to cut your legs from under you. It does not matter what part of the business you are in, they are there. The legislators, the regulators, our competitors, our customers, have I missed any? Yes, sometimes ourselves.

What is our first line of defense? We can sit around and say we are alternate, renewable, green, and/or-special. But what most of our customers want to hear is whether or not we are cheap. Therefore, our first line of defense, in today's and the future market, is price. It is just that simple. If we do not control our cost and maintain a competitive edge, we are history, period.

Where is the best place to start cost control? I will answer that with another question: where is the biggest cost? I would guess in most organizations, at least in mine, it is in M&O. Unfortunately, one of the biggest portions of M&O is labor. Here is the hard part, labor equals people. And when we talk people, we talk emotion. That is when things get tough. Would it be as simple as this? You have an unnecessary piece of equipment sitting around, that costs $75,000 to $100,000 a year to keep. What would you do? I know it sounds cold, but be honest and think about it. I realize that I work for a public utility and this may be a bigger issue for me than for some of you. However, I think there is an opportunity for us all to make improvements with this resource.

The key area is communication. It is crucial for our employees to know and understand what is going on in our industry. They may not like the message, but at least they have information they can act on and make choices about. They will feel themselves to be a part of the change, rather than the focus of the change. Most people see this as humane treatment, that its important from a societal point of view, but its also important from an economic point. If people know they are going to be treated fairly and kept informed, they do not spend their time thinking and worrying about themselves and what might be. Rather, they will work on the problems at hand. The effects of lay offs and other personnel actions are quickly put behind them and productivity returns to normal, usually at higher levels.

We need to continue training and developing our people. The quality of the people within the industry will determine the success of this industry. There is something else to think about. Who knows more about your operation than the people involved in it? And I mean everybody involved in it, from top to bottom. If you really want to cut M&O cost, try asking all of your people what you need to make this operation more efficient. Then ask them what you do not need to make this operation more efficient. You just might be surprised at the answers you get. Do not overlook the obvious.

One area I feel we might be missing the boat is in our health and safety programs. We are morally and legally obligated to have these programs, so why not get our money's worth. The cost of a disabling injury could very well cover the annual cost of a good health and safety program, not to mention the other not so obvious cost associated with disabling injuries. Where could you use an extra $30,000 to $40,000, which is about the cost of a disabling injury, plus maybe another $25,000 in OSHA fines. Now, think about this. I bet you have people in your organization that have worked their entire career without an injury. Ask them how they do it, they just might tell you.

Another necessary component of cost cutting and M&O is sharing of information within our industry. Yes, even with our competitors. Meetings like this and the GRC annual meetings are an excellent forum for sharing information and are vital to our success as an industry. It is important to continue looking for ways to increase the value of the geothermal industry as a whole. There are a lot of good reasons to work together on projects. The DOE loves to co-fund projects that are sponsored by multiple industry members. Having a steam supplier, a generator, an equipment manufacturer, and the DOE supporting and working together on a project is an ideal situation. Even better is a situation like the Lake County Waste Water Project, where the local community is also a major player. Everyone wins -- the project sponsors and the industry. You do not have to wait for the DOE to participate. If partnering a project makes sense, do it.

Another significant opportunity for cost reduction is reviewing maintenance practices and taking advantage of new technology -- things like establishing predictive maintenance programs. Predictive maintenance is a program that evaluates the actual condition of plant equipment utilizing various non-intrusive monitoring techniques. It is often referred to as condition-based maintenance. The goal is to minimize material and labor cost, while maximizing the reliability and longevity of plant equipment by performing the right maintenance on the right equipment at the right time. In other words, repairs to plant equipment are scheduled and performed based on the operating conditions of the machine rather than a time-based schedule for failure. Some of the technologies used are vibration analysis, thermography, oil analysis, acoustic monitoring, and current monitoring. Depending on the equipment, one or more of these methods can be combined to help evaluate the present operating condition of a given machine. But do not waste your time monitoring equipment that is cheaper to replace than repair. The key here is not the technology, but what you do with the information that technology allows you to gain. Last but not least, just apply a little plain old common sense to your maintenance and operations. Look for the obvious, do not do things just because it is the way that we have always done so in the past. Look for the not so obvious, take advantage of new technology and maybe even new ways of thinking.

In summary, think about the big hitters I talked about. Staffing to the right size and taking care of your people can result in significant savings to any operation. A cooperative spirit and free exchange of information helps everyone and will make our industry strong and competitive. Take advantage of new technology where appropriate, but use a little common sense while you are looking at it.

Energy Conversion/Power Plant Cost-Cutting

Kenneth Nichols,
Barber-Nichols, Inc.

I was asked to talk a little about power plants, and I am sure you are all aware of these things. It became a little more apparent to me, or at least backed up my earlier conviction, after listening to some of the other speakers, particularly Darcel Hulse yesterday. I have always felt that the conversion efficiency of the power plant needs to be as high as practical, in order to reduce the overall cost of the project. Darcel pointed out yesterday, that money spent early on a project for exploration and well field development is actually compounded so that a dollar spent early is like spending two more dollars on the power plant. I really think you do not want to short-change the power plant, you do not want to trim too much cost out of there because you will want to optimize the performance within practical limits.

There are a lot of improvements we can make. During yesterday's session, we talked a little about some new direct-contact condenser film material that NREL is going to be trying at The Geysers unit number 11. The film will reduce significant steam carry over in the direct- contact condenser. More efficient compressors are also being installed to handle the noncondensables. Actually, if we were using turbo compressors and that film for the entire noncondensable extraction system, we would generate approximately 7 percent more power out of the unit 11 turbine. This is a significant improvement and it is not very costly. The payback would probably be in much less than a year. If we keep looking for other improvements, we could squeeze another 10 or 15% out of these power plants that would really help the overall cost.

Because of reservoir resource decline, many of the turbines in geothermal plants are not running at their design point. They are running under design pressure, with significant loss. That is why some people eventually modify their plant or make one turbine do what two were doing. We will need to think about this decline early in the design of the power plant by anticipating the conditions to be faced. Consequently, we may be able to develop a design that maintains a high efficiency over the life of the plant, or at least some of its life. The other thing I was going to talk about other than plant design was O&M cost. I would like to talk about our experience with small binary systems that really do have a very low O&M cost partly due to their small size. We had to design these systems to operate independent of operators, running unattended 90 percent of the time.

I used to think that necessity was the mother of invention, but Darcel told us yesterday that it was desperation. I have had a first hand experience with that. Our little binary systems operate on Freon 114, an ideal fluid for the low-temperature range. The systems are very efficient.

The turbine runs directly at the generator speed eliminating the need for gear boxes. Freon 114 is also non-flammable and non-toxic. Unfortunately, somebody decided that it was such a stable fluid that it gets into the upper atmosphere and tends to destroy the ozone. Freon is no longer available. Desperation has led us to seal our systems so tightly that we have not added any working fluids in two years. Further, we can not get Freon, nor can we afford it if we get it. What was once 99 cents a pound when we built those plants is now over $11 a pound. Desperation has caused us to really, really control our O&M cost at these small plants.

I was really impressed when I went to PG&E and visited their unit 11, where we are going to be installing a turbo compressor. The plant has a turbine designed to generate 100 megawatts, but due to reservoir pressure decline it was generating only 60 megawatts. There were only two operators attending the plant, with a two-hour period unattended during the night. I have been at several independent power projects producing 10 to 15 megawatts. I am amazed at the number of people working at these facilities. I guess that at some point in time their desperation might correct things. I think we need to design these plants to be self supporting and operating with a very small number of people. We must also pay particular attention to maintenance, preferably design these plants so they are relatively maintenance free. We have some ideas on how to do that. Eventually with all of these efforts we can all stay alive.

OPEN DISCUSSION:

Ken Pierce: In sitting here and listening to you all, it occurred to me that we talk about individual activities such as drilling, reservoir engineering, power plant maintenance, and so on. But these are not all independent. When optimizing independent events, the sum of the optimums is not necessarily the optimum for the system. Has anybody looked at all of these activities together? And are there trade offs that can be played on maintenance vs. planned efficiency, or otherwise? Are there things you can play together in the overall system?

Louis Capuano: From the drilling side, we are in direct communication at all times with the exploration side as to what we think, how we design the program, and how we ultimately complete and have a usable well, both for exploration and development purposes. We are in communication with them from the time they pick their target. There is not a lot of communication prior to picking the target or while the targets are picked.

Drilling engineers also talk to the reservoir engineers all the time, as to the type of measurements to be made during drilling and the type of hole needed at the end of the well completion. In other words, we discuss the kind of resource are we looking for. When you start drilling, the big question is what are you looking for? Are you looking for single- or two-phase fluids? We also communicate quite a bit during well testing. Right after the well is completed and tested, the project goes to the next phase of determining the power plant system. There is constant communication between the various groups. It may sound like we are disjointed, but I think the way we get from one end to the other is by following a path, with a different guide for different parts of the journey. So we do communicate with each other.

Mohinder Gulati: I would essentially endorse what Louis said. Reservoir engineers are the ones who have the ball to turn the evaluated project over to the next person, the power plants guys. Up until that point, they work very closely with the exploration and drilling people. As each well is drilled, the next location is guided by the lessons of the resource from previous experience. The process of determining the next well to be drilled is not an independent one, it is guided by what we have learned on site. In fact, in our exploration process we are generally prepared and ready to move to more than one location to expand our options. We go to location A or B, depending on the results from the current well. It is an integrated and mutually dependent process.

Jerry Huttrer: Speaking for the exploration side, I agree that we do a lot of thinking prior to the investigation of a project with the drilling people. We obviously look at the overall permitting situation. If someone asks to drill in a national park, in that case, you kind of walk away. We are trying to reduce cost for the drilling people. If our exploration leads us to a target that sits right in the middle of a river bed, smack off the edge of a cliff, under a power line, or a condition not conducive to drilling, we then evaluate our results and make our recommendations with a logistical access and the cost of environmental permitting in mind. Retreating a little bit to the beginning of a project, most of the exploration work I have done has been scheduled in phases. If in the early stages the project looks absolutely terrible, most of the time we will walk away early and cut cost at that point. But there is communication from management and communication through the explorationist during the various phases of exploration. Finally, we certainly do coordinate with the drilling people who follow on, either for exploration or delineation wells.

Tim Hollingshead: I would like to say a couple of things from the maintenance and operations point of view. It seems to me that one of the reasons why The Geysers has been as successful as it has been is because of the communication between the steam suppliers and the generators. We have ongoing standing committees that meet on a regular basis, like every week or so. There is clear and open communication at various levels between PG&E and Unocal, for instance. Discussing mutual problems and trying to come to agreeable solutions on both sides, falls to higher level communication between officers of the company and workshops like this.

A real good example is the turbo compressor that you heard about over the last couple of days, and that Ken Nichols is intimately involved in. It is a joint project between Barber-Nichols, PG&E, Unocal, and the DOE. These are the kind of things I was referring to in my opening remarks. Information sharing is where we really gain as an industry. If we are going to be anything, we have got to have good communication. That is like the bottom line.

Mike Wright: Ken, maybe I heard your question a little differently. Did you ask if anybody has studied this whole process as a system? I think there have been a couple of attempts that some people in the room have been associated with. I know that Sue Petty, Bill Livesay, Dan Entingh, and a few other people looked at a complete exploration development model for a number of selected theoretical geothermal systems. They tried to identify the really high- cost items -- items that seem to be amenable to improvement and technology. What certain improvements and technology would do in terms of cents per kilowatt hour bottom line. I do not think that the model has been extended as much as it could be, neither has it been updated lately. I do not know if anyone wants to comment on that, but that was one attempt to see things from a systems point of view. We probably have not done enough. Bill, do you want to comment on that?

Ken Nichols: I can comment a little because in the latter part of that study, I was involved in helping Susan and Bill. Basically, it says the same thing that Darcel said yesterday, that there is a large amount of money in exploration and well field development. When the time is compounded, its a big item and the total cost is no big surprise.

From my perspective, there is really pretty good coordination between all the disciplines that are key to develop a geothermal project. What the power plant designer needs is the enthalpy of the resource, some of the chemistry, and the level of noncondensable gases. The biggest surprise, particularly when developing a new resource, is the anticipation of reservoir decline or how stable the resource will be over a period of time. We have all had a lot of surprises, where things do not hold up as well and sometimes they do.

Louis Capuano: One of the things we tried to do with that study was find ways to put a dollar value on risk. We tried to get answers for such common questions as how long should a well test run? Should you drill an extra well? If you look at instrumentation across the board, it is always expensive. We have to find ways to reduce risk or shorten the time for the expensive operation. We actually try to put a dollar value on risk reduction by the length of the test, or the kind of logging or analysis program used when looking at both the geological and reservoir data.

Jim Combs: Approaching this thing from a different standpoint, I think that one of our problems with cost cutting is that this industry has a hard time living with innovations. We kind of do something one way and keep doing it forever. Five years ago, we started talking about slim holes to reduce the cost of exploration and get reliable reservoir parameters less expensively. We finally got a program started four years ago and people are now doing something about it. When I look at things like multiple leg drilling, for the last five years we have drawn from multiple legs at The Geysers. But people keep designing the upper hole at the old 9-5/8" completion, restricting increased production by sticking to smaller hole size. The industry has to be more innovative, and there are some innovations coming out. I think too often we keep doing things the way we always did because we think we understand it better.

Jerry Huttrer: That is a good point. I would like to just make another comment about slim holes. The recent innovations are the result of Jim Comb's, John Finger's, and some others' efforts. I also happen to be very enthusiastic about slim holes. I wonder whether we might not be able to shortcut exploration in the future by putting some emphasis on the efficiency and cost of slim hole drilling. It seems to me that some of the exploration processes can be shortcut. We can go into places and drill slim holes perhaps a little earlier than we ever have in the sequence. We can find out whether there is anything at all down there, and if we do, we can use the slim hole information to calibrate any further surface geophysics or geochemistry that we undertake. In too many cases, we run survey after survey and get a bunch of redundant information until somebody finally takes a big jump and says, "OK, lets take a chance and drill a well." I am beginning to think that maybe we ought to drill slim holes earlier, if we can drill them relatively inexpensively and eliminate some of the surveys that are always giving us ambiguous results. We can then gradually reduce ambiguities as well as save money. This may help get through the inertia of our industry to stay with the old methods, as Jim was just saying. It would take a breakthrough for people to take the risk of springing for a little larger increment of money a little earlier in the survey. I throw that out as a possible wrinkle in our current exploration style.

Louis Capuano: As far as your comments about The Geysers, they are still drilling the upper hole with 9-5/8" and side tracking with 13-3/8" inside a 16" diameter hole. One of the reasons they are doing side tracks in the lower part of the 9-5/8" is because the original hole is not in choke flow. Nowadays, a good well can produce 60,000 pounds per hour or 3.3 megawatts, where in the old days that was not even a keeper. They are now bringing smaller wells into the same 9-5/8" casing at a deeper depth. They get two 60,000-pound wells adding to 120,000 pounds, but still not in a choke flow situation. It does advocate drilling 9-5/8" multi-leg wells in some cases at The Geysers. A key to it all is finding the reservoir that supports a choke flow situation and having a bigger size casing.

Mohinder Gulati: We have just completed a slim hole exploration program, but not spent the time to evaluate it in terms of what we got in return for the amount spent on the program. Our initial reaction is that there is plenty room for cutting cost in slim holes. The drilling per foot index is not the only one we have to look at. We have to look at the mobilization and demobilization, the cost of moving the rig from point A to point B, and whatever else is involved. Similarly, we will also have to look at the various components that go into the rig. We are currently using the hybrid rig, and our first experience indicates that there is room for improvement.

Jerry Huttrer: I am currently working on a little project that I have been sort of championing for a year or two. The project involves the identification of what I call compact yet powerful drill rigs, which might address what Mohinder was talking about. I think there is significant room in the industry for cutting the size of the rigs we use to drill production wells. This study may lead to recommendations regarding the optimum size for slim hole rigs. We have been drilling slim holes for many years and the size of those drills have decreased very significantly. What I am hoping will result from this little study is a production well rig that will not be a whole lot larger than a slim hole rig. As a result, the cost of mobilization and demobilization, the location cost, and the environmental impact, among others, will be minimized. The Unocal efforts will then show more economic promise.

Mike Wright: Louis, earlier you mentioned that the time spent over the hole, some of the costs associated with equipment, and experience can all help control and reduce cost. Would you comment on how you would apply the results of slim hole drilling to help you drill the first production hole less expensively?

Louis Capuano: Essentially, a slim hole tells me what I am going to encounter. It helps me determine where the problem zones are and where to ideally select my casing shoe on the production well. There is no need to run any more production casings than necessary. If the formations are competent, we can cut production casings shorter and run surface casings to cover any lost circulation or weaker zones. It helps me design a casing in such a way that only as much casing as necessary is used, without overlaps. It also helps me anticipate problem zones, such as lost circulation zones. If a slim hole at the same location encounters circulation loss at 2000 feet, I will have to make a decision on how to proceed. Do I want to keep the loss zone or cover it with pipe? To cover it with pipe, I might want to run my casing just to the other side of it at 2100 or 2200 feet. To keep it as a potential zone, I will have to run my casing to 1900 feet and drill through the lost circulation zone later.

As a drilling engineer, the slim hole helps me make decisions as to the best way of approaching the drilling program. It helps me streamline the casing program and the drilling technique that I am going to use. This includes the cement design, whether I am to incorporate mud or air drilling services. It also tells me the location of the hard and soft sections inside the hole, that is particularly useful information for directional work.

Slim hole rigs usually require a two- to four-man crew to work daylight hours or around the clock, whatever the case may be. Surprisingly, the hourly rate for slim hole rigs is not that much different from that of a big rig. The difference is in, like Jerry pointed out, the rig mobilization, the location, and the casing size required. But in many cases the big rig can drill faster.

I was talking to rig builders just last week and they tell me they are gearing up to build rigs again. It is the first time they are building new rigs from scratch in the last ten years. The new rigs are coming off the yard at anywhere from $7 to $11 million, depending on what you want, they are coming out high. The inventory of rigs is just gone. They either went overseas, people bought and took them away, or they were chopped up and taken for pieces. During the boom days there were 4,800 rigs in the United States. Presently, I think there are just under or right around 1,000. I do not think we can put half the 4,800 rigs to work right now if we were given the demand.

If you are paying so much an hour for a rig, you will still be paying for crews and fuel and there is not that much money left for the rig itself. When conducting exploration drilling, you will have to make a decision up front on how good you feel and whether you want to pay for a well real fast. Sometimes the exploration well is not going to be used for anything other than investigation purposes. I was attending a DOE meeting years ago at this hotel when Carel Otte came up and said "we have drilled all the obvious geothermal resources, now we have to find the ones we do not see at the surface." Since then, we have started looking at slim hole systems when developing new wells and/or fields.

Jerry Huttrer: I had an experience with one project where for several years we exclusively used slim holes. We stepped out about 10 to 15 feet from the slim hole when drilling the production well. We reduced the cost of drilling production wells by almost 30 percent, compared to what we had incurred before doing any slim hole drilling. As Louis said, there were many benefits that accrued from the design of the hole.

Some of the intangible benefits include the confidence you get when you know where you are headed. The slim hole information serves as a highway map. The driller knows exactly, or pretty close, what comes his way in the next 5, 15, or 20 feet. It is a whole different environment. I can cite at least four rigs that are under construction and that the manufacturers' claim will come on the street fully equipped with white side walls, sunroof, fox tail, and fuzzy dice. As for price, the whole rig for under $5 million, and still be able to drill between 10,000 to 12,000 feet with a 4-1/2" drill pipe. This is an encouraging price. It may not be as high as Louis said. Let us hope I am right.

Mike Wright: How much better could we get in power plant efficiency without a huge breakthrough in technology, or how can we build power plants faster and cheaper?

Ken Nichols: I think it is a matter of tweaking the power plants a little bit. Mai Hattar, of CE Holt Company, gave a talk yesterday afternoon about the study that they did for EPRI on new generation geothermal power plants. Their study did not indicate any major milestones nor increments in efficiency. However, by tweaking things here and there it is possible to get a 10 to 15 percent performance improvement. The biggest thing is that we have to keep the plants running at their optimum points and make sure they are not affected by design problems.

Jim Combs: I guess I would agree with Ken on quite a bit of that. We have been doing quite a bit of work with General Electric, primarily on The Geysers Unit 13 steam path change out. We are going to be seeing some significant benefits from that, but it is costly. One of the things that we have been trying to do is to go through some of the sloppy designs from early years and improve them. The majority of our equipment is Toshiba design that was designed and installed with the assumption that we had an endless reservoir that was going to go on forever. It did not make any difference whether the machine was efficient or not. That was the bad news. The good news, once we figured we had a finite reservoir and that we needed to take advantage of the steam available, it gave us a lot of opportunity to go in and make some design changes. We tightened up clearances and made improvements on existing equipment. It really was not all that expensive, and we have been fairly successful with it.

If you look at the results over the last couple of years, the reservoir decline at The Geysers has been mitigated to some degree. There can be numerous arguments made about the mitigating factors. I like to think of it as a combination of more injection of water into the ground, curtailing operation of some units, as well as some efficiency improvements. The key is to continue to look for improvements that are not expensive and do not affect the cost of production. There is no point in making vast improvements on the machine if it drives your cost of production sky high and no one wants to buy your energy.

Unidentified Commentator: There is at least beginning to be some thought about some synergy. It is one of the other things that we need to start thinking about. Let us assume that one of the operators has decided to bring ground water to inject into the reservoir to maintain pressure. In the mean time, some clever guy identifies that the ground water is going to go right past the power plant. This guy asks why don't we run the ground water past the gas ejectors? By doing so, we will be able to cool the ejectors and heat up the injection water. We will not be using much cooling water out of the system and we will get some bang for our buck in a couple of different ways. It really puts together all sides of the problems, and I think that is how we are going to cut costs.

Marshall Reed: We have had some proposals from researchers and people in industry to try to cut operating and maintenance costs by looking at the chemistry that is necessary to keep plants operating. We are thinking primarily of corrosion abatement, from putting caustic in and trying to keep corrosion down in the northwest part of The Geysers. The amount of chemicals used for hydrogen sulphide abatement at The Geysers is enormous and the cost is very high. In some of the Basin and Range plants, inhibitors are pumped downhole to keep down calcium carbonate scaling. Ken Nichols also mentioned the cost of fluorohydrocarbons for use as heat exchanger fluids, and whose cost of replacement have become enormous. Is it worthwhile for us at the Department of Energy to fund research on substitution of chemicals or different ways of applying chemicals to cut operating costs? Is that a real concern in the O&M for power plants and/or field operations, or are we just tweaking things on the edge?

Tim Hollingshead: The simple fact of the matter is that chemicals are still one of our largest areas of cost. Over the last few years, there have been some huge advancements with abatement systems that have reduced our operating budget significantly. But there is still a lot of room for improvements. I do not expect to see the giant savings that we have had in the past, but there is still a lot of room for development. We have several proposals right now in front of the Geothermal Power Organization for future R&D work in that area.

Ken Nichols: In some binary plants, there is a scaling problem with geothermal brines in the heat exchangers. There are some chemical additives that can be used that seem to be fairly cost effective. When we were running the direct-contact heat exchanger (DCHX) research program way back in the early 1980s at East Mesa, we found some additives that really kept the carbonate in solution. The carbonate still comes out of solution when the brine is flashed and CO_2 released. But rather than just accumulate on vessel walls and in pipings, the scale stays in solution as a fine particulate matter.

I do not know what to do with the working fluids that happen to be fluorocarbons that are not on the favorable list anymore. There are alternative working fluids that have come out with the new environmentally friendly refrigerants. Unfortunately, because of the difficulties in manufacturing them, plus I suppose all the research that went into them, they are still very expensive. They are $8 to $10 a pound. So, it seems we are just caught there in the trap.

Mike Wright: Carl Paquin, do you want to add anything to any of this power plant stuff? How much do you think can be increased in efficiency terms with some reasonable innovations?

Carl Paquin: I have to agree with Tim and Ken that probably there are some opportunities for efficiency improvements. The costs right now are extreme. We have to look for low-lying fruit to pick. The direct-contact condenser idea that NREL came forward with was a real opportunity, and I am glad that DOE and NREL brought that to our attention. The Barber-Nichols turbo-compressor idea, that we are working on together, also seems to be another winner. Trying to find some more examples right now is really kind of tough.

Our iron chelate chemicals typically run for about $3 million a year, sometimes more at The Geysers. I know our chemists have been asking for a substitute or some other process with which to clean the steam. Three million dollars is significant. If we could find some opportunity to reduce the need for that chemical through better controls, less expensive chemicals, or maybe another process for cleaning the steam, that would really help us. Another thing I mentioned earlier in my presentation today was the desuperheating that we are having to do to control stress-corrosion cracking. There is 20 megawatts lost right there, that is quite a bit of production. We need to come up with some way of preventing stress- corrosion cracking without having to replace our rotors with, say, high-twelve chrome. This will require coming up with a coating or a process of scrubbing the steam before it enters the plant. By doing this, we can have the 20 megawatts that we have had to give up for at least 10 years.

Mike Wright: One of the things that Darcel mentioned yesterday as part of his model was increased well productivity. Mohinder, do you have any idea how much improvement in productivity could reasonably be expected by things that we might see on the horizon and how we might do that? I might ask the same question to some of the other reservoir engineers or drillers, maybe Keshav has a good idea on how to do this?

Mohinder Gulati: One method, which I am sure you are all aware of, is to increase the size of the wellbore. Big hole drilling requires spending more for the well. Therefore, you have to optimize the additional spending and the expected returns. Do the calculations to see if what you are getting in return is worthwhile.

Other than that, we have some wells that are shut-in and will not produce because the temperature has gone down. As the fluid comes up the wellbore, part of the fluid flashes and provides the lifting mechanism for the two phase mixture. The temperature here is below the critical temperature. A well that was a good producer is no longer a good producer because of a 10 degree decline in temperature. It was not a big decline, the well is still 400 plus degrees, but because of less reservoir pressure it just will not produce. We have been thinking of air lifting the well or find some other way to make it produce. The productivity of a well is governed by many factors, so you look at those factors within your control that you can tweak. These factors include the reservoir pressure and temperature, salinity, friction losses created by the diameter of the wellbore, and the wellhead flowing pressures. Sometimes you can reduce the wellhead flowing pressure and increase productivity. Friction is something within reach and that can be reduced by drilling a bigger hole, but it comes at a price.

Keshav Goyal: I think Mohinder has touched most of the points which take care of well productivity. The only thing I can add is drilling the well with multiple legs, but that has a penalty to pay. Calpine has drilled four wells with multiple legs, of which two are successful. The remaining two wells actually lost productivity because they happened to be near injection wells, or somehow injection water managed to reach one of the legs. We do not have any inexpensive way to clean a well with multiple legs. If the legs block, we lose a well. If it were a single leg hole, we could use a rig to clean the hole as many times needed. But if it is a well with multiple legs, we lose whichever leg that blocks.

Douglas Jung: I am not a reservoir engineer, but I do work with them and the drilling people quite often. We do a lot of work on production enhancement. We have been looking at increasing productivity, especially in some of the resources that have been declining, by basically sucking the resource out of the ground using two-phase eductors and/or steam ejectors. On some of these wells, you can get as much as 15-percent increase in production for every PSI drop in wellhead pressure. If you have a strong well sitting relatively close by and you basically suck it into the system, you can get as much as a 40-percent increase in some wells. This will mean keeping the weak wells flowing into the system. We have also been doing quite a bit of work on neuronet simulators and two-phase modeling. Through some of these techniques, we can reduce choke points and increase productivity by an additional 15 to 20 percent, but normally by about 5 to 10 percent. These little tricks and details can be used to increase productivity and are pretty cost effective.

Mike Wright: Any other comments on increasing the productivity of these systems?

Carl Paquin: Tim, we have talked about bringing in more water to sustain The Geysers. If we can keep it operating at current levels, by sustaining productivity, we minimize cost increases as the reservoir declines. Tim, do you have something to add to that? What are some of the issues with trying to bring in a very large quantity of water from Santa Rosa? The Lake County waste water pipeline is about 75 megawatt equivalent and Santa Rosa's might be 5 to 10 times that amount. From the reservoir perspective, can The Geysers handle that much water and sustain it?

Tim Hollingshead: I guess you kind of put me a in funny spot there, Carl. The more we produce, the more megawatts we have to spread our cost over, the cheaper we are. The simple fact of the matter, if the cost of production gets to the point where we can be the producer of choice over other generation, we are going to run more. Everybody in here experienced the wonderful declines in the price of natural gas and what it did to the business. When you throw in hydro and other things in on top of that, its kind of a dog-eat-dog world. If our prices are not competitive, we are not going to run. It is just that simple. It is a kind of vicious circle. Steam field problems because of plugged wells, bridged wells, and numerous other things can cause the field to not produce. One area that Unocal and PG&E have been very responsive to is trying to figure out what to do to get the price in line and make sure that the resource is more attractive to the grid.

Mohinder Gulati: Unocal's share of the Lake County pipeline is roughly equivalent to the condensate that comes from a 200 megawatt power plant. Currently, we are supplying steam to generate about 600 megawatts. Therefore, the incremental amount of condensate that we will be handling is very small, an increase of about 30 percent. We have no qualms about our ability or the reservoir's ability to handle the Lake County waste water that will come in, whenever the pipeline is complete.

The Santa Rosa waste water is another story. We will need to do a lot more thinking and planning. I am not sure if we have completed all of our analysis. But I can share with you the way we are planning to approach this problem. One is the disposal aspect and the other is the recharge aspect. From the city of Santa Rosa's standpoint, it does not matter whether we are examining it as a disposal or as a recharge project. In all our planning we have to keep in mind both things. Ideally, we would like it to be a recharge project forever because the waste water would be available forever. However, we have to be prepared in case there is some short circuiting in the reservoir that we do not kill the goose that lays golden eggs. There are areas in the reservoir (where we know there is good fracture permeability but no steam) that provide adequate insurance and protection to handle the water. There can be some kind of short circuiting in the reservoir, and it is not the first time that we have seen that happen. We have had good injectors, but after a few years of operation the nearby production wells got cooler. We were able to handle the situation. It requires planning. All we have to do is make sure that the project is still profitable, keeping in mind the potential risks involved.

Dennis Nielson: I guess this question is for Louis. I have a number of friends in the oil and gas industry that are singing the praises of cost savings from using coiled tubing technology and down hole mud motors. I really have not heard anything about that in the geothermal context. Is there a potential for using that technology?

Louis Capuano: Yes, we are doing a lot with coiled tubing. Currently, we are mostly doing abandonments using coiled tubing. We are not doing any drilling with it because it comes back to what Mohinder said, that you increase productivity by increasing hole size. We have not gotten to the point where we can drill a big enough hole with coiled tubing and make it commercial. But we can now drill slim holes with the coiled tubing. There are a few studies underway to look at this application for exploration purposes. I have looked at a couple of the recent papers as for the drilling end of it. Where you see the oil and gas folks singing the praises is not necessarily for just the drilling, but more for well-cleaning type applications. They are doing quite a bit of tube cleaning in the Imperial Valley, what they call tube-and-unit. But again, its just a clean out situation, not necessarily drilling.

Dave Lucas: About 20 years ago, there was a fairly extensive DOE and industry program in hydraulic fracturing for geothermal wells that was largely unsuccessful. Hydraulic fracturing technology has come a long way in that period of time. There is also high-energy gas cracking that has a potential for near wellbore stimulation. I was wondering if the panel could comment on whether you see a new project in that area? Would it have a benefit, or do you think the physics of hydraulic fracturing in this environment are completely out of line with any expectation for improved productivity?

Mohinder Gulati: I am familiar with the last go around at The Geysers and I know that it was not very successful. We lost all the fluid. I am not sure of recent advancements in the technology. But if we are still counting on the fluid to transmit pressure, that will be tough to do. Simply because the permeability in geothermal wells is much higher than the permeability encountered in oil and gas wells. The problem we had last time, probably more than 10 years ago, was that we lost all the fluid and no amount of fast pumping could really fill up the wellbore. The wellbore has to be full in order to transmit pressure from point A to point B. I am not really aware of recent technology that shows any promise.

Louis Capuano: The other aspect is to be able to control and direct the fracture to the right position. The Hot Dry Rock project has been successful in connecting two wells within a fracture zone. But where is the production? Where within a marginal well would you fracture to increase its production? Can you propagate that fracture in the proper position? I have experienced wells where the side track well was successful and only thirteen feet from the original dry hole. Why could we not fracture in between it? It may not be the weakest point in the well. But there is a lot more work to be done in this area. I do not know if we can actually make good wells out of bad ones by just putting pressure on them. This certainly is a good idea. I hope we can do something with it.

Allan Jelacic: I just thought I would put you guys on the spot a little bit and ask for each of your opinions as to the single technology improvement that has the greatest cost impact in geothermal development. Just pick one out and give your reasons why you think it would have that greatest cost impact.

Mohinder Gulati: Fracture mapping will be the one to reduce the cost of drilling. The number of wells, not the dollars per foot, is the big ticket item in geothermal development. Anything we do to reduce total drilling cost will really help.

Louis Capuano: It is not drilling, but the technique used for targeting. If the reservoir engineer maps the fracture and can tell me where to drill, we can reduce those dry holes. Overall, we can make a better system out of it. With fracture mapping you can size and target the reservoir and we can then size the hole to its ultimate production. In other words, either drill a big or a small hole. If we know the location of the fracture, we can design anything we want to and possibly drill from one location and hit it at various different points. We could then minimize the number of locations, the pipeline necessary for collection, and everything else.

Jerry Huttrer: I will follow the same discussion for fracture mapping. But what goes through my head is whether we are talking exclusively fracture mapping from drill holes or whether we need to put some efforts into the surface methodology, so we can extrapolate from surface evidence and properly target the wells in the first place. I really have not decided which one needs the emphasis. Years ago, there was a theory that if you mapped horizontal fracture patterns and extrapolate them in three dimension, in the Z direction, that they were repetitive in any part of the world. It was kind of a take off on fractal theory. And it makes me think that perhaps there is room for both in developing techniques for surface mapping that can be accurately extrapolated to depth as well as mapping fractures from existing drill holes and targeting the second well or the kick-off more accurately.

Mike Wright: How about from the power plant point of view. What would you guys say is the biggest, the best, thing you could do if you had half a million bucks or something. Ten million?

Tim Hollingshead: Actually, the question came up earlier about the value of chemicals, anything to reduce the cost of chemicals in the plant. I will expand on that. The main reason why we even talk about chemicals most of the time is because of the abatement process. That is still a big cost of doing business at The Geysers. Anything we do to continue to reduce chemical costs is going to be a benefit. And especially, if we can do things with the advanced direct-contact condenser project, we will be gaining in more than just the reduction in chemical costs because of better detainment of gases in the condensers. We are also looking at gaining some benefits from reduced back pressure and a lot of other things. So, it is a kind of multi-faceted situation where you try to gain in more than one area. And I think as we move along, the more these type of projects we find, the more we reduce chemical costs and increase production because of efficiencies gained in equipment. That is going to be a much better situation for us.

Ken Nichols: I would like to talk a little about the other end of the scale that we have not talked about, small power plants. These plants seem to have a significant amount of interest for small village power and off-grid applications, and might tie in with slim hole technology. I think what we need to develop is a much more cost-effective small power plant that is very reliable and easy to maintain -- one that does not require high technology nor highly trained people, because those types of people may not be available where we might put these plants. The other advantage of small power plants is they will help the industry maintain competitiveness by serving as test facilities. By installing these power plants using slim hole technology, it will allow us to evaluate the resource and get long term data. If the resource turns out to be good, we can then build the larger plant. So, I think we need to do something to reduce the cost of these plants, and there are a few ideas running around.

Louis Capuano: The other thing I thought of, Allan, are power sales contracts. If you give us a few more of those, I am sure we can develop anything.

Unidentified Commentator: I am not one of the panel members, but certainly one of the big problems in natural gas and similar-type projects was finding fractures. The first thing done for solving this problem was providing big tax incentives, but tax incentives went away in 1992. What has happened since is that the oil and gas industry decided that the most important thing to measure is stress inside the holes they drilled to find out which way the fractures would be open. And, one of the things that we continually do not do in geothermal, which we can do in slim holes, is measure the state of stress. If we do that, we can begin to start talking about where in the subsurface producible fractures can be located.

Mike Wright: It is probably time to wrap this up. I really appreciate everybody's participation and I especially appreciate the panel's preparation. I think some good ideas have come out of this, I certainly have leaned a few things and I hope you have too.

Session 8:
Summary

Chairperson:

Allan J. Jelacic, Director
Office of Geothermal Technologies
U.S. Department of Energy

Status of GEA Review of DOE Geothermal Research Program

Philip Michael Wright
ESRI, University of Utah

The Geothermal Energy Association (GEA) will be conducting a series of workshops related to the DOE R&D program, the first of which will take place tomorrow and the next day. This workshop will be focussing on drilling research and development. Most of you probably know about this workshop scheduled for the next two days. If you have a burning desire to be there, please see me. I know some of you have already signed up but if others of you have not done so and want to come, please see me. Anybody from industry is welcome to attend on Friday.

The objective of these workshops is to provide information and recommendations to DOE on the R&D needs and priorities of the geothermal industry. As a GEA officer, I will be conducting these workshops and it is something you might guess I am interested in. I have been interested in geothermal R&D for 20 years now.

During these workshops we try and ask what the R&D priorities should be. We carefully listen to feedback we get from participants and then convey the information to the Department of Energy. We are not trying to necessarily take the place of some of the other R&D advisory committees nor do we try to replace any of them. I think the industry needs to take a look at its own problems and ask for the help that it feels it needs, independently of outside influence.

Each of these workshops are generally held for two days. During the first day, an all inclusive discussion takes place between industry participants and invitees from national labs, universities, and others who know about the topic at hand and have something good to contribute to the workshop. Discussions are focussed on the problems faced by the geothermal industry and participants have an opportunity to make presentations and put their thoughts out on the table. The second day of these workshops is for industry participants only. The industry panel considers all the inputs from prior day discussions in an informal but fairly systematic fashion. During this exercise, my role is to act as a clear channel, I hope. I do not participate but rather record the discussions and write a final report on the recommendations. This is how we conducted the Hot Dry Rock R&D workshop that was held in December of last year and we will continue to use the same format.

Our next workshop on permeability mapping and detection will be held in Santa Rosa on June 4 and 5. As most of us have observed from discussions during this last panel and others we have had over the last year, I think everybody identifies permeability detection as being one of the big problems in geothermal energy development today. We need to be able to find permeability from the surface or from a limited number of bore holes and target wells to intersect permeable regions. This is one area where we could realize significant cost savings.

Immediately following the permeability mapping and detection workshop, we will have one on reservoir production. The reason we are putting the two workshops back to back is because, as you can probably guess, a lot of the same people will be involved. Perhaps not all of the same people, but a lot of the same people. I am also tentatively planning to do workshops on energy conversion, O&M cost reduction, and on geothermal gas turbine integration probably in the July time frame. I was informed that the GRC is going to have a workshop in advance of its annual meeting in Portland that deals with O&M cost reductions. So, at this point I do not know what the GEA will do about the workshop on the same topic. We may wait and see the results of the GRC's workshop or we may have our's anyway. We will have to talk to our annual meeting committee and the people who are planning to attend that workshop.

We are also planning to have a workshop on energy conversion. This will involve primarily everything on the surface including power plants, gathering systems, cooling towers, and the effects of chemistry on the energy conversion process. A couple of weeks ago, I attended a workshop in Denver sponsored by EPRI and NREL that dealt with geothermal-gas turbine integration. I was impressed with the idea and thought that there might be a chance to look at marrying these two disparate technologies and coming up with a project that would be viable from an economic viewpoint . The motivation here is to try and create a little bit of a geothermal market in the United States, where none exists today. We must get the cost of some of our geothermal projects down to where they can more or less compete head to head with natural gas, for either new generation or re-powering. If not, we can not compete and thrive from the opportunities out there. Therefore, I plan to back to back those last three, or at least two, workshops on energy conversion, O&M cost reduction, and geothermal-gas turbine integration in the July time frame.

I also want to give a brief overview of some of the other things we have done in the GEA. On March 18 through 20, we had an open house in Washington, D.C. where we officially opened our office. Some of you already know all this, it might come as news to others though. On March 20, we had a reception for Senator Mark Hatfield on Capital Hill. Both Senator Hatfield and his wife attended and stayed with us for about 45 minutes, which is kind of unheard of. We gave Senator Hatfield a lifetime achievement award for his continued support in helping geothermal energy R&D budgets through the Senate, year after year. You might know that Mark Hatfield is the Chairman of the Senate Appropriations Committee, the full Appropriation Committee. He is probably the most powerful guy in the Senate. We hear a lot about Dole and some of the others, but Hatfield has his hands on the pull strings. So, that makes him a pretty powerful guy but he is retiring at the end of this term. He has been a constant geothermal supporter and we were very happy to give him that award.

On April 24, the GEA will participate in the House Renewable Energy Caucus Expo. You might ask, what is the House Renewable Energy Caucus? In the House of Representatives, Senator Dan Schaefer of Colorado has organized a bi-partisan caucus composed of about half Republicans and about half Democrats who support the development of geothermal and renewables energy. The caucus currently has 66 members and it is growing. Senator Schaefer wants to get it up to 100. The Expo on April 24 will be the big roll out of that program and GEA will sponsor a booth there. Pearl Dorr will be attending the booth and is responsible for the exposition. The other renewables will be there of course, and energy efficiency technologies are trying to get in on the act. So, we think that this caucus is a great step forward in terms of getting the word out, not only for renewables but more specifically for geothermal in the House of Representatives. This membership in this caucus may ultimately be extended to the Senate, too.

On June 10 through 12, the International District Energy Association (IDEA) will have a meeting in Washington and the GEA is going to be exhibiting at that conference. In return, the IDEA folks will exhibit at the GRC annual meeting. So, look for their booth at the annual meeting later this year.

Another thing coming up on June 17 through 21 is the World Renewable Energy Conference in Denver. There will be a geothermal session and Ralph Burr from the Department of Energy is responsible for that session. Both the GEA and the GRC will have booths there. A couple of thousand people are expected to attend the conference.

At the end of June, the GEA and the GRC are getting together and planning a conference with the Comision Federal de Electricidad (CFE) in Morelia, Mexico. Dave Anderson and Ann McKinney are working on the conference agenda and you may want to contact them for more information. Some of you probably will be asked to make presentations.

In August, the Institute of Electrical and Electronics Engineers (IEEE) convenes the thirty-first Intersociety Energy Conversion Engineering Conference (IECEC) in Washington, D.C. The American Society of Mechanical Engineers will be participating at this conference and will have a session on geothermal energy which is being put together by Gary Schulman and Vahab Hassani of NREL. So, if you are interested in presenting a paper, please check on whether the agenda is closed or not. I think I heard there were a dozen or so papers on geothermal, so we are well represented. If you are in Washington in the August time frame or plan to be there, try to show up at this meeting.

So, this is what the GEA has done and planning to do at this point. And just in closing, let me say that if any of you are in Washington please plan to stop by and see our office. Call Perle Dorr or Anne McKinney, make an appointment, and they will show you around. They can further help you with contacts in Washington. And, we are glad to have them. The office is up and running and we think we are making progress at last.

Closing Remarks

Allan Jelacic, Director
Office of Geothermal Technologies

Well, this raps it up for another year. Program Review XIV -- the fourteenth annual get together of the community -- was a very successful meeting. However, my opinion really does not count, it is your opinion that counts. I would therefore request you to please fill out the evaluation forms if you have not done so already. We do take your inputs seriously and we try to respond to your suggestions. Please tell us what you think and do not be afraid to criticize or suggest improvements, we will be most happy to receive them.

It is time to bid adieu, but before we do that I would like to thank some people. First of all, I would thank the people who made this possible and that is our support contractor PERI, including Alex Moore and Eyob Easwaran at the back of the room as well as Cindy Bland and Annie Peters outside. I think they did a really terrific job this year as always and I would like to give them a round of applause. Finally, thanks to all the speakers and presenters who provided a lot of useful information to all of us. Most of all, I would like to thank members of industry who came to this meeting. This meeting is really your meeting, it is set up for you and I hope you find it very useful in your work. Thank you all and see you next year.

Appendix

Geothermal Program Review XIV

The Geothermal Program Review XIV was held April 8 - 10, 1996, at the Berkeley Marina Marriott in Berkeley, California. Over 120 individuals from industry, universities and research organizations, national laboratories, DOE, and state/federal agencies were in attendance. Thirty-nine evaluation forms were received. The responses are outlined below.

Evaluation Summary

Comments from the evaluations revealed that 90% of the participants strongly agreed/agreed that the information presented increased their knowledge and/or understanding of the DOE Geothermal Energy R&D Program. Seventy-seven percent strongly agreed/agreed that holding concurrent sessions was a way to effectively spend their time at the conference. As for the panel discussion format, 84% strongly agreed/agreed that it improved information exchange and increased interaction among government, industry, and utility participants. Ninety-seven percent of the participants strongly agreed/agreed that the conference logistics were well-arranged and organized. Overall, 92% of the participants strongly agreed/agreed that the conference was excellent.

Suggestions for Future Topics

- Bring in some manufacturers - there weren't any speaking, though a few were present. What are their needs? What would it take to get them involved? What involvement is desired?
- Invite a speaker from California Energy Commission for the overview session or a luncheon speaker
- Suggested topics:
  * How do we sell America on Geothermal as the major power generation source?
  * Direct Use
  * Detailed multi-year hot-water reservoir studies and reporting of case histories
  * Injection in hot-water reservoirs and reservoir management
  * Financing and Market Development
  * International - does DOE really have a program?
- Include a policy discussion for new participants, i.e, without the predictable inputs of the usual speakers
- Include laboratory presentations on capabilities related to geothermal technology
- Focus on a few items and have more depth to the technology

Suggestions to Improve Future Conferences

- Include break-out sessions and working groups to identify areas to focus DOE/National Lab Research
- Some of the meeting rooms were too small for the audience; invitations were much too late for proper planning!
- Include the R&D works from California Energy Commission
- Please allow the payment of registration fee by credit card
- Have separate discussion panels for each area of the Geothermal markets (i.e. Exploration, Drilling, Reservoir, Production); perhaps another way would be include New Technology/Geothermal Technology
- The concurrent sessions created conflicts of areas of equal interest
- Make panel discussions shorter - 1½ hours
- Do not think panel discussions are effective in getting information and technology transferred
- Have more informal opportunities to network and interact with other participants - I believe it would pay off to DOE (who wishes to communicate its programs) and to industry participants (who are looking at way to remain competitive)
- Expand conference a ½ day or a day, if needed, to cover all topics in single sessions
- Where major breakthroughs have not taken place, don't have topics presented each year
- This is not a conference - it is a review for the tax payers by R&D performers. Thus the idea of papers is not appropriate. Reports is a more correct term. Formality of papers restricts discussions.
- Free lunch would be nice!
- Supply one or offer copy of each speaker's overheads and slides

Other Comments

- Seems like it's always the same cast of characters and cronies of DOE program managers. The "good old boy" network is alive and well in the DOE Geothermal division. It's difficult for progress to be made on R&D when the division cannot open their eyes to new ideas and new/different researchers.
- Scheduling the meeting to start right after Daylight Savings Time reduces jet lag by 1 hour!, but I still think March is a better month to have the meeting - please hold the meeting at a downtown hotel so we can go out in the evening
- An industry panel could be used to review the DOE program and make suggestions as to improvements by ranking projects as to industry priority
- Very well done; planning support excellent
- Should be held in conjunction with a technical conference - i.e., GRC Annual Meeting
- The current emphasis on drilling R&D is rewarding
- Balance in R&D (among short, mid, and long term) is extremely important
- Have conference closer to the city - it's difficult without a car
- It would be nice to try a meeting in Santa Rosa and maybe a tour. This is one of the most useful meetings of the year. Keep it up.

- Berkeley Marriott was a good venue for this meeting
- Return to Berkeley Marina (or similar facility); much improved communications/ discussions due to limited space and lace of "big city" distractions
- Why are conferences held annually in Bay area? How about having them in Southern California or Nevada once in a while? Although industry in those areas have some représentations here, as a whole, they were under represented at this review.

Final Agenda

Monday, April 8, 1996

7:00 - 9:00 pm	Opening Reception and Conference Registration

Tuesday, April 9, 1996

8:00 - 9:00 am	Continental Breakfast and Conference Registration
9:00 - 11:45 am	**Overview Session** **Chairperson - Allan Jelacic, Director, Geothermal Division, U.S. Department of Energy**
9:00 am	Welcome and Announcements Allan Jelacic, Director, Geothermal Division, U.S. Department of Energy
9:15 am	OUT Keynote Presentation Allan R. Hoffman, Acting Deputy Assistant Secretary, Office of Utility Technologies, U.S. Department of Energy
9:35 am	California Energy Company Presentation Thomas R. Mason, President and Chief Operating Officer, California Energy Company
10:00 am	BREAK
10:30 am	Geothermal Energy - Business Challenge - Technology Response Darcel L. Hulse, Group Vice President, Geothermal and Power Operations, Unocal Corporation
10:55 am	Maintaining a Competitive Geothermal Industry V.P. Zodiaco, Executive Vice President, Oxbow Power Corporation
11:20 am	Where Is the Geothermal Program Heading? Allan Jelacic, Director, Geothermal Division, U.S. Department of Energy
11:45 am - 1:30 pm	**GEA Luncheon - Utility Deregulation**

Tuesday, April 9, 1996 (continued)

1:30 - 5:30 pm	**Concurrent Session A - Exploration and Reservoir Technology** **Chairperson - Tsvi Meidav, Trans-Pacific Geothermal Corporation**
1:30 pm	Introduction Tsvi Meidav, Trans-Pacific Geothermal Corporation
1:40 pm	Overview Marshall Reed, Geothermal Division, U.S. Department of Energy
2:00 pm	Fracture Mapping Dennis Nielson, Earth Sciences and Resources Institute, University of Utah
2:20 pm	Integrated Exploration Tools Paul W. Kasameyer, Lawrence Livermore National Laboratory
2:40 pm	Summary of Geothermal Research at the Idaho National Engineering Laboratory G. Michael Shook, Idaho National Engineering Laboratory
3:00 pm	BREAK
3:30 pm	Tracer Research at ESRI Michael C. Adams, Earth Sciences and Resources Institute, University of Utah
3:50 pm	Advances in the TOUGH2 Family of General-Purpose Reservoir Simulators Karsten Pruess, Lawrence Berkeley National Laboratory
4:10 pm	Overview of Fundamental Geochemistry Basic Research at the Oak Ridge National Laboratory David J. Wesolowski, Oak Ridge National Laboratory
4:30 pm	Combined Case Study Overview - Coso, Basin and Range, and Sumikawa Field, Japan Sabodh K. Garg, S-Cubed
4:50 pm	Focus of the Hot Dry Rock Program After Restructuring David V. Duchane, Los Alamos National Laboratory
5:10 pm	Review of Geothermal Research at the U.S. Geological Survey John H. Sass, U.S. Geological Survey, U.S. Department of the Interior
5:30 pm	Adjourn for the Day

Tuesday, April 9, 1996 (continued)

1:30 - 5:10 pm	**Concurrent Session B - Energy Conversion** **Chairperson - Ken Nichols, Barber-Nichols, Inc.**
1:30 pm	Introduction Ken Nichols, Barber-Nichols, Inc.
1:40 pm	Overview Raymond LaSala, Geothermal Division, U.S. Department of Energy
2:00 pm	Summary of Materials Research Lawrence E. Kukacka, Brookhaven National Laboratory
2:20 pm	Next Generation Geothermal Power Plants Study Mai Hattar, CE Holt Company
2:40 pm	Turbocompressors for Noncondensible Gases Ken Nichols, Barber-Nichols, Inc.
3:00 pm	BREAK
3:30 pm	Operation of Mammoth Pacific's MP-100 Turbine with Metastable, Supersaturated Expansions Gregory L. Mines, Idaho National Engineering Laboratory (invited)
3:50 pm	Heat Rejection Studies Carl Bliem, Consultant to the National Renewable Energy Laboratory
4:10 pm	Demonstration of a Biphase Topping Turbine Lance Hays, Douglas Energy Company
4:30 pm	Recent Advances in Biochemical Technology for Processing Geothermal By-Products Eugene T. Premuzic, Brookhaven National Laboratory
4:50 pm	Chemical Models for Optimizing Geothermal Energy Production John H. Weare, University of California at San Diego
5:10 pm	Adjourn for the Day

Geothermal Program Review XIV

Wednesday, April 10, 1996

7:30 - 8:00 am	Continental Breakfast and Conference Registration
8:00 am - Noon	**Concurrent Session A - The Geysers** **Chairperson - Steven L. Enedy, Northern California Power Agency**
8:00 am	Introduction and Overview Steven L. Enedy, Northern California Power Agency
8:30 am	Geologic Research at The Geysers Jeffrey B. Hulen, Earth Sciences and Resources Institute, University of Utah
8:50 am	Microearthquake Source Mechanism Studies at The Geysers Geothermal Field California Ann Kirkpatrick, Lawrence Berkeley National Laboratory
9:10 am	Optimization of Injection into Vapor-Dominated Geothermal Reservoirs Considering the Effects of Adsorption Roland N. Horne, Stanford University
9:30 am	Injection Tests in the Southeast and Central Geysers Benjamin J. Barker, Unocal Geothermal Division
9:50 am	Southeast Geysers Effluent Pipeline and Injection Project Mark Dellinger, Lake County (CA) Special Districts
10:10 am	BREAK
10:40 am	Power Plant Retrofits at The Geysers - Past, Present, and Future Carl Paquin, Pacific Gas & Electric Company
11:00 am	Panel Discussion: Lessons Learned at The Geysers and Next Steps Moderator: Marcelo J. Lippmann, Lawrence Berkeley National Laboratory
Noon - 1:30 pm	Lunch (not hosted)

Wednesday, April 10, 1996 (continued)

8:00 - 10:40 am	**Concurrent Session B - Drilling** **Chairperson - Louis E. Capuano, Jr., ThermaSource, Inc.**
8:00 am	Introduction Louis E. Capuano, Jr., ThermaSource, Inc.
8:10 am	Overview David A. Glowka, Sandia National Laboratories
8:30 am	Slimhole Drilling John T. Finger, Sandia National Laboratories
8:50 am	Development of Advanced Synthetic-Diamond Drill Bits for Hard-Rock Drilling David A. Glowka, Sandia National Laboratories
9:10 am	Status of the NADET Program Carl R. Peterson, NADET Institute, Massachusetts Institute of Technology
9:30 am	Advanced Drilling Systems Study Kenneth G. Pierce, Sandia National Laboratories
9:50 am	Lost Circulation David A. Glowka, Sandia National Laboratories
10:10 am	BREAK
10:40 am - Noon	**Concurrent Session B - Direct Use and Geothermal Heat Pumps** **Chairperson - David Anderson, Geothermal Resources Council**
10:40 am	Introduction and Overview David Anderson, Geothermal Resources Council
11:10 am	Capital Cost Comparison of Commercial Ground-Source Heat Pump Systems Kevin Rafferty, Geo-Heat Center, Oregon Institute of Technology
11:35 am	Geothermal Heat Pump Consortium Paul Liepe, Geothermal Heat Pump Consortium
Noon - 1:30 pm	Lunch (not hosted)

Wednesday, April 10, 1996 (continued)

1:30 - 3:25 pm	**Cutting Costs Panel Discussion** **Moderator - Phillip Michael Wright, Earth Sciences and Resources Institute, University of Utah**
1:30 pm	Introduction Phillip Michael Wright, Earth Sciences and Resources Institute, University of Utah
1:35 pm	10-minute Opening Remarks by Panelist #1 (to highlight exploration cost-cutting) Gerald Huttrer, Geothermal Management Company, Inc.
1:45 pm	10-minute Opening Remarks by Panelist #2 (to highlight drilling cost-cutting) Louis E. Capuano, Jr., ThermaSource, Inc.
1:55 pm	10-minute Opening Remarks by Panelist #3 (to highlight reservoir management cost-cutting) Mohinder Gulati, Unocal Geothermal Division
2:05 pm	10-minute Opening Remarks by Panelist #4 (to highlight energy conversion/power plant cost-cutting) Daniel Schochet, Ormat, Inc.
2:15 pm	10-minute Opening Remarks by Panelist #5 (to highlight operation and maintenance cost-cutting at dry steam plants) Timothy W. Hollingshead, Pacific Gas & Electric Company
2:25 pm	10-minute Opening Remarks by Panelist #6 (to highlight operation and maintenance cost-cutting at dual flash and binary plants) Panelist #6 TBD
2:35 pm	Panel Discussion All
3:25 pm	BREAK
3:55 - 4:25 pm	**Summary Session** **Chairperson - Allan Jelacic, Director, Geothermal Division, U.S. Department of Energy**
3:55 pm	Status of GEA Review of DOE Geothermal Research Program Phillip Michael Wright, Earth Sciences and Resources Institute, University of Utah; and Thomas R. Sparks, Unocal Corporation
4:15 pm	Closing Remarks Allan Jelacic, Director, Geothermal Division, U.S. Department of Energy
4:25 pm	Conference Adjourns

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