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The Role of Research in the Changing World of Energy Supply

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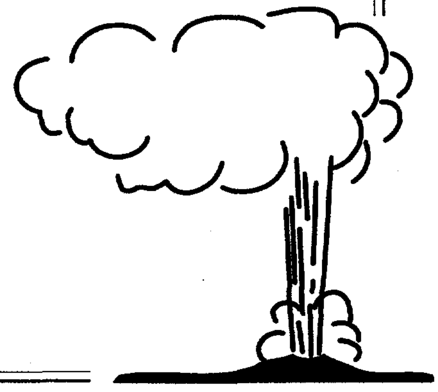

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Preface

The U.S. Department of Energy's Office of Geothermal Technologies conducted its annual Program Review XV in Berkeley, March 24-26, 1997. 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 "The Role of Research in the Changing World of Energy Supply."

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 XV consisted of seven 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 XV helped ensure its success.

Allan Jelacic

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

Session 1:

Overview

The New World Ahead

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DOE Office of Utility Technologies

Note: This article has been reprinted from the May issue of the GRC bulletin. It is based on a presentation made at the DOE Geothermal Program Review XV in San Francisco on March 28, 1997.

Restructuring of electric generation markets is a topic that's on everyone's minds and lips these days, especially in Washington, D.C. The U.S. Department of Energy (DOE) is deeply involved in drafting utility restructuring legislation for the Clinton Administration--legislation that is currently undergoing a thorough interagency review.

It is widely recognized that restructuring will ultimately determine the environment in which renewable technologies are going to compete in a deregulated power generation market. It is also recognized that restructuring presents a series of challenges--as well as a series of opportunities--for the renewable energy industry as a whole.

First, the challenges. Certainly, with increasing competition a reduction in generation costs is important, and options to achieve that are now being carefully considered.

On Capitol Hill, the question is frequently asked, "How can any renewable resource compete with 1.8 cents/kilowatt-hour electricity generated with natural gas?" The fact is, nothing can right now. But in the long run, fossil fuel costs will rise and reserves will dwindle, forcing the world to rely on a different energy system. It's just a matter of time.

The Public Utilities Regulatory & Policy Act (PURPA), which stimulated a lot of activity in the renewable industry, is now under attack by many interests. Those with renewable energy contracts under PURPA know that some of those contracts are likely to be traded away at some point in the new competitive generation environment.

And old issues of integrating intermittent renewable generation like solar and wind into the electrical grid are being raised again as the restructuring debate proceeds. For renewables like biomass and geothermal, this is not an issue because they are both baseload power sources.

At a time when federal restructuring is pending and the national debate over a competitive electricity generation market is under way, many of us in the power sector are unsure of the future. That market uncertainty presents a challenge for all of us in government and industry to maintain solid support for our technology development activities.

I believe that renewables are going to do well in a restructured environment, because increasing competition means that customers can express their preferences in ways that they could not in the past. Clearly, there is a strong desire by many electricity customers for "green" energy, environmental protection and for energy systems that create jobs and new export markets.

We're already starting to see the beginnings of an important new renewable market thrust in this country--"green pricing." And though I don't believe the market for green power will carry the day for renewables by itself, it's a very important trend.

People understand that environmental protection is important. Seventy percent of those surveyed indicate their belief that climate change is a serious issue that must be addressed. Early indications are that people are willing to pay more for clean energy. Renewable energy technologies are environmentally attractive. A number of utilities are already involved in renewables, and many more are getting the message from their customers.

When a major Texas utility surveyed its ratepayers, they were surprised to learn the depth of support for energy efficiency and renewable power. As a result, the utility is establishing an aggressive green marketing program. At the same time, many other utilities are beginning to recognize that if they are to compete in a deregulated environment, they will have to provide services their customers want. And green energy is a service that customers want.

There's been a lot of discussion about "public benefits" in the new competitive generation environment, including low-income support, renewables, efficiency, the environment, and research and development. I don't think there is any question that there will be continuing support for these public benefits. But I suspect there will be a tradeoff between support for paying off stranded assets--mostly nuclear--and support for the public benefits of renewable energy options. There's also a lot of discussion about portfolio standards, wires charges and so on, but one way or another, we will continue public support for renewable technologies.

If there is one incentive for renewables that I would fall on my sword for, it is net metering, where individuals can sell locally generated power to utilities at the same rate that they purchase power from them. Currently, many utilities sell power at the full market rate, but buy power at their avoided cost rate, which is usually a third or a fourth of the market rate. Net metering is a national policy in Japan and Germany, and 17 states in this country have implemented net metering programs. It is an important policy incentive that encourages people to install renewable technologies at their homes, businesses and industries.

There's been a lot of debate over the right approach to continuing support for renewables, and I suspect it will go on for several years. But I am hopeful that legislation will come from the 105th Congress.

The first federal legislative proposal on restructuring came from Rep. Schaefer (R-CO), chairman of the House Renewable Energy Caucus, and that bill is now under consideration. Schaefer wants to mandate customer choice by the year 2000, while Sen. Dale Bumpers' (D-AR) legislation would mandate choice by 2003. Both bills include portfolio standards to assist market penetration of renewables.

Why are renewables important? Just about all renewable technologies have proven their effectiveness and reliability, and that is certainly the case for geothermal projects.

We are working to improve the technical performance of renewable technologies, which may be the easiest problem we have to address. The harder problems are how to get renewable technologies into people's hands, how to pay for them, and how to set up the non-technological infrastructure needed for widespread renewable deployment.

Certainly in many applications around the world, renewables are the least-cost power option. Our thinking on power cost is distorted in this country because of our low energy prices. But outside the United States, it's a very different world. In Japan, electricity costs the consumer 20 to 25 cents per/kWh. In Germany, the numbers are in the range of 18 to 20 cents/kWh. Even in Alaska, electricity costs range from 40 to 60 cents/kWh.

And in many parts of the world it's hard to put a price on electricity because there is no access to it. In fact, over two billion people in the world have no access to electricity, even in this day and age. And there is probably another billion people who have such limited access, that for all intents and purposes, it is no access. Considering that the world's population is 5.8 billion, these figures represent a significant portion of the people on the earth.

Renewables in various forms are suitable for off-grid applications, and are already cost effective in many cases where it is too expensive to extend electrical transmission infrastructures.

There's a lot of economic and job creation potential here. And renewables are obviously the most environmentally responsible technologies available for power generation--as well as for transportation which is a major energy issue in the United States.

The World Bank has estimated that over the next 40 years developing countries alone will require five million megawatts of new generation capacity to meet the needs of their citizens.

What does five million megawatts mean? The world's total installed capacity today is less than three million megawatts. Even if the World Bank's estimate is off by a factor of two, we will essentially have to double installed world generation capacity in the world during the next 40 years.

So what does this mean in dollar terms? A reasonable range for installing new capacity is $1,000 to $2,000 per kilowatt, which translates into $5 trillion to $10 trillion without the cost of associated power transmission infrastructure.

From the point of view of renewables--which obviously will not be able to capture a large percentage of that capacity in the near-term--every one percent of the projected worldwide need for new capacity represents $50 billion of investment. If renewable technologies can capture several percent of that need, we're looking at a potential for several hundred billion dollars of potential renewable technology sales worldwide over the next four decades.

We're very fortunate in this country to have a large base of renewable energy options. We're bringing down the cost of wind technology and solar cells while raising their efficiency, and certainly in geothermal much is being done to reduce costs and improve exploration and development technologies. All of these activities are important for making renewable competitive.

Shipments from the photovoltaic (PV) industry are still very small, but are growing rapidly. We have currently reached our production capacity in the United States, but will be dedicating many new manufacturing facilities this year. We fully expect this sector to grow very rapidly, with PV technology integrated into building construction a major focal point for public access as solar costs continue to decline.

Many parts of the country--especially the Southwest--can potentially generate large quantities of electricity with PV and solar thermal technologies. PV cells with currently available 10 percent conversion capability covering only one tenth of Nevada's 13,000--acre site where nuclear weapons were once tested would generate three trillion kilowatt-hours of electricity--or all of the nation's current electricity demand!

Though the U.S. wind industry is struggling right now, the world is taking off with this technology, with approximately 6,000 megawatts of installed wind capacity. The United States was Number One for a long time, but Europe is now the world leader. Germany is first in new installations there, while India now has over 700 megawatts of installed wind capacity--a number that is growing rapidly. And we hope that with new developments in coming years, U.S. wind technologies can recapture a significant share of the world market.

The United States has a lot of wind potential. Most U.S. wind capacity is currently in California (17,000 machines), but there are about a dozen states that have more wind potential than the Golden State, mainly from the Dakotas south to Texas. Today's machines provide power at 5 cents/kWh with a 17-mph average wind speed. The next generation of machines should produce power at 2.5 cents/kWh at 15 mph, or just under four cents/kWh at 13 mph. With these technology, we can open up the wind market in the Plains States.

We are very fortunate both in the United States and around the world to have a lot of biomass. It is CO_2 neutral, and of course it is a baseload power source. With this renewable energy option we have an opportunity to combine agricultural policy with energy policy, to allow farmers to grow dedicated energy crops that provide revenue while getting them off government subsidies for not growing crops.

We can convert biomass into energy in a variety of ways. We can burn it, but in the long run the most effective way is to gasify it for fueling high-efficiency combustion turbines. DOE has a series of projects underway to determine how to most effectively use biomass for energy production. We're learning to do that with bagasse in Hawaii, wood in Vermont, switch grass in Iowa, and alfalfa in Minnesota. Finally, the export market for biomass power equipment will be very large.

And there are a lot of interesting things happening in the geothermal industry. The goal of 3.5 cents per kWh for a 200°C, 1,500-meter deep hydrothermal facility depends on many technological factors such as chemistry and drilling methods, but the industry is moving toward being competitive with natural gas.

The geothermal industry has made a lot of very important progress in slimhole drilling, reducing the cost of characterizing geothermal sites, and the new bi-phase turbine increases the efficiency of extracting energy from geothermal steam and water. The industry is making advances in binary systems to get more energy from a given amount of input, and a five percent efficiency boost has been realized at The Geysers in California with direct contact condensers. And though some independently operated geothermal plants are about to go "over the cliff" with loss of Standard Offer contracts, California is trying to be responsible as it puts its electric competition law into effect.

Finally, deployment of geothermal heat pumps is going very well. We expect a reduction of some 2,000 megawatts of peak electricity demand with the installation of ground-source heat pumps by the year 2000. Working through the Geothermal Heat Pump Consortium, we have a major partnership with the electric utility industry to increase deployment from 40,000 per year in 1994 to 400,000 by the year 2000.

If we are to make a difference in people's lives in most parts of Africa, South America or Asia, we have to provide them with free-standing power sources. When people have no power source to start with, giving them even a 30- or 40 watt photovoltaic panel or small wind machine can make a very large difference in their lives. On a village basis, we may be able to develop local geothermal resources as well.

Perhaps most important of all, people are beginning to smell real money in selling renewable technologies, and that's what it will take to achieve widespread deployment. Geothermal has been working for a long time to make a go of it financially, and emerging renewable technologies like photovoltaics are starting to take off.

Electricity is already big business in the United States, with over $200 billion in annual sales. Worldwide sales are $900 billion, and growing rapidly. And large companies are getting into the business of selling small power systems around the world.

An important point in promoting renewable is that they are localized energy sources. When most U.S. communities buy energy, they are buying it from somewhere else--they are importing either energy or fuel, and exporting dollars that are not invested in their communities. This is an important issue, because when local communities export dollars they are exporting jobs as well. If that money could be invested locally through renewable technologies, those communities would benefit economically. *Dollars from Sense, the Economic Benefits of Renewable Energy*, a nearly completed report from the National Renewable Energy Laboratory, documents the economic impacts of renewable energy options on local communities.

The important message that must be brought home is that by generating our own energy locally, we really do help the local economy. On a national basis, we're importing $50 billion worth of oil right now--money that is not being invested in the United States and returning benefits to us. If we continue on the path we're on right now, that number will grow to $100 billion in the early part of the next century.

Renewables fit into many parts of the power sector--both for generation and support of the transmission and distribution network. Geothermal is an extremely important technology in that regard. It is attractive environmentally, and has great potential around the world.

The United States is a geothermal technology leader and we must maintain that position, though we're up against some really tough international competition. Other countries with geothermal interests support their geothermal industries in ways that we are just learning to do--but there is political resistance to such methods here.

A big issue in Washington is corporate welfare. In my opinion it's a phony issue. We have to work with our industries if we are to be competitive in the global market. We would be naive if we tied our hands behind our backs for ideological reasons, while other countries like Denmark, Germany and Japan are working closely with their industries to capture attractive global markets.

Investments in technology are important to the future economic health of our country. It shouldn't be a partisan issue--it's just smart policy.

Looking at the world energy situation, I conclude there is no way to project today's system into the long-term future. We are going to be using fossil fuels for a long time, and like the past, the transition to a different energy system will take 50 to 100 years. But we cannot continue indefinitely with today's world of high dependency upon fossil fuels, especially when you see the Chinese and the Indians starting to consume energy as we have.

Just think about transportation issues alone. If a reasonable fraction of Chinese and Indians start driving cars the way we do, demand and prices for petroleum resources will spiral out of control, international supply problems and resulting tensions will be very serious, and the environmental consequences will affect all of us. It just won't work.

Ultimately, we will have to move to a different kind of energy system, but it will take time. We will learn to run cars on something other than oil--we will move to electric drive for our wheels. The only question is where the electricity will come from, whether from a fuel cell initially run on natural gas and eventually from hydrogen or advanced batteries. The point is that we have to move to a different transportation system, and so will the rest of the world.

And finally, there is a limit on the earth's fossil fuel resource. Whether it takes another 50 or 100 years, it will run out--we know that. Even the head of Shell UK Ltd., a highly respected strategic planner, has said, "There is clearly a limit to fossil fuels. Fossil fuel resources and supplies are likely to peak around 2030, before declining slowly. Far more important will be the contribution of alternative renewable energy supply." That is the future.

For many reasons, financial and otherwise, I don't see nuclear filling the energy needs of developing countries. I believe renewable resources in all their different forms will be the basis of the new world energy system. We're going to use what we have where we have it--all renewable energy is local. But there is no question that we are moving toward this major transition.

Geothermal resource development is an important part of that transition--and DOE will continue to work with geothermal and your colleagues in the other renewable industries to make sure that we get to that new world as quickly as we can.

COMMENTS BY
R. BRENT ALDERFER
COMMISSIONER
COLORADO PUBLIC UTILITIES COMMISSION
TO THE GEOTHERMAL PROGRAM REVIEW 15
MARCH 25, 1997

RESEARCH TO DIE FOR--R&D IN THE COMPETITIVE ELECTRIC MARKET

"Scientists must adapt to doing more with less," part of the headline, Rocky Mountain News, March 8, 1997.

You may know this news better than anyone. Federal programs provided 50 percent of the nation's science and engineering support in 1976. By last year the number was 35 percent.

Reporting the message of the National Science Foundation, Director, Neal Lane, at a symposium on March 6th, the article continued:

> Funding for individual scientists to pursue knowledge is fading, but . . . tomorrow's <u>administrators</u> will need a scientist's knowledge . . . if industries are to prosper in the competitive global marketplace.
>
> "Scientists will be in the thick of the turmoil," Lane said. "It will raise science and engineering to a much more prominent level in the 21st century."

So is that what's ahead, more prominence, less dollars?

This article caught my eye because I thought maybe that was why you asked a state utility commissioner to speak here today. So that you could see live what that future looks like--less dollars, more prominence. Okay, so we're not prominent either, so maybe that isn't the reason I'm here.

In fact the regulators' future in a competitive market is rumored to be even less promising than R&D.

I am here both personally and in my role as chairman of the Renewables Subcommittee of the NARUC Energy Resources Committee. I am optimistic that we can strengthen renewable energy and R&D in a competitive electric market?

My article of faith is customer choice.

As distinguished from retail wheeling, unbundling, or even direct access, customer choice is the 800-pound gorilla of electric restructuring.

Even though in some ways the debate of restructuring is just opening, with the actions of several of the states that are leading in this area, notably California among them, and with nothing more, 30 million customers will choose their electricity suppliers starting January 1, 1998. That covers territory with population of 80 million people, approaching one-third of the U.S.--a multi-billion dollar market that for the most part doesn't yet exist.

That's where we are at what is just the beginning of the national debate on deregulation. Real debate on several Congressional bills, including Congressman Schaefer's and Senator Bumpers' is just underway. The Administration's bill is expected the end of this month or early next month.

As you know, this is a global shift to competitive markets. The United Kingdom led the charge to free the colonies on this one. South America is well along, and as I said, we are coming along.

Okay, how does this move to global competitiveness in the electric industry play out for renewable funding, and specifically for R&D?

Unfortunately, often what I hear so far is, "when competition hits, there ain't gonna be no more renewables funding," let alone R&D. In fact I would say it is that assessment--"there ain't gonna be none"--that I most often hear as the reason to support renewables portfolio provisions and other policies currently under consideration for support of renewables. This is what someone yesterday called the "help me, I am handicapped approach."

We need a much more powerful animal than that.

Luckily, we've got one. The gorilla--customer choice.

Even in states not open to competition, monopoly utilities are serving up real-time tariffs, green pricing, industrial discounts, energy services, financing and other customer-choice options.

What does customer choice mean for renewables generally and R&D specifically?

Well for starters there is money in it, judging by the lobbying and public relations campaigns.

Senator Murkowski has called electric deregulation the "pinata of lobbying." And financial reports of donations to key members of Congress support that title.

The Edison Electric Institute levied a special assessment on member power companies to raise $3 million in lobbying funds for electric deregulation, and I've heard the comment that they should have raised more.

How many of you saw the Super Bowl advertisement "Nobody likes a monopoly?"

Reportedly that ad is part of a $200 million current-year advertising budget--that's one company, one year--to build support for deregulation.

You might ask yourself as you consider the rest of these comments, who was ENRON marketing to? Who was the Super Bowl ad directed to?

So there are dollars being spent. The question is where do we end up on renewables and R&D?

Well let's start with the customers.

Customer preference surveys, nationally, show remarkably consistent demand for clean and green generation well in excess of the current generation mix, which is thought to be about 2 to 2 1/2 percent non-hydro renewable, nationally. Thus far, retail choice pilots bear out the customer preference surveys on green choice and efficiency.

Some examples:

A national telephone survey of voters by a partnership of eight utilities from Pennsylvania to the West Coast (Allegheny Power, Cinergy Corp., PacifiCorp, Pennsylvania Power & Light, Portland General Electric, Utilicorp United, Wisconsin Energy Corp. and Wisconsin Power & Light) reportedly found 80 percent of voters favored (53% strongly favored) strong environmental standards applied equally to all fossil fuel power plants.

Sixty eight percent of voters who defined themselves as very conservative reportedly favored the environmental standards. A strong majority, 69 percent, favored mandatory investments in energy efficiency, and 57 percent favored a Renewable Portfolio Standard to establish a minimum percentage of renewable energy.

Utility specific surveys prompted by new market opportunities are uncovering the same profiles.

Three Central and South West Company utilities in the sovereign energy state of Texas conducted week-end-long town meetings on energy choices with, what they term, scientific random samples of customers. They polled their customers before and after the event, in what is called deliberative polling.

The Texas utilities listed these conclusions:

Customers want a mix of resources

Customers want to pursue efficiency first (assuming cost of options were the same)

Customers are willing to pay most extra for renewable options ($5-$7 per month)

Customers have strong environmental concerns

Customers have some concern about competition

The numbers were very consistent with the other national and regional results, virtually down to the percentages, with some 80 percent putting air pollution concerns as serious or very serious, and 30 to 40 percent willing to pay $5 or more per month for renewables.

The pilot direct access programs in New England tracked the same numbers, with thirty percent to a third opting for higher monthly bills in favor of what was thought to be green power. Now, yes it is true the Green rate was below what the customers were formerly paying from their utility, but it was higher than competing suppliers. And rather than a reason to discount the results, I would say it is a circumstance and opportunity that exists in many areas of the country with high electricity prices, thanks to nuclear, PURPA contracts or other circumstances.

These deliberative polling results are very interesting because they may offer a glimpse into the future of consumer choice markets, where more street-smart consumers have sorted through the claims (or come through the abuse?) and have become educated in the market.

So what about the notion that everyone favors green until they find out the costs? Did it show up? It did, very strongly. The percentage of customers saying the utility should pursue renewables as the first choice dropped significantly following the town meetings--in all three service areas--in favor of efficiency as the first pick, and to a smaller extent, fossil fuels as the first pick.

So did these results dampen the utilities' enthusiasm for renewables? No, just the opposite. These Texas utilities report that they are hard at it, developing green product offerings to meet the demand. Why? Because while the virgin view of renewables lost ground when customers got a better picture of the costs and options, the percentage of customers (in all three service territories) willing to pay more for renewable energy, from $1 to $7 per month more, went up a lot, from 2 to 3 times, depending on the price. Music to a marketer's ear.

Other utilities have followed the same path and come out in the same place--with more green product offerings.

In my state of Colorado, where there is no competitive retail market for electricity, we recently approved a green-pricing tariff for Public Service Company of Colorado. The monopoly utility's customers may choose to pay a premium of 2.5 cents per kilowatt/hour for wind energy. Customers can sign up for 100 kilowatt/hour per month blocks of power (that's $2.50 per month extra per block) from wind generation facilities to be newly constructed based on the subscriber uptake. Average residential customer use being about 500 kilowatt/hours per month, total wind energy would add $12.50 per month. Selecting only two blocks would allow customers to choose the $5.00 per month range that polls say is optimal.

The news on March 22, 1997 reported that before doing any marketing, Public Service opened up the program for subscriptions and 100 people called in to subscribe. Whether you think that is a lot or not, more are certainly needed to complete that program, but what was the company's take on it? The Company was cheered and surprised, the article said, quoting the company spokesperson as saying, "If this is an indication of things to come, I think the people of Colorado definitely are telling us this is what they want, and what we want to provide them with choices."

Customer choice without deregulation? I would say so. And if it works, it will be the first utility-sponsored wind generation, up to 20 megawatts, in Colorado.

Okay the customer choice gorilla is hungry, and apparently he wants more greens in his diet. If we court this customer choice gorilla as I suggest, is there any money in it for renewables? And how does that get translated into applied R&D?

First of all I think as engineers and scientists we don't like to think about marketing or sales promotions, or that the public has anything to do with research or development, or should. We somehow think it isn't quite ethical. By the way, I still like to think of myself as an engineer, with my EE degree in 1974--after that I went bad and went to law school. Those lawyer jokes are getting so bad, I prefer to think of myself, when I can, as an engineer.

Back to marketing, I say another way to look at ethical marketing is if you believe that the product you're offering has the value and is worth the price premium you're asking, then that is ethical marketing, at least it is marketing I can feel good about. If you do not believe it is worth it, than that would be unethical marketing.

But the comparison or complaint from the renewables community that natural gas prices are too low, or we can't compete with low price alternative, misses the marketing opportunity. When selling a car, you wouldn't say: this is great car; it has many valuable features that make it a perfect car for you, but I don't think you should buy it because it costs more; I think you should buy a Ford Falcon. We wouldn't take that approach, because it doesn't reflect the value we see in the product. It also doesn't sell the product.

And marketing response of the public opinion may ultimately decide every scientific research agenda, and having public opinion with you, rather than against you, may mean everything.

I want to look at four examples of successful or long-standing research projects fueled by public opinion: (1) the search for the missing link in human evolution, (2) the Copernican theory of a helio-centered universe, (3) the NASA space program, and (4) the nuclear energy program. Don't worry this will be a quick look.

The public debate and associated search for missing links between species, particularly between humans and apes, we usually associate with the publication of the Origin Of Species, in the mid-19th century.

But according to a book I am reading by Ken Wilber, out of Boulder Colorado, the public fascination started earlier. Rousseau asserted in 1753 that humans and higher apes were members of the same species.

And guess what famous policy maker may have been the first to turn this inquiry into financial gain? None other than P.T. Barnum. Almost one hundred years later, in advertising in 1842, Barnum described these exhibits in his show:

> the Ornithorhincus, or the connecting link between the seal and the duck, two distinct species of flying dish, which undoubtedly connect the bird and the fish; the Mud Iguana, a connecting link between reptiles and fish--with other animals forming connecting links in the great chain of Animated Nature.

This was nearly two decades before the publication of the Origin of Species.

Let's call this the Barnum/Darwin partnership for purposes of our discussion.

Public debate and recognition also preceded the scientific theory of a heliocentric universe. One of the principal proponents of a decentralized universe was a man named Giordano Bruno. And it was the public debate not the research findings on the possibility of other inhabited worlds that as Wilber says "jolted the medieval mind out of the Middle Ages and into the Renaissance." The research agenda to answer the question followed with Galileo and Kepler looking for what now had crossed the line of public recognition.

And what was Giordano's reward for his public leadership in bringing forth this public research agenda? Well he came to the attention of the Inquisition, and he was burned at the stake. That was literally research to die for.

Yet the research agenda he helped launch, the search for inhabited worlds, continues to receive funding and make the news today.

Likewise, the highest profile research projects today, NASA space program and nuclear power plants, both I would say, arose out of strong public leadership and recognition. Not public consensus but recognition. John Kennedy's declaration of a man on the moon is approaching 40 years. Whether you like the results of those programs or not, no one would argue they don't command large amounts of money.

Learning by example from these legendary research efforts, how do we compare? How have renewables done in jolting the public mind in the 20th century?

Most of us would agree funding will be down. Referring to these declines, your key note address last year said, "We have also seen little in the way of externality revenues domestically, in spite of the fact that we hear most people support renewables. That support has not been translated into increased payments for renewables."

I agree. I wouldn't agree that it can't be, but I agree that is has not been.

So I urge you to go public. Now's the time. The market and market opinions are just now being formed and will be formed beginning January, 1998, for the 30 million residents then open to choice. Individually and as an industry, the Bruno proponents of renewables need to take renewable issues to this next level of public recognition. Having all the answers is not required. That's what the R&D is for. Getting the attention of the Customer Choice gorilla is absolutely necessary.

Now let me note something here. I often hear renewables advocates saying, well we don't know if the number will hold up, whether the surveys will result in actual sales. It will or it won't, based on the marketing and public appeal. The survey is just a background preference, and it's encouraging. Like the salesman who showed a dramatic increase in sales when asked how he did it, replied that he started selling to customers who wanted to buy. But polling is not marketing.

When electricity deregulation advocates started five years ago to push for deregulation, do you think any survey would have showed a desire to have electricity choice. No, who cares right? Now we have 30 million people with choice in January.

How many remember the Sprint "pin drop" ad? Yes, that was at the start of the long-distance competition marketing. That ad changed the industry to fiber optics. Now, would any background poll have shown customer preference that telephone companies bury a different kind of cable in the ground, that there should be no more copper wire and only fiber? No. And I would guess a survey wouldn't have even shown a desire ahead of time for higher quality voice transmission. Independent of polling, that marketing changed that industry, and it changed the capital investment in that industry.

The same can be done here. But who's going to place the ad?

A spokesman from the UK, which as I said has a jump on the U.S. in deregulation, at the NARUC meeting in Washington last month, described focus-group results on marketing efficiency services to the public in Great Britain. They found the focus groups did not grab the efficiency aspect, but rather the technologies that offered energy efficiency. The high-tech side. One advertising idea that resulted was an E=MC2 campaign, the slogan, "Efficiency Means Cash To You."

Alright, what are some specifics? First, directed to the public arena, I urge you as geothermal leaders to join with other renewables leaders to launch the equivalent of the milk campaign for renewables. With 30 million customers hitting the market this January, this is a market share issue. When industries want market share they appeal to the buyers.

At the Renewable Power Marketing Initiative sponsored by NREL last month, participants from several renewable segments threw out ideas like "When you choose, choose clean," with appropriate personalities to serve as public spokesperson. I don't know if they were thinking of utility commissioners or something a little more Hollywood. I think it was the latter. Geothermal as a baseload renewable needs to be part of those initiatives.

Those are some ideas on the public side. There are more. Some are very exciting and creative, for brand logos and seals of recognition internationally to inject the distinction between green and nongreen energy deeper into the market place, as an incorporated feature--like "Intel inside"--in marketing other products. Again, no customer survey would show a desire for particular specifications or type of chip. But with this marketing, a supplier can leverage the higher dollars in the retail sale to produce higher profits for a small constituent.

How many of you would pay one dollar per night more for a hotel room at a hotel that used only renewable power? You would, or you would if it used geothermal or whatever was important to you. And the dollar or two at most could more than cover the increased cost of renewable electricity.

Dr. Charles Gay, until recently Director of NREL, now with his New Energy Resource Alliance, leads some of these efforts, which could greatly accelerate markets for renewable energy beyond a direct energy sales.

Those efforts need enthusiastic support, not to make one project or another a success, but to jolt the public fascination with the possibility of clean, renewable power for the next century. Personally I urge a goal that all power generation is clean by the year 2020, and renewable by the year 2050. With the public awakening to goals like that comes a runaway renewables market that makes the $200 million advertising budgets I noted earlier look small.

As we're working on that public campaign in the competitive market, what are the specific transition mechanisms for renewables in a competitive market? Let me note the big four.

Customer "Right To Know" labelling standards
Renewable Portfolio Provisions
Matching Systems Benefit Charge
Comparability

First, customer labelling. If the customer choice gorilla wants greens in his diet, why not get monopoly regulation out of the way and let him eat greens? That is the goal, as long as you know there's enough food, and that no one is teasing the gorilla.

This is a brand new consumer market, for a product measured in kilowatt hours that no one can see (except when it strikes your house, in which case it's free--the ultimate renewable), to be supplied by former monopolists and sold by a new crop of brokers, with billions of dollars at stake. There may be some teasing going on.

The hoopla in the New Hampshire pilot included hot-air balloons, bird feeders, ice cream, tree saplings, and compact fluorescent bulbs. No one is certain yet whether all that swayed customers.

But a couple of things you might guess did happen. Customer confusion is one.

Green means different things to different people. And suppliers scrambling to meet the demand are coming up with different products called Green. Call it green labeling or Green Seal certification, customer informed choice, or "right to know," in this new market, labeling is one of the issues lawmakers need to look at, because uniformity is critical here to consumer understanding. Not only different claims, but different standards could prolong the confusion.

Providers marketing their electricity in the New England pilots as "green," made claims ranging from all-hydro to no hydro, no nuclear, no coal. To my knowledge, no supplier offered renewable energy as green because it simply was not available in sufficient supply.

This is probably the second renewable issue for legislators, minimum renewable supply, which I'll address in a minute.

So what about labeling? Can labeling standards assist in translating customer preference to market share? Experience with food labeling would say so.

Remember when the biggest thing on food labels was vitamins. In the eighties as health claims came to the fore, the FDA with the industry standardized a few new terms, like "low fat" and "low sodium," along with uniform, ingredient-based disclosure. Immediately the number of low-fat, low-sodium products and their market share increased. The agreed-upon language of the market quickly translated formerly latent customer demand into new market share.

Confusion over product claims can also kill the market through bad first impressions.

As General Motors introduces its EV1 electric car in California, they require prospective buyers to complete a questionnaire to be sure they are suitable candidates. General Motors explains:

> "We do not want anybody in the vehicle unless they are 100 percent sure it fits their needs, because this vehicle could rewrite history. But if we fail in consumers' minds, people are going to think, 'Why should I ever bother dealing with an electric car?' It could mean the whole industry fails."

The same applies to product claims for electricity. And, unlike the relatively slow-paced introduction of electric cars, a market where there is some experience with cars and car salespeople, the thirty million customers who hit the market on January 1st are in a brand new game.

The National Association of Regulatory Utility Commissioners, at the annual meeting last fall, passed a Customer "Right-to-know" Resolution in support of minimum, enforceable, uniform standards for the form and content of labeling of retail electricity sales.

With good reason. Labeling offers maximum public benefits with minimum regulatory interference. We have a wealth of experience to draw on for creating least-intrusive, most-effective labeling standards.

In addition to mandatory food labeling at the FDA, the recently updated FTC Green Guides set standards for environmental seal-of-approval logos and the chasing arrow symbols and address categories of environmental benefit claims, such as degradable, recycled content and ozone friendly. The FTC reported general consensus of comments when it updated the guides last fall that the guides "increase the flow of specific and accurate environmental information to consumers, enabling them to make informed purchasing decisions." (FTC News Release October 4, 1996). The report claimed most commenters thought the Green Guides met these goals "without undue burden on industry," and with insignificant or no cost to consumers.

To reinterpret that experience for the electricity market, the National Council On Competition And The Electric Industry, with assistance from Department of Energy, recently created the Electricity Information Disclosure Project to work with a federal interagency task force and industry to explore labeling options, and then develop initial ideas through customer surveys and focus groups, which are underway now. That may be the start of the ongoing industry collaborative.

I strongly encourage you to participate. The renewables industry should be strongly supporting labeling and disclosure standards. Disclosure will not only add market share to clean producers but it will move forward the public recognition I talked about at the start. In fact I would ask any industry opposed, why a uniform use of a few terms would not advantage all competitors, particularly those looking to profit from informed, rather than misinformed, choice. Whatever the answers, I think an industry council is the way to go, to allow the market language to develop over time.

Second, the Renewable Portfolio Standard opens the door for a market in renewables by requiring that all sales contain some percentage of renewable power. One purpose for the RPS is to continue in the market the national interests in energy diversity security and environmental improvement.

But, in addition, I think the Renewable Portfolio Standard may be the only way to assure that market barriers to renewables are removed in each market, and that all transmission, ISO and industry trade practices can accommodate differentiation and sale of renewables. It won't do any good to "choose clean" if the power can't get to the customer.

The Small Matching System Benefit Charge proposal authored by Commissioner Rich Cowart from the Vermont Commission begins the jump from government to industry financing of R&D. This proposal applies a small nonbypassable charge on all kilowatt/hours entering the transmission grid to provide matching funds for state renewable, R&D, efficiency and low income programs. With this approach, federal lawmakers can preserve public interest programs with maximum state choice, minimum burden, competitive neutrality, and no federal tax impact. This proposal models similar industry-financed mechanisms already used in the telecommunication markets and builds on that record.

Comparability would level the playing field among sources in a competitive market by requiring some basic level of emission controls or credits for all sources. Without it, the cheapest, dirtiest sources fare best in the market--a result that's contrary to the public interest. I think everyone would admit that ultimately the market that's set up should drive toward clean, not away from it. This is the market answer to the externalities problem that regulation never solved.

So as you might guess, I am bullish on renewables and customer choice. They go together with a future of more possibility than ever could occur with government R&D alone.

I personally support a goal that all electricity sources are clean by 2020, and renewable by the years 2050. I noticed the Shell Oil scenario shows 50% renewables by 2060. Now on these goals when you heard them I would bet that your mind said either "Too fast," or it said "Too slow." But in fact the goals are neither, except as ultimately the public says. Public fascination and runaway renewables market could produce an even quicker result.

The future is open. It takes some courage, but it promises bigger results.

It also promises hope. After all, wouldn't you agree, "Research To Die For" has a much happier ring today than it did two hundred years ago?

Summary of GEA Workshops -- Review of DOE's Geothermal R&D Program

Phillip M. Wright
Geothermal Energy Association

Over the past year, the Geothermal Energy Association (GEA) has been conducting a series of workshops to develop a new assessment of industry's R&D needs. The importance of directing R&D toward industry needs was reiterated again at yesterday's GEA-sponsored seminar on "Renewable Energy and Electricity Restructuring." And in my work at the GEA, I help provide DOE with information on industry's technology needs to lower the cost of generating electricity.

Let me start off with data from the Energy Information Administration (EIA) on total U.S. energy consumption by fuel type for 1995. Oil and gas support more than half of the consumption, with oil having the largest chunk. Coal with 22 percent, nuclear with about 8 percent, and renewables with about 7 percent support the remaining consumption. The total energy consumption was just about 91 quads (quadrillion Btu per year).

When looking at U.S. <u>electricity</u> supplies by fuel type, coal has the lion's share, natural gas has a pretty small but a certainly growing share, petroleum is just a little sliver these days, nuclear supplies 20 percent, and renewables supply about 11.8 percent, a pretty respectable number. Breaking renewables down even further using data published in 1994, hydroelectric and biomass are the big ones. However, most of the biomass generation is not grid connected, but is used on site. Among the other renewables, geothermal supplies about 5 percent, solar 1.1 percent, and wind 0.06 percent. In terms of grid-connected renewable electric power generation, geothermal is second only to hydroelectric.

What does the future hold for us? According to a recent EIA report looking out to the year 2015, coal usage is predicted to grow; natural gas is predicted to grow very rapidly; nuclear is expected to peak and then really decline rapidly after about 2010, due to decommissioning of power plants; petroleum will kind of bump along and level out; and renewables will grow at a very small rate of only 2 or 3 percent. This is just one projection. The words we heard this morning lend a lot more encouragement to a faster renewable growth than this projection would indicate. The fact is we really do not know what our future fuel mix will look like. As Allan Hoffman said, at some point fossil fuels will begin to be scarce and renewables will start becoming increasingly important. This could actually happen relatively soon if we realize that global warming is indeed a serious issue for which we would really have to accelerate our use of renewables.

How can we really accelerate our use of renewables? The key, I think, is better technology. In terms of geothermal technology, we have been working on better methods of drilling and viewing the subsurface, producing wells, preventing scaling and corrosion, and energy conversion. This is the same list since I got involved in this business more than 20 years ago. It's not that we have not made a lot of progress. We have made enormous progress but it happens that a lot of these problems are very difficult to solve. As with all industries, we keep making incremental progress and continue to find ways to improve on last year's improvements. For example, this is certainly something we see in the computer business these days. We think we have the latest computer, and six months later we are dissatisfied in having spent 3,000 bucks on something obsolete and not the "hottest thing on the market."

In spite of all the time spent and progress made, there are still very important problems to be solved. To this end, the GEA organized a series of workshops to discuss industry's research needs. Four workshops, one each for hot dry rock, drilling, permeability detection, and reservoir production have been conducted to date. One more workshop on energy conversion is scheduled for April. We will then have identified a complete set of research needs.

Some general recommendations have come out of these workshops. Conducting R&D on a problem-oriented and needs-driven basis is really the thing that we are trying to implement. We need to define what the needs are -- the technological problems that need to be solved. Accordingly, we will advise the DOE program to focus on a few key problems instead of striking out in 50 or 60 different directions. Similarly, just one or two sites for testing, demonstrating, and comparing new technologies and methods must also be established. Oxbow has been very supportive of this idea and permitted use of the Dixie Valley site for testing purposes and Dick Benoit has been a good guy to work with there.

In terms of drilling, one of the recommendations was to develop a better understanding of lost circulation and cementing problems. We really need to better understand the nature of permeability, lost circulation, and recovery methods. We also need to improve the placement of surface casing strings. Lost circulation problems often happen in the upper parts of wells and we will have to find ways of securing the upper wellbore without cement plugging operations. One of the ideas was to use a cheap expandable casing.

Additional drilling recommendations included:

- undertaking a study of methods employed by other industries to mitigate lost circulation.
- developing improved methods and procedures for cuttings removal and remediating damage to producing zones.
- evaluating lower-cost designs for wellheads and other drilling equipment.
- developing a temporary wellbore lining to reduce formation damage and loss circulation.
- continuing development of downhole mud motors, hammers, and water jet supplemented diamond enhanced drilling equipment.
- establishing a standing drilling R&D panel
- increasing funding to the Geothermal Drilling Organization

Many of these items are currently being worked on. As you know, Sandia National Laboratories takes the lead in the Geothermal Drilling R&D Program, and Dave Glowka the Sandia manager, recently produced a monumental report on drilling technology and R&D needs. It has been a good effort at helping guide this important drilling program, and I must say that Dave's plan addresses the problems very well. One last recommendation was for DOE and lab researchers to work more closely with industry, even to the extent of going out and sitting on a drill rig for a couple of months. They need to see how things go in the field, especially in places like the Philippines and Indonesia, where the problems are somewhat different from those found in the United States.

Moving on to permeability detection, the problem here is to find the plumbing system in the subsurface. Basically, how to remotely detect permeability, drill into it, and get a producing well instead of a dry well. Therefore, drilling costs and the percentage of successful wells become more important than the drilling process itself. Some of the recommendations suggested developing inexpensive methods to map subsurface geology and lithology and to remotely detect fractured and permeable zones.

How do we find a permeable zone in the subsurface? How do we find this plumbing? It's a problem that has received a lot of attention for more than 20 years and we still don't know how to do it very well. However, considerable improvements have been made in seismic methods in the past 20 years, especially in data processing and interpretation techniques as well as in hardware and equipment. The same can be said for the electrical methods in many respects. It's time to take a new look at how these methods might apply in rain forests or high topography areas and finding the plumbing system at depths of 1 to 2 kilometers. It's a very difficult problem, but I'm convinced we can make great improvements to the methods we use today.

We need better methods to determine if producing zones are performing at their maximum. How can we know that we're getting the most out of a well? Maybe something could be done to stimulate more production. We need to develop methods to determine whether to kick off a well, in case we just missed a permeable zone. Which direction, or do we move to another site? A lot of these things are more or less guesses today.

In many parts of Indonesia, the Philippines, and the northwest United States you can't see much of the surface geology because it's covered by vegetation and weathered layers. Therefore, we need to develop methods for mapping the geology beneath the weathered layers and vegetated areas. In terms of understanding production and improving well tests, we need to develop a slick line temperature, spinner, and gamma tool that is a lot less expensive than currently available tools.

Moving on to reservoir production, the recommendation was to focus the program more toward injection and to continue the development of non-radioactive liquid tracers for temperatures greater than 300°C. Injection is increasingly viewed as a bigger problem. We also are finding many more wells hotter than the 250°C we initially thought we were going to find. You probably have heard that the Japanese recently drilled a 550°C well at the Kakonda field. We will need to develop not only tracers but other downhole tools for these increasingly higher temperatures. The proper values for the physical parameters that govern reservoir properties have to also be developed. Reservoir simulators have to also be coupled with geochemical models. These are very difficult and computer intensive problems requiring development of new software. Software from the petroleum industry just doesn't apply. It will need to be modified to adapt to the geothermal environment.

It is also important that we develop better methods for well stimulation. I personally feel that we could materially improve well production if we could fracture into adjacent plumbing systems. Much of the pressure drop in producing wells takes place right near the wellbore and if the impedance can be mitigated to a significant extent, each well could produce more. Therefore, fewer wells would be needed and drilling costs would drop.

There was also a recommendation to create a couple of monographs, one on injection into vapor-dominated systems, The Geysers obviously being the motivation, and the other on the nature and operation of two-phase liquid-dominated systems. A strong recommendation was also made to somehow convince management and bankers on the need to gather vital resource data by monitoring and evaluating resources that are under production. Such data gathering will allow predicting reservoir characteristics at an earlier stage and estimating how much production we might get.

Why are we doing all this? According to fairly recent data, coal use in the third world is climbing very rapidly while slightly leveling off in the industrialized nations. The former Eastern bloc countries have large coal reserves but coal use has taken a big downturn. This downturn is only temporary and once these countries get on their feet again, coal use is likely to continue to increase. Consequently, world carbon emissions will increase until we can put more renewables on line and combat global warming.

As you are aware, the average atmospheric temperature and carbon dioxide concentration have increased over the last half decade. In fact, it's gone up in a fairly documented way since the 1800's. While nobody really argues with the increases, some argue whether the two are related. Is our use of fossil fuels actually causing this global warming? That we don't know, but the meteorologists tell us that within maybe 20 years, there will be enough historical data for their models to provide a definite answer. However, geothermal energy and all the renewables must be prepared to mitigate this rise in atmospheric carbon dioxide in case we're harming the earth's environment in a way that will lead our future generations into decline. That's what we're trying to do with all this. With that, I'll close and thank you very much.

Keynote Speech at
DOE Geothermal Program Review 15, San Francisco

Dick Benoit
Oxbow Power Services Inc.

Good morning and welcome to my first "keynote presentation." I am flattered to be here, even if I suspect this is some kind of initiation into middle age. With my newly acquired middle age dignity I will try to minimize character assassination as I confine my comments to geothermal resource issues and the research needs associated with the resource. This by no means implies that the above ground hardware is not worthy of research. In fact, I would dearly love to see some power plant engineer devise a way to double the efficiency of geothermal power plants as this could take a lot of heat off me and my friends who deal with the various resource issues. This may not be out of the question as I am hearing stories about a new silica inhibitor which might be a key to turning single-flash plants into dual-flash plants.

Geothermal research is an exceptionally broad and fascinating topic for anyone dealing with resource issues. In many industries there is a relatively clear division between researchers and those working to discover or routinely produce a product. In the gold industry I personally know a number of geologists who have worked for more than 10 years and have not performed any work that I would call research or published any significant papers. Sure, they create geologic maps and look at cuttings and use some standard geochemical techniques but at the end of the day they are not increasing the fundamental understanding of their resource. They are simply utilizing tools others have developed. The same can be said for most of guys in the oil and gas industry. R & D and exploration and production are clearly separated departments.

In the much smaller geothermal industry we are fortunate that things are different. Virtually all of the resource people that have managed to remain employed or at least involved in this industry can legitimately claim to have participated in true research which has increased our fundamental knowledge about the character and extraction of the geothermal resource. I would even go so far as to say that in many cases research activities is what has led to employment longevity in this industry. Over the past two decades research or collaboration with bona fide researchers has been required for companies to successfully develop projects and survive. Twenty five years has been plenty of time to weed out the individuals and companies that could not technically advance and many have disappeared over the years.

I would like to take a look back about 20-25 years ago in a light-hearted manner and show some examples of where we were in our understanding of the geothermal resource. This will show how far we have come as a result of research.

1. In 1974 I suspect everyone in this room was unaware that temperatures could get colder with depth near geothermal systems. We now recognize that this happens all the time in the vicinity of active geothermal systems and we have turned this common

feature into a viable exploration tool.

2. In the late 1970's one company was still evaluating geothermal wells with drill stem tests. Another company drilled 8 identical wells in one prospect, and the small diameter casing program never evolved or improved. The management of another company decreed no logs could be run in flowing wells. These three cases show the hazards of having a company managed by people with no background in geothermal research and all three companies are no longer directly involved in the geothermal industry.

3. In the 1970's we focused research on the fancier logging tools and worried about things such as M-N crossplots. Seldom is a neutron log even run in the industry now. It took a long time to get a reliable hot hole TPS tool in routine use.

4. Prospects were abandoned by companies because of concern about carbonate scaling in production wells.

5. We actually thought that hot dry rock would be a commercial and competitive source of electricity.

The list could go on and on but in spite of this history we have survived and greatly improved our skills through research. For many of us in this room this survival amounts to approximately half a lifetime of work. Yet as things change-they still remain the same and some old unsolved 1970's problems continue to haunt us.

Twenty years from now, at my initiation into old age I would like to be able to give the talk which takes a light hearted look at what I am going to say in the next 10 or 15 minutes.

I would like to focus on two areas crucial to the survival of the industry, exploration and reservoir sustainability. Exploration is not currently the most pressing problem facing the domestic industry but U. S. operators working overseas, especially in Indonesia, are having a sporting time of exploration right now. Sustainability is not yet a concern for U. S. operators overseas but it is now the main resource concern in the United States. Sustainability is becoming a concern in the older fields of the Philippines and in several years it will become a big issue in Indonesia.

EXPLORATION

In 1974 I started exploring for 1000 MW reservoirs for Phillips Petroleum Company in the Basin and Range province. We were supposed to be looking for something resembling The Geysers. Nevermind that it was 1976 before I ever set foot in The Geysers. The beauty of The Geysers was that holes could be drilled on a grid and the productivity of wells could be predicted by how close a well was to a certain temperature-gradient contour. The Geysers also had the advantage of having many cubic miles of fractured rock. (I am still waiting for the details on how this fracture network was created.) By the late 1970's it became apparent to everyone that The Geysers was a freak of nature and not an appropriate model for most geothermal reservoirs.

The Geysers experience cut both ways as those outside The Geysers did not find another Geysers and those inside The Geysers didn't do so well exploring other areas in the United States.

For about 15 years we have known that the fundamental challenge in geothermal exploration is to be able to locate a crack with an aperture of a few inches to a few feet (or even several fractures) at depths of 1000 to 4000 meters. Our progress appears to have been minimal judging by the number of unsuccessful hot dry wells or second legs required to make a successful well. This holds true even in the mid 90's. Research is needed to develop methods for determining when to attempt a redrill and to develop stimulation methods so we can improve the productivity of dry or marginal wells.

I don't think I am being particularly pessimistic in stating we will never come up with a black box that can be used on the surface to unequivocally detect a few cracks at a depth of 2000 m. It is far more realistic to expect that our advances are going to evolve from an improved basic geological understanding of geothermal reservoirs. I know I am not the only guy in this room to believe that the crude and simple cartoons we presently call conceptual models of geothermal systems are inadequate to truly portray the resource. A site specific understanding of an individual resource is a slow learning process coming from the integration of literally thousands of bits of data which may or may not be related to each other or to the geothermal system. Only research and publicized experience and case histories will help us advance in this arena.

It is not fair to expect that a rookie in the industry will be up to this task and accountants cry that it takes too long and costs too much for an experienced geothermist to spend the man years that it takes to obtain the detailed understandings required to predict where the edge of a reservoir might be or where injection might be most effective. This process can never be turned into a cookbook or a quick consulting job. The best we can realistically hope for in the next decade is that new tools and better understanding when combined with thoughtful analysis tilts the odds of making successful decisions a couple of more percentage points in our favor.

The domestic geothermal industry now is crying that low cost natural gas is making us uncompetitive and therefore we can not obtain contracts. I would like to point out that our relatively low success rate in finding fractures is also a significant factor. As a personal example at Dixie Valley which is probably the most straight forward Basin and Range geothermal area I can not with a straight face promise even a 50% chance of success on an initial wildcat well. The potential cost of a $2 to 3 million dry hole up front tends to ruin the economics of the thin deals.

As the drilling stories gradually trickle out of Indonesia it is becoming clear that there are a wide variety of resources and that in many of them locating quality fractures is as difficult as it is domestically. I have not yet done any exploration overseas but I can see that exploration in the volcanic arc environments presents new challenges that domestic geologists in the industry have not faced before. One of these is simply being able to get reliable temperature-pressure-spinner logs. Getting reliable memory tools into the remote projects seems to be one of the most important short-term things that can be done to help the overseas explorationist. Spending some research dollars on foreign projects will provide some important results and may even modify the way we view our domestic reservoirs. Given enough experience in Indonesia for example, we might find the key to finding some developable reservoirs in the Cascade Range.

To finish with exploration, we have a very difficult fundamental problem to address. We have made progress in the last two decades, even if it is painfully slow, and we will make progress in the coming years but it is not going to be quick or easy and we will not come up with a magic method which takes the place of careful and detailed analysis of the local geology. Research will provide us with better high-temperature logging tools, but the interpretation of these logs will still require knowledgeable analysis.

RESERVOIR SUSTAINIBILITY

In the United States this is where industry's efforts are now focused, even if management's immediate objective amounts to meeting a rolling average or maintaining a 80 or 90% capacity factor the ultimate goal is sustainability. There are two available tools to replace depleted production, makeup wells and injection. For some very understandable reasons, makeup drilling always seems to be the first tactic used. By the time a plant is on line the technical people have demonstrated some kind of acceptable success rate and management has become comfortable with production well drilling, even if the accountants are having some heartburn. Any geologist with any time in the industry knows enough to leave a few spots open for infill wells so there are usually some easy targets for the first couple makeup wells and they are generally successful.

At the start of production the injection strategy is in place for better or worse and is largely untested and unproven. Everyone is rightfully nervous about the injection program and with a few cost overruns in the production drilling, efforts are made to cut the injection side costs. Seldom, if ever, has a well been targeted and drilled specifically as a long-term injector prior to the start of construction of a power plant. Most injection wells in service today were drilled as producers and later condemned to injection for various reasons. Would some of our projects be performing better if injection was given its due importance at the beginning of a project? Recent tracer research has now given us the ability to detect chemical tracers in the few parts per trillion range so there is now no excuse for operators not being on top of their injection program.

Injection is really the only management tool we have for getting the most out of a reservoir once the plant is sized and built. We have no control over the reservoir temperature, the heat stored in place, the fracture surface area, the amount of water in place, the porosity, or the permeability or a number of other factors. We can control the amount of water we inject. Most importantly we can control where this fluid is injected. However, we have a long way to go in truly understanding injection. By example, there is no generally agreed upon "best" strategy for injecting. Continued research on reservoir simulation should be able to provide a method for "experimenting" with the location and flow rates of injection wells before we actually have to return a drop of fluid to the reservoir.

Beyond injection of produced fluids we get into the up and coming area of injection augmentation where water other than from the geothermal resource is injected into the reservoir to support pressure. Certainly the efforts at The Geysers in capturing water for injection has been the overall technical success in this field for the past 15 years. However, I do point out that even with the injection augmentation at The Geysers a much smaller percentage of fluid is returned to the reservoir relative to production than at any liquid-dominated resource.

Conservation of water has been mimicked by the other operators of liquid dominated reservoirs, at least in the United States. There are some foreign operators that are not following the water conservation crowd and they are paying a very big price in lost megawatts and shortened reservoir life.

We are now aware of the limits of even the perfect injection program that focuses solely on returning only reservoir fluids. Again, the leader in injection augmentation on a big scale is The Geysers with the Lake County pipeline. This really is a quantum leap from the smaller existing water capture schemes.

The next step in the evolution of injection augmentation will be to do the same thing in a controlled manner in a liquid-dominated reservoir. When I say in a controlled manner I am referring to instances where injection outside a reservoir has led to excessive natural augmentation with rapid cooling of production wells. Here chemical interaction between the reservoir fluid and the augmentation fluid is more of a concern as massive amounts of solids can potentially precipitate. Research in chemical modeling may provide us with predictions of fluid compatibility and even where and how solids are likely to form. The ideal reservoir for this next test will be one in which reservoir pressure and not temperature is the limiting factor.

A successful injection augmentation program will share some of the characteristics of a successful injection program in that the sooner that augmentation can be instituted the more effective it will be as smaller amounts of augmentation water can be spread over greater periods of time to more effectively mine the heat.

Many of you are aware that there is a major research effort underway at Dixie Valley covering many topics. I do not have any great revelations to make at this time about a work in progress. The ultimate goal of this research is to get a more complete understanding of a relatively simple reservoir along a normal fault. The key questions are why do some areas contain abundant fractures and why are others impermeable? and how can we best locate and most efficiently utilize these fractures? This covers both exploration and sustainability.

What is not well known about this effort is that it has introduced a number of new researchers to the geothermal industry. I am hoping that these individuals who manage to attend meetings other than the GRC, Stanford, and the DOE Program Review will breathe some new energy into geothermal research on our fundamental problems. Over the years it is no secret that the geothermal industry has shrunk and the industry technical leaders, particularly in the geosciences have probably become a little too focused on working on the routine problems of survivability. There is a lot of experience and geothermal wisdom in this group but much of this talent seems to be focused on narrow specific topics with day to day urgency.

Over the past several years the geothermal literature contains remarkably little in the way of serious discussion on fracturing in rocks or along faults and sustainability of reservoirs. Inside the industry we seem to be just nibbling around the edges of these topics. A major research focus on these problems with some new thinkers would help industry.

Over the past decade the academic side of geothermal research has more or less vanished. I can't help but suspect that this is having an unseen impact on the direction of our research that is not good. The entire industry should be making efforts to induce those with new insights or unbiased perspectives to enter our community. We could use some spirited discussion on many topics.

Now to close out this talk I will make one very simple and almost trite prediction. Ten years from now the players and personnel involved in the production of geothermal resources will either be new to the game or will be the ones who have continued to play an active role in geothermal research. Those who do not participate in research will not have a long-term future in this industry. Research is most effective when everyone participates.

Thank you for your time.

Concurrent Session 2:

Exploration and Reservoir Technology

FRACTURE MAPPING IN GEOTHERMAL FIELDS WITH LONG-OFFSET INDUCTION LOGGING

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ABSTRACT

The mapping of producing fractures in a geothermal field is an important technical objective in field development. Locating, orienting, and assessing producing fractures can guide drilling programs and optimize the placement of production and injection wells. A long-offset multicomponent borehole induction resistivity tool capable of surviving the high temperatures encountered in geothermal wells has recently been developed in a NEDO project, "Deep-Seated Geothermal Reservoirs," and tested in a high temperature environment. Several characteristics of this device make it ideal for detecting producing fractures. Whereas commercial induction logging devices have source–receiver separations of 1 m, this device has multiple sensors with separations up to 8 m, allowing for deeper penetration and the ability to straddle fracture-induced washout zones in boreholes. The three-component measurements also make it possible to map the strike and inclination of nearby fractures and other three-dimensional structures. This, in turn, allows for accurate projection of these structures into the space between wells.

In this paper, we describe the design of the tool and show results of a performance test carried out in an oil-field steam flood. Data from vertical sensors are compared to conventional logging results and indicate the recent formation of a low-resistivity zone associated with high temperatures due to steam flood breakthrough. Horizontal field data indicate that the high-temperature zone is irregular in the vicinity of the borehole and more pronounced closest to the steam injector.

INTRODUCTION

The mapping of producing fractures in a geothermal field is an extremely important technical objective in field development. Locating, orienting, and assessing producing fractures can guide drilling programs and optimize the placement of production and injection wells. This results in fewer dry holes and substantial cost savings in field development.

Recently, NEDO and GERD have developed a long-offset borehole induction resistivity tool capable of surviving high temperatures (Sato et. al., 1996). This Multi-Frequency Array Induction Logging (MAIL) tool features an array of multicomponent sensors offset 4 to 8 m from the transmitter. This array and the multifrequency operation make it possible to resolve fracture zones within geothermal wells.

In this paper, we briefly describe the design and operation of the tool and compare it with more conventional induction logging tools. We then show field results from an observation borehole near an oil-field steam flood. In our field example, the well encounters a nonuniform high-conductivity zone associated with subsurface steam.

DESCRIPTION OF THE MAIL TOOL

The MAIL tool was designed by NEDO and GERD engineers in 1994 and was built by an American contractor, Electromagnetic Instruments. It was designed for high resolution mapping of the conductivity structure in geothermal wells. A schematic drawing of the tool (Figure 1) indicates that it has a multifrequency transmitter section in one end and an array of induction coil and fluxgate sensors distributed throughout the rest of the tool. Five vertically oriented induction coil sensors are spaced 4, 5, 6, 7, and 8 m from the transmitter; two horizontal field sensors are situated at 7.5 m; and a three-component fluxgate magnetometer lies 3 m from the source. The fluxgate magnetometers are used for tool orientation. The transmitter may operate at 3, 12, 24, and 42 kHz, but it is more powerful at the lower frequencies.

Signal detection, synchronous stacking, and analog to digital (A/D) conversion are accomplished within the tool before transmission to a personal computer (PC)-controlled surface station. Software on the PC is used to control the data collection sequence, apply calibration corrections, and display and store results.

The tool has also been hardened for a high-temperature, high-pressure environment. Special temperature-resistant polycarbonate materials house the sensors, and a high-vacuum stainless-steel dewar protects electronic components so that the tool can withstand downhole temperatures of 260°C for up to 12 hours. This configuration makes the tool suitable for use in many geothermal wells. An oil compensation system is used for pressure maintenance to depths of up to 4 km.

Several characteristics of this device make it ideal for detecting producing fractures. The long source–receiver offsets of the induction coil sensors make it useful for detecting structure well away from the borehole. Typical induction logging devices have source–receiver separations of 1 m, whereas this device has separation up to 8 m allowing up to a 10-m penetration into the formation. In addition, many producing fractures in geothermal wells are associated with washout and lost-circulation zones, thereby making conventional (short-offset) logging ineffective. Long-offset sensors, which easily straddle such zones, are affected less by nearby well structure. In addition, the multiple sensors and frequencies allow for building radially and azimuthally varying images of the resistivity with depth. Finally, the three-component measurements also make it possible to map the strike and inclination of fractures or other heterogeneities. This, in turn, will allow for the accurate projection of these structures into the space between wells.

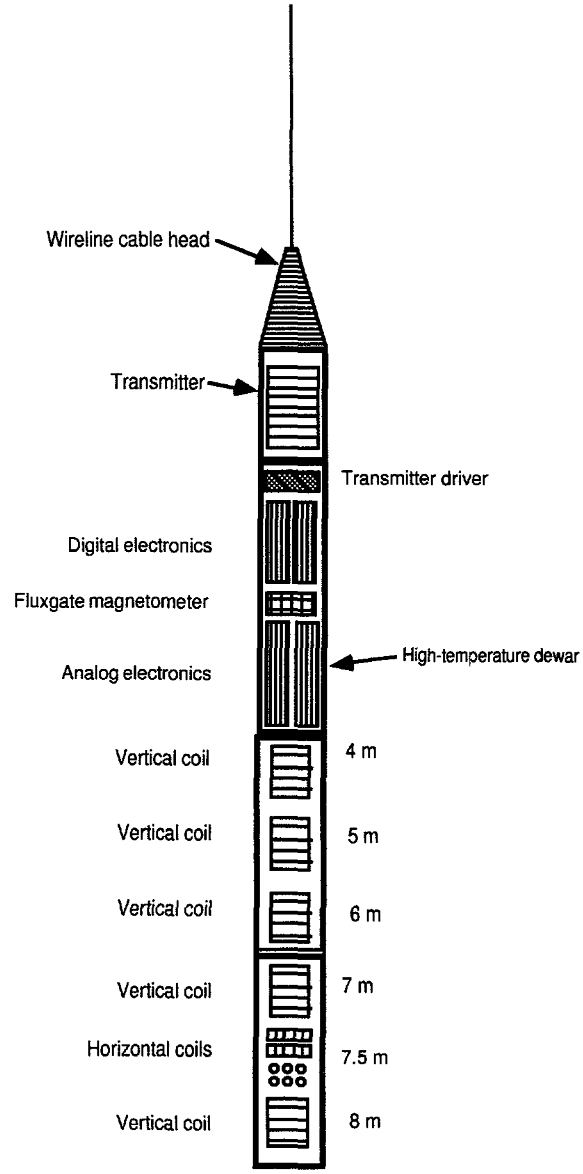

Figure 1. *Schematic diagram of the MAIL long-offset induction logging device.*

FIELD APPLICATION

The MAIL tool was initially tested in the WD-1 well at the Kakkonda geothermal field in central Japan in 1995. The tool was operated at temperatures in excess of 190°C at depths exceeding 2.6 km (Sato et al., 1996; Uchida et al., 1996). Results from this test were designed to identify low-resistivity zones associated with through-going fractures.

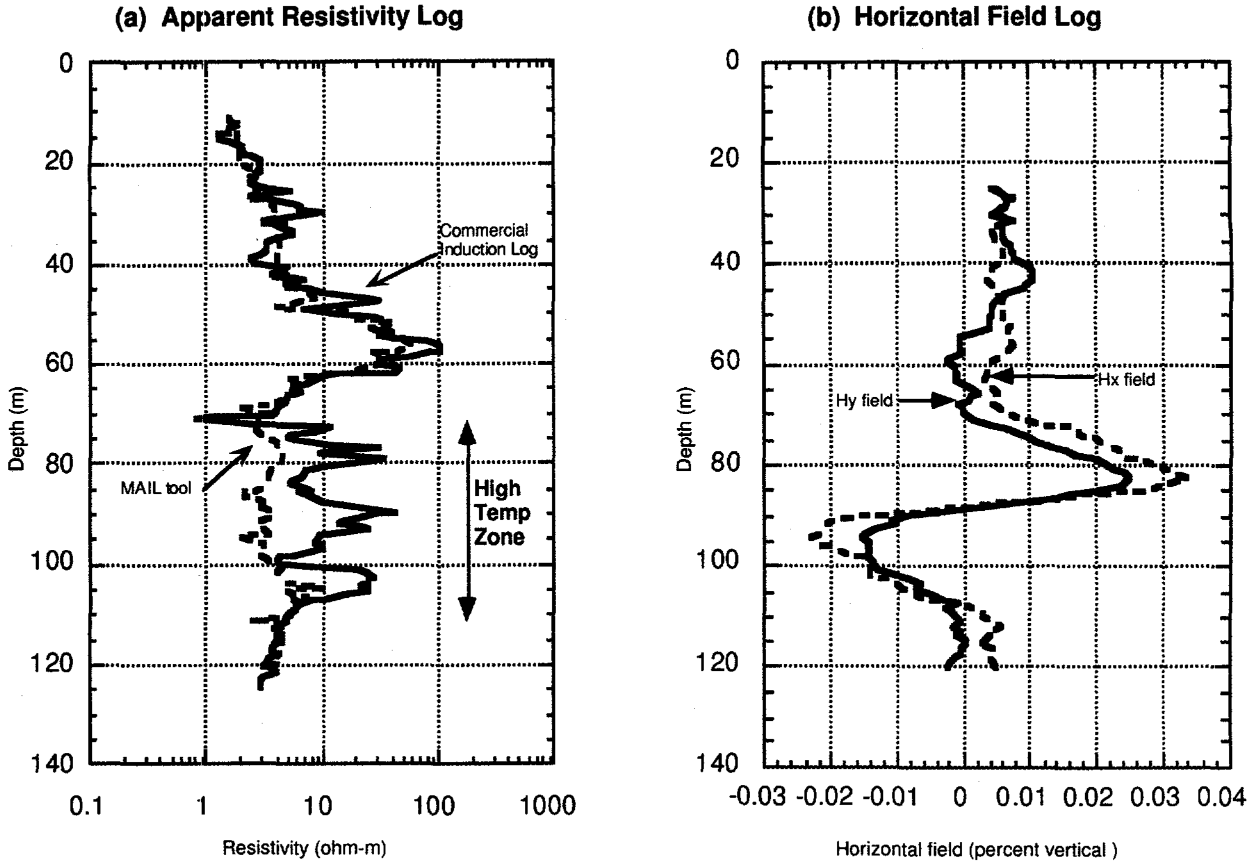

Figure 2. *(a) Comparison of apparent resistivity logs measured with the MAIL tool and conventional induction logging data in the same borehole. Note: the MAIL data was collected after steam injection. (b) Horizontal magnetic fields from the MAIL in the same borehole.*

Recently, a performance test of the tool was made at the Lost Hills oil field in central California, where Mobil Exploration and Production U.S. operates a shallow steam flood for enhanced oil recovery. Several steam injectors and fiberglass-cased observation wells are available at this site for making measurements. This site was chosen for its well-characterized structure and the presence of a high-temperature zone near the observation well.

We deployed the tool in a fiberglass-cased observation well located 30 m from a steam injector. The observation well has several nonuniform, high-temperature zones due to the recent steam flood in addition to evidence of a high-conductivity zone adjacent to the well (probably pyrite from gas evolution). In the past, we used this and a companion observation well for crosshole electromagnetic studies that tracked the injected steam plume for several years (Wilt et al., 1995). We therefore have a good idea of the electrical resistivity structure in the region between the boreholes.

In Figure 2a, we show the commercial induction resistivity log from the borehole collected immediately after drilling in 1992 and the MAIL 5-m offset log from December 1996. The two responses are similar in the upper reaches of the well but differ below 60 m, where the resistivity measured with the MAIL tool is significantly less than the commercial log. This difference is primarily due to the high-temperature zone in the borehole (in excess of 130°C) caused by the nearby steam injector. The replacement of insulating oil with hot water and steam is consistent with the more than 50% reduction in resistivity observed with the logs. The MAIL log is smoother than the older induction log because the longer source–receiver offset averages a larger volume.

In Figure 2b, we plot the horizontal field responses from the MAIL log in the same borehole. Note that for a homogeneous or horizontally layered medium, the horizontal fields from a single borehole logging device are zero. These fields are nonzero only where the formation adjacent to the borehole is heterogeneous. They may therefore indicate a fracture zone or a nonsymmetrical structure, such as a steam zone. In this case, the horizontal fields display a crossover anomaly with peaks corresponding to the boundaries of the high-temperature zone. This structure is consistent with a low-resistivity zone (steam plume) that is more pronounced east of the well, or toward the steam injector. Note that these data have not been corrected for tool rotation.

Preliminary modeling of these data using a conductive sheet model indicates that the structure is either a single eastward dipping plume-like body or a series of subparallel sheet conductors. Further 3-D modeling is required to distinguish between these possibilities.

RECENT KAKKONDA SURVEY

In March of 1997, the MAIL tool was redeployed in the WD-1 well in Japan (described above). In this recent test, the tool was run to depths greater than 3 km with the bottom hole temperatures higher than 200°C. Preliminary data analysis indicates that the tool was working properly, with vertical field data essentially duplicating the commercial induction resistivity log. Significant horizontal fields were measured at two depths within the well; each corresponding to high conductivity zones potentially associated with geothermal flow. Detailed data processing and interpretation from this survey is currently underway, and results will be published when analysis is complete.

CONCLUSION

The advent of long-offset induction logging could potentially have significant consequences for geothermal field development. The orientation of producing fracture zones could potentially be determined from these measurements; it may also be possible to locate nearby producing zones from "near miss" exploration boreholes.

ACKNOWLEDGMENT

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Isotopic and Noble Gas Geochemistry in Geothermal Research

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ABSTRACT

The objective of this program is to provide, through isotopic analyses of fluids, fluid inclusions, and rocks and minerals coupled with improved methods for geochemical data analysis, needed information regarding sources of geothermal heat and fluids, the spatial distribution of fluid types, subsurface flow, water-rock reaction paths and rates, and the temporal evolution of geothermal systems. Isotopic studies of geothermal fluids have previously been limited to the light stable isotopes of H, C, and O. However, other isotopic systems such as the noble gases (He, Ne, Ar, Kr and Xe) and reactive elements (e.g. B, N, S, Sr and Pb) are complementary and may even be more important in some geothermal systems. The chemistry and isotopic composition of a fluid moving through the crust will change in space and time in response to varying chemical and physical parameters or by mixing with additional fluids. The chemically inert noble gases often see through these variations, making them excellent tracers for heat and fluid sources. Whereas, the isotopic compositions of reactive elements are useful tools in characterizing water-rock interaction and modeling the movement of fluids through a geothermal reservoir.

INTRODUCTION

The Geothermal Program at Lawrence Berkeley National Laboratory has long had a productive relationship with the geothermal industry in developing effective production and exploration strategies using subsurface geophysics and reservoir modeling. It is our aim to compliment these and other existing U. S. Department of Energy programs by providing, through fluid chemistry and isotopic analyses, needed information regarding sources of geothermal fluids and heat (e.g., Truesdell et al., 1987; Gunderson, 1989; Kennedy and Truesdell, 1996), the spatial distribution of fluid types (e.g., Kennedy et al., 1991; Norman et al., 1997), subsurface flow and water-rock reaction paths and rates (Johnson and DePaolo, 1994, 1996, 1997), and the temporal evolution of geothermal systems (e.g., Moore and Gunderson, 1995). The value of isotopic measurements of elements in geothermal fluids is that they provide a quantitative measure of material balance. For instance, variations in the isotopic compositions of the light elements H, C, and O have proven to be very useful in geothermal reservoir studies by providing insights into the source of recharge fluids and estimates of water/rock ratios and reaction temperatures (e.g., Giggenbach, 1991). However, much additional information can be obtained through studies of the variations in the isotopic compositions of the noble gases (He, Ne, Ar, Kr and Xe) and reactive elements such as B, N, S, Sr and Pb. As a fluid moves through the crust the chemistry and isotopic composition will be modified either in response to the varying chemical, temperature and pressure environments and/or by mixing with fluids of a different composition. The isotopic composition of the fluids and their chemical constituents will either be conserved during these processes, thus preserving information related to initial conditions and sources, or modified in a fashion that can be used to diagnose what chemical reactions are occurring along the flow path and what materials are reacting with the fluids. Isotope systematics also have an additional advantage in that it can be applied to fluid samples collected from producing wells, surface hydrothermal (and non-thermal) springs, fumaroles, etc., and fluid inclusions, as well as rocks and minerals related to the geothermal system.

The noble gases are chemically inert and therefore they can see through the chemical reactions modifying fluid compositions, making them excellent natural tracers for identifying heat and fluid sources. For instance, in a geothermal fluid associated with a magmatic source, the $^3He/^4He$ ratio can be as much as ~100-1000 times higher than that expected from crustal sources which are dominated by radiogenic ^4He. How much higher will depend on the intensity and time since the last input of fresh magma and the proximity of the sampled fluid to the magmatic source. Recent studies of steam produced at The Geysers indicates that the helium, and probably CO_2, in some portions of the field is ~100% magmatic (Kennedy and Truesdell, 1996). Whereas, helium in fluids from the Dixie Valley geothermal field in the Basin and Range Province of Nevada is, at most, ~7% magmatic (Kennedy et al., 1996).

The isotopic compositions of chemically reactive elements, such as Sr, Pb, and S, combined with fluid chemical compositions are useful tools in characterizing water-rock interaction and modeling the movement of fluids through a geothermal reservoir. In general, the isotopic composition of a reactive element at any point along a fluid flow path will be a product of both the isotopic composition of the original source fluid and that of the solute acquired from the local reservoir rock by chemical reaction and ion exchange. Spatial distributions in isotopic compositions combined with coupled reaction-transport models can be used to identify important reaction paths and estimate fluid velocities (e.g. Johnson and DePaolo, 1994, 1996, 1997). Similar models can also be applied to variations in the isotopic composition of noble gases, despite their inert chemical nature. For instance, the helium isotopic composition in a magmatic fluid moving through a crustal reservoir will be modified due to the addition of radiogenic ^4He, thus decreasing the helium isotopic composition as a function of transit distance from the source. The resulting gradient in isotopic composition will be a function of the ^4He addition rate and the fluid velocity. If the system has reached a steady state, the ^4He addition rate to the fluid will be equivalent to the local production rate from U and Th decay. For reactive elements, the isotopic gradient will be governed by reaction rates, crystal/liquid partition coefficients (which generally are known), and fluid velocity.

HEAT AND FLUID SOURCES

The noble gases in geothermal fluids, particularly helium, are extremely useful for identifying heat and fluid sources. Crustal magma chambers are driven by heat and mass from the mantle where the $^3He/^4He$ ratio is ~10^{-5} (in mid-ocean ridge basalts, MORB, the ratio is 8-9 Ra, where Ra is the ratio in air, 1.4×10^{-6}). The crust, on the other hand, is enriched in radiogenic ^4He, derived from natural radio-decay of U and Th, and is therefore characterized by a $^3He/^4He$ ratio of ~10^{-8} - 10^{-7} (0.02 - 0.10 Ra). Unlike other chemical or isotopic systems, the helium isotopic composition of a fluid can provide definitive evidence for a magmatic source of heat and volatiles. Most recently we have used noble gases to evaluate heat and fluid sources in the high temperature reservoir (HTR) of the northwest Geysers and in Dixie Valley.

The Geysers: A nearly-field-wide accelerated decline in pressure and steam production occurred at The Geysers in the late 1980's. As a result of this crisis, DoE began a program to examine the reservoir processes at The Geysers in order to better understand the sources of steam and noncondensable gases, and predict changes in pressure, steam flow and gas content. We found that noble gas isotope abundances in steam from the Coldwater Creek field of the northwest Geysers show mixing between a nearly pure magmatic gas with high $^3He/^4He$ and low radiogenic $^{40*}Ar$ (R/Ra > 8.3, Ra is the ratio in air and $^{40*}Ar/^4He < 0.07$) and a second magmatic gas that had been diluted by crustal gas (R/Ra < 6.6 and $^{40*}Ar/^4He > 0.25$) (Figure 1). The nearly pure magmatic, ^3He-enriched component is correlated with high total helium to non-condensable gas ratios and the ratios of total helium to atmospheric noble gases, and is accompanied by mantle-like $^3He/CO_2$. The steam samples most enriched in the pure magmatic end-member are from the high-temperature reservoir and are also the most enriched in total gas and HCl. These findings led to an hypothesis of active magma degassing beneath the northwest Geysers, suggested that a significant fraction of the noncondensable gases produced with steam from the high-temperature reservoir is magmatic, and has added new constraints to genetic models of the steam and its evolution (Kennedy and Truesdell, 1996).

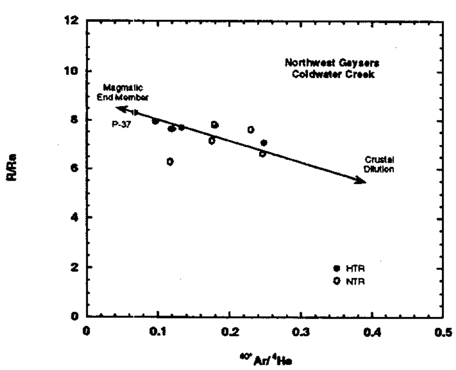

Figure 1: Helium isotopic (R/Ra) in steam from The Geysers plotted against the ratio of radiogenic $^{40*}Ar$ to ^4He. Steam from P-37, the most enriched in mamgmatic He also contains the most gas and HCl.

In collaboration with Joe Moore (EGI, Salt Lake City, UT), we have analyzed noble gases extracted from fluid inclusions in core samples from The Geysers. The samples were selected to provide a representative suite covering the wide range in temperature and salinity occluded by various vein minerals (Moore and Gunderson, 1995). Fluid inclusions are not formed unless mineral deposition occurs, so inclusion formation would not be expected when the reservoir was occupied by a low-pressure vapor and, therefore, the inclusions reflect conditions in an earlier liquid-dominated system. The fluid inclusions record a zoned halo of decreasing temperature and salinity with distance away from the 1.3-1.4 Ma felsite intrusion and are , therefore, likely to be related to the igneous intrusion. Noble gases extracted from fluid inclusions from representative sections of the temperature-salinity halo are, within experimental uncertainties and in all but one case, enriched in magmatic helium with a nearly constant $^3He/^4He$ ratio of ~ 6 Ra (Figure 2). But the helium isotopic compositions are not correlated with position in the zoned halo. In fact, the sample (L'esperance-2) with a nearly pure radiogenic helium component (0.5 Ra, Figure 2) is located only ~280 meters from the top of the felsite intrusion. Because of a limited data set, it is not known to what extent, how, or whether the fluid inclusion data is related to the magmatic helium enrichments in the present day production fluids of the high-temperature reservoir. However, none of the fluid inclusions analyzed to date have helium isotopic compositions (~6 Ra) approaching the very high values found in steam from the present-day vapor-dominated high-temperature reservoir (8-9 Ra).

Dixie Valley: The Dixie Valley geothermal field, owned and operated by Oxbow Geothermal Corp., is located in the Basin and Range Province in a tectonically active region characterized by extension and high regional heat flow. The power plant provides

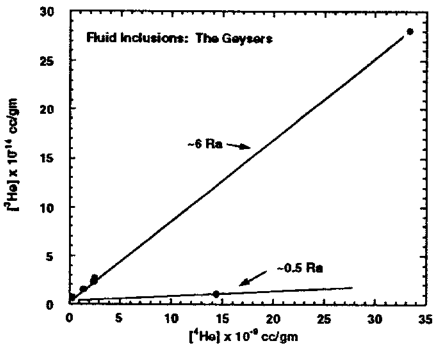

Figure 2: Helium isotope concentrations in fluid inclusions extracted by vacuum crushing hydrothermal vein minerals.

56 Mwe and the reservoir is one of the most productive in the Basin and Range Province. Late Miocene basalts represent the most recent volcanic activity in the Dixie Valley area (Waibel, 1987) suggesting that deep fluid circulation in an area of high regional heat flow (Sass, 1995), and not a shallow magma chamber, is the driving force for the Dixie Valley geothermal system. However, near-vertical and wide-angle seismic reflection data collected in the area provide evidence for a magma body at the base of the crust (Jarchow et al., 1993). Resolving these issues is extremely important for developing exploration and production strategies in the Basin and Range Province.

Noncondensable gas samples from high-pressure separator stations that provide steam to the Dixie Valley geothermal plant were analyzed for noble gas elemental and isotopic compositions (Kennedy et al., 1996). The atmospheric noble gas component is presently dominated by gases carried into the system by re-injected fluids. However, helium contents in excess of that expected for the injectate represent a contribution from a primary reservoir fluid. The helium isotopic compositions (0.70-0.76 Ra) are elevated relative to that expected for radiogenic production in the crust (0.02-0.10 Ra) indicating that as much as ~7.5% of the helium in the reservoir fluid is magmatic or mantle-derived. This mantle signature, however, is not very strong when compared to other geothermal systems which are known to be associated with recent igneous activity, such as The Geysers discussed above. The modest helium enrichments and lower $^3He/^4He$ ratios at Dixie Valley favors, (1) fluid circulation through an aged and non-active magma chamber, perhaps the source chamber for the Miocene basalts in the vicinity, or (2) fluid transport along the range-front fault from deeper sources, either a deep melt zone (e.g., Jarchow et al., 1993) or perhaps direct communication with upper mantle fluids (e.g., Ellwood et al., 1995).

COUPLED REACTION-TRANSPORT MODELS

The natural spatial distribution in the isotopic composition of geothermal fluids when combined with coupled reaction-transport models can provide important information regarding chemical reaction paths and fluid velocities through geothermal reservoirs (e.g. Johnson and DePaolo, 1994). Coupled reaction-transport models can also be extremely useful in interpreting spatial and temporal changes in fluid isotopic composition induced during the course of tracer tests. Typically the concentration of chemically reactive trace elements, such as Sr, in fluids is orders of magnitude lower than in solid phases through which the fluid flows. Therefore, as a result of mineral dissolution, mineral precipitation, and ion exchange the isotopic composition of the reactive element in the fluid will be a product of both the isotopic composition of the original source fluid and that of the solute acquired from the reservoir rocks.

As derived by Johnson and DePaolo (1994), the following equation describes the spatial distribution of an isotopic ratio in a fluid for one-dimensional steady-state advective flow (in this simplified example dispersion is assumed to be negligible):

$$r_f(x') = r_s + (r_{f,0} - r_s)\exp(-N_D x')$$

Where r_f and r_s are the isotopic ratios in the fluid and released to the fluid by the dissolving solid phases, respectively, and N_D is the Damköhler number which is a dimensionless parameter that is proportional to the ratio of the reaction rates to the average fluid velocity. The distance variable (x') has been scaled relative to a characteristic length of the system, ℓ, such that ($x' = x/\ell$). In this manner, the isotopic disequilibrium between the fluid and the solid phase decays away in the fluid by a factor of e for each distance ℓ/N_D traversed, as depicted in Figure 3.

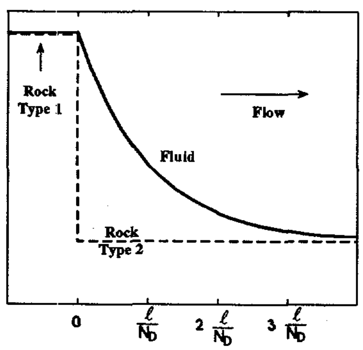

Figure 3: The evolution of an isotope ratio in a simple water-rock system as a function of distance. The fluid is initially out of isotopic equilibrium as it crosses the rock type change (x=0). The disequilibrium decays by a factor of e for each distance ℓ/N_D traversed.

It is also evident from Figure 3 that a fluid in isotopic equilibrium with one rock type that passes into another isotopically dissimilar rock type will evolve toward a new isotopic equilibrium at a rate governed by the Damköhler number. At the very least, measurements of spatial differences in fluid isotopic compositions across a poorly characterized geothermal field will give an indication of fluid flow direction. More careful measurements may yield estimates of N_D that are adequate for constraining fluid velocities. Changes in fluid isotopic compositions observed while monitoring a production well will signal temporal changes in the hydrologic regime. Spatial variations in N_D may be used to identify zones of unusually high hydraulic conductivity in otherwise homogeneous rocks. For instance, a fluid moving through a highly permeable zone, such as a fracture, would travel long distances before attaining isotopic equilibrium with the host rock (Figure 4). Finally, in those situations where injection fluids have an isotopic composition distinct from reservoir rocks and fluids, temporal and spatial monitoring may be used to identify locations of fast pathways and estimate fluid velocities between injection and production wells, providing an excellent natural tracer for liquid phases in geothermal systems. In a similar manner, helium concentration and isotopic compositions can be used to monitor the vapor phase.

It is our philosophy that through an integrated isotopic approach to the study of geothermal systems, it is possible to use isotopic data to clearly identify fluid and heat sources, estimate fluid velocities or residence times, establish hydraulic connectivity, estimate the rock-to-fluid heat transfer efficiency, measure the reactivity of the fluids with the rocks, and to map these parameters within the system. By coupling isotopic and chemical data to improved theories or models for interpreting isotopic variations; reservoir models incorporating subsurface geophysics and isotope geochemistry will generate clearer pictures of geothermal systems and how they evolve.

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2-D Model of fast path Sr isotope pattern

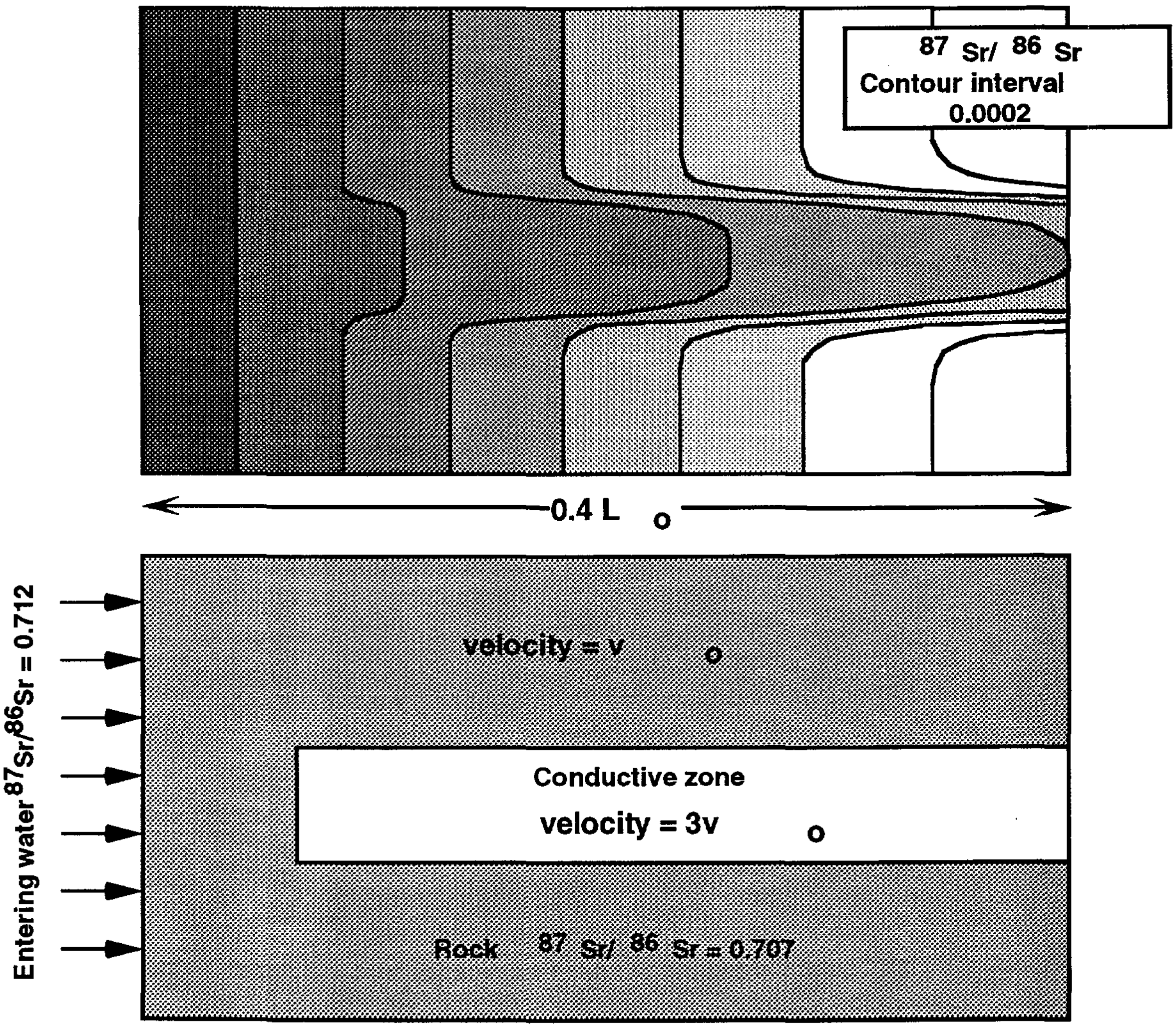

Figure 4: Isotopic evolution of a fluid flowing into an isotopically distinct rock mass containing a zone of high conductivity. The Domköhler number is smaller in the more conductive zone where the fluid velocity is higher; this zone could be identified via isotope measurements because the fluid equilibrates over a longer distance.

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HIGH TEMPERATURE WATER ADSORPTION ON THE GEYSERS ROCKS

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ABSTRACT

In order to measure water retention by geothermal reservoir rocks at the actual reservoir temperature, the ORNL high temperature isopiestic apparatus was adapted for adsorption measurements. The quantity of water retained by rock samples taken from three different wells of The Geysers geothermal reservoir was measured at 150 °C, 200 °C, and 250 °C as a function of pressure in the range $0.00 \le p/p_0 \le 0.98$, where p_0 is the saturated water vapor pressure. Both adsorption (increasing pressure) and desorption (decreasing pressure) runs were made in order to investigate the nature and the extent of the hysteresis.

Additionally, low temperature gas adsorption analyses were performed on the same rock samples. Nitrogen or krypton adsorption and desorption isotherms at 77 K were used to obtain BET specific surface areas, pore volumes and their distributions with respect to pore sizes. Mercury intrusion porosimetry was also used to obtain similar information extending to very large pores (macropores). A correlation is sought between water adsorption, the surface properties, and the mineralogical and petrological characteristics of the solids.

INTRODUCTION

This project has been undertaken in order to expand our understanding of the adsorption/desorption processes occurring in rocks found in geothermal reservoirs, with the intention of using such information in improving the efficiency of the recovery of geothermal energy. The results of the water retention measurements can be used as one of the inputs to geothermal reservoir models. The main goals were:

- to measure water retention by the reservoir rocks at temperatures approaching the actual reservoir conditions and to explore the temperature dependence of adsorption;
- to investigate the hysteresis behavior;
- to characterize the rocks included in the study with respect to water adsorption capacity;
- to research the possibility of estimating this capacity using available properties of the rocks.

Such properties as porosity, BET specific surface area, total pore volume and pore volume and area distributions with respect to pore size can be obtained by methods that are standardized and relatively inexpensive in contrast to high temperature water adsorption measurements.

Since the vapor pressure in vapor-dominated geothermal reservoirs in their undisturbed state is equal to the saturation pressure of liquid water at the measured reservoir temperature, the reservoir must contain some amount of free water present in wide pores and fractures (Pruess and O'Sullivan, 1992). The steam drawn from such a reservoir initially comes from the evaporation of this water. After the reserve of this free water is exhausted, the water retained in smaller pores and adsorbed on the surfaces will start to evaporate, and the pressure will decline. The process of depletion of a steam-dominated reservoir assuming thermodynamic equilibrium in all its volume (no flow restrictions) is shown schematically in Figure 1. The flat (nearly horizontal) part of the solid curve in Figure 1 illustrates that it is impossible to estimate the amount of water initially present in the reservoir by measuring the reservoir pressure, since the withdrawal of large amounts of water at this stage will be associated with a very small decline

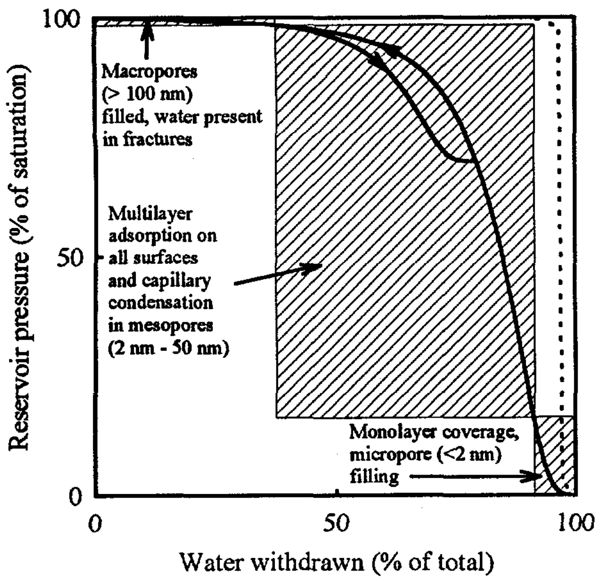

Figure 1. Pressure decline during depletion of a vapor-dominated geothermal reservoir.

in pressure. In the later stages of the reservoir operation the amount of water left in the reservoir can be determined, if water retention capacity as a function of pressure is known for the rocks found in the reservoir.

As seen in Figure 1, the reservoir pressure observed with adsorption present (solid curve) will be lower than the pressure without adsorption (dotted curve) in the later stages of the reservoir operation. With any mechanism of lowering water activity (either interactions with solid surfaces or with dissolved substances present) a gradual decline in pressure will be observed instead of an abrupt fall to zero when all the water is withdrawn. Since the decline in pressure tends to slow down a further depletion, water pressure lowering acts as a mechanism stabilizing geothermal reservoirs, by delaying a complete dry-out. This aspect can be depicted as the presence of a 'capillary suction' which keeps the moisture inside the rocks at the conditions where liquid water would quickly evaporate. The increased interest in adsorption properties of the geothermal reservoir rocks is then parallel to the increased interest in the behavior of vapor-dominated geothermal reservoirs in the later stages of their exploitation, when the pressure is substantially lower than the saturation pressure at the nominal reservoir temperature.

It should be emphasized that the transition between bulk water and the water that is held by interactions with the solid surface is gradual. The division of the relative pressure range into the subranges (Figure 1) corresponding to the formation of a multilayer, micropore filling, multilayer adsorption, and capillary condensation is not rigorous, since in some pressure ranges these mechanisms of water retention are present simultaneously, and they smoothly transform into each other. Since the fluid-solid interactions are not fully understood at the molecular level, different models are used for description of different regimes of liquid retention on solid surfaces. In all cases, the macroscopic result of the liquid-solid interaction is the change in the retained liquid's activity as compared to pure bulk liquid.

EXPERIMENTAL

Apparatus

The ORNL high-temperature isopiestic facility is a unique apparatus capable of accurate measurements (typically ± 1mg) of the change in mass of twenty 2-18 g samples simultaneously under high temperature and high pressure conditions (Holmes *et al.*, 1978). This ability makes it possible to measure water retention by materials characterized by relatively small surface areas like The Geysers rocks. The samples are placed inside a high-pressure, high-temperature autoclave in pans fitting in holes in a steel disk which can be rotated by the operator. The pans are placed in turn on the torsion suspension electromagnetic balance and weighed *in situ* by adjusting the electric current through the balance coil. The null point is detected by an optoelectronic system using a collimated light source, a dual photoresistor and a servoamplifier. The current through the coil that is required to bring the balance beam back to the null point is recorded. Figure 2 shows a schematic diagram of the experimental setup.

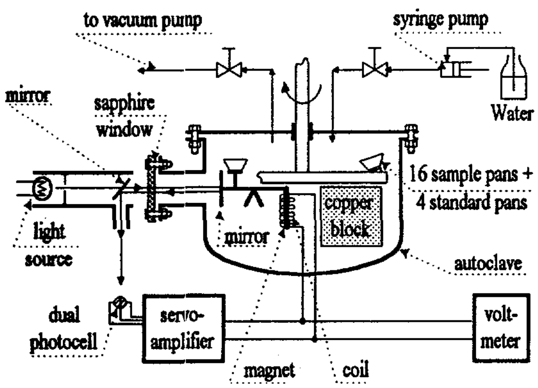

Figure 2. *Schematic of the isopiestic apparatus with torsion suspension balance and optoelectronic null detector for in situ weighing.*

In contrast to the most commonly used sorptometers, the quantity measured using this apparatus is the change in the mass of the solid instead of the change in the vapor pressure caused by adsorption or desorption The mass is measured by comparison with a set of standard weights placed inside the pressure vessel together with the samples. This method makes the results particularly reliable and free of large systematic errors. The densities of the samples, which have to be known in order to correct for the effect of buoyancy, can be measured inside the autoclave by weighing the samples in vacuum and then in the atmosphere of a compressed gas of known density (e.g. Ar). The samples may be left under the same vapor pressure for many days and the change of mass with time can be continuously monitored. The experimental details and procedures were described previously (Gruszkiewicz *et al.*, 1996).

Samples

The measurements were performed on core samples taken from the producing steam reservoir. Well numbers and approximate footages were as follows:

- NEGU-17, 8530-8530.5 ft (rubble)
- Prati State 12, 6261.7-6261.8 ft
- MLM-3, 4336-4336.3 ft.

The rocks were crushed and sieved. Three fractions were prepared of each sample with the following grain sizes: 2.00 - 4.25 mm ('coarse'), 0.355 - 2.00 mm ('medium'), and 0 - 0.355 mm ('fine').

The densities of the rock samples were close to each other and equal on average to 2.775 ± 0.03 g/cm^3. Both density determinations by measuring the effect of buoyancy in argon and by mercury porosimetry indicated that the density of the NEGU-17 well samples might be higher than that of the other two wells by up to 0.03 g/cm^3. This difference is smaller than could be expected if the significant differences in mineralogy and in specific surface areas of the three metagraywackes, as discussed below, are taken into account.

RESULTS

Temperature dependence and hysteresis

Figures 3 and 4 show the experimental results for water retention on the medium fractions of NEGU-17 and MLM-3 rocks, respectively, at 150, 200 and 250 °C. The physical adsorption on these rocks shows the following features:

- there is essentially no temperature dependence of the adsorption branches,
- as the temperature increases the hysteresis loop narrows in both the amount of the adsorbate and the pressure range,
- water retention is reversible,
- the hysteresis loops persist to very low pressures in the case of MLM-3, but distinct closure points are present in NEGU-17.

While on the adsorption branch the water is present both as multilayer adsorbate and as capillary condensate, in principle all of the excess retention on the desorption branch is due to capillary condensation. This explains why water retention on the desorption branch decreases with increasing temperature, while the adsorption branch is nearly temperature independent. Both the pressure range of the hysteresis loop and the excess water retention should decrease with increasing temperature, since capillary

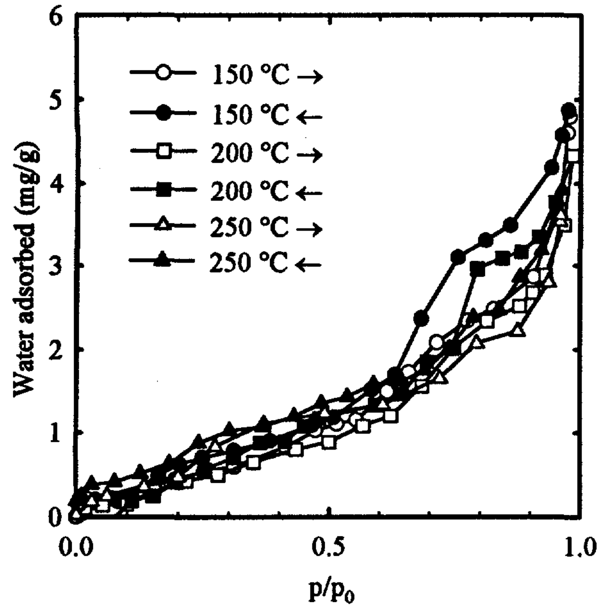

Figure 3. Adsorption/desorption isotherms of water on the medium fractions of the NEGU-17 medium grain size sample.

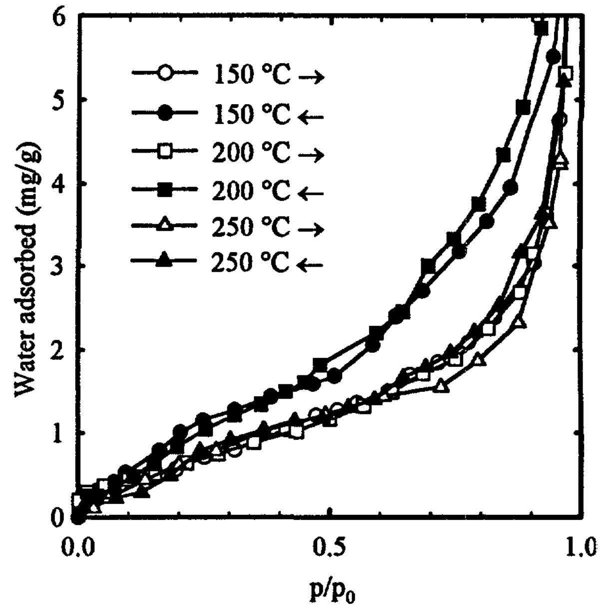

Figure 4. Adsorption/desorption isotherms of water on the medium fractions of the MLM-3 medium grain size sample.

condensation depends strongly on temperature. An analysis of the Kelvin equation,

$$\frac{p}{p_0} = e^{-\frac{4K(T)}{d}}, \qquad K(T) = \frac{\gamma(T)\ V_m(T)}{RT}, \quad (1)$$

indicates that for a constant pore diameter d, the changes in the surface tension γ, and the molar volume of the liquid V_m accompanying the increase of the temperature T would cause an approximately linear increase of the corresponding relative pressure p/p_0. According to equation 1 applied to water, the capillaries smaller than d = 20 Å (2 nm) should be filled with water at relative pressures equal to at least

$$\left(\frac{p}{p_0}\right)_{2\,\text{nm}} = 0.297 + 0.00187\,t \qquad (2)$$

where t is the temperature in °C. The relative pressures calculated from equation 2 agree well with the experimentally observed inception points for the hysteresis loop at 150 °C and 200 °C. At 250 °C the hysteresis loops are very narrow, and the inception points are not well defined (Figures 3 and 4).

Since the mechanism of water retention on the adsorption branch is mainly multilayer adsorption, with a heat effect similar to that of condensation into bulk water, there is little or no change of the amount of water adsorbed this way with temperature. Since the activity of the adsorbate changes with temperature in the same way as the activity of free water, p/p_0 remains constant. It should be noted that the shapes of adsorption isotherms obtained from the Kelvin equation for capillary condensation and from the BET equation for multilayer adsorption can be very similar, so that it is not possible to distinguish between the two regimes on the basis of the isotherm shapes at one temperature.

The causes for the low-pressure hysteresis on very heterogeneous rock samples are hard to identify definitively. Certainly some of the components found in the altered graywacke show this behavior, which was previously found (Gregg and Sing, 1982) to be due in some cases to the solid structure changes(swelling) caused by the adsorbate or to reversible hydroxylation-dehydroxylation. Low-pressure hysteresis of water on calcite was observed (Gregg and Gammage, 1972) and attributed to the penetration of water into the lamellar solid, with some dissolution. The presence of solutes in the adsorbate water could additionally shift the isotherm to lower pressures.

Irreversible water retention

Apart from the reversible adsorption, illustrated in Figures 3 and 4, and found mainly in the coarse and medium fraction samples, extensive *irreversible water retention* was observed in the small grain size samples. Figure 5 shows that the

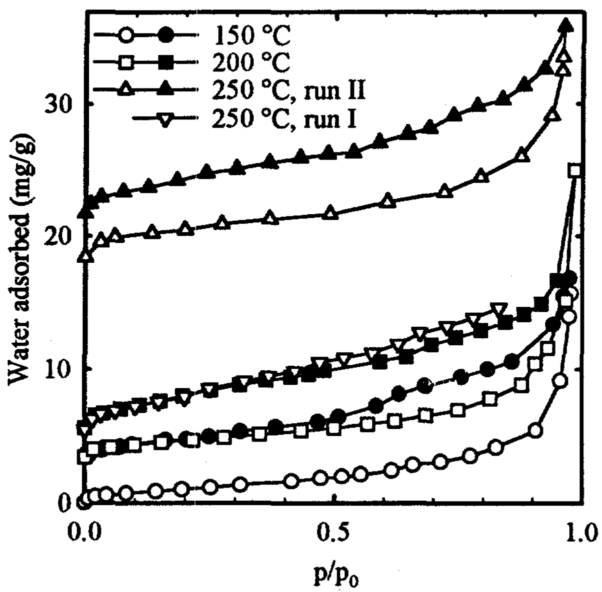

Figure 5. *Adsorption/desorption isotherms of water on the small grain size fraction of the MLM-3 metagraywacke.*

amount of water irreversibly bound by solid minerals can be very large compared to the capacity of the porous rock structure for physical and reversible chemical adsorption. It is interesting that at least part of the irreversible water retention, whether it is referred to as chemical adsorption or mineral alteration, occurs only on fresh surfaces formed by milling, since it was not observed on coarse and medium size samples. It is also possible that the mineral with the most capacity for bonding water is occluded as small grains in other materials, so that before milling it is not accessible to vapor. The milling process can also produce fine cracks in the crystals, where water is trapped very firmly (Gammage and Gregg, 1972).

SEM photomicrographs of the surface of the rock samples have shown the presence of large clusters of long crystals (needles) of an alteration mineral identified by X-ray diffraction as prehnite, $Ca_2Al_2Si_3O_{10}(OH)_2$. The occurrence of these clusters is rather sporadic, but is much more abundant in the samples examined after the high temperature adsorption experiments. Similar fibrous material found in samples of cores from the same The Geysers wells as in this study was previously identified as actinolite. (Hulen *et al.* 1991)

Nitrogen and water adsorption, mercury intrusion, and rock compositions

Water differs from neutral adsorbates, such as nitrogen, in polarity, the presence of hydrogen-bond bridges, and the ability to form chemical bonds with the mineral surfaces, or even react with the bulk of the minerals, so that crystal structures are altered. These differences will certainly have an impact on the measured adsorption isotherms and specific surface areas determined from nitrogen and water adsorption. It is known that the porous material's capacity for water adsorption can be either larger or smaller than its capacity for nitrogen adsorption, depending on the chemical nature of the adsorbent, its preparation, etc. All the nitrogen adsorption isotherms obtained in this work had well defined hysteresis loops closing at $p/p_0 \approx 0.45$ (a rather typical value for nitrogen). Nitrogen adsorption/desorption isotherm for medium grain size samples of the three cores investigated are shown in Figure 6. The following characteristics of the samples can be immediately deduced from Figure 6:

- there are large differences in the amounts adsorbed by the three cores (the ratio MLM-3 : NEGU-17 : Prati State 12 at $p/p_0 = 0.4$ is 1 : 2.56 : 0.29, the BET surface areas are 1.31, 4.06, and 0.36 m^2/g, respectively);

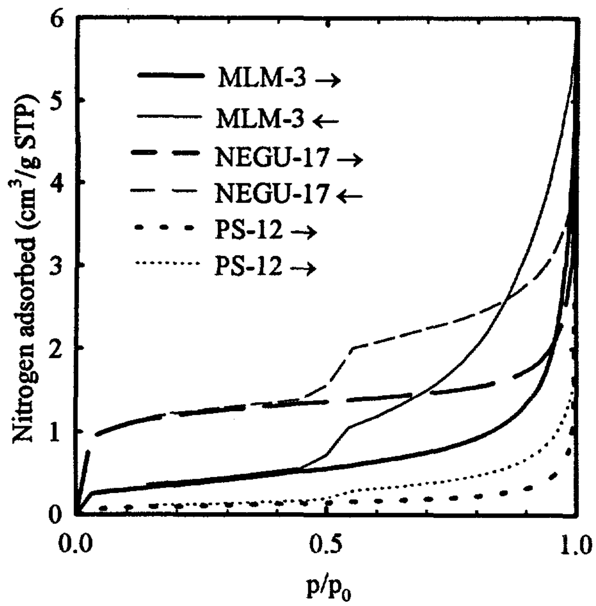

Figure 6. Adsorption/desorption isotherms of nitrogen at 77 K on the medium fractions of the cores of the three wells investigated

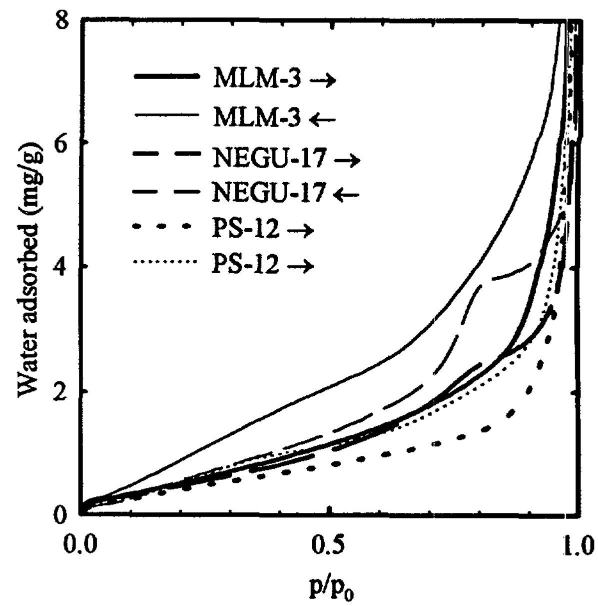

Figure 7. Adsorption/desorption isotherms of water at 200 °C on the average medium and coarse grain size fractions of the cores of the three wells investigated

- the NEGU-17 metagraywacke has the largest specific surface area and its pore area distribution is shifted towards smaller pores compared to the other two cores;
- the MLM-3 metagraywacke has the largest high pressure nitrogen retention, which is likely due to the presence of more macropores.

The relative capacities of various materials for nitrogen adsorption at 77 K cannot be used directly to predict relative capacities for water adsorption, even if the materials are similar. A comparison of Figure 6 with Figure 7, its analogue for high temperature water adsorption, supports this conclusion. Figure 7 shows water adsorption isotherms of the three cores (averages of the medium and coarse fractions) at 200 °C. The following characteristics of water adsorption can be observed:

- the solid-fluid interactions are relatively stronger (as compared to the fluid-fluid interactions) in nitrogen than in water;
- in contrast to nitrogen adsorption, the amounts of water retained by the three cores at low relative pressures are similar (the ratio MLM-3 : NEGU-17 : Prati State 12 at $p/p_0 = 0.4$ is 1 : 0.90 : 0.74;
- the NEGU-17 isotherm has a visibly different shape from the other two isotherms.

There is convincing evidence, obtained by different methods, indicating that the NEGU-17 metagraywacke has not only significantly more micropores but also less very wide macropores than either MLM-3 or Prati State 12. Pore volume distributions were calculated from both nitrogen and water adsorption isotherms. The results were in a very good qualitative agreement, and they both showed a very distinct enhancement of adsorption in the very narrow pore range for NEGU-17 in comparison with the other two cores. Average pore diameters from nitrogen adsorption BET surface areas and total pore volumes for MLM-3, NEGU-17, and Prati State 12 were 272 Å, 66 Å, and 286 Å, respectively. The average pore diameter for NEGU-17 calculated using the Langmuir specific surface area is even lower (47 Å). The pore volume distributions obtained from mercury intrusion tests are shown in Figure 8.

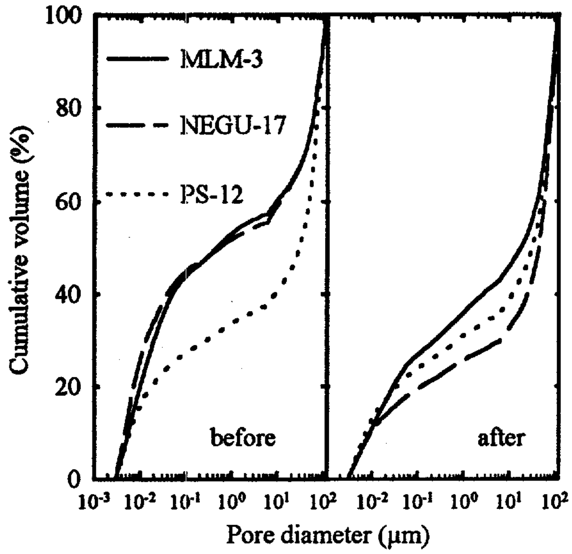

***Figure 8.** Normalized cumulative pore volume distributions obtained from mercury intrusion porosimetry.*

Mercury intrusion can provide information about porous structures in a wider pore size range than nitrogen adsorption, but its precision is lower in the narrow mesopore and micropore ranges. For these reasons the differences between the samples in these ranges are not visible in Figure 8. However, Figure 8 shows a shift towards wider pore sizes which took place during high temperature water adsorption experiments, in NEGU-17 and MLM-3 samples, while Prati State 12 pore volume distribution remained unchanged. Since the smallest pores are most affected by changes occurring on the surface or by solid dissolution and subsequent deposition, the Prati State 12 metagraywacke apparently has by far the smallest amount of very narrow pores. Partial destruction of the finest pores was also indicated by the decrease by 20 to 30 per cent in the BET specific surface areas of all the rock samples investigated after the high temperature water adsorption measurements.

Total pore volumes (and hence total porosities) are difficult to measure unambiguously by either adsorption or mercury intrusion. The adsorption isotherms of rock samples are characterized by a steep increase of the amount of water retained with the increase in pressure towards saturation, so that the isotherm is apparently asymptotic to the $p/p_0=1$ axis. Such behavior is not universal in porous materials, since often a plateau at high relative pressures is found. The lack of a plateau indicates that the pore volume distribution is relatively even in the upper end of the pore size range, and there is no distinct upper pore size limit. Since the widest pores contribute significantly to the total volume (although usually not to the total surface area), this limits the accuracy of total pore volume determinations. The distinction between internal and external volume is arbitrary, and small changes in the relative pressure or mercury filling pressure may introduce large errors. Total porosities obtained in this work from mercury intrusion tests are shown in Figure 9.

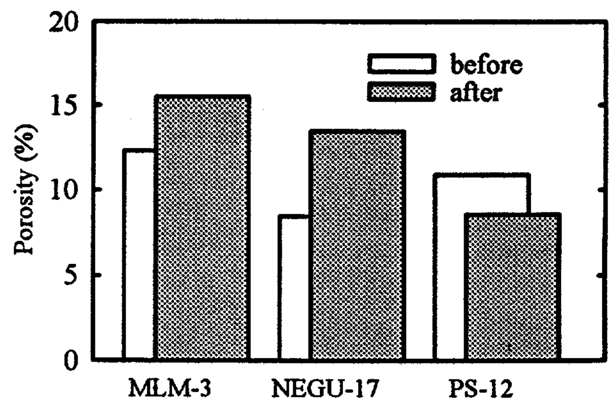

***Figure 9.** Porosities of the samples before (open bars) and after (shaded bars) high temperature water adsorption experiments.*

The porosities were measured by the Micromeritics laboratory using a mercury filling pressure of 1.59 psia, and a final pressure of 60,000 psia. The results are significantly higher than those reported by Satik *et al.* (1996) for similar materials (up to 5.5 per cent for MLM-3 metagraywacke) or by Gunderson (1992) (1.1 to 5.6 per cent for NEGU-17 graywacke). The reason for this discrepancy is not clear. The differences in the mercury intrusion procedures, sample grain sizes, and random differences between the samples can significantly impact total porosity results.

The percentages of the components that account for more than 95 per cent of the metagraywacke are given in Table 1. (Hulen, 1997)

	MLM-3	NEGU-17	PS-12
quartz	38	19	45
albite	30	16	21
chlorite	14	31	13
illite	11	14	4
epidote	1	2	11
adularia	traces	8	3
organic	1	6	2

Table 1. *Compositions of the metagraywacke samples.*

The compositions shown in Table 1 indicate that the fine NEGU-17 metagraywacke differs significantly from the other two more coarse-grained samples in the relative amounts of quartz, albite, and chlorite. It also contains much more organic matter. The Prati State 12 metagraywacke contains more quartz and epidote but less illite than either NEGU-17 or MLM-3. Chlorite has a layered structure similar to montmorillonite and other minerals forming clays and capable of a reversible uptake of water with swelling and splitting into lamellar structures. Quartz and feldspars have more rigid, three dimensional structures which do not accommodate water or small cations as easily. However, their surfaces can be irreversibly hydroxylated.

CONCLUSIONS

Measurements of adsorption of water on rock samples were made for the first time at the reservoir temperature. The amounts of water retained by samples of three cores taken from The Geysers reservoir as a function of relative pressure of steam at 150 °C, 200 °C, and 250 °C are the principal results of this work. These results support the view that only the amount of water held in the pores as capillary condensate can change significantly with temperature. This means that the amount of water retained by the porous solid on the desorption branch of the hysteresis loop decreases with increasing temperature, and the hysteresis loop narrows. It is estimated that at 250 °C, and at p/p_0 up to 0.9, no more than 20 per cent of the water present in the rocks investigated can be retained by the capillary condensation mechanism (with liquid-gas menisci of small, mesopore scale radii, present). Below p/p_0 =0.75 at this temperature there is practically no temperature-dependent capillary condensation, and adsorption/desorption essentially does not depend on temperature in the range investigated.

Reversible physical adsorption/desorption was observed on all the samples. Both the MLM-3 and Prati State 12 metagraywackes show low pressure hysteresis, but the NEGU-17 does not. The latter rock has the finest structure of the three and shows some microporosity, which, however, does not affect significantly the amounts of water adsorbed..

Irreversible bonding of water occurs on all the samples after they are milled to finer grain sizes (below 0.355 mm). The amount of water retained irreversibly can be many times larger than the capacity for physical adsorption. The fact that only fine grain size fractions show appreciable irreversible water retention indicates that the minerals susceptible to chemical adsorption (or alteration) are initially protected by a material that does not bond water, or has already been altered. The differences in water and nitrogen adsorption find their reflection in the mineral composition of the rocks, but a detailed analysis of the roles played by various component minerals would require further studies.

It is not surprising that the differences in the BET nitrogen adsorption specific surface areas of the samples do not reflect the differences in water adsorption capacity. Since the relative strength of the solid-fluid interaction (compared to the fluid-fluid interaction) is much greater in highly polarizable nitrogen than in the polar and hydrogen bridged water, nitrogen molecules can penetrate some pores that the smaller water molecules can not. As a result, some microporous solids with polar groups may show an enhancement of low-pressure adsorption which is much greater for nitrogen than for water.

Total porosity is difficult to measure accurately and it can not be treated as a reliable measure of water adsorption capacity. Low temperature nitrogen adsorption/desorption results can be useful if the pore volume and area distributions are analyzed and calculated in a uniform way. Since geothermal reservoir rocks show a variety of structures, with various configurations of the pore systems and with composition-dependent reversible chemical adsorption, water retention estimates obtained from such calculations are not expected to be reliable. The best estimates of water retention may be obtained from experiments at ambient or moderately superambient temperatures which can be corrected for the temperature dependence of the capillary condensation.

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VOLATILITY OF HCl AND THE THERMODYNAMICS OF BRINES DURING BRINE DRYOUT

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ABSTRACT

Laboratory measurements of liquid-vapor partitioning (volatility) of chlorides from brines to steam can be used to indicate the potential for corrosion problems in geothermal systems. Measurements of volatilities of solutes in chloride brines have established a possible mechanism for the production of high-chloride steam from slightly acidic high temperature brines. Questions concerning the fate of NaCl in the steam production process have been addressed through extensive measurements of its volatility from brines ranging in concentration from dilute solutions to halite saturation. Recent measurements of chloride partitioning to steam over brines in contact with Geysers rock samples are consistent with our concept of the process for production of high-chloride steam.

INTRODUCTION

The production of corrosive steam is a problem which affects the development and operation of geothermal resources, including The Geysers. High concentrations of chloride (to ~100 ppm) have been noted in some wells, particularly in the higher-temperature reservoir characteristic of the Northwest Geysers. The source of this corrosive, high-chloride steam is of significant interest, particularly as an understanding of the production of this steam could lead to the development or optimization of mitigation methods for addressing corrosion problems. To address these questions we have carried out a number of laboratory studies of the partitioning of relatively nonvolatile solutes between brines and steam, including experiments in which brines in contact with rock samples from The Geysers are evaporated to dryness with continuous sampling of steam condensate and analysis of the composition of these samples as functions of temperature and brine concentration. In this project, a part of the ORNL program 'Fundamental Thermodynamics of Geothermal Systems,' we have determined the thermodynamic partitioning constants for HCl (Simonson and Palmer, 1993) and NaCl (Simonson et al., 1994).

The assumption underlying the application of liquid-vapor equilibrium measurements to the problem of high-chloride steam production from a vapor-dominated reservoir (e.g., The Geysers) is that a brine source exists in equilibrium with steam. In cases where the steam pressures are too low for equilibrium with a coexisting brine at the reservoir temperature, application of the equilibrium volatility results to questions of steam composition requires that either: (1) any reaction between undersaturated steam and (dry) rock does not change the chloride composition of steam compared with the brine-equilibrated values, or (2) that the properties (i.e., solute volatilities) of brines adsorbed on reservoir rocks are essentially those of the bulk brine, after adjusting for the lowering of the activity of water. These requirements appear at first to limit severely the application of an assumed brine-steam equilibrium mechanism for high-chloride steam formation to problems encountered in vapor-dominated reservoirs. However, significant problems with high-chloride steam have been noted in some wells in the 'high temperature' region of the Northwest Geysers. Shook (1995) has developed a conceptual model for a vapor-dominated reservoir with a high-temperature 'feature' which indicates significant liquid content (as high-salinity brine) in the high temperature zone, and seismic data support the presence of liquid (Romero et al., 1995). Regardless of the source of chloride in steam, mitigation of high chloride by desuperheating to partial condensation requires knowledge of the liquid-vapor partitioning of solutes in order to optimize the extent of desuperheating. Thus an understanding of brine thermodynamics and solute volatility over wide ranges of temperature and composition relates directly to problems arising from the presence of corrosive solutes in geothermal steam.

From our initial study of HCl volatility (Simonson and Palmer, 1993) it was clear that partitioning of significant levels of chloride to steam as HCl would require that the brine pH at temperature be too low to be consistent with rocks which did not show alteration by strongly acidic fluids. High-temperature pH values below 3 are required to volatilize HCl to the extent of 100 ppm chloride in steam at 350°C, and this pH requirement is essentially independent of brine salinity due to the effect of additional NaCl on the activity coefficient of HCl(aq) (Simonson and Palmer, 1993; Simonson and Palmer, unpublished results). Our experiments have also shown that addition of the hydrolyzable ions Mg^{2+} and Ca^{2+} at temperatures to 350°C does not lower the brine pH sufficiently to give chloride concentrations in steam at levels to 100 ppm.

Some wells in the Northwest Geysers show high concentrations of ammonia as noncondensible gas (M. Walters, pers. comm.). We have shown that consideration of the volatility of ammonium chloride (Palmer and Simonson, 1993) gives a mechanism for the production of high-chloride steam from high-salinity brine of near-neutral pH at 350° C (Simonson and Palmer, 1995). However, the volatility of NaCl raises important questions for an assumed high-temperature equilibrium between highly saline brine and steam, in that only very low levels of sodium have been found in wellhead condensate samples. Measurements of the volatility of NaCl(aq) can give important information on the possibility of chloride transport to steam from equilibration with brines in geothermal systems, in that a relatively high volatility of NaCl implies either that the steam was not in equilibrium with a saline brine at high temperature in the reservoir, or that some mechanism (e.g., precipitation on depressurization) exists to effectively 'strip' NaCl from steam on production.

Here we report the results of recent experiments on the volatility of chlorides over NaCl(aq) brines at temperatures to 350°C and at concentrations ranging to halite saturation. Comparisons of these new results with available and extrapolated literature measurements are made, and implications for a conceptual reservoir model including equilibration of steam with saline brines are discussed. Finally, we describe some very recent experiments and preliminary results obtained from equilibration of NaCl(aq) with rock samples from the high-temperature reservoir of the Northwest Geysers.

EXPERIMENTAL

The apparatus and techniques used in our laboratory measurements of solute partitioning from brines to steam at high temperatures have been described in detail previously (Simonson and Palmer, 1993; Palmer and Simonson, 1993). Coexisting brine and steam are equilibrated at temperatures to 350°C in a platinum-lined autoclave of ~600 cm^3 internal volume, and samples of the two phases (liquid and steam condensate) are withdrawn for subsequent analysis through platinum sample lines. Samples are analyzed for both chloride and counterion (e.g., Na^+) concentrations primarily by ion chromatography, with other techniques used as appropriate. No recharge of the liquid phase occurs through a given series of vapor-phase sample acquisition, and the experimental series can be extended through solid-brine saturation (e.g., halite precipitation) to the {solid + vapor} two-phase condition as desired. A highly simplified schematic of the high-temperature lined autoclave is shown in Figure 1.

NaCl Partitioning

It has proven to be remarkably difficult to obtain reliable values for the partitioning of NaCl(aq) to three-phase saturation with our apparatus and techniques. The very low

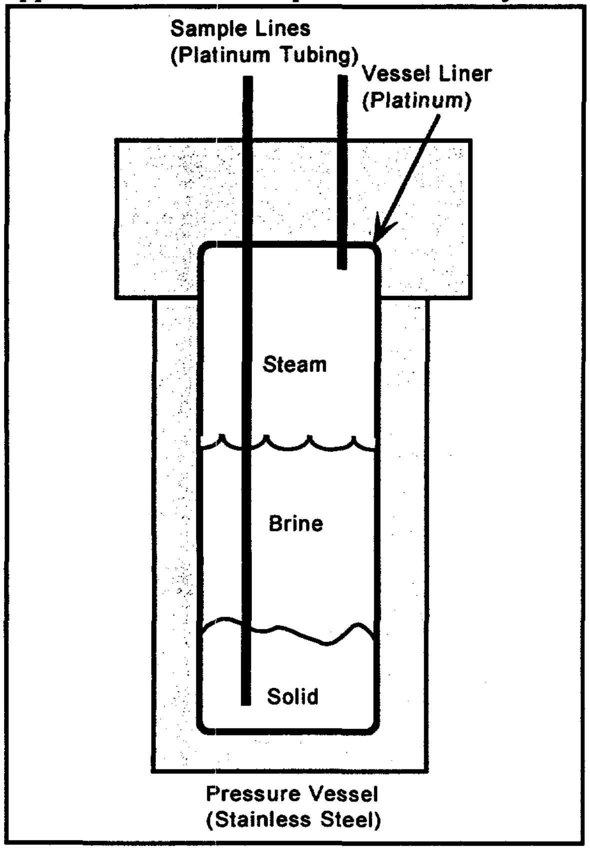

Figure 1. High-temperature lined autoclave for liquid-vapor equilibration and sampling.

volatility of NaCl requires complete separation of vapor from entrained brine within the apparatus. For example, contamination of steam condensate samples at 250°C with approximately 100 ppb of entrained brine droplets results in an apparent concentration in steam which is too large by an order of magnitude. In addition, superheating of lines to prevent solution reflux on sampling may lead to precipitation of NaCl(cr) within the lines, and anomalous low values of the condensate concentration. The very large uncertainties in the experimental results are reflected in Figure 2, where our recent data are compared with values along the three-phase line given by Bischoff and Pitzer (1989), and with those extrapolated from halite solubilities in dry steam as measured by Armellini and Tester (1993).

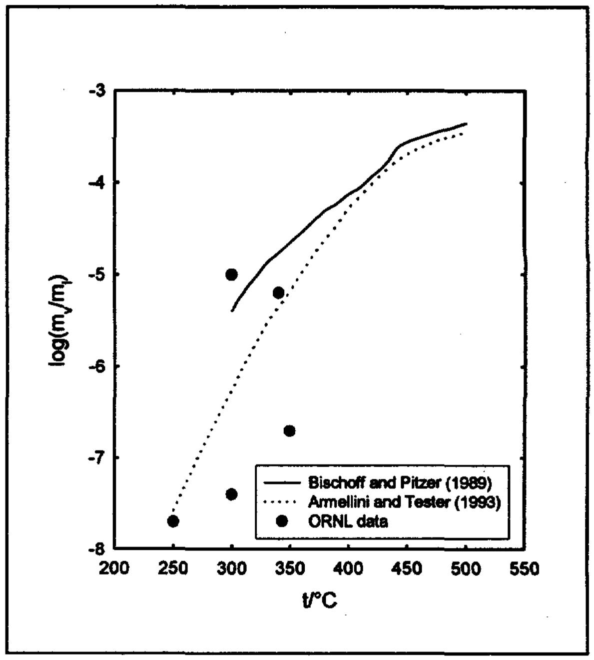

Figure 2. Ratios of vapor and brine molalities of NaCl(aq) from 250 to 500°C.

It is clear that a definitive selection between the curves shown on Figure 2 for the NaCl concentration in steam in the three-phase system cannot be made based on the scattered results obtained in our new measurements. Further, the curve reported by Bischoff and Pitzer (1989) is based in the subcritical region on direct experimental measurements on the three-phase assemblage at temperatures to 325°C, while below 400°C the curve of Armellini and Tester (1993) represents an extrapolation in both temperature and density of their two-phase (halite + steam) results. However, our results for NaCl(aq) volatility at lower brine concentrations do not extrapolate smoothly to the values for the three-phase assemblage given by Bischoff and Pitzer; a pronounced minimum in the ratio m_V/m_l appears in the plots of this ratio against brine molality. The lower-molality volatility data obtained in this program extrapolate relatively smoothly to the curve taken from the work of Armellini and Tester, as shown in Figure 3.

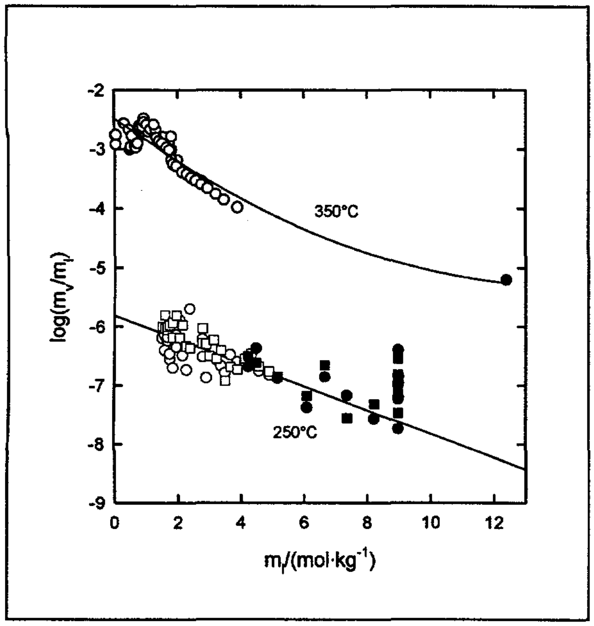

Figure 3. Partitioning of NaCl(aq) and extrapolation to halite saturation. Different symbols represent distinct series of runs.

The experimental data for NaCl(aq) partitioning cited by Bischoff and Pitzer (1989) are from Bischoff, Rosenbauer, and Pitzer (1986). Their experiments were carried out using fresh, unbuffered solutions at each temperature, with excess NaCl(cr) added to insure halite saturation at temperature. Steam condensate samples were analyzed for chloride ion only, with sample pH checked to determine whether excess HCl had volatilized in the experiments. At 300°C, just below the temperature range of the experimental values, it is possible to estimate the amount of chloride which should be present in a vapor sample obtained from fresh, unbuffered NaCl(aq) brine by combining the hydrogen ion molality in solution calculated from the equilibrium quotient for the ionization of water in NaCl(aq) media (Busey and Mesmer, 1978) with the equilibrium constant for HCl partitioning (Simonson and Palmer, 1993). This calculation indicates that a chloride molality of about 6×10^{-5} should be present from HCl partitioning, giving a pH near 4 in the condensate sample and corresponding to about 3 ppm if the chloride is assumed to be NaCl in the sample. This compares with a value of 2.4 ppm NaCl in steam at three-phase saturation as given by Bischoff and Pitzer (1989). It is not reasonable to extend this calculation to significantly higher temperatures, and Bischoff, Rosenbauer and Pitzer did not note low pH in any of their samples. However, it appears that there remains some question concerning the volatility of NaCl at high molalities, including the halite-saturated condition, which are unfortunately not resolved by our recent experimental results. The partitioning of NaCl to steam from halite-saturated brine at 350°C may be as high as about 20 ppm (Bischoff and Pitzer, 1989); the lower estimate extrapolated from Armellini and Tester is about 5 ppm. Either of these levels would require some mechanism for stripping NaCl from steam equilibrated with brine at 350°C, as steam condensate samples generally contain less than 1 ppm Na. It may be possible to determine partitioning from saturated solutions more reliably from measurements of halite solubility in superheated steam as a function of temperature and density, and we expect to attempt these measurements using a packed-column equilibration apparatus.

Chloride partitioning over rock samples

It is clear from the lack of sodium in wellhead condensate samples that partitioning of NaCl to steam is not a significant contributor to the total chloride causing problems in the Northwest Geysers. We have measured the concentration of solutes in steam condensate samples obtained from the multiphase systems (steam + brine + rock samples +/- halite) to address the possibility that equilibration of brines with reservoir rocks could lead to high chloride levels in steam.

Measurements have been carried out at 300°C on NaCl(aq) brines in equilibrium with samples from well MLM-3 and at 245°C with a sample from L'esperance-2. The MLM-3 sample used (provided by J. Hulen, EGI) has been characterized as caprock while the L'esperance-2 sample (provided by T. Anderson, UNOCAL Geothermal) is attributed to the high-temperature reservoir of the Northwest Geysers (Moore and Gunderson, 1995). In both cases the rock samples were ball milled and sieved (+50-200 mesh) and treated with dilute HCl(aq) at 25°C to remove any freshly exposed carbonates. The samples were then rinsed repeatedly with deionized water and decanted to remove fines, then dried in a vacuum oven at 110°C to remove any residual HCl.

Approximately 70 g of the MLM-3 sample was placed in the platinum liner of the volatility apparatus as indicated in Figure 1, and ~200 g of NaCl(aq) unbuffered brine, initially 1 mol·kg^{-1} added to the system. Several days were allowed for initial equilibration at 300°C prior to withdrawal of any steam samples. All steam condensate samples were analyzed by ion chromatography.

Samples from this run indicated essentially no chloride in excess of that expected from the volatility of NaCl. However, high levels of both cations and anions other than sodium and chloride were found, and ammonia was present in excess. The additional cation was tentatively identified as ammonium ion, although the presence of excess ammonia prevented quantitative determination of the cation concentration in the condensate samples. The anion was identified as thiosulfate by its retention time on the ion chromatography column. It was not possible to quantify with good precision the levels of thiosulfate present in the samples due to the extremely long retention time (strong binding) of this ion on the column. Noting the apparent lack of any enhancement of chloride partitioning over this sample and the significant difficulties in sample analysis introduced by the ammonia and thiosulfate, further equilibrations of the MLM-3 sample beyond the initial series at 300°C were not carried out.

After several equilibration series in the volatility apparatus of NaCl(aq) with no rock samples present, and subsequent thorough cleaning of the platinum liner, the rock sample from L'esperance-2 was loaded in the apparatus with NaCl(aq). Some difficulties with the apparatus were encountered on initial heating of the system to 300°C, and after repairs a series of steam condensate samples were obtained at 245°C. A strong odor of sulfides noted on the initial heating of the system to 300°C was found to be significantly lessened in the runs at 245°C; it remains to be seen whether the strong evolution of sulfides (apparently H_2S) from the L'esperance-2 sample will recur at higher temperature or whether volatile sulfides were effectively stripped from this sample on initial heating.

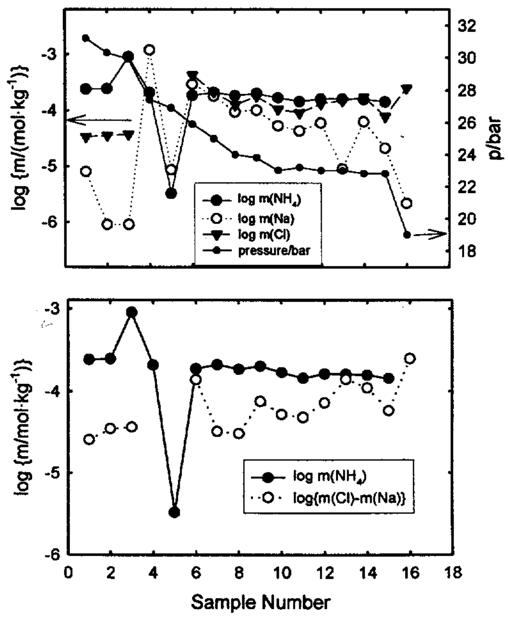

Figure 4. Molalities in steam condensate samples from equilibrations over {NaCl(aq) + L'esperance-2 rock} at 245°C.

Analyses of solutes in steam condensate samples taken from equilibrations over {NaCl(aq) + L'esperance-2 rock} at 245°C are shown in Figure 4. The average pressure during sampling is shown for each sample in the upper plot; the range of nearly constant pressure indicates halite saturation. A blockage in the liquid-phase sample line precluded sampling of the brine during this run. The total sodium ion molalities in the condensate samples after Sample #3 are too high to be consistent with partitioning of NaCl, and we tentatively attribute the observed high sodium ion concentrations to entrainment of liquid in the vapor samples. It should be noted that as the brine concentration was of the order of 10 mol·kg^{-1}, entrained moisture (brine) in steam at the level of 10 ppm would be sufficient to give the high sodium levels noted in the condensate samples.

If the high sodium concentrations in steam condensate are attributed to brine carryover, the extent of transport of chloride as a true vapor species should be indicated by the difference in chloride and sodium molalities in the condensate samples. These values, and the molalities of ammonium ion in the condensate samples as determined by the magnitude and retention time of ion chromatograph peaks, are shown in the lower plot of Figure 4. There is a clear enhancement of chloride in steam over that associated with NaCl, to the level of about 1 ppm Cl in steam. The ammonium molalities in the condensate samples are consistently higher than the chloride concentrations. These ammonium ion levels cannot be attributed to brine carryover, as no ammonium ion was added to the initial brine and it is unlikely that ammonium ion at levels higher than 1 $mol \cdot kg^{-1}$ could have been leached from the rock sample.

The concentrations of ammonium ion, ammonia, and hydrogen ion in a high-chloride brine which are consistent with the chloride and ammonium concentrations shown in the lower frame of Figure 4 can be calculated from the partitioning constants for NH_3, NH_4Cl and HCl. This calculation has been described in detail previously (Simonson and Palmer, 1995). For the present case the results indicate a brine pH at temperature of about 5.0, with $\sim 3 \times 10^{-5}$ $mol \cdot kg^{-1}$ ammonia and $\sim 5 \times 10^{-5}$ $mol \cdot kg^{-1}$ ammonium ion in solution.

It is clear that the apparent enhancement of chloride partitioning shown in these samples warrants further investigation, and additional experiments on these samples are in progress. Particular areas for attention in these studies include obtaining both liquid and condensed-vapor samples from the equilibrium assemblages, and in addressing the role of H_2S in establishing brine pH at low and high temperatures. In analyzing these condensed-vapor samples it was found that the sample pH remained remarkably constant at pH = 5.0. The chloride and ammonia concentrations appear to preclude an ammonia/ammonium buffer as a control for the pH at room temperature. We have noted that the samples contain H_2S, but have not as yet been able to quantify the concentrations in the samples. In addition, analyses by ICP/mass spectrometry indicate the presence of significant levels of iron, magnesium, and boron in the condensate samples, including those which are assumed not to be contaminated by entrained brine. It is expected that further detailed study of the volatilities of components from brines equilibrated with these rock samples will provide significant new information on the distribution of solutes to steam in the high-temperature reservoir of the Northwest Geysers.

ACKNOWLEDGEMENTS

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Tracing Fluid Flow in Geothermal Reservoirs

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Abstract

A family of fluorescent compounds, the polycyclic aromatic sulfonates, were evaluated for application in intermediate- and high-temperature geothermal reservoirs. Whereas the naphthalene sulfonates were found to be very thermally stable and reasonably detectable, the amino-substituted naphthalene sulfonates were found to be somewhat less thermally stable, but much more detectable. A tracer test was conducted at the Dixie Valley, Nevada, geothermal reservoir using one of the substituted naphthalene sulfonates, amino G, and fluorescein. Four of 9 production wells showed tracer breakthrough during the first 200 days of the test. Reconstructed tracer return curves are presented that correct for the thermal decay of tracer assuming an average reservoir temperature of 227°C. In order to examine the feasibility of using numerical simulation to model tracer flow, we developed simple, two-dimensional models of the geothermal reservoir using the numerical simulation programs TETRAD and TOUGH2. By fitting model outputs to measured return curves, we show that numerical reservoir simulations can be calibrated with the tracer data. Both models predict the same order of elution, approximate tracer concentrations, and return curve shapes. Using these results, we propose a method for using numerical models to design a tracer test.

Introduction

With the increased use of reinjection in geothermal reservoirs, tracers have become an important tool in developing reservoir management strategies. If injectors are positioned too close to producers, a risk of short circuiting develops, resulting in the possibility of premature thermal breakthrough. If injectors are placed too far away, the injected water will not provide sufficient pressure support to the reservoir. Since chemical breakthrough is more rapid than thermal breakthrough, a tracer test can provide important interwell flow data that can be used to optimize injection well placement and injection flow rates.

Given the requirement to reinject all of the brine that is produced, most geothermal reservoirs employ several injection wells. In order to determine the destiny of water injected into separate injectors, the operator must employ a separate tracer for each well. Therefore, for multiple well tracing, several tracers are needed.

Whereas few tracers have qualified for low-temperature geothermal reservoir applications, even fewer are available for intermediate-temperature (< 250°C) and high-temperature (< 300°C) applications. Not only must the candidate compounds possess good thermal stability, they must also be nontoxic, affordable, detectable, and nonadsorptive under reservoir conditions.

Due to their excellent detectability, fluorescent compounds have been extensively used as ground-water tracers. Until recently, however, fluorescein was the only fluorescent compound possessing sufficient thermal stability for intermediate-temperature applications. And, previous to this study, no fluorescent compounds have been reported for high-temperature tracer applications.

Although laboratory experimentation is essential in determining the suitability of candidate compounds, tracer evaluation is incomplete without field testing. Perhaps the most challenging aspect of tracer test design is the determination of the appropriate quantity of tracer required for a test. The use of an insufficient quantity results in no detected tracer at the production wells, and no flow path information is obtained. The use of excessive quantities of tracer, which is often done in order to insure breakthrough, is not only expensive, but leads to the use of even greater quantities of that chemical for any subsequent tests in order to overcome the induced high background levels.

We demonstrate the feasibility of using numerical simulation to model the flow of tracer throughout a geothermal reservoir for the purpose of aiding in tracer-test design. Models of the geothermal reservoir at Dixie Valley, Nevada, were developed using the two finite difference simulators, TOUGH2 and TETRAD. Predicted tracer return data were compared to those measured in a recent tracer test conducted at the Dixie Valley geothermal reservoir. Using these data and results, we propose a method for estimating the minimum quantity of tracer required to obtain reliable interwell tracer-breakthrough data.

Fluorescent Geothermal Tracers

Recently, Adams and coworkers (1992) studied 39 aromatic acids to determine their suitability as tracers in intermediate- and high-temperature reservoirs. These anionic compounds were especially attractive as tracer candidates, since due to electrostatic repulsive forces, they resist adsorption onto negatively charged reservoir rock.

The benzenesulfonates were the most stable of all compounds tested, showing no decay upon exposure to temperatures of 300°C for two weeks. However, the average detection limit for these nonfluorescent compounds was relatively high at about 10 ppb. In contrast, highly fluorescent compounds like fluorescein have detection limits approaching 10 ppt, or 3 orders of magnitude lower.

Polycyclic aromatic hydrocarbons (e.g., naphthalene, anthracene, and pyrene) are well-known for their strong fluorescence. By sulfonating these highly fluorescent compounds, we reasoned that we could create a family of tracers that would be fluorescent, water soluble and non-adsorptive on reservoir rock. Sulfonation was considered to be preferable to carbonation due to the greater thermal stability of sulfonated polycyclic aromatic compounds.

We have conducted a survey of the literature and of vendors to determine the availability of various polycyclic aromatic sulfonates. Table 1 summarizes the results of that survey, showing the chemical structures, costs, and minimum measurable concentrations of representatives from each category. For comparison, two xanthene dyes, fluorescein and rhodamine WT are included in the table. Besides amino G, which is discussed in this study, fluorescein and rhodamine WT are the only two field-tested fluorescent geothermal tracers reported in the open literature. The most populous and affordable subgroup in Table 1 is the naphthalene sulfonates, including the amino-substituted naphthalene sulfonates. These compounds are the focus of this study.

Experimental Methods

Candidate tracer compounds were tested for resistance to thermal degradation by subjecting them to autoclave conditions of temperature and pressure that simulate a geothermal reservoir. The candidate compounds were dissolved in buffered aqueous solutions at a concentration of 25 ppm by weight and adjusted to a room-temperature pH of 6.5. The buffer consisted of 0.747 gm/l of KH_2PO_4 and 0.403 gm/l of Na_2HPO_4.

Eighteen-ml aliquots of the buffered tracer solution were transferred to 30-ml quartz ampules and purged with argon to remove elemental oxygen. The ampules were carefully sealed using an oxymethane flame, while continuing to purge with argon.

The sealed vials were transferred to a water-filled, one-liter capacity autoclave (Autoclave Engineers, Philadelphia, PA), which was heated to the target temperature. The time that was required for the autoclave to attain operational temperature was between 2 and 3 hours, whereas the cool-down time was about 4 hours. In all cases, the interior of the reactor was maintained within 1°C of the target temperature for a duration of 1 week. The pressure inside the autoclave was the pressure of steam under saturated conditions at the target temperature.

The samples were analyzed using a Perkin Elmer LS30 spectrofluorometer, which uses a pumped xenon lamp source. The spectrofluorometer was also used to obtain spectral scans of the various analytes, since the excitation and emission wavelenth maxima differ considerably from compound to compound.

Whereas the spectrofluorometer is a powerful research tool for methods development and for analyzing relatively pure samples, it is inadequate for analyzing several analytes simultaneously, since excitation and emission bands often overlap. In addition, geothermal reservoir water contains significant interferences in the ultraviolet spectrum, which is the region employed for the analysis of naphthalene- and amino-naphthalene sulfonates. For more demanding analyses that involve multiple analytes and matrix interference, we used a High Performance Liquid Chromatograph (HPLC) with fluorescence detection (Waters Corporation, Milford, MA). In order to take advantage of the high resolution of reverse-phase chromatography, we used a C18 column (e.g., Waters Nova-Pak 150 mm x 4.6 mm) and ion-pairing agents. The mobile phase consisted of a pH 7.5 phosphate-buffered 5 Mmol solution of tetrabutyl ammonium phosphate in varying proportions of methanol and water. The use of this HPLC method allows for the chromatographic separation of analytes both from each other and from reservoir interferences.

Results and Discussion

Table 2 reveals the chemical structures, costs, detection limits, and the range of thermal stability for several members of this group.

As shown in the table, the detection limits for the amino-substituted naphthalene sulfonates are considerably lower than the detection limits for the naphthalene sulfonates, indicating that the amine group enhances the fluorescence of the naphthalene sulfonate. Furthermore, when solutions of amino naphthalene sulfonates are heated to 300°C under conditions that simulate a geothermal reservoir, they are completely converted to products that fluoresce in comparable magnitude to the naphthalene sulfonates. Based upon these observations, we infer that the decay products are possibly the deaminated naphthalene sulfonates.

Tracer Test Modeling

Although testing under simulated laboratory conditions is an essential component in the development of new tracers for geothermal applications, the evaluation process is incomplete without fullscale field testing. In a tracer test at Dixie Valley, Nevada, we tested one of the candidate naphthtalene-sulfonate tracers, amino G. An additional objective of the field test was to determine the suitability of using numerical simulation modeling to assist in the design of tracer tests.

The Tracer Test

On May 29, 1996, 169 kg of a 50% by weight aqueous solution of the dipotassium salt of fluorescein and 100 kg of the disodium salt of 7-amino-1,3-naphthalene disulfonic acid (amino G acid) were mixed with approximately 3000 kg of produced reservoir brine and pumped into injector 25-5 (Figure 1) over a period of about 20 minutes. The 9 production wells were sampled weekly and the samples were analyzed for fluorescein using a Perkin Elmer LS-30 luminescence spectrometer at excitation and emission wavelengths of 475 nm and 510 nm respectively. Amino G was analyzed using a Waters HPLC equipped with fluorescence detection at excitation and emission wavelengths of 245 and 445 nm respectively.

The mean temperature of the brine at the Dixie Valley reservoir was recently shown to be between 225°C and 230°C (Adams and Davis, 1991). For the purposes of this exercise, it is

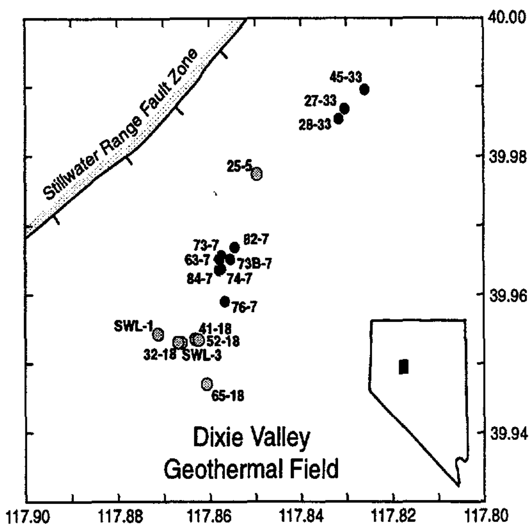

Figure 1. Wellhead locations in Dixie Valley, Nevada, geothermal field. Injection wells shaded grey, production wells shaded black. Stillwater Range normal fault zone, dipping 52-54° to the southeast, is shown in upper left.

assumed that the mean brine temperature is 227°C, which is within the range of this recent measurement. From a knowledge of fluorescein decay kinetics, it is possible to correct for thermal decay and to reconstruct "conservative" fluorescein return curves. Based upon parameters obtained in the study by Adams and Davis (1991), the rate expression at 227°C was found to be:

$$C = C_0 e^{-0.00792t}$$

By correcting the measured fluorescein return-curve concentrations using expression 4, it is possible to construct conservative tracer return data. Figure 2a shows the uncorrected return curves for all of the wells where fluorescein appeared, and Figure 2b shows the return curves after correcting for thermal decay. Since the minimum measurable concentration was approximately 10 parts per trillion (ppt), only the return curves for wells showing fluorescein concentrations greater than 10 ppt are shown in Figure 2b. Whereas amino G also appeared at all of the wells that produced fluorescein, only the fluorescein returns were modeled in the numerical simulation exercise.

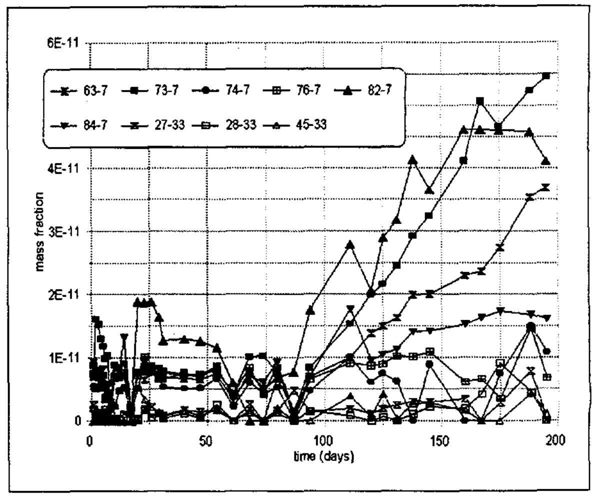

Figure 2. (a) Fluorescein mass fractions measured at 9 production wells.

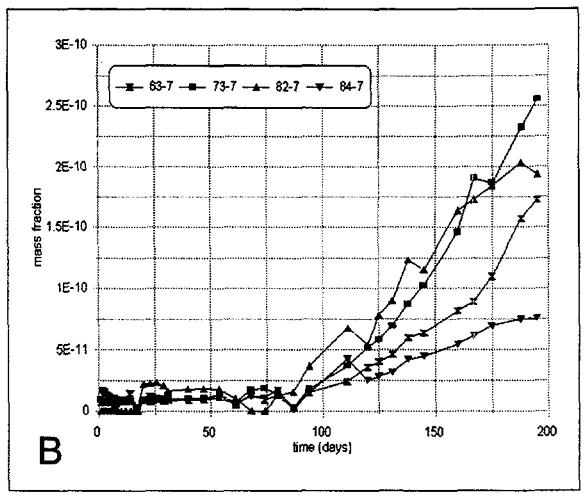

Figure 2. (b) Fluorescein mass fractions at 4 production wells after correcting for thermal decay.

The Reservoir Models

Models of the reservoir at Dixie Valley were developed using the finite difference, numerical simulation programs TOUGH2 (Preuss, 1991) and TETRAD (Vinsome, 1995). The models were configured to simulate the flow of a short pulse of tracer injected into well 25-5 (Fig. 1). The model outputs were then fit to the actual tracer production data by adjusting reservoir thickness, permeability and porosity, within reasonable limits.

Both TOUGH2 and TETRAD allow for the separate tracking of two aqueous components. The "first water" represents all of the water initially present in the reservoir as well as essentially all of the water that is reinjected. The "second water" is injected into an appropriate injection well over a very short period of time at the beginning of the simulation. It represents the pulse of tracer that is used to trace the flow of injectate. After the injection of the tracer pulse, the injector is immediately switched back to injection of the first water. Although the two aqueous components mix thoroughly as they are convected throughout the reservoir, the second water emerges as dispersed pulses in the production wells.

For simplicity, a two-dimensional Cartesian grid was used to represent the reservoir (Fig. 3). This is justified since the reservoir is defined largely by a set of fractures closely associated with the Stillwater Fault, which possesses remarkably constant dip and strike angles within the Dixie Valley geothermal field and which therefore can be reasonably approximated as a plane. In addition, all of the wells except one are completed within this highly fractured fault zone.

The 442-element grid that was used in both the TOUGH2 and TETRAD models is shown in Figure 3. This figure shows the locations of the completion intervals of the seven injection wells and nine production wells that were active during the tracer test. Tracer was injected only into well 25-5. With a flow rate of about 284 kg/sec, this well alone accounts for over half of the total injection into the field. The remaining injectors are distributed between shallow and deep completion intervals in section 18. Six of the nine production wells are clustered in section 7; the remaining three are located in the northeast end of the reservoir in section 33.

The top of the grid was positioned 1676 m below the ground surface, and the initial pressure within the grid was hydrostatic. The initial temperature was set at 227°C uniformly throughout the reservoir, whereas the reinjected water had a temperature of 100°C.

In the case of the TOUGH2 model, Neumann (no-flow) boundary conditions were maintained

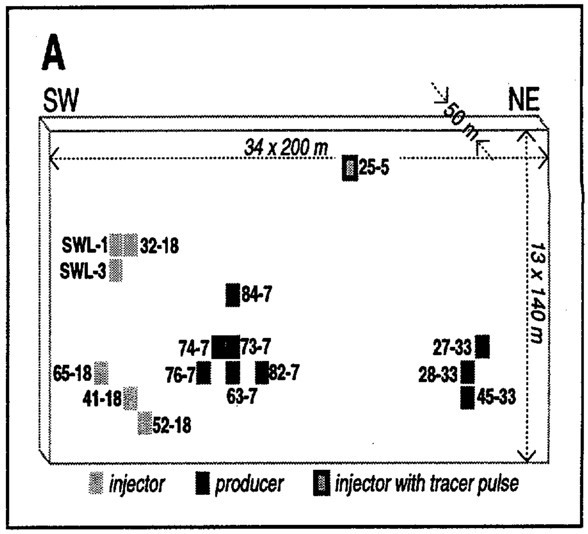

Figure 3. (a) Schematic grid used in both TETRAD and TOUGH2 numerical simulations. Well positions (based on wellhead location) are projected onto the assumed planar fault zone. Completion intervals for production wells (black) and injection wells (grey) are shown.

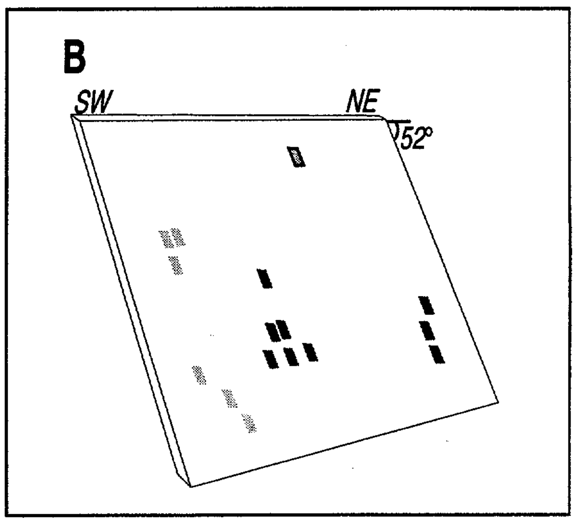

Figure 3. (b) In both simulation models, we rotated the gravity vector to simulate the planar fault zone dipping 52° to the southeast. Well symbols are the same as in Figure 3a.

on all surfaces except for the uppermost blocks at either end of the reservoir. At these blocks, the elements were given Dirichlet (constant temperature and pressure) boundary conditions. In the case of the TETRAD model, the columns of blocks at either end were designated as steady-state aquifer elements, which allow for flow into the reservoir. Such conditions were chosen because only about 82% of the produced water is returned as injectate. If the boundaries were entirely closed, two-phase conditions would soon develop in the reservoir and likewise in the model. The choice of these boundary conditions allows for flow throughout the reservoir to be dominated by the injection and production wells, while allowing for make-up flow into the reservoir as needed to maintain single-phase (liquid) conditions. Although the Dixie Valley reservoir consists of a complex network of faults and fractures extending throughout a heterogeneous rock matrix, it was defined for the purposes of this modeling exercise as an isotropic and homogeneous porous medium.

Results and Discussion

Figure 4 shows the first 200 days of tracer-return data, corrected for thermal decay, and simulation results from TOUGH2. Although the match is imperfect, the simulated curves reflect the general order of elution, position, size and shape of the measured curves. The match is particularly good for the producer 82-7, which shows the strongest return, whereas the simulated returns underpredict to varying degrees the measured returns for the remaining section-7 wells.

Figure 5 shows the return-curve data in combination with the simulation results for the TETRAD model. Again, the simulated curves reflect the

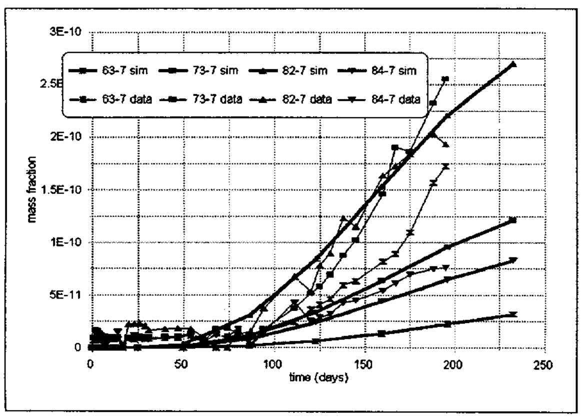

Figure 4. Measured return curves (thin lines) and simulated return curves using TOUGH2 (thick lines).

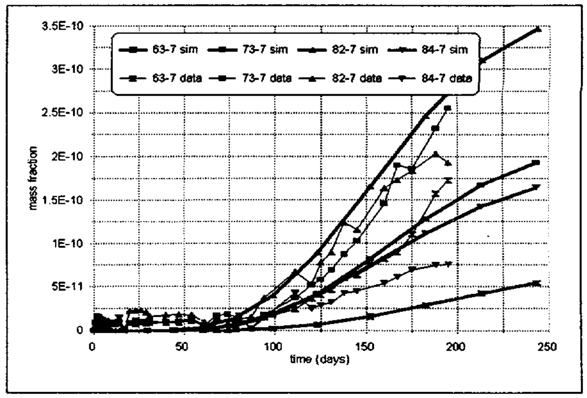

Figure 5. Measured return curves (thin lines) and simulated return curves using TETRAD (thick lines).

general order of elution, position, size and shape of the measured curves. The TETRAD-generated curves bracket the measured data, with two curves (wells 82-7 and 84-7) being overpredicted and two curves (wells 73-7 and 63-7) being underpredicted. Since both models represent a two-dimensional, homogeneous and isotropic porous medium and the reservoir is doubtlessly a three-dimensional, anisotropic, heterogeneous, and fractured medium, the similarity between both the TOUGH2 and TETRAD modeled results and the data.is remarkable.

Tracer Test Design

In designing a tracer test, the reservoir engineer must estimate the minimum quantity of tracer required for breakthrough at the producers and the probable injectate flow patterns. A knowledge of flow patterns is required in order to estimate the first arrival times and peak arrival times of tracer, which in turn are used to determine appropriate sampling locations and sampling frequency. In order to estimate the minimum amount of tracer, the reservoir engineer needs only to minimize the duration of the simulated tracer-injection pulse, since, for a constant flow rate, the pulse duration is directly proportional to the mass of tracer injected. The minimum pulse duration occurs when enough tracer has been injected to result in return curve concentrations at the production wells that exceed the minimum measurable concentration of the detector by a comfortable margin. Of course, if thermally unstable tracers are used, the tracer decay kinetics must be determined and accounted for.

Summary and Conclusions

A preliminary analysis of a family of fluorescent compounds, the polycyclic aromatic sulfonates, has produced a number of promising geothermal tracer candidates for intermediate- and high-temperature applications. Among the most promising are the naphthalene sulfonates and amino-substituted naphthalene sulfonates. Whereas the naphthalene sulfonates were found to be very thermally stable and reasonably detectable, the amino-substituted naphthalene sulfonates were found to be somewhat less thermally stable, but much more detectable.

A tracer test was conducted at the Dixie Valley, Nevada, geothermal reservoir using one of the amino-substituted naphthalene sulfonates, amino G acid, in combination with fluorescein. Breakthrough of both tracers was evidenced at 4 of the reservoir's 9 production wells. Using TOUGH2 and TETRAD, relatively simple two-dimensional models of the tracer flow patterns were developed by fitting model outputs to measured return curves. Since fluorescein decays rapidly at the average reservoir temperature of approximately 227°C, it was necessary to correct the return curves for tracer decay, using kinetics developed under conditions that simulate the geothermal environment. Both models were equally successful at simulating the return curve shapes and elution order as well as the approximate concentrations of produced tracer. We have proposed a method for using numerical models to design a tracer test.

Acknowledgements

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Preuss, K. (1991), TOUGH2--a general-purpose numerical simulator for multiphase fluid and heat flow. Lawrence Berkeley Laboratory, Earth Sciences Division, LBL-29400.

Vinsome, K. (1995) Tetrad user's manual, version 11.5, ADA International Consulting Ltd., Alberta, Canada.

Table 1: Candidate Polycyclic Aromatic Sulfonic Acid Tracers

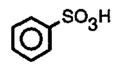
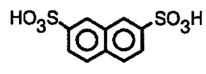
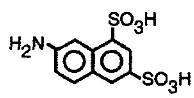
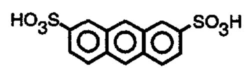
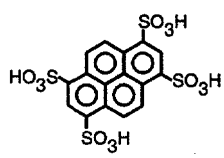
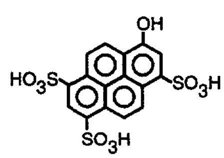
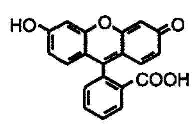
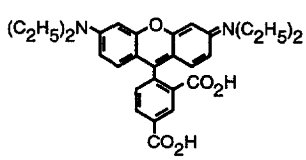
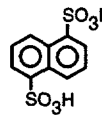
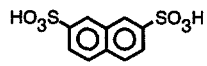
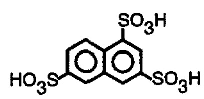
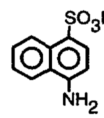
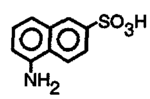
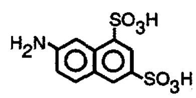
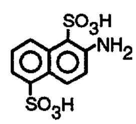
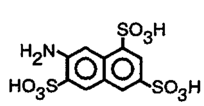
family	example	detect. limit	cost ($/kg)	approx. T range (°C)
benzene sulfonic acids	 benzene sulfonic acid	10 ppb	11	< 300
naphthalene sulfonic acids	 2,6-naphthalene disulfonic acid	1 ppb	65	< 300
	 amino G acid	10 ppt	13	< 250
anthracene sulfonic acids	 2,8-anthracene disulfonic acid	NA	NA	NA
pyrene sulfonic acids	 pyrene tetrasulfonic acid	1 ppb	3000	< 300
	 pyranine	10 ppt	75	< 250
xanthenes	 fluorescein	10 ppt	15	< 250
	 rhodamine WT	10 ppt	200	< 180

Table 2: Candidate Naphthalene- and Amino-naphthalene Sulfonic Acid Tracers

family	example	detect. limit	cost ($/kg)	approx. T range (℃)
naphthalene sulfonic acids	 1,5-naphthalene disulfonic acid	1 ppb	60	< 300
	 2,6-naphthalene disulfonic acid	1 ppb	65	< 300
	 1,3,6-naphthalene trisulfonic acid	1 ppb	70	< 300
amino-naphthalene sulfonic acids	 4-amino-1-naphthalene sulfonic acid	10 ppt	85	< 250
	 5-amino-2-naphthalene sulfonic acid	10 ppt	15	< 250
	 amino G acid	10 ppt	13	< 250
	 2-amino-1,5-naphthalene disulfonic acid	10 ppt	11	< 250
	 7-amino-1,3,6-naphthalene trisulfonic acid	10 ppt	15	< 250

FIELD-SCALE SIMULATION OF MATRIX-FRACTURE INTERACTIONS

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Introduction

Simulation of flow in fractured media continues to be among the most challenging problems faced in geothermal reservoir engineering. Because of the lack of information regarding specific matrix-fracture characteristics (e.g., fracture distribution, spacing, and aperture, and interfacial area for exchange of fluid), explicit representation of the reservoir is generally not feasible. Instead, a multiple (usually dual) continua model is used. In multiple continua models, specific details of the reservoir are replaced with averaged properties (average fracture spacing, for example). Such averaging facilitates the simulation of fractured reservoirs; however, field-scale simulation remains numerically intensive. For example, it has been stated that 5-10 nested shells are required in the Multiple INteracting Continua (MINC; Pruess and Narasimhan, 1982) formulation in order to adequately resolve transient pressure and saturation gradients between the fracture and matrix domains (Zimmerman et al., 1992). While this results in a large amount of additional work (compared with a single porosity system of the same dimension), it should be noted that the MINC method *is* capable of resolving such transients, whereas most dual porosity simulators cannot.

Many of the numerical models used to simulate flow in fractured media invoke variations on the Warren and Root (1963) model of fractured reservoirs. The Warren and Root (W&R) model treats the fractured reservoir as dual continua. One continuum contains the fracture domain and the other contains the matrix domain. 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 has been referred to as the "pseudo-steady state assumption," and is known to be inaccurate at "small" times, especially in reservoirs with large fracture spacings and highly compressible fluids (see, for example, Najurieta, 1980).

This paper describes recent efforts at relaxing the assumptions inherent in the W&R formulation through use of analytical solutions to the equations governing interporosity flow. For slightly compressible fluids, the governing equation is the well-known diffusion equation, for which analytical solutions are readily available (e.g., Crank, 1975). This work was recently presented (Shook, 1996) for the case of a single rock matrix surrounded by fractures. Those results will be presented, and the extension to field-scale simulation will be discussed.

Resolving the pressure gradient: Single block case

Mass conservation equations written for dual continua formulations contain a matrix-fracture interaction term, Q, describing the fluid flow between the two continua. This term Q can be derived from Darcy's law and the characteristics of the matrix-fracture interfacial area. Assuming single phase flow in a three-dimensional fracture network of spacing L, with all six sides of the rock matrix in contact with fractures, the interaction term can be written as (Shook, 1996):

$$Q = -\sum_{\#Blks}\sum_{faces} A\frac{k}{\mu}\vec{\nabla}P = -V_b\frac{6}{L}\frac{k}{\mu}\vec{\nabla}P \qquad (1)$$

This expression is completely general, and only requires that the pressure gradient be correctly resolved.

Warren and Root (1963) and other workers in the field assumed that the pressure gradient could be approximated as the pressure difference between the two continua expressed over some characteristic distance. Using the fracture half-spacing as that distance, the assumption of pseudo-steady state results in the following expression for the pressure gradient.

$$\vec{\nabla}P = \frac{P_{fr} - P_{ma}}{L/2}$$

When this is used in Equation 1, the matrix-fracture interaction term becomes:

$$Q = -V_b\frac{12}{L^2}\frac{k}{\mu}(P_{fr} - \overline{P}_{ma})$$

where $12/L^2$ is known as the shape factor. Values used for the shape factor range from $12/L^2$ (Kazemi et al., 1976) to $60/L^2$ (Warren and Root, 1963).

It has long been known that this assumption of pseudo-steady flow is incorrect at small time. For example, Najurieta (1980) shows that the transition time to pseudo-steady state flow depends on, among other variables, rock and fluid compressibility and matrix dimensions. Zimmerman et al. (1992) show that the W&R-predicted response to a step function change in pressure at the fracture face converges very slowly to the correct solution. Zimmerman et al. (1992) further state that the W&R-type equation (i.e., a constant shape factor) always predicts an incorrect time dependence on pressure at some time scale. In order to preserve the simplicity of the W&R formulation and correctly resolve pressure gradients, one must start with Eqn. 1 and remove the linear approximation for the pressure gradient.

By using analytical solutions to the diffusion equation, Shook (1996) obtained a semi-analytical expression that correctly describes the pressure gradient over all time scales. The exact solution to the problem is given as (assuming spherical coordinates; Crank, 1975, p 91):

$$\frac{\partial P}{\partial r} = (P_{fr} - P_{ma})\,\frac{\pi^2}{3a}\,\frac{\sum_{n=1}^{\infty} \exp\left(-\frac{n^2\pi^2 Dt}{a^2}\right)}{\sum_{n=1}^{\infty} \frac{1}{n^2}\exp\left(-\frac{n^2\pi^2 Dt}{a^2}\right)} \qquad (2)$$

where r is the spatial coordinate in the matrix, a is the characteristic matrix half length (in spherical or cylindrical coordinates, the radius; in linear coordinates, it is fracture half spacing), t is time, and D is the diffusivity of the matrix (fluid + rock):

$$D = \frac{k}{\varphi\,\mu\,c_t}$$

Equation 2 contains two infinite series; however, these series converge relatively rapidly, and may typically be truncated after only a few terms. The number of terms required to obtain an accurate solution is:

$$N_{Terms} = \frac{L}{\sqrt{4Dt}}$$

Thus, the infinite series (which are intractable in a numerical model) are approximated by a finite-limit DO loop, and the pressure gradient for interposity flow is easily obtained.

The new method was validated by comparing solutions against fine grid simulations in 1-, 2-, and 3-D, as described in Shook (1996). Here, we show only the validation results for the 3-D case. For comparison purposes, W&R results are also shown. A schematic is given for the test problem in Figure 1. The grid employed for the fine grid simulation was 21 x 21 x 21. Both the new formulation and the W&R simulation used two grid blocks; one for the fracture domain and one for the matrix. Aside from the differences in the numerical grid, properties were identical between the fine grid and dual porosity simulations.

The test case is an example of matrix mass depletion. From a uniform initial condition of 1000 kPa, fracture pressure was dropped to 100 kPa at t=0, and was held constant throughout the simulation. Because of the pressure difference between the matrix and fracture, flow occurs from matrix to fracture. Interporosity mass flow rates are shown in Figure 2. Excellent agreement is observed between the fine grid simulation and the new formulation, except at very early times. Further analysis of the fine grid simulation indicates that this grid was insufficiently fine to capture the correct pressure gradient at early time (i.e., the grid blocks are too large). Comparisons between the new formulation and analytical results indicates that the new method is extremely accurate over all time scales. That is to be expected, since this formulation is based on a truncated version of the analytical solutions. In contrast, the W&R simulation exhibits significant error over all time scales.

Generalization for Field-Scale

The formulation described above works well for a single rock matrix surrounded by fractures which are subjected to a single change in pressure. It appears that one could readily generalize the formulation to account for multiple matrix blocks, so long as the change in pressure were restricted to a single step change. However, a more realistic situation is one in which there are an arbitrary number of changes in fracture pressure occurring on a field scale (i.e., an arbitrary number of numerical grid blocks). As discussed below, that problem is substantially more difficult to solve using an extension of the above formulation.

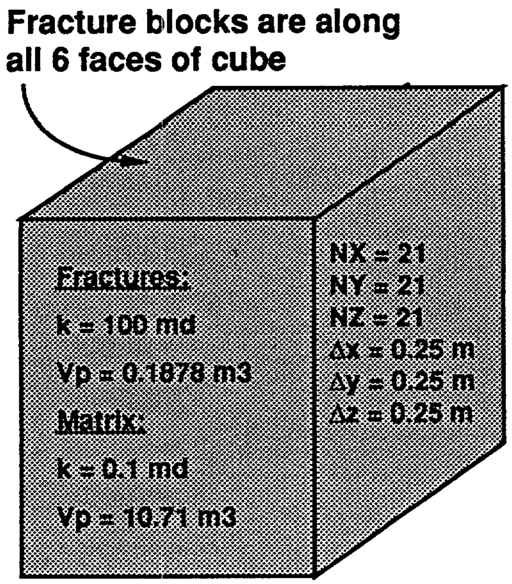

Figure 1. 3-D fracture validation problem

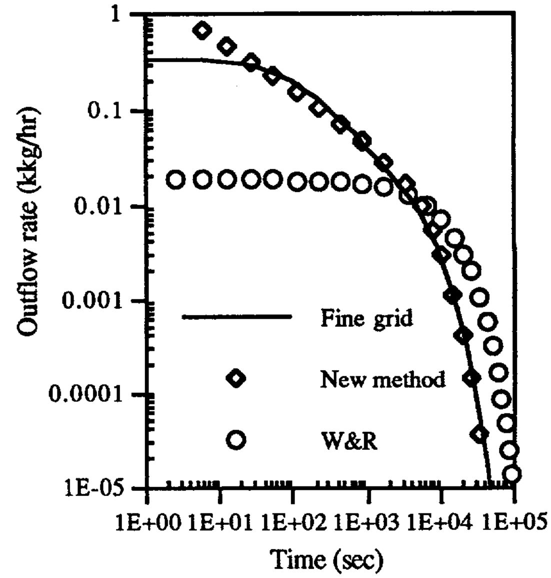

Figure 2. 3-D validation results from Shook, 1996.

The general solution for matrix pressure as a function of time and space (again assuming spherical coordinates) is (Carslaw and Jaeger, 1959, p 233):

$$P(r,t) = \frac{2}{ar}\sum_{n=1}^{\infty} \exp\left(\frac{-n^2\pi^2 Dt}{a^2}\right)\sin\left(\frac{n\pi r}{a}\right) x$$

$$\left\{\int_0^a r' P(r')\sin\left(\frac{n\pi r'}{a}\right)dr' - n\pi D(-1)^n \int_0^t \exp\left(\frac{n^2\pi^2 D\tau}{a^2}\right)P(\tau)d\tau\right\} \quad (3)$$

The first integral above accounts for the initial condition, and the second for changes in fracture pressure, both of which are damped through time by the exponential decay term (term 1).

One may take either of two approaches in solving Eqn 3. Typically, the initial condition is treated as a constant, and all subsequent variations in pressure are captured in the second integral. While this is mathematically tractable, it appears to be numerically difficult. The first integral is trivially solved, but solution of the second integral requires that all previous changes in fracture pressure be stored. Furthermore, since the previous changes in fracture pressure are damped in time, it is not a matter of "updating" the effects of previous changes in pressure, but rather a recalculation at each time step. While it is true that "old" changes in pressure decay with time (and therefore could be omitted from consideration), an *a priori* means of evaluating how many such changes can be omitted does not appear to exist.

A second means of evaluating the general solution, and one that is currently being investigated, is to update the initial condition at the end of every time step, and consider only the current change in fracture pressure. That is, identify a parametric function that accurately describes the pressure distribution in the matrix, and evaluate the second integral only over the current time step. In this approach, constraint equations are used to identify the unknowns in the expression P(r,t). The idea of a parametric expression for pressure has been used by several researchers (e.g., Vinsome and Westerveld, 1980; Pruess and Wu, 1993). Our current approach is simpler in that we are attempting to describe the matrix pressure explicitly; it is after all an initial condition. Therefore, no iteration on the unknowns in the expression are required. Constraint equations in this case include fracture pressure, pressure gradients at the matrix-fracture interface and matrix center, and average matrix pressure - all known from the converged solutions from the last time step. This solution has not yet been proven out, but remains the current topic of research on this project.

Summary and Future Work

A new, semi-analytical method of treating interporosity flow has been developed and validated. This new method, while generalizable to field-scale problems, is likely to be restricted to cases in which a single change in fracture pressure occurs. In order to develop the approach for field-scale work, one must go back to the general solution for matrix pressure, and either, 1) treat the initial condition as a constant and store all previous variations in fracture pressure, or 2) update the initial condition at each time step, and treat only the current variation in fracture pressure as a perturbation acting on the system. From our preliminary studies, the second option appears to be more readily implemented. Current efforts are focused on the identification of a parametric expression for pressure that is both simple enough for use, and accurate in describing the initial pressure distribution at each time step.

Acknowledgements

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Nomenclature

English

- a — characteristic diffusion length in rock matrix (fracture half-spacing in 1-D, effective matrix radii in 2-D and 3-D) [=] m
- A — Cross sectional area [=] m^2
- c_t — Total compressibility (rock + fluid) [=] kPa^{-1}
- D — diffusivity (k/jmc) [=] m^2/s
- k — permeability [=] m^2
- L — Characteristic rock matrix length (fracture spacing) [=] m
- P — Pressure [=] kPa
- P_{ma} — Average matrix pressure [=] kPa
- q — Volumetric flux [=] m/s
- t — Time [=] s
- Q — Matrix/fracture Source/sink term [=] m^3/s
- V_b. — Grid block bulk volume [=] m^3

Greek

- φ — Porosity [=] vol. pore space / bulk volume
- μ — Viscosity [=] mPa-s

Subscripts

- fr — fracture
- ma — matrix
- I — initial (condition)

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DEVELOPMENT OF INVERSE MODELING TECHNIQUES FOR GEOTHERMAL APPLICATIONS

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ABSTRACT

We have developed inverse modeling capabilities for the non-isothermal, multiphase, multicomponent numerical simulator TOUGH2 to facilitate automatic history matching and parameter estimation based on data obtained during testing and exploitation of geothermal fields. The ITOUGH2 code allows one to estimate TOUGH2 input parameters based on any type of observation for which a corresponding simulation output can be calculated. In addition, a detailed residual and error analysis is performed, and the uncertainty of model predictions can be evaluated. One of the advantages of inverse modeling is that it overcomes the time and labor intensive tedium of trial-and-error model calibration. Furthermore, the estimated parameters refer directly to the numerical model used for the subsequent predictions and optimization studies. This paper describes the methodology of inverse modeling and demonstrates an application of the method to data from a synthetic geothermal reservoir. We also illustrate its use for the optimization of fluid reinjection into a partly depleted reservoir.

INTRODUCTION

Numerical modeling is an essential tool for the study of basic multiphase flow processes in geothermal reservoirs. Moreover, simulation of future field performance can be used to design, analyze, and optimize various operational scenarios. The latter requires that site-specific, model-related parameters are available on the scale of interest. Inverse modeling can be used to determine effective model parameters by using quantitative information from well tests and past field performance and minimizing the differences between model results and field observations.

Inverse modeling greatly enhances the interpretative potential of numerical reservoir simulations. It can be applied in several modes, providing useful information for three different reservoir management problems. First, it can be used to design and optimize a well testing program for reservoir characterization. The ability of a proposed design to identify hydrogeologic parameters such as the permeability of productive features can be assessed by performing inversions of synthetically generated data. Such an approach is described in detail in Finsterle and Pruess (1996).

The second mode of application is the analysis of the actual data from laboratory and field tests, or data obtained during field exploitation. An example that illustrates the analysis of laboratory data from a graywacke core plug from The Geysers Coring Project is given in Finsterle and Persoff (1996). Also a synthetic field example is discussed below.

Thirdly, the minimization algorithms developed for automatic model calibration can also be used to optimize certain aspects of field operation, e.g., injection rates can be determined such that the thermal output in adjacent production wells is maximized for minimal injection costs. An illustrative example is discussed below. It is important to realize that this type of analysis requires detailed knowledge about actual and hypothetical costs associated with field operations, and - more important - a model of the geothermal reservoir that is able to accurately predict the system behavior for a variety of injection and production scenarios. Optimizing reservoir operations requires conducting a thorough characterization of the geothermal field, which in turn must be based on a good test design. All aspects are supported by inverse modeling.

In this paper we give a brief introduction to the main concepts of inverse modeling. A synthetic example is provided to demonstrate the main application of the method, i.e., automatic calibration of a numerical model of the geothermal reservoir to production data (history matching). We then discuss the possibilities and limitations of using inverse modeling techniques for the optimization of a field operation such as water injection into a partly depleted geothermal reservoir.

INVERSE MODELING THEORY

The core of an inverse modeling code is an accurate, efficient and robust simulation program which solves the forward problem. We use TOUGH2 (Pruess, 1991) to simulate fluid and heat flow in a geothermal reservoir. A summary description of the TOUGH2 version used in geothermal applications can be found in Finsterle et al. (1997).

The determination of reservoir properties from performance data, such as pressures, temperatures, enthalpies, and flow rates, is referred to as the inverse problem. The indirect approach to inverse modeling consists of minimizing some norm of the differences between the observed and simulated field responses which are assembled in the residual vector $\mathbf{r}$ with elements

$$r_i = z_i^* - z_i(\mathbf{p}) \tag{1}$$

Here z_i^* is an observation (e.g., pressure, temperature, flow rate, etc.) at a given point in space and time, and z_i is the corresponding simulator prediction, which depends on the vector $\mathbf{p}$ of all unknown or uncertain model parameters, including initial and boundary conditions. Since the residual vector $\mathbf{r}$ comprises observations of different units and accuracy, we introduce a vector $\mathbf{y}$ with the residual weighted by the inverse of the standard deviation σ_i:

$$y_i = r_i/\sigma_i \tag{2}$$

Depending on assumptions about the error structure of the residuals, different norms of $\mathbf{y}$ may be chosen:

$$\|\mathbf{y}\|_\beta = \left(\sum |y_i|^\beta\right)^{1/\beta} \tag{3}$$

If the error structure of the residuals is assumed Gaussian and described by a covariance matrix $\mathbf{C}_{zz}$, the L_2-norm $(\beta = 2)$ seems appropriate, and the objective function S to be minimized is the sum of the squared weighted residuals:

$$S = \mathbf{r}^T \mathbf{C}_{zz}^{-1} \mathbf{r} = \sum_{i=1}^{m} \left(\frac{r_i}{\sigma_i}\right)^2 \tag{4}$$

where m is the total number of observations. In maximum likelihood theory, it is shown that minimizing S is equivalent to maximizing the probability of reproducing the observed system state.

For solving reservoir management problems, where a cost function is to be minimized, the L_1-norm $(\beta = 1)$ is chosen, in which the sum of the absolute residuals is minimized. In this case, the "data" z_i^* to be matched are zero for expenses, and a large number for profits.

Due to strong nonlinearities in the functions $z_i(\mathbf{p})$, an iterative procedure is required to minimize the objective function S. The Levenberg-Marquardt modification of the Gauss-Newton algorithm (Levenberg, 1944; Marquardt, 1963) has been found to be suitable for our purposes. The basic idea of this method is to move in the parameter space along the steepest descent direction far from the minimum, switching continuously to the Gauss-Newton algorithm as the minimum is approached. This is achieved by decreasing a scalar λ_k, known as the Levenberg parameter, after a successful iteration, but increasing it if an uphill step is taken. The following system of equations is solved for $\Delta\mathbf{p}_k$ at an iteration labeled k:

$$(\mathbf{J}_k^T \mathbf{C}_{zz}^{-1} \mathbf{J}_k + \lambda_k \mathbf{D}_k)\Delta\mathbf{p}_k = -\mathbf{J}_k^T \mathbf{C}_{zz}^{-1} \mathbf{r}_k \tag{5}$$

Here, $\mathbf{J}$ is the sensitivity matrix with elements $J_{ij} = -\partial r_i/\partial p_j = \partial z_i/\partial p_j$. It relates a change in an observable to a corresponding change in a hydrological parameter. $\mathbf{D}$ denotes a matrix of order n (n being the number of parameters to be estimated) with elements equivalent to the diagonal elements of matrix $(\mathbf{J}_k^T \mathbf{C}_{zz}^{-1} \mathbf{J}_k)$. The improved parameter set at iteration level $k+1$ is calculated:

$$\mathbf{p}_{k+1} = \mathbf{p}_k + \Delta\mathbf{p}_k \tag{6}$$

While the Levenberg-Marquardt algorithm is especially efficient for solving non-linear least-squares problems, it can also be used for the minimization of L_1-norms when using larger values for λ_k.

Under the assumption of normality and linearity, a detailed error analysis of the final residuals and the estimated parameters can be conducted (for details see Finsterle and Pruess (1995)). For example, the covariance matrix of the estimated parameter set is given by:

$$\mathbf{C}_{pp} = s_0^2 \left(\mathbf{J}^T \mathbf{C}_{zz}^{-1} \mathbf{J}\right)^{-1} \tag{7}$$

where s_0^2 is the estimated error variance given by:

$$s_0^2 = \frac{\mathbf{r}^T \mathbf{C}_{zz}^{-1} \mathbf{r}}{m-n} \tag{8}$$

As a byproduct of calculating the Jacobian matrix $\mathbf{J}$, one can qualitatively examine the contribution of each data point to the solution of the inverse problem as well as the total parameter sensitivity.

The inverse modeling formulation outlined above is implemented in a computer program named ITOUGH2 (Finsterle, 1997).

HISTORY MATCHING

The purpose of this section is to illustrate the use of the proposed methodology for the characterization of geothermal reservoirs. ITOUGH2 provides the flexibility to take advantage of almost any type of data collected during well testing or field exploitation. For the sake of simplicity and reproducibility, we will analyze a synthetic case.

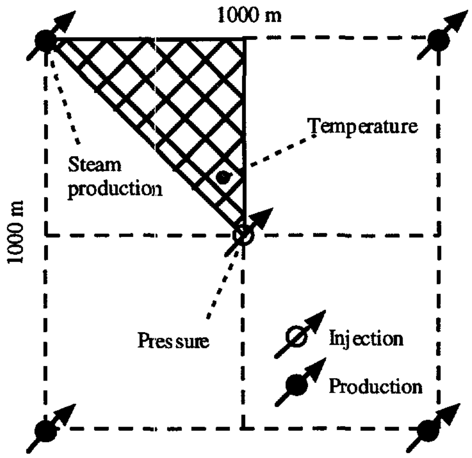

Figure 1. Five-spot well pattern with grid for modeling 1/8 symmetric domain. Observation points and type of data measured is also indicated.

We consider a two-dimensional five-spot production-injection problem (Figure 1) previously studied by Pruess (1991) and Pruess and Wu (1993). The problem specifications correspond to conditions typically encountered in deeper zones of two-phase geothermal reservoirs. The medium is assumed to be fractured with embedded impermeable matrix blocks in the shape of cubes with side lengths of 50 m. The permeable volume fraction is 2 % with an intrinsic porosity of 50 %. Reservoir thickness is 305 m. Water with an enthalpy of 500 kJ/kg is injected at a rate of 8 kg/s. Production occurs against a prescribed bottomhole pressure of 90 bars with a productivity index of 5×10^{-12} m^3.

We assume that pressure measurements are taken in the injection well, temperature is measured in an observation well, and the vapor flux is recorded at the production well assuming a pressure of 8 bars and a temperature of 170 °C at the steam-liquid separator.

TOUGH2 is run in forward mode to generate synthetic data for five years of field performance history, and random noise is added to simulate measurement errors. Subsequently, the model is automatically calibrated against these observations in order to determine certain input parameters considered unknown or uncertain. The parameters include the logarithm of the effective fracture permeability, fracture spacing and the initial reservoir temperature. The true, initial and estimated parameter sets are shown in Table 1. The calculated pressures, temperatures, and steam flow rates are shown in Figure 2. The squares are the synthetically generated data, the dash-dotted lines represent the simulation result with the initial parameter set, and the solid line is the automatically obtained match. The true parameter set is identified very accurately within 8 ITOUGH2 iterations.

Table 1. *Five-Spot Well Pattern: True, Initial, and Estimated Parameter Set*

Parameter	True Value	Initial Guess	Best Estimate
log (perm. [m²])	-14.2	-13.5	-14.2
fracture spacing [m]	50.0	20.0	48.1
temperature [°C]	300.0	270.0	299.2

In this system, steam generation and thus thermal power output declines after about 2.5 years of production, and is reduced to less than a third of the initial production after 5 years. Concurrently, temperature in the vicinity of the injection well start to decrease as a result of fluid injection and local boiling, leading to lower pressures. Increasing injection rates may help maintain steam production, provided that the enthalpy of the produced fluid does not decline significantly, as will be discussed in the following section.

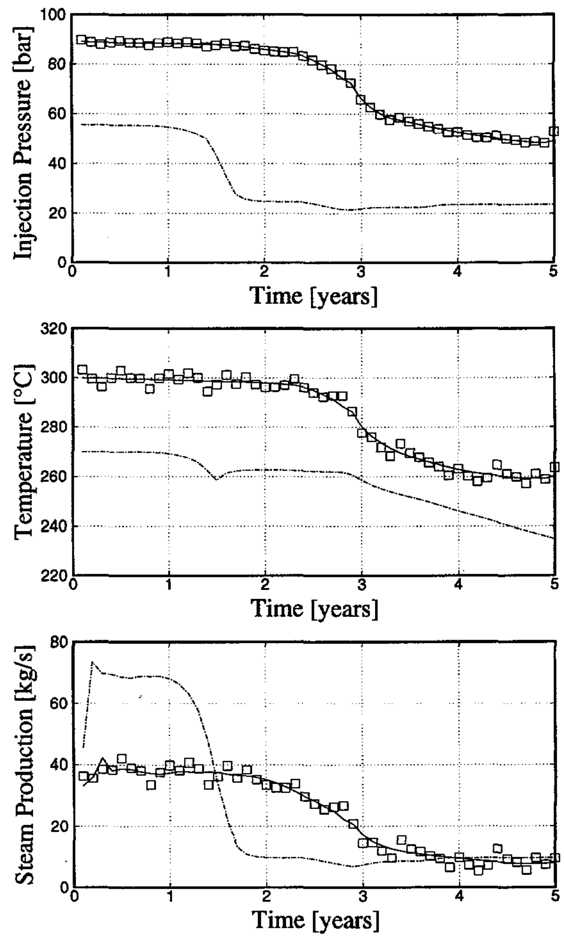

Figure 2. *Five-spot well pattern: Automatic history matching of pressure data in the injection well, temperature data in the observation well, and steam flux data at the separator. Squares represent the synthetically generated data. Dash-dotted and solid lines are the calculated system response with the initial and final parameter set, respectively.*

A detailed analysis of inverse modeling results including a discussion of parameter sensitivities is given for a similar, albeit more complex example in Finsterle et al. (1997). The purpose of this example is simply to illustrate the history matching capabilities of ITOUGH2 and to introduce the simulation problem used for the subsequent optimization study. Recall, however, that calibration is an important step in any study that is based on predictive modeling.

OPTIMIZATION OF FLUID INJECTION

As mentioned above, Figure 2 shows the general characteristics of a partially depleted geothermal field with reservoir pressure decline and a gradual decrease in steam production. Fluid injection has been proposed as a means to extend the life of geothermal resources.

In the example given, during the first five years water was injected at a constant rate of 8 kg/s. The question arises at which rate fluid should be injected in the future to maintain or even increase thermal energy output. Provided that liquid injection actually increases fluid production, there is obviously a tradeoff between higher returns from increased power generation versus the costs associated with the reinjection. This leads to an optimization problem that can be solved using the methodology outlined in the previous section.

Evaluating and optimizing the economics of developing and managing a geothermal field involves consideration of a complex interplay of factors, including capital investments, operating expenses, and revenues. Not only the amount of expenses and revenues but also their timing can have large impacts on project economics. Matters are complicated by the fact that future reservoir performance and future economic factors are both subject to uncertainty. Analyses of geothermal project economics usually employ probabilistic concepts and sophisticated models of cash flow analysis, but tend to be highly simplistic in their representation of reservoir processes which drive production behavior and injection performance (Sanyal et al., 1989; Martono, 1995).

Inverse modeling by means of ITOUGH2 offers a capability to integrate financial analysis and optimization with detailed reservoir modeling. In what follows this is illustrated with a synthetic example which intentionally uses a very simplistic cost function. Our objective is to convey the concept of an "integrated" optimization, in which a detailed process model of reservoir performance is combined with a consideration of economic cost and revenue factors in a fully coupled manner.

The following simplistic cost function has been chosen to demonstrate the proposed approach:

$$S = \sum_{\Delta t}\left(q_{inj} \cdot c_{inj} - q_v \cdot h_v \cdot f \cdot c_{elec} + q_l \cdot c_l\right) \cdot \Delta t \qquad (9)$$

Here, q_{inj} is the injection rate [kg/s] to be determined which is multiplied by the specific costs c_{inj} [$/kg] to yield the costs for the injected water. q_v and h_v are the vapor production rate and enthalpy, respectively, the product of which is the thermal energy produced per time unit.

In the model considered, the thermal output is multiplied by a factor $f = 0.25$ to yield the electric power output which then can be multiplied by the specific price for electric energy c_{elec}. Since the latter is a gain, it is subtracted from the injection costs. Finally, we add a penalty term to minimize liquid production q_l. Assigning a relatively large value for the hypothetical costs c_l favors a mode of operation that would produce high-enthalpy fluid. The specific costs are time dependent, and are therefore integrated over the entire prediction period (e.g., 30 years) to yield a total cost estimate.

Note that q_{inj} is both the input parameter to be optimized and part of the cost function to be minimized. Production rates q_v and q_l and steam enthalpy h_v are the result of a TOUGH2 simulation, i.e., they depend not only on q_{inj} but also on all the model parameters either prescribed or estimated by inverse modeling. It is this dependence that makes site characterization, model development, and calibration crucial steps in solving management problems by means of reservoir simulation.

It should also be realized that Eq. (9) proposed here can be extended to include more sophisticated cost functions and additional costs and profits which may depend on both input parameters and output variables in a non-linear fashion.

The example discussed below is based on specific injection costs c_{inj} of 200 $/acre-ft (which may include pumping and water treatment costs), an energy price of 0.05 $/kWh, and a hypothetical cost of 0.01 $/kg to penalize liquid production.

In the first example we try to determine a constant injection rate which minimizes the total costs over a 30-year production period. Since only one parameter is considered, the total costs can be evaluated for the entire range of reasonable injection rates, i.e., no minimization algorithm is needed. Figure 3 shows the individual cost contributions and the total cost as a function of injection rate. Since we are only interested in relative costs, no currency unit is indicated in all plots showing costs. Steam production and thus energy return increases almost linearly with injection rate, and is about 3.5 times higher for q_{inj} = 11.6 kg/s (the optimum injection rate) as compared to the scenario with no fluid injection, and 30 % higher as compared to the base case with an injection rate of 8 kg/s. If injection rate is further increased, however, liquid water enters the production well, and the enthalpy of the steam declines, reducing the thermal output of the well. It is obvious that the liquid produced from the reservoir can be replenished to the point at which thermal breakthrough occurs. The injection costs and penalty function are insignificant in this example, but make the minimum more pronounced. In conclusion, the solution to the optimization problem is almost completely governed by the hydrogeology of the reservoir. Only non-linear cost and penalty functions would greatly affect the optimum injection rate.

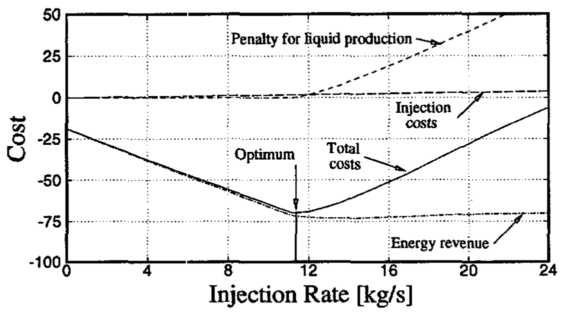

Figure 3. Injection optimization: Injection costs and energy return as a function of injection rate calculated for a 30-year period. The total costs to be minimized also contains a penalty cost for liquid production.

In the second example we try to further reduce costs by allowing the injection rate to vary with time. We arbitrarily subdivide the 30-year production period into three 10-year intervals, and determine three injection rates, one for each period. This optimization problem is solved by using the minimization algorithm mentioned above. We discuss the result of this optimization by comparing it with a no-injection scenario, the base case scenario (injection at a constant rate of 8 kg/s), the previously obtained solution (constant rate of 11.6 kg/s), and a high injection rate of 32 kg/s which is not an optimum. Since the minimum of the total cost is almost identical with the maximum of steam production, we can take the predicted steam flux at the separator as an indication of total system performance, where the profit is the area under the curve multiplied by the steam enthalpy of 2769 kJ/kg and the steam price (i.e., $f \cdot c_{elec}$). Recall that injection costs and the costs from producing low-enthalpy fluid, which are not directly seen in the plot of steam production, are taken into account when determining the optimum injection rate.

Figure 4 shows the five different injection scenarios and the resulting steam production as a function of time. If injection is stopped after five years, steam production ceases almost completely within another few years. Continuous injection at 8 kg/s supplies enough fluid that steam production is maintained at about 9 kg/s. The optimum constant injection rate of 11.6 kg/s determined in the previous case increases the steam production by about 30 %, but is limited by thermal breakthrough at the end of the production period. To demonstrate the effect more clearly, injection at a higher than the optimum constant rate, e.g., 32 kg/s, is considered, resulting in a higher production for about 7 years. However, this is followed by a sharp decline so that on a 30 year time frame significantly more energy can be produced with the smaller injection rate. The high injection rate is also associated with high injection costs and large quantities of liquid produced at the wellhead. Finally, if variable injection rates are specified as determined by the optimization algorithm, the overall energy production can be further increased with only moderately higher injection costs. The three injection rates are 18.4, 13.4, and 8.9 kg/s for the 5-15, 15-25, and 25-35 year injection period, respectively. The average injection rate is 13.6 kg/s, i.e., injection costs are increased by only about 17 % compared to the optimum value obtained with a constant rate of 11.6 kg/s. Recall that injection costs are minor compared to the increase in revenue from steam production for the assumed specific costs.

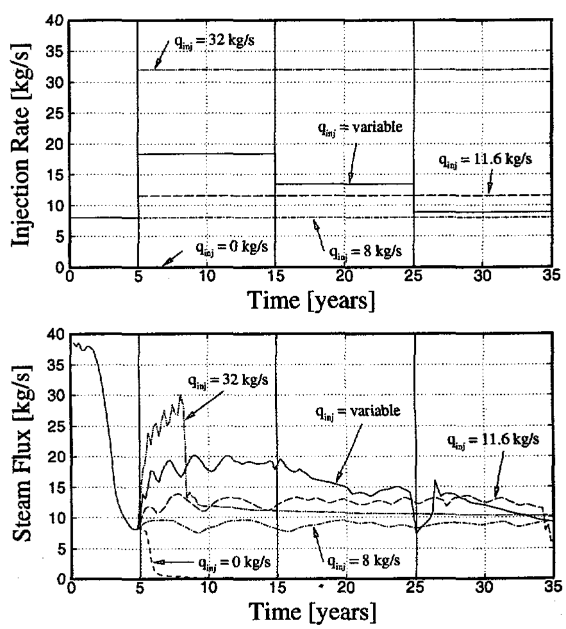

Figure 4. Injection optimization: Steam production at separator as a function of time for five different fluid injection scenarios shown in the upper panel.

The optimum injection rates are declining with time. High injection rates seem acceptable at early times when reservoir temperatures are high. At later time, it is not only the shortage of fluid but also of thermal energy that limits steam production. Note the short period of temperature decline and enhanced liquid production near t= 25 years, which leads to a reduction of the proposed injection rate for the final period.

From this last observation and the system behavior as seen with the high injection rate it becomes obvious that the solution depends on the time frame used for optimization. Short-term solutions tend to favor large injection rates whereas lower injection rates are considered optimal if energy production has to be sustained over longer time periods.

We want to point out that the oscillations seen in Figure 4 are due to finite space discretization employed in the numerical simulations. These effects are particularly severe in problems with coupled thermal and phase fronts as in our case. For a detailed discussion of this problem the reader is referred to Pruess et al. (1987).

CALIBRATION AND OPTIMIZATION

We have mentioned in the previous section that the optimum injection rate is strongly dependent on the production rate and steam enthalpy, and for the case studied here, is only mildly influenced by the costs associated with fluid injection, liquid production and energy prices as long as they are in realistic proportions to each other. While the actual profit obviously depends on the details of the economic model, the optimum at which the total costs are minimized is virtually governed by the time at which unwanted thermal interference occurs in the production well. In other words, the accuracy of the simulation model is essential for the outcome of the optimization study.

To clarify this point, we define and evaluate a measure of the uncertainty associated with the cost prediction. Errors in the calculated cost result from (i) simplifications and systematic errors in the conceptual model of the geothermal reservoir, (ii) uncertainties in the model parameters, (iii) variations in the injection rates, and (iv) simplifications in the cost function and uncertainties in the cost factors. Issue (i) is by far the most important one because errors in the conceptual model usually have a strong impact on predictions, resulting in systematic errors much larger in magnitude than errors from the other sources.

Note that accurate simulation of water injection into geothermal reservoirs is a challenging task. Complex coupled processes of fluid and heat flow in heterogeneous, fractured formations must be modeled, and the flow problem has to be solved in a stable and efficient manner. The issues arising when modeling water injection into vapor-dominated reservoirs are discussed in a companion paper (Pruess et al., 1997).

The second largest source of prediction errors is the uncertainty associated with the hydrogeologic input parameters used in the model. Recall that model-related parameters may be estimated using inverse modeling, and that estimates of their uncertainties are calculated based on Eq. (7). We have studied the impact of parameter uncertainties on the calculated total cost by means of Monte Carlo simulations. A standard deviation of 0.3, 10 m, and 5 °C was assigned to the three parameters $\log(k)$, fracture spacing and initial reservoir temperature, respectively, and 300 TOUGH2 simulations have been performed based on randomly generated parameter sets. As a result of these simulations, a probability distribution (histogram) of the total costs can be drawn. This distribution is compared to the result of a similar Monte Carlo simulation, where the injection rate is considered variable with a standard deviation of 1 kg/s. A comparison of the two histograms is an indication of the relative importance of parameter uncertainty versus the uncertainty in the optimum injection rate. Note that a more rigorous study would imply solving the optimization problem for each Monte Carlo realization of the hydrogeologic parameters, giving the actual range of injection rates as a result of parameter uncertainty.

Figure 5 shows the two histograms. The one in bold represents the distribution as a result of uncertainty in the hydrogeologic parameters, and the thin line columns show the distribution due to uncertainties in the injection rates. The minimum cost as determined above is indicated at -174. Reservoir conditions more favorable than the ones used during the optimization may actually lower the total costs. On the other hand, many parameter combinations lead to significantly higher costs if injection occurs at the presumably optimum rate. These parameter sets usually have a lower permeability and/or reservoir temperature than expected. There is a considerable risk that the reinjection rate is sub-optimal, and that the operation is less profitable than expected, as indicated by the 90 % percentile which indicates that 10 % of the 300 Monte Carlo simulations realized costs above -26 monetary units.

The distribution discussed above is compared to the one that results from uncertainty in the injection rate. Since the mean of the injection rate is taken to be the optimum one for the best estimate parameter set, costs are always higher when perturbing the optimum pumping schedule (both increasing and decreasing the injection rate leads to higher costs). Nevertheless, the uncertainty in the cost estimate is bounded with a

90 % percentile at -147 which is relatively close to the minimum cost.

The analysis presented here is qualitative in nature. It was performed to illustrate the significance of reservoir characterization. Model calibration is important because errors in the parameters are a major source of prediction uncertainty. Again, test design and data analysis using inverse modeling can reduce the uncertainty in the estimated parameters, leading to more reliable model predictions which justify the use of automatic minimization routines for the determination of optimum reinjection schedules.

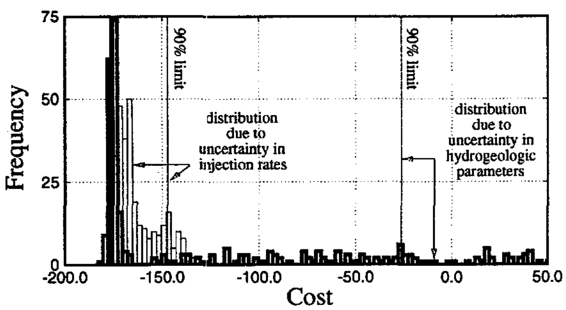

Figure 5. *Uncertainty analysis: Cost distributions determined by Monte Carlo simulations reflecting prediction uncertainty as a result of uncertainty in the hydrogeologic parameters (bold line columns) and due to uncertainty in the injection rate (thin line columns).*

CONCLUDING REMARKS

The purpose of this paper was to show the flexibility of an inverse modeling approach for automatic history matching and the estimation of model parameters by performing a joint inversion of all available data. In addition to automatic model calibration, the ITOUGH2 code provides a number of semi-quantitative measures to study parameter sensitivities, correlations between parameters and observations, prediction uncertainties, total parameter sensitivities, and the potential benefit from taking measurements of a certain kind and in a certain location. This information is useful for the design and optimization of reservoir characterization and monitoring programs.

The advantage of inverse modeling procedures is that they overcome the time and labor-intensive tedium of trial-and-error model calibration. Effective, model-related parameters are automatically determined on the scale of interest. This ensures that the reliability of subsequent predictions can be improved if they are based on the same or a consistent conceptual model of the geothermal reservoir.

We also demonstrated the use of inverse modeling techniques for the optimization of a reinjection operation. Injection rates have been automatically determined to maximize energy production while avoiding potential drawbacks from thermal degradation and liquid breakthrough at the production well. It was shown that such an optimization study requires an accurate simulation model, i.e., sophisticated process modeling and calibration are the key issues that need to be addressed when using numerical simulations to support reservoir management.

This study was performed using a generic model of the geothermal reservoir, and a very simplistic economic model for calculating the cost function. However, the sophisticated process description of the TOUGH2 simulator along with automatic model calibration capabilities provide the basis for a reliable prediction of the geothermal reservoir behavior. The output of a site-specific process model can and should be linked to a detailed economic model for a combined optimization which takes into account the interaction between field operations and fluid and heat flow in the reservoir.

ACKNOWLEDGMENT

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WATER INJECTION INTO VAPOR- AND LIQUID-DOMINATED RESERVOIRS: MODELING OF HEAT TRANSFER AND MASS TRANSPORT

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ABSTRACT

This paper summarizes recent advances in methods for simulating water and tracer injection, and presents illustrative applications to liquid- and vapor-dominated geothermal reservoirs. High-resolution simulations of water injection into heterogeneous, vertical fractures in superheated vapor zones were performed. Injected water was found to move in dendritic patterns, and to experience stronger lateral flow effects than predicted from homogeneous medium models. Higher-order differencing methods were applied to modeling water and tracer injection into liquid-dominated systems. Conventional upstream weighting techniques were shown to be adequate for predicting the migration of thermal fronts, while higher-order methods give far better accuracy for tracer transport. A new fluid property module for the TOUGH2 simulator is described which allows a more accurate description of geofluids, and includes mineral dissolution and precipitation effects with associated porosity and permeability change. Comparisons between numerical simulation predictions and data for laboratory and field injection experiments are summarized. Enhanced simulation capabilities include a new linear solver package for TOUGH2, and inverse modeling techniques for automatic history matching and optimization.

INTRODUCTION

Reinjection of produced brines and spent condensate is the preferred method for disposal of geothermal waste fluids. In addition it can serve as a means for providing pressure support to production wells, and for accelerating and enhancing energy recovery (Stefansson, 1997). These objectives are especially important in vapor-dominated reservoirs, whose very existence indicates that fluid reserves are naturally limited. The crucial importance of injection for sustaining production at The Geysers is now well recognized (Enedy et al., 1992; Goyal, 1995), and efforts are underway to increase injection rates and minimize net fluid withdrawal (Barker and Pingol, 1997).

Injection can also have detrimental effects, such as thermal degradation and declining flow rates at production wells (Barker et al., 1992). Maximizing beneficial effects from injection while avoiding potential drawbacks requires careful engineering design and monitoring. Mathematical modeling of injection effects is an important tool for accomplishing this task.

Water injection into geothermal reservoirs gives rise to complex coupled processes of fluid flow, heat transfer and rock-fluid interactions. In vapor-dominated systems, injection will induce boiling and condensation effects with two-phase flow of water and steam. Further difficulties arise from reservoir heterogeneities, especially fractures, which may strongly affect migration patterns of injected fluids and rates of heat transfer between rocks and fluid.

From a mathematical viewpoint the equations describing fluid and heat flow in geothermal production-injection systems are moderately non-linear for liquid-dominated systems, but strongly non-linear for vapor-dominated systems because of phase change and two-phase flow effects. Modeling of injection effects is fairly easy for 1-D homogeneous porous media, but becomes increasingly difficult when taking into account 2-D and 3-D flow geometries with gravity effects, and heterogeneities on a range of scales.

Past research has led to the development of numerical simulators for injection modeling, such as TOUGH2 (Pruess, 1991a), that can provide a description of the important phenomena associated with injection. The goals of our ongoing efforts are to (i) develop an understanding of fluid flow and heat transfer mechanisms during injection into fractured vapor-dominated reservoirs; (ii) identify conditions that are conducive to unwanted thermal interference, and develop approaches for anticipating or mitigating such effects; (iii) improve the representation of chemically complex fluids, and of changes in permeability and porosity during injection due to mineral dissolution and precipitation effects; (iv) test and demonstrate accuracy of reinjection modeling techniques by comparison with laboratory and field data; and (v) enhance the robustness, accuracy, efficiency and practical useability of numerical simulators for injection design.

VAPOR-DOMINATED SYSTEMS

Water injected into depleted vapor zones in reservoirs such as The Geysers and Larderello is believed to migrate primarily along networks of interconnected fractures (Beall and Box, 1989; Thompson and Gunderson, 1992). Water will be partially imbibed into the low-permeability rock matrix, and be partially vaporized due to heat transfer from the reservoir rocks. Early efforts at modeling these processes used either homogeneous porous media approximations (Pruess et al., 1987; Pruess, 1991b), or idealized the fracture-matrix system as interacting continua (Calore et al., 1986).

As a step towards a more realistic appraisal of injection into vapor zones in fractured rocks, we have studied the behavior of boiling injection plumes in individual sub-vertical fractures. A schematic of the fracture-matrix system we consider is shown in Fig. 1, while Fig. 2 gives a general view of injection plume behavior in high-angle fractures.

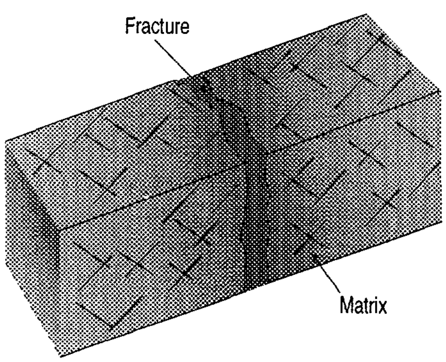

Fig. 1. Schematic of a sub-vertical fracture, with attached matrix rock of low permeability.

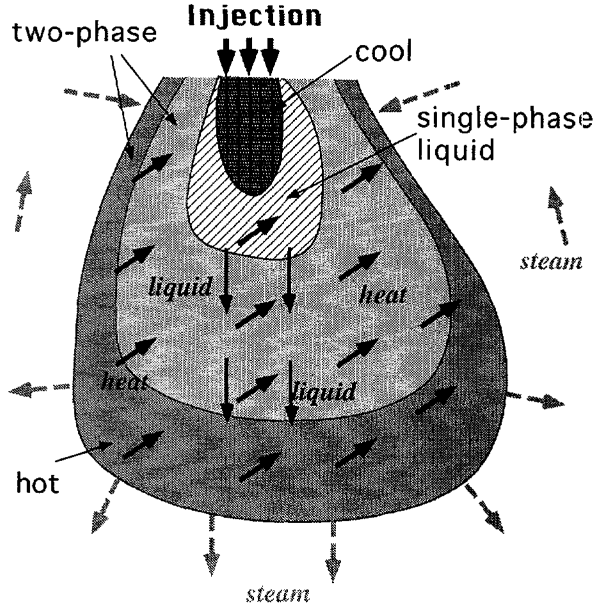

Fig. 2. Schematic of an injection plume in a hot high-angle fracture in a vapor-dominated reservoir.

For the numerical simulations, the fractures are modeled as two-dimensional heterogeneous porous media (Pruess and Tsang, 1990). To represent multi-scale heterogeneity, our TOUGH2 general-purpose simulator was enhanced to permit permeability assignment to individual grid blocks according to $k_{ij} = \zeta_{ij} \times k_{ref}$, where k_{ref} is a "reference" permeability, and the ζ_{ij} are stochastic spatially-correlated "permeability multipliers." Our process description includes a consistent description of capillary pressure and vapor adsorption effects. Capillary pressure functions are scaled with permeability on a grid block-by-grid block basis according to $P_{cap} \rightarrow P_{cap}' = P_{cap}/\sqrt{(\zeta_{ij})}$ (Leverett, 1941).

An average of simulated injection plumes for four different stochastic realizations of the same underlying heterogeneity structure is shown in Fig. 3. One may hope that homogeneous fracture models would be capable of capturing injection behavior in heterogeneous fractures "on average." However, comparison with a simulated injection plume in a homogeneous medium with the same average permeability (see Fig. 4) shows that this is not the case. In the heterogeneous fractures there is stronger lateral water migration than in the homogeneous fracture, suggesting that the shape of the plume in the homogeneous fracture cannot be taken as representing an average of the heterogeneous plumes. It appears as though homogeneous reservoir models could seriously underestimate the potential for breakthrough of liquid water at neighboring steam production wells.

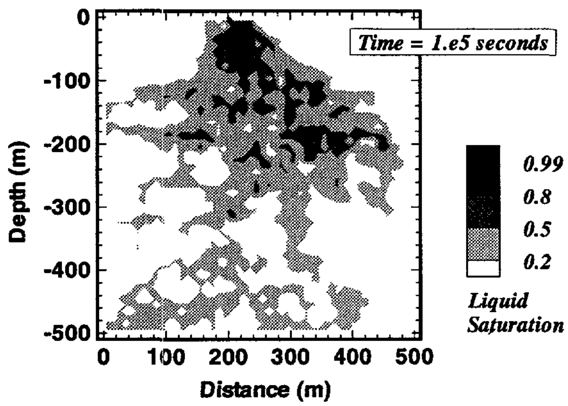

Fig. 3. Average of four simulated injection plumes in heterogeneous fractures.

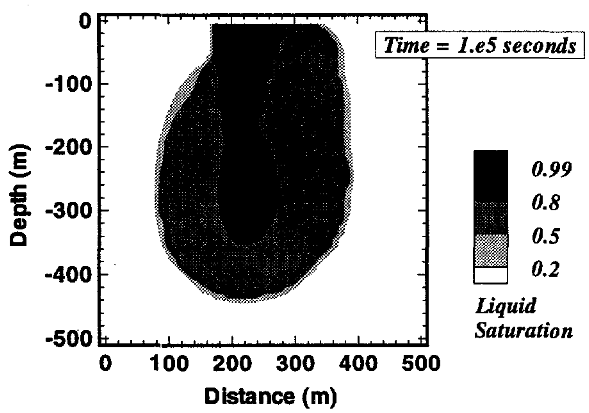

Fig. 4. Simulated injection plume in homogeneous fracture with averaged permeability.

Our simulations show that boiling of injected fluid gives rise to strong vapor pressure gradients which, in turn, have strong effects on plume migration. This can be understood by noting that for the temperature and pressure conditions of interest in vapor-dominated systems, vapor acts like a more viscous fluid than liquid water (has larger kinematic viscosity). A more detailed analysis is available in recent reports (Pruess, 1996a, b). The fact that vapor has larger kinematic viscosity than water indicates that, in addition to gravitational instability of water over steam, the migration of injection plumes may also be subject to hydrodynamic instabilities (Fitzgerald et al., 1994).

TRACER MONITORING

Injected water differs from native reservoir fluids not only in terms of temperature but usually also with respect to concentrations and isotopic composition of dissolved solids. These differences can be used as natural tracers to monitor the movement of injected fluid. More detailed tracking of the fate of injected fluid is possible by adding cocktails of man-made tracers (Adams, 1995). Advancement of thermal fronts is retarded relative to fluid movement by heat exchange with the reservoir rocks. Tracers can be selected to minimize retardation, in which case they migrate ahead of thermal fronts and can serve as early indicators of potential thermal breakthrough. Depending on flow geometry and reservoir heterogeneities, fluid temperatures T, tracer concentrations C, and phase saturations S in injection plumes may appear as anything from sharp fronts to broad distributions.

In numerical simulation of injection, the profiles of (T, C, S) are subject to artificial broadening due to approximations introduced by discretizing the continuous space and time variables. This "numerical dispersion" effect can lead to unreliable, grid-dependent predictions for arrival of injected water and tracer and temperature fronts at production wells. Numerical artifacts can be minimized through finer space and time discretization, but at the expense of a greatly increased problem size. A more effective approach is the use of higher-order differencing schemes that employ the same total number of grid blocks but achieve greater accuracy in strongly advective situations.

Our ongoing work on implementing higher-order "total variation diminishing" (TVD) differencing schemes into the reservoir simulator TOUGH2 was described in a recent paper (Oldenburg and Pruess, 1997). In that paper it was shown that TVD schemes give far better accuracy for mass transport problems than conventional finite differences with single-point upstream weighting.

Here we are demonstrating application of the Leonard-TVD scheme (Leonard, 1984) to a test case involving injection into and production from a two-dimensional horizontal fracture zone. Problem specifications are similar to the production/injection problem presented in Oldenburg and Pruess (1997). The fracture zone is modeled as a horizontal layer of 12.2 m thickness with uniform high permeability of 10^{-12} m^2. Initial conditions are single-phase water at a temperature of 300 °C and a pressure of 120 bars. The reservoir rock adjacent to the fracture zone is assumed impermeable, and at a uniform initial temperature of 300 °C. Conductive heat transfer to the fracture is modeled with the semi-analytical technique of Vinsome and Westerveld (1980).

Production and injection wells are arranged in a five-spot pattern with 400 m well spacing (Fig. 5). For simplicity we model one quarter of the five-spot pattern, which was discretized into 400 square grid blocks (20 x 20) of length 10 m on a side. Cold water (T ≈ 30 °C) is injected at a rate of 16 kg/s (full-well basis), while the production well operates on deliverability against a flowing bottomhole pressure of 90 bars. Four kg of tracer is injected over a period of 10 days starting at t = 0. In order to emphasize issues of early breakthrough of injected fluid, a 42.4 m wide channel with 10 times higher permeability of 10^{-11} m^2 is assumed to be present over 80 % of the distance between injection and production wells.

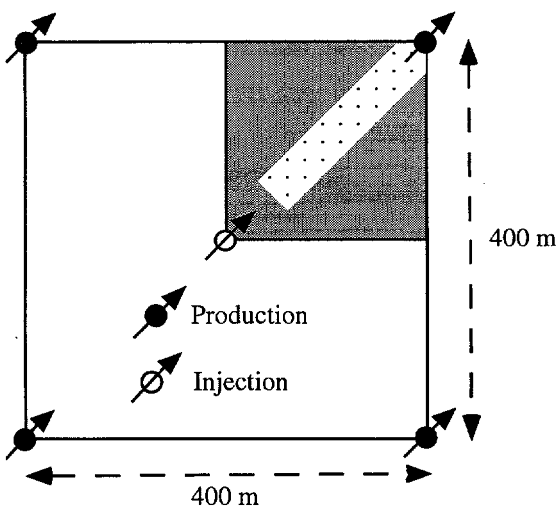

Fig. 5. Five-spot well pattern. Shading shows a 1/4 symmetry element; the stippled region is a high-permeability channel.

We use the module EOS7R (Oldenburg and Pruess, 1995) for components water, brine, tracer1, tracer2, air, and heat. For this preliminary application, the tracer is the brine component which is non-sorbing, non-decaying, and non-volatilizing although EOS7R is capable of handling all of these processes for the two tracer components.

Simulation results after 6 months using conventional upstream weighting for thermal energy and tracer mass fractions are shown in Fig. 6. The temperature field shows the effects of cold injection fluid entering the system but being retarded by heat conduction from the reservoir rocks. The tracer mass fraction field is advanced relative to heat since no retarding effects (e.g., adsorption) are present for the tracer. Tracer breaks through in a broad distribution prior to arrival of the temperature front at the production well. Results for the same problem obtained with the Leonard-TVD scheme are shown in Fig. 7. There is little difference in the temperature distributions, which are very broad because of conductive heat transfer from the wall rocks, so that physical dispersion dominates over numerical artifacts. However, the more accurate modeling of tracer transport achieved with the higher-order differencing scheme results in much steeper concentration profiles, and more than two times higher peak concentrations for the tracer.

This example as well as other simulations not shown here indicate that higher-order differencing schemes can give significantly different and more accurate predictions for tracer behavior in liquid- and vapor-dominated systems (Oldenburg and Pruess, 1997). These schemes improve our ability for designing and interpreting tracer tests, thereby aiding in the monitoring of injection effects, and in improving the design and operation of injection systems.

IMPROVED PROCESS DESCRIPTION

In collaboration with Italian geothermal researchers, we have developed a fluid property module for TOUGH2 that features a realistic description of multiphase mixtures of water, non-condensible gas, and sodium chloride for temperatures in the range of 100-300 °C, pressures up to 800 bars, and dissolved salt mass fraction up to halite saturation (Battistelli et al., 1997). Called "EWASG," this module includes salinity effects on heat of vaporization of the aqueous phase, and on viscosity, density, enthalpy, and vapor pressure, as well as effects of salinity on gas solubility.

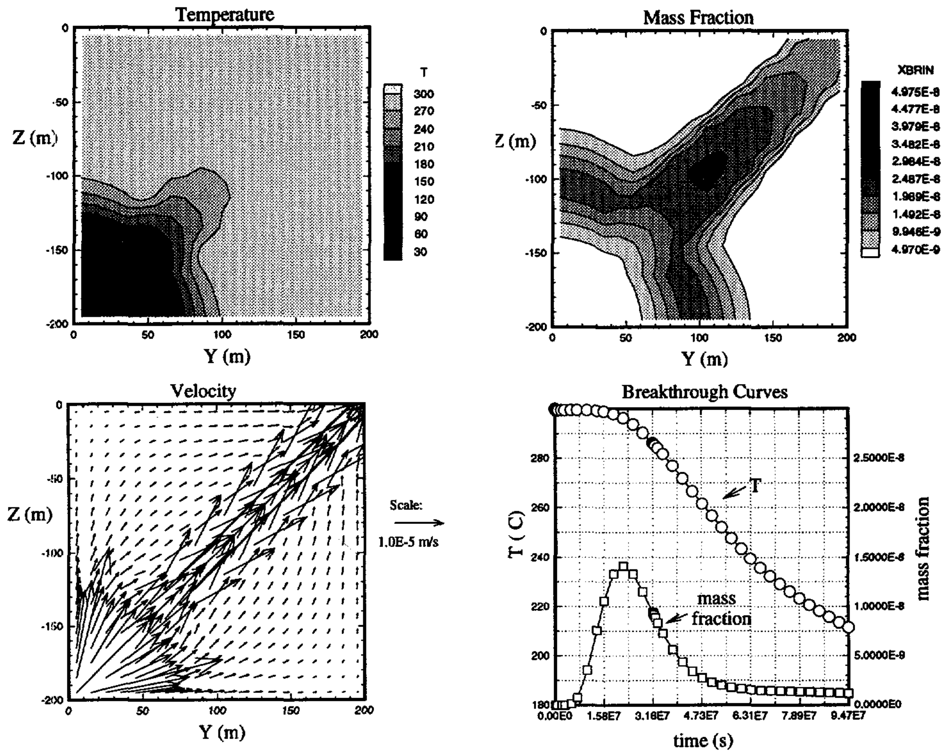

Fig. 6. Simulation results after 6 months of injection obtained with upstream weighting.

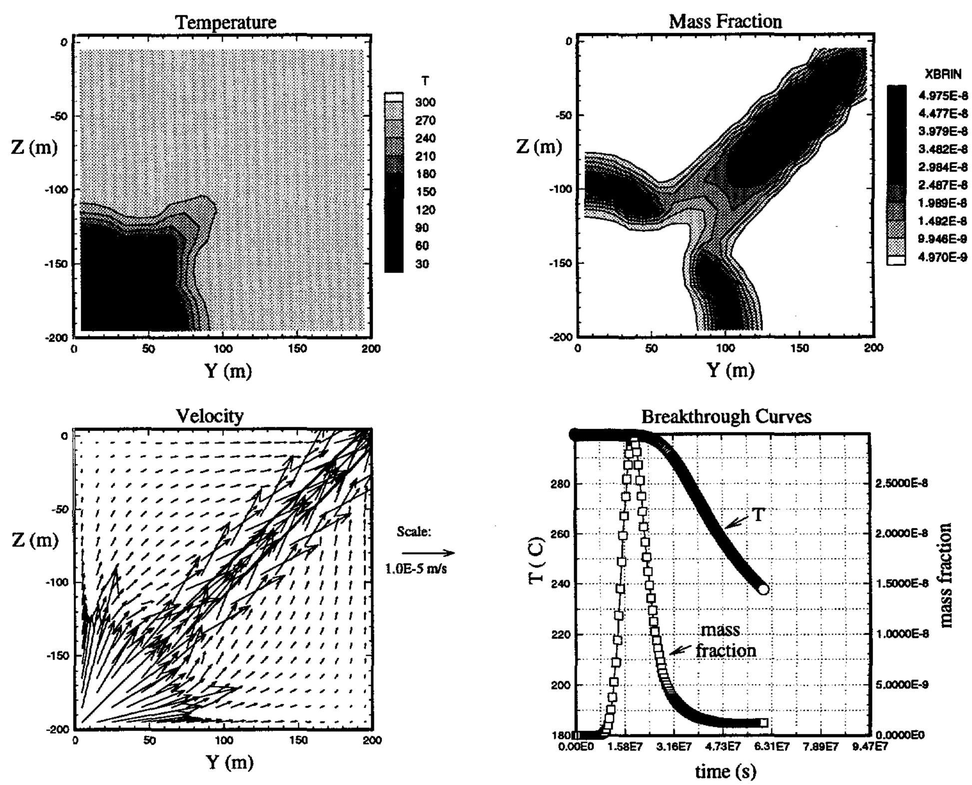

Fig. 7. Simulation results after 6 months of injection obtained with higher-order differencing.

Vapor pressure lowering from capillary and vapor adsorption effects is also taken into account. The non-condensible gas can be chosen to be air, CO_2, CH_4, H_2, or N_2. Solid NaCl can precipitate or dissolve as dictated by its temperature-dependent solubility. Associated changes in porosity and permeability are also modeled.

EWASG is currently undergoing beta-testing, and is expected to be included in the next release of a TOUGH2 upgrade. It provides a more accurate capability for modeling geothermal production-injection systems than previously available fluid property modules. Illustrative applications will be included in a forthcoming paper (Calore et al., in preparation).

ENHANCED SIMULATION CAPABILITIES

The numerical simulation of injection entails the solution of coupled sets of linear equations with often poorly conditioned matrices. For example, modeling of tracer injection will typically lead to matrices for which 2/3 of the elements on the main diagonal are zero. We have developed a new conjugate gradient algorithm and new preconditioners that provide a stable iterative solution for such problems (Moridis and Pruess, 1997).

In addition, inverse modeling capabilities have been developed which can be used for automatic history matching, and for optimizing the design and operation of production/injection systems (Finsterle et al., 1997). More details are given in a companion paper (Finsterle and Pruess, 1997).

COMPARISON WITH DATA

Fitzgerald et al. (1996) performed a series of laboratory experiments in which model fractures assembled from roughened glass plates were used to study fluid injection into superheated vapor zones. Ether was used as the working fluid instead of water, so that experiments could be conducted at moderately increased temperatures and ambient pressures. Temperature profiles measured at different times were compared with predictions using a version of TOUGH2 in which thermophysical properties of water were replaced with those applicable to ether. Good agreement between experimental data and numerical predictions was found throughout both the inner single-phase and outer two-phase regions.

Pruess and Enedy (1993) presented a study of injection interference in the southeast Geysers. Injection into a well caused strong and rapid interference with production from a neighboring well whose steam feeds were at 200 - 800 m distance from the injection points. A numerical simulation using a fracture-matrix model was able to replicate the decline of production rate during injection, and the (over-)recovery of production following injection shut-in.

These results provide support for the physical process model implemented in TOUGH2, as well as for the numerical approximations used.

SUMMARY AND OUTLOOK

Injection into liquid-dominated reservoirs gives rise to coupled fluid and heat flows, while injection into vapor-dominated systems is further complicated by phase change effects (boiling and condensation). Robust numerical simulation capabilities are available for modeling these processes.

As geothermal reservoir management is maturing there is a need for continuing improvements in (i) the representation of physical and chemical processes during injection, (ii) the description of reservoir heterogeneities on different scales, and (iii) the useability of simulators for optimizing injection monitoring and design. Our research efforts as summarized in this paper aim at responding to these needs.

ACKNOWLEDGEMENT

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REDUCTION OF OPERATIONS AND MAINTENANCE COSTS AT GEOTHERMAL POWER PLANTS

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ABSTRACT

To reduce chemical costs at geothermal power plants, we are investigating: a) improved chemical processes associated with H_2S abatement techniques, and b) the use of cross dispersive infrared spectrometry to monitor accurately, reliably, and continuously H_2S emissions from cooling towers. The latter is a new type of infrared optical technology developed by LLNL for non-proliferation verification.

Initial work is focused at The Geysers in cooperation with Pacific Gas and Electric. Methods for deploying the spectrometer on-site at The Geysers are being developed. Chemical analysis of solutions involved in H_2S abatement technologies is continuing to isolate the chemical forms of sulfur produced.

INTRODUCTION

We have established a new program at Lawrence Livermore National Laboratory (LLNL) aimed at identifying expertise and technology at LLNL that can be used to help reduce operations and maintenance costs at geothermal power plants. We are working with industry to identify the top chemistry and corrosion issues facing geothermal power production. Initial work has been focused at The Geysers following discussions with Pacific Gas and Electric (PG&E). The issues being addressed are planned to be of benefit to the geothermal industry as a whole. Future work will involve additional industry participants and other national laboratories, and address other issues.

Power plants at The Geysers must limit the atmospheric release of noncondensible hydrogen sulfide (H_2S) gas that is contained in geothermal steam. Our initial work focuses on two problems related to H_2S emission control: 1) reducing the cost of chemical processing involved in H_2S abatement through use of alternative abatement chemicals, and 2) measuring H_2S in cooling tower emissions which would permit efficient use of abatement chemicals.

PG&E presently uses two technologies to abate hydrogen sulfide based on oxidizing the reduced sulfur in H_2S to more oxidized, less toxic forms. Sulfur is oxidized either by using an iron chelate (FeHEDTA, where HEDTA = hydroxy-ethylenediaminetriacetic acid), or by using vanadium(V) salts and anthraquinone disulfonates as dual redox catalysts in the Stretford process for oxidation of HS^- by oxygen in carbonate solutions. The first technology requires use of a fairly expensive chemical reagent (FeHEDTA) which requires replenishing. The Stretford process produces large amounts of an alkaline solution that contains sulfur in a variety of chemical forms, some of which, such as thiosulfate, build-up to unacceptable levels.

PG&E is interested in finding less expensive, alternate reagents for both processes. Iron chelate is the most expensive aspect of H_2S abatement at The Geysers: its replenishment costs approximately $3 million annually. PG&E is also interested in enhancing the purity and market value of elemental sulfur separated from the Stretford solutions, and in minimizing the undesired build-up of thiosulfate ions in Stretford solutions. Improvements in these processes will be applicable to other geothermal fields with H_2S problems, and in particular to more than 100 Stretford units in use throughout the world.

There is presently no way to continuously and accurately monitor H_2S emissions from cooling towers. Monitoring is not only required to ensure air quality compliance, but also to control the addition of H_2S abatement chemicals. PG&E currently measures H_2S emissions using portable analyzers at 36 sample points per stack on a regular basis to determine iron chelate demand. Real-time monitoring of stack emissions could save an estimated $300K per year by varying the addition of chelate according to changes in fluid chemistry or plant operation, while assuring continued emissions compliance.

Real-time monitoring of the composition of steam from production wells is also needed to determine the demand for steam "desuperheating". Unocal, the supplier of steam to most of the PG&E power plants, currently sprays geothermal condensate into the mainsteam pipeline upstream of the power plants. This scrubs chlorides which contribute to stress corrosion cracking in the steam turbine. Steam desuperheating, however, results in the generation loss of about 10 to 20 MW for all the Geysers power plants. A real-time monitor of steam chloride content could determine the need for steam desuperheating.

CURRENT PROJECTS

We are evaluating the feasibility of continuous infrared spectral monitoring of H_2S emissions from cooling towers using a new type of infrared optical technology developed by LLNL for non-proliferation verification. The cross dispersive infrared spectrometer is a tool for infrared field measurements that is unique in that it has no moving parts, yet it can make spectral snapshots of the entire infrared region while being nearly immune to external vibrations. It can be over 100 times more sensitive than existing infrared instruments, and is capable of high resolution, being able to distinguish over 10,000 infrared colors.

The continuous H_2S monitor project is unique in that it is affected by spectrometer availability. The proof of principal experiments will use an existing remote sensing spectrometer, and demonstrations are to be scheduled around existing commitments for the instrument.

With regards to H_2S abatement, we are focusing initially on less expensive alternatives to the FeHEDTA chelate, and on reducing thiosulfate buildup in Stretford solutions. This project takes advantage of LLNL's expertise and facilities in analytical chemistry, as required to detect the many chemical forms of sulfur in the H_2S abatement solutions.

RESEARCH STATUS

The measurement of H_2S directly across the cooling tower by infrared absorption is a measurement challenge. H_2S absorbs radiation in the infrared only weakly. The concentrations of H_2S in the cooling towers will range down to 1 part-per-million and this will require a measurement precision of better than 0.1%. We have modeled the absorption of H_2S in the presence of other tower constituents and find that H_2S will have regions of unobstructed absorption. The infrared instrument has demonstrated the required level of precision in laboratory settings. However, assessments of the application of infrared spectroscopy, discussions with PG&E personnel and site visits suggest that direct line-of-sight measurements of H_2S through a cooling tower, although the most direct, may be problematic owing to reduced transmissivity through cooling tower "fog". A mid-infrared laser will be used to measure transmissivity in this spectral region to assess the feasibility under a variety of operating conditions. Other options that are being considered include multiple sample ports located inside the cooling towers that continuously withdraw vapors to a common analysis location, and alternately, headspace analysis of the fluid just before entering the cooling towers.

We obtained fluid samples from PG&E of the effluent solutions from the two currently used technologies for H_2S abatement at The Geysers and characterized their ionic and elemental composition. Complete chemical characterization of the solutions is a requisite first step in analyzing the current process, from which point improvements can be considered. Results indicate that much of the sulfur is present as sulfate, thiosulfate and other oxysulfur ions in both the Stretford and iron chelate-treated solutions. Sodium polysulfide (Na_2S_x) is also apparently present in the alkaline Stretford solutions.

The significant concentration of sodium polysulfide is of special interest. Although known to be an intermediate in the oxidation process, it was not expected in the reactor sampled. Further analyses and sampling must confirm this finding, which could impact design of chemical treatments for H_2S abatement. Care has to be exercised in the sulfur analysis. For example, the iodometric titration method will not detect sulfate ion nor elemental sulfur at acidic pH, but will detect other chemical forms. Chemical analyses of the solutions are continuing to better isolate the forms of sulfur in the solutions.

FUTURE WORK

We will measure the absorption of H_2S in the laboratory to establish minimum detectable concentrations with our spectrometer. We will measure the transmission of infrared light through the cooling tower "fog" with a mid-infrared laser. Predicated on favorable transmission results, we will fabricate an optical system that will allow us to measure the H_2S concentration in the cooling tower. We will also measure headspace gases from the condensate pipe leading to the cooling towers. On-site experiments will be conducted at The Geyser power plants that will measure the H_2S concentrations in the condensate stream at various locations along the pipe leading to various cooling towers. We will also evaluate the feasibility of using the spectrometer to continuously monitor the concentrations of corrosive components of produced steam.

We will complete the quantitative chemical analyses of the Stretford and iron chelate effluents. In view of seeking more effective techniques for sulfur control, we will determine the mode of decomposition of the Stretford solution upon acidification, seek improved ways of extracting elemental sulfur and thiosulfate ions from the Stretford solutions, and identify less-expensive alternatives to the iron chelate oxidation technology.

We will continue to work with the geothermal industry to extend our list of industry collaborators and best match LLNL technologies and expertise with industry-wide O&M needs.

ACKNOWLEDGMENTS

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Concurrent Session 3:
Energy Conversion

Geysers Advanced Direct Contact Condenser Research

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1) Introduction

The first geothermal application of the Advanced Direct Contact Condenser (ADCC) technology developed by the National Renewable Energy Laboratory (NREL) is now operational and is being tested at The Geysers Power Plant Unit 11. This major research effort is being supported through the combined efforts of NREL, The Department of Energy (DOE), and Pacific Gas and Electric (PG&E).

NREL and PG&E have entered into a Cooperative Research And Development Agreement (CRADA) for a project to improve the direct-contact condenser performance at The Geysers Power Plant. This project is the first geothermal adaptation of an advanced condenser design developed for the Ocean Thermal Energy Conversion (OTEC) systems. PG&E expects this technology to improve power plant performance and to help extend the life of the steam field by using steam more efficiently. In accordance with the CRADA, no money is transferred between the contracting parties. In this case the Department of Energy is funding NREL for their efforts in this project and PG&E is contributing funds in kind. Successful application of this technology at The Geysers will provide a basis for NREL to continue to develop this technology for other geothermal and fossil power plant systems.

Geysers Unit 11 was selected for installation and demonstration of the NREL technology. The Unit 11 condenser is an excellent test case due to a high noncondensable gas load and a high amount of steam carryover to the gas removal system. The ADCC technology is expected to yield a 5% increase in power production as a result of the improved direct-contact condensation process. Projections for Unit 11 are an overall 4.5 MW improvement in power production. In addition to improved power production, substantial reductions in abatement chemical usage are projected.

2) Objectives

NREL and PG&E arranged this project under a CRADA to best fit the needs of each organization. The overall objective of this project for NREL is the demonstration of their new ADCC technology that can improve the geothermal resource utilization and make U.S. industry more competitive. PG&E will gain unrestricted use of this technology for The Geysers Power Plant. NREL brings to the project this new process and the technical expertise to adapt the technology to geothermal systems. PG&E provided the Geysers Unit 11 for the demonstration, along with detailed engineering, construction and operation of the new system.

Specific objectives that have been completed to date:

1. The development and evaluation of the ADCC condenser computer simulation model. The model was developed by NREL as a predictive tool to determine expected process conditions and flows for the conceptual design.

2. The conceptual design of the Unit 11 main condenser modification. NREL and PG&E worked together to finalize the conceptual design to include the best configuration for the internals of the main condenser. A final detailed engineer-

ing design for the condenser modification was then completed.

3. The identification of improvements to the Unit 11 H_2S abatement system. The changes in the condensation process provided by the NREL ADCC system has led to the development of process improvements to the H_2S abatement technology for Unit 11.

4. Design and procurement of a new three-stage hybrid gas removal system. Output from the NREL model was used to size new steam jet air ejectors and a new inter condenser. The model was also used to modify the existing inter and after condensers.

5. All parts and equipment have now been installed, and the Unit was functional as of mid-February, 1997. H_2S emission and power production tests are underway.

3) Process Description - Existing

The Unit 11 condensation scheme prior to the retrofit is presented in Figure 1. The description of the process equipment shown in Figure 1 along with typical flows (both before and after the modifications) are listed in Table 1. The turbine exhaust steam flows into a direct-contact condenser and is condensed as it makes contact with the cooling water that cascades through the condenser. The condensate and cooling water mixture collects in the hotwell and is pumped out to the cooling tower to be recycled as circulating water. Cooling water is drawn into the condenser by the vacuum. The noncondensable gas is removed from the condenser by a two-stage steam jet condenser system. The inter and after con-

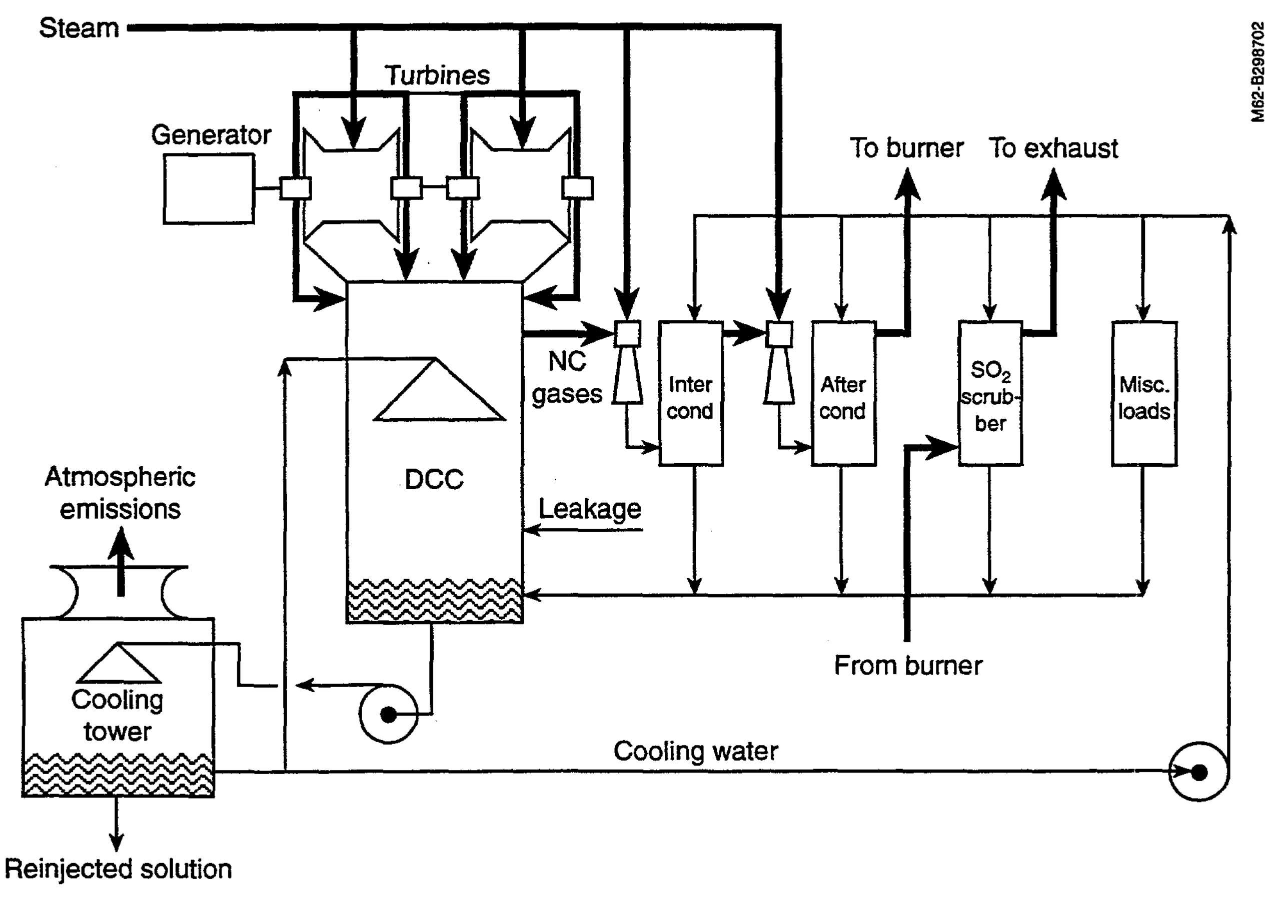

Figure 1. Simplified schematic of the cooling water circuits for Unit 11 power plant prior to modifications

Table 1. Major Process Flow Streams

Stream	Description	Typical Flow, Lb/ Hr Before	After
1	Plant steam supply	1,320,000	1,320,000
2	First stage auxiliary steam jet supply	77,000	26,000
3	Second stage auxiliary steam jet supply	48,000	16,500
4	Turbine compressor auxiliary steam supply	N/A	13,000
5	Third stage auxiliary steam jet supply	N/A	44,000
6	Main circulating water supply	40,000,000	40,000,000
7	Main condenser condensate	41,320,000	41,320,000
8	Auxiliary cooling water supply	2,565,000	1,400,000
9	Inter condenser 1 cooling water supply	1,900,000	775,000
10	Inter condenser 2 cooling water supply	N/A	315,000
11	After condenser cooling water supply	665,000	310,000
12	Inter condenser 1 condensate	1,977,000	801,000
13	Inter condenser 2 condensate	N/A	331,500
14	After condenser/Gas cooler condensate	713,000	323,000
15	Combined Inter condenser 2 and After condenser condensate	N/A	654,500
16	Main condenser non-condensable gas exhaust	97,000	24,000
17	Inter condenser 1 non-condensable gas exhaust	21,000	21,000
18	Inter condenser 2 non-condensable gas exhaust	N/A	20,500
19	After condenser cooler non-condensable gas exhaust	20,600	20,600
20	Cooling tower air exhaust	38,000,000	38,000,000
21	Cooling tower blowdown	330,000	330,000
22	Sodium hydroxide supply	as required	as reqd.
23	Metal catalyst supply	as required	as reqd.

densers are open vessels with a single spray nozzle.

Past studies have confirmed poor cooling water and steam mixing. Steam vapor carryover was large because the temperature of the vent gas leaving the main condenser was roughly equivalent to the hotwell temperature.

4) Process Description - Modified

The NREL ADCC system altered the condenser internals. Plastic structured packing are now used as the contact media. NREL worked closely with PG&E to arrive at the best internal configuration. The final design was arrived at after a number of iterations. Several designs were studied and rejected for either performance or constructability reasons.

The temperature of the noncondensable gas leaving the main condenser approaches the temperature of the cooling water, about 25°F cooler than the hotwell. At this cooler temperature the vapor pressure of water is substantially lower and thus water vapor would only be about 20% of the vent gas composition. The result is a large reduction in vent gas mass flow which lowers condenser back pressure and steam demand for the gas-removal steam jet ejectors. The net effect is increased power production through more efficient condensation and more available steam for the turbine.

The gas removal system was changed from a two-stage system to a three-stage system to better utilize the steam resource in conjunction with the new main condenser modification. This change involved the installation of all new steam jets and a new second inter condenser vessel. Metal structured packing are now installed in all inter and after condensers.

Another modification incorporated a steam-turbine driven gas compressor or turbine/compressor (TC) as the third stage in the gas removal system. This machine was designed and built by the Barber Nichols Company of Arvada, Colorado. It lowers auxiliary steam use even further and provides greater flexibility in meeting future noncondensible gas loads. Spent steam from this turbine section supplies the shaft steam seals on the power turbine. Excess spent steam is dumped into the after condenser. A bypass third stage steam jet air ejector is also installed as a back up for the TC when the TC is unavailable for service.

Although the TC system was installed at the same time as the ADCC system, it is a separately funded project. Participants include Pacific Gas and Electric Co., The Department of Energy, Barber Nichols, and UNOCAL Geothermal.

5) Model Development

A computer simulation model for the ADCC technology has been developed to evaluate the conceptual design and provide a predictive tool for determining performance improvement and effects on H_2S chemistry. The model for the geothermal system incorporates the computer code used for the OTEC thermal performance but is expanded to take account of the high amounts of noncondensable gas loading unique to geothermal units. Geothermal chemistry is included in the model, particularly H_2S partitioning in the condenser and the chemical reactions associated with H_2S abatement.

The model is configured to calculate each condensation section independent from the other. The program uses an iterative method to solve the equations for twenty three variables as a function of packed bed depth. Convergence is achieved by mass balance and charge neutrality. Once convergence is achieved, sixteen tables of data are output for each condenser. The data include gas and liquid temperatures, composition of liquid and gas streams, concentrations of all chemical species in both liquid and gas, and mass flow rates at any specified depth through the packing.

The input files for the model were based on existing plant operating data adjusted for the expected changes in the steam supply. The projected steam conditions used in the model are listed in Table 2. The overall steam flow to the unit is expected to be 1.32 million lbs/h. The incoming noncondensable loading is estimated to be 19,700 lbs/h with the composition listed in Table2.

Table 2. Projected steam composition

Steam Composition	
NC gas content, %(wt/wt)	1.5
Main steam H_2S content, mg/kg	740
NC gas composition, mole%	
hydrogen	17
nitrogen	1
methane	7
carbon dioxide	70
hydrogen sulfide	5

6) Model Results -Thermal

The model was used to size the new three stage gas removal system. The predicted vapor carry over reduction resulted in a substantial auxiliary steam reduction. The present auxiliary steam load of 130,000 lbs/h is expected to be reduced to 92,000 lbs/h using the three stage steam jet system and only 56,000 lbs/h when the Barber-Nichols TC is in service. The auxiliary steam savings will mean more steam can be diverted to the power turbine. The overall improvement in generation resulting from the ADCC modification and the new gas removal system is expected to be 4.5 MW. The ADCC modification will provide approximately 2 MW and the new gas removal system is expected to provide the remaining 2.5 MW of power savings.

Table 3. Auxiliary Steam Flow, Lb/H		
	Present System	NREL ADCC
First Stage Ejectors	77,000	26,000
Second Stage Ejector	N/A	16,500
Third Stage Ejector	48,000	44,200*
TC	N/A	13,000
Main Turbine Steam Seals	5,000	0**
Total (Aux steam flow)	130,000	55,500

*Not included in the total as this jet is expected to be only used as a back up to the TC

**Steam seals supplied from TC turbine exhaust

7) Model Results - Chemical

The NREL model predicts that a significant shift in the H_2S absorption occurs with the modified condenser design. The greatest amount of H_2S absorption is no longer expected in the main condenser but in the second inter condenser and the after condenser. This change in location has led to new strategies for H_2S abatement.

Comparison To TAPPI Model

H_2S partitioning results from the model were compared with present operating data and a previous H_2S equilibrium model used by PG&E known as the TAPPI program. The two models agree quite well as shown in Table 4. The difference between the NREL model and the TAPPI program is how the H_2S equilibrium is calculated. The NREL model calculates the amount of H_2S absorbed based on known mass transfer characteristics for the packing being used. The TAPPI program is based on overall equilibrium and for the mass balance calculates the condensate leaving the condenser to be in equilibrium with the gas entering. This means that the NREL model predicts less than 100% efficient H_2S absorption while the TAPPI program is more conservative.

Table 4. A Sample of Predicted H2S Partitioning Under Identical Conditions, %H_2S

NREL ADCC System Compared to TAPPI

	NREL Liquid	NREL Gas	TAPPI Liquid	TAPPI Gas
Inter condenser 1	2	98	1	99
Inter condenser 2*	2	98	1	99
After condenser*	4	96	2	98

* The calculations are based on a condensate pH of 6.5 in each condenser for comparative purpose and do not reflect the values expected during actual operation.

The TAPPI model was beneficial in evaluating the NREL model and in troubleshooting initial versions of the code. Initial results from the NREL model showed no influence of pH on H_2S partitioning. Both the TAPPI program and operating experience demonstrate a strong dependence of H_2S partitioning as a function of pH. It was found that the chemical reaction module of the NREL model was completing the H_2S reaction to sulfur based solely on equilibrium. This did not allow for the kinetics of the system to account for the presence of HS^- existing in equilibrium with H_2S, which is the primary mechanism that drives the pH dependence. The code was later modified and the present version shows appropriate pH effects.

Effect on Partitioning

The H_2S chemistry results from the NREL model led to the conclusion that a more effective approach to H_2S abatement could be achieved. The NREL model predicts that 95% of the incoming H_2S partitions into the noncondensable gas stream in the main condenser. Less than 48 lb/h of H_2S, which is less than the Unit 11 regulatory compliance value, is predicted to accumulate in the main condenser condensate. The majority of the H_2S that is absorbed occurs in the second inter condenser and the after condenser. These condensate streams will not be returned to the main condenser to take advantage of the lowered absorption of H_2S in the main condenser.

Inter and After Condenser Condensate Treatment

Alternative methods were evaluated for treating the dissolved H_2S in the condensate of the second inter condenser and after condenser. The three considered options were:

1) Closed system with direct condensate reinjection

2) Closed system with iron catalyst treatment

3) Reroute of condensate to the cooling tower basin.

If less than the regulatory compliance value of H_2S is absorbed in the main condenser, treatment of the main condenser condensate with iron chelate would not be necessary. Options 1&2 are attempts at accomplishing the combined condensate H_2S abatement without feeding iron chelate to the main circulating water. Options 3 requires iron chelate to be fed to theentire system.

As of now, Option 3 has been implemented. The combined condensate from the second inter condenser and the after condenser is piped to the far end of the cooling tower and discharged through a submerged header into the cooling tower basin. The H_2S in the condensate reacts with the iron chelate present in the circulating water. The circulating water saturated with oxygen which helps to drive the reaction chemistry towards completion. Piping the combined condensate to the end of the cooling tower increase the residence time by a factor of 10. The net effect is that the H_2S abatement can be accomplished with less iron because there is enough time for the iron to be used multiple times. Condensate reroute has been very successful at reducing iron requirements at other PG&E units equipped with surface condensers.

This implementation has several advantages: it can be accomplished with the lowest capital cost, it greatly reduces the demand for the highest priced chemical, and it is a conservative approach to modifying the H_2S abatement system. The blowdown from Unit 11 will still contain some iron chelate which is important because Unit 11 blowdown is currently being pumped to Unit 17 and is the source for iron chelate at that unit. Using this iron a "second" time at Unit 17 reduces Unit 17 iron costs substantially. This option is also conservative in the sense that should the main condenser absorb more H_2S than predicted, sufficient iron will be available to maintain H_2S emission in compliance.

8) High Temperature Protection

Several other features are also installed to protect the main condenser plastic structures from high temperatures. High temperatures can result if steam is entering the main condenser when there is not enough vacuum. This is a mainly a danger during unit start up and shut down. The protection features include:

1) An air operated main steam shut off valve (AOV): This 42" valve will close within 6 seconds. Compressed air is used instead of a motor driven actuator to ensure operation following a station black out.

2) Main condenser shell side temperature probes: An array of fast response probes monitor temperatures within the condenser. A "high temp" signal will start the existing turbine exhaust hood spray system. A "high high temp" signal will trip the new AOV closed.

3) Vacuum breaker time delay: The vacuum breaker valves will be delayed several seconds from opening following a unit trip. Main condenser cooling water flow will then continue long enough to ensure condensation of the steam trapped between the trip valves and the condenser.

9) Status to Date

All modifications are now complete at Unit 11. The Unit has been operated with both systems, namely, the turbo-compressor and back-up jets. For gross power levels of up to 55 MW, the back pressures in the main condenser are now lower than ever experienced at this Unit. At full load of 75 MW, with the T/C system on, the back pressure is once again lower than prior experience. However, at these higher power levels, for operation with jets alone, the after condenser experiences flow limiting problems, commonly termed, flooding. PG&E and NREL are working together to arrive at an acceptable solution to extend the capacity of this after condenser.

When this condenser's required capacity is realized, the main condenser back pressure is projected to be less than 3 in. Hg at full load, with wither the T/C or all jets. On account of this improvement, the heat rate for the Unit is projected to improve at least by 5 percent at full load.

Performance tests for the modifications will be scheduled and conducted upon completion of emission and power production tests. We expect these tests to occur within the next two months.

10) Acknowledgments

The authors would like to thank Ray LaSala, our DOE geothermal program manager, and Carl Paquin, R&D manager at PG&E for their continued support for this project. We also acknowledge the commitment of a group of coworkers who made the modeling, design, procurement, and installation possible.

Revised manuscript 3/20/97.

NCG TURBOCOMPRESSOR DEVELOPMENT PROGRAM

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ABSTRACT

Barber-Nichols, Pacific Gas and Electric and UNOCAL as an industry group applied for a DOE grant under the GTO to develop a new type of compressor that could be used to extract non-condensable gas (NCG) from the condensers of geothermal power plants. This grant (DE-FG07-951A13391) was awarded on September 20, 1995. The installation and startup of the turbocompressor at the PG&E Geysers Unit 11 is covered by this paper. The turbocompressor has operated several days at 17000rpm while the plant was producing 50 to 70 MW.

INTRODUCTION

The unit was designed, manufactured and tested by Barber-Nichols in their Arvada facility. The unit was then shipped to the PG&E Unit 11 Power Plant at the Geysers in September of 1996. Installation of the unit was delayed for a few months from the initial planned date because of power demands by the PG&E system. The plant shutdown was to allow for several other changes to the plant including installation of the NREL -PG&E condenser mods. These mods included a new improved non-condensable gas removal system with smaller steam jets for the first and second stages and incorporates the B-N Turbocompressor as the third and final stage of compression.

DESCRIPTION OF THE T-C

High performance NCG extraction can be achieved by using centrifugal compressors. Centrifugal compressors have higher efficiencies than ejectors or liquid ring pumps. The efficiency of the compressor can be as much as four times better than an ejector and about twice the efficiency of a liquid ring pump. If a turbine is used to drive the compressor the unit can operate at variable speed which provides a large range of operating pressure ratios and flow rates. The compressor itself has a nearly two to one flow range. Driving the compressor with a intregal steam turbine provides much increased flexibility compared to electric motor driven units plus the equipment is much smaller as it either eliminates a large speed increasing gearbox or a multiple stage compressor.

The design for the Barber-Nichols turbocompressor incorporates these features. The compressor is driven by a turbine mounted on the other end of the compressor shaft. The rotating assembly is supported on water lubricated bearings that allow a short compact sealing arrangement between the bearings and the overhung turbine and compressor. Figure 1 shows a sketch of the unit.

THE INSTALLATION AND STARTUP

The turbocompressor unit was supplied from Barber-Nichols mounted on an equipment skid that contained the bearing lubrication reservoir, pumps, filters, and control system. A picture of this assembly is shown in figure 2. Additional equipment supplied that is not assembled on the skid is a turbine run and speed control valve, a bypass recirculation control valve and an emergency lubrication supply tank that provides water to the bearings in the case of a black shutdown.

The unit was installed by PG&E personnel on the turbine deck at the Unit 11 Power Plant. A view of the installation is shown in figure 3. A schematic of the three stage hybrid gas removal system is shown in figure 4. A third stage steam jet is shown in this figure and was added because at one time it was thought that the turbocompressor may not be delivered in time and also since the turbocompressor is a new design the jet provides a backup. If problems were to develop with the turbocompressor it would not force an outage of the entire plant. The bypass line from the after- condenser to the compressor inlet is to provide increased flow to the compressor during start-up and other times when the non-condensable gas flow is at a low value. This occurs when the main turbine is not yet running but the main condenser must be pumped down and also when the plant is operating at a low power level.

The turbocompressor was first started on January 31, 1997 as the Unit 11 plant was being started after the shut down and plant mods were completed. Plant start up of a large geothermal plant after significant mods requires a few days and it was not planned to parallel the main turbine during the first runs of the turbocompressor. The vacuum system was operated and the turbocompressor operated at design speed of 16000rpm. The main turbine was then rolled at a low speed while the water distribution in the main condenser was evaluated. The turbocompressor operated well but did experience some surge conditions due to the low NCG flow rates. The bypass valve and piping did not provide sufficient recirculation flow to keep the compressor completely out of surge but it did not cause a problem because the surge effects were very soft. The compressor load would change which caused a speed change, as the main turbine flow was increased to bring this turbine to synchronous speed there was sufficient flow combined with the recirc flow to prevent surge. The unit was operated for two days, during this time the bearing water became contaminated with geothermal brine . It was felt this was the result of the turbine exhaust valve going shut inadvertently while attempting to adjust the back pressure. The turbocompressor turbine is operated at a back pressure of approximately 6 psig as this steam is used for the main turbine steam seals. This valve went shut several times while its automatic control was being set-up causing the turbine exhaust pressure to exceed 40 psig. This probably caused steam to flow past the seals and into the lube system. This contaminated water caused the 440C bearing journal sleeves to crack in a 24 hour period which occurred while the unit was shut down on Sunday 2/2/97.

The unit is presently being modified to incorporate bearing surfaces that should be resistant to the geothermal contaminants and we are also incorporating some modifications to the seals to prevent contamination by the geothermal steam. We anticipate that the unit will be back on line in 2-3 weeks.

The unit has operated several days at 17000 rpm while the plant was producing 50 to 70 MW. The vacuum system maintains lower condenser pressures when the turbocompressor is on line than with the backup steam jet. The PG&E operating personnel are enthusiastic about the unit and its operating characteristics. We consider these problems the kind that one runs into with a new design and we are confident that the proper fixes can be made to make this unit the reliable high performance machine it is intended . We treat these problems as being significant but we and confident that we will solve these problems quickly.

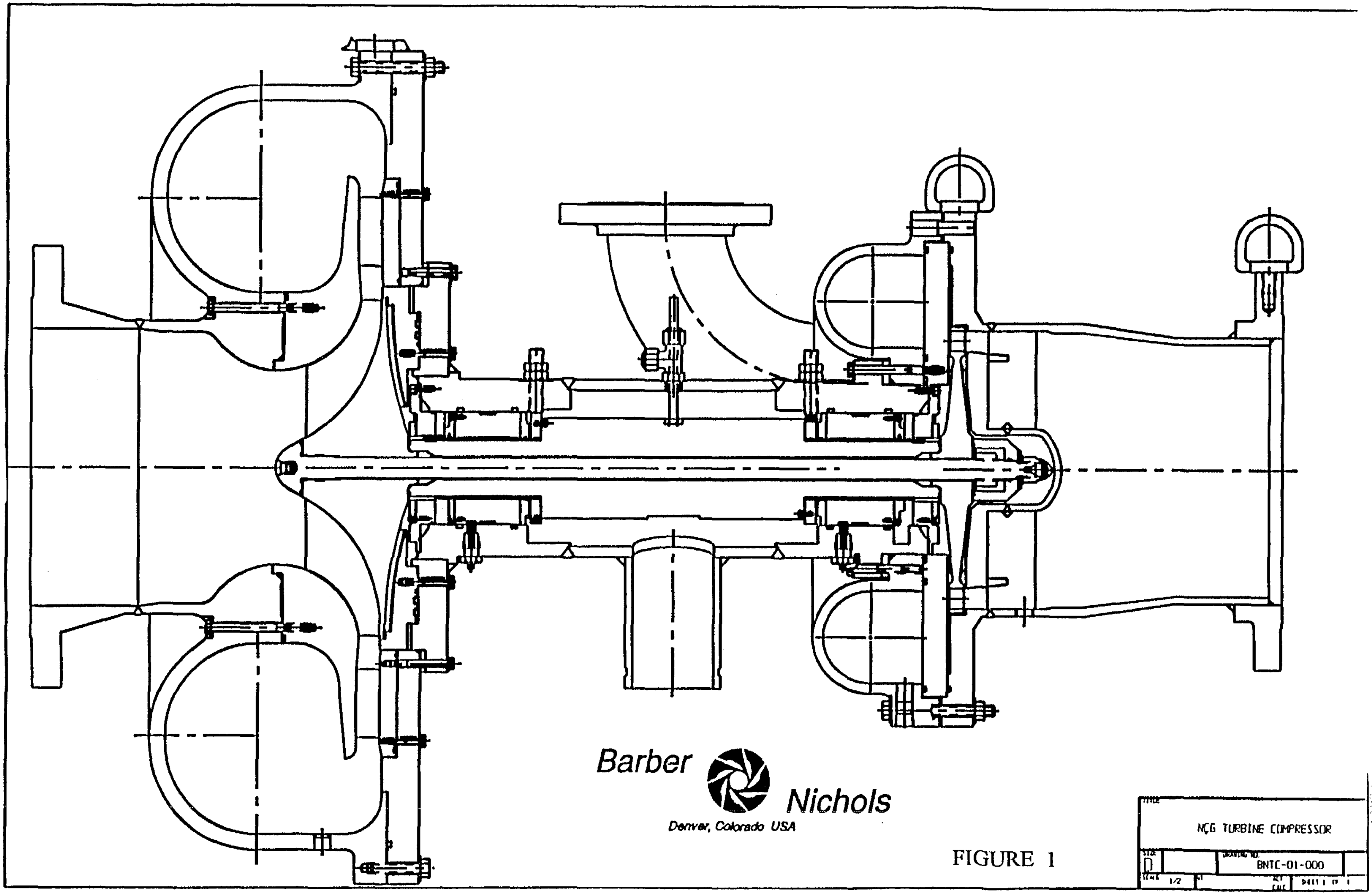
Barber Nichols
Denver, Colorado USA
NCG TURBINE COMPRESSOR
BNTC-01-000
1/2

FIGURE 1

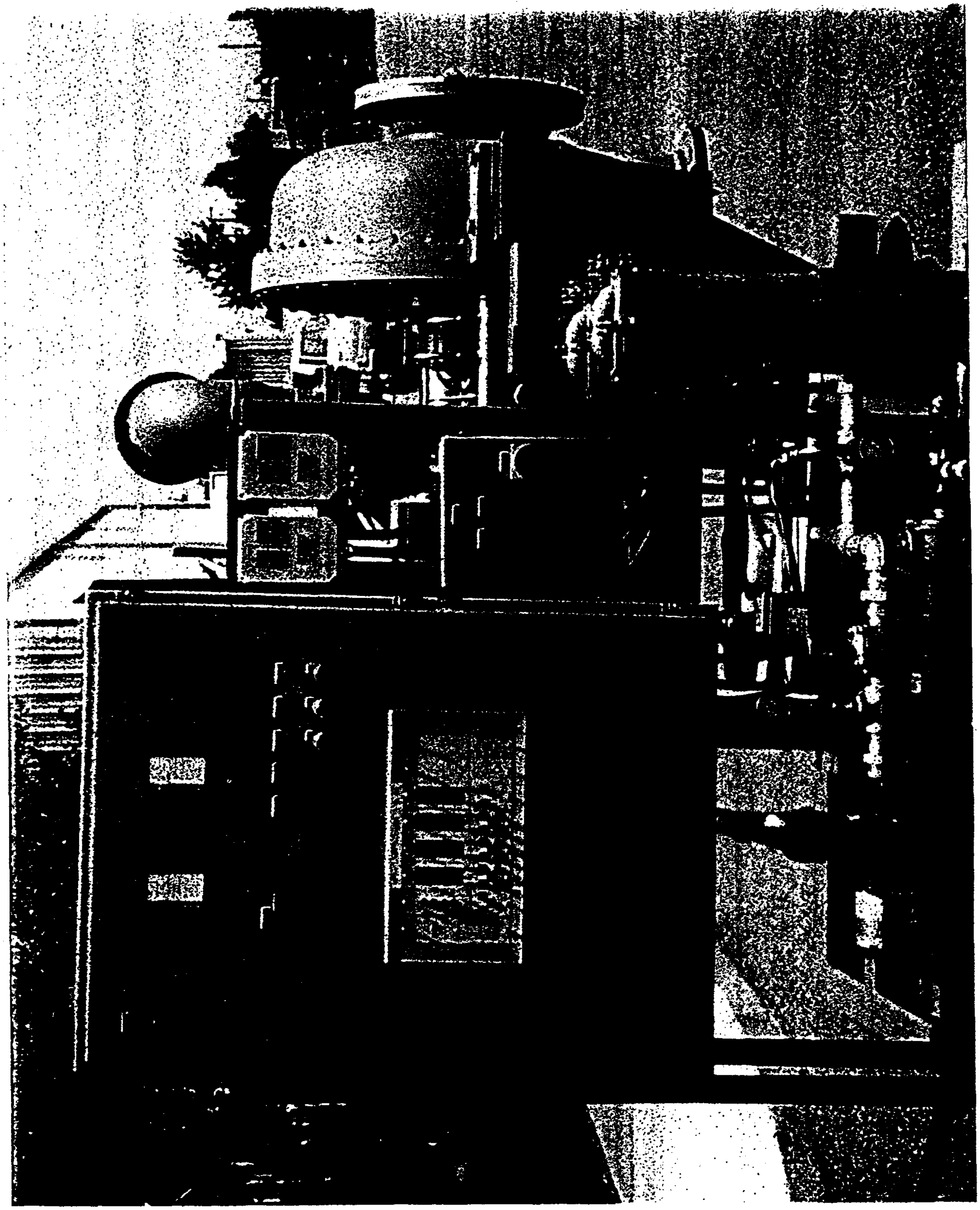

FIGURE 2

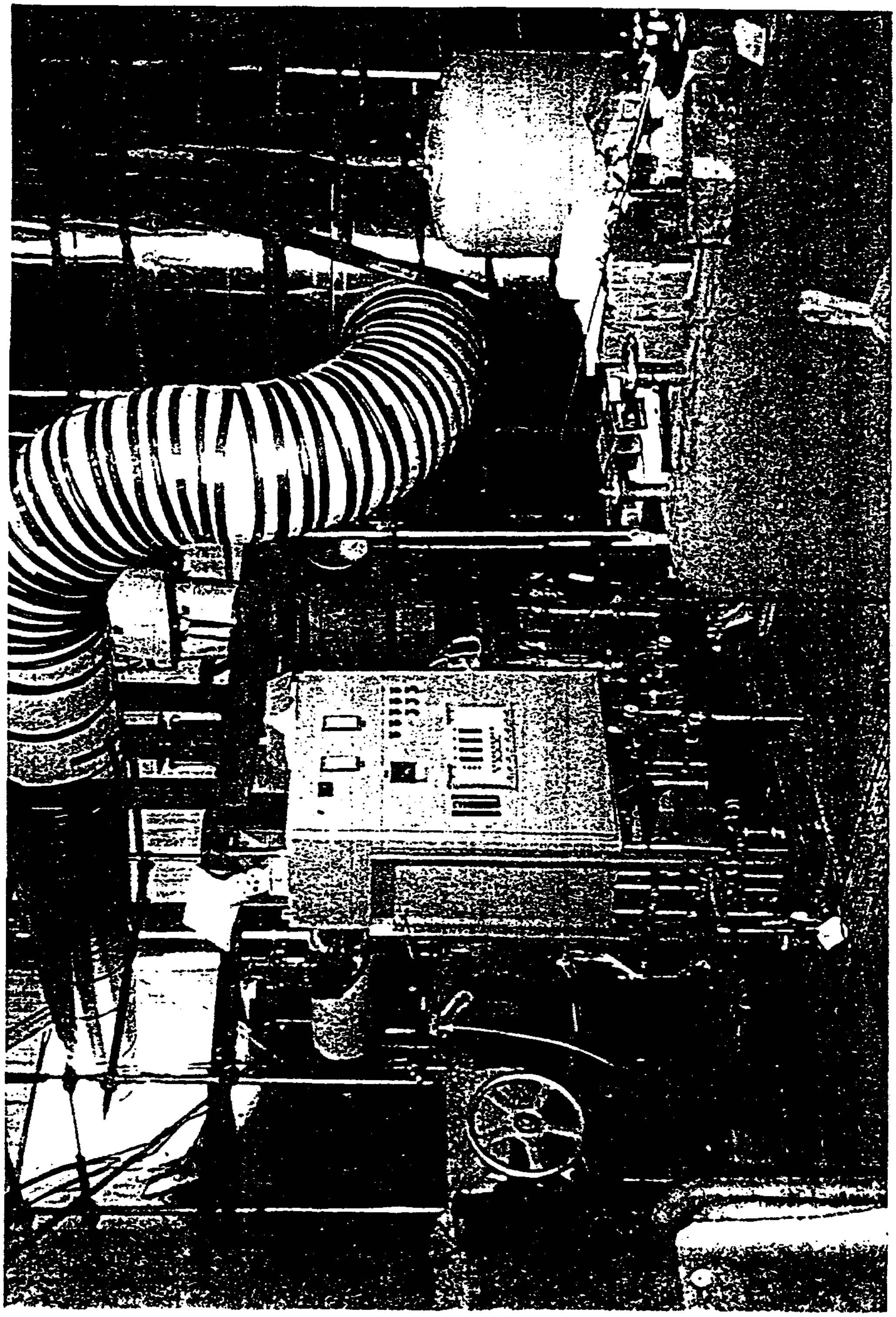

FIGURE 3

FLOW DIAGRAM

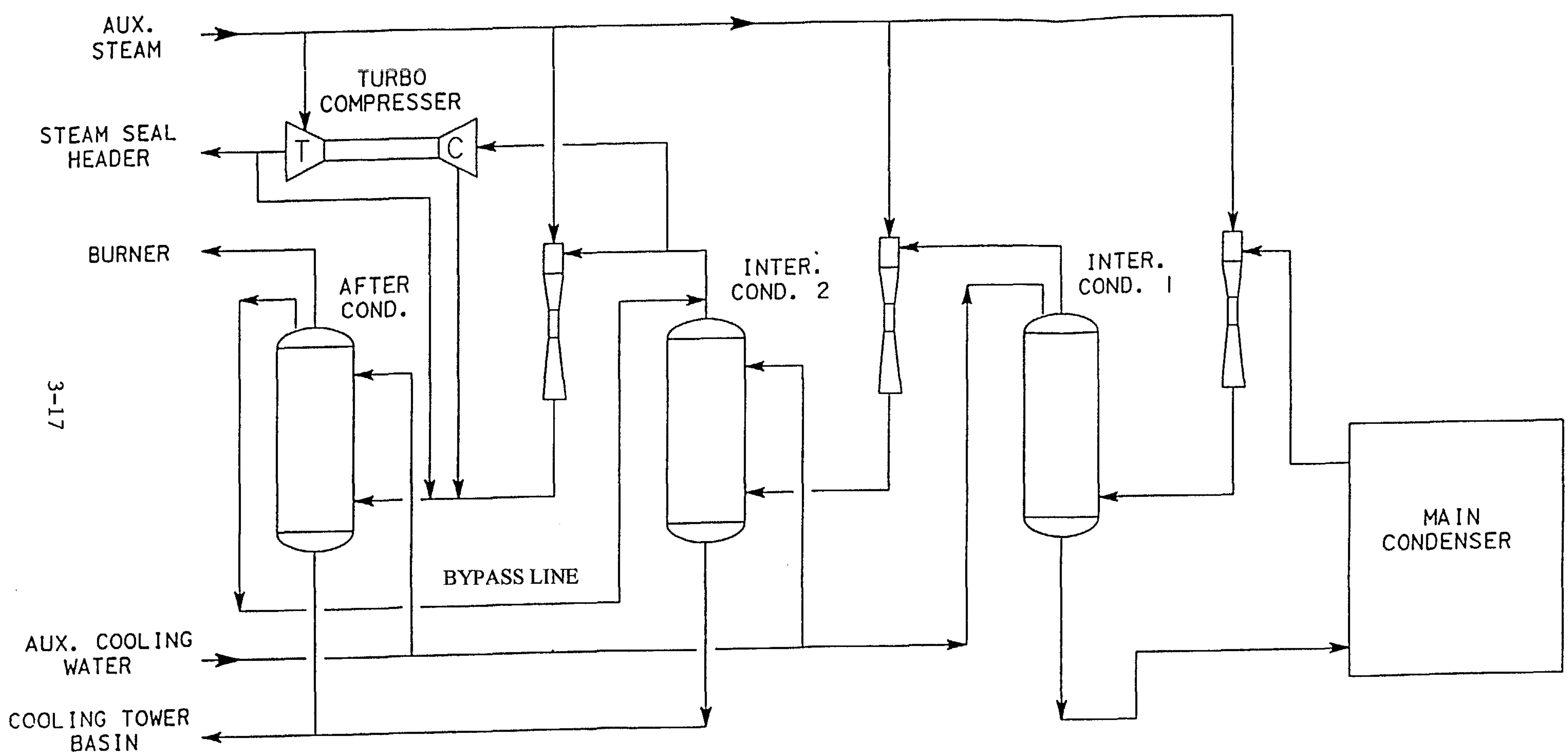

FIGURE 4

PROGRESS ON THE BIPHASE TURBINE AT CERRO PRIETO

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ABSTRACT

The status of a Biphase turbine power plant being installed at the Cerro Prieto geothermal field is presented. The major modules for the power plant are completed except for a back pressure steam turbine. The power plant will be started in April 1997 with the Biphase turbine alone followed by the addition of the steam turbine module two months later. The current power plant performance level is 2780 kWe due to a decline in the well. An increase in power output to 4060 kWe by adding the flow from another well is planned. The addition of five Biphase power plants with a total power output of 21.2 megawatts is described.

INTRODUCTION

Installation of a Biphase turbine power plant at the Cerro Prieto geothermal resource is nearing completion. The Biphase plant accepts high pressure steam and brine flow from a geothermal well, converts the two-phase pressure letdown energy to power, and provides steam at the pressure required by the existing steam turbines at Cerro Prieto.

The project, which was initiated by the U.S. Department of Energy (DOE), is jointly supported by DOE and the California Energy Commission (CEC) under the geothermal loan grant program. In addition, private support was provided by E&Co, an environmental organization, and Douglas Energy Company. Comisión Federal de Electricidad will purchase the power generated by the plant. The power revenue will be used to pay operation and maintenance expenses and to repay the CEC loan and E&Co loan.

Figure 1 is a schematic of the plant illustrating its operation. Brine and steam from the geothermal well enter the Biphase turbine. The mixture is expanded from 700 psia to 360 psia in a two-phase nozzle. The steam and brine are separated by the rotating separator.

The resulting high velocity steam flows through axial impulse blading generating power. The separated brine is slowed to the separator speed by frictional drag generating additional power.

The separated steam leaving the Biphase turbine flows to a back pressure steam turbine in which it is expanded to the required central plant pressure, 126 psia, generating additional power.

The steam leaving the back pressure steam turbine flows back to the existing separator and is subsequently routed to the existing central steam turbine. The separated brine flows to the existing separator and is subsequently routed for disposal.

A bypass line is provided, allowing the well flow to bypass the Biphase turbine power plant in the event of a trip or other shutdown. Uninterrupted well operation and steam supply to the central plant thereby results.

The power plant layout is shown in Figure 2. The Biphase turbine and back pressure steam turbine are mounted on separate skids, each with its own generator. The use of individual skids were required by the use of an existing steam turbine generator for the project. Future power plants will have the Biphase turbine and back pressure steam turbine mounted on a single skid with a common generator.

The plant controls and electrical switchgear are located in the module indicated. The control trailer is a temporary installation used for startup and monitoring. When other plants are installed and started this module will be moved.

POWER PLANT STATUS

The power plant consists of six major modules, five of which are complete.

Biphase Turbine Generator - The Biphase turbine generator skid is shown in Figures 3 and 4, ready for shipment to the site. The Biphase turbine and generator are rated at 1100 kW. All on skid piping, valves, instrumentation, electrical wiring, instrumentation wiring and conduit have been installed and checked. The unit will be set on its foundation March 25th.

Water Lubrication System - The completed water lubrication system is shown in Figure 5. This system provides water at 525 psia to lubricate the silicon carbide bearings of the Biphase turbine. The system has completed pressure tests and flow testing and will be set on its foundation on March 25th.

Transformer Skid - The main transformer provides step up of the Biphase turbine and steam turbine power from 2400 volts to 13,800 volts. The unit will be set on its foundation on March 25th.

Electrical and Control Module - The switchgear and controls for the Biphase turbine and the steam turbine are installed in the module. Installation, calibration of relays and electrical checkout have been completed. The electrical and control module will be installed on its foundation on April 3rd.

Office and Control Trailer - This unit has the startup quarters and control monitors installed and is ready for shipment. It will be installed on March 25th.

Steam Turbine Generator - The steam turbine generator skid is an existing radial inflow unit which is being refurbished for this project. Refurbishment of the electrical components and lube oil system have been completed. The gear and turbine rotors are being overhauled at the manufacturer and will be completed and reinstalled on the skid on April 21st.

The current plan is to complete the installation of the Biphase turbine generator during April. This part of the total plant will be started up and operated by itself.

The steam turbine will be installed during May while the Biphase turbine is being operated. During an inspection shutdown after 30 days of operation, interconnection of the steam turbine subsystem with the Biphase turbine subsystem will be completed and combined operation will occur in July.

CHANGE IN GEOTHERMAL WELL CHARACTERISTICS

During the two years elapsed since the start of the project, the characteristics of the project well 103 have changed significantly. Figure 6 shows the wellhead pressure, enthalpy, and flow rate versus time. The decline from the values in 1994 to the present result in less available energy for conversion.

At the start of the project, the available energy from the two-phase letdown was 6740 kW. Currently, the available energy is only 4790 kW.

The design output of the plant at the original well condition was 4180 kWe. The current well condition would give an output of 2780 kWe (with a modified steam turbine rotor).

In order to increase the power output to the full design capability, the flow from a nearby well will be piped to the Biphase power plant by CFE. The history of that well, E-15, is shown in Figure 7. Expansion from both wells to the Biphase turbine casing pressure will produce approximately 1000 ft/s two-phase velocity. Four of the eight nozzles will be used for well 103 and the other four for well E-15.

The total power from the two well flows with a new steam turbine rotor will be 4060kWe.

The current project plan is to install the Biphase turbine and steam turbine "as is" to demonstrate performance of the Biphase turbine and system operation while new nozzles and the new turbine rotor are fabricated and well E-15 piping is installed.

The plant will be shut down for installation of the new nozzles and rotor and interconnection with the piping from E-15. After startup the full 4060 kWe should be reached. The produced power and estimated schedule are shown in the table below:

Configuration	Well No.	Power kWe	Start Date
Biphase Turbine Alone	103	710	4/30/97
Biphase Turbine + Steam Turbine with Existing Rotor	103	1850	7/15/97
Biphase Turbine + Steam Turbine with Modified Rotor	103 +E-15	4060	11/15/97

20 MEGAWATT BIPHASE POWER PLANT

Comisión Federal de Electricidad has stated their intent to install additional Biphase power plants when the first unit is successfully demonstrated.[1] The optimal installation increment appears to be 20 megawatts. The wells at Cerro Prieto were surveyed and a 20 megawatt (nominal) power plant installation was designed. The installation uses 5 Biphase power plants and produces 21.2 megawatts from ten (10) wells.

Cost experience with the current project was used to determine the cost. The installed cost, including electrical transmission lines is estimated to be $11,046,000. The cost per kilowatt is therefore $523/kW. The effective steam rate is about 5 lb/kW.

The well survey indicated the potential for three additional 20 MW installations.

SUMMARY

Installation of the completed Biphase turbine power plant modules at Cerro Prieto Well 103 began on March 25th. Initial operation at 710 kW is planned for April 1997. Power will be increased to 1850 kW in July 1997 when the back pressure steam turbine is installed. Addition of flow from a nearby well, E-15, and installation of a modified steam turbine rotor will increase the power output to 4060 in November of 1997.

[1]Oropeza, Alejandro and Hays, Lance, "Small Biphase Wellhead Plant for the Cerro Prieto Mexico Geothermal Field", Geothermal Resources Council, 1996 Annual Meeting, Portland, Oregon, October 1996.

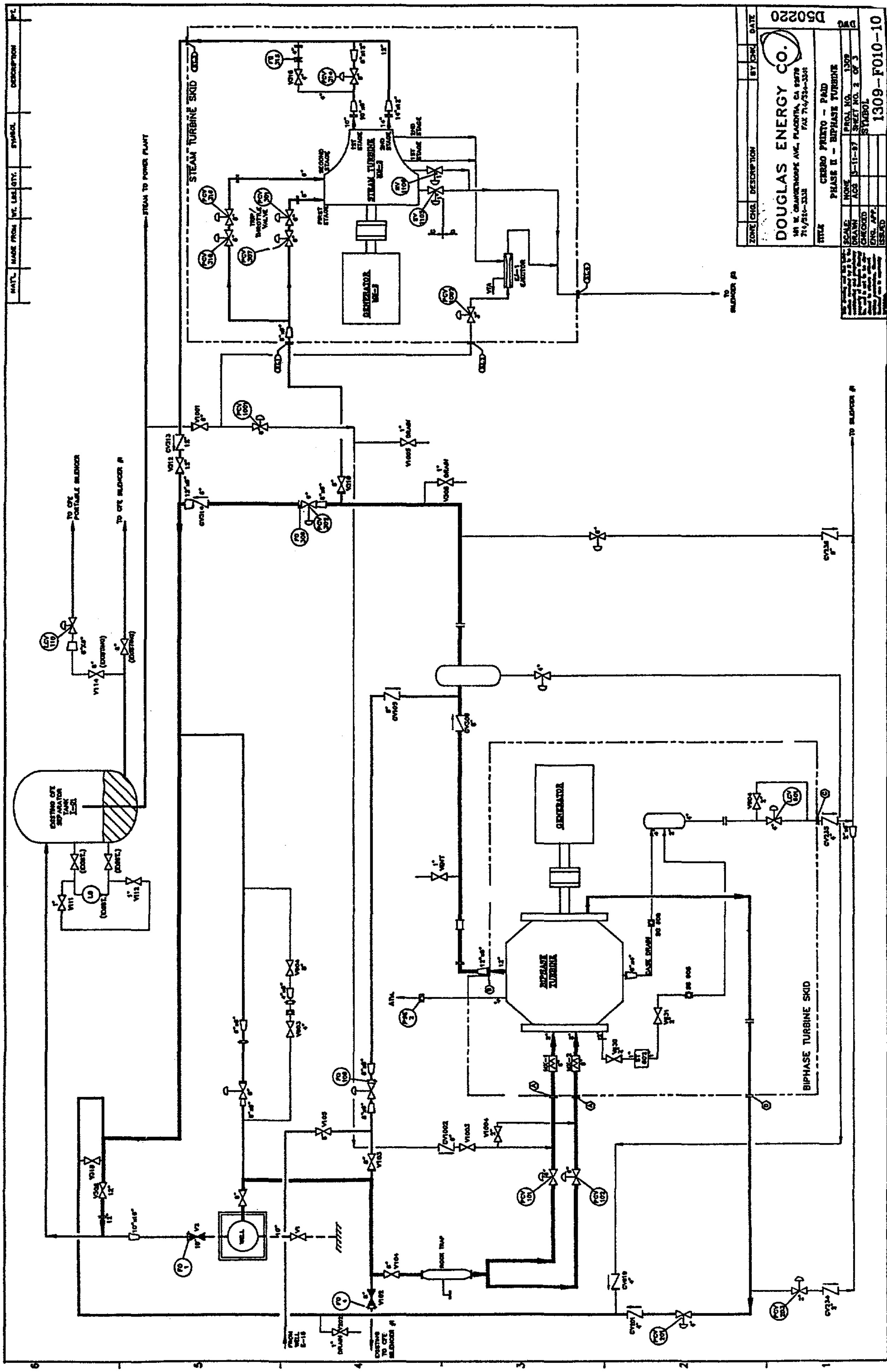

Figure 1. Schematic of Biphase Power Plant.

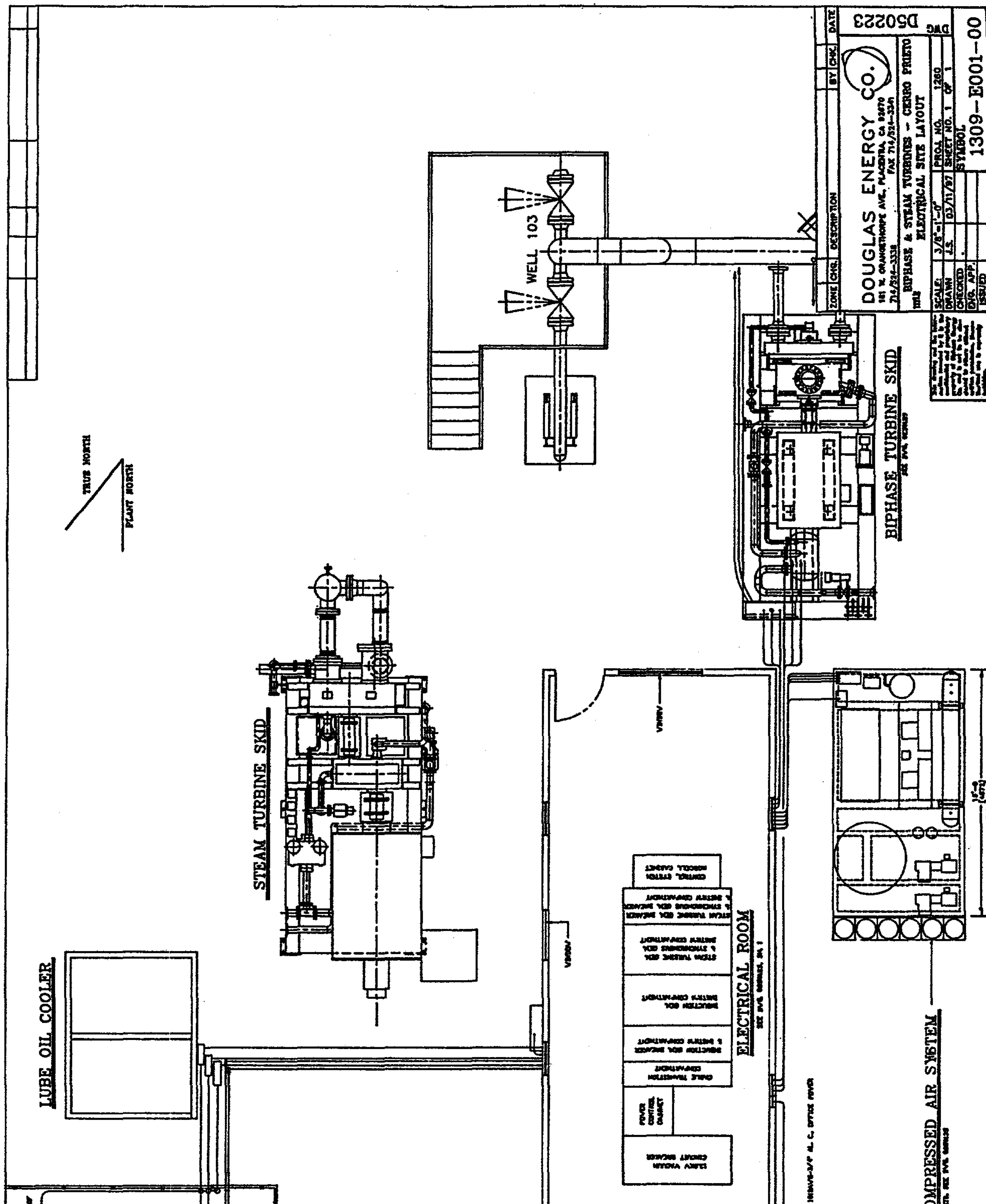

Figure 2. Layout of Biphase Power Plant.

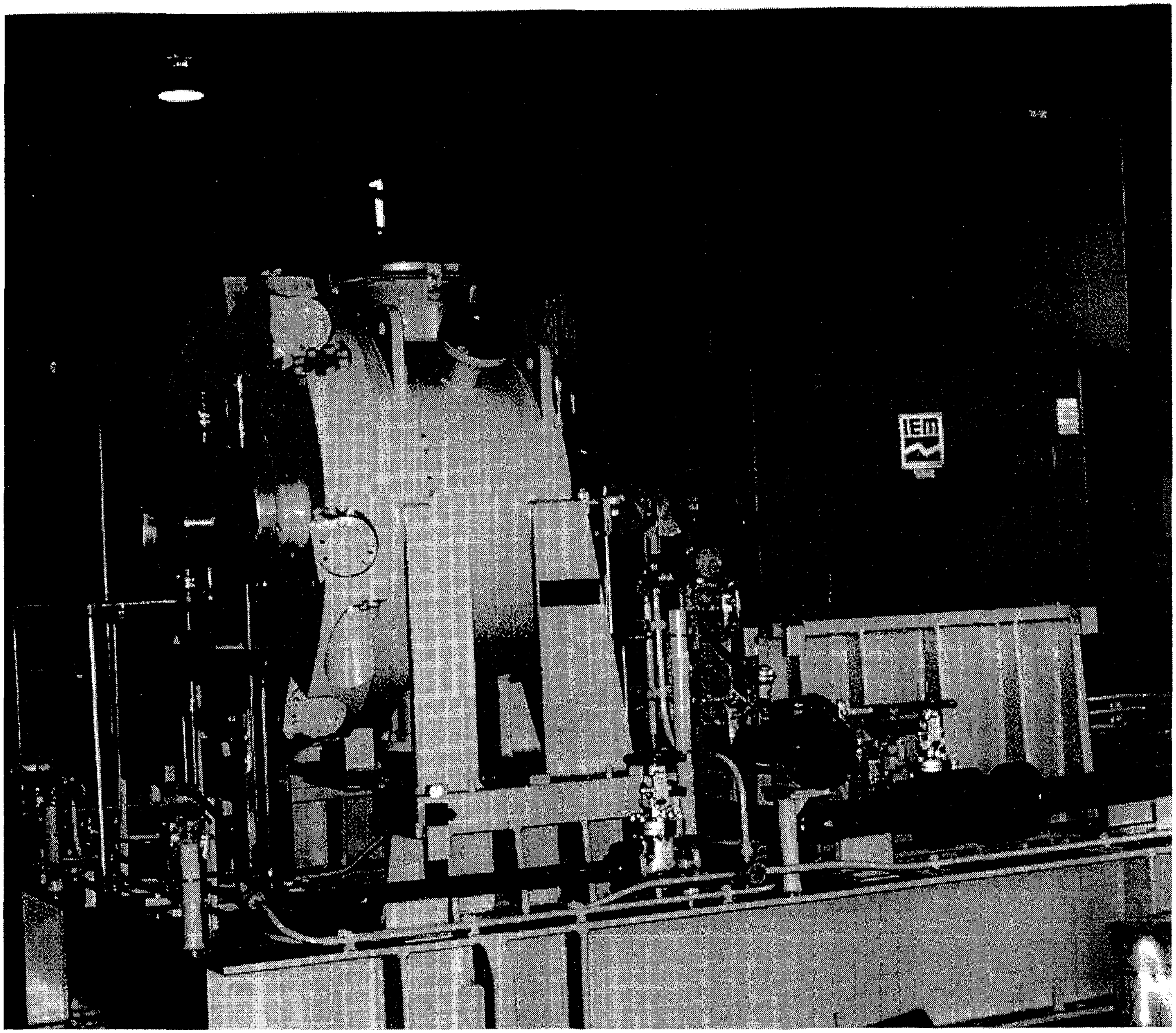

Figure 3. *Biphase Turbine Generator for Cerro Prieto*

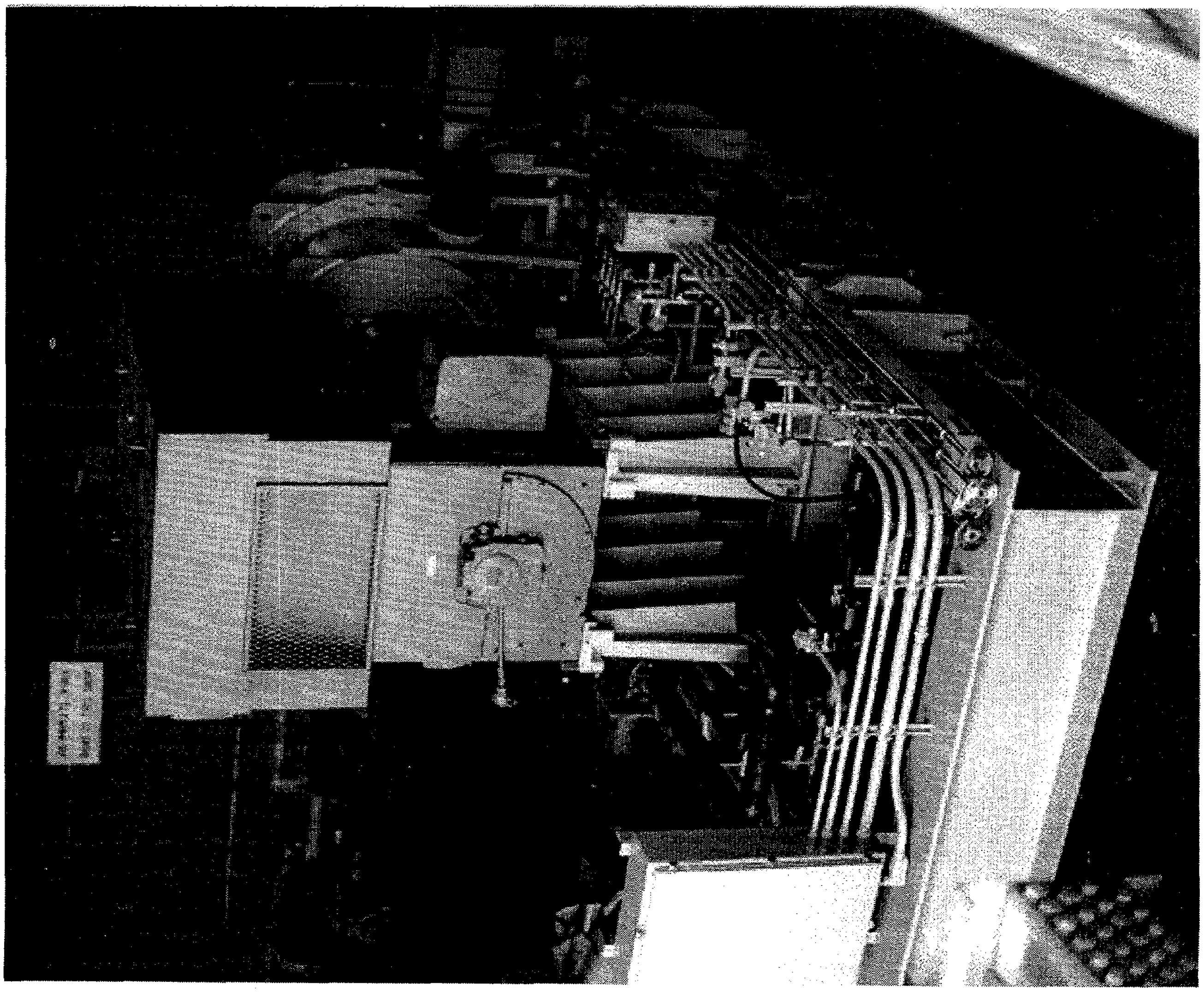

***Figure 4.** Biphase Turbine Generator Skid*

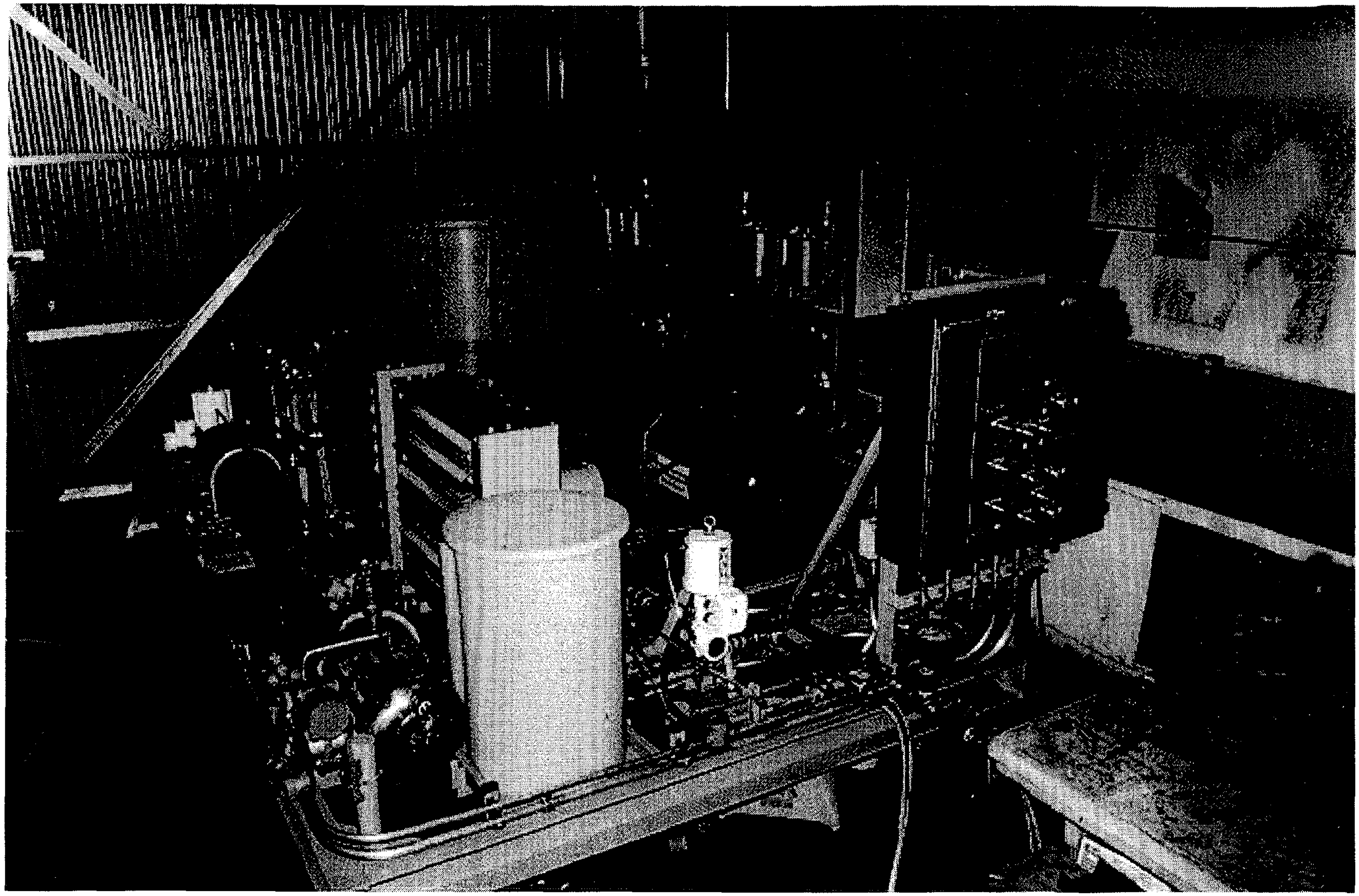

Figure 5. ***Water Lubrication System***

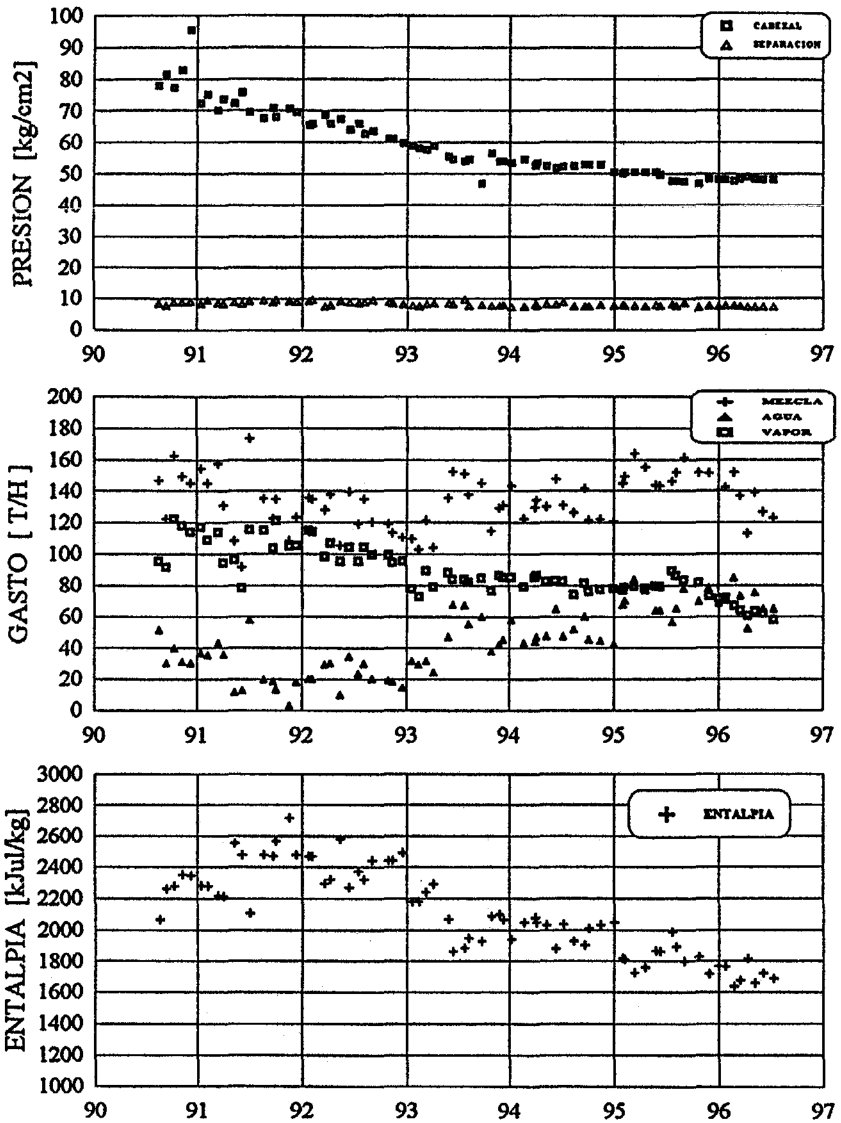

Figure 6. *Time Characteristics of Well Number 103. Pressure (presion), flowrate (gasto) and enthalpy (entalpia) by year.*

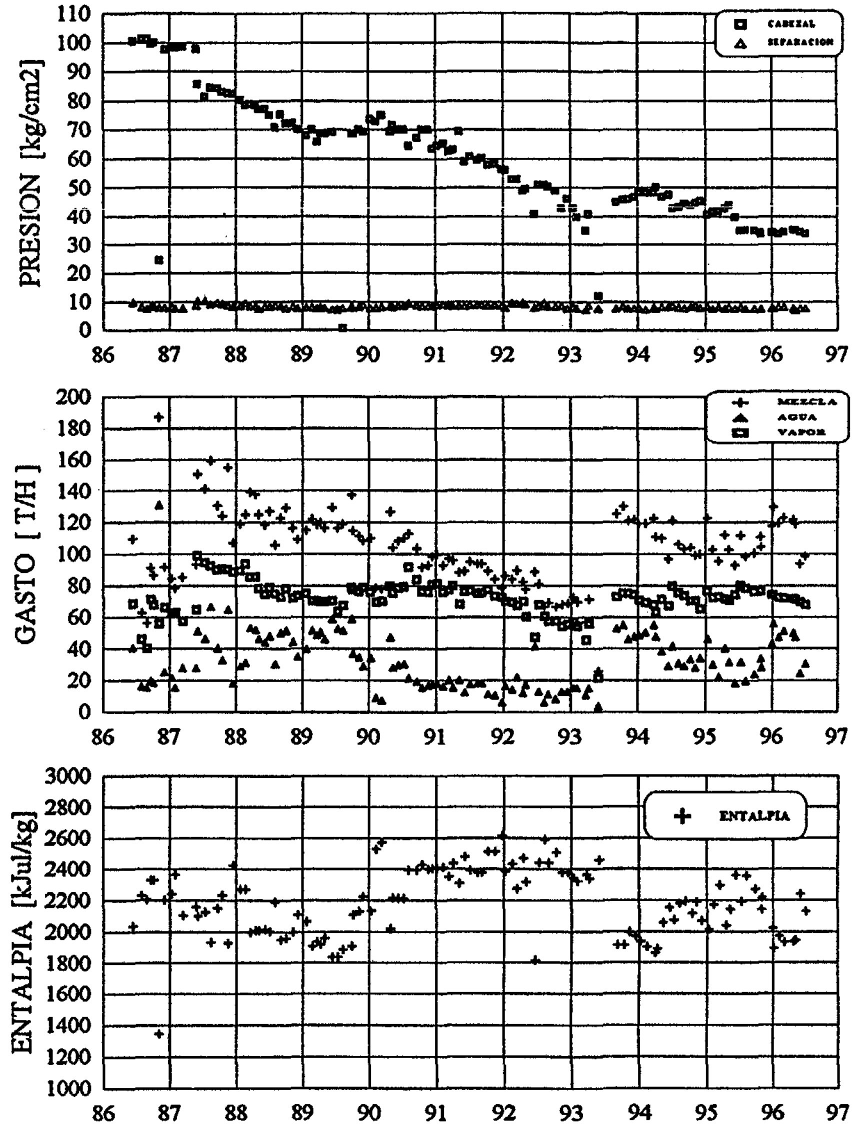

Figure 7. *Time Characteristics of Well Number E-15. Pressure (presion) flowrate (gasto) and enthalpy (entalpia) by year.*

MODELING AND ANALYSIS OF ADVANCED BINARY CYCLES

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ABSTRACT

A computer model (Cycle Analysis Simulation Tool, CAST) and a methodology have been developed to perform value analysis for small, low- to moderate-temperature binary geothermal power plants. The value analysis method allows for incremental changes in the levelized electricity cost (LEC) to be determined between a baseline plant and a modified plant. Thermodynamic cycle analyses and component sizing are carried out in the model followed by economic analysis which provides LEC results. The emphasis of the present work is on evaluating the effect of mixed working fluids instead of pure fluids on the LEC of a geothermal binary plant that uses a simple Organic Rankine Cycle. Four resources were studied spanning the range of 265°F to 375°F. A variety of isobutane and propane based mixtures, in addition to pure fluids, were used as working fluids. This study shows that the use of propane mixtures at a 265°F resource can reduce the LEC by 24% when compared to a base case value that utilizes commercial isobutane as its working fluid. The cost savings drop to 6% for a 375°F resource, where an isobutane mixture is favored. Supercritical cycles were found to have the lowest cost at all resources.

INTRODUCTION

An effective means to improve the performance of binary cycle power plants designed for low- to moderate-temperature, liquid dominated resources is to use mixed hydrocarbon working fluids rather than pure hydrocarbons. The value of using mixed working fluids, which typically consist of two main components and are termed *binary*, has been shown in earlier work by Demuth (1981). Demuth found that the most promising binary mixture for a 280°F temperature resource was a 90% propane and 10% isopentane mixture. The Next Generation Geothermal Power Plants (NGGPP) study (Brugman et al., 1996) also identified mixed working fluids as an attractive and low risk modification. Mixtures of non-adjacent components that have a mass fraction of the light component greater than 85% tend to be the most effective in increasing geofluid effectiveness and reducing the LEC of the plant. The performance increase is a result of the thermodynamic behavior of the binary mixtures. The mixed working fluids change phase in the boiling, for the case of a non-supercritical cycle, and condensing processes over a temperature range, rather than at a fixed temperature as for a pure fluid. This property of mixed working fluids has the effect of reducing irreversibilities in the cycle and improving plant performance (Bliem et al., 1988).

In this study, a computer simulation tool and economic analysis spreadsheet are used to find the optimum binary working fluid, based on the lowest LEC, for a 50 MWe plant with air cooled condensation situated at four typical resources. The performance results of this study are compared to the base case results that used a similar cycle with commercial isobutane as presented in the NGGPP study. The computer simulation tool and economic spreadsheet were initially written by Bliem (1995) and further developed and modified at the National Renewable Energy Laboratory (NREL). CE Holt Company provided the economic information used for the base cases in the NGGPP study and this data was used in the LEC calculations.

This paper presents the results and preliminary analysis. Much remains to be explored in the results and more thorough analysis will be presented in future papers.

General Approach

For each resource a variety of binary fluids were used to determine design cycle performance in terms of geofluid effectiveness, second law efficiency (the ratio of the net work extracted from the cycle to the availability of the geofluid based on its reinjection temperature limit, which, as the lowest temperature allowed for the geofluid, represents the state of lowest availability), and LEC. For each fluid studied at a resource the heater pressure, heater pinch point, and condenser bubble point temperature were varied until the plant with minimum LEC was found. The plants optimized with different working fluids were then compared to find the plant at the particular resource with the lowest overall LEC. This plant's performance was then compared to the base case plant using commercial isobutane to gauge the improvement possible with the optimum binary fluid.

The resource temperatures considered in this work were 265°F (similar to the Thermo Hot Springs resource in Utah which will be referred to as RE-1), 300°F (similar to the Raft River resource in Idaho, RE-2), 330°F (similar to the Vale resource in Oregon, RE-3), and 375°F(similar to the Surprise Valley resource in California, RE-4). Reinjection temperature limits for these resources were 66°F for RE-1, 98°F for RE-2, 125°F for RE-3, and 156°F for RE-4. These values were determined by Bliem from the information on the resources provided by EPRI in the NGGPP study. Actual conditions at the resources may be different from the information given in the NGGPP study. The resources may be considered to be typical low- to moderate- temperature, liquid dominated resources. The geofluid reinjection temperature was not allowed to go below the temperature limit in the cycle analyses. The geofluid reinjection temperature became a significant limitation for the two hottest resources. Design environmental air temperature was 50°F at all resources. CE Holt's design air temperatures ranged from 47°F to 51°F with an average of 49°F.

Cycle Analysis Software Tool (CAST)

The cycle analysis software tool (CAST) developed at NREL sizes plant components and estimates plant performance using established typical heat transfer coefficients in the heat exchangers and isentropic efficiencies of the turbine, gearbox, generator, and feed pump from the NGGPP study. The CAST program uses simplified methods that speed computation; for example, no frictional losses are considered in the plant piping. The simplified methods do not deliver large inaccuracies in the results—comparisons between the CAST program results and CE Holt's base case results show good agreement considering the simplifications. Since the program is used to provide comparative cycle performance results, the relative ranking of the plants with different fluids is valid.

In this work, the CAST program was modified to calculate the plant equipment sizes and plant performance over a range of heater pressures, heater pinch points, and condenser bubble point temperatures. The results were written to a text file that was then imported into the economic analysis spreadsheet. Heater pressures ranged from 200 psia to 630 psia for RE-1, RE-2, and RE-3. Heater pressures ranged from 200 psia to 850 psia for RE-4. The heater pressures were limited to 630 psia for resources RE-1 through RE-3 because the economic information from CE Holt was for plants at those three resources with pressures of 235 psia, 325 psia, and 610 psia, respectively. It was thought that the economic information for a 235 psia plant, in the case of RE-1, could be used up to approximately 600 psia without significant problems due to a change in rating of the high pressure fittings. For RE-4, the economic information was for 850 psia, so the cycle analysis was allowed to go up to that pressure. Heater pinch points ranged from 2°F to 14°F. Condenser bubble point temperatures ranged from 60°F to 150°F. The condenser pinch point was calculated using an NTU-effectiveness method given the inlet and outlet working fluid state points and entering air temperature. In all cases, the turbine expansion was outside the saturation dome. The turbine inlet state point was determined from the minimum entropy value required for a dry expansion to the condenser pressure.

The fluids studied were binary mixtures of propane and isopentane, and isobutane and hexane. These were identified in earlier studies as the most promising mixtures. The mass fraction concentration of the heavy component was allowed to vary from 2% to 15%. Pure propane, isobutane, and isopentane were also analyzed. Property information on the mixtures and pure fluids was obtained from the NIST14 database. The NIST14 source code was modified to generate the property data files required by the CAST program.

The economics spreadsheet used the value analysis technique developed by Demuth and Whitbeck (1982) and described by Bliem et al.(1996). This technique determines the incremental change in LEC due to changes in the component sizes and power production of a modified plant compared to a base case plant for which equipment sizes, flow rates, and costs are available. CE Holt provided the detailed equipment sizes, flow rates, and costs for their base cases in the NGGPP study. CE Holt used commercial grade isobutane, a mixture of approximately 96.6% isobutane, 1.8% n-butane, and 1.6% propane, in their base case cycles. This information was put into the economics spreadsheet. The economics spreadsheet determined the LEC for each case at a given heater pressure, heater pinch point, and condenser bubble point temperature. The plants were then ranked according to LEC and the lowest value found for each fluid. The values for each fluid were then ranked to determine the overall lowest LEC and best fluid for the resource.

RESULTS

Resource Temperature of 265°F (RE-1)

The geothermal resource at 265°F temperature (Thermo Hot Springs, RE-1) showed the greatest potential for LEC reduction. The base case plant used a heater pressure of 235 psia, heater pinch of 10°F, and condenser bubble point temperature of 83°F. The geofluid effectiveness was 2.44 W/$\dot{m}_{geo}$, second law efficiency, 23.3%, and LEC, 0.1022 \$/kWhr. The base case was first optimized which resulted in an LEC of 0.0828 \$/kWhr, 19% lower than the base case value. Note that both the base case and the optimized base case use commercial isobutane as working fluids. Then the CAST program was used to study the effect of a series of mixed working fluids on the LEC. The CAST study showed that the best mixed working fluid for this resource was 98% propane and 2% isopentane, which when used in a plant designed for it delivered a geofluid effectiveness of 3.62 W/$\dot{m}_{geo}$, second law efficiency of 34.6%, and LEC of 0.0776 \$/kWhr, a 24% reduction from the base case. This plant had a heater pressure of 620 psia, heater pinch of 6°F, and condenser bubble point of 80°F. The plant with the next higher LEC, 0.0778 \$/kWhr, used a mixture of 95% propane and 5% isopentane. The results for the LEC study are summarized in Figure 1. The mixtures are designated "M" followed by the light and heavy fluid names and the percentage composition of the heavy fluid. The optimized base case is designated by "Comm iC4." Propane mixtures have lower LECs than isobutane mixtures at this resource. All of the plants had a brine outlet temperature that was higher than the reinjection limit of 66°F.

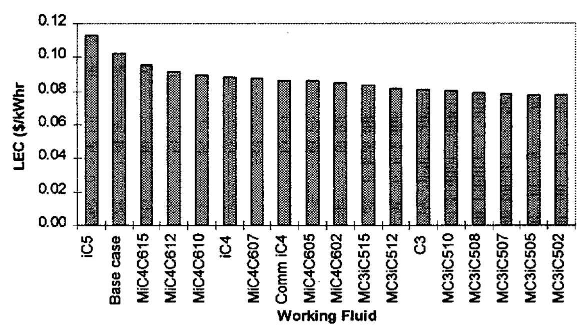

Figure 1. LEC results for RE-1.

The geofluid effectiveness results are shown in Figure 2 for a sampling of the working fluids studied. The fluids are arranged on the x-axis according to their LEC ranking. To illustrate one of the differences in performance between propane and isobutane mixtures, compare an isobutane mixture plant using 95% isobutane/5% hexane (MiC4C605) with the nearest plant, in terms of LEC, using a propane mixture. This plant uses 85% propane/15% isopentane (MC3iC515). The propane mixture has the lower LEC primarily because of the significant reduction in turbine size. The propane mixture plant has a turbine exit area of 2.11E-7 ft^2/lb of geofluid flow, but the isobutane mixture plant has a turbine exit area of 4.51E-7 ft^2/lb. Heat exchanger sizes are approximately the same for the two plants.

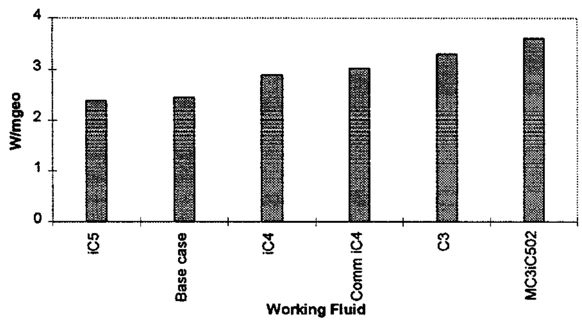

Figure 2. Effectiveness results for RE-1.

It is interesting to compare the performance of the best fluid to others to illustrate why that mixture is delivering the lowest LEC. First, compare the best fluid, 98% C3 / 2% iC5, to pure C3. There is a small component of heavy fluid in the mixture, but it is practically pure propane. In terms of cycle performance, there is greater geofluid effectiveness for the mixture because it is condensing at a slightly lower average temperature. The mixture's dew and bubble points in the condenser are at 84.5°F and 80.0°F, for an average temperature of approximately 82°F. The pure propane condenses at 84°F. The condenser pressure is also lower for the mixture than for the pure fluid: 142 psia vs. 152 psia. The lower condensing temperature and pressure increase the work output of the mixture cycle. Also, because the condenser pinch point temperature difference in the mixture cycle is about 0.5°F higher than for pure propane, the amount of cooling air flowrate is reduced, which reduces fan power requirements.

If a little bit of isopentane makes such an improvement, what happens when the fraction of isopentane is increased? The pure propane and best propane mixture allow the cycle to operate under supercritical conditions. The addition of more isopentane causes the cycle to become subcritical at the maximum pressure allowed, 620 psia. This is the case for 88% C3 / 12% iC5, which has a heater pressure of 560 psia for the cycle with lowest LEC. The subcritical cycle has significantly lower geofluid utilization. Also, as the percentage of isopentane increases, the heat transfer coefficient in the tubes of the condenser decreases, thus increasing the size of the condenser. The tube-side heat transfer coefficient for the 88% C3 mixture condenser is 34% lower than the 98% C3 mixture condenser.

It is also useful to compare the best propane mixture to the base case results. The performance increase is due to two effects. The first is that the propane mixture plant operates with a supercritical cycle, whereas the base case cycle is subcritical. The supercritical cycle operates with lower irreversibilities in the heater because the heating process has a lower average temperature difference. Secondly, the non-isothermal condensation behavior of mixtures reduces irreversibilities in the condenser. Commercial iC4 behaves similarly to pure iC4 in that is has a practically constant condensing temperature. Its temperature difference between bubble and dew points in the condenser is low—only 1.2°F. However, the best propane mixture shows strong non-isothermal behavior during condensation with a 4.5°F temperature difference between bubble and dew points. This behavior in the condenser increases the plant's performance in the same way as for the heater. When the economic analysis is done for these two cycles, one finds that even though the condenser and heater are smaller for the base case cycle, that cycle does not deliver a lower LEC because of its much lower power output.

Resource Temperature of 300°F (RE-2)

The 300°F resource (Raft River, RE-2) also showed significant potential for LEC reduction. The base case plant had a heater pressure of 325°F, heater pinch of 10°F, and condenser bubble point temperature of 87°F. Its second law efficiency was 30.6%, geofluid effectiveness, 4.04

$W/\dot{m}_{geo}$, and LEC, 0.079 \$/kWhr. The results from the CAST program showed that the plant with the lowest LEC used a mixture of 93% propane/7% isopentane. This plant used a heater pressure of 620 psia, heater pinch of 12°F, and condenser bubble point temperature of 82°F. Its second law efficiency was 39.1%, geofluid effectiveness was 5.17 $W/\dot{m}_{geo}$, and LEC was 0.0700 \$/kWhr, 11% lower than the base case. The LEC results are shown in Figure 3 for a sample of the fluids studied. All of the plants had a brine outlet temperature above the reinjection limit of 98°F.

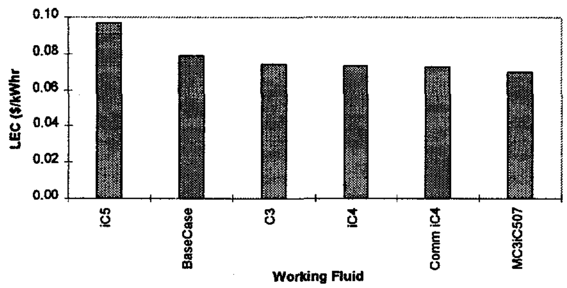

Figure 3. LEC results for RE-2.

The geofluid effectiveness results are shown in Figure 4.

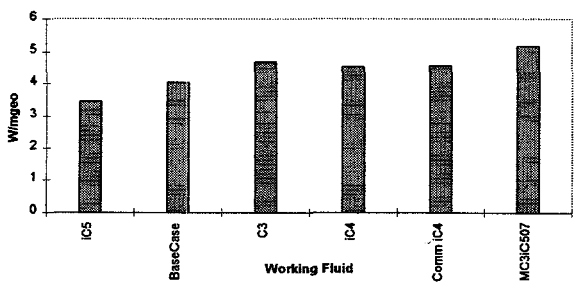

Figure 4. Effectiveness results for RE-2.

Resource Temperature of 330°F (RE-3)

The results from the CAST program showed that if the CE Holt base case plant is optimized, the LEC is reduced from the base case value of 0.0677 \$/kWhr to 0.0637 \$/kWhr, a 6% reduction. No other fluid had a lower LEC than commercial isobutane. Figure 5 shows a sampling of the working fluids studied. The commercial isobutane plant (optimized base case) delivers a lower LEC than the base case because of its higher effectiveness. Optimizing the base case by lowering the heater pressure from 610 psia to 560 psia lowers the working fluid specific enthalpy difference through the turbine by 1.6%, but the working fluid flowrate can be increased 8% (because the turbine inlet temperature is lower by 6°F with the 50 psia drop in pressure, the working fluid flowrate can be increased), resulting in increased gross turbine power and higher geofluid effectiveness. The parasitic losses in the pump and condenser fan power differ for the two cases, but the differences are small enough not to have a significant impact on the net power. The heat exchangers are slightly larger for the optimized base case cycle, but this does not end up affecting the LEC significantly. Also, all of the plants that used pure propane or a propane mixture had brine outlet temperatures that were limited by the reinjection temperature limit of 125°F. All of the plants that used pure or commercial grade isobutane or isobutane mixtures had brine outlet temperatures that were above the reinjection limit.

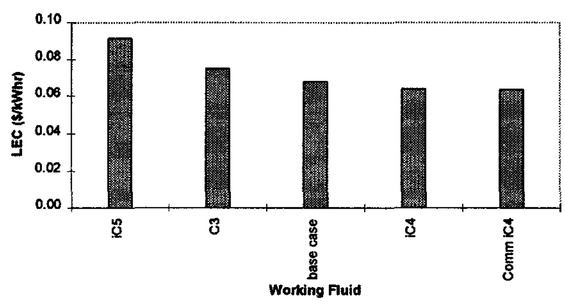

Figure 5. LEC results for RE-3.

The geofluid effectiveness values are shown in Figure 6. The base case value is 6.0 Whr/lb and the optimized base case is at 6.6 Whr/lb.

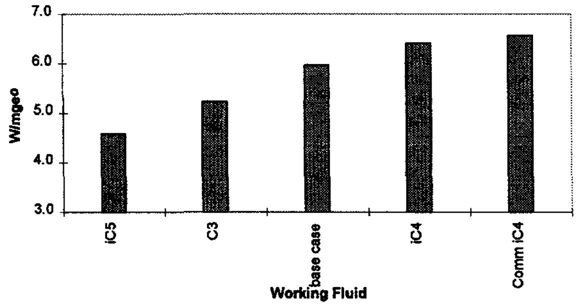

Figure 6. Effectiveness results at RE-3.

Resource Temperature of 375° F (RE-4)

The CAST program results showed that a plant using a mixture of 93% isobutane / 7% hexane had an LEC of 0.0597 $/kWhr, 6% less than the CE Holt base case value of 0.0633 $/kWhr. The LEC results are shown in Figure 7 for some of the fluids studied. The base case and the optimized plant using the isobutane mixture both used a heater pressure of 850 psia. A geofluid outlet temperature limit of 156°F was imposed on the optimization studies, even though the base case had a brine outlet temperature of 150°F, and most of the plants in this study had brine outlet temperatures that were limited by the reinjection temperature limit. Bliem performed a study of the EPRI-supplied resource conditions and determined that 156°F was a more suitable temperature limit. It should be noted that if the reinjection temperature limit is allowed to be 150°F, the LEC for the plant that used the 93% isobutane / 7% hexane mixture became 0.0590 $/kWhr, 7% lower than the base case. The best case from this study has a higher geofluid effectiveness and higher efficiency than the base case even with the limitation to a reinjection temperature of 156°F. The reduction in cost is due to higher net work output from this cycle and somewhat to savings in equipment cost. The heat exchanger area in the heater/vaporizer unit is about half the size of the base case unit. There are also savings in turbine cost: the best case has a turbine 18% smaller than the base case unit. The air-cooled condenser area is about 20% higher for the best case versus the base case, but the savings in the other components more than offset its higher cost.

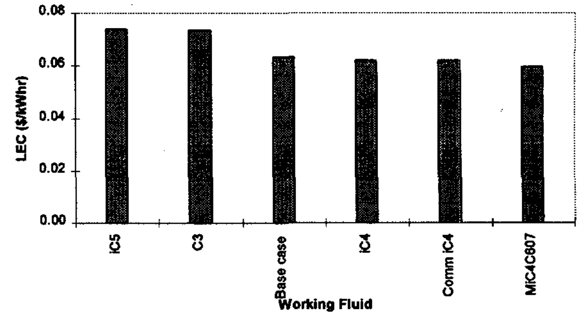

Figure 7. LEC results for RE-4.

The geofluid effectiveness results are shown in Figure 8. The effectiveness for the base case is 8.49 Whr/lb and that for the best fluid is 8.66 Whr/lb.

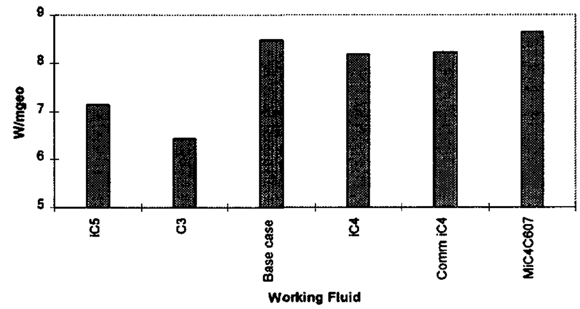

Figure 8. Effectiveness results for RE-4.

Discussion

Two observations may be made about the results for the economically optimum working fluids. First, supercritical cycles are demonstraed to have lower LECs. This is shown in the results for RE-1 and RE-2. For both RE-1 and RE-2, the best fluid is a propane mixture with heating at 620 psia, which is above the critical pressure of propane. The use of propane allows supercritical cycles at these resource temperatures.

The second observation is that when all cycles are supercritical, isobutane mixtures tend to deliver lower LECs. The RE-3 resource is hot enough to allow supercritical cycles for the isobutane mixtures in addition to the propane mixtures. The best fluid at this resource is commercial isobutane at a heater pressure of 560 psia, and with an LEC 5.9% lower than the base case value. In comparison, the plants that used propane mixtures had LECs higher than the base case. The plants that used propane mixtures usually have turbines about half the size of the isobutane mixture turbines, and the heaters are somewhat smaller, but the condensers are larger. The increase in condenser area leads to higher parasitic loads in addition to capital cost. The condensers are generally larger because the propane mixture flowrates are greater, leading to higher heat rejection loads. Also, at some resource temperatures, the plants that use isobutane mixtures are often not constrained by the geofluid reinjection temperature limit, but the plants that use propane mixtures are.

At higher temperature resources, such as RE-4, where most fluids are limited by the geofluid reinjection temperature, the plants that use isobutane mixtures have lower LECs primarily because of higher effectiveness and efficiency values than the plants that use propane mixtures. The best fluid at this resource is 93% isobutane / 7% hexane, and the best propane mixture is 88% propane / 12% isopentane. The turbine in the propane mixture plant is less than half the size of the unit in the isobutane mixture plant, and the heater is 23% smaller. The condensers are about the same size. But the isobutane mixture plant's effectiveness and efficiency are 21% higher than the propane mixture plant's values and the increased plant performance has a greater effect on reducing LEC than the savings in two component sizes.

The LECs for the best plant and base case at each resource temperature are shown in Figure 9. Also shown are the LECs of three mixtures at each resource temperature. The figure shows that the highest potential for LEC reduction is at the lowest resource temperature. The propane mixture plant performs well at the lowest temperature, but poorly at higher temperatures. The 93% isobutane / 7% hexane plant has a low LEC at the highest resource temperature, but performs worse than the propane mixture and commercial isobutane plants at low temperatures. The commercial isobutane line shows the potential for LEC reduction when the base case, which used this fluid, is optimized for each resource.

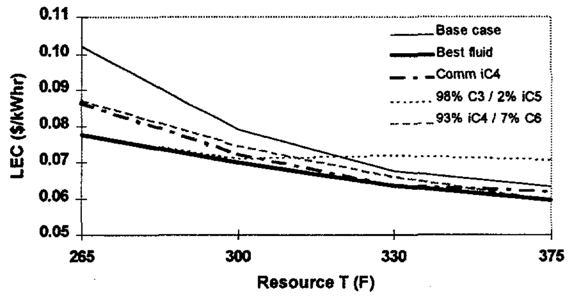

Figure 9. LEC results summary for all resources.

CONCLUSIONS

Significant savings in the cost of power production can be achieved if hydrocarbon mixtures are used in binary plants at low- to moderate-temperature geothermal resources. The amount of cost reduction increases with decrease in resource temperature. At the 265°F resource, the reduction in LEC from the base case is 24% when a propane mixture is used. At the high temperature resources studied, the amount of LEC reduction is diminished. For the 375°F temperature resource the LEC reduction was 6% when an isobutane mixture was used. Propane mixtures are favored at the low end of the range of resources studies, and isobutane mixtures at the high end. Also, the study found that the optimum fluids for a resource tend to be those that have a supercritical cycle.

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GEOTHERMAL MATERIALS DEVELOPMENT

AT BROOKHAVEN NATIONAL LABORATORY

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ABSTRACT

As part of the DOE/OGT response to recommendations and priorities established by industrial review of their overall R&D program, the Geothermal Materials Program at Brookhaven National Laboratory (BNL) is focusing on topics that can reduce O&M costs and increase competitiveness in foreign and domestic markets. Corrosion and scale control, well completion materials, and lost circulation control have high priorities. The first two topics are included in FY 1997 BNL activities, but work on lost circulation materials is constrained by budgetary limitations.

The R&D, most of which is performed as cost-shared efforts with U.S. geothermal firms, is rapidly moving into field testing phases. FY 1996 and 1997 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. In addition, plans for work that commenced in March 1997 on thermally conductive cementitious grouting materials for use with geothermal heat pumps (GHP), are discussed.

INTRODUCTION

The commercial availability of improved and cost effective materials will significantly enhance the ability of DOE/OGT to meet their announced goals of improving the efficiency of geothermal energy conversion 10 to 20% and reducing drilling and completion costs by 30%. The importance of materials R&D to the geothermal industry was detailed in a study of R&D priorities published in 1994.[1] A panel consisting of representatives from geothermal developers, utilities, consulting firms and contractors assigned a very high priority to corrosion and scaling control. Well completion and lost-circulation control also received high priorities, but at levels below corrosion and scaling. Materials needs exist for specific components such as downhole drill motors, pumps, casing, packers, blow-out preventors, drillpipe protectors, rotating head seals, and heat exchangers. As a result of the small and uncertain geothermal market, industry generally will not develop the special materials required for these critical components on its own. In particular, improvements in lost circulation control, lightweight carbon dioxide resistant well-completion materials, downhole drill motors, and methods for bonding high temperature elastomers to metals for use in drilling components will significantly reduce well costs.

These industrial priorities are being addressed in the Geothermal Materials Development Project. The work consists of laboratory-scale and field testing efforts, the latter performed as cost-shared activities with industry and other national laboratories.

To date, this cooperative R&D effort has resulted in many materials advances that are now used commercially by the geothermal industry. The most significant has been in high temperature elastomers. Developed under OGT sponsorship by L'Garde, Inc., the Y-267 elastomer can be classified as a technology breakthrough[2]. Three major U.S. seal manufacturers acquired the technology from the DOE, and molded parts are now commercially available from many firms. The elastomers are widely used in well logging tools, packers, valves, and other equipment. OGT-sporsored work has also been performed to modify Y-267 EPDM to enhance its performance in drillpipe protectors, rotating head seals, and blow-out preventors, and these results were utilized in the Geothermal Drilling Organization (GDO) programs on these components.[3]

Another successful materials advance was the development of high-temperature polymer concrete formulations.[4] These materials are now available for use as corrosion resistant linings at temperatures up to 260°C. This development served as the basis for ongoing work on thermally conductive composites, the results from which show promise for use as low cost corrosion and scale-resistant liners for heat exchange applications.

Cements represent another area where considerable progress has been made. The results from this effort currently serve as the basis for the selection of cements used for geothermal well completions throughout the world.[5] This work also served to elucidate reaction pathways that are now leading to the successful development of lightweight CO_2-resistant cements.[6] Field testing of these advance materials is expected to commence in the Summer of 1997.

Handbooks published in 1981 and 1983 that summarized the performance of materials in geothermal environments were widely used outputs from the program.[7,8]

In FY 1996, the Geothermal Materials Program consisted of four activities that are all continuing in FY 1997. 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. In addition, a new activity which focuses on reducing the first cost and improving the efficiency of geothermal heat pumps (GHP) by the development of thermally conductive grouting materials for coupling the heat exchangers in GHPs to the surrounding soil, was started in FY 1997. Descriptions and summaries of the results from each of these activities are given below.

RESULTS

1. Advanced, CO_2-Resistant, Lightweight Cements

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

A recently encountered problem that is severely reducing 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.[9] In the first case, 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 potential corrosion on the outside surface 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 the current cement research activity. Design criteria established by industry and ranked in order of importance are as follows:

1) compatible with conventional field placement technologies, 2) carbonation rate <5% after 1 yr in brine at 300°C containing 500 ppm CO_2, 3) compressive strength >5 MPa at 24 hr age, and 4) slurry density $\leq$1.2g/cc. Other important characteristics needed are: 1) life expectancy 20 yr, 2) pumpability of ~4 hr at >100°C, 3) bond strength to steel >70KPa, and 4) H_2O permeability <0.1 m Darcy.

The commercial availability of a well cement that meets the established design criteria will decrease the cost of well completions due to reductions in lost circulation control episodes, increase the life expectancy of wells, and reduce environmental concerns regarding blow-outs. It will also permit development of higher temperature, higher CO_2 content brine resources that are not currently exploitable due to cement deterioration concerns.

Halliburton Services and the Unocal Corporation participate in this Task with BNL on a cost-shared basis. The former identifies retarders for the BNL-developed cements, performs engineering-scale placement tests, makes economic evaluations, and performs mechanical, physical and chemical characterizations to verify that BNL derived data are reproducible. Unocal also conducts validation tests and will provide the well and ancillary equipment for field testing.

Approach

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

Phase 1 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 the most promising formulation are being 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 (API) 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 to develop cementing materials produced by acid-base reactions between calcium aluminate cements and phosphate-containing compounds has produced very promising results. Several candidate systems were evaluated with respect to their properties and cost. Studies of the cementing phases formed, microstructure developed, carbonation rate, and changes in strength and permeability after exposure to CO_2 solutions at 300°C were completed. A cement formulation based upon Na_2O, CaO, Al_2O_3, SiO_2, P_2O_5, and H_2O appeared the most promising, and it gave results that met the property and cost criteria necessary for use as a well completion material. As a result, it was tentatively selected for use in a full-scale downhole test to be performed overseas in the Summer of 1997. Plans for testing at the Salton Sea as part of a ongoing GDO program on lost circulation control are currently being formulated. The cement formulation consists of 23.7 wt% Class F fly ash; 15.8 wt% calcium aluminate cement, 31.4 wt% of a 40 wt% sodium metaphosphate solution, and 29.1 wt% Al_2O_3. The latter is in the form of lightweight, hollow ceramic microspheres. This formulation has a slurry density of ~1.2 g/cc, and after hydrothermal curing forms a strong, CO_2-resistant cement. As an example, a 180-day laboratory test to measure the durability of the BNL cement in high CO_2 brine was completed. In this test, BNL and conventional class G cement samples were exposed in an autoclave to a 4 wt% Na_2CO_3 solution (CO_2 equivalent 15,700 ppm) at 300°C. The results are summarized in Table 1. Data for compressive strength and phase formation are given. As noted, the BNL cement formulation exhibited a strength decrease of 35% to a value of 8.5 MPa within the first 30 days, and then remained constant for the duration of the test. No evidence of reactions between the cement and CO_2 was detected. The reason for the initial reduction in strength seems to be the growth of crystalline hydroxylapatite phases in the analcime layers. The latter are responsible for strength development. Once a well-formed hydroxylapatite phase is present, the strength stabilizes.

In contrast, the conventional lightweight class G cement-based formulation used as a control exhibited a 65% decrease in strength before an apparent leveling off at 5.2 MPa after 60 days. Analyses indicated the formation of calcite ($CaCO_3$) as a carbonation reaction compound and xonotlite [$Ca_6Si_6O_{17}(OH)_2$] as the major hydrate product, after exposure for only 7 days. Within 30 days, a major portion of the xonotlite phase had been converted into calcite and pectolite [$NaCa_3H\,Si_3O_9$]. Thus, it is apparent that the xonotlite which is responsible for strength development in Class G cement undergoes alkali carbonation degradation;

$$Ca_6\,Si_6\,O_{17}\,(OH)_2 \xrightarrow{Na_2\,CO_3} Na_2\,Ca_3\,H\,Si_3\,O_9 + Ca\,CO_3$$

With prolonged exposure, additional CO_2 will react with the $CaCO_3$ to form water soluble calcium bicarbonate. Continuous leaching of the latter will result in increased porosity and permeability, and decreased strength.

Based upon these results, it is clearly apparent that the BNL-developed lightweight cement is superior to the conventionally used class G cement when exposed to hydrothermal fluids containing high levels of CO_2.

As mentioned above, the incorporation of the hollow Al_2O_3 microspheres with the cementing matrix yields slurry densities of ~1.2g/cc. It should be noted that these microspheres may not be commercially produced in some overseas regions, and to import them may be cost prohibitive. If so, and/or a slurry density of 1.3 to 1.6 g/cc is acceptable, lower cost nitrogen gas-surfactant agent foaming systems can be used.

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. 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 suitable liner that could be used 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.

This Task is performed as a collaboration in which BNL supplies the lined heat exchanger tubes and performs materials analyses. Another DOE national laboratory (first INEL and subsequently NREL) provides a test skid and the thermodynamic analyses. Industry (CalEnergy) provides the test site and operates the test skid.

The technical feasibility for the use of high temperature composite materials for corrosion protection was demonstrated by BNL in the early 1980s, and since then they have been used successfully by the geothermal industry. BNL has patented these formulations.[10, 11] It was then shown that significant increases in the thermal conductivity of the polymer-matrix composites could be achieved by the incorporation of high conductivity materials

TABLE 1
Cement Durability Upon Exposure to CO_2-Enriched Brine #

Cement	Exposure Day	Compressive Strength MPa	Phases Present* Major	Minor
BNL	0	13.1	AN	HOAp, Q, SA
"	7	11.0	AN	HOAp, Q, SA
"	10	9.7	AN	HOAp, Q, SA
"	30	8.5	AN, HOAp	Q, SA
"	60	8.6	AN, HOAp	Q, SA
"	90	8.4	AN, HOAp	Q, SA
"	180	8.5	AN, HOAp	Q, SA
Class G	0	14.5	XO, Q	SA
"	7	11.0	XO, Q	P, SA, CAL
"	10	8.3	XO, Q	P, SA, CAL
"	30	7.6	Q, P, CAL	XO, SA
"	60	6.2	Q, P, CAL	XO, SA
"	90	5.2	Q, P, CAL	XO, SA
"	180	5.2	Q, P, CAL	XO, SA

*AN: analcime, HOAp: hydroxylapatite, Q: quartz, SA: sanidine-shelled microsphere, XO: xonotlite, P:pectolite, CAL: calcite
#Temperature 300°C, CO_2 equivalent 15,700 ppm

(SiC, etc.) as fillers.[12] Conductivities approaching those of Type-410 stainless steel were obtained. It was later shown that the addition of high temperature antioxidants into the composite significantly reduced the rate of scale deposition and adhesion to the surface. Work to develop a low cost, low fouling, replacement material for the high alloy steels used in geothermal heat exchange applications was then initiated. The following design criteria were established: 1) heat transfer and fluid-flow characteristics similar to those of AL-6XN tubing, 2) fouling coefficient <50% of AL-6XN when used in brines typical of the Salton Sea KGRA, 3) cost not more than twice that of mild steel, and 4) suitability of the use of conventional technology for joining PCL tubes to tube sheets.

In FY 1994, a 75-day field test of carbon steel tubing lined with a thermally conductive polymer composite (PCL) was conducted under conditions that simulated those in a bottoming cycle in a multi-stage flash geothermal process. The heat exchanger consisted of four 6-meter lengths of 2.54-cm o.d x 1.24 mm wall tubing lined with a 0.76-mm layer of the PC. The hypersaline brine inlet and outlet temperatures were 108° and 89°C, respectively. Concurrently, AL-6XN control tubes were evaluated under similar temperature, pressure, flow and brine composition conditions.

In FY 1995, analyses of the heat transfer, fouling and corrosion resistance performance of the PCL were completed. The post-test examination indicated that the base metal was fully protected by the lining. In addition, the heat transfer performance and fouling rate of the PCL tubes were similar to those of the high alloy controls. In FY 1996, preliminary design, manufacturing and cost studies for utilizing the composite in full scale shell-and-tube heat exchangers were conducted. These NREL-coordinated results established that contingent upon the development of a cost-effective method for joining PCL tubing to the tube sheets, significant reductions (17 to 65%) in the cost of a heat exchanger could be realized.

Approach

The work is being performed as a collaborative effort between BNL, NREL and private industry (CalEnergy). BNL performs the fundamental and applied research necessary to define high temperature polymer and 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 coefficients, cost estimates, and the management of field testing. They also coordinate manufacturability studies and technology transfer activities.

CalEnergy 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 performed. Design, manufacture method and economic studies are then conducted by a heat exchanger manufacturer and NREL.

Status

Plans for a second large-scale field test of a PCL heat exchanger were formulated in FY 1996 and contractual negotiations are nearing completion.

BNL has continued work to identify methods for improving the surface texture and scale-bonding characteristics of PCLs applied to carbon steel tubing. As part of this effort, fundamental work to elucidate the interactions that take place at PCL- or polymer-scale interfaces was performed. The results from these studies indicate that polymers containing ester, ketone, or ether groups should not be used in PCL formulations. These groups were found to react with divalent cations such as Ba and Ca that are present in geothermal brines. The reactions promote hydrolysis of these groups to form carboxylic acid which subsequently reacts with Ba and Ca hydroxides through general acid-base reaction routes. These form Ba- and Ca- complexed carboxylate salt derivatives such as -COO···M···OOC-, where M is Ba or Ca. The formation of these interfacial reaction products results in chemical bonding which enhances the shear bond strength (>7 MPa) of scale on PCL surfaces. The use of polyaryl-type polymers such as polyphenylene sulfide (PPS) should significantly reduce the magnitude of the bonding, and thereby make the use of hydroblasting practical for descaling PCL surfaces. This issue will be addressed in Field Test No. 2 that will be performed in the Summer of FY 1997.

3. Corrosion Mitigation at The Geysers

Corrosion problems at The Geysers have increased as steam pressures decline. These have contributed to decreases in electric power generation, increased operating cost, and safety and environmental concerns. In FY 1990, BNL initiated cost-shared work with geothermal steam producers and electric power generating companies active at The Geysers that focuses on low cost solutions to these difficult materials problems.

Currently four industry-identified materials problems are being researched. These are: 1) erosion and cavitation-resistant liners for steam transmission piping systems, 2) stress corrosion resistant materials for turbine components, 3) low cost corrosion resistant coatings for dry cooling tower applications, and 4) corrosion resistant coatings for vent gas blowers.

Problem 1 is being addressed with the Northern California Power Agency (NCPA). Erosion/cavitation occurs in the transmission piping tees located at the well heads. Pacific Gas and Electric Company (PG&E) problems with turbine components (Problem 2) have necessitated the use of expensive titanium blades, but methods for the retrofit of older turbine rotors are needed so that steam desuperheating can be eliminated. Problem No. 3 now has a low priority with PG&E since the installation of any type of dry cooling tower is probably not economical. Of much higher priority for them is Problem 4, vent gas blower materials. When exposed to moisture saturated gas containing

H_2S, H_2, CH_4, and CO_2 at~80°C, these cast iron casings fail within two years due to corrosion and erosion.

Based upon our extensive experience, materials, developed at or identified by BNL, are selected and test components supplied by operators at The Geysers are prepared for field evaluations. All BNL in-house laboratory testing in this Task is conducted in steam that simulates the fluid at The Geysers. Testing in brine is conducted in Program Activity No. 4.

Approach

The approach being used to meet the project objectives is to optimize polymer, polymer cement composite and pre-ceramic formulations, previously developed under DOE/OGT sponsorship, for specific end-use applications at The Geysers. The identification of need, performance of prototype and full-scale field evaluations, and subsequent economic studies are performed as cost-shared activities with firms active at The Geysers. In FY 1996, engineering ceramics and metal alloys were added to the types of materials under investigation.

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 these 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.

Status

In FY 1996, laboratory and field testing efforts being performed as cost-shared activities with geothermal companies active at The Geysers were continued. Details for these activities are summarized below:

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 inspection for a total exposure time of 57 mo as of February 1997. 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.

Dry Cooling Tower Components

Prototype sections of polymer coated finned-tubed 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 still 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, but PG&E has not reported the results from more recent inspections.

Turbine Components

Work to evaluate the usefulness of nickel aluminide (NiAl) alloys and high temperature polymers as corrosion resistive coatings on turbine components is being performed as a cooperative effort with PG&E. In April 1996, samples of turbine blade materials coated with PPS that was chemically bonded to the substrate by use of a zinc phosphate coupling system, were prepared for evaluation in a turbine simulator at PG&E. These tests are in progress.

Concurrent with the above field testing, laboratory evaluations of materials such as NiCoCrAlY, Cr_3C_2-NiCr and NiAl are underway. Additional materials to be evaluated include Cr_3C_2, WC-based (e.g., WC-Co, WC-CoCr) and TiC-based coatings. ZrO_2 and TiO_2 coatings deposited on NiAl using sol-gel synthesis technology will also be studied. Test variables will include placement method and coating thickness. Coating adherence and permeability will be measured.

Vent Gas Blowers

A program was started in FY1997 to identify corrosion resistant coatings for use on the cast iron casings of the PG&E vent gas blowers at The Geysers. Failure of these components due to corrosion and erosion frequently occurs within 2 years. Several potential systems were identified and field testing started in January 1997. An exposure time of 5 to 6 months is anticipated. The coating systems selected for evaluation were NiAl, PPS, ethylene methacrylic acid, and ethylene tetrafluorethylene.

As other materials needs at The Geysers are identified by industrial advisory groups, BNL will initiate R&D directed towards solving those problems.

4. Advanced Coating Material Evaluations

Corrosion and scale deposition continue to adversely affect geothermal plant operating costs, energy conversion efficiency, and utilization factors. To combat corrosion, 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 metals.

Since the general utilization of high alloy steels is cost prohibitive for most geothermal plants, current practice is to attempt to minimize corrosion and scale deposition 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 that currently 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.

Recently, the technical and economic feasibilities for the use of biochemical processes for the treatment of geothermal wastes and mineral recovery have been demonstrated at BNL.[13] As a result, considerable industrial activity is underway as cost-shared efforts with BNL. Portions of these processes operate with low pH (~ 1), high chloride content, brine sludges at temperatures up to 80°C. To make these processes cost effective, low cost and corrosion resistant materials of construction are needed.

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

Approach

The project objectives are being met by the performance of a multi-phase effort 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 is conducted in this phase of the effort. Contingent upon these results, potential commercial sources and development partners for the technology are identified in Phase 3. Field testing of coated prototype and full-scale process components at the Salton Sea KGRA and other locations is being conducted in Phase 4. Contingent upon these results, Phase 5 will consist of economic studies and the completion of technology transfer.

Status

A number of high temperature polymer and polymer-matrix composite coating systems are under investigation. These include PPS, ethylene metacrylic acid, and acrylic epoxy polymers; and ethylene tetrafluoroethylene copolymer. In attempts to enhance abrasion resistance, crystalline zinc phosphate compounds and NiAl alloys are being evaluated as coupling systems between metal substrates and the polymer topcoats. Methods such as plasma flame spray, chemical vapor deposition and physical vapor deposition are being considered as technologies for placement of the coatings. Test environments include hypersaline brine at 300°C and pH 1 biochemical reagent solutions at temperatures up to 80°C containing *Thiobacillus ferrooxidans*.

A cost-shared effort with CalEnergy to field test PPS-coated pipe is in progress. Two 61-cm-long sections of 25-cm-diam pipe were shipped to them for field testing at one of their Salton Sea power plants, but to date the test has not been started. The inner surfaces of both pipe sections were first cleaned by grit-blasting. This was followed by the application of a BNL developed zinc phosphate conversion coating, the purpose of which is to enhance bonding between polymer-based topcoating materials and the metal substrate. It also provides corrosion protection. One pipe section was then coated with two layers of PPS. This is an extremely acid resistant, high temperature (~300°C), highly crosslinked material.

A second pipe has one layer of PPS and an outer layer of a PPS-silicon carbide (SiC) composite over the zinc phosphate. Our goal with the composite is to improve the abrasion resistance of PPS. If the PPS systems are shown to be durable, flame spray applied PPS is a likely candidate for evaluation since the technology is suitable for field use. Therefore, it may be possible to retrofit existing pipelines.

In FY 1997, advanced engineering ceramics such as TiC,TiN, and Cr_7C_3 were included in the investigations. These systems have higher temperature capabilities than polymer-based composites and will be more resistant to abrasion. Their adhesions to metal substrates and the ability to form impermeable, thin (~1 micron), durable coatings are unknown, particularly upon exposure to low pH hydrothermal environments. Potential applications are for well casing, pumps, valves, and other moving parts seeing liquid dominated fluids.

Testing to identify suitable materials of construction for use in process components used in the biochemical treatment of geothermal wastes has been initiated. For use as baselne data, corrosion tests on 316L stainless steel
were completed. After 10 weeks exposure to a high chloride, low pH brine at 60°, coupons that were totally immersed or totally in a vapor zone did not show any visible corrosion. Coupons that were partially immersed exhibited pitting corrosion above the liquid level.

Tests on thermal sprayed ethylene methacrylic acid and ethylene tetrafluoroethylene in the same brine were also completed. The total test duration was 18 weeks. The ethylene methacrylic acid coatings showed no visible signs of deterioration other than slight surface staining and some loss of gloss. No disbondment occurred. One of the ethylene tetrafluorethylene coatings developed blisters at the coating-substrate interface and had poor adhesion at the conclusion of the test. The other ethylene tetrafluorethylene coating did not exhibit any disbondment. The variation in performance is probably due to the fact that the blistered coating was the first prepared and the thermal spray parameters may not have been optimal for this polymer. Neither of the ethylene tetrafluoroethylene coatings showed any staining or surface changes. It is concluded that both of these coatings appear suitable for corrosion protection in the studied environment provided that sufficient adhesion is achieved. Further studies on these coatings will examine abrasion resistance and adhesion at elevated temperatures.

Corrosion tests on 316L stainless steel and coated carbon steel coupons exposed to *Thiobacillus ferrooxidans* are also in progress. Slight corrosion of the 316L coupons in the vapour zone has been observed. Immersed coupons appear to be undergoing biofouling. Both coated and uncoated coupons have surface deposits. At the conclusion of the test period, the coupons will be cleaned and inspected for corrosion beneath the biofilm.

5. Geothermal Heat Pump Grouting Materials

The objective of this new activity that commenced in March 1997, is to reduce the first cost of installing the ground coupled heat exchangers in geothermal heat pumps (GHP) by 10 to 20%.

Vertically-oriented ground-coupling devices for GHP systems normally consist of a U-tube arrangement inserted into ~50-m-deep boreholes. The total borehole depth depends on factors such as heating and cooling load, soil type, local climate and heat pump model.

Techniques have been developed for the design and installation of such systems which have resulted in adequate performance, but the cost of installation of these systems has been a barrier to widespread utilization. Ideally, the buried heat exchanger should be designed for minimum length, requiring minimal resistance to heat flow between the circulating fluid and the native soil. The composition of backfill material that is placed around the heat exchanger, along with proper backfilling technique, can have great impact on exchanger performance. Thermal performance of the heat exchanger could be enhanced throughout the heating and cooling season with the use of a backfill material that has sustained high thermal conductivity, thus providing an efficient thermal bridge between the heat exchanger and the surrounding native soil. For example, analysis conducted by Martinez and Sullivan of SNL has shown that performance can be improved by 15% if the backfill grout is twice as thermally conductive as the surrounding soil or by 25% if the grout is four times as conductive.

If this activity is successful, significant reductions in the installation cost of a GHP and increased unit efficiency will result. Environmental concerns regarding the possible contamination of ground water with metals originating from the conventionally used bentonite grouts will also be eliminated.

Approach

The approach that will used to meet the project objective will be to first quantify required mechanical, physical and cost criteria for the grouting material. The R&D needed to meet these criteria will then be conducted in three phases. Phase 1 will consist of laboratory studies to identify, characterize and optimize promising formulations with respect to the design criteria. The data obtained in Phase 1 will then be used in performance modeling of GHP systems. Phase 3 will consist of field testing to verify the technical and economic practicality of the advanced grouts with GHPs. Phase 2 and 3 will be collaborative efforts with SNL, the University of Alabama and Oklahoma State University.

Status

As a precursor for the experimental effort, design criteria for advanced grouts were compiled. These are as follows: 1) cost <\$0.21/liter, 2) thermal conductivity dry, 1.9W/m.°K, and wet 2.2W/m.°K, 3) pumpability ΔP <0.69 MPa through a 61m length of 2.54 cm Tremie tube at 37.7 liters/min, and 4) permeability $<10^{-7}$ cm/sec.

Although formal experimental work in this activity did not commence until early March 1997, previous work at BNL has established the technical feasibility for meeting the design criteria. This effort studied grouts designed to have the following properties: low viscosity, compatibility with conventional mixing and pumping equipment, environmentally safe, low shrinkage, low permeability, low cost, and readily available constituents. The mix design was based on BNL grout formulations for stabilization and containment of hazardous wastes. A variety of filler materials were evaluated and the thermal conductivities of the product compared with those for conventional bentonite and cement grouts. In addition, admixtures commonly used to enhance the properties of grouts and other cement-based materials were utilized.

The results from these initial studies have been reported.[14] Thermal conductivities between 1.7 to 3.3 W/m.° K in the moist state and 1.4 to 3.0 W/m.° K in the dry state were achieved. Values of 0.56-0.80 W/m.° K were measured for low solids bentonite and cement grouts in the moist state. The bentonite grouts desiccated and cracked on drying and they would effectively act as an insulator in such a condition. Further improvement in the grout thermal conductivity is possible by optimizing the packing fraction and filler content and the use of suitably sized steel fibres.

CONCLUSIONS

The goal of the DOE/OGT-sponsored Geothermal Materials Development Project is to provide the technical and managerial basis for the performance of high payoff materials R&D so that the results are available to industry during plant retrofits and when they commence development of higher temperature and chemically aggressive hydrothermal resources. Materials needs have been defined by inputs from Industrial advisory panels, the GDO, professional societies, and two studies made by the National Research Council.

Corrosion, scale deposition and well completion remain 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.

Significant progress in materials development has been made since Program Review XIV. With respect to well completion, phosphate-modified calcium aluminate cement-flyash mixtures yield low cost, high strength, CO_2-resistant cements. The incorporation of hollow Al_2O_3 microspheres into the cement matrix yields slurry densities of 1.2 to 1.3 g/cc. The use of nitrogen gas-surfactant agent combinations instead of the expensive microspheres, yields a considerably lower cost product with a slurry density of 1.3 to 1.6 g/cc.

The durability of the cement in high CO_2 (~15,700ppm) content brines was demonstrated in laboratory tests. No evidence of carbonation was observed after a 6 month exposure to a 4 wt% Na_2CO_3 solution at 300°C. Some strength retrogression resulting from phase transformations that occurred within the first 30 days, was noted. Beyond that time, the strength remained constant at ~8.5 MPa for the remainder of the test. This value greatly exceeds the strength criterion for a well cement.

Based upon the above data, the reproducibility of which has been demonstrated by industry, plans have been made to complete wells with the formulations this Summer.

The corrosion-protective capability of thermally conductive polymer composite liners (PCL) applied on carbon steel tubing, has been demonstrated. Studies to reduce the magnitude of the adherence of scale deposited on the polymer surfaces are in progress. As part of this effort, fundamental studies to elucidate the interactions that take place at PCL-, or polymer/scale interfaces were completed. The results indicated that polymers containing ester, ketone or ether groups should not be used in the presence of hypersaline brines. Reactions between these groups and Ba and Ca divalent cations present in the brine result in chemical bonding of the scale to the coating surfaces, thereby making it very difficult to descale using hydroblasting techniques. Plans to substantiate these findings by the field testing of tubing lined with polyphenylene sulfide

(PPS) and a PPS-SiC composite have been made, and the test should commence in the early Summer of FY 1997.

The field testing of several prototype geothermal process components coated with BNL-developed materials systems is in progress at The Geysers and other tests are planned for the Salton Sea KGRA. Three general types of protective coatings; polymers, ceramics and composites are included. Components being tested include piping, dry cooling towers, turbine blades, rotor housings, and vent gas blowers. Coatings for use in biochemical processes for the treatment of geothermal wastes are also being evaluated. In conjunction with these tests, methods for the field application of the coatings are being identified. To date, flame spray techniques have given excellent results.

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GEOTHERMAL ENERGY CONVERSION FACILITY

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BACKGROUND

With the termination of favorable electricity generation pricing policies, the geothermal industry is exploring ways to improve the efficiency of existing plants and make them more cost-competitive with natural gas. The Geothermal Energy Conversion Facility (GECF) at NREL will allow researchers to study various means for increasing the thermodynamic efficiency of binary cycle geothermal plants. This work has received considerable support from the U.S geothermal industry and will be done in collaboration with industry members and utilities.

The GECF is being constructed on NREL property at the top of South Table Mountain in Golden, Colorado. As shown in Figure 1, it consists of an electrically heated hot water loop that provides heating to a heater/vaporizer in which the working fluid vaporizes at supercritical or subcritical pressures as high as 700 psia. Both an air-cooled and water-cooled condenser will be available for condensing the working fluid. In order to minimize construction costs, available equipment from the similar INEL Heat Cycle Research Facility is being utilized.

STATUS

While this facility bears considerable resemblance to INEL's Heat Cycle Research Facility, there are a number of important differences that raised some safety concerns. A considerable amount of the equipment being used is old. The facility will be located atop a mesa in Golden, Colorado where hard winter freezing and lightning strikes are common, there is no source of water, and the rock surface prohibits below-grade work. Also, as a result of the bidding process, the construction contract was awarded to a firm different from the one that performed the conceptual design. To address potential safety issues, a detailed process hazard analysis (PHA) was conducted on January 20-21, 1997. The PHA team consisted of NREL personnel, the engineering contractor, outside process hazard consultants, and Greg Mines from INEL who contributed his operating experience with the INEL facility. A number of safety-related design and construction recommendations were made, and the costs of these were subsequently estimated. NREL is currently awaiting additional funds to incorporate these changes into the design and construction. If this funding becomes available soon, it is now expected to have the facility operational by November 3, 1997.

The initial tests at the GECF will focus on measuring the performance improvements expected from using mixed working fluids. Computer simulations have indicated a reduction in levelized electricity cost of as much as 24%. Fluids to be tested include mixtures of isobutane/hexane and propane/isopentane. We also intend to test various combinations of air- and water-cooled condensers, including configurations in which the working fluid is on the shell side of the water-cooled condenser. We intend to involve INEL personnel in this effort to benefit from their previous experience and also are very interested in obtaining ongoing industry input as we develop a detailed test plan.

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

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ABSTRACT

The Idaho National Engineering and Environmental Laboratory's Heat Cycle Research project is developing a technology base that will increase the use of moderate-temperature hydrothermal resources to generate electrical power. One of the concepts under investigation is the use of a metastable, supersaturated turbine expansion. This expansion process supports a supersaturated vapor. If brought to equilibrium conditions, liquid condensate would be present in the expanding vapor. Analytical studies show that a plant designed to operate with this expansion will have an improvement in the brine effectiveness of up to 8% provided there is no adverse impact on turbine performance. Determining the impact of this expansion on turbine performance is focus of the project investigations being reported.

BACKGROUND

Heat Cycle Research project investigators at the Idaho National Engineering and Environmental Laboratory (INEEL) have identified binary power cycles that improve cycle performance to levels approaching thermodynamic maximums (Demuth, 1981; Demuth and Kochan, 1981; and Bliem and Mines, 1991). These cycles maximize the power production (on a per unit mass basis) from moderate-temperature, liquid-dominated hydrothermal resources. Subsequent field investigations have validated the assumptions made in the performance projections. The investigations also confirmed the adequacy of existing design methods and tools necessary to incorporate the use of these concepts into the design and operation of a binary power plant.

INEEL's Heat Cycle Research project is examining the effect of metastable, supersaturated vapor expansions on the performance of a binary cycle turbine. During this turbine expansion, the working fluid vapor expands into the equilibrium two-phase region. If the fluid is brought to equilibrium at that point, liquid condensate would form. This formation is not an instantaneous process; it requires the chance grouping of molecules and/or nucleation sites for the drops to form. Because condensate formation is delayed, the vapor is referred to as *supersaturated* and the expansion is considered to be a metastable process. Turbine expansions supporting a supersaturated vapor are not unique. In condensing steam turbines, the "Wilson Line" is used to estimate the extent to which the expansion can proceed, maintaining supersaturated steam without condensation.

In steam turbines the expanding vapor enters the two-phase region during the final portion of the expansion process. In the binary cycle the working fluid vapor enters the two-phase region early in the expansion process. For the binary cycles of interest, an isobutane working fluid or a mixture of isobutane and a heavier component provides a high cycle performance. These fluids have a retrograde dew point curve on a temperature-entropy (T-s) plot. In contrast to steam, these fluids become drier (superheat) as they expand.

A typical "dry" turbine expansion and the metastable turbine expansion are illustrated on the T-s schematic in Figure 1. In this binary cycle, the working fluid leaving the condenser (point 1) is pumped to the heater inlet (point 2). The fluid is then preheated and vaporized at a supercritical pressure to the turbine inlet conditions (point 3). An isentropic expansion from the turbine inlet to the exhaust condition (point 4) occurs completely outside the two-phase region, i.e., it is completely "dry". (In

Mammoth Pacific's turbines, the vapor entering the turbine is heated to a higher inlet entropy than represented by point 3 to assure that the expansion is completely dry. This is typical of most commercial plants.)

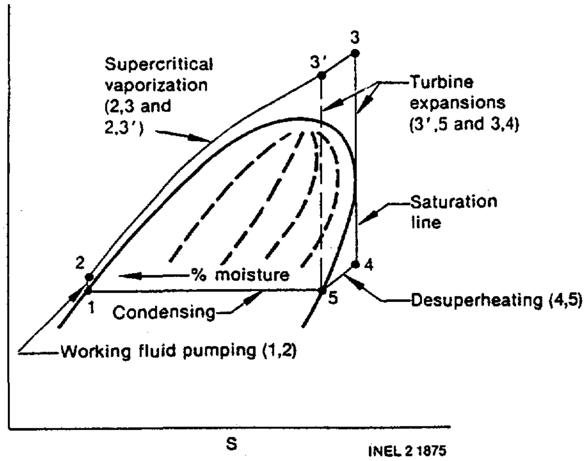

Figure 1: Binary Cycle Showing Two Types of Turbine Expansions

Demuth (1982) proposed modifying this supercritical cycle to allow the ideal turbine expansion to pass through the two-phase region (represented by the process from point 3' to point 5.) After a theoretical examination of the condensation behavior of the hydrocarbon working fluids in these expansions, Demuth concluded that condensate droplets might not form. Droplets that form would be very small and tend to evaporate as the expansion proceeds. If this expansion proceeds without adversely impacting turbine performance, the cycle performance improves by up to 8%.

Field investigations were conducted at the Heat Cycle Research Facility (HCRF) to determine the impact of these expansions on a binary cycle turbine. Initially the condensation behavior of the metastable expansions was examined using a converging-diverging nozzle to simulate an ideal, isentropic expansion process. Investigators found that the formation of condensate was delayed until reaching a maximum equilibrium moisture level of 5% to 7%. Initially droplets forming tended to evaporate, however as the equilibrium moisture level increased they did not.

During the final phase of the HCRF investigations, the impact of these expansions on turbine performance was examined (Mines 1993 and Mines 1994). Both an axial-flow, impulse turbine (provided by Barber-Nichols Engineering) and a radial-inflow, reaction turbine (provided by Rotoflow Corporation) were tested. The turbines had a nominal power output of ~40 horsepower. All turbine tests were conducted at supercritical inlet pressures. Isobutane and isobutane-hexane mixtures were used in testing over a range of inlet conditions producing controlled levels of moisture in the turbine expansion.

Neither turbine was impacted at inlet conditions corresponding to the onset of condensate formation during the nozzle tests. The radial-inflow turbine efficiency did not degrade until an isentropic expansion from the inlet condition exhausted the turbine within the two-phase region. The impulse turbine efficiency was not affected until the actual turbine exhaust conditions were within the two-phase region. The maximum equilibrium moisture level at the degradation in the radial-inflow turbine efficiency was 13%. In the impulse turbine, the equilibrium moisture level corresponding to the efficiency degradation was 20%.

The impulse turbine was operated at supercritical pressure and inlet entropies and temperatures less than the critical point values. The fluid entering the turbine was a liquid. At this extreme operating point, the equilibrium moisture level of the vapor exhausting the turbine was greater than 25%. The maximum moisture level in this expansion was 100%. It occurred as the fluid crossed the bubble point line and entered the two-phase region. At this condition the impulse turbine efficiency had decreased by ~13 percentage points. During subsequent operation, the efficiency returned to previous levels for completely "dry" expansions.

At the conclusion of the field testing the efficiencies of the turbines were not permanently affected as a result of operation with the metastable expansions. Neither turbine was tested for more than three hundred hours. The HCRF testing left unanswered the question as to whether these expansions would adversely affect performance over the operating life of a commercial turbine. With the assistance of Rotoflow Corporation and CE Holt Company, the project reached an agreement with Mammoth Pacific Limited Partnership (MPLP) to continue the investigation these expansions at one of MPLP's commercial binary facilities near Mammoth Lakes, CA.

MAMMOTH INVESTIGATIONS

Mammoth Pacific Limited Partnership operates three power plants with a total design capacity of ~40 $ME_{(e)}$ adjacent to Casa Diablo Hot Springs near Mammoth Lakes. All three plants are binary plants utilizing an isobutane working fluid. The plants were designed by CE Holt Company and utilize Rotoflow radial-inflow turbines.

In the agreement reached with MPLP, the project assumed the risk for the potential damage to the turbine rotor and vanes by purchasing these components for the extended investigation. This also allowed the pre-test condition of these components to be established. MPLP agreed to install the components in the MP1-100 turbine and operate the plant at the selected inlet conditions for a minimum of 6 months.

The project initially intended that the investigations at Mammoth be conducted at a turbine inlet pressure that was near or above the critical pressure of isobutane. The design inlet pressure of the MP1-100 turbine is 500 psia. After evaluating the operation of the MP1-100 plant, the project concluded it would not be possible to operate the plant at the desired turbine inlet pressures without adversely impacting the power produced. Operation at a supercritical pressure would require changing the design of the turbine rotor and vanes, which was not acceptable to MPLP. The project concluded that the MP1-100 turbine could operate at sub-critical inlet pressures and conditions similar to those producing the onset of condensate formation in the HCRF nozzle tests. With MPLP's concurrence, the investigation proceeded for a period of six months at the MP1-100 plant.

The new turbine rotor and vanes were obtained from Rotoflow and installed in November 1995. Before installation the surfaces of these components that would be exposed to the expanding vapor were photographed, establishing the pre-test condition. After the installation of the new components, the turbine operated for ~140 hours at the nominal conditions to establish a baseline performance with completely dry expansions.

On November 13, 1995 the turbine inlet conditions at MP1-100 were adjusted to a pressure of ~450 psia and a superheat level of ~1^{o} to 2^{o}F. At equilibrium, a vapor expanding isentropically from this inlet condition would have maximum moisture levels of 1% to 2%. The efficiency of the MP1-100 turbine during the first 100 hours of operation, as well as during the period just prior to starting the test is shown in Figure 2. The plotted efficiency clearly shows improvement after the new rotor and vanes were installed. The daily variations with air temperature are also apparent. With the new components, the efficiency of the MP1-100 turbine improved by 10 to 15 percentage points.

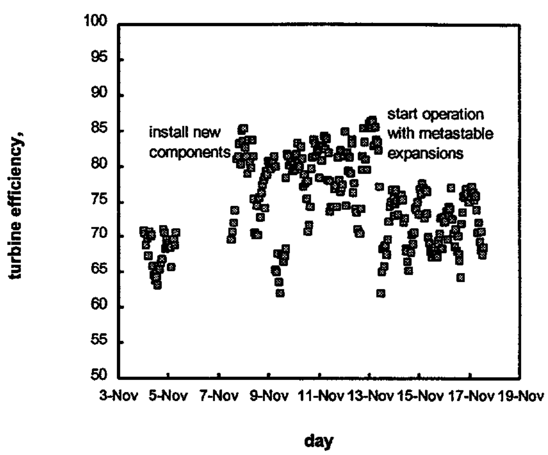

Figure 2: Performance of MP1-100 Turbine at Start of Operation with Metastable Expansions

The new rotor and vanes were identical in design to the components that they replaced. The turbine design utilizes a pressure difference to "clamp" on the vanes to reduce by-pass around the vanes and direct flow through the nozzles formed by the vanes. After the installation of the new components, the clearances within the turbine were such that this "clamping" process was improved, leading to higher efficiencies. It is difficult to identify any trend in performance during the first 100 hours of operation, other than the daily variation with the ambient air temperature and corresponding changes in the condenser pressure.

When the operation with the metastable expansions started, the turbine efficiency dropped by ~10 percentage points. Before starting the investigation with the metastable expansions, the turbine inlet pressure was ~275 psia. (The MP1 facility was operating under reduced brine flow conditions utilizing half the working fluid pumping capacity.) To achieve the desired level of supersaturation (equilibrium moisture level) in the turbine expansion, an inlet pressure greater than 450 psia is required. In order to raise the inlet pressure to the desired level, it was necessary to throttle the isobutane vapor flow with the turbine vanes. The throttling with the vanes adversely impacts the turbine efficiency. The efficiency drop that occurred (see Figure 2) when the inlet pressure was raised at the start of operation with the metastable expansions resulted from this throttling. (In raising the turbine inlet pressure to 450 psia, the turbine vanes were closed to an indicated 40% to 45% open.)

Although the turbine efficiency degraded, there was little change in the brine effectiveness. MPLP could divert the excess brine from MP1-100 to its other facilities and increase the power production from those plants. This allowed the MP1-100 turbine to operate at higher inlet pressures without adversely the total power output from MPLP's facilities.

The turbine at the MP1-100 facility has operated in this mode since November 1995. The initial agreement with MPLP allowed the unit to be operated until May 1996 with these expansions. In May MPLP agreed to continue to the investigation until September of 1996 and provide data to the project. (MPLP continues to operate the unit with the modified inlet conditions.) In January 1996, the inlet pressure was increased to 465 psia ± 5 psi and the superheat at the inlet was reduced to $1^{o}F \pm 0.5^{o}F$. In June 1996, the turbine inlet pressure was raised to 475 psia ± 5 psi with no change in the level of superheat at the turbine inlet. The inlet conditions of the MP1-100 turbine through the extended investigation are shown in Figure 3.

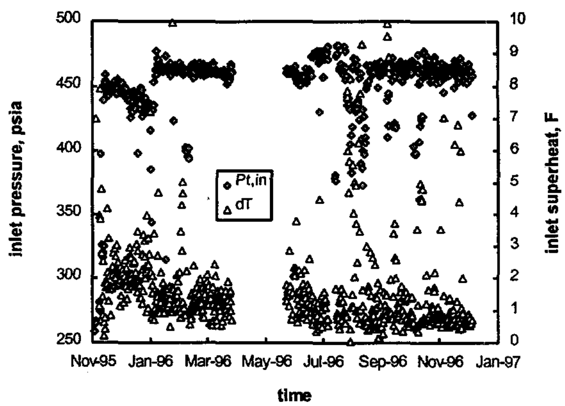

Figure 3: The MP1-100 Turbine Inlet Conditions During Operation with Metastable Expansions

The data shown in Figure 3 is at 12 hour intervals; data was recorded hourly. From March through May, the data acquisition system at the MP1-100 facility was not operational. During this period, the turbine operated at the modified inlet conditions producing the metastable expansions. The control panel indicators were used to monitor the turbine operation.

During operation with the metastable expansions, it was occasionally necessary for MPLP to modify the MP1-100 turbine operation to adjust for power demands and accommodate at MPLP's other facilities. These periods of operation correspond to the points in Figure 3 at the lower inlet pressures and/or higher superheat levels at the turbine inlet.

The efficiency of MP1-100 turbine during the operation with the metastable expansions is shown in Figure 4. (The turbine efficiency presented in this paper is calculated using the generator power and the measured working fluid flow rate to determine the actual turbine work on a per unit mass basis.)

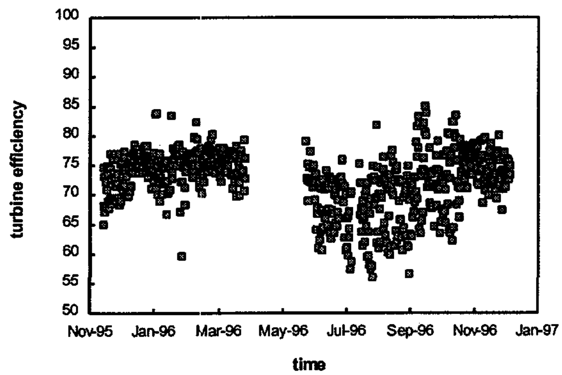

Figure 4: Performance of MP1-100 Turbine During One Year of Operation with Metastable Expansions

The efficiency plotted is at the same 12 hour interval as the inlet conditions in Figure 3 (noon and midnight). Through the failure of the data acquisition system, there does not appear to be a trend in the efficiency of the MP1-100 turbine other than the daily variation with the ambient temperature. In May 1996 when the data was again available, the peak daily efficiency was slightly lower. This trend continued through the summer, and then as the ambient temperatures began to decrease, the peak efficiencies increased. In November of 1996, the peak efficiency was similar to those in November 1995 when the test started. During the summer operation there was considerable variation in the turbine efficiency. This variation is due in part to the larger daily variations in the air temperature. More frequent changes in the MP1-100 plant operation in response to power demands and changes in operation at MPLP's other plants also contributed to this variation.

To confirm that the efficiency variations in Figure 4 were due to the effect of the ambient air temperature on condensing temperature and pressure, the efficiency was evaluated as a function of the air temperature. This evaluation is summarized in Figure 5 where the efficiency in two month intervals is plotted as a function of the air temperature.

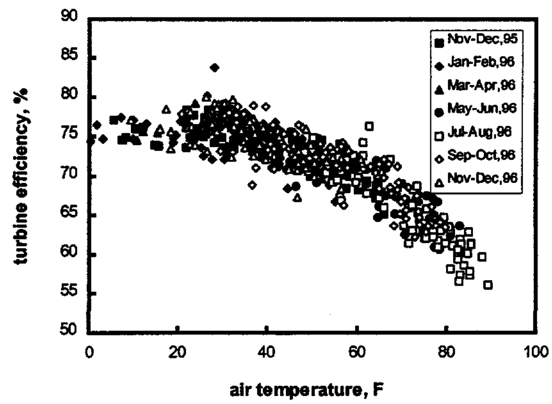

Figure 5: The Effect of the Ambient Air Temperature on the MP1-100 Turbine Performance with Metastable Expansions

This data is on the same 12 hour intervals as the data presented in the previous two figures. In order to evaluate the effect of air temperature, only the data for operation with the metastable expansions is included. This data clearly illustrates the effect of the air temperature on turbine efficiency, particularly at the higher ambient temperatures. Over the range of ambient conditions shown, the efficiency of the MP1-100 turbine varied by over 20 percentage points.

The data shown in Figure 5 suggests there is no degradation in performance with time. In Figure 6, only the only turbine efficiency for the November-December, 1995 and for the November-December, 1996 periods is plotted. Except for one data point, this figure shows there is little difference in the MP1-100 turbine performance after one year of operation with the metastable expansions.

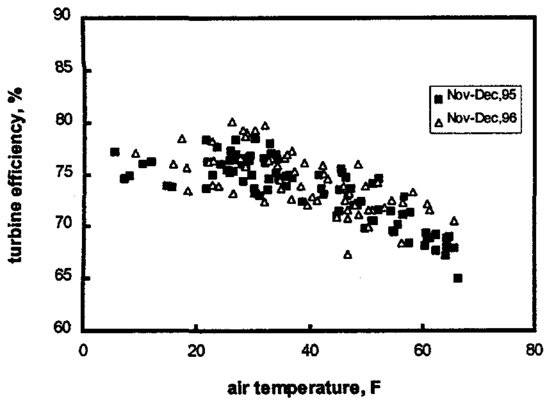

Figure 6: Efficiency of the MP1-100 Turbine During First and Final Months of Operation with Metastable Expansions

The degree of supersaturation in the turbine expansion during this investigation is shown in Figure 7. In this figure the turbine inlet entropy is plotted as a function of time. During the investigation of these expansions at the HCRF, the onset of condensate formation occurred at inlet entropies that would produce equilibrium moisture levels slightly greater than 5%. During the year investigation with the MP1-100 turbine, the equilibrium moisture levels in an isentropic expansion exceeded 5% in excess of 400 hours (5% of the time). Over the year, the turbine operated with the metastable expansion over 85% of the time.

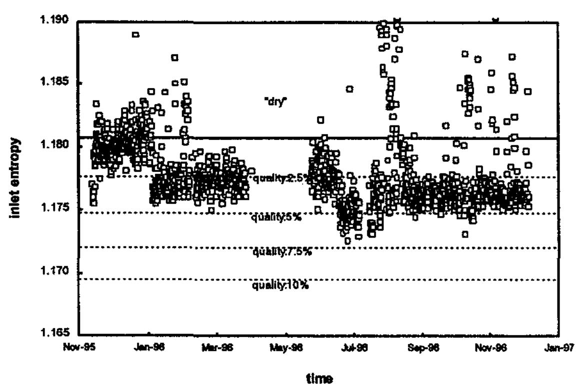

Figure 7: Turbine Inlet Entropies During the Metastable Expansion Investigation at MP1-100

The impact of these expansions on the MP1-100 plant performance during this period is shown in Figure 8 as a plot of the brine effectiveness with time. The data plotted includes the MP1-100 plant brine effectiveness during the operation to establish the baseline performance. Despite the efficiency penalty associated with throttling flow with the vanes for the extended test, the plant continued to produce an equivalent power output when operating with the metastable expansion. The effect of the ambient air temperature on the performance of the plant is apparent. At the higher exhaust pressures corresponding to the higher air temperatures, the plant power output decreases because of the lower ideal turbine work and the lower turbine efficiencies. At the end of the first year the plant brine effectiveness was equivalent to the performance at the start of the investigation.

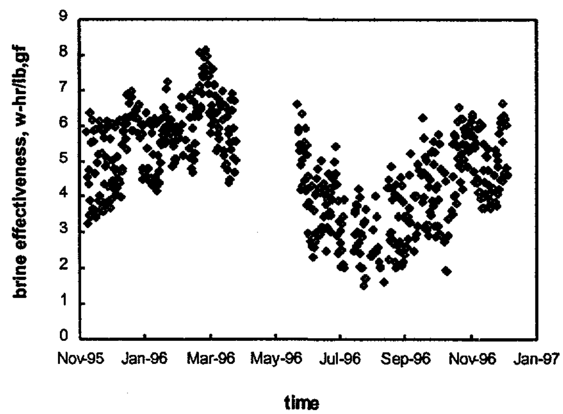

Figure 8: Performance of the MP1-100 Plant During Operation with the Metastable Expansions

SUMMARY

The following summarizes the results of the first year of operation with metastable turbine expansions at Mammoth Pacific's MP1-100 plant.

i.) There has been no measured degradation in the performance of the turbine at MPLP's MP1-100 plant that can be attributed to operation with the metastable, supersaturated expansion.

ii.) To achieve levels of supersaturation while operating at sub-critical inlet pressures, the MP1-100 turbine has operated with no problems at superheat levels of ~1°F.

iii.) During the year, turbine efficiency varied by 20% due to the changes in air temperature and its effect on condenser performance.

iv.) There was some degree of supersaturation in the expanding vapor in the turbine over 85% of the time during the first year of operation. Approximately 5% of the time, the turbine operated at inlet conditions corresponding to the onset of condensate formation during the nozzle testing at the HCRF.

v.) For the current operations at the MP1-100 plant, in order to operate the turbine with the metastable expansion it is necessary to throttle the flow with the turbine vanes to raise the turbine inlet pressure. There is an efficiency degradation of up to 10 percentage points associated with this throttling.

vi.) Despite the efficiency penalty associated with throttling with the turbine vanes, the brine effectiveness for the MP1-100 plant was not impacted by operation with metastable expansions. If this penalty could be reduced or eliminated, the brine effectiveness would have increased when using metastable expansions.

The MP1-100 turbine continues to operate at inlet conditions producing a metastable expansion supporting a supersaturated vapor. The MP1-100 facility is scheduled to be shutdown in May of 1997 for maintenance activities. At that time the turbine rotor and vanes will be visually inspected. If damaged, the components will be removed and subjected to a more detailed examination. If there is no damage to these components, MPLP is tentatively planning to expand the usage of this expansion to one or more of its other binary facilities.

ACKNOWELDGEMENTS

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ADVANCED BIOCHEMICAL PROCESSES FOR GEOTHERMAL BRINES CURRENT DEVELOPMENTS

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ABSTRACT

A research program at Brookhaven National Laboratory (BNL) which deals with the development and application of processes for the treatment of geothermal brines and sludges has led to the identification and design of cost-efficient and environmentally friendly treatment methodology. Initially the primary goal of the processing was to convert geothermal wastes into disposable materials whose chemical composition would satisfy environmental regulations. An expansion of the R&D effort allowed to identify a combination of biochemical and chemical processes which became a basis for the development of a technology for the treatment of geothermal brines and sludges. The new technology satisfies environmental regulatory requirements and concurrently converts the geothermal brines and sludges into commercially promising products. Because the chemical composition of geothermal wastes depends on the type of the resource and therefore differs, the emerging technology has to be also flexible so that it can be readily modified to suit the needs of a particular type of resource. Recent conceptional designs for the processing of hypersaline and low salinity brines and sludges will be discussed.

BACKGROUND

Geothermal energy is a major energy resource. At the present time, about 5700 megawatts per year of power are generated from geothermal energy in twenty different countries. (A Global View of Geothermal Energy, 1966; Freeston, D.H. 1955). In addition, another 11,000 thermal megawatts per year are being used for space heating and direct applications. Further, it is anticipated that another 250,000 MW of new capacity will be needed between now and the year 2010. Compared to coal and oil, geothermal energy is a clean resource of electric power. However, on cooling of the spent high saline brines, a sludge is produced which is considered a mixed waste and, therefore, subject to regulatory constrains. Processing of low salinity brines produces a chemically different residue disposal of which is also regulated. The latter type of byproduct is associated with the Geyser type brines and the former with the Salton Sea type brines.

Biochemical treatment of geothermal brines involves a ten variables process (Premuzic et al., 1996a; Premuzic et al., 1996b). Optimization of these variables led to the design of a process in which two biocatalysts are used in 85% to 15% proportions. This conceptual design processes about 1300 Kg/h of geothermal sludge produced from hypersaline resources and yields a 1200 Kg/h cake from which toxic and valuable metals, originally present in the starting material, have been removed. The produced residue meets regulatory requirements (Royce, 1985) and can be disposed of as a non-regulated waste. The filtrate, which now contains toxic and valuable metals, is neutralized with lime and filtered. The neutralized cake can be further treated for the recovery of valuable metals and the filtrate can be re-injected into a well. In this process, the kinetics of metal solubilization are fast (<8 hours per batch) with solubilization efficiencies of better than 85%. Because of the differences in the chemical nature of the geothermal resource and the residues generated in the production of power from low salinity geothermal brines, the overall biochemical process had to be modified. BNL, under a

Collaborative Research and Development Agreement (CRADA) with CET Environmental, Inc. and their agreement with PG&E, have jointly developed a process which is specific to the Geysers-type geothermal waste. In this particular type of waste, one is dealing with a sulfur cake contaminated with iron, some silica, arsenic, and mercury. Initially, two treatment scenarios have been considered. In the first scenario, a slurry is treated with two biocatalysts. This treatment yields a residue of crude sulfur and an aqueous phase containing arsenic and mercury. The aqueous phase can be re-injected. In the second scenario, the sulfur is first extracted with a solvent, yielding a high grade sulfur product. The residue, after the removal of sulfur, is then treated as described in the first scenario. Because of regulatory restrains, the solvent extraction scenario was abandoned. Follow-up R&D allowed to explore several alternatives. Extended research into further optimization of the processes for the treatment of residues produced in the generation of geothermal power from high and low salinity brines has made possible additional cost savings and simplifications in the design of the technology.

The results from this research and development effort will be briefly discussed in the next section.

RECENT ACTIVITIES

Analysis and re-evaluation of the original process design for the treatment of sludges produced from high salinity geothermal resources (Premuzic et al., 1996a; Premuzic et al., 1996b) suggested further improvements. Modification of the three major steps in the process: (1) the use of two biocatalysts; (2) processing of the filter cake; and (3) avoidance of the lime neutralization step could lead to significant savings. Changes in these steps, a combination of biochemical and chemical processing, and the use of available reagents adds to further cost savings. Thus, the use of a single biocatalyst proved to be possible. Further, re-processing of the filter cake into a high quality silica, which can be used as a filler, coupled with recycling and re-injection as well as metal recovery options resulted in the process summarized in Figure 1. The process shown in Figure 1 also indicates potential profits that may

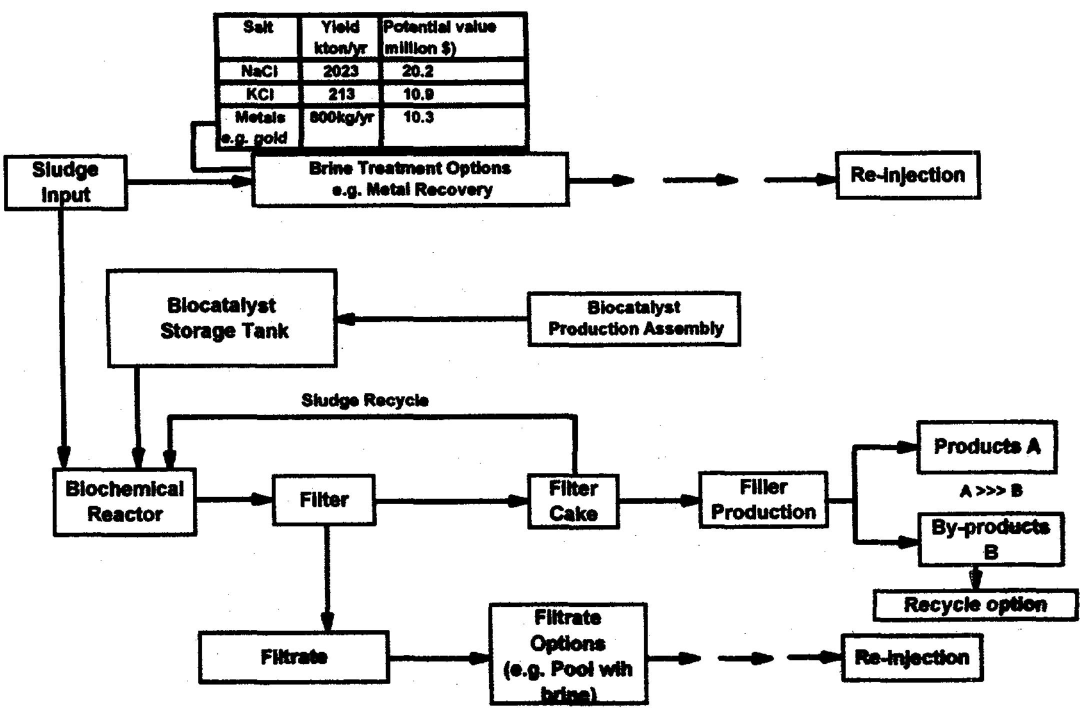

Figure 1. Total processing of geothermal sludges & brines

be generated from valuable metals and salt recovery options. Figure 2 shows a conceptual flow sheet for the processing of 500 Kg/h of a hypersaline sludge. This process assumes the use of a single biocatalyst, recyclable water, and aqueous chemical reagents. The economic significance of such a processing scenario is shown in Table 1. Field demonstration strategies for these processes are currently being explored.Re-evaluation of the processing of sludges produced in the production of geothermal power from low salinity brines has led to similar improvements. However, to accomplish this, certain variations had to be taken into consideration. The chemistry of geothermal sludges changes on storage. Further, in the case of sludges generated at Geysers, the biochemical solubility of mercury is less then that of arsenic. Thus, the initial biochemical treatment solubilizes arsenic and mercury. However, while a better than 80% solubilization of arsenic renders a product well within the total threshold limit concentrations (Royce, 1985) for arsenic, it does not do so for mercury. Also, on standing the solubility of mercury appears to also decrease, while that of arsenic does not. The first evidence that changes in the chemical speciation of mercury may occur has been observed in experiments dealing with the solvent extraction of sulfur (Premuzic et al, 1996b). A reduction of about 50% in solubility relative to arsenic has been observed under identical experimental conditions. While the chemistry of the changes in the chemical speciation of mercury has yet to be determined, for the sake of expediency, an alternative processing strategy for the Geysers type sludges has been developed. In this modification of the original process, a single biocatalyst is used to remove arsenic and concurrently, reduce the volume of the original waste by 90%. (Figure 3). In this process, a high grade of sulfur is produced. It is anticipated that optimization of the process will

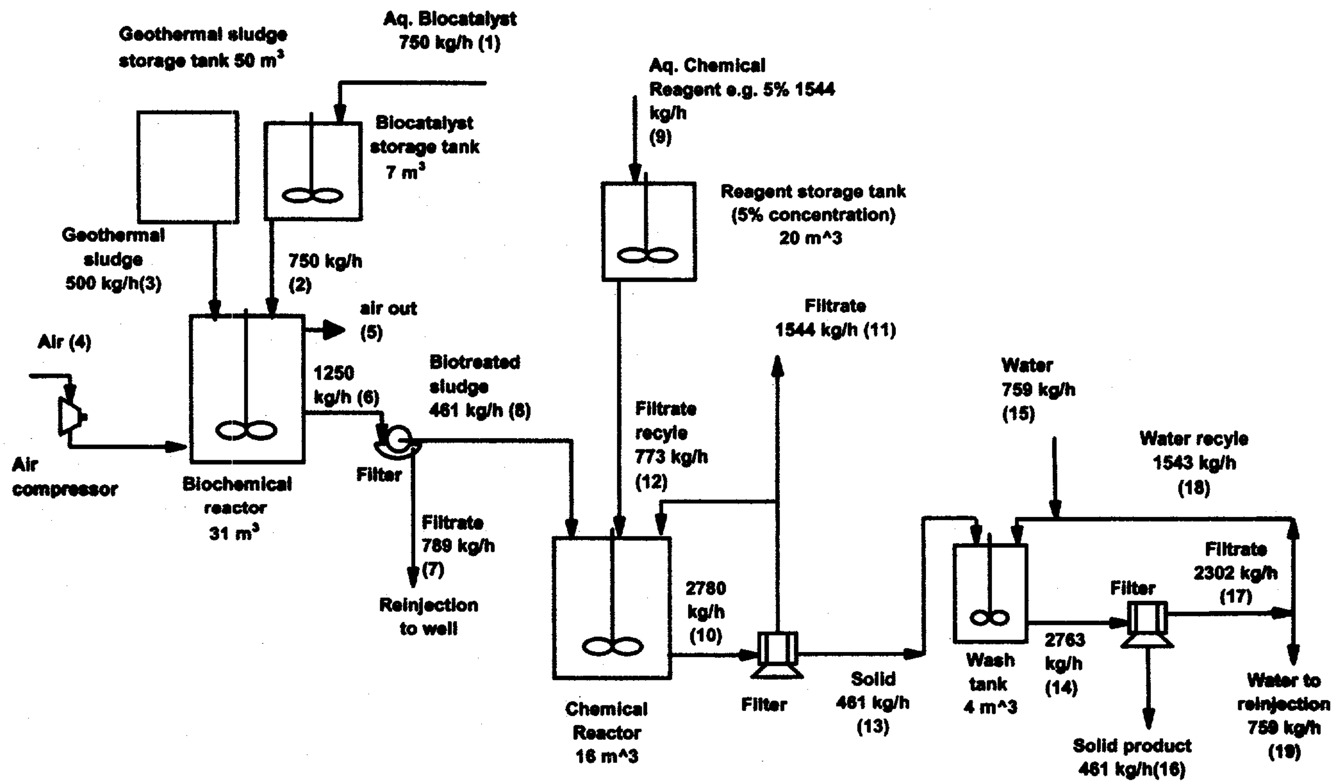

Figure 2. Conceptual process flowsheet for the treatment of geothermal sludges 500 kg/hr

Table 1. Filler production from geothermal brines cost analysis of process changes

	Original Case Two Biocatalysts	Second Case One Biocatalyst	Third Case One Biocatalyst and a Chemical Reagent
Capital Investment (thousands of dollars)	4080	3606	3606
Total Expenses (thousands of dollars per year)	6751	6652	2980
Revenue from filler sales and savings from avoiding waste disposal (thousands of dollars per year)	16517	16517	16517
After tax net profit (thousand of dollars per year)	6347	6412	8799
After tax rate of return on investment %	164	186	253

yield a marketable, agricultural grade sulfur. This sulfur is produced by conventional sublimation technology which does not involve any solvent extraction steps. The light powdered residue (B, Figure 3) consists

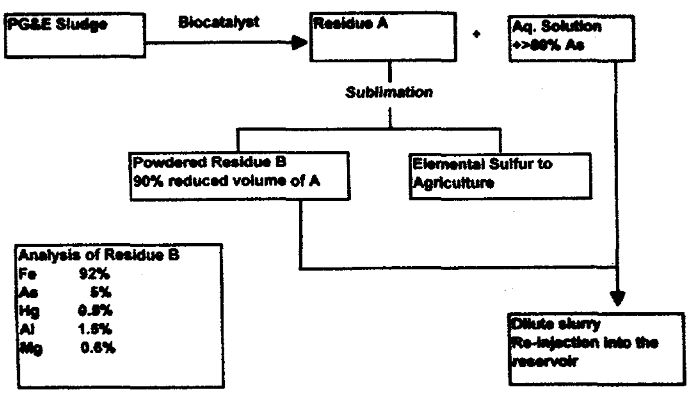

Figure 3. The overall simplified process for Geyser-type geothermal sludges

predominantly of iron (>92%) and small amounts of arsenic, alumina, mercury, and magnesium. In the current process design (Figure 4) residue B is slurried and re-injected with the arsenic bearing aqueous phase generated in this process.

CONCLUSIONS

1. Combination of biochemical and chemical technology for the treatment of geothermal

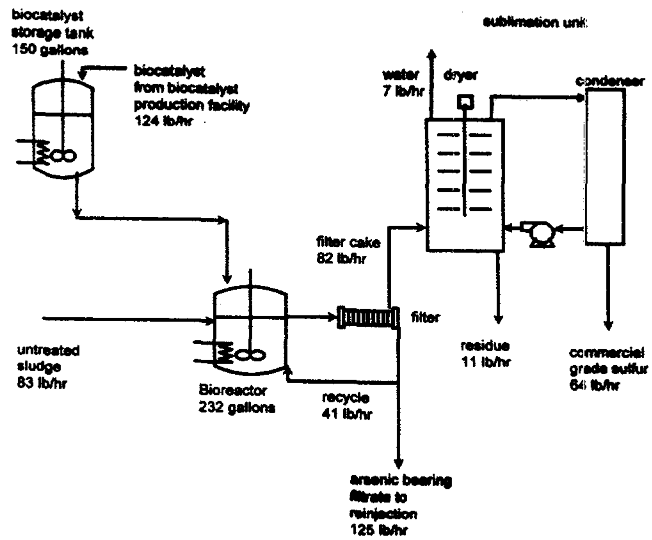

Figure 4. Conceptual process flowsheet for treatment of Geyser-type geothermal sludges

brines and sludges is cost-efficient and yields commercially viable by-products.

2. The emerging technology minimizes wastes and utilizes available recycling options.

3. Close collaboration and partnering with industry, particularly CET Environmental Services, PG&E, and CALEN enables a full development and field applications of the emerging technology.

ACKNOWLEDGMENTS

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THE GEOTHERMAL POWER ORGANIZATION

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ABSTRACT

The Geothermal Power Organization is an industry-led advisory group organized to advance the state-of-the-art in geothermal energy conversion technologies. Its goal is to generate electricity from geothermal fluids in the most cost-effective, safe, and environmentally benign manner possible. The group achieves this goal by determining the Member's interest in potential solutions to technological problems, advising the research and development community of the needs of the geothermal energy conversion industry, and communicating research and development results among its Members. With the creation and adoption of a new charter, the Geothermal Power Organization will now assist the industry in pursuing cost-shared research and development projects with the DOE's Office of Geothermal Technologies.

ORGANIZATION

The Geothermal Power Organization (GPO) was formed from the combination of two existing industry advisory groups: the Energy Conversion Panel (ECP) and the Technical Advisory Group (TAG). The ECP aimed to bring together geothermal industry managers to outline broad programmatic goals and strategies. The TAG focused more on the short-term technological needs of the geothermal power plants. Given the similarities in mission and the overlap in membership of the ECP and TAG, they were combined into the GPO in 1993.

A fundamental change in the structure of the GPO has been underway over the past two years to allow the organization to review and comment on cost-shared project proposals to the DOE's Office of Geothermal Technologies. To achieve this new capability, the organization has created a new Charter, elected Officers, and signed a Memorandum of Understanding to facilitate the submittal of cost-shared project proposals to the DOE's Golden Field Office. With the approval of its new Charter, the GPO adds another function to those it has performed in the past. The GPO's current functions are to:

- determine the Member's interest in technological solutions to energy conversion problems,
- advise the geothermal industry and R&D groups of the interests and priorities of the organization,
- facilitate the communication of laboratory and field research results to the geothermal energy conversion industry,
- present comments on proposal for industry-led, DOE cost-shared projects.

Membership in the GPO is open to all industrial organizations and individuals working in the geothermal energy conversion field. Members must review and approve the GPO Charter, pay a one-time Initial Fee of $400, and appoint personnel to serve as Representatives to the GPO. Member fees are held in a bank account at the Geothermal Resources Council and are used to defray any Board expenses. GPO Members include: plant operators, plant owners, equipment manufacturers, project developers, utilities, consultants, and environmental organizations.

The group meets twice a year, in the spring at the DOE Office of Geothermal Technologies' Program Review and in the fall at the Geothermal Resources Council Annual Meeting. Attendance at GPO meetings are open to all interested individuals.

COST-SHARED PROJECT PROPOSALS

The Energy Conversion Program of DOE's Office of Geothermal Technologies provides funds for cost-shared projects in its annual budget. The projects require a minimum of 51% industry cost share in the form of money or goods and services. Each project requires the participation of two partners; one partner must be an industrial organization or individual and a member of the GPO. The other partner must be a non-federal-government entity; membership in the GPO is not a requirement for the second project participant.

Figure 1 below shows the path that a project submitted to the GPO for review follows. The Sponsoring Member submits a written project proposal to the GPO Board which, in turn, forwards copies to the GPO Members for review. The Members submit their written review of the proposal back to GPO Board. The Board summarizes the Members' comments and sends the original proposal, the Members' comments and the Board's summary of those comments to the DOE. If the DOE decides to co-fund the proposal, it negotiates the financial contract directly with the Sponsoring Member.

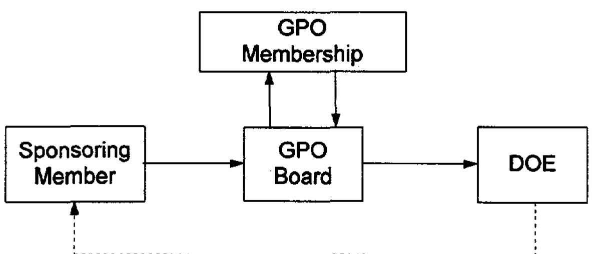

Figure 1. Project proposal flow diagram.

STATUS OF THE GPO

With the approval of the MOU and the signature of the new Charter by the Board Members, the GPO is actively soliciting Members to formally join the new organization. With a diverse body of Members, project proposals for DOE co-funding will be accepted for review.

NREL'S ROLE IN THE GPO

NREL had operated the ECP and the TAG for the benefit of the DOE and the geothermal industry. The new GPO is industry led, so NREL's role has changed to a more administrative one. Questions regarding the structure of the GPO, pertinent information regarding the submittal of project proposals, or any other issue related to the GPO can be directed to:

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Concurrent Session 4:

The Geysers

GEOLOGIC RESEARCH AT THE GEYSERS -- 1996

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INTRODUCTION

In response to the onset of field-wide pressure declines at The Geysers geothermal field in northern California (**Figure 1**) the Department of Energy's Geothermal Division in 1990 inaugurated sponsorship of a dedicated, multiyear research effort designed to mitigate the pressure drop and to allow steamfield operators to make more informed forecasts of steam supply and quality well into the 21st century. EGI and its predecessor, the University of Utah Research Institute, have from the onset been key participants in this important research effort. For example, Moore and Gunderson (1995), utilizing fluid-inclusion and stable-isotopic methods, deciphered the field's intricate magmatic-hydrothermal history. Hulen et al. (1991, 1992) and Hulen and Nielson (1995a) identified major textural and mineralogic differences between the productive steam reservoir and its relatively impermeable caprock. For example, they showed that metamorphic vein aragonite and calcite had been removed wholesale, from the metaclastic-rock-hosted portion of the reservoir, by hot, possibly mildly acidic waters circulating prior to formation of the modern vapor-dominated regime; in this way, perhaps <u>10 cubic kilometers</u> of new porosity was created as valuable water-storage space for the ensuing vapor-dominated geothermal system. Hulen and Walters (1993) and Hulen and Nielson (1993, 1996) mapped the composite felsic pluton underlying and heating the still vigorously active hydrothermal system, and documented the nature of porosity in that portion of the steam reservoir hosted by this vast igneous body.

It had long been suspected that The Geysers felsite was, at least in part, the crystallized magmatic equivalent of the overlying 1.1 Ma Cobb Mountain volcanic center of the Clear Lake volcanic field (Hearn et al., 1981, 1995). However, attempts to date the felsite had been unsatisfactory. To rectify this situation during the past year, we obtained several new high-precision $^{40}Ar/^{39}Ar$ age dates for the pluton (Hulen et al., 1997). The new dates confirmed the felsite/Cobb Mountain-center correlation, and in a surprising way, outlined in the following pages, led to a better understanding of fracturing mechanisms at The Geysers.

Even more circuitously, argon-argon age dating of vein adularia from Geysers Coring Project corehole SB-15-D helped constrain the most likely types of fracturing in the steam reservoir. Coupled with analysis of temperature-sensitive vitrinite and pyrobitumen present in the metaclastic-rock-hosted portion of the reservoir, thermal-history modeling of the adularia age date showed that violent hydraulic rock rupture was likely to have been a dominant mode of fracturing in what are now the steam reservoir's uppermost reaches.

Research to augment the drilling phase of The Geysers Coring Project (GCP) was essentially completed during 1996. A well-

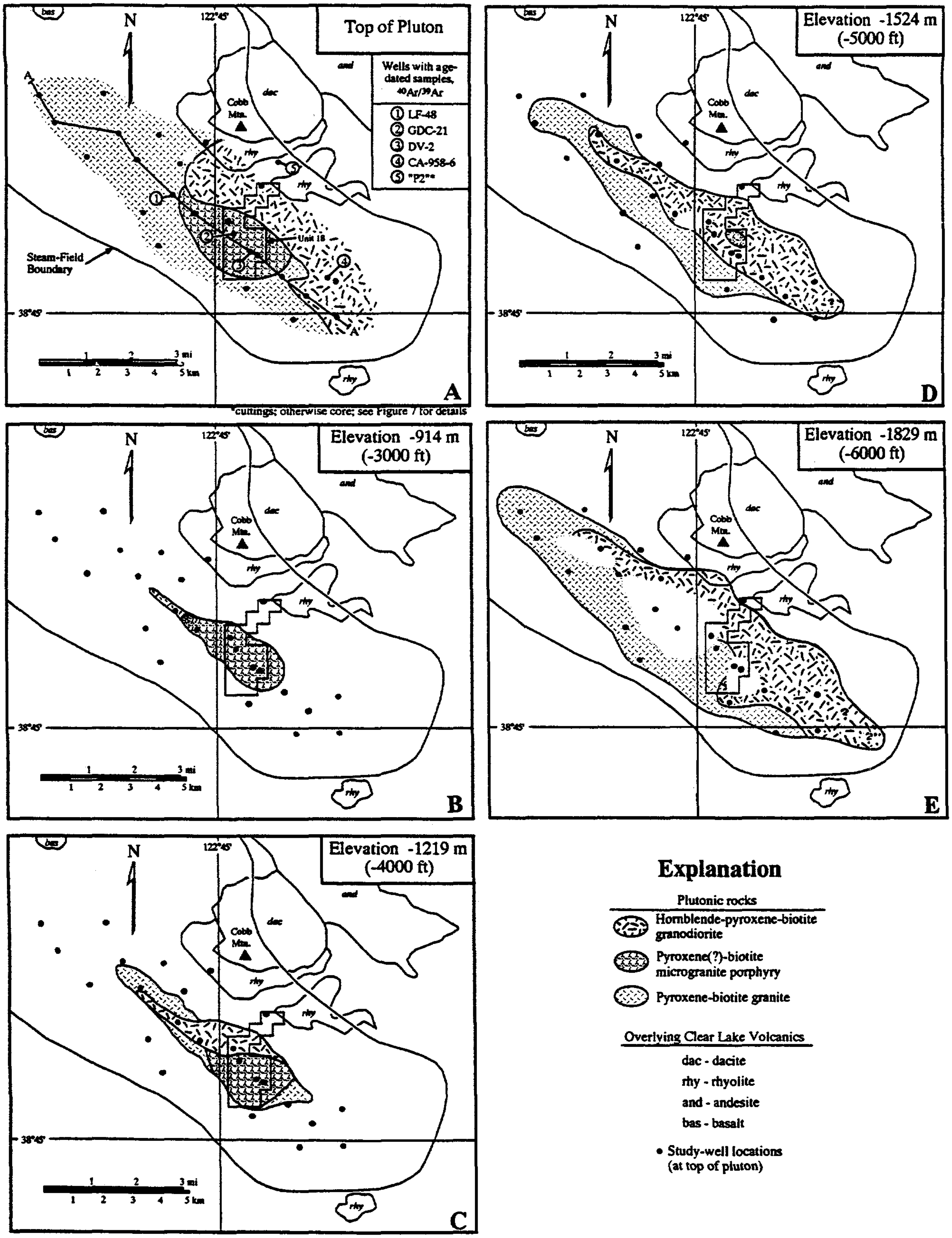

Figure 2. Geologic maps of The Geysers felsite.

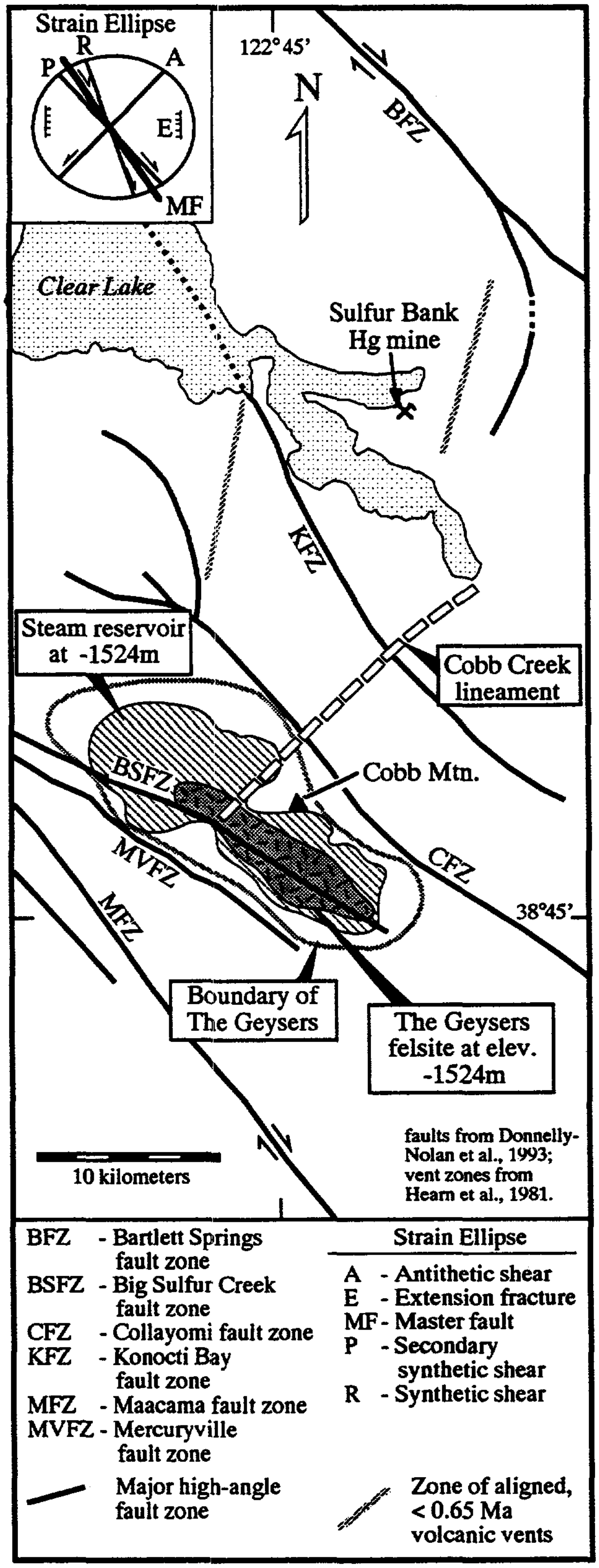

Figure 1. Location map, showing position of The Geysers steam field and "felsite" pluton relative to highly generalized major regional high-angle fault zones.

attended special symposium on GCP research results was held in Santa Rosa, CA in late August. Abstracts of the presentations were combined with previously unpublished baseline geologic information (e.g. detailed X-ray diffraction and vitrinite-reflectance analyses) in a symposium proceedings volume (Hulen [ed.], 1996), which is currently being expanded and refined to produce a two-volume special issue of the international journal *Geothermics*, scheduled for publication in 1998.

THE GEYSERS FELSITE

Acquisition of previously confidential drift surveys for critically located felsite-study wells allowed us in 1996 to map the configuration and composition of this intrusive complex in its full three-dimensional scope for the first time. The newly obtained well courses permitted plotting literally thousands of geochemical, lithologic, and mineralogic data points for the felsite as accurate, strategically positioned level maps and cross sections. These, we believe, will be useful to the steamfield operators in guiding future exploration and production efforts in this important sector of The Geysers resource.

It has long been known that the felsite has a pronounced northwest-southeast orientation **(Figure 1)**, parallel to the prevailing regional structural grain of the San Andreas right-lateral strike-slip fault system (e.g. Stanley and Rodriguez, 1997). The new felsite maps and cross sections reveal that individual intrusive phases in the pluton have this same orientation **(Figure 2)**. In view of this geometry, we believe it likely that the felsite, at least at the levels tested by drilling to date, was either intruded within a dilational pull-apart zone -- or perhaps within a large dilational jog -- of a San Andreas style strike-slip fault. This interpretation helps constrain the likely nature, and even orientation, of the major, tectonically induced and steam-transmitting fractures in The Geysers reservoir, utilizing the now-familiar strike-slip-regime fracture models of structural geologists like Aydin and Nur (1985; see also strain ellipse of **Figure 1**).

Figure 3 presents two coincident 12-kilometer-long vertical sections drawn along the northwest-trending "spine" of the felsite. The upper part of the figure shows the distribution of major rock types, and the lower portion maps the corresponding intensity of borosilicate (tourmaline and ferroaxinite) mineralization. Major steam entries in the felsite show strong affinities (or lack thereof) with both this mineralization and its host rocks.

Although the relationship is far from perfect, there is a distinct tendency for felsite-hosted steam entries to be concentrated along the top of and above the major granodiorite phase of the pluton -- a phase newly dated at 1.1 Ma (Hulen et al., 1997). This relationship suggests that the high-temperature, liquid-dominated hydrothermal system which later became The Geysers steam field may have been generated by the granodiorite, the youngest and most mafic of the three major plutonic pulses (Hulen and Nielson, 1996; Hulen et al., 1997).

Counterintuitively, major steam entries in the felsite are <u>not</u> positively correlated with borosilicate enrichments (**Figure 3**, bottom). The steam entries occur near these entries, but in rock which is relatively fresh. Although the borosilicate zones were clearly once wide-open conduits, perhaps even breccia pipes and dikes, they were clearly and effectively plugged to further fluid flow by deposition of tourmaline and younger ferroaxinite. This finding has important implications for efficient injection of waters to replenish the field's depleted reserves. It seem clear that the injectate should be introduced into fresh rather than mineralized felsite for best results.

VITRINITE GEOTHERMOMETRY

We have continued to utilize the broad array of natural geothermometers available for The Geysers field in order to (1) advance understanding of the field's hydrothermal history; and, perhaps unconventionally, (2) help constrain likely mechanisms of fracturing as well as preferred fracture orientations and textures. Geothermometers utilized in the past at the field include those based on mixed-layer illite/smectite expandability (Hulen and Nielson, 1995a); and fluid-inclusion homogenization temperature (Moore and Gunderson, 1995). We have continued to evaluate these, but have usefully added vitrinite reflectance (VR), an ideal parameter in the organic-rich Franciscan-Assemblage metaclastic sequence which hosts much of the steam reservoir.

Vitrinite is a type of organic matter derived from woody terrestrial plant debris. Its reflectance increases irreversibly in response to both time and temperature (e.g. Barker and Pawlewicz, 1994). Temperature is overwhelmingly the dominant factor in this process, so in high-temperature settings like The Geysers, vitrinite reflectance can be used as an effective peak geothermometer.

Paleotemperatures calculated from the reflectance of vitrinite in the core from GCP corehole SB-15-D (utilizing reflectance-temperature equations presented by Barker and Pawlewicz, 1994) range from about 285°C to about 330°C. In most cases, this is

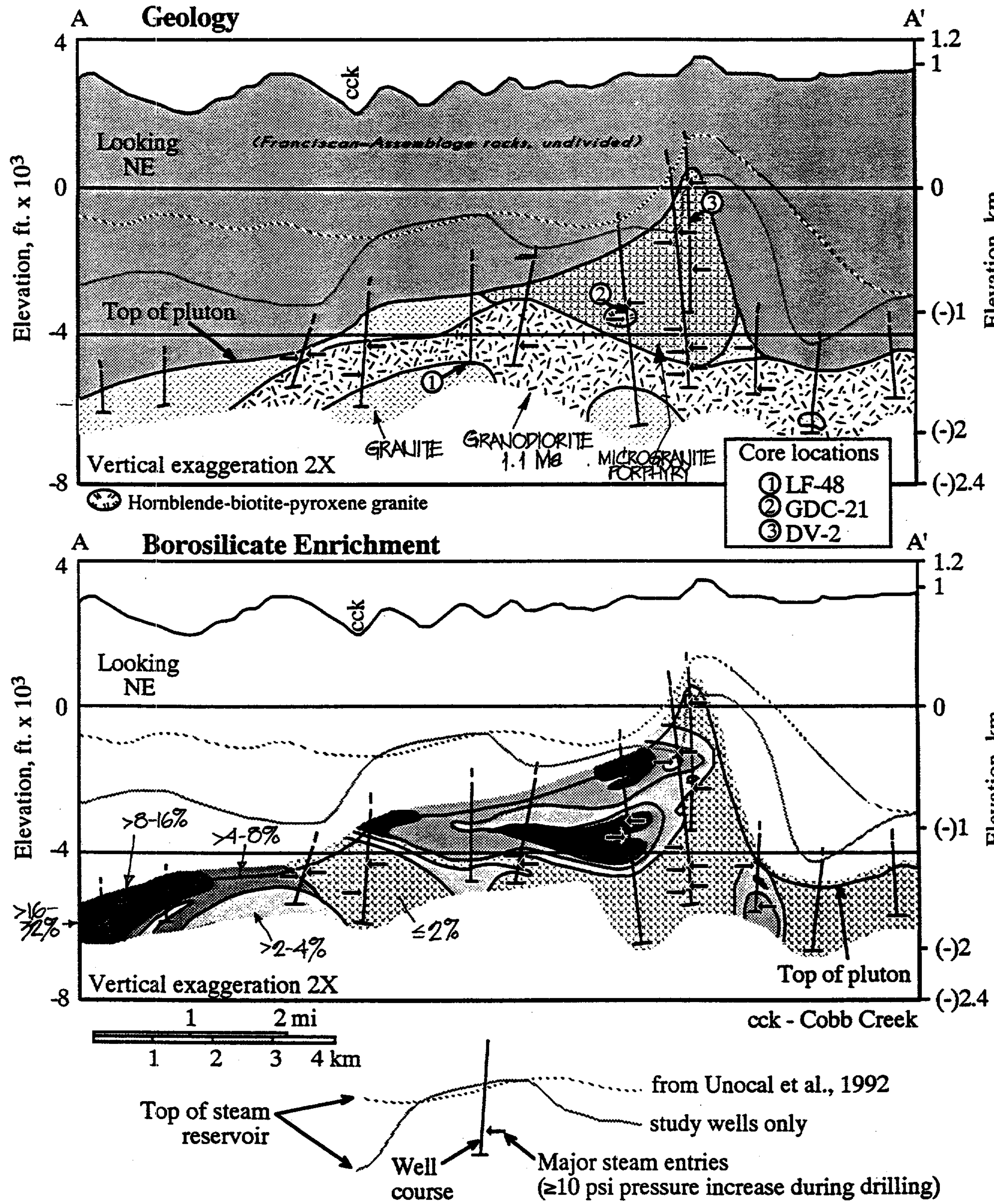

Figure 3. Longitudinal geologic and borosilicate-enrichment cross sections through The Geysers felsite.

10-30°C greater than corresponding maximum fluid-inclusion paleotemperatures, but far less than paleotemperatures determined from the interlayer smectite content of mixed-layer illite/smectite (e.g. Hulen and Nielson, 1995a). Taken together, the paleotemperatures obtained from the different sources clearly record a cooling trend accompanying the transition from hot-water- to vapor-dominated conditions.

An important and quite unexpected use for the VR maximum paleotemperatures emerged from our research -- the constraint of thermal-history modeling of argon-argon incremental-heating age spectra.

ADULARIA AGE-DATING AND THERMAL-HISTORY MODELING

Relatively early-precipitated vein adularia from the deeper portion of GCP corehole SB-15-D was age-dated, in support of our research, by Matt Heizler of the New Mexico Geochronological Research Laboratory (Hulen et al., 1997). The adularia was collected from a depth of 471.8 m, in the uppermost steam-reservoir portion of the corehole. A corresponding series of vitrinite-reflectance measurements were made on the metagraywacke hosting the vein.

The adularia yielded an age spectrum ranging from about 0.35 Ma to 0.57 Ma -- the latter being a minimum age of precipitation. Two argon-closure-temperature domains were calculated for the feldspar, one at about 320°C; the other, corresponding to the older age, at about 375°C. Remember that the maximum temperature experienced by this rock was about 330°C (from VR). Therefore, we can state with reasonable assurance that the adularia's minimum age is also its actual age of crystallization -- 0.57 Ma.

Numerical thermal-history modeling of the age spectrum for the SB-15-D adularia reveals that the feldspar underwent a profound drop in temperature sometime between 275,000 and 200,000 yr ago (Hulen et al., 1997). We have speculated that this temperature drop could have accompanied the transition from hot-water-dominated to vapor-dominated conditions, since vigorous boiling and venting would lead to cooling of the affected hydrothermal system. J.N. Moore, in addition, has shown that CO_2-rich primary fluid inclusions in SB-15-D at this depth and above must have been precipitated in a vapor-dominated regime (Hulen et al., 1997). Accompanying liquid-rich primary inclusions homogenize at about 290°C. These relationships suggest that The Geysers was already vapor-dominated, at this site and elevation, at about 0.26 Ma.

The age of the adularia also provides an important piece of indirect evidence that suggests the liquid-dominated Geysers system was overpressured at this site when it was at its thermal maximum. This overpressuring not only would be conducive to the venting alluded to above, but conceivably could have induced natural hydraulic rock rupture.

EVIDENCE FOR AND IMPLICATIONS OF HYDROTHERMAL-SYSTEM OVERPRESSURING

Age dating of The Geysers felsite and the SB-15-D adularia provide important clues to the likely position of the paleosurface at (1) the time of granodiorite intrusion, 1.1 Ma; and (2) the time of adularia precipitation, 0.57 Ma. We know that the granodiorite and the Cobb Mountain volcanic center are contemporaneous. Therefore the paleosurface of the Cobb Mountain volcanic center (still preserved), and by implication above the rest of The Geysers hydrothermal system, was slightly more than 1 km above sea level (Hulen et al., 1997). We also know the modern elevation of the surface at the SB-15-D site, and can therefore calculate a paleosurface corresponding to 0.57 Ma by assuming a constant erosion rate since 1.1 Ma (about 0.4 mm/yr). In short, we believe that the paleosurface at 0.57 Ma may have been at an elevation of about 810 m.

If we accept this paleosurface estimate, fluid-inclusion paleotemperatures suggest that at the time the adularia crystallized, the causative hot-water-dominated system was at temperatures and pressures certainly sufficient for the system to vent vigorously if breached by a fault, and possibly even high enough to break the rock hydraulically.

The SB-15-D core is laced with delicate, high-angle hydrothermal veins (like the adularia-bearing vein which was age-dated) with absolutely no sign of displacement. We believe that these veins may have formed in hydraulic fractures. Consideration of the modern local stress regime (Oppenheimer, 1986), extrapolated to 0.57 Ma, suggests that such fractures would have a north-northeast trend. Therefore, even though the SB-15-D cores were not oriented, we may be able to predict their preferred direction. If this conclusion withstands further scrutiny, we should be able to say something about likely preferred pathways for injection to replenish this sector of The Geysers resource.

RESEARCH PLANS AND PROPOSED EGI-INDUSTRY COOPERATIVE VENTURES

The combination of precision age-dating, fluid-inclusion microthermometry, petrographic and paragenetic study of vein minerals, vitrinite-reflectance analysis, and numerical thermal-history modeling, applied to the SB-15-D core, has proven to be a powerful "toolbox" for probing the secrets of The Geysers hydrothermal system's complex origin and evolution. We have also shown that in this particular part of the field, this approach also helps constrain the nature and geometry of the steam-reservoir's all-important fracture network. There is every reason to believe that this integrated, multidisciplinary approach would yield equally useful results in other parts of the field.

Subject to the geothermal operating companies' review and approval, we would propose to extend this approach to the northwestern part of the field, concentrating on the "high-temperature" reservoir which yields high concentrations of noncondensible gases as well as high-chloride steam (e.g. Walters et al., 1988). The Aidlin sector, in particular, would seem an especially fitting subject for this research, since it is the most "pristine" of the Geysers' production areas and reportedly has produced relatively high-NCG steam in the past. Another suitable sector would be the Ottoboni production area, where the northwesternmost penetrations of The Geysers felsite occur. We have also initiated a broader study of vitrinite reflectance in the many other cores collected from throughout The Geysers and utilized previously for fluid-inclusion and stable-isotope studies (e.g. Moore and Gunderson, 1995). Finally, in view of the powerful evidence for past overpressuring and perhaps hydraulic fracturing in the SB-15-D core, we would propose to complete detailed geologic mapping of the old Sulphur Bank production area, in which SB-15-D is located. Here the effort would be focused on location and characterization of ancient, eroded, hydrothermal vents which could have served as the conduits for the vigorous venting which gave birth to this part of The Geysers steam reservoir.

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STEAM-WATER RELATIVE PERMEABILITY

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ABSTRACT

A set of relative permeability relations for simultaneous flow of steam and water in porous media have been measured in steady state experiments conducted under the conditions that eliminate most errors associated with saturation and pressure measurements. These relations show that the relative permeabilities for steam-water flow in porous media vary approximately linearly with saturation. This departure from the nitrogen/water behavior indicates that there are fundamental differences between steam/water and nitrogen/water flows. The saturations in these experiments were measured by using a high resolution X-ray computer tomography (CT) scanner. In addition the pressure gradients were obtained from the measurements of liquid phase pressure over the portions with flat saturation profiles. These two aspects constitute a major improvement in the experimental method compared to those used in the past. Comparison of the saturation profiles measured by the X-ray CT scanner during the experiments shows a good agreement with those predicted by numerical simulations. To obtain results that are applicable to general flow of steam and water in porous media similar experiments will be conducted at higher temperature and with porous rocks of different wetting characteristics and porosity distribution.

INTRODUCTION

The concept of relative permeability is an attempt to extend Darcy's law for single-phase flow of a fluid through porous media to account for simultaneous flow of several phases. In this regime the flow of each phase is governed by the microscopic pressure gradient of each phase and the fraction of the overall permeability that is associated with it. This fraction, normally expressed as a fraction of the medium's permeability to single-phase fluid normally the wetting phase, is called the relative permeability. Since being introduced by Buckingham in 1907 and used extensively by investigators in the 1930's, relative permeability has been traditionally expressed as a function of saturation principally because it was believed that it depended on the pore volume occupied by the fluids (Hassler, 1944). Whereas a great many experiments have shown this to be true, a number of other experiments have shown that relative permeability depends on several other parameters such as interfacial tension, wetting characteristics and viscosity ratios of the flowing fluids (Fulcher et al., 1983; Osoba et al., 1951). Since these parameters are expected to change with the type of fluid, porous media and even with temperature, it should be expected that relative permeability would change for a given set of materials and experimental conditions. In addition it is necessary to define residual saturations which normally indicate the smallest saturation for a given phase to become mobile. The curves and the residual saturations together define the relative permeability relations. For most cases these relations can be expressed as simple mathematical functions (Corey, 1954; Brooks and Corey, 1964).

Application of Darcy's law to the description of simultaneous flow of two or more phases of fluids in a porous medium requires the use of relative permeability relations (Hassler, 1944; Osoba et al., 1951; Corey, 1954; Brooks and Corey, 1964). In most applications in petroleum engineering such as those involving the flow of oil and water as in water flooding and oil and gas as in gas injection, these relations are well known and can be determined from routine laboratory experiments (Osoba et al., 1951). However, for the flow of steam and water or for the general case of single-component two-phase flows these relations are not well known. To our knowledge, none of the relations that have been reported in the last few decades are known to be error free (Verma, 1986; Sanchez, 1987; Clossman and Vinegar, 1988). The main difficulties in these experiments, as we show later in this paper, have been due to inaccurate measurements of fluid saturations and inappropriate assignment of pressure gradients to individual phases.

Other techniques involving analysis of enthalpy transients from producing geothermal fields have been used to infer relative permeability relations (Grant, 1977; Sorey et al., 1980; Horne and Ramey, 1978). However these techniques do not eliminate all the variables and quite often the in-situ fluid saturations and the overall permeability structure (i.e matrix, fracture) are unknown. These curves are therefore approximations at best. As shown by the experiments reported by Osoba et al. (1951) and by Hassler (1944), laboratory measurements of relative permeability can still have error if capillary end-effects are not taken into account. The end-effects are known to cause pressure gradients and by extension saturation gradients resulting in a nonuniform distribution of fluids in the core particularly at low flow rates. Ignoring this effect may result in underestimating the relative permeability of the wetting phase and attributing a permeability value for the nonwetting phase to a wrong saturation (Verma, 1986). Though this type of error can be avoided for the two-phase, two-component flows under isothermal conditions, all of the experiments meant to determine steam and water relative permeability relations reported in the past have not been able to completely eliminate these errors for two main reasons: 1) measurements of fluid saturations are not easy since the phase change with pressure drop along the core implies that the material balance methods used in isothermal cases are inapplicable, and 2) the varying pressure gradients along the core due to the combined effect of the capillary end-effects and varying flowing fractions due to phase change generally imply that any average pressure gradient measurement across the core would be different from the actual gradients at points along the core. In the experiments reported here the errors discussed above have been reduced significantly by using X-ray computer tomography (CT) to measure fluid saturations and by using pressure gradients from zones with constant fluid saturations to compute the relative permeability relations.

In this work it was not possible to conduct the experiments under perfectly adiabatic conditions as the X-ray CT scanner imposes limits on the type of materials that can be used thus effectively eliminating the use of guard heaters. However, heat losses were minimized by using a thick layer of high performance insulation material. In addition heat losses from the core were measured at several locations using heat flux sensors. Numerical simulations were carried out to determine the optimum experimental conditions. This included determining the appropriate core length, the effect of heat losses and the time required for the onset of steady state conditions. In this paper, we begin by looking at the origins and the concept of relative permeability with a literature review. Following this our experimental apparatus and the method used are described together with the conditions that have to be met in order to overcome some of the errors associated with laboratory measurements. Next the results of the numerical investigations are discussed. Finally, we shall present the experimental investigations and a discussion of the results.

LITERATURE REVIEW

Relative permeability relations reported in the past have been from the two main sources: 1) Theoretical methods using either field data from well tests or production histories of the wells in producing fields, 2) Laboratory experiments performed by injecting either single or two-phase fluids through small cores or porous medium models.

Relative permeability relations derived from field data have generally been obtained by matching enthalpy data (Grant, 1977; Sorey et al., 1980; Horne and Ramey, 1978). In deriving these relations the reservoir is normally treated as a porous medium. The enthalpy is then determined as a function of in-situ fluid saturations which have to be estimated from the flowing fractions. These models suffer from a number of shortcomings due to the assumptions used. As discussed by Heiba et al. (1983), experiments are the most reliable method to determine relative permeability. However, laboratory techniques also suffer from limitations imposed by boundary effects caused by capillary forces. Capillarity introduces nonlinear effects on the pressure and saturation distribution of the wetting phase at the core exit. Thus experiments must be designed to eliminate these effects. Osaba et al. (1951) have given a summary of the methods used to obtain relative permeability for two-component systems that eliminate or minimize such effects and that have been used successfully in problems of oil and gas. Capillary pressure effects can be overcome by use of sufficiently long cores or by use of high injection rates (Osoba et al., 1951). Our experience shows that even conducting experiments at some rates referred to as high in published literature still leaves substantial end-effects. Thus taking pressure gradients across the core and averaging the saturation over the entire core still leads to errors in computing relative permeability. The second most common source of error has been in the determination of saturation. A number of techniques have been reported, yet each can be shown to have difficulties of some kind when applied to steam-water flow.

One of the earliest attempts to measure relative permeability relations for single component two-phase flow was reported by Miller (1951). In these experiments liquid propane was injected into a core. Propane was allowed to flash as it moved across the core thus creating a two-phase flow with increasing gas fraction as the fluid moved further downstream. From the pressure and temperature measurements along the core and application of material and energy balance it was possible to determine the flowing fractions at each point and therefore to estimate the relative permeability relations. It is not clear whether capillary end-effects were adequately eliminated, and the calculated saturation could not be checked by other independent means.

Among the first attempts to measure saturations directly were those reported by Chen (1976) and Council (1979) using a capacitance probe method. In this technique, the saturation was obtained from a calibration based on the relation between the capacitance and the saturation within the core (Council, 1979). However the margin over which readings were obtained was small, thus leaving doubts on the reliability of the relative permeability relations obtained. Chen et al. (1978) recommended the use of a gamma-ray densitometer for measuring saturations. Later, Verma et al. (1985) and Verma (1986) used a gamma-ray densitometer for experiments using an artificial sand pack. Though this was an improvement over the capacitance probe, the portion of the sample accessed by the densitometer was small (5%). Problems with overheating of the equipment during the experiments resulted in only a small part of the relative permeability curve being investigated. In addition, fluid bypass between the core holder and the sand pack was suspected to contribute to the larger steam relative permeability obtained in the experiments.

Recently, Sanchez (1987) reported the use of average recovery time of a tracer injected with the fluid to determine the water saturation in the core. In these experiments, pressure was measured at only two points a short distance from the either end, effectively ignoring capillary end-effects. Sanchez (1987) estimated an average water saturation representing the whole core and ignored the variations in saturation expected from the capillary end-effects at low flow rates. In addition, the pressure drops reported by Sanchez (1987) over the interval of 50 cm are about 0.3 bars and phase change due to the pressure drop alone even in the absence of capillary end-effects would lead to a saturation gradient along the core. It is therefore possible to question the accuracy of these results.

Clossman and Vinegar (1988) are probably the first to report the use of X-ray CT scanner to measure water and steam saturations in porous materials. They investigated steam-water relative permeability in cores from oil fields at residual oil saturations. The cores used for the experiments were rather small i.e., 15.4 cm in maximum length and 2.47 cm in diameter. The flow rates were also moderate, 3.31 cc/min to 20 cc/min. Steam quality was determined from two temperature measurements at the inlet and exit. The same readings were used to estimate heat losses from the core. Relative permeability relations were calculated from pressure measurement at the same points. Temperatures were not measured along the core but the distribution within the core was assumed to vary in three possible ways, linear, quadratic and constant. The core was enclosed in an aluminum sleeve kept under vacuum conditions to minimize heat losses. Clossman and Vinegar (1988) found that the relative permeability values for the steam phase were close to those reported by Brooks and Corey (1964) but those for the liquid phase were somewhat smaller. Though it is not clear how much each of the assumptions contributed to the final curves, Clossman and Vinegar (1988) did not investigate the influence of capillary end-effects which were bound to be significant due to the small core lengths and low flow rates they used. Secondly, it may be inaccurate to assume that the temperature within the core would vary in the manner assumed in their calculations. In two-phase systems, temperature and pressure are coupled by the Clausius-Clapeyron equation and depend on the capillary end-effects, giving rise to temperature variations that are highly nonlinear and not quadratic.

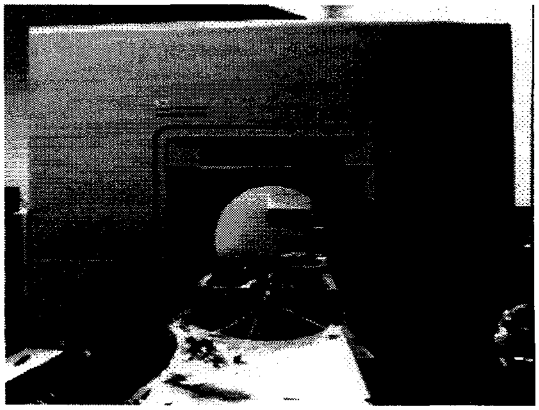
More recently Piquemal (1994) has reported relative permeability relations for steam and water using methods similar to those used by Verma (1986). The porous medium was an unconsolidated material packed in a tube 25 cm long and with an internal radius of 5 cm. Pressure and temperature were measured at four points 5 cm apart along the core holder. The injection rates were changed from 10^{-4} to 10^{-3} kg/s (6.0 to 60.0 gm/min). The experiments were conducted at 180 °C. Though Piquemal (1994) did not discuss any errors in his measurements, the experiments were subject to the same problems reported by Verma (1986) who used a similar apparatus. The problems include limitations on saturation measurement by the gamma-ray densitometer and steam by-pass between the porous medium and the core holder. It is important to notice that the results reported by Piquemal (1994) are different from those obtained by Verma (1986) who observed enhanced permeability of the steam phase. Piquemal (1994) obtained results suggesting that steam-water flows are similar to nitrogen-water.

This review shows that there is a wide range of results that have been reported, some of which even used similar experimental apparatus. The main reason for this has been the difficulties in measuring saturations accurately and using incorrect pressure gradients to compute relative permeability. The investigations reported in this paper overcame these difficulties by using the X-ray CT scanner to measure saturation accurately and by evaluating pressure gradients actually within the zones of constant saturation only.

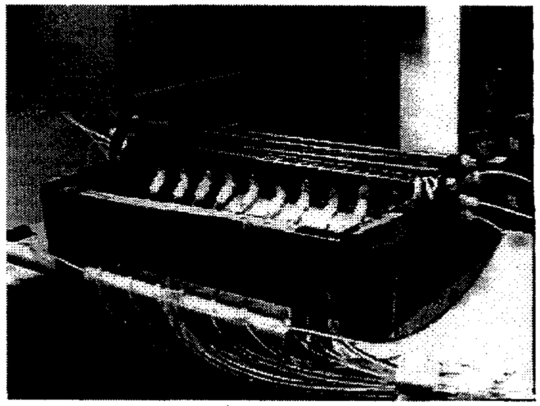
EXPERIMENTAL APPARATUS AND PROCEDURE

The description of the apparatus for these experiments was discussed in Satik et al. (1995) and Ambusso (1996). In general, it consists of an injection unit, and a core holder made of epoxy. The injection unit consisted of two furnaces to generate steam and hot water. Two temperature controllers were used to control the temperatures of the two furnaces. Temperatures were measured by the thermocouples inserted in ceramic protection tubes embedded within the outer most layer of the epoxy core holder. A 12-channel thermometer unit was connected to a computer for storing and displaying the temperature data. The thermometer gathered readings from the eleven J-type thermocouples, eight of which were located on the core while the other three were on the steam line, the water line and the mixing point for the steam and water at the injection end of the core. Pressures were measured by using eleven pressure transducers each with its own read-out screen. Some of the transducers were also connected to chart recorders. Direct monitoring of pressures and temperatures during the experiment enabled us to determine when steady state conditions had been reached. Heat losses on the core body were measured by using heat flux sensors placed at various locations along the core body.

The core (rock) samples used for these experiments have been described in detail in Ambusso (1996) and had the following properties; permeability 600md, porosity 20%, length of 38 cm and diameter of 5.04 cm. The core sample was first heated to 450°C for twelve hours to deactivate clays and to get rid of residual water. The two ends of the core were then covered by the end plugs fitted with nipples for injection and production of fluid. Eight ports to measure temperatures and pressures were then fitted at the fixed intervals along the edge of the core before the rest of the core was covered completely by high temperature epoxy. The core was tested for leaks before being covered with an insulation material made of ceramic blanket. The core was placed on a motorized bench that could be moved to precise locations and scanned as required. A picture of the experimental apparatus within the X-ray CT scanner is shown in Figure 1.



(a)



(b)

Figure 1: Pictures of (a) X-ray CT scanner and (b) the core holder used in the flow experiments

Saturations were measured by using a high resolution X-ray CT scanner. As a requirement, however, high density materials such as most metals or large pieces of intermediate density materials like some forms of plastics could not be placed in the area being scanned since they are almost opaque to X-rays. This imposed a severe restriction on the types of materials that could be used for constructing the core holder. A review of previously published literature did not reveal a core holder without any major metal parts that had been used for this type of experiment. Several investigators (e.g. Closmann and Vinegar, 1988) have reported using core holders made of aluminum materials. They however used X-rays at higher energy levels than our X-ray CT scanner equipment could handle. This ruled out the use of similar designs for the experiments. The first step therefore was to design and construct a core holder that could be used in the CT scanner and that could also withstand high temperatures and pressures for extended periods of time. In addition, the issues associated with minimizing heat losses had to be resolved since guard heaters, which have been used previously in similar experiments, could not be used

(Verma, 1986; Sanchez., 1987). Several attempts were made to ultimately design such a core holder, as described in more detail by Ambusso (1996).

The experimental procedure was as follows. First, air inside the pore space was displaced out by injecting several pore volumes of CO_2 then the core was scanned at predetermined locations to obtain dry-core CT (CT_{dry}) values. Next, water was injected into the core to remove CO_2 and to eventually saturate it completely. This step continued until the core was completely saturated with water, at which time the core was X-ray scanned again at the same locations to obtain wet-core CT (CT_{wet}) values and, pressure and temperature readings were taken at this time. Steady-state relative permeability experiments involve injection of varying fractions of steam and water, at a constant total flow rate, into the core. Measurements done at each step result in a single data point on relative permeability vs. saturation curve. Starting from completely water saturated core and injecting steam at increasing fractions will give rise to a drainage process while the opposite procedure gives rise to an imbibition process. Each step continued until steady-state conditions at which injection and production rates became the same for both steam and water and also pressures and temperatures stabilized. At the onset of steady-state conditions, another X-ray scanning was done along the core at the same locations to obtain CT (CT_{exp}) values corresponding to the particular steam-water fraction. Next, the steam-water fraction was changed, keeping total flow rate constant, and the above procedure was repeated.

After the experiment was completed, an interpretation software was used to calculate the porosity and saturation distributions from the *CT* values obtained with the scanner. To calculate porosity the following expression was used:

$$\phi = \frac{CT_{wet} - CT_{dry}}{CT_{water} - CT_{air}} \quad \text{.......................................} \quad (1)$$

where CT_{water}, CT_{air} are CT numbers for water and air, respectively. Similarly, the expression used to calculate saturations is:

$$S_{st} = \frac{CT_{wet} - CT_{exp}}{CT_{wet} - CT_{dry}} \quad \text{....................................} \quad (2)$$

and

$$S_w = 1 - S_{st} \quad \text{..} \quad (3)$$

where S_{st} and S_w denote steam and water saturations, respectively.

RESULTS

NUMERICAL

Prior to the experiments, numerical simulations were carried out to determine the optimum dimensions of the core required to overcome capillary end-effects and to evaluate the effect of injection rates and steam fractions on the results. The effects of heat losses on the temperature, pressure and saturation measurements were also evaluated. In addition, the numerical simulations were used to estimate the time required for the experiments to reach steady state conditions. These simulations were described in Ambusso et al. (1996).

The STARS software was used for the numerical investigation. This program is a multicomponent thermal simulator specifically designed to handle heavy oil operations such as surfactant flooding, steam injection and in-situ combustion in single and dual porosity media, and fractured reservoirs. Three main aspects were investigated; the effect of the type of relative permeability curves, the effect of flow rates and flowing fractions on pressure, temperature and saturation and the effect of heat losses on fluid distribution along the core and fluid segregation due to the combined effects of gravity and condensation. Several methods of investigation were used. In all of the cases the physical dimensions of the models were similar to those used for the experiments (a core of 5.08 cm in diameter and 43.2 cm in length). Permeability and porosity values were set to 600 md and 20%, respectively. The injection and production points were fixed at the centers of the end plates. In each simulation run, the parameters of interest were saturation, pressure and temperature.

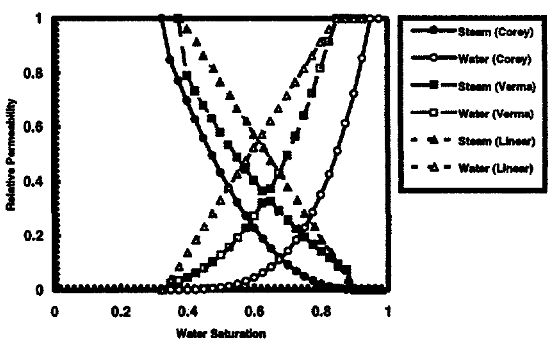


Figure 2: Relative permeability curves used for the numerical simulation.

Three types of relative permeability curves were used in the numerical simulations: the widely used Corey (1954), the linear curves and the curves derived by Verma (1986). These curves are shown in Figure 2.

In particular, the curves reported by Verma (1986) were of interest since these curves represent a more recent measurement and the methods used to obtain them were similar to ours. In order to reduce the number of variables between the curves the irreducible saturations for the liquid phase from the curves obtained by Verma (1986) were used for all of the curves.

In order to reproduce the end-effects it was necessary to incorporate a capillary pressure in the simulator. These functions are well known for oil and water under static conditions. In the case of steam-water flow in porous media, however, these functions are currently not known. We therefore used the relations for water and nitrogen given in a parametric form - $C*ln(Sw)$ (Aziz, 1995), where C is a constant. To mimic the capillary end-effects, the core was divided into several small blocks. The first and the last blocks were assigned zero capillary pressure. In real situations the capillary pressure may be small but will always be non-zero in the injection lines.

Figure 3 shows the numerical simulation results of saturation distributions obtained using different relative permeability curves. The total injection rate is 14 cc/min of water and the steam quality is 0.1. In all of the cases the flow was modeled as adiabatic. It is clear that the linear relative permeability curves predict lower steam saturations. They also give lower pressure drops across the core for all of the injection rates. This is consistent with the higher mobility predicted (equal to unity for all saturations) for the combined flow steam and water. In all of the cases the steam saturation increases marginally towards the production end until the end-effects reverses the trend. This, too, is consistent with the flashing of water into steam as the pressure declines. In all of the cases, the capillary end-effects are very strongly expressed but decrease as flow rate increases. The results also show that it is possible to have a substantial flat saturation profile even for modest injection rates. These curves suggest clearly that the type of relative permeability curve has a significant influence on the results obtained.

To investigate the effect of flow rate, the relative permeability curves obtained by Verma (1986) were used. In each case the steam quality (in mass) was kept constant at 0.05. The injection rates were 8, 15 and 20 cc/min. Figure 4 shows the numerical simulation results of saturation distributions at these three flow rates. These results show the expected behavior. The portion of the curve affected by the capillary end-effects decreases as the flow rate increases. The pressure and temperature also rise to higher values as the flow rate increases. These results show that the appropriate length for the core which is not to be affected by end-effects is about 30 cm. Therefore a core length of 43.2 cm was selected to be used for the experiments.

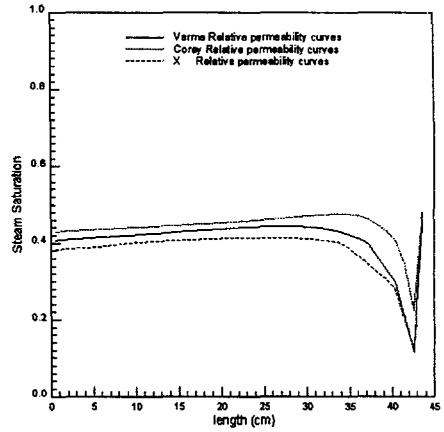


Figure 3: Saturation distribution for different relative permeability relations.

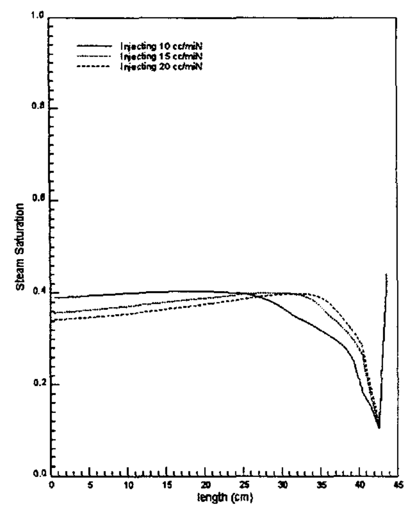


Figure 4: Saturation distributions for three different injection rates, obtained from the numerical simulation.

To investigate the effect of heat loses on fluid segregation, a three-dimensional numerical model was constructed by dividing the core into a 100x3x3 grid in the x, y and z directions, respectively. Insulation around the core was added as an additional layer of low thermal conductivity in the y, and z directions. The thickness of the insulation was set to 2.54 cm and the porosity and permeability of the insulation were set to zero. In the simulator, the thermal properties were set to those provided by the manufacturer. The curves obtained by Verma (1986) and a flow rate of 12 cc/min were used to generate the results shown in Figure 5. The results are for the middle three layers from the uppermost to the lowest. As expected, the temperature and pressure are practically the same for all of the blocks at a given cross-section except at the end blocks where there exists a non-axial flow. Saturations vary only marginally in the vertical direction.

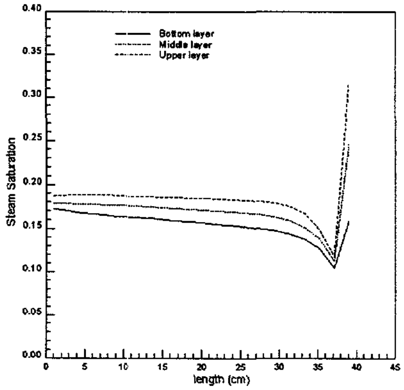


Figure 5: Saturation distributions for three vertical layers, obtained from the numerical simulation.

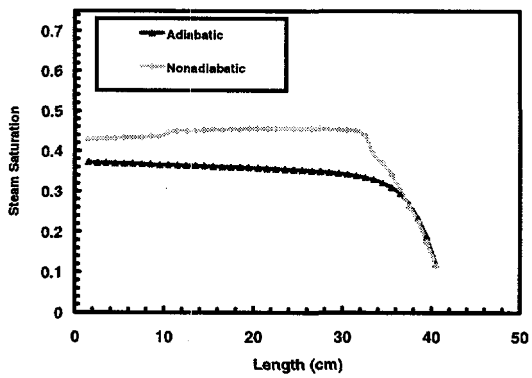


Figure 6: Saturation profiles for adiabatic and non-adiabatic cases, obtained from the numerical simulation.

To compare the results obtained with and without heat losses a one-dimensional model was constructed with the same dimensions. The comparison of results from these two models is shown on Figure 6. There still is a flat saturation profile over the most of the early part of the curve but the capillary end-effects are more strongly expressed and start earlier for the non-adiabatic case. Also, the steam saturation does not show the marginal increase observed for the adiabatic cases but is rather simply flat. This is an important aspect of these results since only one value of saturation was computed per section, effectively making the experiments one-dimensional. Recognition of the variation in saturation was an important confirmation of acceptable results. This indeed was the case. These results indicate that heat losses will affect the measurements but the main features will be unaffected. Thus a flat saturation profile, which is required to evaluate relative permeability accurately, is still present and is of sufficient length.

EXPERIMENTAL

The single core dynamic method was used for the measurement of the relative permeability. This method required that a two-phase mixture of steam and water be injected into the core. By changing the flowing fractions of each phase and letting the system adjust itself to steady-state conditions, the relative permeability relations were determined from the knowledge of the flowing fractions and the measured pressures and temperatures. To determine the flowing fractions it is necessary that the enthalpy of the injected fluid be known accurately. Thus it is important that the injected fractions of the components in the core be known before injection and the phase change accompanying pressure drop be considered. Though it has been suggested that in the porous media the process of boiling and phase change may require more energy due to capillary forces (Udell, 1982), experiments by Miller (1951) with light gasoline showed that the temperature and pressure follow values close to those for flat surface thermodynamics. For this reason steam table values were used to compute flowing phase proportions in the core.

We used two methods to inject fluids of known enthalpy. The first was to inject a two-phase mixture that was heated to high temperature but always keeping the pressure above saturation so that the fluid always remained in the liquid phase upstream of a throttle valve set to release fluid only after some threshold pressure has been reached. The enthalpy of the two-phase mixture would be the same as that of the liquid water corrected for heat losses along the line, the kinetic energy being negligible in this case. This method is a modification of that used by Miller (1951) and Arihara (1976) who injected the fluid as a single phase into the core. For these experiments this method was used for injection of fluid at low enthalpy to obtain relatively low steam fractions and proved useful since steam table values could be used to determine the enthalpy given either the temperature or the pressure. The second method was to mix streams of steam and water. Due to difficulty in keeping both streams close to saturation, steam was superheated by a few degrees and liquid water was kept a few degrees below the boiling point. This too enabled the use of steam table values for computation of the phase fractions. This approach was used to obtain high steam fractions.

After assembling the core and the auxiliaries, the experiment was initiated by first determining the porosity of the core. This was done by taking X-ray CT scans of the core at various locations when it was dry and again when it was fully saturated with water. First, a steady stream of carbon dioxide was passed through the core for several hours and the initial scan, referred to as the *dry scan*, was performed to obtain CT_{dry} values. Following this, a steady stream of water at low flow rate (5 cc/min) for sufficiently long time (12 hours) to saturate the core completely with water. A second scan, referred to as the *wet scan*, was then conducted to obtain CT_{wet} values at the same locations as the *dry scan* was performed. By using Equation 1 and these two sets of images obtained at every point scanned it was possible to determine the porosity distribution of the core. The average porosity was found to be about 20%. These scans also revealed that the core had a few vugs identified as points with higher porosity from the bar scale. After the porosity distribution had been determined the absolute permeability was determined by flowing water at different flow rates and measuring pressures along the core. Three rates were used and the results are summarized in the Table 1. The results were taken after an hour of injection. The readings show that there is a small dependence of permeability on injection rate.

After determining the absolute permeability, the core was brought to experimental conditions by injecting hot water. Increasing the temperature of the water was done in stages to avoid problems of rapid thermal expansion and shock. These heating stages at low flow rates provided an additional opportunity to check the permeability of the core at higher temperatures. The permeability values at higher temperatures were found to be within the range of those measured at the room temperature, giving credence to the assumption that permeability does not change with temperature.

Table 1: Permeability measured at different injection rates.

Rate cc/min	Pressure psig	Pressure psig	Permeability md
10	7.8	6.5	944
15	10.2	8.5	1082
20	13.1	10.8	1102

Once the target temperature for the experiments had been reached, the core was allowed to attain thermal equilibrium before any readings were taken. During the experiment the phase fractions of the injected fluids were changed 14 times while attempting to increase the steam fraction (and steam saturation in the core). Each of these 14 attempts will be referred as steps in this description. For the first four steps only the water line was used. The steam fraction was adjusted by changing the injection temperature and the flow rate. For the subsequent five steps both the steam and water lines were used. In practice, controlling injection temperature and steam fractions was a very difficult task since the steam generators took too much time to reach thermal equilibrium each time the flow rate or temperature was changed. As a result the steam fractions being injected were initially either less or more than intended and slowly stabilized at the correct values. The same problem was also encountered when water flow rate was changed.

Steady-state conditions were recognized by the stabilization of temperature and pressure. Typically stabilization took three to five hours, though the measurements reported here were taken after at least eight hours. Once a steady state had been confirmed, the measurements of temperature and pressure were recorded together with the heat flux sensors readings. The X-ray CT scans were then taken at locations where the dry and wet scans had been taken to obtain CT_{exp} values. These scans were then processed into saturation images using Equations 2 and 3. The saturation profiles presented in this paper were obtained by averaging the saturation values over a cross sectional area of the core. To determine whether the distribution was uniform each image had to be examined. In general the images showed very uniform saturations for most sections for all flow rates.

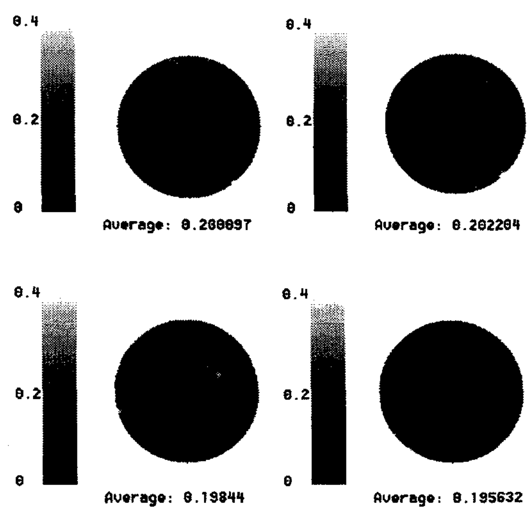


Figure 7: Selected images for porosity distributions obtained from the X-ray CT scan.

In general all of the images gave an average porosity of 20±0.5%. In spite of this uniform value some images had regions of local variations in porosity. Figure 7 shows the porosity distributions obtained from the X-ray CT scanning at four locations along the core. Some of the images show zones with somewhat different porosity. It is not clear whether the anomalous zones are due to larger pores or due to a different packing of sand grains. Otherwise, the porosity over the most of the core length is very close to the average porosity. This core can therefore be considered a close approximation to a uniform porous medium.

Figure 8 shows all of the saturation profiles obtained during the experiments. In general all of the saturation profiles show a decreasing trend from the injection end to the production end which was also observed in the numerical simulation results for the non-adiabatic case. The first and second steps of injection show a few irregular trends at 17 cm and at 25 cm from the injection point. These trends are also repeated to a lesser degree at the same points at higher saturations. These anomalies are attributed to the inhomogeneities existing in permeability or porosity. These are however minor and the saturations still reflect the general trend. In addition, the values of saturation are never really constant but change gradually. Thus the flat saturation profiles are not always "flat". However the values change very little over the most of the core length and can be averaged over an interval to a representative value. In addition, from previous experience with other experiments (e.g. oil and water) relative permeability typically changes monotonically with saturation by small amounts. Therefore, relative permeability computed over regions where saturations vary by less than ±2 % can be considered to be constant.

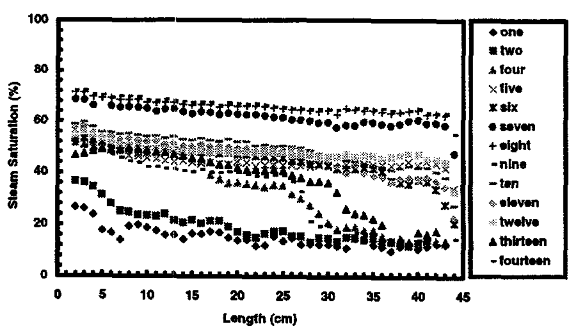


Figure 8: Saturation profiles for all of the steps conducted during the experiment.

The saturation profiles shown in Figure 8 reveal a number of other interesting features. The capillary end-effects are observed at low steam flow rates with high steam fraction. This can be seen for steps that are different in rates but have the same steam fractions (e.g. Steps 4 and 5). This supports some of the results obtained from the simulation where the end-effect is very strong at small flow rates.

Figures 9 and 10 show steady-state temperature and pressure profiles, respectively. As described in the experimental apparatus section, the thermocouples were inserted in ceramic tubes within the outer most layer of the epoxy. Thus the thermocouples probably did not make direct contact with the core. This might have led to lower temperature readings than expected. The pressure readings were taken using teflon tubes attached on the core body. To ensure that the readings were for the water phase these tubes were filled completely with water. By this method water in the tubes was assumed to be in contact with water in the core. In general all of the pressure measurements reflected the expected behavior i.e. decreasing values along the core from the injection end. The values were read by pressure transducers which had a minimum scale division of 1 psi. The error was therefore about 0.5 psi. This value was taken into account when computing the relative permeability.

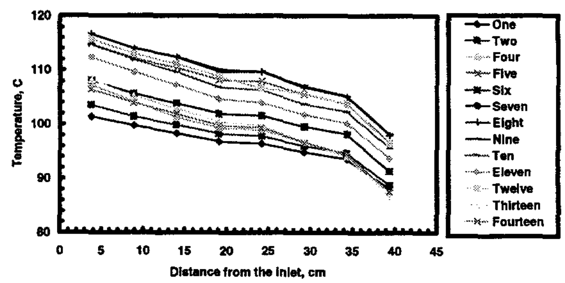


Figure 9: Temperature profiles for all of the steps conducted during the experiment.

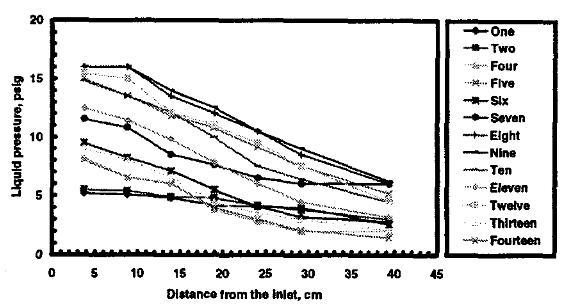


Figure 10: Pressure profiles for all of the steps conducted during the experiment.

Since it was not possible to use guard heaters the experiments were not conducted under perfect adiabatic conditions. Thus the interpretation of the results must take heat losses into considerations. This requires that the heat lost through the system be accounted for and the flowing fractions corrected accordingly. Heat losses were measured only on the body of the core. In the steam and water line, the heat losses were estimated by recording the temperature drop while flowing a known amount of fluid. Since the heat loss rate is only governed by the temperature difference between the material being considered and the surrounding, these results could be extended to the case of any other fluid under similar conditions. This was done to estimate the heat lost from the injection lines before and after the mixing of fluids.

The starting point of this derivation are the conservation equations for mass and energy fluxes:

$$m_t = m_v + m_l \quad \text{.......................} (4)$$

$$m_t h_t = m_v h_v + m_l h_l + Q \quad \text{..............} (5)$$

where m and h refer to mass flow rate and enthalpy, respectively and the subscript t refers to total, v to vapor phase and l to the liquid phase. Q is the total heat lost upstream of the point being considered.

Then using flat interface thermodynamics the steam fraction (x) in the flow at any time would be given by:

$$x = \frac{m_t(h_t - h_l) - Q}{m_t h_{lv}} \quad \text{.......................} (6)$$

h_{lv} is the latent heat of vaporization at the prevailing temperature and pressure.

Then the relative permeabilities to steam and water can be calculated by the corresponding Darcy's equations for each phase in terms of the mass flow rates:

$$k_{rl} = -\frac{(1-x)m_t \mu_l \nu_l}{kA\dfrac{\Delta p}{\Delta x}} \quad \text{.......................} (7)$$

and

$$k_{rs} = -\frac{x m_t \mu_s \nu_s}{kA\dfrac{\Delta p}{\Delta x}} \quad \text{.......................} (8)$$

Thus a knowledge of the values of flowing mass fractions in the above equations and pressure drop along a column of the core with constant or flat saturation provides a value for the relative permeability.

Critical to the evaluation of the flowing fractions is the knowledge of the injected enthalpy and the heat losses. Table 2 shows the heat losses on the core body which were computed from the measurement of the heat flux directly. Determining heat losses along the injection lines were however a major challenge. They were estimated from the temperature drop while injecting water during the heating process. In Table 3, we show the heat loss rate calculated from the product of the mass flow rate and the enthalpy difference corresponding to the temperature drop between the back-pressure valve and the mixing point. The values lie on a straight line when plotted which lends credibility to the approach. These heat loss values, though high, represented less than 5% of the total for high flow rates and were twice this for low flow rates.

To determine the flowing fractions at a particular point, the heat losses upstream of the point under consideration was evaluated and subtracted from the total energy at the injection point. The heat lost in the injection line was estimated from the plot of heat loss rate vs. injection temperature, obtained using the values given in Table 3 (Ambusso, 1996). The second component was the heat lost on the core before the fluid reached the point under consideration. This could be estimated from the heat flux sensor measurements which indicated how much heat was being lost in the radial direction. In the direction of flow, the temperature gradient also leads to conductive heat transfer. This component is small compared to heat lost in the radial direction and was neglected in the computations.

Table 2: Heat loss rate obtained from the heat flux sensors.

	Heat Loss Rate, kW/m^2			
Step	Sensor 1	Sensor 2	Sensor 3	Sensor 4
2	0.37634	0.1209	0.109663	0.111083
4	0.378717	0.147147	0.126428	0.11005
5	0.379233	0.148283	0.124775	0.110567
6	0.387138	0.148283	0.124775	0.110567
7	0.402225	0.138725	0.107028	0.135573
8	0.417157	0.15345	0.140017	0.118833
9	0.417157	0.167759	0.130302	0.133016
10	0.408632	0.160167	0.133636	0.127078
11	0.400158	0.163525	0.140482	0.140998
12	0.407908	0.162233	0.140017	0.142342
13	0.385433	0.1581	0.137433	0.124
14	0.380267	0.151383	0.128392	0.113925

Table 3: Heat loss along the injection line.

Flow Rate cc/min	T_{upst} °C	T_{downst} °C	Enthalphy Change, kJ/kg	Heat Loss, W
10	58.4	55.8	10.882	1.81367
10	68.3	64.9	14.246	2.37433
10	100.9	94.6	26.601	4.4335
15	105.9	102.1	20.266	5.0665

To use the heat losses from the heat flux sensors, it was found convenient to convert the heat flux sensor readings into graphs that gave the cumulative heat lost as the fluid moved along the core. This was done for each set of measurements. Thus to compute the flowing fractions, Equation 6 was used after Q had been calculated from the summation of the heat lost on the body and the heat lost along the injection line. These were then converted into volumetric flow rates for the prevailing temperature and pressure. Since the pressure and therefore the specific volume of steam changed along the core, the volumetric flow rate was computed for all the points along the core and the average value over the interval used. The volumetric flow rates were surprisingly similar and generally did not differ by more than 2% over 5 cm intervals.

Table 4: Summary of important results.

Step	q_{water}, cc/min	q_{steam}, cc/min	S_{st} %	k_{rw}	k_{rs}
1	15	0	15-10	0.84658	0
2	13.6	414.6	22	0.781885	0.091682
4	7.78	274	38	0.337338	0.521257
5	7.82	1062	50	0.305915	0.747689
6	3.46	625.7	53	0.209797	0.657116
7	3.49	762.6	64	0.086876	0.839187
8	0.16	1007.8	68	0.024954	0.9122
9	0.19	1007.7	68	0.031423	0.900185
10	4.052	883.8	63-54	0.151571	0.695009
11	4.31	708	52-49	0.182994	0.72366
12	5.82	559.7	49	0.202403	0.680222
13	5.77	436.5	45-39	0.28281	0.608133
14	7.73	893.8	43	0.365989	0.507394

The next parameter of interest was the temperature dependent viscosity particularly for water which varied between 252 and 211 x 10^{-6} kg/m-s. The arithmetic mean of the values at the two end points was used for a given interval. A final correction to the results was to include the errors due to pressure measurements. This was done for all the intervals. The error assumed in each case was ±0.5 psi. Table 4 shows a summary of the essential data from all of the steps conducted during the experiment. The relative permeability values computed from the experimental data are plotted in Figure 11. The relative permeability for the steam and water phases vary approximately linearly with saturation. In view of the common usage of so-called "X curves" in numerical simulations, this is a rather fortunate result.

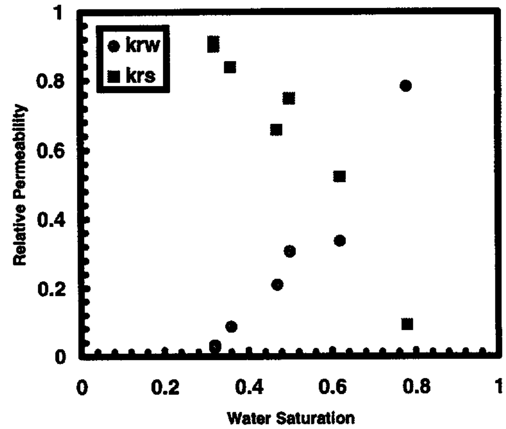


Figure 11: Relative permeability for steam and water.

TRANSIENT APPROACH

Recently we have embarked on a second approach to measuring relative permeabilities, that makes use of the results of the transient boiling experiments reported by Satik (1997). The basis of this approach is to use the inverse modeling approach reported by Finsterle et al (1997) to infer the relative permeabilities indirectly by matching the results of the transient boiling experiments using the simulation code ITOUGH2 developed at Lawrence Berkeley National Laboratory. This method has advantages and disadvantages over the steady-state measurements. The main disadvantage is that the measurement is indirect, and is therefore subject to model error. The main advantage is that the transient experiments are much shorter in duration and therefore can often overcome the challenges we encountered with premature failure of the epoxy core holders in the steady-state experiments.

This new approach is currently in progress, so here we will describe the results from the transient experiments that we intend to match with ITOUGH2.

Two transient experiments have been conducted using two different Berea sandstone core samples. The core sample was positioned horizontally in the first experiment while it was positioned vertically in the second experiment. Two complete sets of experimental data were obtained from these experiments for the case in which the heat flux was increased. These included porosity and saturation distributions determined using the X-ray CT data, and also pressure, temperature and heat flux readings.

The length and diameter of the cores used in both experiments were 43 cm and 5.04 cm, respectively. Before being used in each experiment, both cores were scanned using the X-ray CT scanner at various locations to ensure that they were free of inhomogeneties. Both cores were found to have very similar X-ray CT images. By using the Darcy equation with the results of the wet-core step during each experiment, the absolute permeability of both cores was calculated to be around 500 md. During both experiments, we scanned a total of 42 slices along the core. Using dry and wet X-ray CT data, a three-dimensional porosity profile of each core was constructed. All of those slices for each core indicated a fairly homogenous core. The porosity data were then averaged over each circular slice in order to obtain porosity profiles given in Figure 12. The figure shows a uniform porosity distribution for both cores. The minimum, maximum and average porosity values were calculated to be 0.196, 0.208 and 0.2012 for the first core and 0.1826, 0.1881 and 0.1865 for the second core, respectively.

Recently, we reported the preliminary results from an earlier horizontal boiling experiment (Satik and Horne, 1996). Rather unusual temperature profiles were found in the experiment. Comparison of the steam saturation profiles obtained from the X-ray CT scanning with the corresponding temperature and pressure profiles indicated an inconsistency. The steam saturation profiles showed non-zero values up to temperatures of as low as 50 °C. Although pressures were not measured during this experiment they were assumed to be above atmospheric pressure since the outlet of the core was connected a water reservoir placed next to the core. This unusual behavior was initially attributed to air trapped inside porous medium and air dissolved in the water used to saturate the porous medium (Satik and Horne, 1996). To remedy this problem, the experimental procedure was changed to remove any possible preexisting gas phase in the system. During the new procedure, the core was first vacuumed to 0.00319 psi before the experiment. The water used to saturate the core was then deaerated by preboiling it in a container.

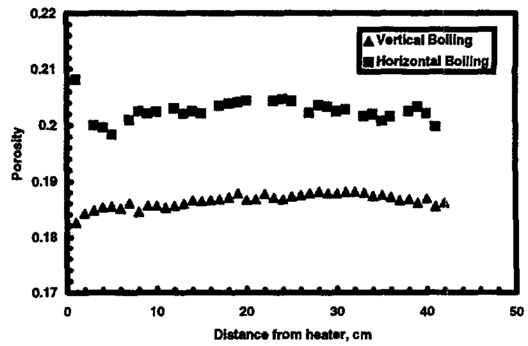


Figure 12: Average porosity profiles along the core, calculated from X-ray CT data obtained during both boiling experiments.

During the first experiment, in which the core was horizontal, the core was scanned and three-dimensional porosity distributions were obtained eight times before and after heating in order to observe the first formation of the steam phase. These three-dimensional porosity distributions were then averaged over each circular cross-section of the core that was scanned in order to obtain the average porosity profiles, four of which are given in Figure 13. All of the curves displayed in the figure, except the curve at 2770 min, show a fairly uniform porosity profile along the core and are within close proximity to each other. The deviation of the curve at 2770 min at distances closer to the heater suggests the first appearance of the steam phase. The comparison of all eight porosity curves with pressure and temperature data indicated that a steam phase did not appear until the appropriate boiling temperature. This results is important because it confirms that air was successfully removed from both porous medium and the water used to saturate it.

Both boiling experiments were conducted by increasing the heater power setting incrementally to reach a desired heat flux value. Figure 14 shows the history of the heater power settings and the heat flux values obtained from heat flux sensors for both horizontal and vertical experiments. The same heater was used in both experiments, thus the magnitude of the power generated by the heater was similar in both cases at the same power setting value.

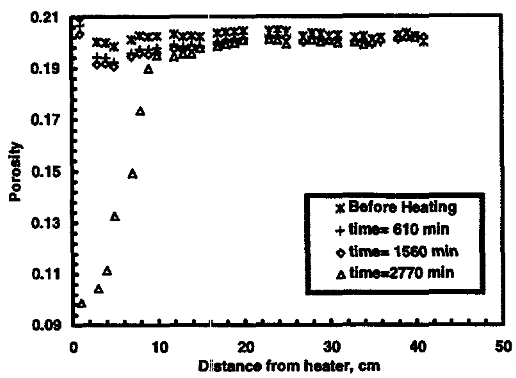
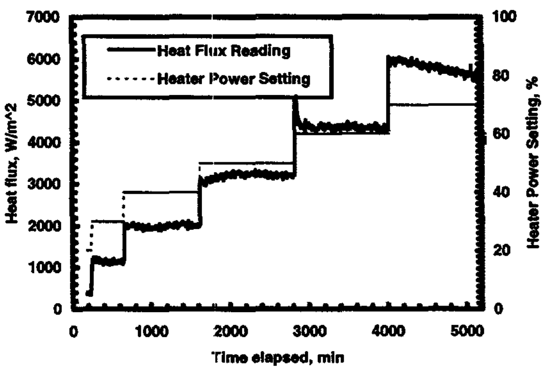
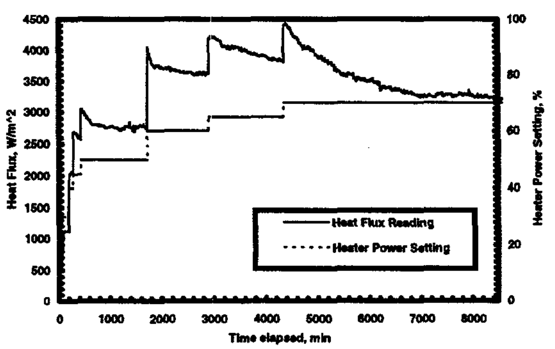


Figure 13: Average porosity profiles along the core, obtained from the X-ray CT scanning conducted at four times during the horizontal boiling experiment.



(a)



(b)

Figure 14: Heater power settings and corresponding heat flux values obtained from the heat flux sensor: (a) horizontal experiment, (b) vertical experiment

During the horizontal experiment, we recorded both the centerline and wall temperatures at ten locations along the core. The centerline temperatures were measured in thermowells extending to the center of the core. The wall temperatures were measured over the outer layer of the epoxy and next to the thermowells. In Figure 15, we show the comparison of the histories of the centerline and wall temperatures obtained at four locations along the core length. The figure shows both transient and steady state (where the temperature profile flattens) sections of the temperature profiles at each heater power value. The maximum temperature reached during the first experiment was 225°C. As shown in Figure 15, the maximum difference between the two temperature profiles was less than 2°C. This suggested that the radial temperature gradient along the core was not significant for this set of experimental conditions and therefore it would be adequate to measure wall temperatures only.

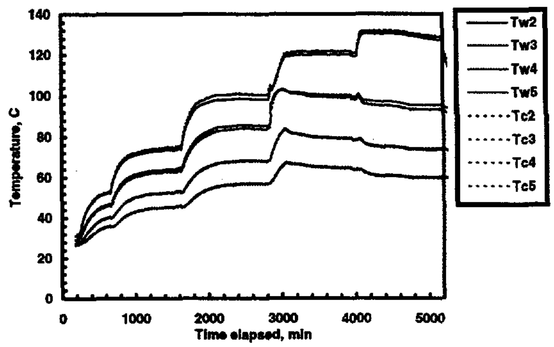


Figure 15: Comparison of the histories of four centerline and wall temperatures during the horizontal boiling experiment.

The core was scanned several times to obtain three-dimensional steam saturation distributions during the experiment. These three-dimensional steam saturation distributions were then averaged over each circular cross-section of the core that was scanned in order to obtain the average steam saturation profiles. In Figure 16, we show four of these saturation profiles. The saturation profile at 2770 min shows a two-phase (steam and water) zone followed by a completely water-filled zone while the profile at 5130 min shows three distinct regions of completely steam, two-phase and completely water. As expected, the steam saturation is higher at locations closer to the inlet, where the heater is located, and decreases towards the outlet.

The comparison of the saturation profile with the corresponding centerline temperature profile at 5130 min is shown in Figure 17. Steam saturation at 100^oC is about 56% and vanishes at about 52^oC. This suggests that the previous problem of the apparent existence of a steam phase at inappropriate temperatures still existed. This behavior was also observed on the other profiles obtained at different.

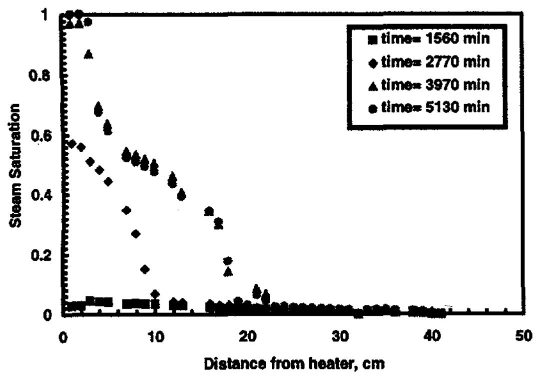


Figure 16: Average steam saturation profiles along the core, calculated from X-ray CT data during the horizontal experiment.

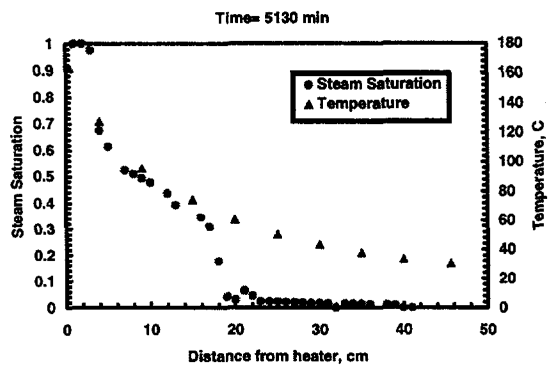


Figure 17: Comparison of the steam saturation and temperature profiles along the core during the horizontal boiling experiment.

Following the horizontal experiment, another experiment was conducted with the core holder positioned vertically to study the effect of gravity on the results. Since the core used for the horizontal experiment had developed extensive cracks during the cooling stage, another core that had similar properties was prepared and used for the vertical experiment. This experiment was also carried out by varying the heater power setting from 20% to 70% incrementally (Figure 14b). Again, to ensure the removal of any gas phase existing in the porous medium or dissolved in the water saturating it, the procedure employed in the first experiment was also used in the vertical experiment.

Measurements of temperature and pressure were taken at ten locations along the core during the experiment. The temperature profiles in Figure 18a show the transient and stabilization stages of each power change. On the other hand, the pressure profiles seem to exhibit an oscillatory behavior until about 5500 min at which time they start to stabilize (Figure 18b). Although not recognizable due to the scale of the graph in Figure 18a, these oscillations also exist in the temperature profiles.

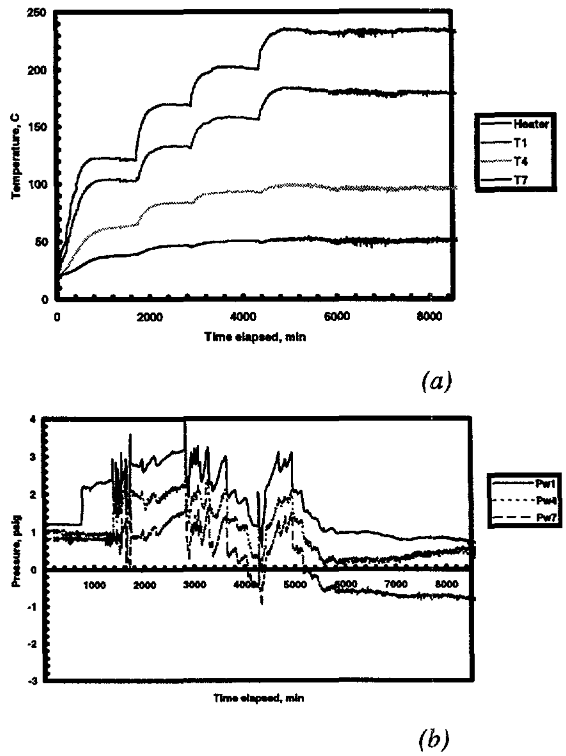
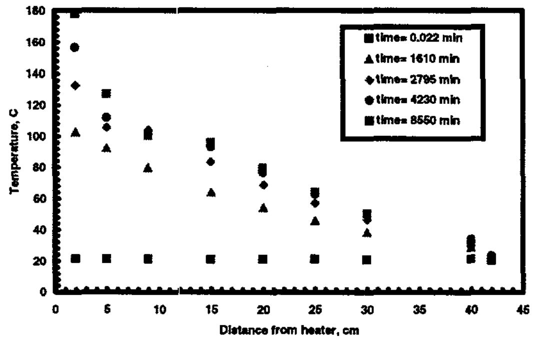
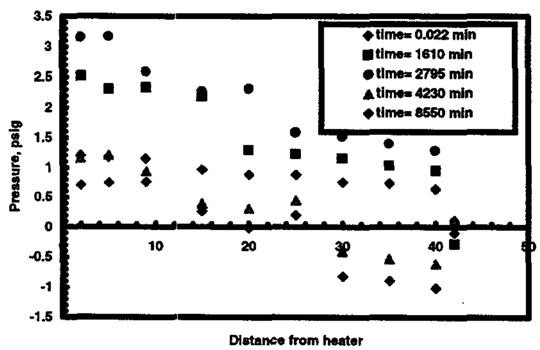


Figure 18: Histories of (a) temperature and (b) pressure obtained during the vertical boiling experiment.

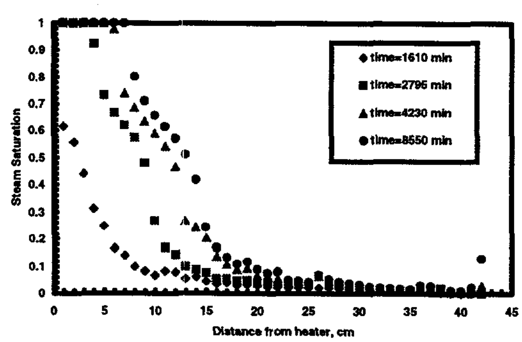
In Figure 19, we show pressure, temperature and saturation profiles obtained at four times during the vertical experiment. Each profile was obtained at the onset of steady-state conditions after each time the heater power was changed. At the beginning of the heating (the curves at 0.022 min), temperatures, pressures and steam saturations along the core was at room temperature, hydrostatic pressure and zero, respectively. After the heater power was increased to 50% (see also Figure 14b) temperatures close the heater started to raise (Figure 18a). The saturation profile at 1610 min shows about 60% steam saturation at the closest location to the heater. The corresponding pressure profile is consistent with the saturations, showing higher pressures closer to the heater that may also indicate the formation of steam phase. As the heater power was increased further, dry-out conditions occurred, leading to existence of the three zones of dry steam, two-phase and liquid water zones (profiles at 2795, 4230 and 8550 min). However, the pressure profiles at 4230 and 8550 min show an unusual behavior, a decrease at all locations along the core. Currently we do not understand the cause of this pressure drop but it could be attributed to a small leak in the core or to a complication with pressure transducers. The pressures increased again during the cooling stage of the experiment, indicating a possible problem with the pressure transducers. To improve the accuracy of pressure measurements in the experiments, the acquisition of more accurate pressure transducers is in progress.



(a)



(b)



(c)

Figure 19: Steady state (a) pressure, (b) temperature and (c) steam saturation profiles along the core, obtained during the vertical boiling experiment.

The temperature profiles showed consistent behavior this time. The previous problem of steam phase existing at inappropriate temperatures did not exist in this experiment. As illustrated in Figure 20, the steam saturation profile indicates a dry steam zone and a liquid water zone connected by a two-phase region. Temperatures are consistent with saturations: A substantial temperature drop in the dry steam zone is due to the low steam-phase thermal conductivity, a rather small temperature gradient in the two-phase zone is due to the pressure gradient and heat losses and the temperature profile in liquid water zone.

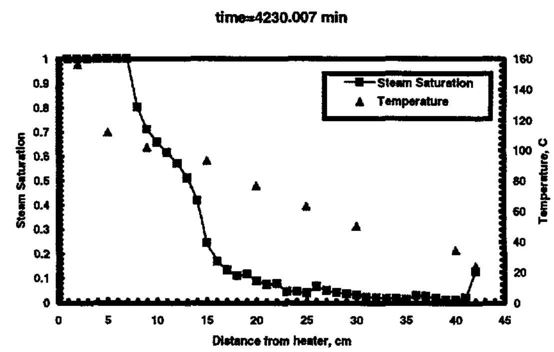


Figure 20: Comparison of the steam saturation and temperature profiles along the core during the vertical boiling experiment

In Figure 21, we show three-dimensional steam saturation profiles, obtained by X-ray CT scanning, at four times during the vertical experiment. The time values corresponding these four images are 1610, 2795, 4230, and 8550 min. The first image shows a two-phase zone followed by liquid water zone while the other three images have the three regions of steam, two-phase and liquid water. These images also show that the boundary between the dry steam and two-phase zone is sharp, indicating a uniform temperature distribution within the dry steam zone. The two-phase zone, on the other hand, has a different behavior. Within the two-phase zone, steam saturation is higher towards the edges of the core while the water saturation is higher closer to the centerline of the core, indicating a possible two-phase convection.

Finally, in Figure 22 we show a comparison of the steam saturation profiles of both horizontal and vertical experiments at the same power values. These results show the effect of gravity. In the horizontal case, the length of the dry steam zone is shorter and the two-phase zone is longer than those in the vertical case. These results are expected since the two-phase zone, which has large compressibility, is expected to shrink in the vertical case simply due to the gravity of the liquid layer overlaying it.

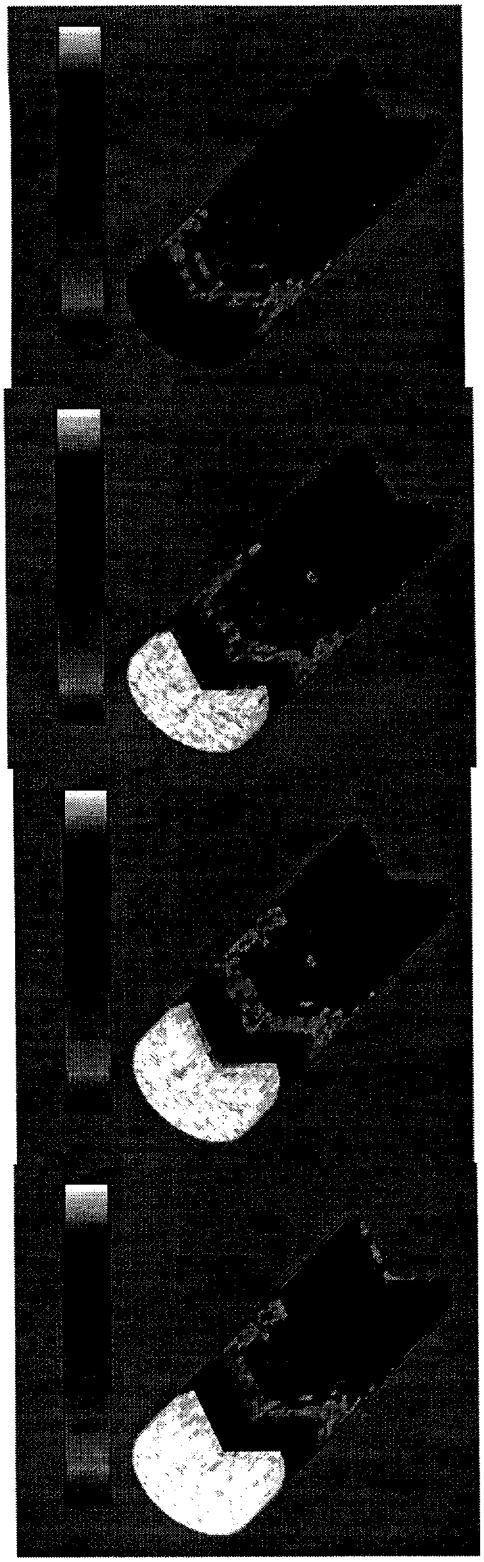


Figure 21: Three-dimensional steam saturation distributions along the core, calculated from the X-ray CT data obtained at four times during the vertical experiment.

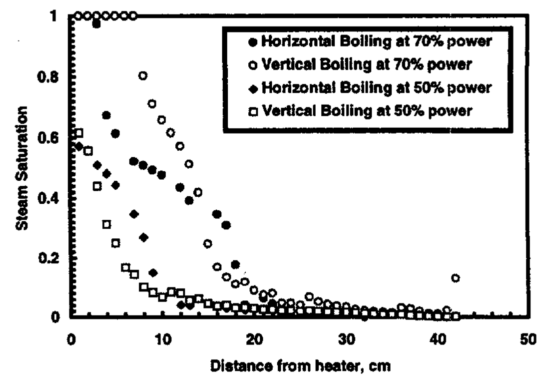


Figure 22: Comparison of the steam saturation profiles obtained at the same heater power values during the horizontal and vertical experiments.

In summary, two boiling experiments were conducted by using Berea sandstone core samples: one with a horizontal core and another with a vertical core. In a previous paper (Satik and Horne, 1996), we reported on the results of the first preliminary horizontal boiling experiment during which we observed an inconsistency in the apparent existence of a steam phase at inappropriately low temperatures. Analysis of the results suggested several improvements on the design of the experimental apparatus and procedure (Satik and Horne, 1996). With the new apparatus and procedure, one horizontal and one vertical experiment were conducted. Using an X-ray CT scanner, three-dimensional porosity and steam saturation distributions were obtained during the experiments. Temperatures, pressures and heat fluxes were also measured. In the new experimental method, both the core and the water used to saturate it were deaerated before the experiments. Both centerline and wall temperatures were measured during the horizontal experiment. The maximum difference between the centerline and wall temperatures was found to be less than 2°C, hence the wall temperatures were found to be adequate to represent the temperature of a circular slice along the core.

Steady-state steam saturation distributions showed a progressive boiling process with the formation of the three regions of steam, two-phase and liquid as the heat flux was increased. The steam saturation distributions obtained using the X-ray CT data did not indicate any significant steam override in either experiment. The previous problem of steam existing at inappropriate temperatures was not observed in the vertical experiment although it persisted to a small extent in the horizontal case. The cause of this effect is still undetermined. Comparison of the three-dimensional saturation profiles from both experiments indicated a longer two-phase zone in the horizontal case than that in the vertical case. This result is expected since the two-phase zone has higher compressibility. Pressure data obtained from both experiments indicated possible problems with pressure transducers. Improvements to the accuracy of the pressure measurements are currently in progress.

CONCLUSION

The relative permeability curves presented in this paper have been derived from experiments in which the saturations within the core have been measured by using an X-ray CT scanner. Furthermore the saturation profiles have been shown to follow very closely what is expected from the numerical simulation. The residual limits are not well defined in the experiments, because it was not possible to inject steam at 100% quality due to condensation in the injection line. It was also not possible to estimate the steam relative permeability at low saturations as the correction for the enthalpy of the injected fluid was very close to the correction in heat lost from the injection line and the core body. These end points are however inferred from the relative permeability curves and are about 20% for the water and less than 10% for the steam phase.

Several relative permeability relations for flow of steam and water in porous media derived from experiments have been proposed in the past (Chen et al., 1978; Council and Ramey, 1979; Verma, 1986; Clossman and Vinegar, 1988). In all of the curves reported in the past the relative permeability for one or more of the phases have tended to follow the relations obtained by Corey (1954) for nitrogen and water. However none of the previous investigators have measured saturation directly in the manner of the experiments reported here. As a result, none of them has measured the pressure of a single phase alone over any interval. Unlike previous investigations, these results show that the relative permeability for both phases are enhanced in comparison to relations obtained by Corey (1954).

The principal feature of the measured relative permeability curves is their close similarity to the so-called "X curves". Use of the "X curves" for geothermal simulation has been common, but until now has been based only on philosophical arguments.

At the moment, we are working to confirm these results by repeating the steady-state experiments and by obtaining independent estimates by matching the results of the transient experiments using the inverse simulation tool ITOUGH2.

ACKNOWLEDGMENTS

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DECLINE CURVE ANALYSIS OF VAPOR-DOMINATED RESERVOIRS

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ABSTRACT

Geothermal Program activities at the INEEL include a review of the transient and pseudo-steady state behavior of production wells in vapor-dominated systems with a focus on The Geysers field. The complicated history of development, infill drilling, injection, and declining turbine inlet pressures makes this field an ideal study area to test new techniques.

The production response of a well can be divided into two distinct periods: transient flow followed by pseudo-steady state (depletion). The transient period can be analyzed using analytic equations, while the pseudo-steady state period is analyzed using empirical relationships. Yet by reviewing both periods, a great deal of insight can be gained about the well and reservoir. An example is presented where this approach is used to determine the permeability thickness product, kh, injection and production interference, and estimate the empirical Arps decline parameter b. When the production data is reinitialized (as may be required by interference effects), the kh determined from the new transient period is repeatable. This information can be used for well diagnostics, quantification of injection benefits, and the empirical estimation of remaining steam reserves.

INTRODUCTION

Decline curve analysis is commonly used to forecast the production from a well, lease, or even an entire field. The simplicity of the technique renders it easy to use and explain to the users of production forecasts. The goal of this study is to extend the Fetkovich (1980) production decline method to vapor-dominated geothermal reservoirs using customary imperial geothermal production units. Specific objectives are to determine the kh from the transient response and map the distribution across the reservoir to identify regions of high kh, to determine the appropriate time periods for empirical decline curve analysis, and to identify injection and production interference.

Analytic expressions for dimensionless pressure, dimensionless production rate, dimensionless decline time, and dimensionless decline rate have been derived for saturated steam. A "Geysers-like" numerical model was used to validate the analytic terms (Faulder, 1996a, 1996b). The derived dimensionless terms are applied to a set of wells located in the southeast Geysers to demonstrate the practical utility of the extended method to estimate the permeability-thickness from the transient production response. Finally, an example is presented demonstrating the general procedure, including injection and production interference.

DECLINE CURVE PRACTICE

Production decline curve analysis has been used at The Geysers since 1969 when Ramey (1970) demonstrated that The Geysers shallow steam reservoir was undergoing depletion through the use of material balance calculations, the p/z method (Whiting and Ramey, 1969), and production decline curve analysis. Empirical rate-time semi-log analysis using the Arps equation (Arps, 1945) is a standard method to forecast remaining steam reserves for individual wells and leases at The Geysers, (Enedy, 1987; Enedy, 1989; Sanyal et al., 1989, Goyal and Box, 1990; Goyal and Box, 1992). In areas responding to water injection, semi-log incline rates have been used to quantify the production response, (Goyal, 1994).

Fetkovich (1980) noted that the concepts of dimensionless pressure and dimensionless time from pressure transient analysis could be used to analyze the transient production response of a well. A dimensionless production rate was defined as the reciprocal of dimensionless pressure. Fetkovich defined two additional dimensionless terms; the dimensionless decline time and the dimensionless decline rate. These last two terms were used to completely describe the transient production and the pseudo-steady state periods. Dimensionless decline time and dimensionless decline rate were used to construct a production decline type curve covering the entire production response of a well producing at a constant backpressure. The transition from transient to pseudo-steady state production for a bounded system occurs at a dimensionless decline time of about 0.25. A type curve match can be used to estimate reservoir properties during the transient flow period and used to directly determine the Arps exponent b during the pseudo-steady state period for a well undisturbed by interference effects. Thus, from the production response of a well, two important reservoir engineering parameters can be obtained, the kh and the Arps exponent b. In practice, the exponent b is generally sought, as it can be used to forecast a production schedule and estimate remaining reserves.

DECLINE EQUATIONS

Analytic equations have been derived for the transient flow period treating steam as a real gas using the Fetkovich type curve. These equations have been previously presented (Faulder, 1996a, 1996b) and are summarized below with the definition of terms is provided at the end of the paper. The dimensionless time, dimensionless real gas potential, and dimensionless rate for imperial geothermal units are

$$t_D = \frac{0.006329kt}{\phi\mu c r_w^2} \qquad \textit{Eq. 1}$$

$$m(p)_D = \frac{kh}{1207\dot{m}}\left(\frac{\rho z}{p}\right)_{res}[m(p) - m(p_{wf})] \qquad \textit{Eq. 2}$$

$$q_D = \frac{1207\dot{m}}{kh}\left(\frac{p}{\rho z}\right)_{res}\frac{1}{[m(p) - m(p_{wf})]} \qquad \textit{Eq. 3}$$

During the transient production response the dimensionless decline rate and dimensionless decline time are

$$q_{Dd} = \frac{\dot{m}(t)}{\dot{m}_i} = \frac{\dot{m}(t)}{\dfrac{kh}{1207}\left(\dfrac{\rho z}{p}\right)_{res}\dfrac{[m(p) - m(p_{wf})]}{\left[\ln\dfrac{r_e}{r_w} - \dfrac{1}{2} + s\right]}} \qquad \textit{Eq. 4}$$

$$t_{Dd} = D_i t = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_w}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]} \qquad \textit{Eq. 5}$$

Finally, the permeability-thickness product can be calculated from a match point with the Fetkovich type production decline curve using Eq. 6.

$$kh = 1207\left(\frac{p}{\rho z}\right)_{res}\frac{\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2} + s\right]}{[m(p) - m(p_{wf})]} \bullet \qquad \textit{Eq. 6}$$

$$\left[\frac{\dot{m}(t)}{q_{Dd}}\right]_{\text{match point}}$$

Once the production transient has reached a closed boundary, the production response enters pseudo-steady state. The empirical Arps equation is valid only during this period to characterize the decline response and forecast future production.

$$\dot{m}(t) = \frac{\dot{m}_i}{[1 + bD_i t]^{1/b}} \qquad \textit{Eq. 7}$$

The value b can vary from 0 to 1 for a hyperbolic family of curves, with b=0 for an exponential decline and b=1 for a harmonic decline. If b lies outside of the range from 0 to 1, interference effects may be present and the data should be reinitialized.

DATA ANALYSIS

The production response of a well in a bounded reservoir consist of two distinct flow periods, a transient production followed by pseudo-steady state. Different types of reservoir information can be obtained by each flow period. The transient flow period can provide information on the permeability-thickness product of the well's drainage volume, an estimate of the wellbore skin factor, and an estimate of the drainage radius. The pseudo-steady state period can be used to identify the onset of interference and forecast a production schedule and remaining reserves.

Data Preparation
Typically, geothermal wells do not produce to at a constant back-pressure during the initial transient flow period. The production must be normalized to an arbitrary standard reference pressure using Eq. 8.

$$\dot{m}_n = \dot{m}\frac{[m(p_{st}) - m(p_{std})]^n}{[m(p_{st}) - m(p_{wf})]^n} \qquad \textit{Eq. 8}$$

This requires an estimate of the exponent n. The static reservoir pressure can be estimated using the modified Rawlins and Shellhardt equation for the real gas potential (Poettmann, 1986).

$$\dot{m} = C[m(p_{st}) - m(p_{wf})]^n \qquad \textit{Eq. 9}$$

Values of C and n are estimated during the first few months of initial production to history match the transient deliverability. It has been the author's experience in reviewing over 60 wells at The Geysers, that using the real gas potential method, n is equal to one. Sanyal et al. (1989) state that using the pressure squared variant of the Rawlins and Shellhardt equation, n can vary from 0.5 to 1. Once C and n are obtained, Eq. 10 is used to estimate the static reservoir pressure.

$$m(p_{st}) = \left(\frac{\dot{m}}{C}\right)^{1/n} + m(p_{wf}) \qquad \textit{Eq. 10}$$

The calculated static wellhead pressure can be compared to the measured wellhead pressure during periods of extended shut-in as a check on the calculated static pressure. Finally, the production rate is normalized to a standard reference wellhead pressure by Eq. 8.

Transient Flow Period
The transient period encompasses the time from the initial production until the pressure transient encounters a closed boundary. The steam production response during this time period is governed by the transient equations given above.

One of the practical difficulties in analyzing the initial transient production response is determining the time of onset of pseudo-steady state. A log-log plot of time versus $1/C^n$ was found to be extremely diagnostic for estimating the time of transition to pseudo-steady state production response (Poettmann, 1986; Hinchman et al., 1987). An abrupt change in slope in this plot indicates the start of pseudo-steady state flow.

Once the transient flow period has been identified, a log-log plot of normalized flow rate versus time can be overlain on the Fetkovich type production curve and a match obtained. From this match the permeability-thickness can be calculated using Eq. 6.

Pseudo-steady State Flow Period
The empirical Arps equation is strictly valid only during the pseudo-steady state flow period. Thus, the above technique is very helpful to identify the start pseudo-steady state.

The type curve match of the transient period is used to estimate the decline parameters (b and D_i) for the pseudo-steady state period. If the production data plots on the Fetkovich curve between a b of 0 to 1.0 and trends along a distinct path, then the corresponding b can be used to characterize the production decline. Unfortunately, most of the wells reviewed exhibit interference effects and the production response is not confined between a b of 0 to 1.0 for long periods of a well's production history.

Interference Effects
The production data may not plot on a single trend due to perturbation in field operations. The drilling of an infill well will cause all surrounding wells to readjust their drainage radii to accommodate, which results in an increase in the apparent decline rate. Conversely, the initiation of injection will provide additional steam from boiling and also change the production decline behavior. These observations can be used to identify injection and production interference effects and assist the engineer in quantifying interference. Whenever interference is observed, the production data should be reinitialized at that time and the data replotted for an accurate quantification of the decline parameters. Reinitialization of the production data involves noting the starting time at which interference occurs, treat this time as time zero, and replotting the remaining data on a log-log plot of normalized flow rate versus time.

Injection interference will cause the production response to shift to the right (to a higher b value) and after a period of time develop a new decline. The difference between the extrapolated old decline and the new decline can be used to quantify the benefits of injection. This same response when viewed on a semi-log rate-time plot may be very subtle and difficult to identify, and may lead to an under-estimation of the benefit of injection. A review of the production response with the Fetkovich type production decline curve can delineate time periods for further detailed analysis. This approach is analogous to pressure transient analysis where the log-log plot of Δp vs Δt is used to delineate flow periods for further detailed analysis.

Production interference can be identified when an established production response shifts to the left to a lower b or even below $b = 0$. Since the Arps equation requires that b be greater than 0, the production data must be re-initialized and a new match obtained on the Fetkovich type production decline curve to obtain a new b.

Example

An example is presented to illustrate the determination of the transient and pseudo-steady state flow periods, the permeability-thickness product from the transient period, estimation of b during the pseudo-steady state period, and injection and production interference. This example is from The Geysers reservoir, using open file production data available from the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources.

The example well A is from the southeast Geysers reservoir and exhibits both production and injection interference effects. The wellhead pressure, calculated static pressure, measured production and the normalized production are presented in Figure 1. The normalized production rate exhibits an apparent decline of 13%/yr for the first 2000 days and in fact this decline could approximate the entire production history. The time period from 2000 days to 2800 days shows evidence of production interference. At 2800 days, the normalized rate exhibits an increase of about 10 Klbm/hr and then production continues to decline, suggestive of injection interference.

A log-log plot of time versus $1/C^n$ is presented in Figure 2. A break in the slope is noted at 1000 days, diagnostic of the onset of pseudo-steady state. A type curve match of the transient production response focuses on the first 1000 days. This match is presented in Figure 3. The match points calculate a kh of 43.4 D-ft. The pseudo-steady state production response follows an Arps exponent b of about 0.4. At 1916 days, the production response falls below $b = 0$, indicating the onset of production interference effects. The production data is reinitialized and a second plot prepared, see Figure 4. The transient response due to the production interference lasts for approximately 550 days at which time the production response enters pseudo-steady state. The match point is used to calculate a kh of 38.1 D-ft. Injection interference is noted at 2859 days and the data again reinitialized, as shown in Figure 5. The transient response lasts about 750 days before the well enters pseudo-steady state. The production response now follows a b of about 0.3. The match point yields a kh of 40.4 D-ft.

SUMMARY

The above analysis demonstrates very good repeatability of the well's kh of 40.6±2.7 D-ft. Furthermore, the production response contains three period of transient production comprising a large fraction of the producing time, as shown in Figure 6. Thus, for these time periods, use of the empirical Arps equation is inappropriate and will give misleading results.

This approach is being used to review the open file production data at The Geysers to generate a kh map of the reservoir. This map can be used for other studies including identification of areas favorable for injection and correlation of permeability with geologic features.

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NOMENCLATURE

Latin Symbols

b Arps hyperbolic decline exponent

C Rawlins and Schellhardt constant, Klbm-cp-hr^{-1}-psi^{-2}

c compressibility, psi^{-1}

D_i initial decline rate, time^{-1}

h reservoir thickness, ft

k permeability, mD

m mass rate, lbm/hr

$m(p)$ real gas potential, psia^2-cp^{-2}

n exponent, dimensionless

p pressure, psi

r radius, ft

s skin, dimensionless

t time, days

z real gas deviation factor, dimensionless

Greek Symbols

μ dynamic viscosity, cp

ρ density, lbm-ft^{-3}

ϕ porosity, fraction

Subscripts

D dimensionless

Dd dimensionless decline

e external

n normalized

res reservoir conditions

st static

std standard reference pressure

wf well flowing

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Figure 1. Production Data for Well A

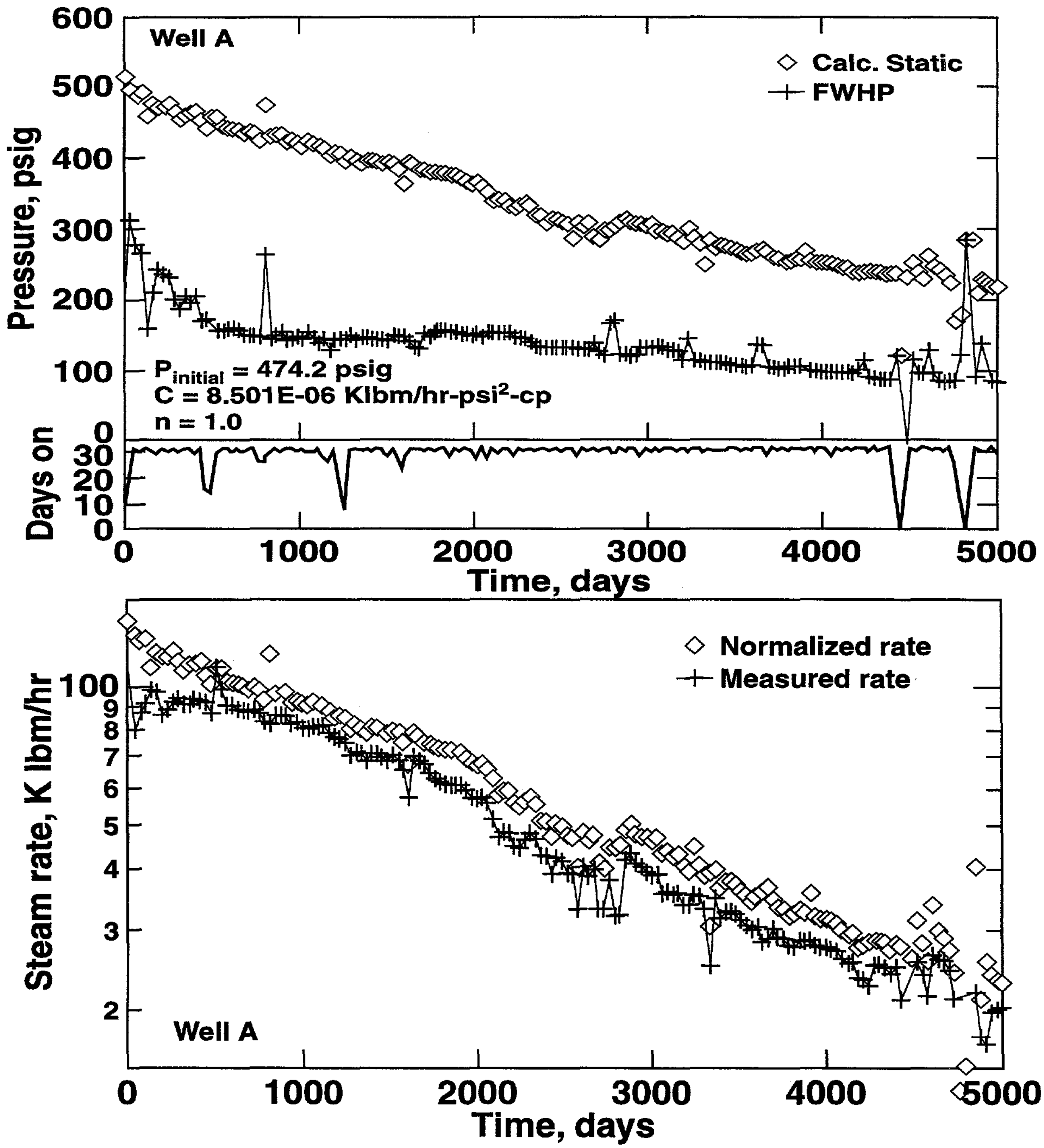


Figure 2. Time vs. $1/C^n$ for Well A

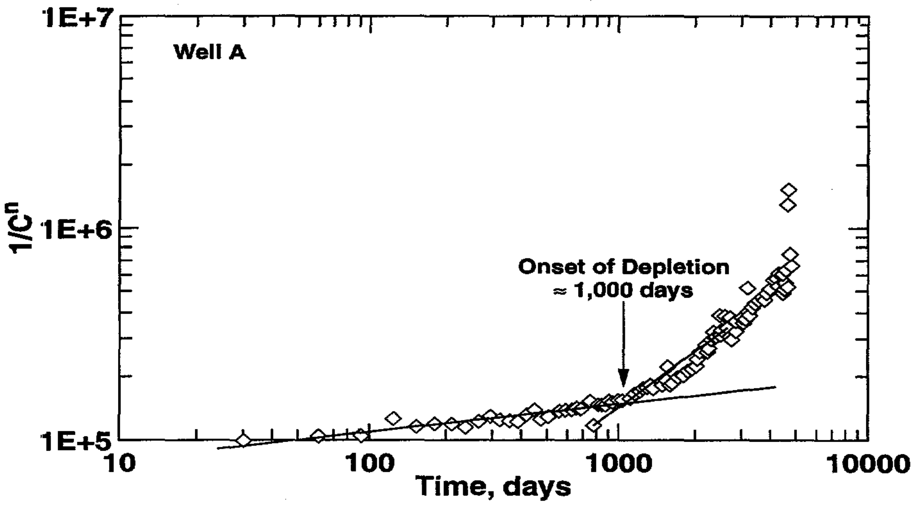


Figure 3. Type Curve Match for Well A

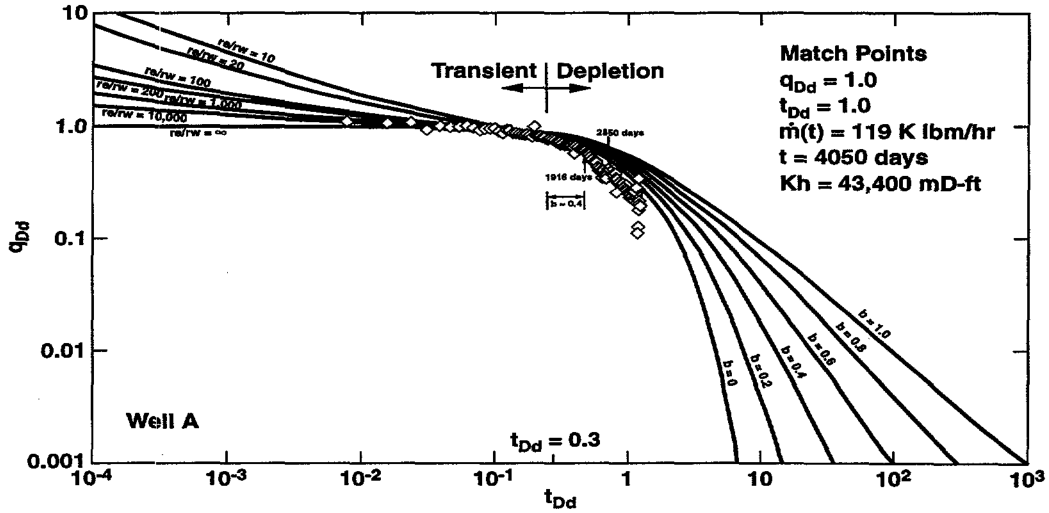


Figure 4. Type Curve Match for Well A, Data Reinitialized At 1916 Days

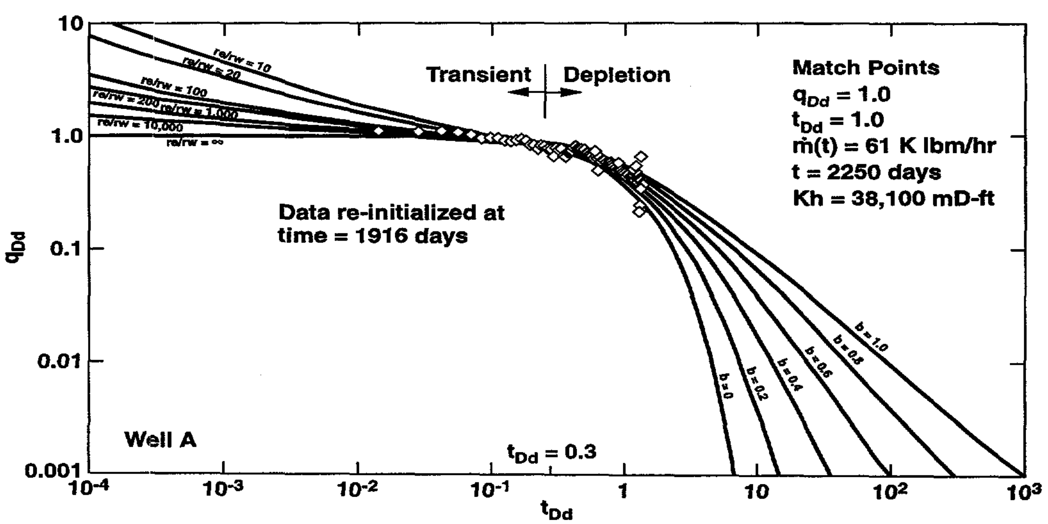


Figure 5. Type Curve Match For Well A, Data Reinitialized At 2859 Days

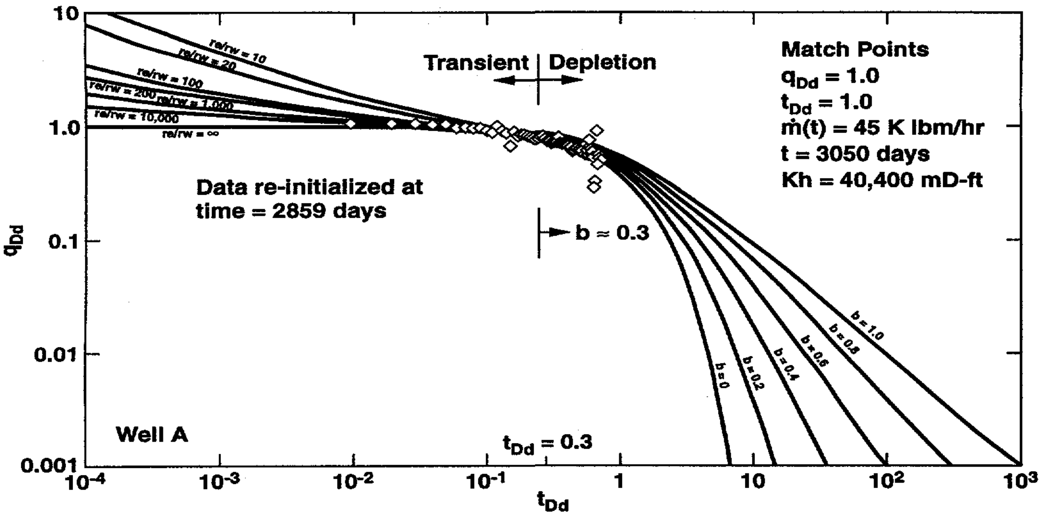
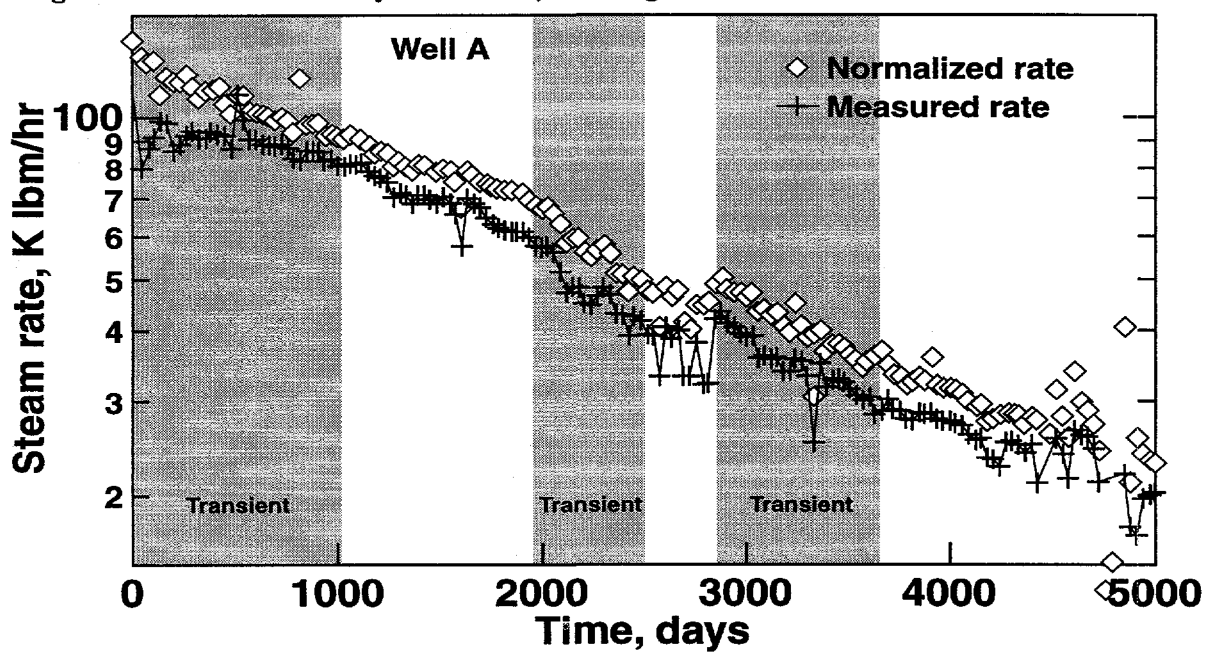


Figure 6. Production History For Well A, Showing Transient Periods



Concurrent Session 5:
Drilling

GEOTHERMAL DRILLING TECHNOLOGY UPDATE

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ABSTRACT

Sandia National Laboratories conducts a comprehensive geothermal drilling research program for the U.S. Department of Energy, Office of Geothermal Technologies. The program currently includes seven areas: lost circulation technology, hard-rock drill bit technology, high-temperature instrumentation, wireless data telemetry, slimhole drilling technology, Geothermal Drilling Organization (GDO) projects, and drilling systems studies. This paper describes the current (March 1997) status of the projects under way in each of these program areas.

INTRODUCTION

The cost of geothermal energy is remarkably low given its advantages relative to other forms of electricity-producing energy. Even so, the cost must be reduced further in order for this clean and reliable resource to expand beyond its current market in the United States. Significant cost reductions can still be realized for drilling and completing geothermal wells. The high temperatures, hard rock, and fractured formations encountered in geothermal drilling account for the higher cost of these wells compared with oil and gas wells to the same depth. Approximately 35-50% of the cost of a geothermal power project is due to the cost of drilling and completing the wells. Advanced technology development and implementation has the potential for reducing these costs by 25%, and that is the goal of the Sandia Geothermal Drilling Technology Program.

The Sandia program is very broad, having evolved over several years to include expertise and technology development in seven distinct but related areas. There are actually significant advantages to conducting a comprehensive, diverse geothermal drilling research program rather than a narrow, highly focused one. First, the geothermal drilling process is complex and has been developed over many years by many talented people. The most assured way to improve the process is by rigorous development and implementation of incremental improvements in many areas (accompanied, of course, by the occasional breakthrough, which is harder to guarantee). Incremental improvements add up to the significant savings in drilling costs that are needed to make geothermal energy more cost competitive.

Second, in the cooperative R&D environment, it is more efficient to carry several projects simultaneously. This is because each project frequently hits hold points where work must stop until someone else completes their part of the work. Multiple projects allow an efficient utilization of the research staff.

Third, in this modern era, many projects require an ensemble of staff with expertise in several disciplines. Projects that were once mechanical in nature now require electrical and software engineering. Tools developed for wellbore instrumentation and logging require mechanical support for placement in the geothermal environment. The diversity of talent needed for a broad program is also available to contribute to any single project.

A number of the Sandia projects are scheduled to be completed this year. This will allow the undertaking of additional new projects that will be initiated to respond to the current needs of the geothermal drilling industry. A continuing effort is under way to define industry needs and develop R&D projects that address those needs.

The remainder of this paper describes the current status of projects in each of the following program areas:

- *Lost Circulation Technology;*
- *Hard-Rock Drill Bit Technology;*
- *High-Temperature Instrumentation;*
- *Wireless Data Telemetry;*
- *Slimhole Drilling Technology;*
- *Geothermal Drilling Organization Projects;*
- *Drilling Systems Studies.*

LOST CIRCULATION TECHNOLOGY

Lost circulation continues to be a costly problem in geothermal drilling, accounting for 10-20% of the cost of a typical well. The goal of the Sandia program in this technology area is to develop tools and techniques for reducing lost circulation costs by 30-50%, thereby reducing geothermal well costs by 3-10%.

Detecting and characterizing a loss zone is the first step in reducing the cost of treating it. Sandia has developed a device called the **rolling float meter** for measuring the outflow rate of drilling fluid from a well, thereby allowing lost circulation rates to be quantified. Sandia has also tested a commercial **Doppler flow meter** (marketed by Peek Measurements, Houston, TX) for measuring drilling fluid inflow rates as an augmentation to the pump stroke counters currently used. These instruments form the basis of a system for detecting even slight differences between inflow and outflow rates, thereby allowing lost circulation and gas or steam kicks to be rapidly identified.

Data obtained with these flow instruments over the past several years have shown that they are capable of: detecting even very minor (<10%) fluid losses as soon as they occur; determining the depth of a loss zone; determining the thickness of a loss zone; detecting mud pump problems such as plugging and mechanical failure; detecting clay booting of the annulus in wireline coring; and evaluating the effectiveness of cementing operations for lost circulation control.

Based on cooperative field testing of the rolling float meter by Sandia and several different companies over the past several years, Sandia has recently re-designed the meter to lincrease flow rate sensitivity and to make it more rugged in the drilling environment. The second-generation meter is currently undergoing extensive field testing on both a wireline core rig and a production-well rig. At least one company is interested in equipping a large number of their rigs with these flow meters.

Sandia is also evaluating an **automated mud density meter** marketed by Gulton Statham (Costa Mesa, CA). This meter utilizes a differential pressure transducer and two sensitive diaphragms placed at a known vertical distance apart in the mud tank. If the meter proves to be accurate, its routine use in geothermal drilling could help prevent lost circulation caused by inadvertent mud weighting and help drill with more confidence in high-pressure steam zones.

A lost-circulation **expert system** is being developed by Tracor, Inc., under contract to Sandia as a Geothermal Drilling Organization (GDO) project, with support from CalEnergy. Under this project, Tracor is developing a software package that monitors the drilling parameters coming from a wide variety of instruments: inflow rate, outflow rate, pump stroke rate, drill pipe pressure, weight-on-bit, rotary speed, drilling torque, and penetration rate. This information is analyzed by a system that filters the data and continually compares it with models of expected performance, identifying problems in real time and providing assistance to the driller in diagnosing and correcting them. Phase I of this project is nearing completion, where existing field data are being used with the developing software to test the system's response to real data. Development of the full system is expected to be completed with two years.

Reducing the cost of a lost circulation treatment is the next obvious place to look for cost savings. Conventional cementing practices include tripping the pipe out of the hole to remove the bit, tripping back in with open-end drill pipe, and pumping a "balanced" cement plug into the open wellbore. In a small-diameter well, a balanced cement plug tends to fill the wellbore and associated fractures in the vicinity of the open end of the drill pipe, without moving down the wellbore. The plug is held in place by the presence of the drilling mud beneath it and a balance of viscosity effects acting within the cement plug and along the wellbore wall. Such a treatment can be highly effective for loss-zone sealing when it works as described.

In large-diameter wellbores, however, cement pumped into the wellbore tends to channel down through the drilling fluid to the bottom of the wellbore. If the loss zone is not on bottom, a cement plug must be built from the bottom up to the loss zone before a significant cement volume flows into the loss-zone fractures. To further complicate the process, it is sometimes difficult to get cement to flow into and plug a loss-zone fracture, even though drilling fluid readily flows into it. Consequently, multiple cement plugs are often required to seal a single lost circulation zone.

Under another GDO project, Sandia and several industry partners are conducting field evaluations of **alternative cement treatments** for lost circulation control. These include cementitious LCM, nitrogen-foam cement, and lightweight, CO_2-resistant cement. CalEnergy, Halliburton, and Brookhaven National Laboratory are participating in this project by providing rig time, alternative cementing materials, and pumping services. Sandia is instrumenting the wells and providing funds for surface and downhole logging to characterize the loss zones and evaluate the effectiveness of the cement treatments.

Sandia has also developed a downhole tool, known as the **drillable straddle packer**, for improving the effectiveness of downhole cement placement for lost circulation control. The packer is an expendable tool that employs two flexible-fabric bags that are inflated with cement to isolate a section of wellbore for cement placement. Cement injected into the wellbore between the two bags is thereby directed into the loss zone, reducing the volume of cement required to seal the zone. The inflated bags also retard the flow of wellbore fluids into the loss zone during cement injection, thereby reducing cement dilution and improving the chances for an effective seal.

During the past year, Sandia has tested the drillable straddle packer in its large outdoor facility called **the Engineered-Lithology Test Facility (ELTF)**. In this facility, clay and gravel layers can be emplaced to simulate impermeable and permeable zones, respectively. Sections of 15-inch I.D. concrete tube are placed vertically to simulate a large-diameter wellbore, with spacers between the tube sections at the permeable gravel zones to create simulated fractures. Cement treatments can be conducted in this facility, then the geologic material can be removed to map the location of the hardened cement.

Tests in the ELTF have demonstrated the viability of the drillable straddle packer concept. In a test conducted without the packer, with open-end drill pipe situated at an upper permeable zone, the cement channeled to the bottom of the simulated wellbore and into another permeable zone first, before it flowed into the upper gravel zone. In an identical test where a straddle packer assembly was located to straddle the upper zone, the packer was completely effective in directing all of the cement into the straddled permeable zone.

As a final laboratory test before fielding the drillable straddle packer, full-scale transparent wellbores are now being constructed. Four 15-inch and two 7.5-inch diameter wellbores are being fabricated from acrylic and will be erected in the ELTF. Each wellbore will have three side openings at different levels simulating permeable zones like those constructed in the clay/gravel tests. A cement treatment through open-end drill pipe and a similar treatment using a drillable straddle packer will be conducted in each wellbore. Copious video-camera coverage of each treatment will track and record the flow of cement in each case. This data will hopefully provide additional evidence of the merits of the drillable straddle packer, leading to a field test in FY98.

HARD-ROCK DRILL BIT TECHNOLOGY

Slow rock penetration is another high-cost characteristic seemingly inherent to geothermal drilling. Penetration rates of 10-20 ft/hr and bit lives of only several hundred feet are typical. Hard, abrasive, fractured rock and high operating temperatures are to blame for such poor performance, as compared with typical bit performance in oil and gas drilling. The goal of the Sandia program is to double the penetration rate and life of geothermal drill bits, which should reduce geothermal well costs by about 15%.

Sandia's drill bit program concentrates on improving synthetic-diamond drill bits for hard-rock applications. The centerpiece of the program is a set of unique test facilities for evaluating the cutting and wear performance of drag cutters in rock. The **Single-Cutter Test Facility** (SCTF) is used to screen cutter geometries and materials for their rock cutting capabilities and to quantify cutter performance in terms of the three-dimensional forces acting on the cutter. Using data from this facility and Sandia's PDCWEAR computer code, the performance of any given cutter when placed on a multiple-cutter bit can be predicted.

The SCTF is being used in several projects. The performance of cutters on a **Track-Set bit** are being evaluated as part of a joint project with Security DBS. In the last year, a large number of tests were completed and the results transferred to this industry partner. Security DBS is using the data to improve their existing codes for designing Track-Set bits. These bits differ from conventional PDC bits in the placement of cutters and the degree of interaction among cutters on the bit. They potentially drill in a more stable pattern in hard rock, thereby reducing bit vibration and increasing bit life. Additional SCTF testing will be conducted in the next year in support of this project.

The SCTF will also be used in support of a number of **Small Business Innovative Research** (SBIR) projects currently managed by the DOE Office of Geothermal Technologies. Sandia will test new cutters emerging from these projects and compare the results with cutting performance data for conventional PDC cutters.

The **Cutter Wear Test Facility** (CWTF) is another unique facility in which cutter performance can be measured, in this case wear performance. The CWTF is essentially a laboratory drill rig with which holes can be efficiently drilled into a 3-ftX3-ftX3-ft sample of rock, such as Sierra White Granite. Up to 85 holes nearly three feet deep can be drilled through the top face of the rock, which is mounted on an air pallet for ease of movement between holes. Standard operating conditions of 60 RPM and 30 ft/hr provide an aggressive cutting and wear environment. A three-cutter core bit is used in which the center cutter is the test cutter. Photographs and measurements of the test cutter wearflat are taken after each 3-ft hole. Cutter wear *vs.* volume of rock drilled can then be plotted for each test cutter as a comparative measure of its rock cutting durability.

The CWTF was placed into operation within the past year. Baseline wear rates for conventional PDC cutters have been established and shown to be repeatable. Testing has begun on various configurations of **PDC claw cutters** in a cooperative project with Dennis Tool Co. This type of cutter employs diamond-filled grooves in the tungsten carbide substrate backing up the PDC layer. These grooves help concentrate stress on the rock and improve cutting performance.

This year, Sandia also completed the numerical modeling of claw cutters employing various groove designs (number, depth, width, spacing) and diamond table thicknesses and has ranked the cutter configurations in order of their combined minimum thermal and mechanical stresses. The comparative wear tests of the same configurations in the CWTF will be used with the numerical results to identify the most wear-resistant configurations.

The CWTF will be used in the Summer of 1997 by a researcher from the University of Southwestern Louisiana to study the phenomenon of **drag-cutter chatter** while drilling hard rock. In this joint DOE- and industry-funded project, the design features and drilling parameters that control cutter chatter are being investigated as a means for extending PDC bit life in harder rock. Compliance will be introduced into the CWTF drill string and bit as necessary to induce cutter chatter, and the controlling parameters will be studied using accelerometers and strain gages.

The CWTF will also be used in support of several other projects conducted by Sandia and others, with funding from the **National Advanced Drilling and Excavation Technology (NADET) Institute** and the **Small Business Innovative Research (SBIR) program at DOE**. Cutters produced under theses projects with alternative synthesizing or bonding techniques will be tested in the CWTF for relative abrasive wear resistance. Sandia is currently investigating the possibility of covering this facility and the SCTF under a Master Statement of Work, which will allow private industry to pay for proprietary testing services at the facility. This will make these unique facilities more readily available for industrial technology development.

Hughes Christensen has largely completed their study of **impregnated diamond drill bits** under contract to Sandia. They experimentally evaluated a number of drill bit design parameters, such as diamond size and quality, diamond placement density, and matrix material type, by building experimental bits and testing them in three types of hard rock. Hughes Christensen is currently incorporating the results of this study into the design of their impregnated-diamond drill bits.

A project funded by NADET was recently initiated in which a **mudjet-augmented PDC bit** will be built and laboratory tested. The idea of using directed, moderate-pressure (<6,000-psi) mudjets at the cutter/rock interface will be brought to reality and evaluated. Security DBS, Dynaflow, Inc., and Terra Tek will participate in the design, fabrication, and testing of the bit.

The process of fabricating **explosively compacted drag cutters** is being investigated by the NM Institute of Mining and Technology. NM Tech has been studying the process of creating cylindrical cutters composed of consolidated boron sub-oxide (such as B_6O). The material has been found to have a hardness approaching that of diamond and a fracture toughness approaching that of tungsten carbide. These characteristics could make it an ideal rock cutting material. NM Tech has already produced cutters that Sandia has successfully tested in short rock cutting tests in the SCTF. Under the present contract, cutters will be produced and tested in the CWTF for wear resistance in cutting rock.

HIGH-TEMPERATURE INSTRUMENTATION

The ability to obtain reliable downhole data in geothermal wells is essential to understanding a geothermal reservoir and optimizing operation of the field. The high cost of conventional wireline logging in the harsh, remote geothermal environment inhibits it use and thereby limits the amount of data available on most geothermal reservoirs. If lower-cost logging methods were available and widely used, it is conceivable that the improved reservoir knowledge gained could reduce the need for one in twenty wells. That represents a 5% savings in the cost of drilling the wells for a geothermal project and seems a reasonable goal for the Sandia program in this area.

To reach this goal, Sandia has developed a suite of high-temperature, memory logging tools. These tools are microprocessor-based data acquisition systems using electronic data storage and battery power to eliminate costly conducting wirelines. Slicklines, available on most rigs and easily pickup-mounted, can be used to run these tools. The tools are heat shielded with dewars (essentially steel Thermos® bottles) and can gather data for up to 10 hours at 400°C. The tool memory is downloaded to a computer and correlated to depth after the tool is reeled back to the surface.

The memory tool nearest commercialization is the **pressure/temperature/spinner memory tool**. This tool originally had only temperature and pressure measurement capabilities and has been successfully field tested in that configuration, accumulating over 40 logs without a single failure. The tool's accuracy and reliability are its primary advantages over currently available tools.

Sandia advertised this past year in the *Commerce Business Daily* for companies interested in commercializing the pressure/temperature memory tool technology. Pruett Industries responded vigorously and is currently working with Sandia to add spinner capability to the tool and market it. Pruett is interested in both selling the tool and offering a logging service using the tool. Sandia has re-programmed the onboard computer to measure counts from the Pruett spinner, and hardware is being assembled to attach the spinner to the tool. Field testing of the combined tool is scheduled in April, 1997.

Sandia is currently building its second **spectral gamma memory tool**. The first tool was successfully tested in the SB-15 well at The Geysers in 1995. The data are still being analyzed and compared with core, but it has been shown that the location of fractures in the core correlate very well with the higher counts of potassium detected by the tool. The second tool will have a larger crystal for better operation in large-diameter wells. Upon completion of the second tool, the tools may be field-tested in Indonesia in late 1997.

The **downhole steam sampler** is also a dewared memory device that condenses and collects a 150 ml sample of steam at a selected downhole location. An onboard computer, memory, and pressure and temperature sensors record data on the thermodynamic state at which the sample is obtained. This information can also be used to actually trigger the sampling. The tool has been tested at the wellhead of a Unocal well in The Geysers. Steam samples were obtained that agree well with samples obtained with a conventional surface steam sampling technique. Unocal and Thermochem, Inc., will be funded through Sandia to further use and develop the tool and sampling technique in The Geysers over the next one or two years. Sandia will continue to provide technical support to this project as requested by the industry partners.

A **core-tube data logger** has also been developed and extensively tested by Sandia. This tool attaches to the core-tube used to retrieve rock core samples in wireline core drilling operations. The tool measures and stores temperature and borehole inclination while drilling, and the data are downloaded to a surface computer when the core-tube is retrieved to remove the rock core. This simple device provides essentially free data on downhole drilling conditions and borehole trajectory. The tool has been tested in cooperation with Tonto Drilling Services and Boart Longyear and found to be of significant value. This tool is further described in a separate paper in these proceedings.

The next generation of high-temperature logging tools is being promoted by developing a universal logging tool circuit employing **silicon-on-insulator semiconductor technology**. These electronic chips are capable of operating unshielded at temperatures as high as 300°C. All the components necessary for a downhole logging tool are expected to become commercially available within the next two years. Sandia is purchasing these components and qualifying them for use in a logging tool circuit as they become available. The feasibility of using **thermal batteries for logging operations** is also being evaluated at Sandia. These batteries operate at extremely high temperatures (>300°C) but may be operable at lower temperatures with proper design and electric thermal jackets.

The feasibility of a **high-temperature slimhole televiewer** is also being investigated. Working with the Energy and Geoscience Institute, we are: examining the value of data obtained in the past with low-temperature slimhole televiewers in mapping fractures; doing conceptual design work to identify potential design features that would enable a new televiewer to be used more easily in the field; and to scope out, identify, and document the level of industry support that a high-temperature slimhole televiewer would have. If the feasibility of such a tool is found to exist based on all these factors, a project plan will be developed for proposed implementation in FY98.

WIRELESS DATA TELEMETRY

Transmitting data from the bottom of a well is problematic in cases where a conducting wireline cannot be easily or economically installed. Wireless telemetry methods have the potential for reducing well costs by providing an economical means for transmitting data to the surface. Sandia is working on several wireless telemetry techniques for this purpose.

An **acoustic line-shaft pump alignment system** is currently under development and testing in cooperation with Johnston Pumps. This system will allow line-shaft pumps to be aligned while the pump is running using acoustic alignment signals actively generated downhole. The acoustic signals are transmitted up the line shaft and production tubing and interpreted at the surface to properly adjust the shaft alignment. Johnston Pump is working cooperatively to develop this Sandia invention and will, if successful, license its use in the field within the next two years.

A **core-tube latching detector** has also been developed and tested within the last year in cooperation with Tonto Drilling Services. This system is a passive listening device that allows the driller to identify the sound made by the core-tube landing above the bit downhole and latching in place. It consists of a pair of noise canceling headphones, a surface-mounted accelerometer, and filtering and amplifying circuitry to pick up and amplify the landing and latching sound. In cases where it is difficult to hear this sound unaided, the driller must allow extra time to be sure landing and latching of the core tube has occurred before resuming drilling. It is estimated that 5% of all geothermal exploration core drilling costs can be attributed to this extra waiting time. The latching detector was successfully field tested in the summer of 1996. Further testing and technology transfer is anticipated in the near future.

Sandia has been working cooperatively with Baker Oil Tools on a **wireless production monitoring tool**. This battery-powered device is attached to bottom of the production tubing, measures downhole temperature and pressure during production, stores the data in memory, and transmits it to the surface on command via sound waves traveling up the production tubing. This tool should be ready for field testing this spring or summer. Although Baker's interest in the tool is primarily for petroleum production, the tool would have applicability in some geothermal wells if the high-temperature silicon-on-insulator technology described above proves feasible.

The transmission of high-speed downhole drilling data to the surface with a technique known as **surface area modulation (SAM) telemetry** is also being investigated at Sandia. This technique employs a method for transmitting electrical signals through the earth and tubulars in the well. A field test in a 2,000-ft oil production well was conducted last year that demonstrated a data transmission speed of 2400 baud. If real-time downhole conditions such as bit vibration could be transmitted to the driller, the potential for effectively using PDC bits in hard-rock drilling would increase dramatically. Pockets of stability undoubtedly exist in weight-on-bit/RPM space that could be found if the driller had a means for detecting bit response as these variables are changed. Under the current project, the SAM telemetry process is being studied and modeled to better understand its application in a geothermal drilling environment, and a field test to demonstrate feasibility is planned within a year.

SLIMHOLE DRILLING TECHNOLOGY

Geothermal exploration costs can be significantly reduced if slimholes are drilled instead of production-sized wells. The goals of the Sandia program in the slimhole technology area are to: 1) document and further reduce the relatively low cost of slimhole drilling as compared with larger wells; and 2) demonstrate that slimhole test data can be used to accurately predict production rates in large-diameter wells in the same geothermal reservoir.

Under contract to Sandia, Maxwell Technologies is continuing with **analysis of data from Japanese slimholes and production wells**. The data analyzed from wells having liquid feed-zones have shown that production well characteristics can, in fact, be accurately predicted based on slimhole production and injection data. Work is continuing on wells with two-phase feed-zones at the Kirishima field, Japan.

With completion of the CalEnergy exploration project at Newberry KGRA, Oregon, CalEnergy has agreed to release the **slimhole drilling data for a cost-shared slimhole** drilled there in 1995. A final report on that project will be released in the near future.

Sandia has served as the drilling advisor for a **geothermal slimhole exploration project at Fort Bliss, TX/NM**. To date this year, four slimholes have been drilled to define the resource. Sandia has used the opportunity to further evaluate some of our developmental hardware, such as the second-generation rolling float meter and the core-tube data logger. Sandia will also do data analysis of any reservoir testing and will document the project.

A **geothermal slimhole handbook** is being written that summarizes the Sandia experience with drilling and testing geothermal slimholes. The handbook will discuss drilling techniques, drilling costs, design considerations, and testing techniques. The handbook will be published this year.

GEOTHERMAL DRILLING ORGANIZATION PROJECTS

The GDO consists of approximately 20 member organizations that cooperate on the development and field testing of technologies for reducing geothermal well costs. GDO projects are cost-shared by DOE (through Sandia) and participating GDO members. In addition to the lost circulation GDO projects previously described, the following projects are also under way.

Novatek is developing a **mud-driven percussive hammer** for improving penetration rates in hard rock. CalEnergy, Unocal, and Amoco are contributing in-kind services to the project. Novatek has a patented mud hammer design that shows significant potential for long-term downhole operation. Under this project, Novatek is building two different hammer sizes and testing them both the laboratory and in the field.

Baker Hughes Inteq has developed a **positive-displacement downhole air motor**. The tool was field tested more than a year ago, but it failed because of improper operating conditions. Although DOE funding for the project has been expended, BH Inteq is still interested in conducting another field test of the tool under more properly controlled conditions. An impediment to the progress of this project is the scarcity of wells drilled in the U.S. that would benefit from the use of the air motor. Field testing overseas, perhaps in Indonesia, is being considered.

Smith International has developed a **high-temperature, high-pressure valve-changing tool** for geothermal well master valves. This tool is placed through a lubricator into the well below the master valve. It is essentially a high-pressure packer that can be activated to shut off the flow of a geothermal well so that repair or replacement of the master valve can be accomplished. Previous tools were rated for 1000 psi and 400°F. The tool developed under this project is rated for 1600 psi and 600°F. Initial laboratory testing of the tool has been successfully completed. Additional laboratory and field testing is scheduled for 1997.

Insulated drill pipe is being developed by Drill Cool Systems with assistance from Sandia. The purpose of insulated drill pipe is to reduce downhole temperatures encountered during the drilling process. This would reduce drilling fluid conditioning costs, increase tool life, and improve the environment for downhole electronics. Drill Cool and Sandia will conduct laboratory testing to verify the design of the drill pipe insulation. Drill Cool will add the insulation to a string of pipe they have purchased for this purpose, and field testing will be conducted in cooperation with CalEnergy to verify its performance.

DRILLING SYSTEMS STUDIES

The geothermal drilling process involves the highly integrated interplay of machinery and procedures; consequently, opportunities for cost savings should be sought at the system level. Sandia has several ongoing studies that can be classified as systems studies.

A **hydrothermal well cost study** is under way with Livesay Consultants to update and expand upon an earlier study of geothermal well costs. Models of well drilling and completion processes are being developed along with documentation of cost elements. The resulting software will allow a well designer or drilling engineer to evaluate various well drilling and completing options for their cost-saving potential. The software will also be useful in identifying the impacts of improved technology on well costs, thereby allowing research to be focused on high-payoff technologies.

A **study of alternative wellbore lining methods** is also under way with Livesay Consultants. This project is funded by the NADET Institute. It will examine alternative methods for casing and lining geothermal wells to reduce costs associated with lost circulation, wellbore-diameter reduction with depth, and expensive casing materials. Previous studies and development programs will be examined and evaluated to identify promising concepts and plan a proposed development program.

Geothermal Management Co. is conducting a **compact rig study** under contract with Sandia. In this study, the commercial availability of drill rig components needed for a state-of-the-art geothermal drill rig is being assessed. Drill rig manufacturers were surveyed and visited to determine current trends in rig design and to obtain accurate cost estimates for building an ideal compact geothermal drill rig. This study will be completed and published this year.

CONCLUSION

DOE's Geothermal Drilling Technology Program at Sandia covers a wide range of technology areas. Each of the areas is progressing at a steady pace, and several projects are expected to be completed this year with commercialization of the resulting technology. Industry advice is continually sought in an effort to re-direct the program to have maximum positive impact on the industry. In addition, program researchers spend a considerable amount of time in the field at drilling sites testing new technology and observing drilling operations to help define the problems that cost money. The future content of the program will be shaped largely by these interactions.

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NATIONAL ADVANCED DRILLING AND EXCAVATION TECHNOLOGIES INSTITUTE
STATUS REPORT, MARCH, 1997

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ABSTRACT

The National Advanced Drilling and Excavation Technologies (NADET) program is intended to pool support, talent, and technologies of the industries dependent upon drilling and excavation technologies to initiate, coordinate, and sustain programs capable of developing substantial technological advances. The NADET Institute has been funded by the DOE Office of Geothermal Technologies and is now supporting seven projects aimed at advanced geothermal drilling technologies. The Institute seeks to broaden its base of funding and technological support from both government and industry sources. Encouraging progress has been made with the support of dues-paying industrial members and industrial sponsorship of a substantial drilling research study.

BACKGROUND

The National Advanced Drilling and Excavation Technologies (NADET) program was founded on the premise that only a cooperative, interindustry program serving those industries that depend upon drilling and excavation technologies could initiate and sustain the type of programs necessary to achieve substantial advances beyond the capacity of corporations and industries acting independently. Among the industries to be served, the geothermal power industry seeks substantial reductions in well drilling costs to better compete with other power sources. As attendees at this Geothermal Program Review know, the NADET Institute has been supported by the Department of Energy's Office of Geothermal Technologies to initiate and sustain research to that end. The expectation is, in keeping with the format of the NADET Institute, that interindustry participation will provide the much needed return on this initial geothermal investment. At this time, with the beginnings of substantive industry support, the outlook is optimistic.

PROGRAM FOCUS

The immediate program focus is of course advanced drilling technologies applicable to geothermal drilling, as discussed in a following section. Advances in this area will certainly be of interest in other areas as well, but to justify substantial interindustry support and to benefit from technological exchanges it is necessary to broaden this focus and to address specific needs within all participating industries. In a series of workshops, a three-part focus was defined. Workshops were held for mining, geothermal drilling, tunneling, sensing, and oil and gas drilling. An environmental drilling workshop is scheduled for April 3 in conjunction with a National Ground Water Association meeting in Las Vegas. An interindustry NADET workshop will be scheduled in the near future to explore and confirm the interindustry benefits of such cooperation.

From the workshops to date, from numerous additional discussions, and from NADET Institute's own Board of Directors, a three-part focus has emerged:

- Advanced excavation concepts and materials, including both mechanical and nonmechanical excavation mechanisms;
- smart drilling systems (e.g., downhole sensing and decision-making systems and associated

smart system operation and control); and

- line-while-advancing systems, ranging from case-while-drilling to simultaneous tunnel boring and lining.

While some view this ambitious set as anything but focus, the fact is that most opportunities for substantial advance demand attention to the entire drilling or excavation system, and there is considerable interaction among these three areas.

SPONSORED RESEARCH

With funding from the DOE Office of Geothermal Technologies, the NADET Institute is managing a research and development program consisting of seven projects. The project selection process began with a request for preliminary proposals issued on March 1, 1996. The RFP was deliberately a loosely defined, broad net, seeking new ideas, with preliminary proposals limited to five pages. Sixty-one responses were received by the closing date, April 8, 1996. In view of the loosely defined program and short turn-around time, the short format was well-received by all respondents. Preliminary proposals were reviewed on May 3 by a panel of nine individuals drawn from industry, academia, and government. Sixteen final proposals were invited, with the suggestion that two of them be combined. Consequently, fifteen final proposals (limited to 10 pages) were received by June 7, 1996. On July 8, the same review board selected seven proposals for funding, totaling about $918,000 as listed in Table 1. Procedures for reviewers are attached as Appendix A, and abstracts of the selected projects are reproduced in Appendix B.

Most observers comment that this selection contains no "revolutionary" concepts, citing the absence of the ubiquitous laser drill. In that sense this observation is correct. In defense of the selections, there were no "revolutionary" preproposals that were even remotely interesting to the reviewers. As reflected in the selections, preproposals were dominated by concepts for advanced (typically diamond) materials and for processing such materials. While not unanticipated technologies (many of the selected projects are extensions or expansions of existing programs), these advanced materials do offer remarkable promise. They are particularly promising for rough-running, high-temperature drilling in hard and broken rock as encountered in geothermal wells.

Of the selected projects, that on wellbore lining methods is, in this author's opinion, the most like to lead to revolutionary advances. It is also the highest risk and will probably take the longest to develop. Clearly, however, if successful it will have greater impact, both within and beyond the geothermal drilling industry, than any other single project on this list. Also unlike the others which seek confirmation or development of known concepts, this is a study in search of concepts. In short, it is the kind of high-potential, high-risk project that requires the long-term shared support that the NADET Institute intends to provide. It is potentially revolutionary.

BROADENING THE SUPPORT BASE

It is essential, both for advances in the geothermal drilling area and for advances in other areas, that NADET Institute broaden its financial and technological base. The Institute seeks both government and industrial support, but the ultimate base must rest on industry. There can (and should) be no prolonged government support if the program is not of recognized benefit to the drilling and excavation dependent industries and to the clientele they serve.

Two white papers have been written, outlining the important roles that government and industry each play in support of the Institute, and justifying those roles in terms of the benefits derived. Copies of these white papers are available on request.

The NADET Institute continues to seek broad government support from a number of government agencies. Although nothing concrete can be cited at this time, the outlook is promising.

Progress has been made on industrial support. A program of support through dues-paying membership has been devised, with industrial dues dependent upon company sales (or sales of drilling and excavation related company division). Dues are set at .1% of sales, with minimum dues of $5,000 and maximum $50,000. Dues are intended to cover operating expenses, with any excess directed to research under the guidance of the Board of Directors. An "Invitation to Join" paper is available, and members of the geothermal industry are invited to join this program in support of their own industry as well as others.

At this time, three companies have indicated that they will join in support of the NADET Institute at the $50K level, and there are encouraging signs from others. In addition, the MOBPTECH coalition (MObil, BP, TExaco, and CHevron jointly supporting R&D for oil and gas drilling) has agreed to fund a $200K compilation of worldwide drilling R&D activities and capabilities. This study will be as valuable to those in the geothermal industry as to those in oil and gas drilling. It is also valuable to the NADET Institute as a foundation for defining both R&D needs and identifying R&D participants. Other industry-supported directed research opportunities such as this have been suggested and will be pursued.

BOARD OF DIRECTORS MEETING

On February 28, 1997, an important NADET Board of Directors meeting was held in the offices of the Nevada Testing Institute in Las Vegas. High on the agenda was a discussion of the Institute's future. Given the funding difficulties commonly encountered in these industries, and the single-source geothermal funding to date, should the NADET Institute continue? The answer, prompted by recent encouraging signs of industry support, was a resounding yes.

In another important discussion it was noted that the NADET Institute as yet has no research program other than that selected and funded by the DOE Office of Geothermal Technologies, directed to the geothermal industry. If the Institute expects industrial support, it must in fact offer additional research programs that are of sufficient interest to be selected by participants from its intended broad industrial base. It was proposed that, with detailed industry participation, two programs be defined:

- line-while-advancing projects having broad applications but sharing common technical issues, and
- smart drilling.

Armed with well-defined programs, the NADET Institute would then launch drives to raise cooperative program research funds to support and sustain projects within these programs (as contrasted to dues income which will support research only if income exceeds operating expenses). The Board agreed with this approach to attracting research funds, provided the effort does not detract from our ongoing effort to secure a sound base and from opportunities presented for directed research projects like the drilling research study and others.

The hurdles are formidable, but the outlook is increasingly positive at this time.

NADET Advanced Geothermal Drilling Projects

"Advanced Geothermal Turbodrill"

William C. Maurer, William J. McDonald and John H. Cohen of Maurer Engineering.

"Improvements to PDC Drill Bits by Microwave Processing of Cemented Tungsten Carbide and Diamond Composites."

Dinesh K. Agrawal, Rustum Roy, and Paul Gigl of the Intercollegiate Materials Research Laboratory, Pennsylvania State University, and Mahlon Dennis of Dennis Tool Company.

"High Performance Mini-disc Bits with Water Jet Flushing."

Levent Ozdemir and Brian Asbury of the Colorado School of Mines and James Friant of Excavation Engineering Associates and the Colorado School of Mines.

"Systems Analysis of Alternative Geothermal Wellbore Lining Methods."

David A. Glowka of Sandia National Laboratories and Bill Livesay of Livesay Consutants.

"Development of a Mud Jet-Augmented PDC Bit for Use with Conventional Rig Pressures."

David A. Glowka of Sandia National Laboratories, Oliver Matthews of Security DBS, Georges Chahine of Dynaflow, Inc., and David Curry of TerraTek.

"Binderless Nanophase Cutter Materials for High Rate Hard Rock Drilling."

Gary Tompa and Oleg Voronov of Diamond Materials Incorporated.

"The Development of New Brazing Processes for the Attachment of TSP Diamonds to Drag Bits."

Bob Radtke of Technology International, Martin Barmatz of The Jet Propulsion Laboratory, John Moore of the Colorado School of Mines and David Glowka of Sandia National Laboratories

NADET Proposal Review Process

July 8, 1996
Hyatt Regency Hotel, SFO
San Francisco, CA

Purpose of Meeting: To select proposals for NADET research awards.

Recusal: In order to safeguard the integrity of the evaluation process and to protect reviewers from charges of real or perceived conflicts of interest, we have developed the following guidelines for recusal from discussion of proposals:

1. You should recuse yourself if you are an employee of a proposing entity.
2. You should recuse yourself if you stand to gain materially if an award is made.
3. You should use your judgment on recusal if you serve on a board of a proposing entity, if you are a consultant to a proposing entity, or if you are significantly involved in advisory activities with a proposing entity.

Background: Today's session is a follow-on to the initial screening session that took place on May 3, 1996. At that session, 16 prospectuses from a total of 61, were selected to be invited to submit full proposals. All 16 proposing entities submitted full proposals by the June 8, 1996 deadline. As suggested by the review panel, two of the three prospectuses on mini-disc designs have been combined into one proposal. There are 15 full proposals to review today. Today's review panel is the same as the original prospectus screening panel.

How the Day is Organized: Today's evaluation session will determine by consensus, which of the 15 proposals will be awarded NADET grants. It is expected that 6 to 10 awards can be made.

Each proposal has been read by all nine reviewers as well as NADET staff. The first half of today's session will be devoted to a thorough discussion of each proposal (15 minutes each). At the end of this discussion period, each reviewer will be asked to score the proposals (from one to ten, with ten being the highest) according to how well the proposal responds to the factors delineated in the RFP.

After lunch, staff will present a preliminary ranking of the scored proposals. The rest of the session will be devoted to a discussion of the proposals as a group. Changes in the preliminary ranking may occur as issues of balance and funding are factored in. By the close of the session, reviewers should reach consensus on the top proposals.

Confidentiality: At the conclusion of the evaluation session, all copies of the proposals will be collected by staff in order to ensure confidentiality. Reviewers are asked not to discuss the proposals or the evaluation process; inquiries can be directed to NADET staff.

Development of a Mud Jet-Augmented PDC Bit for Use with Conventional Rig Pressures

Sandia National Laboratories, Security DBS, Dynaflow, and Terra Tek

This project will develop and demonstrate the effectiveness of a mud jet-augmented PDC bit that drills with improved penetration rates and bit life in hard rock (>20,000 psi compressive strength) using mud pump pressures that are currently available or can be economically installed on the drill rig (<6,000 psi). The proposed mud jet augmentation involves the use of pulsating, cavitating jets directed at the cutter-rock interface near the leading edge of selected cutters on the face of a PDC bit. The bit would take advantage of the synergistic hydraulic-mechanical effects that have repeatedly been shown to result in significant reductions in drag cutter forces in hard rock. Reduced cutter forces result in improved bit life. The goal of this project is to make the primary advantage of PDC bits, which is more efficient and rapid cutting, applicable to hard rock.

Doubling of both bit life and penetration rate over that attainable with roller-cone bits (typically 7-10 ft/hr in hard formations) would reduce geothermal well costs by about 15%, or $300-450k, for a $2-3 million well. Because drilling costs represent about one-half the cost of a geothermal power project, such cost savings would reduce power project costs by about 7.5%. Assuming that total mud jet-augmented PDC bit costs for a given multiple-bit well are $50k more than those for roller-cone bits of the same size, a cost/benefit ratio of about 50/400, or 1/8, is therefore possible.

Under this project, *Sandia National Laboratories* will assist in the design of the prototype bit, using its PDCWEAR code to optimize placement of the cutters and nozzles; and coordinate joint work activities, including planning and design reviews, laboratory and field testing, and reporting. *Security DBS* will lead the mechanical design of the bit; fabricate the prototype bit; participate in laboratory and field testing activities; and assist in planning and reporting. *Dynaflow, Inc.*, will conduct design studies and laboratory testing to optimize nozzle performance for this application; design and fabricate nozzles and provide them to Security DBS for incorporation into the prototype bit; and assist in planning and reporting. *Terra Tek* will conduct laboratory testing of prototype bits under simulated downhole conditions.

Systems Analysis of Alternative Wellbore Lining Methods

Sandia National Laboratories and Livesay Consultants, Inc.

This project will examine alternatives to the conventional practice of lining a wellbore with steel pipe, or casing, sealed in place by pumped cement after a relatively long interval of drilling a constant-diameter hole. A system which could line the hole as it is drilled would be extremely cost-effective, for it would solve or mitigate problems caused by lost circulation, stuck pipe, wellbore instability, and faulty cement jobs around conventional steel casing. Many wells would require fewer casing strings and the casing would be of smaller diameter, accruing additional cost savings. These savings would be especially relevant to the geothermal industry because lost circulation is much worse than in hydrocarbon drilling, and the large production rates for geothermal wells usually require larger casing than in oil and gas wells at comparable depth.

There are eight principal tasks in this project:

1. Review literature and patents, interview past/present researchers to define the state-of-the-art.
2. Define situations or applications in which the wellbore-lining system could be used.
3. From the application scenarios, define functions which the wellbore lining system must perform.
4. Based on the functional requirements, define two or more conceptual systems, realizing that a particular system may not perform all functions.
5. Develop functional and cost criteria for selection of a conceptual design.
6. Identify critical system information, distinguishing between currently available data and that which is still needed for the conceptual design. Estimate data criticality by sensitivity analysis.
7. Develop conceptual layouts of the two most promising systems.
8. Document the study with a Final Report which includes drawings or diagrams of the most promising systems, rationale for the selection process, strengths and weaknesses of each system, estimates of development and operational cost for each system, and a Program Plan for continued development.

Development of New Brazing Processes for Attachment of TSP Diamonds to Drag Bits

Technology International, Inc., Houston, TX, Jet Propulsion Laboratory, Pasadena, CA, Colorado School of Mines, Golden, CO, and Sandia National Laboratories, Albuquerque, NM

This proposal addresses the geothermal drilling problems of dealing with harder rock and higher well-bore temperature gradients. TSP (thermally stable polycrystalline) bits are currently made with small TSP diamonds imbedded in a bit matrix body, resulting in a relatively small cutter standoff, and hence, low penetration rates. The objectives of this NADET project are to (1) develop unique, high attachment shear and impact strength TSP diamond cutters which allows greater cutter exposure, as are lower temperature capacity PDC (polycrystalline diamond compact) cutters, (2) design new TSP drag bits, and (3) demonstrate the capability to economically drill hard-rock in laboratory and field testing. Two new brazing processes for TSP diamond to a drag bit body will be investigated, each with the potential to exceed current state-of-the-art attachment impact and shear strengths.

Doubling of both bit life and penetration rate over that of roller cone bits will reduce geothermal well costs by about 15%, or $300 to $450 savings for $2 to $3 million wells. Because drilling costs typically represent 1/2 the cost of a geothermal power project, total project costs could be reduced by about 7.5%. If TSP bit costs for a given multiple-bit well were $50k more than those for roller cone bits, a cost/benefit ratio of about 50/400 or 1/8 is therefore possible.

Phase I and II will develop two new brazing processes, and, if successful, Phase III will include both laboratory and field performance testing of new TSP diamond drag bit designs. Phase I and II will each be performed in 12 months, and Phase III in 36 months. Technology International, Inc., (TII), the Jet Propulsion Laboratory (JPL), the Colorado School of Mines (CSM), and Sandia Laboratories form an interdisciplinary team which is qualified to effectively transfer technology from the laboratory to commercial applications. For more information contact Bob Radtke, Principal Investigator, Technology International, 2103 River Falls Dr., Kingwood, TX 77339-31543, Ph/Fax: (713) 359-8520, email: radtke@onramp.net.

Improvement of PDC Drill Bits Incorporating Novel Processing of Cemented WC and Diamond Composites.

Dinesh K. Agrawal, Rustum Roy, Paul Gigl,, The Pennsylvania State University, and Mahlon Dennis, Dennis Tool Company

An improved PDC drill bit will be designed and produced during the extended multi-year proposal period. Newly developed microwave sintering is the key in preparing nanocomposites of sintered carbide without the need of grain growth inhibitors. Microwave processing has several advantages over conventional sintering, such as the potential for significant reduction in manufacturing costs, improved mechanical properties and hence enhancement in the performance of the product. Composite diamond layers will protect the bit surfaces. PDC structures plus bonding methods with higher temperature and improved wear capabilities will extend the life of the bit in geothermal environments.

Since microwave processing is known to be highly energy efficient due to the fact that it is accomplished by internal heating of the cement powders, the sintering cycle time of cemented carbide has been reduced by an order of magnitude as compared to conventional sintering methods. Thus, we can sinter micron size WC plus Co tooling in a matter of minutes versus hours. For example, 6% Co tungsten carbide was sintered at 1250-1350°C in 10-30 minutes with a density of 15g/cc and 93 Rockwell A hardness while maintaining the grain size at less than two microns. This would take hours by conventional methods and grain growth inhibitors would be needed. The carbide produced with this method will be used for substrates and wear parts for the PDC's and metal will be applied to a complex bit surface. Modified PDC cutters with diamond wear pads on the supporting carbide substrate will reduce the friction heating due to carbide wearland formation. Less heat generated at the PDC wearland will allow the bit to be used in higher temperature environments. The final innovation that will be applied to the bit development is the high temperature PDC braze which will allow the stress to be reduced in the carbide and the thermal stability of the braze to be increased by as much as 300°C.

Advanced Geothermal Turbodrill

Maurer Engineering Inc.

Maurer Engineering is developing an advanced high-temperature turbodrill for drilling hard rocks at high drilling rates. This turbodrill utilizes 50 sets of turbine blades to convert hydraulic power from the drilling mud to rotary mechanical power to power the drill bit. This advanced turbodrill will be developed by modifying a geothermal turbodrill used in the 1970s in LANL's hot dry rock wells at Fenton Hill, NM. A gear box will be added to the LANL turbodrill to reduce its speed from 1000 to 100 rpm for use with hard rock roller bits. Improved thrust bearings will be used to allow higher bit weights and increase the reliability of the turbodrills. If successful, these advanced turbodrills should increase drilling rates 2-3 fold and allow the drilling of multi-branch geothermal wells that could increase steam production 2-3 fold.

Binderless Nanophase Cutter Materials for High Rate Hard Rock Drilling

Diamond Materials Incorporated

The performance of cutter material has a significant economic impact on the drilling process. It is common that a Polycrystalline Diamond (PCD) bit will drill as much as four to five times the depth of a conventional cone bit, reducing not only the cost per meter but also the trip time which can significantly reduce the cost for deep drilling operations with very high rig rates. Geothermal drilling presents the following obstacles to application of the conventional PCD materials: (1) Elevated temperature of the rock leads to a loss of strength of PCD material due to graphitization assisted by the cobalt present in the polycrystalline diamond matrix; (2) The corrosive down hole environment leads to reduction of strength of PCD and WC/co substrates due to etching of Cobalt binder.

Recently developed Binderless Polycrystalline Diamond (BPCD) materials exhibit superior thermal and corrosion stability. This program will explore performance of BPCD types of materials at geothermal drilling conditions. Research will focus on two main aspects: (1) BPCD cutters material performance under conditions encountered during geothermal drilling including bottom-hole high temperature corrosive environment; (2) Feasibility of integration of the BPCD cutters into corrosion and erosion resistant drill bits that will be produced by high temperature sintering methods. Manufacturing of these drill bits will require thermal stability of the polycrystalline diamond cutters at temperatures on the order of 1200°C.

High Performance Mini-disc Bit with Water Jet Flushing

Excavation Engineering Associates, Inc.
Seattle, Washington

This study and demonstration program involves the use of very small, disc-type cutters, trade named "Mini-discs", applied to popular drill bit sizes. The basic science behind the use of Mini-discs is that they slice the rock, creating tension failures and causing chips to pop off the rock face between the cutter tracks. Average size of the cuttings formed is larger than with conventional hard rock roller cone bits. Specific Energy of Excavation, energy consumed per unit mass of rock excavated, is reduced. For a given amount of power applied, a Mini-disc bit goes faster.

In early Laboratory tests, a 13 1/8 inch bit penetrated at a rate of 70 ft/hr and a 7 7/8 inch bit at over 130 ft/hr, both in 25,000 psi rock. These rates were achieved at less than optimum rpm and with inadequate drill fluid circulation.

This program will focus on drill fluid circulation; pressure, injection points, and a controlled flow path within the bit. The objective is to determine the most favorable injection point, at the lowest hydraulic horsepower which will enhance performance, cuttings removal and at the same time produce adequate bit cooling. The project includes fabrication and laboratory testing of a Mini-disc drill bit.

The project has the potential to substantially reduce drilling costs in several ways.

1. In laboratory experiments, drilling rates were extremely high. The potential for reduced drill crew time on a hole is very cost effective.

2. Bit life, in terms of footage drilled is likely to increase as a result of the penetration rate increases. With disc cutters, life in hours varies little whether the penetration rate is fast or slow. For example, a very reasonable 50 hours life at 100 ft/hr equals 5,000 feet of hole between trips.

3. Bits can be refurbished, in the field, in less than an hour, and at a fraction of the cost of a new bit. This is a particularly valuable feature in serving remote drilling sites.

In summary, the Mini-disc drill bit is a radical design departure from current bits; it presents a new technology rather than minor improvement to the tri-cone bit, which has changed little in the 90 years since its introduction.

Core-Tube Data Logger

**Joseph A. Henfling, Randy A. Normann,
Ronald D. Jacobson, Steve Knudsen, and Doug Drumheller
Sandia National Laboratories**

ABSTRACT

Three types of core-tube data loggers (CTDLs) have been built and tested to date by Sandia National Laboratories. They are: 1) temperature-only logger, 2) temperature/inclinometer logger and 3) heat-shielded temperature/inclinometer logger. All were tested during core drilling operations using standard wireline diamond core drilling equipment. While these tools are designed for core-tube deployment, the tools are adaptable to other drilling modes and equipment.

Topics covered in this paper include: 1) description on how the CTDLs are implemented, 2) the components of the system, 3) the type of data one can expect from these types of tools, 4) lessons learned, 5) comparison of the CTDL's to conventional drilling aids and 6) future work.

INTRODUCTION

Wireline core drilling is increasingly used for geothermal exploration. This drilling technology employs a core-tube to capture continuous rock core samples. Initially the core-tube is allowed to free fall through the mud in the interior of the hollow drill rods. It eventually hits a landing ring and latches just behind the drill bit. Drilling is then initiated and as the drill bit penetrates rock, the core-tube fills. When the core-tube is full it is retrieved using a wireline fitted with a mechanism to mate with the core-tube. Then another core-tube is dropped into place.

The repetitive nature of core drilling gave birth to an idea. What if a memory-based electronic sensory package were mounted in the core-tube? Communications between Sandia and Tonto Drilling led to the idea and development of such a package. It is called the Core-Tube Data Logger (CTDL). The CTDL is a memory tool that rides inside the core-tube, measuring and storing data. The CTDL requires little, if any, additional rig time to use, resulting in essentially "free" information. Downloading data at the surface can be done very quickly, and the CTDL can be returned downhole with the core-tube. Tools retrieved from hot wells require additional time to equilibrate with surface conditions, and it may be necessary to use two tools.

Hardware and software from Sandia's high-temperature instrumentation program made implementation straight forward [1]. The CTDLs use the same basic technology that is present in the Pressure/Temperature Precision Memory Tool [2][3]. The CTDL is not designed to be as precise due to the requirement of the tool. The CTDL can perform a variety of functions depending on the requirements of a particular drilling operation. The CTDL is rugged, requires no special handling, and is easily operated using a standard laptop computer.

Tonto Drilling supplied the initial mating parts to connect the CTDL to the interior of the core-tube for the first series of tests in Elko, NV. Boart Longyear supplied the mating parts for the second series of tests at Fort Bliss. A Dewared CTDL containing two inclinometers is shown in Figure 1.

THE SYSTEM

Typical core-tubes are 10 or 20 feet in length. The CTDL occupies a small percentage of the space inside the core-tube. Periodic short runs are often part of the normal drilling process.

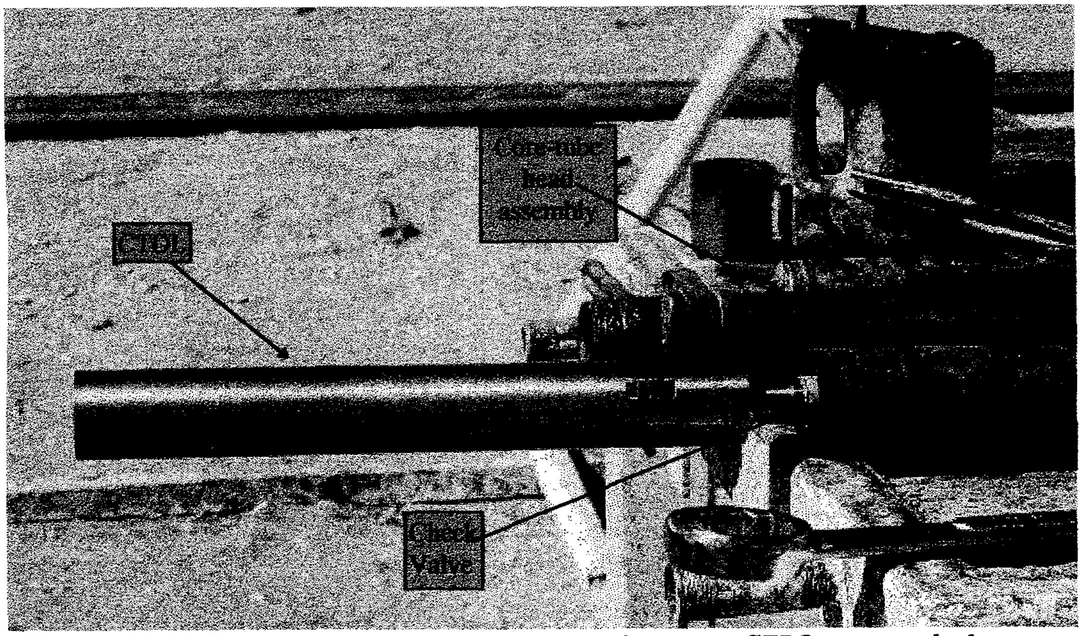

Figure 1. Pictured is the Dewared temperature/inclinometer CTDL prior to deployment.

In some formations, the driller can predict when a short run will be encountered. By coordinating with the driller, these short runs can be utilized as CTDL runs.

To deploy the CTDL the core-tube check-valve must be modified. This valve is located in the lower end of the core-tube head assembly. It prevents drilling mud from being pumped into the core-tube area during drilling, allows well-bore fluid to pass during free fall, and provides a path for the drilling fluid to exit as core enters the tube. The required modification consists of threading the inside bore of the check-valve nut that is used to secure the inner workings of the check-valve. Once the modified nut and adapter are in place, the CTDL can be securely positioned inside the core-tube. This nut can be easily removed from the core-tube head assembly and does not disrupt the drilling operation. The CTDL assembly also includes an adapter that is threaded onto this check-valve nut. The adapter is ported to allow normal operation of the valve.
Different CTDL's have different lengths depending on the application. The tools fabricated thus far are approximately 10 inches in length for the CTDL that measures temperature only, and approximately 18 inches in length for the CTDL that contains the temperature probes and inclinometers. The Dewared CTDL is also 18 inches in length. CTDL's which operate above 400° F, must be longer to allow room for additional heat sinks. This also increases the time that the CTDL can remain in the well. Heat sinks are normally large masses of stainless steel or brass. Eutectic material can also be used in conjunction with, or instead of, the stainless steel or brass heat sinks. Increasing the length of the CTDL to approximately 50 inches (to allow room for additional heat sinks), would allow deployment of the CTDL in wells with temperatures exceeding 700°F.

THE ELECTRONICS

The electronics consist of: 1) sensors; 2) signal conditioners; 3) analog-to-digital converter; 4) microcomputer; 5) memory; and 6) battery. A block diagram of the electronic section of the temperature/inclinometer CTDL is shown in Figure 2.

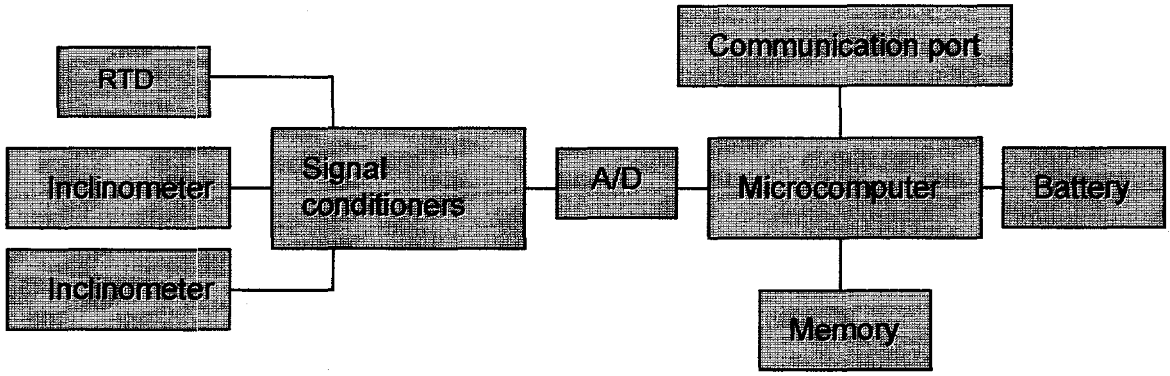

Figure 2. Block diagram of the electronics for the temperature/inclinometer CTDL

Additional measurements such as pressure, temperature, and inclination are easily implemented. To date, temperature and inclination measurements have been incorporated. Depending on the expected well-bore temperature, a resistance temperature detector (RTD) or a thermistor is deployed in the CTDL. The inclinometer we have used, is a one-axis accelerometer calibrated to provide a linear voltage output based on tilt in its sensitive axis. An inclination measurement requires two inclinometers mounted 90 degrees with respect to each other and with respect to the drill bit's longitudinal axis. This allows the CTDL to resolve inclination regardless of the orientation of the CTDL.

The microcomputer utilized in the three tools tested is manufactured by Onset Computing Company (North Falmouth, MA).

The temperature-only CTDL was the first built and tested. It uses a one-channel, 8-bit analog-to-digital converter and can store 1800 data points. The data interval is software-configurable to a range of values between 1 second and 288 minutes. This tool utilizes a Windows-compatible software package with built-in plotting functions. The data can be exported for use in spreadsheets such as Excel. The tool communicates through an RS232 communication port on a laptop PC to establish runtime conditions and to offload its data. The tool has nonvolatile (EEPROM) memory enabling the data to be retained without batteries. It uses a watch-size battery that lasts for approximately one month. The physical size of the basic electronic section is ≈ .75 inches by 1.75 inches, making it ideal for space-restrictive designs. The temperature resolution for this device is approximately ± 4° F.

The second CTDL we built uses an 8-channel, 12-bit analog-to-digital converter, one frequency measurement port, and 14 general purpose I/O lines that can be used for various control functions. It has 0.5 Mbytes of memory that can store 10,000 or more data points, depending on the number of channels in use. This CTDL's parameters are programmed using BASIC. The software enables the CTDL to make decisions based on time and/or sensor information. The current program asks the user pertinent questions to set parameters, such as the time of day and sample interval.

External temperature, internal temperature, inclination, and battery voltage are currently monitored. An on-board Light Emitting Diode (L.E.D.) illuminates when the tool is storing data. This insures the operator the CTDL is functioning properly prior to deployment. The microcomputer in this CTDL uses static RAM memory. This type of memory is volatile and requires the battery to remain connected for memory retention.

The second CTDL is presently deployed using a DOS based program, but a Windows version is imminent. As with the first CTDL, it communicates through an RS232 port on a laptop PC. This CTDL can resolve temperatures to 0.2°F and tilts to 0.3 degree. The basic electronic section is 1.2 inches by 6 inches. Its length is increased based on the number and type of attached sensors. When an RTD and two inclinometers are used, the electronic section is 12 inches in length. Batteries for this tool consist of a standard 9-volt alkaline battery for low-temperature wells where the internal tool temperatures remain below 160°F. For higher-temperature wells, batteries that are rated to 300°F are available from Battery Engineering Incorporated (Hyde Park, MA).

The third CTDL that we've built contains the same instrument package as the second. However this CTDL has an enhanced operating temperature range by virtue of its heat shielding.

FIELD TESTING

The three CTDLs have been tested in the laboratory and in the field at depths of up to 4,000 feet. The temperature-only CTDL and the temperature/inclinometer CTDL (unshielded) have been involved in two field activities. The temperature-only CTDL has seen approximately 15 deployments. The temperature/inclinometer CTDL has seen approximately 40 deployments. To date, the Dewared CTDL has been involved in one field activity with 6 deployments. All CTDLs performed flawlessly with no loss of data.

Examples of the type of data generated by these loggers are shown in Figures 3 and 4. The data contains interesting characteristics. Notice that inclinometers are vibration-sensitive devices. As such, the tilt readings fluctuate when the inclinometers are subjected to vibration.

The inclinometer data in Figure 3 can be explained as follows. The large tilt readings from 0 to 500 seconds indicate the CTDL is being handled. At approximately 500 seconds the tilt reading drops, indicating the tool is just about to be inserted into the well. The tilt readings are low with some fluctuation as the tool is traveling down the well. The tilt readings with no fluctuation from approximately 1,000 to 1,200 seconds indicate the core-tube is in place. At approximately 1,200 seconds the fluctuations vary between 0 and 25 degrees. This is an indication drilling has started.

Drilling continues until 4,000 seconds where the fluctuations stop. This is an indication that drilling has stopped and the overshot is being lowered. The readings at this time gives a good indication of the inclination of the well, 2.5 degrees. At 4,300 seconds, the overshot and wireline has latched onto the core-tube and it is on its way to the surface. The 50 degree tilt reading between 4,500 and 4,900 indicates the core-tube is out of the well and has been placed on an inclined deck waiting to be disassembled. The consistent angle of the inclined deck provides assurance of the tool's tilt calibration.

The temperature plot in Figure 4 can be interpreted using the inclinometer data in Figure 3 as an indicator of drilling activities. When drilling has stopped and the overshot is being lowered, the drilling fluid has some time to equalize with the formation. This is the time to determine the bottom-hole-temperature. In this case it is 117.7°F.

At Fort Bliss, a pseudo log [see definitions] capability for the core-tube logger was demonstrated. An ideal time to have the core-tube logger in place was during a bit change. Removing/installing drill rod to change bits allowed for the CTDL to slowly log the entire well. At Fort Bliss, Sandia had a computerized data acquisition system that recorded the drilling parameters including depth. By synchronizing computer clocks, the files from Sandia's acquisition system was merged with the CTDL file to provide a temperature data vs. depth plot. An example of such a log is shown in Figure 5.

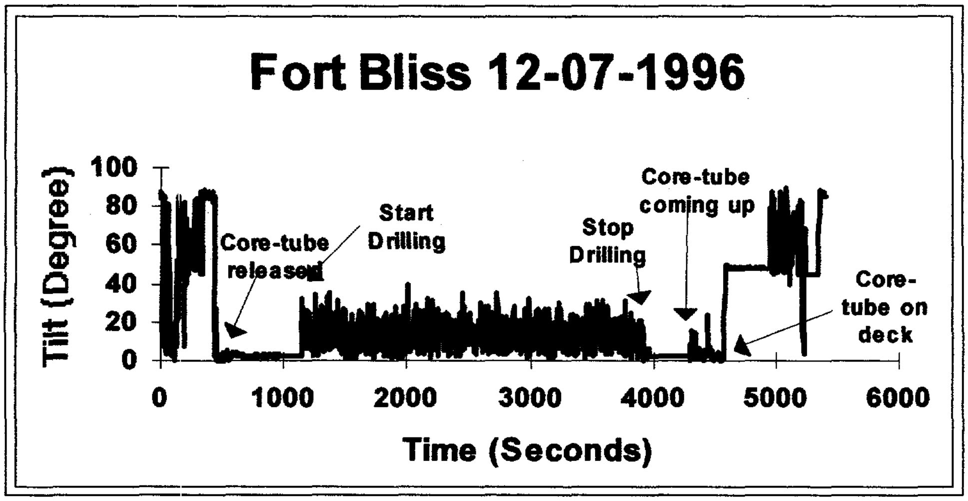

Figure 3. Typical inclinometer plot

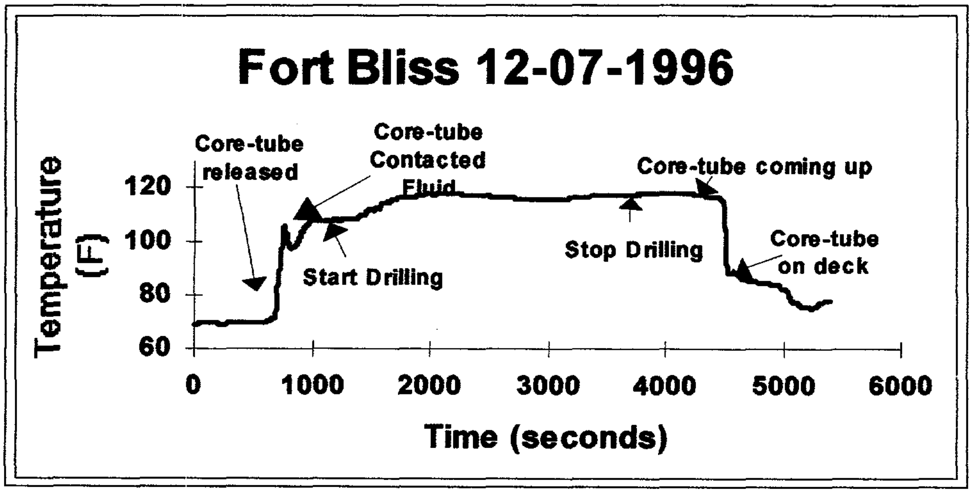

Figure 4. Typical temperature plot .

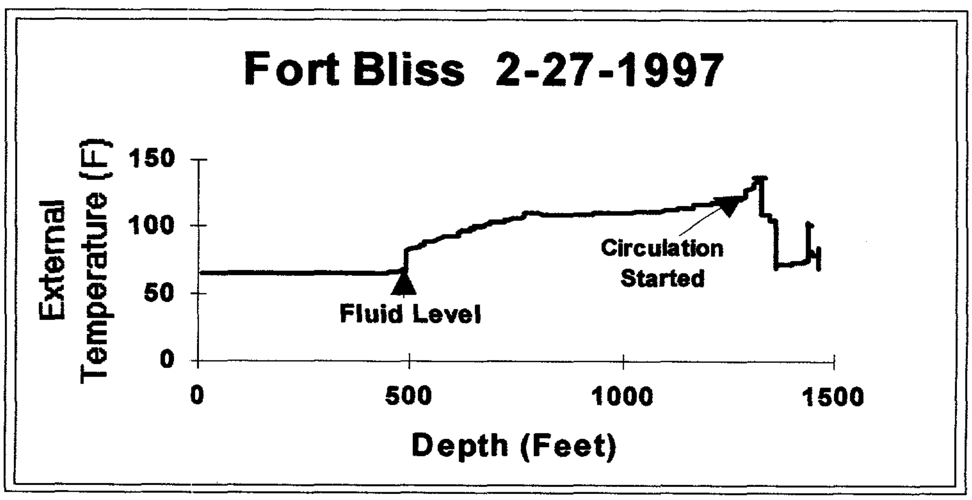

Figure 5. Results of a "pseudo log". The CTDL was placed in the core-tube while the drill string was lowered into the well.

LESSONS LEARNED

Temperature measurement is a function of a number of drilling conditions. When analyzing temperature data, care must be exercised to account for these conditions. For example, if the mud pump is circulating downhole, temperature will be affected. The more that is known about the drilling conditions during the log, the easier the log will be to interpret.

Understanding the inclinometer data also requires being aware of drilling activities. By noting the sequence of events after the core-tube is dropped, a correlation between these events and CTDL data can be observed. The signatures in the data seem to correlate to the following events: 1) tool going in and coming out of the well; 2) dead time between the core-tube landing and the start of drilling; 3) drilling; 4) drilling stopped; 5) overshot going in; and 6) core-tube at the surface. Observing the data over several runs, reveals the characteristic signatures of each event and the appropriate times to obtain accurate measurements of temperature and inclination. The inclinometer data not only provides an inclination measurement, it provides a record of the core run. This record improves the interpretation of the temperature data by providing a means of determining when drilling has stopped and the overshot is being deployed. At this point in the process, there is no fluid circulation. Thus, the well is allowed to equilibrate with its surroundings. The bottom-hole temperature measurement will be optimized during this period.

COMPARISON OF THE CTDL WITH CONVENTIONAL DRILLING AIDS

Maximum reading thermometers have been used in the drilling industry for many years. The information provided to the driller is limited and the maximum temperature location in the well is not guaranteed, but a general idea of the bottom-hole-temperature can be determined.

The present configuration of the temperature/inclinometer tool is comparable to a Drift Indicator Tool. This type of tool is used to track bore-hole drift. It utilizes some form of a centralizer to insure the tool is in alignment with the drill string. This simple, mechanical tool punches a hole in a paper disk to record the well-bore's inclination from vertical. To ensure accuracy, the tool provides a redundant measurement 90 degrees from the first. The tool is deployed between drilling runs and is triggered to take the measurements based on time, motion or the presence of monel (a non-magnetic metal). The maximum reading thermometers and the drift indicator tools are deployed using the rig's wireline.

The CTDL's developed at Sandia will provide the same basic information as conventional tools and a wealth of additional information. The temperature-only CTDL provides a means of obtaining temperature profiles of the well and the apparent drop time of the tool (based on when the tool contacted the wellbore fluid). The temperature profiles change based on well-bore conditions. A record of the profiles provides the driller additional information on the characteristics of the well. The temperature/inclinometer CTDL provides the above information and a history of the core run based on both the temperature and the inclination data along with the inclinometer measurement.

The cost for a CTDL is higher than a maximum reading thermometer, but is comparable to a Drift Indicator Tool. When one adds the benefits of obtaining information not achievable with the other two tools, the CTDL is a worthwhile investment. The estimated cost breakdown for the Dewared temperature/inclination CTDL is listed in Table 1. These costs reflect the component parts, but they do not take into account engineering overhead, and any profit that a service company would require if it is to undertake support of the tool.

Table 1

Sensors	**$ 550**
Electronics	**600**
Hardware	**1500**
Totals	**$2650**

FUTURE WORK

A strain-gauge type pressure transducer would be a valuable addition to the CTDL. It would provide an indication of the fluid level in the well. By observing the pressure change during the "quiet" time (when the overshot is going down to retrieve the core-tube), an indication of the wellbore's permeability would be ascertained. Knowing the fluid level of the wellbore fluid could also be helpful in interpreting the temperature data. Implementation of a pressure transducer in the current Dewared CTDL would not be difficult. It would add approximately $600 to the cost of the CTDL.

The CTDL concept can also be carried over to other types of drilling. For example, a tool could easily be modified to work in conjunction with a single shot or multi-shot camera used in rotary drilling.

CTDL technology can be utilized to determine wellbore temperature prior to cementing operations. The cement is mixed with a retardant to a ratio which is temperature dependent. Too much retardant will result in long curing times while not enough may lead to premature curing. Knowing the temperature would optimize the curing time thus reducing rig costs.

While the core-tube tools take up space inside the core-tube, this has not been an issue thus far. Heat shielding capable of protecting the electronics from temperatures exceeding 700°F would require the length to be increased to approximately 50 inches. This may be acceptable for logs performed daily. Another approach would be to install the logger above the core-tube. A location between the wireline connection and the core-tube assembly is plausible. This approach may be necessary for NQ coring where the inside diameter of the core-tube may not accommodate a Dewared CTDL.

Sandia is currently working on a high-temperature electronics project utilizing high-temperature components as they become available. These components will be capable of withstanding temperatures of 570°F without heat shielding. A temperature logger containing high-temperature components would therefore not require a Dewared vessel or heat sinks. Batteries are a problem also being addressed by Sandia. The Battery Development Department at Sandia is working on a battery capable of bridging the gap between commercially available 390° F high-temperature batteries and 570° F electronics. It is conceivable that a high-temperature temperature logger could be fabricated within the next two years [4].

Three additional concepts are being considered for core-tube logging. In one, an inertial navigation system would be deployed. Directional data would be retrieved with each trip of the wireline. In the second concept, a two-axis inclinometer would measure and store data to determine its *in-situ* core orientation. In the third concept, the CTDL would be utilized as a memory logging tool. This would be accomplished by outfitting the rig's wireline with an encoder to enable the wireline's depth to be recorded. A data logger at the surface would store this information. The CTDL would be lowered into the well at a constant speed. After the log, the two data files would be merged to obtain a data vs. depth profile of the well.

ACKNOWLEDGMENTS

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DEFINITIONS/REFERENCES

The term "pseudo log" is used to describe a log that provides a temperature profile of the well with depth information. This is representative of the type of data provided by a conventional log although not as sensitive. A conventional log is performed in a controlled manner with a tool optimized for this application. The measurements obtained from a conventional log are also referenced to depth.

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A Self Propelled Drilling System for Hard-Rock, Horizontal and Coiled Tube Drilling

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ABSTRACT

Several advancements are needed to improve the efficiency and reliability of both hard rock drilling and extended reach drilling. This paper will present a Self Propelled Drilling System (SPDS) which can grip the borehole wall in order to provide a stable platform for the application of weight on bit (WOB) and resisting the reactive torque created by the downhole drilling motor, bit and formation interaction. The system will also dampen the damaging effects of drill string vibration. This tool employs two hydraulically activated anchors (front and rear) to grip the borehole wall, and a two-way thrust mandrel to apply both the drilling force to the bit, and a retraction force to pull the drill string into the hole. Forward drilling motion will commence by sequencing the anchor pistons and thrust mandrel to allow the tool to walk in a stepping motion. The SPDS has a microprocessor to control valve timing, sensing and communication functions. An optional Measurement While Drilling (MWD) interface can provide two-way communication of critical operating parameters such as hydraulic pressure and piston location. This information can then be telemetered to the surface, or used downhole to autonomously control system parameters such as anchor and thrust force or damping characteristics.

INTRODUCTION

The application of new and innovative drilling and completion technologies including extended reach, short radius, multi-laterals, coiled tube, etc., has allowed the petroleum industry to reach and capitalize on reserves that were either inaccessible or unprofitable with conventional drilling techniques. Drilling operators and equipment suppliers are now pushing the limits of material strength and drill string lock-up as they strive for greater horizontal segments. An extended reach well is defined as one in which the ratio of the measure distance over the true vertical depth of the well is at least 2[1]. Using rotary drilling assemblies, operators have been able to achieve horizontal offsets of 26,000 ft (8 km), and many operators feel the 32,800 ft (10 km) mark can be exceeded by the year 2000[2]. Non-rotating systems such as coiled tubing drilling and short radius drilling are at present unable to approach these extended reach achievements. The current record for coiled tubing horizontal displacement (as of March 96) is 3,256 ft (~ 1 km)[3].

The industry thus has a strong economic incentive to push out the drilling envelope for short radius and coiled tube operations to more nearly match the lateral displacements that are achievable with rotating systems. Many techniques have been studied to attain this goal. These include:

1. Buoyancy reductions;
2. Friction reducers;
3. Hole cleaning;
4. Optimal pipe size or tapered coiled tubing;
5. Straightening coiled tubing;
6. Tandem motors;
7. Performance stabilizers;
8. Rotators, and;
9. Tractor or Self Propelled Drilling Systems (SPDS)

In this paper, I will discuss this last item which has great potential for extending lateral displacement of oil, gas and geothermal wells.

In the case of hard rock drilling, typical of geothermal wells, drillers are constantly battling the damaging effects of shock and vibration. It is well known that vibration during drilling operations has a large, undesirable effect on both the bottom hole assembly (BHA) and the bit. Large vibration levels lead to a reduced rate of penetration (ROP) and catastrophic failures, while lower levels lead to reduced operating life over time and consequently shorter bit runs. In the past, much effort has been invested in measuring and understanding vibration. The benefits of addressing this problem are obvious and include reduced drilling time and costs, reduced maintenance, and lower equipment turnover. SPDS, because it is anchored to the borehole wall near the drill bit, will prevent or minimize the axial vibrations typical of conventional drilling systems which cause the drill bits to repeatedly come off bottom. This is very damaging to the bit and greatly reduces ROP. The bit impact results in large shock levels to the BHA.

DESCRIPTION OF THE SPDS

The SPDS consists of an upper and lower anchor systems to react out drilling forces, and a two-way telescoping mandrel to provide both WOB during drilling and a retracting force to pull the drill string into the hole after a section has been drilled. Figure 1 shows the SPDS in the fully retracted and extended positions. The anchors consist of three sets of pistons oriented 120° apart which extend radially outward to contact the borehole wall. The pistons have a hardened serrated surface to aid in gripping the borehole wall and are spring loaded so that the pistons will return to the retracted position in a fail safe manner in the event of a failure.

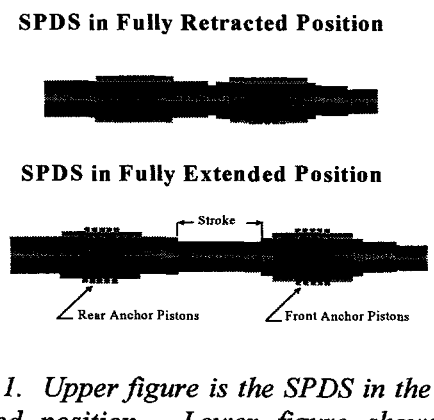

Figure 1. Upper figure is the SPDS in the fully retracted position. Lower figure shows the SPDS extended at its maximum stroke.

The anchor and thrust pistons are actuated via two closed loop hydraulic systems which are powered by turbine driven hydraulic pumps. In the authors' opinion, there are several advantages to this approach over electrically powered systems. A hydraulically powered system can integrate seamlessly into both conventional drilling and coiled tube drilling assemblies because there is no need to run an electrical power cable. In most cases, there is sufficient hydraulic horsepower available from the rig mud pumps to power the system at a satisfactory ROP. Figure 2 illustrates horsepower requirements as a function of ROP at various pulling forces.

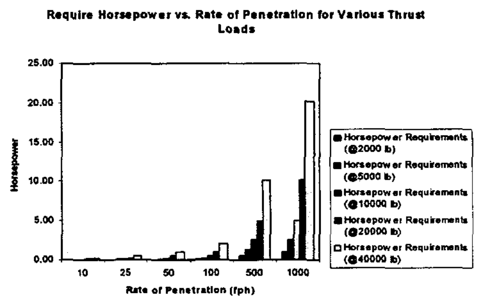

Figure 2. Horsepower required as a function of ROP (feet per hour) at 5 different thrust loads.

Turbine driven hydraulic pumps are a proven downhole technology and have been used to power MWD hydraulic actuators for over 20 years. These pumps can generate in excess of 3,000 psi hydraulic pressure which, in turn, can provide greater thrust loads than can be achieved with an electrical actuator in a similar envelope size. The system electronics includes a microprocessor to monitor system parameters, control the valve timing and communication functions. [Note: The prototype design will be battery powered in order to reduce complexity during the proof of concept, but the design will allow for the addition of a turbine alternator at a later date.] The microprocessor will serve as a node point to allow integration into a typical MWD system architecture for sending and receiving data. Figure 3 is a simplified schematic of the system interfaces.

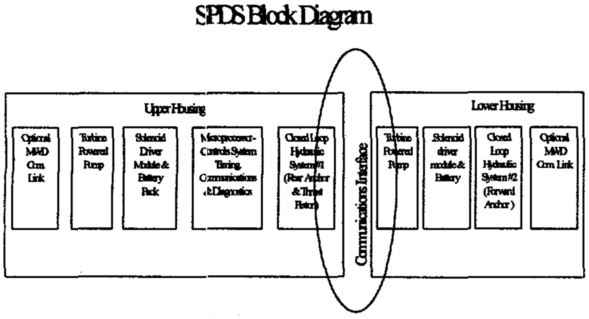

Figure 3. SPDS block diagram

The MWD interface can be accomplished using several different proven downhole techniques including, downhole wet connector, a two wire connector built into the API connection, or "short hop" RF communication techniques. Table 1 at the end of this document shows the design specifications for a range of tools sizes.

The operating sequence of the tool is shown below:

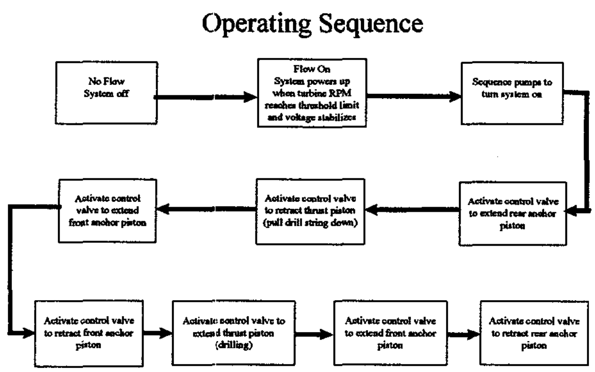

Figure 4. SPDS drilling sequence.

On the rig floor the driller can monitor tool operation by observing the standpipe pressure. Changes in hook load may also observed but are likely to be masked by the frictional drag of the drill string. The SPDS pressure signature is detailed in figure 5. When the pumps are brought online the system will turn but will not begin the drilling sequence until the flow rate is dropped below a level which will trigger the tool. The flow rate is then increased back to the desired operating flow rate (see step 3 in figure 4). As drilling commences (point B in figure 5) the driller will see the pressure increase indicating that the motor is seeing bit torque. The time required for the SPDS to extend to its full stroke is dependent on the bit and formation. Once the piston extends fully, a limit switch will be tripped, telling the microprocessor to extend the front anchors and retract the rear anchors. During this sequence the motor will drill off and the driller will note a drop in standpipe pressure. At this point, the driller would either slack off on the brake or feed more coiled tubing while the tool retracts, pulling the drill string into the hole (point C in figure 5).

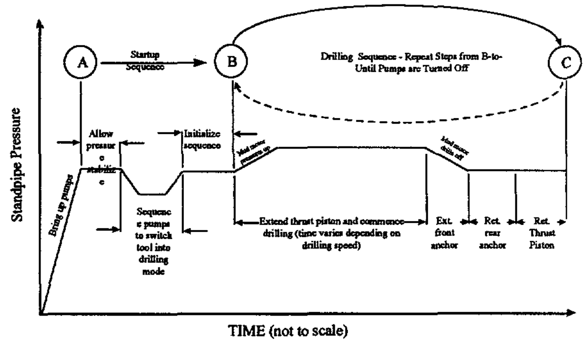

Figure 5. SPDS standpipe pressure sequence during operation

ADVANTAGES FOR HORIZONTAL AND EXTENDED REACH DRILLING

The two major factors that limit lateral displacement in horizontal wells are torque and drag. Torque and drag are caused by the frictional contact forces between the borehole and the drill string. When axial compressive forces exceed a critical value, the pipe or tubing will buckle in a sinusoidal manner. As the compressive force is increased helical buckling will occur causing the drill string to lock up in the wellbore. At this point, further lateral displacement cannot be achieved without either reducing the frictional contact forces or increasing the load at which buckling occurs, i.e., by increasing drill string diameter or reducing hole size. Both of these options may be impossible or undesirable. The problem of lock up is further exacerbated with non-rotating assemblies (coiled tubing & short radius). Leising, et al.[3] explain why this occurs using classical friction theory. This theory shows that the friction force vector opposes the direction of the velocity vector. Therefore with a rotating string (where the surface speed due to rotation greatly exceeds the velocity due to ROP), the friction will largely act to generate torque and the axial weight transmission is nearly frictionless. By utilizing a system that can apply weight at the bit, e.g., a downhole tractor or SPDS, it is possible to significantly extend the reach of horizontal well before lock up occurs. Figure 6 depicts how the SPDS could be utilized in a coiled tubing or short radius BHA.

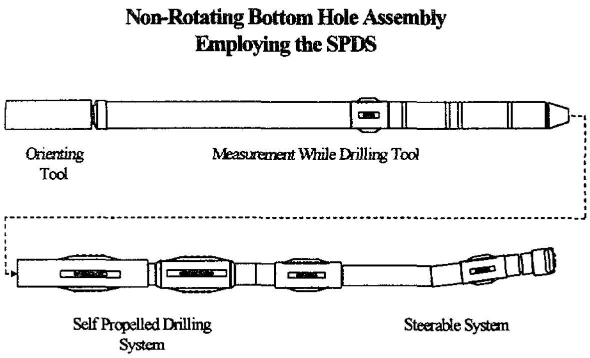

Figure 6. SPDS shown in a typical coiled tubing drilling BHA

Illustrated in Figure 7 are calculated increases in lateral displacement as a function of SPDS pulling force for five different drill string cases. The predicted increases in lateral displacements are impressive.

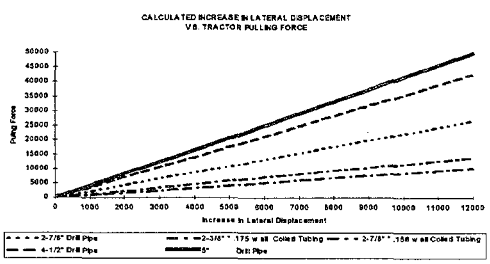

Figure 7. Calculated increase in extended reach vs. SPDS pulling force.

ADVANTAGES FOR HARD ROCK DRILLING

The primary benefit of the SPDS for hard rock applications, when compared to a conventional drilling assembly, is in its manner of applying the drilling loads at the bit. Conventional drilling relies on the BHA weight to develop the desired force or WOB. This method is very inaccurate and difficult to control, since buoyancy, buckling of the drill string and static or sliding friction along the length of the drill string all serve to reduce the actual WOB. Buckling and drag can also influence the torque on bit (TOB). The SPDS eliminates these problems by applying the drilling forces from a point directly above the bit.

Conventional systems also suffer from vibration problems arising from the long length of the drill string, which acts as an axial and/or torsional spring[4]. The resulting damage takes two forms: (1) fatigue of the drill string from the lateral, torsional and axial vibrations; or, (2) acute shock damage to equipment resulting from drill string impact against the wellbore. Lateral vibrations produce cyclic bending stress that weakens and fatigues connections, which may result in connection leaks and wash outs. Conventional drilling systems have natural frequencies in the range from less than 1 Hz to approximately 20 Hz based on the distance between stablizers[5]. The drilling forces have excitation frequencies in the same range due to the drill string rotation and interaction of the bit on the formation. For example, a conventional BHA might have stabilizers spaced 45 feet apart. The lateral natural frequency for a section between these stabilizers is approximately 2.5 Hz. The excitation or drive frequency of a string rotating at 150 rpm is also 2.5 Hz, and therefore excites the BHA into resonance. When the BHA is in resonance, much of the applied energy (WOB and Rotation) is absorbed by drill string vibration, resulting in reduced drilling efficiency.

The vibrations produce additional damage when the vibratory deflections cause the limber BHA to impact against the wellbore. This develops significant shocks at higher frequencies, normally 90 Hz or greater, that are damaging to electronics. MWD equipment specifications for shock and vibration, typically 100 g at 11ms (90 Hz) and 1000 g at 1 ms (1000 Hz), may be exceeded in these conditions.

Axial vibrations of conventional drilling systems may cause the drill bits to frequently come off bottom, causing the ROP to be greatly reduced. The bit impact may also result in large shock levels which are damaging to the bit and the BHA components. Figure 8 shows typical shock levels for various materials at given bit bounce heights[6].

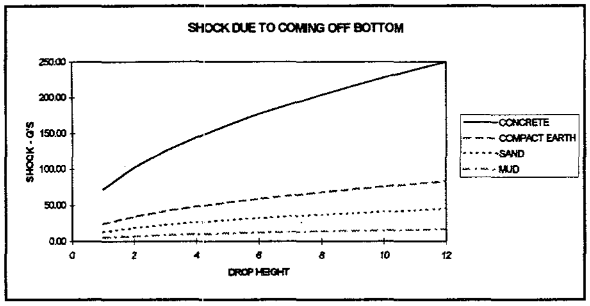

Figure 8. Axial shocks due to the bit coming off bottom at various heights on different materials

The SPDS is designed to increase the natural frequency into a favorable frequency range for drilling. This frequency is above the drilling excitation frequencies and below the shock frequencies. The low frequency drilling excitation forces therefore do not excite the SPDS configuration while providing damping for the higher frequency shocks. The hydraulic drive system of the SPDS provides additional viscous damping, compared to conventional systems which provide only low levels of material and friction damping[7]. The hydraulic damping can be adjusted to provide optimum damping for a variety drilling conditions. Figure 9 compares the response of a typical conventional system to the SPDS. Significant improvements in ROP and bit and BHA damage are well documented through the use of thrusters and equalizers. A thruster is a device that applies force (WOB) proportional to the differential pressure between it and the annulus, like a common hydraulic cylinder. An equalizer is a low spring rate shock sub, specially designed for coiled tubing. It is very similar in principle to the gas spring used on an automobile hatchback[3].

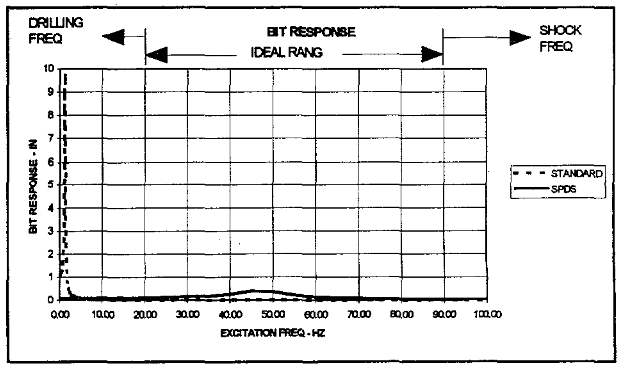

Figure 9. The BHA response of a conventional drilling system compared to the SPDS.

Reich *et al*[8]. have studied over 120 wells where thrusters have proven their ability to significantly improve drilling performance in holes with vibration or shock problems. The advantage of these systems are that they decouple the lower part of the BHA from the remainder of the drill string, and in so doing dampen vibration to provide an even WOB in cases of poor weight transfer typical of highly inclined wells. The SPDS shares these same advantages and we would expect to see similar drilling improvements.

The SPDS does not, however, share the two major disadvantages of thruster technology. The first problem occurs because the thrust is proportional to the pressure drop below the tool. Therefore, when a mud motor begin to stall, the WOB is increased, aggravating the stall. The SPDS has a closed loop hydraulic system and its thrust is independent of mud motor pressure fluctuations. The second limitation of thrusters is that they do not have anchors to react the WOB and their effect is therefore limited to the frictional force of the BHA .

Conclusions

1. Based on the work that has been completed in our Phase I feasibility study, a self propelled drilling system employing hydraulic anchors and thrust pistons is a viable technology.
2. The projected increase in drainhole length by employing the SPDS is impressive.

3. The ability to decouple the drill bit from the BHA via a "thruster" or "Equalizer" has well documented advantages[8]. The SPDS will share these advantages but will not suffer from the problem of increasing WOB when the motor starts to stall, thus exacerbating the stall. The SPDS' thrust load is independent of motor, bit or any other differential pressure below it unlike current thrusters.

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Superhard Nanophase Materials for Rock Drilling Applications

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ABSTRACT

Diamond Materials Incorporated is developing new class of superhard materials for rock drilling applications. In this paper, we will describe two types of superhard materials, (a) binderless polycrystalline diamond compacts (BPCD), and (b) functionally graded triphasic nanocomposite materials (FGTNC). BPCDs are true poly-crystalline diamond ceramic with < 0.5 wt% binders and have demonstrated to maintain their wear properties in a granite-log test even after 700 °C thermal treatment. FGTNCs are functionally-graded triphasic superhard material, comprising a nanophase WC/Co core and a diamond-enriched surface, that combine high strength and toughness with superior wear resistance, making FGTNC an attractive material for use as roller cone stud inserts.

INTRODUCTION

There is a growing need for efficient and economic drilling methods because of the demand for drilling increasing footages of exploratory holes or wells, and for improvement in efficiency of rock removal methods. Wear of rock drilling tools is a major factor determining the economics of rock drilling, since it decreases the penetration rates and increases the drilling forces that can cause fracture of the bit inserts. The type and severity of the wear depends upon the strength and abrasiveness of the rock and on the insert material. Moreover, the situation is complicated when the tool bits are subjected to slurry environments, where they must not only resist the erosion of solid particles, but also be resistant to damage caused by corrosion. This presents a major challenge where two factors may interact synergistically to produce wear rates that are greater than the sum of their effects. In geothermal drilling, higher temperatures and corrosive fluids are encountered and the wear of tools become a major problem. In this paper, we will first describe DMI's high pressure high temperature facility and its binderless polycrystalline diamond compacts which has a relatively higher thermal stability and hence, has the potential for use as drill bits. The next section will outline developments in functionally graded triphasic materials.

DMI's HIGH PRESSURE HIGH TEMPERATURE PRESS

Figure 1 shows DMI's unique multilayered High Pressure Apparatus (HPA) for high pressure consolidation of cobalt-bonded and binderless polycrystalline diamond compacts (PCD), and other hard ceramics[1]. It consists of two shaped anvils of tungsten carbide facing one another, and four supporting steel rings. The anvils compress a container made of lithographic stone. A system of shaped rings and liners are placed around the reaction cell which contains the diamond material. The reaction cell consists of a graphite crucible, which serves as a heater, graphite washers, filler materials, and sample material. Other designs of the reaction cell can be used, depending on the shape and size of the sample required. However, to ensure long life for the unit, it is essential to operate the pressure cell well within the elastic range of the materials of construction Thus, the stresses during the work cycle should nowhere exceed σ (yield strength). This requires that the system be made with a multilayer support, such that when the cylinder is pre-stressed, the supporting stresses are more uniformly distributed through the body of the cylinder, and the apparatus is able to withstand higher pressures in the elastic regime.

The working volume of the cell depends on the hardness and compressive strengths of the materials used. We can write, $V_{max} = V_{max}$ (σ_{cs}, a_i, F, V where a_i and F are size and loading force of the press, σ_{cs} is the compressive strength of the anvil, and V is the volume of the anvil. According to Weibull's theory, the compressive strength of brittle ceramics depends upon volume according to

$$\sigma_{cs} \sim V^{-\frac{2}{3}}$$

Working within the limits set by these theoretical considerations, HPA units have been designed for continuous operation. Typical performance characteristics are pressures of 5-8 GPa at temperatures up to 2000 °C in a working volume of ~1 cm^3.

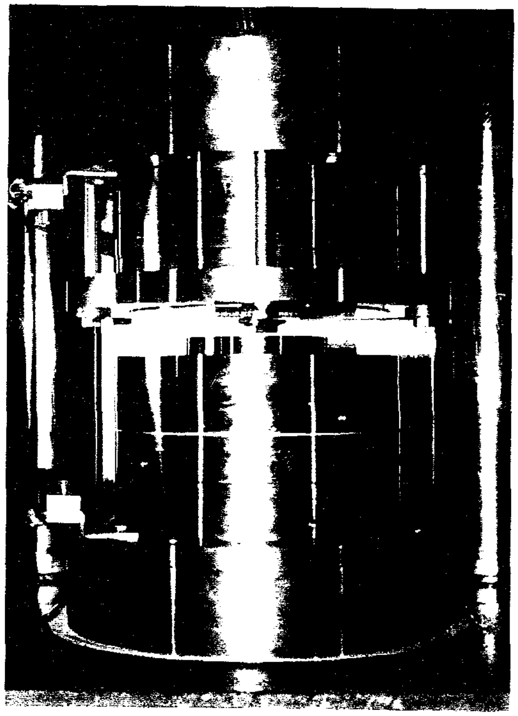


Figure 1. DMI's high pressure/high temperature apparatus.

A. BINDERLESS POLYCRYSTALLINE PCDS

PolyCrystalline Diamond (PCD) compacts are produced commercially from 20-70 micron size diamond powder by high pressure compaction methods, using metal binder phases (Co, Si, Ni). The process was pioneered by Wentorf, DeVries and Bundy[2]. It produces a hard and tough diamond material which is essentially a composite containing a sizable concentration of metal. The cobalt remaining in the PCD structure at the 3 - 10% level acts as a catalyst that promotes graphitization of the diamond phase *starting* at about 500° C. This limits the applications for the PCDs.

For instance, in drilling for oil and gas, the bottom-hole well temperature combined with the heat released from hard rock drilling leads to thermal loads that conventional PCDs cannot withstand. Geothermal drilling presents an even more challenging environment for conventional PCD applications. Here the typical bottom hole temperatures are about 350 °C, and in addition the drill bits are exposed to corrosive fluids. Under these conditions, a relatively small elevation of drill bit temperature which will occur even at low rotary speeds, can lead to catastrophic cutter failure.

The PCD cutter wear depends on cutter speed and wear-flat temperature. Conventional PCD cutters at working temperatures above 750°C experience catastrophic failure; however even at temperatures above 350 °C the cutters will experience accelerated wear rates. Dependence of PCD cutters wear on temperature was studied experimentally by Glowka and Stone[2,3] and Appl et al[4] .

Leading PCD manufacturers are trying to improve the thermal stability of their product by etching out Co (and other metal binder phases) from the sintered pieces by using acids[4]. This is so called Thermally Stable Polycrystalline (TSP) diamond material. The problem with the etching process is that it is very difficult to control, and it is impossible to etch out the Co completely from the PCD structure. It also weakens the PCD compact, since the Co binder phase supports the polycrystalline diamond structure. This leads to higher cost, and reduced consistency of the etched material. The Co that remains in closed pores of the PCD will lead to graphitization of the diamond at elevated temperatures. This limits the effectiveness of etching, especially for larger and thicker PCD pieces. However, despite these deficiencies in recent comparative tests by Glowka et al[5]. TSP cutters have shown only 15-20% of the wear rates of conventional PCD cutters. It was also shown that the TSP disk cutters at 20 RPM wore at almost the same low rate as the PCD cutters at 10 RPM indicating that the TSP cutters have higher thermal wear threshold[5]. These results demonstrate that there is outstanding potential in hard rock drilling applications for Binderless PolyCrystalline Diamond (BPCD) material that has thermal stability higher than TSP compacts.

Approaches to replace the cobalt binder have had much less success in hard rock drilling applications. De Beers introduced another type of PCD that uses silicon as a binder under the trade name of Syndax. This type of diamond composite is more thermally stable than the cobalt bonded PCD, however it has much reduced (about 300%) strength and toughness.

We have demonstrated sintering of BPCD (Binderless PolyCrystalline Diamond), which is a true polycrystalline diamond ceramic. Since it does not have a metal binder component in its structure, the BPCD exhibits high thermal stability, just like natural diamond, and can be heated in inert gases to 1200°C without a significant loss of strength. In Figure 2 we show the ratio of strength at elevated and room temperatures for DMI's BPCD, conventional PCD, and thermally stable PCD (or TSP). Here the BPCD shows no loss of strength with temperature, while material with the binder phase starts losing strength at 600 - 700°C. As would be expected, the TSP diamond start losing strength at 700°C, however at a much lower rate than conventional PCD material. The superior thermal stability of our BPCD material will translate into superior performance in actual drilling operations.

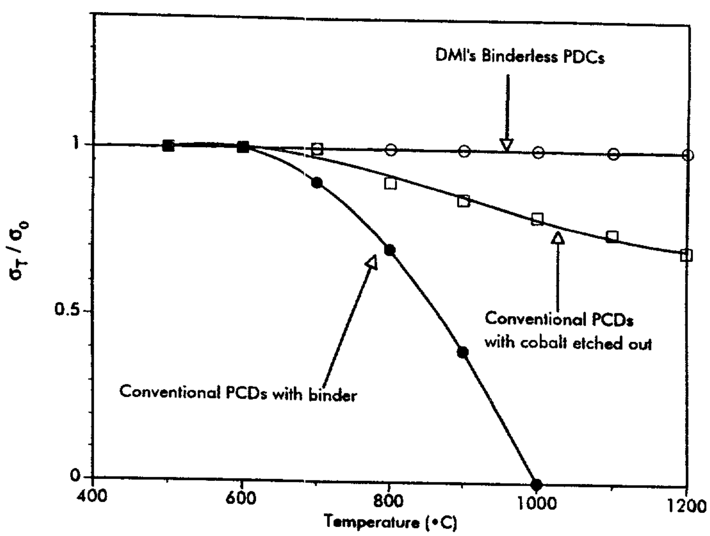
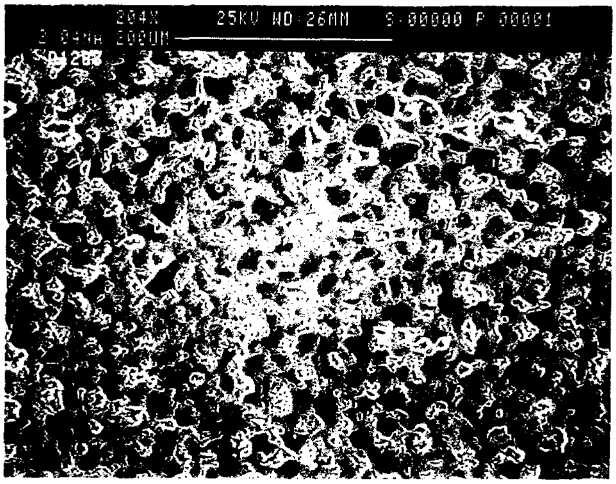


Figure 2. Thermal stability of diamond compacts: ratio of strength at a given temperature to strength at room temperature.

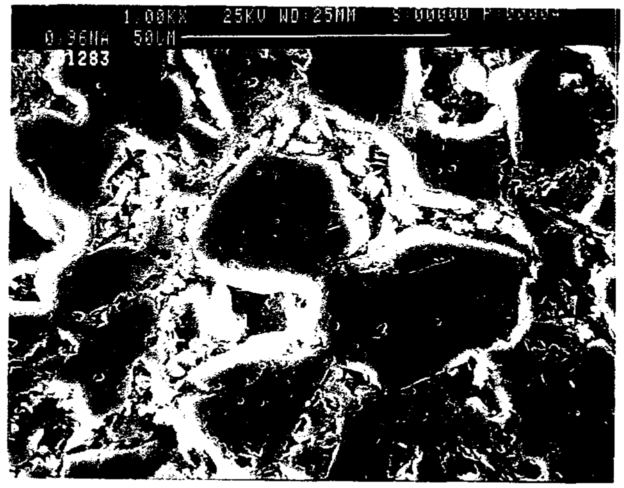
The metal content in DMI's BPCD is limited to the metal content of the original powder that is used for sintering. When synthetic grit is used, the metal content is < 0.5%; however, the compacts can be made from natural diamond with virtually no metal. Typically, the DMI's compacts are made from diamond powder with 1 - 50 μm size particles. The compacts have 92-96% of the theoretical density of diamond monocrystals. SEM of a polished BPCD is Figure 3 shows a bimodal structure. This is due to fracture of diamond particles during loading which helps to obtain a denser green body and helps in the densification.

Sintering of the BPCD compacts is achieved at pressures of about 8 GPa and temperatures ~1800 °C. The technology of sintering BPCD is used as a starting point in the development of nanosize diamond powder sintering. Sintering diamond compacts from submicron grain powders will allow significant increase in material toughness and wear resistance Our approach has been to decrease the particle size of diamond particles and thus addressing the difficulties caused by the low apparent density, high surface area, and agglomeration that are characteristic of very small particle compaction. Sintering of Binderless NanoCrystalline Diamond (BNCD) will require about 15 GPa pressure, which will be achieved in our new High Pressure Cell by making use of nanostructured WC/Co anvils. To date, we have been successful in producing high quality sintered samples with submicron grain size[6].

Granite-log wear test of BPCDs were carried out at our collaborators facility at Kansas State University. The diamond cylinders (~4 mm ϕ x 3 mm high) were mechanically clamped to a tool holder of a lathe and was used for turning granite. Preliminary test on our samples has demonstrated that a wear ratio G (ratio volume of metal rock removed to volume of diamond lost) of 400,000 is



(a) 200 X



(b) 1,000 X

Figure 3 : Microstructure of a binderless BPCD compact. A bimodal type structure is observed due to fracturing of particles under high pressure, ensuring high density.

obtained for a sample that has been heated for 30 minutes at 700 °C in flowing argon. The wear rate compares well with room temperature wear rate of cobalt bonded PCDs. Experiments are underway to determine the wear behavior of at higher temperature.

B. FUNCTIONALLY GRADED TRIPHASIC NANO-COMPOSITE MATERIAL:

Roller cone bits have proven to be most effective in brittle hard rock environments that are prevalent throughout the US mid-continent, Texas and the Rocky Mountains. The hard metal 'stud inserts' have either a chisel, wedge, or hemispherical button shape and are almost exclusively WC-Co alloys with 3-20 wt% Co. Because poor abrasive wear properties of the WC/Co stud inserts limits the performance of today's bits, there is growing interest in improving the abrasive wear resistance of roller cone stud inserts. On the other hand, polycrystalline diamond compact (PCD) bits have proved successful in drilling soft to medium rock formations because they achieve high rates of penetration while also maintaining long bit life[3-5]. Megadiamond produces a diamond-enhanced insert (Figure 4 (b)) that consist of a polycrystalline diamond layer and two transition layers which are integrally bonded to a curved WC/Co substrate to minimize chipping problems.

To circumvent the abrasive wear and chipping problem, we have developed a functionally graded triphasic nano-composite (FGTNC) material[7] ((Figure 4 (c)) where the diamond phase is dispersed within a bicontinuous structure of WC-Co, and the volume concentration of diamond phase gradually decreases from the surface to the interior. The high volume fraction of diamond phase (>50 vol%) will ensure better abrasive wear resistance and physical interlocking of diamond within the bicontinuous WC-Co structure will result in a tough material. The processing methodology involves: (1) presintering of WC-Co powders into a porous preform, (2) chemical vapor infiltration of graphitic carbon into the porous preform, and (3) exposure of the preform to high pressure/high temperature conditions to complete densification and to transform the graphite into diamond.

Recent research[8-10] on nanostructured WC-Co has shown that the hardness can be increased substantially (up to a maximum at about 2200 VHN) by reducing the sintered WC grain size into the 'nanoscale' regime,

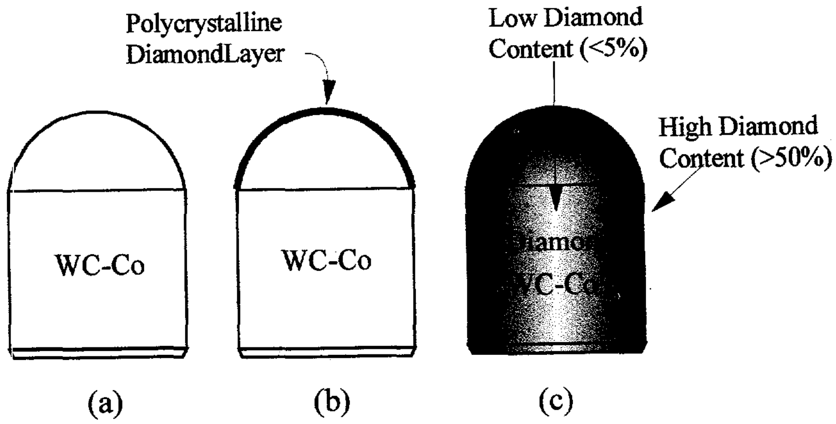


Figure 4: *Roller Cone bit inserts (a) Conventional, (b) diamond faced, (c) DMI's FGTNCs.*

typically < 250 nm. Surprisingly, other properties, such as transverse rupture strength are maintained, but there is some reduction in the fracture toughness (K_{IC}~10 MPa√m). These property enhancements (Table I) suggest their potential utility in roller cone bit technology, not only for stud inserts but also for hardfacing (by thermal spraying) of the entire bit body to enhance its overall resistance to abrasive wear. While we are confident that incorporating these innovations into bit technology will result in improvements in bit performance and durability, we have concluded that there is much more to be gained from a functionally graded triphasic nano-composite (FGTNC) material, consisting of Diamond/WC/Co. Based on developments in the nanostructured WC-Co(high hardness with sintered grain size < 250nm) and on proven concept of PCDs (where diamond-diamond bonding provides very high compressive strength and good abrasive wear resistance) we propose to fabricate a triphasic Diamond-WC-Co nano-composite material, starting from nanostructured WC-Co powder.

Nanophase WC/15 wt%Co powder was uniaxially compacted at 50 MPa into a 3 mm ϕ x 2 mm high sample. A floating die configuration was used to minimize density gradients in the green body. The compact was placed in a graphite crucible and inductively heated to 800°C in flowing H_2 to remove surface oxides. Subsequently, the chamber was evacuated and the sample heated to 900°C for 30 minutes. No significant dimensional changes occurred during this pre-sintering treatment. The pre-sintered compact was 36% dense and had sufficient strength for handling purposes.

Chemical vapor infiltration (CVI) of the porous compact was carried out in a controlled atmosphere thermal gravimetric analyzer (TGA). Weight changes were recorded using a Cahn 1000 micro-balance. The sample picked up ~ 20 wt% carbon (~ 45 vol%). The carbon-infiltrated sample was then placed in the reaction cell of a high pressure/high temperature (HPHT) press. The porous sample was placed in a high temperature high pressure apparatus and subjected to conditions, where diamond is thermodynamically stable and cooled while maintaining the pressure sufficiently high to prevent decomposition of diamond.

The formation of a relatively high volume fraction of diamond was established by Raman Spectroscopy. Raman microprobe spectra were recorded from 1520-1620 cm^{-1} at 0.1 cm^{-1} intervals. The spectra collected at 1290-1390 cm^{-1} showed two peaks, one at 1329 cm^{-1} and the other at 1370 cm^{-1}, Figure 5. The first peak corresponds to diamond and the second peak corresponds to disordered diamond. The absence of a peak at 1580 cm^{-1} clearly shows that there is no uncombined carbon in the sample. The Raman spectra is similar in appearance to that found in a CVD-generated microcrystalline diamond

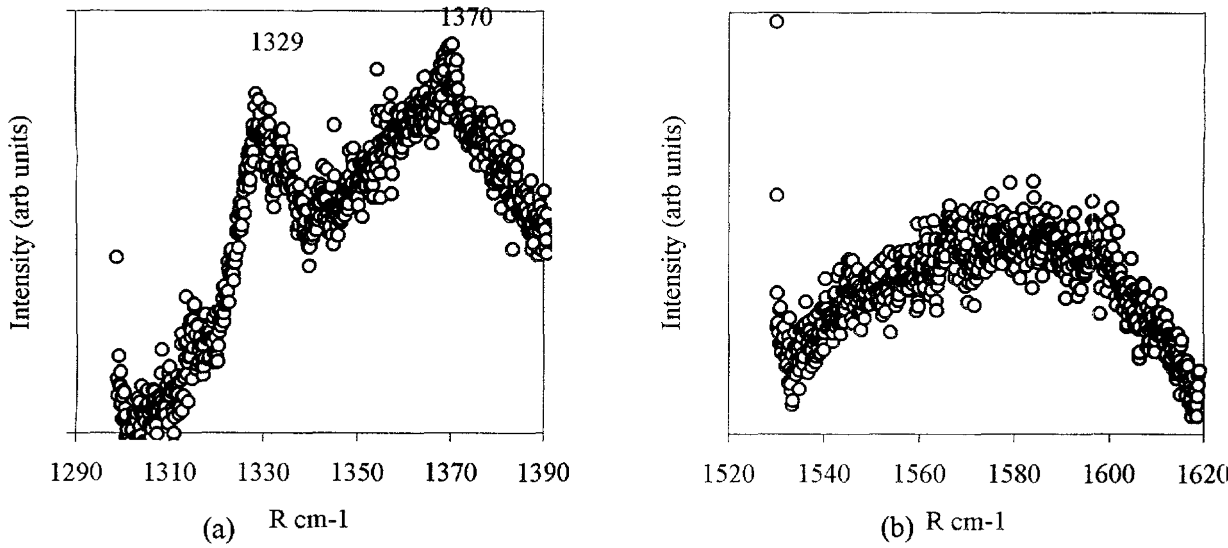
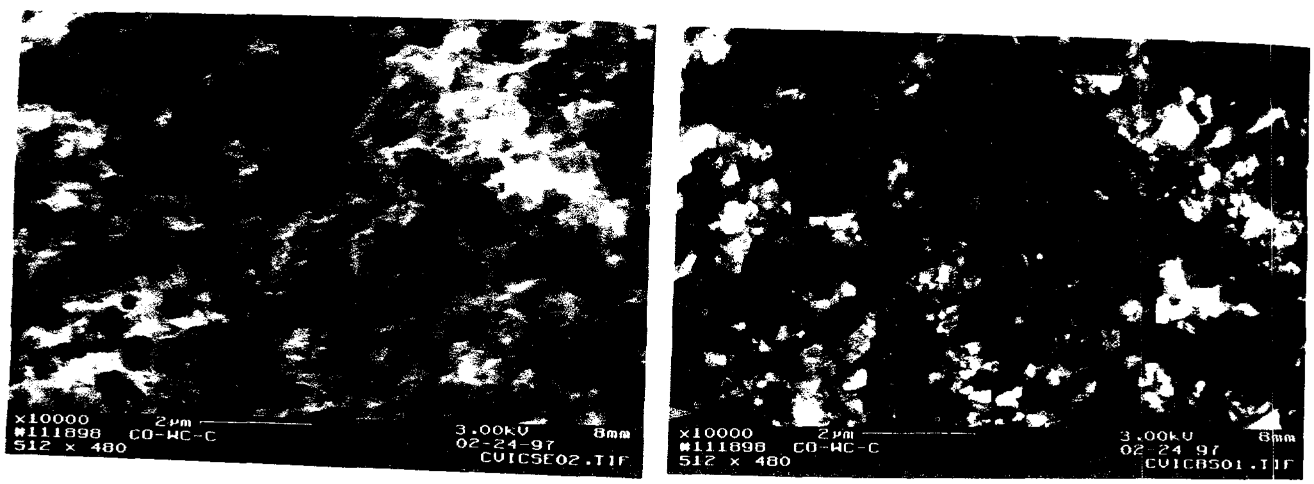


Figure 5 : Raman Spectra of samples (a) in 1290 -1390 cm^{-1}, and (b) in 1530 -1620 cm^{-1}.



(a) 10,000 X (b) 10,000 X

Figure 6. *SEM of FGTNC samples (a) in secondary electron mode, and (b) in back scattered electron mode.*

film. Figure 5, shows bright areas that represent mixtures of WC and Co, and much darker areas that represent diamond. Backscattered electron imaging confirmed this phase distribution.

SUMMARY

We have been successful in developing a binderless polycrystalline diamond compacts which retain their room temperature wear properties even after a 700°C heat treatment. Experiments are under way to determine the compressive strength as a function of temperature. In future, we plan to evaluate the thermal conductivity and friction properties of our BPCDs. Simultaneously, we are improving our pressure capabilities for consolidation of nanoscale powders.

Discovery of a functionally graded triphasic nanocomposites has opened up new opportunities for design of wear resistant materials with good toughness. With suitable process development, cobalt can be substituted by a corrosion resistant matrix, such as Ni-Cr or

Ni-Cr-Mo, for improved performance in geothermal drilling.

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NANOCRYSTALLINE, SUPERHARD, DUCTILE CERAMIC COATINGS FOR ROLLER-CONE BIT BEARINGS

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ABSTRACT

The established method for construction of roller bits utilizes carburized steel, frequently with inserted metal bearing surfaces. This construction provides the necessary surface hardness while maintaining other desirable properties in the core. Protective coatings are a logical development where enhanced hardness, wear resistance, corrosion resistance, and surface properties are required. The wear properties of geothermal roller-cone bit bearings could be further improved by application of protective ceramic hard coatings consisting of nanometer-sized crystallites. Nanocrystalline protective coatings provide the required combination of hardness and toughness which has not been available thus far using traditional ceramics having larger grains. Increased durability of roller-cone bit bearings will ultimately reduce the cost of drilling geothermal wells through increased durability.

TiN and TiCN coatings have been produced by ion beam assisted deposition (IBAD), which combines evaporation with concurrent ion beam bombardment (at temperatures as low as room temperature) to produce ultra-adherent thin films with excellent control over film structure and chemistry. Results indicate that these coatings possess superb adhesion to all substrates (flat or curved), and outstanding high-temperature and chemical stability as well as high fracture toughness. When crystallites are smaller than 10 nm, these coatings exhibit hardness greater than that of larger-grain nitrides or tungsten carbide.

INTRODUCTION

Despite the many advances which have been made in the development of new alloys, further improvement is sought in order to increase the durability of these materials and reduce the cost and energy consumption involved in fabrication and operation (by reducing size and weight). For example, it has been estimated[1] that friction and wear account for a 1.6% loss in the gross national product of developed countries - $116 billion for the U.S. alone in 1995. No single material has both the toughness and wear resistance (hardness) required for geothermal applications. Hard ceramic coatings are ideal bearing materials in terms of wear resistance and frictional properties, although several factors have prevented their application thus far. The bit environment is subject to high shock loads and thus requires materials tougher than conventional ceramics. Currently, components which require hard surfaces are made of carburized steel instead of homogeneous high-carbon steel in order to maintain a sufficiently tough core. If ceramic coatings are incorporated into this construction, the application process of the ceramic coatings should be consistent with the thermal cycles producing the best properties in the steel. Ideally, the deposition temperature of the ceramic coating should not exceed the operating temperature of the bit.

Nanocrystalline ceramic coatings meet both requirements for application to roller-cone bits,[2] due to the increased hardness and toughness of nanograin films and the low-temperature IBAD process used for deposition. In addition, if coatings with hardnesses substantially greater than those of rock fragments (minerals) can be used, the problems associated with bearing contamination can be drastically reduced. A very hard yet tough ceramic surface will therefore allow the development of a much more reliable bearing system. The use of nanocrystalline, hard, wear-bearing ceramic surfaces is the logical extension of the established practice, as well as a novel and revolutionary extension (into high-shock environments) of the applications of ceramic protective coatings.

Ion enhanced processes, by virtue of using an ion beam, "stitch" ceramic films to the substrate during deposition and result in coatings which are more adherent than those produced without ion bombardment. Since deposition can be carried out at room temperature, the temper of the steel substrate is preserved. (In contrast, conventional ceramic coating methods for metal cutting tools are less suitable for carburized surfaces since deposition temperatures are typically at least 500°C, and for many cases are as high as 1000 to 1100°C.) It is well known[3] that heating carburized steels to high temperatures may result in phase transformation to softer materials. Films produced by other conventional techniques, such as thermal spray processes, may suffer from problems with adhesion, coating delamination, and spallation.

Why Nanocrystallites Enhance the Properties of Protective Coatings

Films comprised of nanocrystalline materials often have mechanical properties that differ from those of materials having larger grains. One fundamental reason for this is that, for grain sizes smaller than 100 nm, the volume of material influenced by proximity to a grain boundary becomes significant. At a grain size of 5 nm, approximately 50% of the volume is "near grain boundary" material. Such structural changes have a strong influence on the most fundamental of material properties such as elastic (Young's) modulus and conductivity.

The superplasticity observed in nanocrystalline ceramics or glasses is attributed to the sliding of grains past one another, the shear localized in the near-surface region. It is reported[4-5] that the ductility of zinc oxide and titanium oxide nanoparticles (powder) is drastically improved because the individual nanograins can be moved over one another without breaking the ceramic. In conventional ceramics the large grains do not slide easily and materials are brittle, whereas in nanocrystalline ceramics the smaller grains are easily deformed and less brittle.

Metallic Materials – The strategy on which the development of hard nanocrystalline materials is based depends partly on the material used. More important is the failure mode being avoided. For ductile materials such as metals the failure mode is deformation facilitated by dislocation motion. The benefit of small grains for increased hardness (known as the Hall-Petch[6-7] relation, $H \sim d^{1/2}$) is twofold. The boundaries between small grains are barriers to dislocation motion against which only a small number of dislocations can pile up, because the grain dimension is too small for many dislocations to form. The fine grain structure essentially "spreads out" the stress of dislocation pile-ups between many small grains, as opposed to fewer (but larger and higher-stress) pile-ups at the boundaries between large grains. The second reason nanocrystalline ductile materials resist deformation is that the small dimension inhibits the primary mechanisms for dislocation generation, such as the Frank-Reed source. Therefore, engineering of nanocrystalline metals must be addressed differently than traditional materials. For example, the quasi-crystalline boundary region between crystallites can be considered a unique phase and the structure modeled as a composite.[8]

Ceramic Materials – Hardening of nanocrystalline brittle materials such as ceramics, which undergo little or no deformation before crack generation and propagation, must be analyzed and approached differently from hardening of metals. A brittle material fails when the strain energy in the material reaches the amount necessary to create two new surfaces.

The engineering goal is usually to increase the critical stress for crack propagation (which can lead to failure). It is known that the size of imperfections or flaws in polycrystalline materials is proportional to the size of the crystal. The Griffith formula[9] states that:

$$\sigma_c = \sqrt{\frac{2E\gamma_s}{\pi a_{cr}}} \quad (1)$$

where σ_c is the critical stress, E is the elastic modulus, γ_s is the specific surface cohesive energy, and a_{cr} is one-half the length of the original microcrack. As shown by equation (1), the critical stress is inversely related to the square root of the size of the flaw. Nanocrystalline materials, therefore, possess higher critical stresses due to the smaller flaws (which are proportional to the grain size).

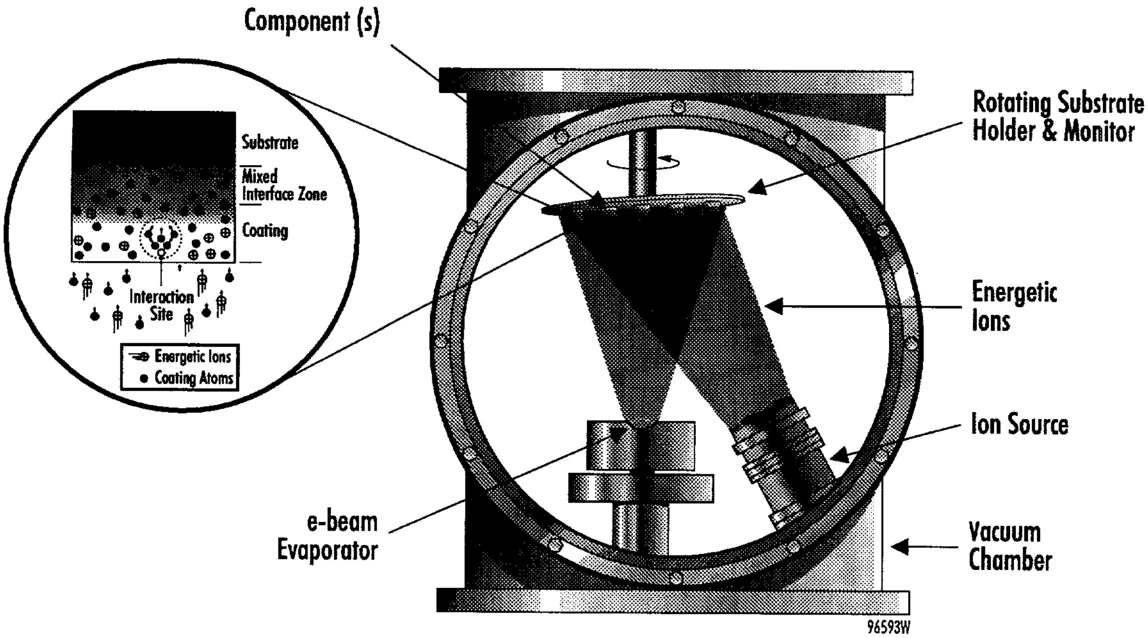
Since the critical stress is the product of the critical strain and the elastic modulus, an increase in critical stress could also be achieved by increasing the elastic modulus of the material without changing the critical strain. However, the elastic modulus is a fundamental material parameter that is largely unaffected by variations in microstructure. The elastic modulus is a direct representation of the characteristics of interatomic forces. The force between two atoms depends on the relative position of the atoms which, at their equilibrium position (the interatomic spacing), balance to result in a zero net force. If the atoms are pushed closer together or pulled farther apart, corresponding to compressive and tensile strain, respectively, the elastic modulus changes. A compressive strain increases the elastic modulus while a tensile strain causes a decrease. However, for a given magnitude of strain the effect is greater in compression due to the asymmetry of the interatomic potential well. Thus if a nanocrystalline composite material containing balanced regions of tensile and compressive strain can be fabricated, the consequence will be a net increase in the bulk elastic modulus of the material and a corresponding increase in hardness.

The strategies described above are most easily modeled using a thin-film type of structure. However, a bulk nanocrystalline composite, in which one phase is discontinuous within a matrix, accomplishes the same basic structural relationship in three dimensions. For this reason, metal and ceramic nanocrystalline composites have been developed which exploit the benefits of closely matching interfaces and exhibit improved mechanical properties.

EXPERIMENTAL PROCEDURE

The IBAD system (see Figure 1) used for this work consists of a 6-inch diameter Kaufmann type ion source which can be operated up to 2 kV. It is equipped with a water-cooled substrate holder with multifunctional rotational capability. Typically, the reaction chamber is pumped with a cryopump to a base pressure of less than 9×10^{-7} torr.

Titanium was deposited using an electron beam evaporation technique. During evaporation, targets were bombarded with ions at



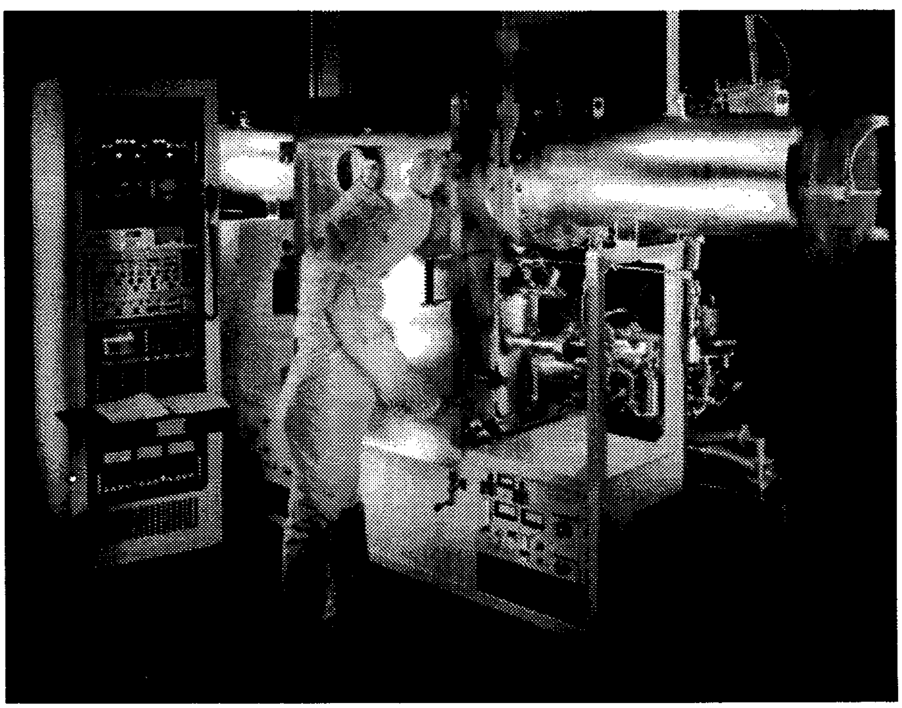


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Figure 1. *(a) IBAD process, and (b) IBAD system.*

energies of 300 and 1000 eV and at a current density of 50 to 300 A/cm^2 using nitrogen (the ratio of N^+ to N_2^+ was approximately one) or argon. Typically, the temperature was below 150°C, although a few samples were produced at higher temperatures to study the effect of temperature. Background pressure during deposition and nitrogen bombardment reached 2 x 10^{-4} torr (note that the reaction chamber was partially backfilled with nitrogen gas). The arrival ratio of nitrogen to titanium ranged from 0.2 to 1.

During film growth, thickness was monitored by a quartz oscillator. After completion of film deposition, the thickness and composition were determined by RBS and selected samples were studied by XTEM. The nominal thickness of all of the TiN films was 0.6 μm. The grain size was determined by dark-field plan-view TEM. Grain size was determined by measuring the dimensions of 70 to 100 grains in the reverse contrast mode of several dark-field TEM images and the mean size of the grains was calculated.

A Buehler microhardness tester with a Knoop diamond indenter was used for microhardness measurements. Microhardness is determined by lowering a diamond indenter onto a material under loads between 0.5 and 50g. As the tip penetrates the surface more deeply, it leaves behind a wider indent. The width-to-depth ratio is characteristic of the indenter; thus, measurement of the width of the indent yields a measurement of depth and, therefore, microhardness. A sample from each test condition was tested in several different spots on the surface under each load.

In addition to microhardness measurements, the nanoindentation technique[10-12] measures hardness and elastic modulus by an ultra-low depth sensing nanoindenter (Nano Instruments Type II) from the loading and unloading curves. In this study the loading segment of the indentation curve was measured by keeping the displacement rate constant (1.7 nm/s) and measuring the displacement until a total displacement of 100 nm was reached. A hold period of 60 sec followed to allow for relaxation of induced plastic flow and creep. Finally, the unloading segment was measured by decreasing the force at a constant rate (100% of the load rate at maximum displacement during the loading segment). The elastic contribution was determined from the unloading curve. From this the elastic modulus and plastic depth were determined. The indentation depth of 100 nm corresponds to less than 15% of the thickness of the thinnest films, so that the influence of the substrate on the measurement can be eliminated.

At this low penetration depth, small deviations of the area function from a Berkovich diamond tip might cause errors in the absolute values of hardness and elastic modulus. Therefore, the measurements were calibrated with data from a SiC bulk sample at a maximum displacement of 100 nm, assuming a hardness of 35 GPa and a elastic modulus of 440 GPa.

EXPERIMENTAL RESULTS

Nanocrystalline Titanium Nitride Films

We have produced TiN films at temperatures below 150°C having gold color and grain sizes from 20 to 100 nm. Figure 2 shows a dark-field TEM image of the TiN film; the grains are about 6 to 10 nm in size, and are clearly shown. An electron diffraction pattern from a large region of the sample is also shown. The interplanar spacings of the three rings of the pattern were 2.45, 2.12, and 1.52Å, which indicates a face-centered cubic structure, and the unit cell dimension was determined to be 4.3Å. This dimension corresponds well with TiN.[13] In addition, a pattern was obtained from a very small region (individual crystal) as shown in Figure 2; this pattern was indexed as a <100> orientation of TiN as shown in the schematic. Based on these observations, it was concluded that the film is exclusively TiN. An example of a TiN film with larger grains (20 to 50 nm) is shown in Figure 3. High-resolution lattice imaging of the TiN grains shows the <111> plane of TiN with d-spacing of 2.45Å. Electron diffraction patterns of these samples again correspond to TiN.[13]

As mentioned before, the hardness of all of our samples has been determined by Knoop microhardness (HK) and nanohardness (GPa) techniques. TiN with grains smaller than 10 nm exhibits a hardness of 25.5 ± 1 GPa. In order to simplify the evaluation of the hardness of our material, we have compared the hardness of TiN measured accurately by nanoindentation techniques (in GPa) with several hardness scales (see Figure 4).

For deposition at high temperatures, it was noted that the rings from the electron diffraction patterns consist of sharp, discrete spots, suggesting that the grains could be free of point defects. The rings could be compared with diffraction patterns from low-temperature deposition of TiN specimens where the rings were relatively more diffuse, suggesting that the grains possess a large number of point defects at the grain surfaces. Nevertheless, hardness of 25.5 GPa was observed.

Figure 5 shows hardness/modulus (theoretical wear resistance) vs. hardness (H) for the samples discussed in this work. All hardness and modulus data presented in this figure were based on nanoindentation measurements. The hardness to modulus ratio (H/E) is considered a better parameter for characterization of the wear resistance of a material than hardness alone.[14,15] It can be expected that the abrasive wear would be reduced with increasing hardness and decreasing elasticity. This is due to the fact that at a given hardness, large strains can be sustained better with a lower elastic modulus. Characteristic H/E values are 0.01 to 0.04 for metals, and 0.1 for diamond.[14,15]

Our impurity-free, stoichiometric TiN with grains smaller than 10 nm (see samples 5 and 7 in Figure 5) shows a hardness of 25.5 ± 1 GPa and H/E of 0.11, which is slightly higher than that of diamond. We have found that for stoichiometric, impurity-free TiN films, hardness and wear resistance increase with reduced grain size. TiN is susceptible to oxygen contamination, which can influence the hardness and wear resistance (hardness/ modulus). We believe that a TiN oxygen-rich phase present at the grain boundaries may result in reduced hardness and wear resistance (see samples 2 and 4 in Figure 5). RBS clearly shows presence of 30% oxygen in these films. These samples also appear gold in color, although they possess titanium oxide (a wide-bandgap material which is transparent to visible light).

Fracture toughness (K_c) is one of the most important properties of ceramic coatings for practical applications in harsh environments. We determined the fracture toughness of our TiN films using the indentation techniques of Pharr *et al.*[12] This method is based on measuring the radial cracking which occurs when brittle materials are indented.[16] Therefore we have used cube-corner diamond indenters to measure the fracture toughness of TiN films produced at low temperatures (< 100°C).

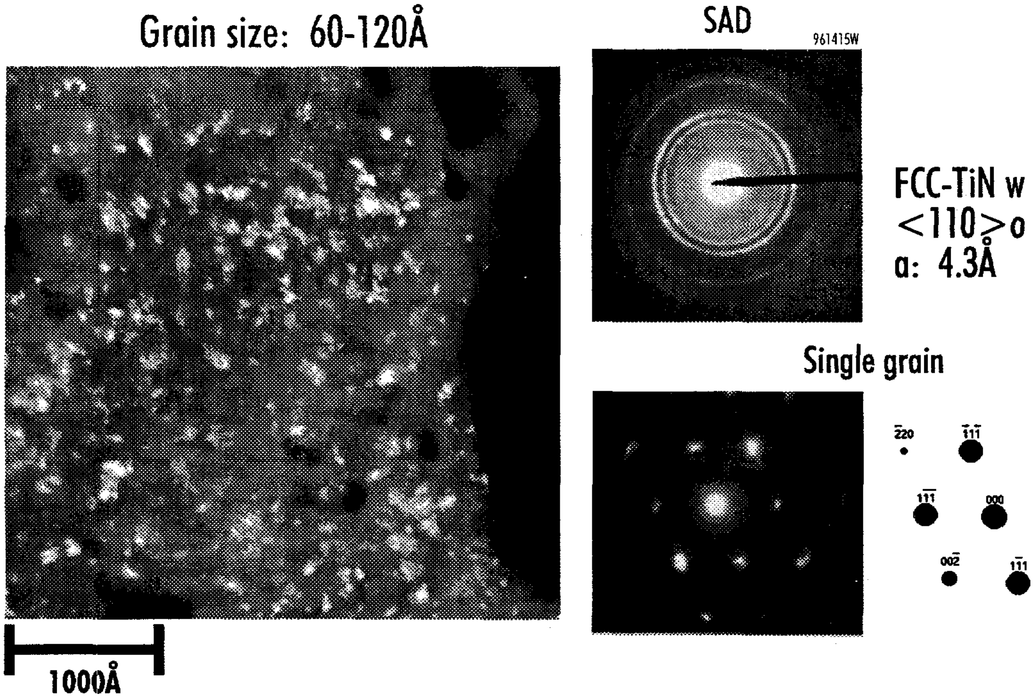

Figure 2. *Dark-field TEM of a TiN film at high magnification having crystallites with dimensions of 6 to 10 nm; selected-area diffraction pattern from a large region showing rings from a face-centered cubic structure corresponding to TiN; electron diffraction pattern from a small region indexed as <110>; and a schematic of the pattern.*

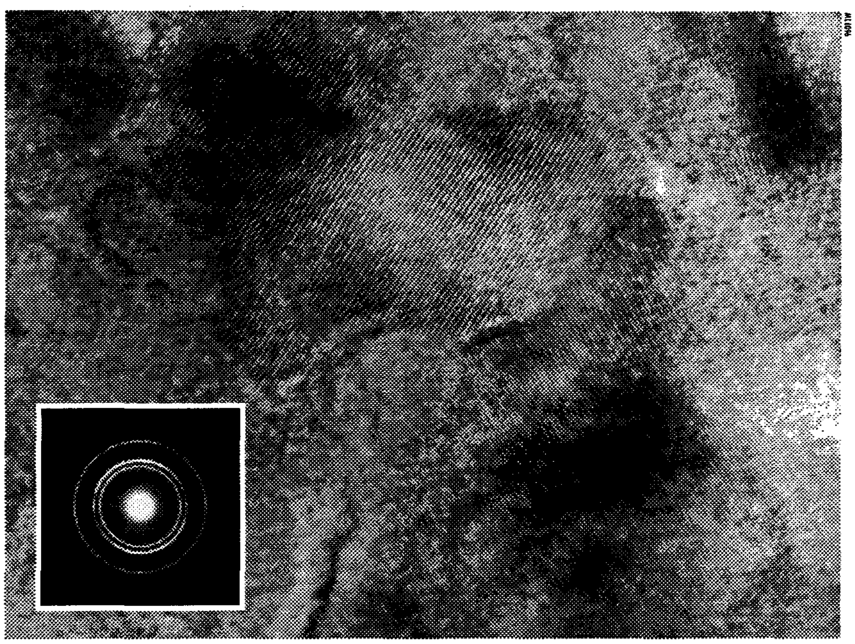

Figure 3. *Electron diffraction pattern and high-resolution TEM image for sample with grains of 20 to 50 nm showing the <111> 2.45Å lattice spacing of TiN.*

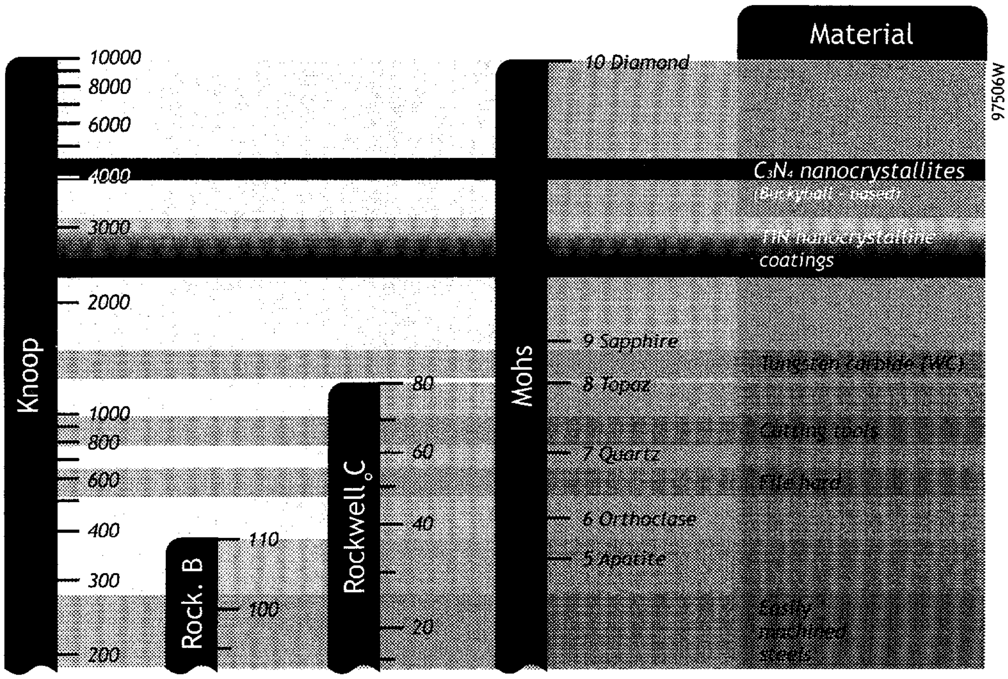

Figure 4. *Comparison of nanoindentation measurements with several hardness scales. Nanoidentation tests show a hardness of 25 to 32 GPa (2500 to 3200 HK) for titanium nitride having crystallites smaller than 10 nm. Data obtained April 7, 1997 show a hardness of 40 to 45 GPa (4000 to 4500 HK) for nanocrystalline C_3N_4, which is expected to be harder than diamond.*

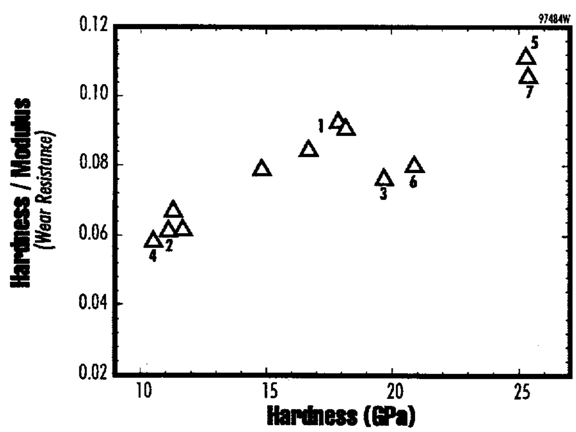

Figure 5. *Hardness/modulus vs. hardness for TiN samples deposited below 150°C with an atom/ion ratio of 5/1. Impurity-free TiN becomes harder with smaller grain size (about 25 GPa for grains smaller than 10 nm), and apparently has a higher wear resistance than diamond. TiN with hardness in the range of 10 to 15 GPa are due to oxygen contaminants or larger grains in the films.*

The fracture toughness K_c is given by:

$$K_c = \alpha\,(E/H)^{1/2}\,(P/c^{3/2}) \qquad \textbf{(2)}$$

where E is the elastic modulus, H is the hardness, P is the peak load, c is the radial crack length and α is an empirical constant which depends on the geometry of the indenter.[12] By accurately measuring the radial crack length from nanohardness measurements at different loads, one can determine the fracture toughness using equation (2).

Figure 6 shows a comparison of nanoindentations in TiN on Si with those in a Si substrate. The nanoindentations were created using loads of 60 mN, 120 mN, and 400 mN on TiN and with 120 mN on Si.

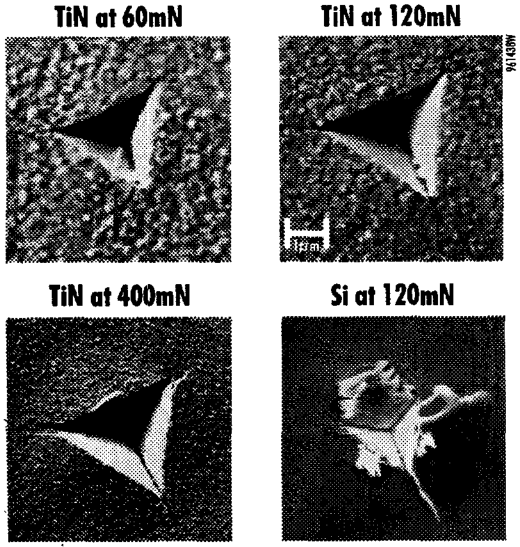

Figure 6. Comparison of cube-corner type nanoindentations in TiN on Si and in Si. From measurements of the radial crack length as a function of load, it was determined that the fracture toughness of our TiN films with grain size smaller than 10 nm is second to Si_3N_4 (see Figure 7).

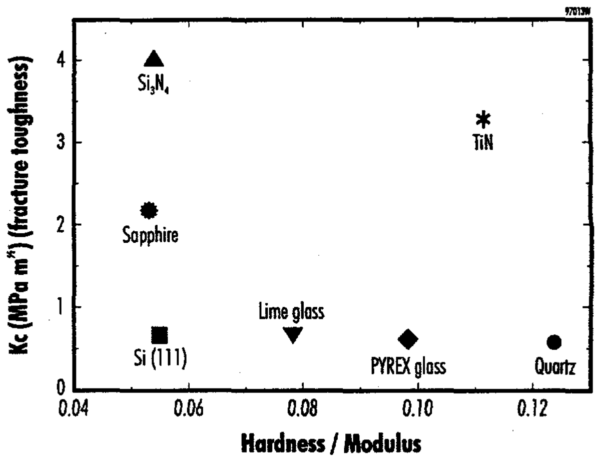

Figure 7. Comparison of fracture toughness of nanocrystalline TiN with that of other materials. Results indicate that TiN is almost as tough as Si_3N_4, which is known to be one of the toughest materials available. However, H/E (wear resistance) of TiN appears to be higher than that of Si_3N_4.

Based on several measurements, a fracture toughness value of 3.3 MPa $m^{1/2}$ was obtained for TiN. Figure 7 shows a comparison of fracture toughness as a function of hardness/modulus (wear resistance) for nanocrystalline TiN (H=25.4 GPa, E = 227 GPa) with other materials. Results indicate that TiN with nanocrystallites (< 10 nm) is slightly lower in toughness than Si_3N_4, but its wear resistance is higher than that of Si_3N_4.

Properties of TiN Produced at 400°C

TiN has also been produced while heating the substrate to 400°C, under conditions similar to those of the samples shown in Figures 2, 3, and 5. Gold-colored, hard TiN films with hardness typically about 20 GPa have been obtained, apparently due to the larger grains produced at higher temperatures. In order to further enhance the adhesion of TiN to metallic substrates, a buffer layer of Ti_2N was first deposited. Note that metal-rich nitrides possess more metallic bonds and thus adhere better to metallic substrates such as steel, but their hardness is slightly less than that of stoichiometric TiN.

Figure 8 shows RBS spectra for as-deposited Ti_2N/TiN at 400°C, and Ti_2N/TiN annealed in air at 500°C. RBS analysis by Rump code shows the deposition of a Ti_2N buffer layer with thickness of 80 nm, and a TiN layer 400 nm thick. Heating the samples to 500°C in air resulted in very little surface oxidation. A small peak from channels 240 to 300 is due to surface oxidation of the first several atomic layers.

Figure 9 shows RBS spectra for as-deposited Ti_2N/TiN/TiCN at 400°C, and Ti_2N/TiN/TiCN annealed in air at 500°C. RBS analysis by Rump code shows the deposition of a Ti_2N buffer layer with thickness of 80 nm, a TiN layer 210 nm thick, and a $TiC_{0.5}N$ layer 180 nm thick. Again, heating the samples to 500°C in air resulted in very little surface oxidation. As mentioned above, a small peak

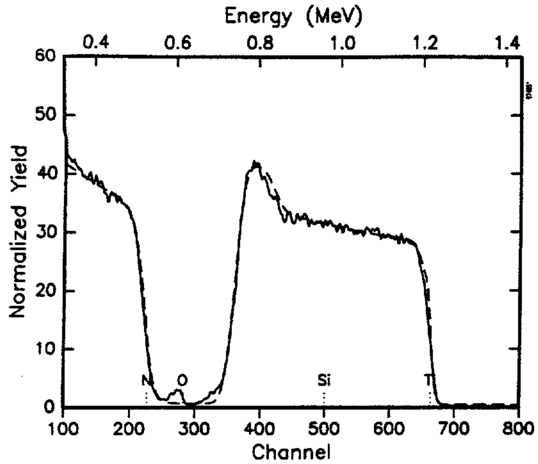

Figure 8. *Comparison of RBS spectra for as-deposited Ti_2N/TiN at 400°C (dashed line), and TiN annealed in air at 500°C (solid line), showing only an extremely small amount of surface oxidation.*

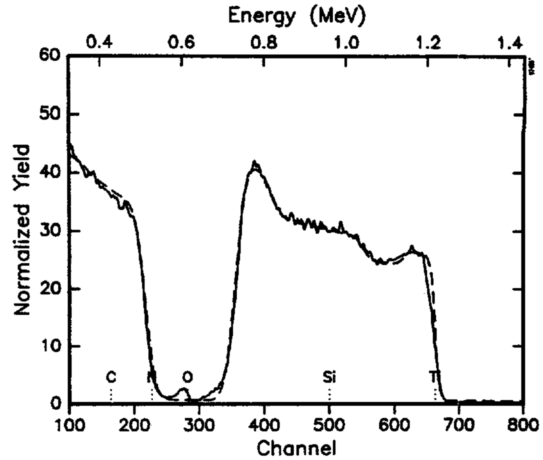

Figure 9. *Comparison of RBS spectra for as-deposited $Ti_2N/TiN/TiCN$ at 400°C (dashed line), and TiCN annealed in air at 500°C, showing only an extremely small amount of surface oxidation.*

from channels 240 to 300 is due to surface oxidation of the first several atomic layers.

Oxidation Resistance Behavior of TiN and TiCN Films

Figure 10 summarizes preliminary microhardness after heating the samples in air. As shown in Figure 10, introduction of carbon into the top layer of TiN results in hardening of the samples by 25%. Annealing of TiN without carbon in air to 500°C resulted in hardening of TiN from 2000 HK to greater than 3000 HK, an apparent 50% increase. Further heating of the sample to 650°C resulted in partial oxidation of the film and softening of the samples. As mentioned above, introduction of carbon into the TiN surface layer resulted in hardening of the samples. No obvious change in hardness was observed after annealing these samples in air to 500°C. In comparison with stoichiometric TiN, TiCN samples show no reduction in hardness after heating to 600°C and 650°C in air. From this data, one can conclude that the Ti_2N/ TiN system is stable as a coating up to 600°C in air. On the other hand, the Ti_2N/ TiN/TiCN system is stable at

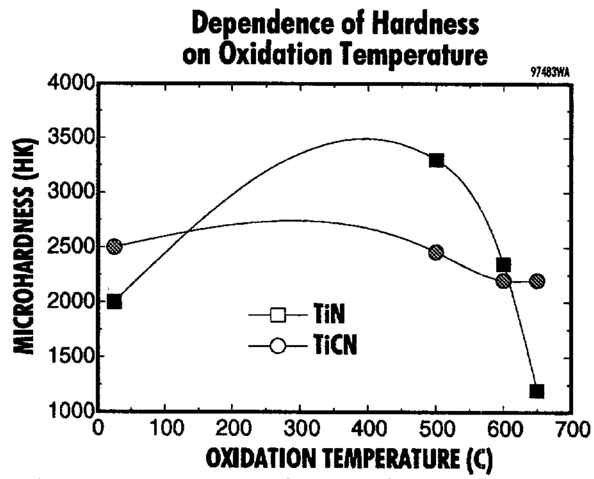

Figure 10. *Dependence of microhardness of Ti_2N/TiN and $Ti_2N/TiN/TiCN$ on temperature for samples heated in air.*

all temperatures measured for this work, up to 650°C. Oxidation at higher temperatures will be carried out in the future.

CONCLUSION

We have demonstrated that IBAD is capable of producing impurity-free (within the accuracy of RBS) films of several ceramics with grains in the nanocrystal (< 10 nm grain size) range. IBAD presents the additional advantage that the low-temperature process enables the coating of temperature-sensitive substrates, such as hardened steels. Low-temperature nanocrystalline TiN has exhibited a hardness of 25 GPa, as compared to typical TiN hardnesses less than 18 GPa, and has a high fracture toughness.

All TiN samples appeared gold-colored, regardless of whether an ion beam was used during deposition. However, mechanical properties of the films are greatly influenced by process parameters, and formation of superhard TiN requires stringent conditions. In the absence of impurities, smaller grains of TiN resulted in harder films. We speculate that, during deposition of TiN at low temperatures in the presence of oxygen impurities, amorphous titanium oxide is formed at the grain boundaries. The gold color of TiN is not altered by the presence of oxygen in the films because of the formation of titanium oxide, a wide-bandgap material which is transparent to visible light.

In summary, we have demonstrated:

- deposition of uniform, smooth, adherent, stoichiometric TiN at temperatures ranging from room temperature to 400°C,
- films consisting of randomly oriented nanocrystallites of TiN (FCC with lattice parameter of 4.24Å) with dimensions ranging from 5 to 100 nm,
- hardness and toughness can be increased by reducing grain size,
- TiN with grain size < 100 nm has shown hardness > 25 GPa and fracture toughness close to that of Si_3N_4, but with higher wear resistance,
- introduction of carbon into the TiN surface resulted in hardening of the surface and enhanced oxidation resistance,
- negligible surface oxidation occurs when TiN is subjected to 500°C heating in air; however, hardness increases by 50%,
- TiCN is oxidation-resistant at all temperatures measured (up to 650°C) with no decrease in hardness.

Our TiN and TiCN multilayer structures not only have good adhesion to all metallic surfaces, but appear to be much more ductile than ceramics with larger grains. It should be noted that, in addition to hardness, toughness and ductility are essential for applications such as rock drilling since the bearings are subjected to severe shock loading This technology can be used to extend the lifetime of critical bearings in roller-cone bits used for rock drilling. TiN and TiCN films also have great potential for improving tribological performance of gears and bearings. The films will prove beneficial in industrial equipment and in transportation applications.

ACKNOWLEDGMENTS

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Development of a Jet-Assisted Polycrystalline Diamond Drill Bit

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Abstract

A preliminary investigation has been conducted to evaluate the technical feasibility and potential economic benefits of a new type of drill bit. This bit transmits both rotary and percussive drilling forces to the rock face, and augments this cutting action with high-pressure mud jets. Both the percussive drilling forces and the mud jets are generated down-hole by a mud-actuated hammer. Initial laboratory studies show that rate of penetration increases on the order of a factor of two over unaugmented rotary and/or percussive drilling rates are possible with jet-assistance.

Background

A major influence on the cost of accessing geothermal energy resources is the time a drill rig spends "over the hole." Low penetration rates, as well as downtime brought about by low bit life, lost circulation, and surface casing problems, highly influence drilling time and therefore drilling costs. To increase the economic range of resources that can be recovered, means of improving each of the above factors must be developed.

Drilling becomes most difficult and expensive in harder rocks, where the penetration rate is frequently slow, and drill bit life is correspondingly short. Softer formations that contain stringers of hard rock are also particularly problematic. In both of these drilling environments, PDC drag bits, which drill quite effectively in softer formations, are rendered useless because of the high temperatures generated by dragging a cutter over the surface of the hard rock. Air- or gas-driven percussion drilling systems have found particular application in some of these slow drilling regions; however, such systems get choked out when water is produced in the well. Such systems are also not particularly effective in soft interbedded rock.

Novatek, in connection with the University of Missouri-Rolla, has investigated the economic potential of a new technology that addresses many of the issues mentioned above. This technology relates to a means of increasing rate of penetration (ROP) and bit life, particularly in hard rock and interbedded hard/soft rock formations.

Approach

Novatek's approach to improving the life and effectiveness of the drilling head is to use a new type of polycrystalline diamond (PCD) enhanced drill bit that combines high-pressure fluid jets with a rotary-percussive drilling action. The heart of this drilling system is a down-hole hammer actuated by drilling mud.[1] This hammer is used to provide the percussive component of drilling as well as the high-pressure fluid jets. Since mud rather than air activates the hammer, it may operate in a flooded well. Figure 1 shows this basic concept, focusing on the cutter/rock interface.

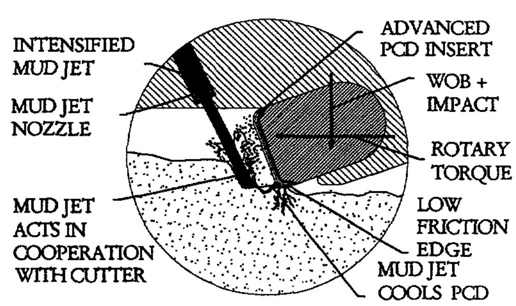


Figure 1. *Jet-assisted Rotary-Percussion Concept*

A discussion of the basic concepts exploited by this new bit follows.

High-pressure fluid jets. High-pressure fluid jets have been the subject of considerable study for rock drilling and mining applications. In pioneering work by Maurer and others[2] it was shown that, with jet pressures of around 10,000 psi, ROP could be more than doubled in softer formations. The initial mechanism by which these jets were combined with mechanical tools was in separate actions: the jets cut slots into the rock, and then the mechanical force from the bit broke the ribs formed between the jet cut slots. Work at the University of Missouri-Rolla (UMR) in 1971 showed that this could reduce the specific energy of material removal by several orders of magnitude.[3] This combination has been referred to as Mechanically Assisted Waterjet Cutting (MAWC) of rock, since the mechanical tool follows the action of the cutting jets. In a modified form this approach has been further developed by FlowDrill, Inc., who have used higher jet pressures to cut a slot around the perimeter of the face into which the drill must advance, thereby increasing ROP to approximately double the unassisted rate.[4]

An alternative approach to this combination was developed in South Africa by Dr. Hood, in 1976.[5] In the method he developed, the jets are directed into the zone where the bit is actively cutting the rock. This zone is approximately 0.08 inches wide and thus calls for some precision in jet location to be effective. However, when properly aligned with the drag bit, not only did the water cool the drag tool, it also allowed, at a lower thrust force, a more than doubling of the penetration.

Subsequent research by Hood and others has shown that jet pressures required are on the order of 6,000 psi.[6] This combination has since been used to extend the range of performance of road headers. On the smaller scale, however, in the application of mechanical tools to hole drilling, this combination has not been explored with the same degree of thoroughness. Initially this was because of the difficulty in combining the high pressure fluid systems required within the logistical framework of a conventional drilling rig, and while some of those problems have been overcome, this constraint has limited the development of this tool to this time. This combination of jets and mechanical tools is referred to as Waterjet Assisted Mechanical Cutting (WAMC) of rock, since the jets act in the zone where the mechanical tool does the initial work, often in rocks which the jets, at that pressure, would otherwise be unable to do any work.

More recently work at UMR has developed a third approach to the combination of jets with mechanical tools.[7] In this method, the jets are directed to exploit the stress field developed around a mechanically loaded tool. In this case the two tools still act synergistically, but the combination does not require the precision of location required by WAMC. In recent tests of this system, the thrust forces at failure dropped by 50%, as the jet pressure was increased from 3,500 to 5,000 psi, when the combination was tested on Georgia granite. This combination is currently referred to as Offset Combined Cutting of Rock (OCCR).

Each of these studies has shown ROP benefits when combining high-pressure jets with mechanical drilling devices. Not insignificantly the jets also scour the face of the rock ahead of the tool enhancing cleaning and thus the performance of all the inserts on the bit. The lack of fine drilling detritus on the face of the rock also benefits the cutting inserts by reducing the friction and therefore the heat generated by drilling. Still another benefit of such a system is that cooling of the cutters is enhanced with the high velocity fluid jets, making them less susceptible to thermal damage. This latter benefit is significant, particularly when PCD cutters are used.

Rotary-percussive drilling action. A rotary-percussive bit has two component parts to the drilling operation, one where the cutters are indented into the rock during an impact, crushing the material, and the second where the bit rotates under normal drilling loads between indentations. It is the authors' thesis that the best gains in ROP will be offered, particularly in deep or horizontal wells, if both drilling mechanisms are allowed to be operative. If such is the case, improved penetration due to hammer impact is followed directly by a shear removal of damaged rock. Hence, in deep wells where rock formations typically act more plastic due to a high pressure head, the bit is not relying solely on axial indentation for penetration. Also, in formations where soft rock is interbedded with hard, pure percussion drilling is not effective, so a rotary element is of great benefit.

Bit Design Issues

As mentioned above, not much work has been done to optimize cutter-jet interactions for the down-hole environment. There are two specific problems that must be addressed in the inclusion of a high-pressure fluid to a cutting bit. The first is the pump required to generate the pressure. Given that the fluid that must be used is often a mud, this imposes wear problems on many conventional high pressure systems. Secondly, once pressurized the fluid must be conveyed to the jetting nozzle. This may be achieved by using a second high-pressure line down through the normal drill string. However, if the high pressure may be generated down-hole, the increased cost and difficulty of using multiple conduit drill pipe may be avoided. Thus, the integration of a jet pumping mechanism within the body of a hammer bit, to generate pressure pulses by the reciprocating motion of a down-hole hammer, provides particular cost advantage.

The rotary-percussive nature of the new drill bit dictates the type of bit design to be used. A flat faced hammer bit, while optimized to withstand axial impact, is poor for providing rotary drilling. In pure percussion or hammer drilling cutters are simply indexed between hammer blows, without a significant normal load. In fact, such a bit cannot be used under heavy weight on bit (WOB), nor can it be used to ream a tapered hole. Under heavy axial load, the button cutters or the bit head on a flat faced bit will typically fail.

On the other hand, a roller cone bit, while providing good rotary drilling action, is non-ideal for the transmission of impact or fluid jet energy to the rock. This is due to the relative complexity of the bit design: several free surfaces exist which reflect and attenuate the impact wave. Such a bit, having welded joints and multi-component bearings, is also not as robust as a fixed cutter bit.

The closest to an ideal design for rotary-percussion drilling is thus anticipated to be a drag type bit. Such a bit features fixed cutters and a solid bit body, which provides for effective impact and fluid jet energy transmission, at the same time providing for rotary cutting.

Preliminary Research - Objectives

Given the above overall design concept, a research program was begun to determine its feasibility and economic potential. The basic objectives of this research were to:

- Establish the feasibility of integrating a high pressure jet generator in a rotary-percussive bit body
- Establish the interactions between the rock, the indenting insert and the high pressure jet stream, and
- Integrate the findings from the first two parts of the study to establish practical viability of this concept.

Each of these objectives was designed to lay the foundation for accomplishing the overall objective of this work, which is the development of a drill bit capable of improved life and effectiveness over current art tools.

Experimental Methods

In pursuing these objectives, both basic design work and fundamental laboratory research was required.

Since both rotary and percussive drilling mechanisms are active in a rotary-percussion system, the influence of a fluid jet on each of these actions was analyzed. For convenience, a water jet was used in this preliminary research, rather than a mud jet. Similarly, jet/cutter/rock interactions were studied under atmospheric conditions, rather than submersed and under hydrostatic pressure load. The basis of comparison for each analysis was the respective drilling mechanism without the assistance of a high-pressure jet.

Percussion tests. Figure 2 shows the basic setup utilized to study the influence of a high-pressure waterjet on percussive drilling. As shown, a core sample of rock is placed atop a stiff platen, and a PCD coated hemispherical indentor is forced into the top of the sample. Forcing of the indentor was accomplished by dropping a 150 lb weight from various heights, ranging from one to six feet, onto the stationary indentor. After indentation, the penetration was measured.

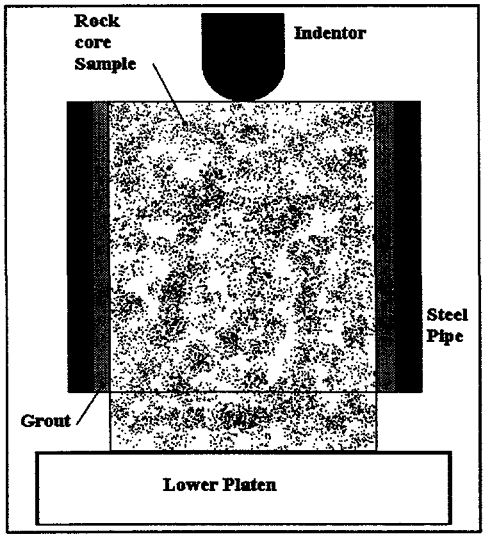


Figure 2. Test Set-up for Low and High Energy Loading Rates

The core was nominally $2^{1}/_{8}$ inches in diameter with a length of 3 inches. Each core sample was confined by cementing the sample in the pipe section with a 9,000 psi hydro-stone in a steel pipe section that was 2½ inches in height and had an inside diameter of 2½ inches. Before cementing the sample in the pipe, each end of the core sample was ground flat with a diamond grinding wheel using a surface grinding machine and standard V-block holders. The core sample was cemented flush with the pipe on the end that was indented. On the bottom end, the core protruded ½ inch to ensure the core was always in contact with the lower platen.

The confinement shown in Figure 2 is a passive system. There is no confinement force on the sides of the sample until the sample begins to experience loading caused by the insert. Consequently, the rock sample does not simulate the semi-infinite plane that a field drilling tool. However, the confinement system was selected because:

a) Testing core is a common geotechnical device. It is possible that this simplified test will ultimately find use in tool performance prediction.

b) The passive system allows failure strains to occur. One goal of the test program was to determine differences in strain failures as a function of rock properties.

Core sized rock also allows the sample to be cut apart after indentation and internal failures investigated and quantified to some extent. The results of core tests will be correlated with indentations into larger semi-infinite rock samples.

Figure 3 depicts the orientation of the waterjet with respect to the rest of the test setup. To build understanding of the optimal position of a jet, two different jet tests were conducted for the above indentation tests: waterjet impact was directed at the rock either during loading or after the load has cycled. In this way, the effect of the timing of the jet was also investigated. When the jet was directed at the rock during impact loading, the jet was turned on, the impact was made, and the jet was immediately shut off upon impact.

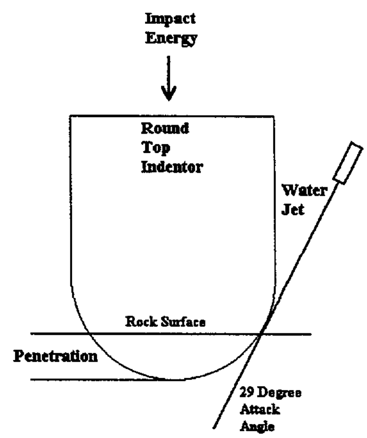


Figure 3. Basic Test Geometry for Jet Assisted Impacts.

Once the rock samples were thus indented and jetted, the samples were slit axially in half, just off center of the indentation and studied for indications of fracture severity and mechanism.

Rotary drilling tests. Figure 4 shows the test apparatus used in evaluating the effect of a high-pressure jet on the rotary component of rotary-percussion drilling. percussion drilling.

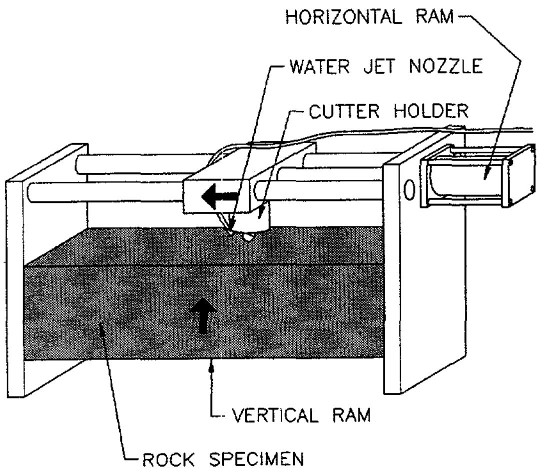


Figure 4. *Test Apparatus for Simulated Rotary Drilling Tests.*

As shown, rotary drilling action is simulated by hydraulically forcing a cutter across a rock sample which is loaded vertically against the cutter. In this test, a specially designed cylindrical PCD cutter was dragged across the rock at a 45° back rake. This back rake was chosen to make the cutter more robust against percussive loading (in contemplation of future testing). The waterjet in this setup was oriented parallel to the cutter's face (also at 45° to the rock).

Testing with the linear cutting apparatus in Figure 4 progressed by setting a certain depth of cut, from 0.05 to 0.20 inches deep, then dragging the cutter across the surface for a series of five juxtaposed passes, measuring the drag (torque) and normal (thrust) load required to drive the cutter. Jet-assisted tests were conducted with a continuous jet over the duration of the cut. Each new specimen was "conditioned" by taking several passes over the surface until repeatable measurements were obtained.

Results

Influence of jet on percussion mode. Figure 5 shows the cross section of a typical rock sample after impact. As shown, as an indenting dome cutter penetrates the rock, it creates zones of damaged rock ahead of the tool; namely, a crushed zone, a strongly fractured zone and a fractured zone. These extend significantly farther into the rock than the level of penetration that the tool conventionally achieves.

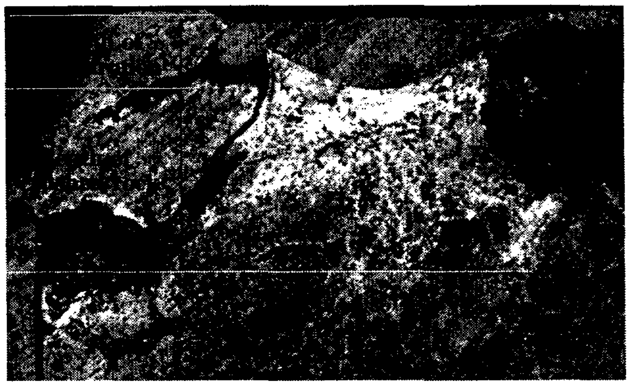
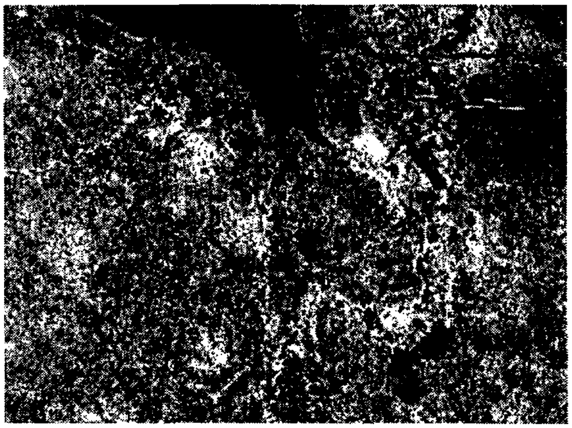


Figure 5. *Section through basalt rock sample under a domed cutter after impact, showing the separate zones of damage, and the relative bit penetration (depth of penetration 0.2 inches).*

Figure 6 shows two samples whose impact penetration have been enhanced by a waterjet (flushed with a 5000 psi jet). As shown, by removing the rock crushed in the first zone, significant benefits can been seen in the use of the fluid jets. It has been found more advantageous to have the jet operating as the cutter enters the rock, since in this way all the crushed rock is removed ahead of the bit, as it is generated, creating a significantly deeper penetration of the tool (Figure 6a). In contrast, where the fluid impacted on the crushed zone of material after the bit had moved only the material directly within the zone of jet impact was removed (Figure 6b).

Figure 7 shows a relative comparison between penetration achieved with and without jet-assistance. As shown, for a given impact energy level, the gain in penetration was on average on

a) Depth of penetration and cavity 0.375 inches.



b) Depth of penetration 0.1 inches, cavity 0.375 in.

Figure 6. *Waterjet enhancement of percussion mechanism, where the jet is applied a) during or b) after bit impact.*

the order of 200%. This finding suggests that a similar gain in penetration rate can be anticipated when the technology is incorporated into a full-scale drilling bit. The data presented above has been derived from the tests using red granite rock specimens; a similar series in basalt has been completed and corroborative tests in a larger test suite (including quartzite, sandstone and limestone) are in progress.

Influence of jet on drag mode. Studies in other venues have shown that when high-pressure waterjets are added to a drag tool that the performance of the tool can be increased. This earlier testing has, however, usually been carried out with the shallower angled bits where the rake

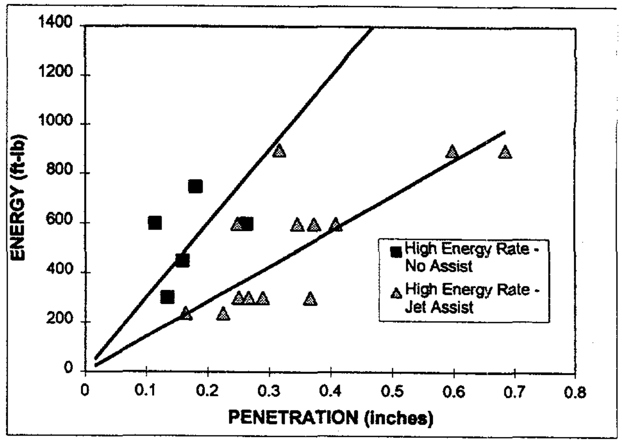


Figure 7. *Relative Penetration of a ¾ inch domed indentor into Missouri red granite (25,000 psi unconfined compressive strength) under impact loading, with and without waterjet (5,000 psi) assistance.*

angle of the cutter face lies closer to normal to the cutting path. In this effort, however, because of the high impact loads transmitted through the cutting tools to the rock during rotary percussive drilling, a much larger positive face angle to the bit has been evaluated (45 degrees). Figure 8 shows the averaged results of three sequential linear cutting test series over Missouri red granite. As shown, both the drag and normal forces on the bit were reduced by waterjet assistance by an average of approximately 40%.

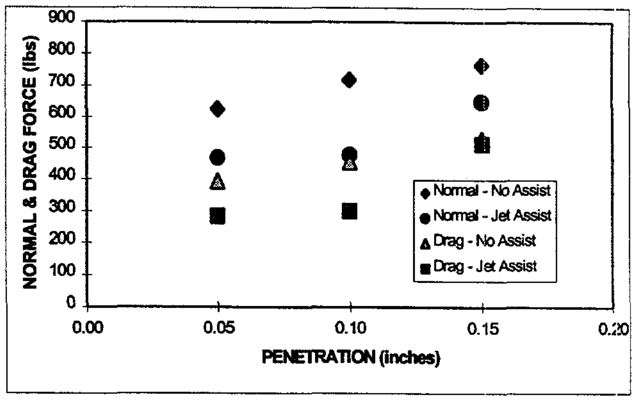


Figure 8. *Effect of Waterjet on Drag Cutter Performance in Missouri red granite. Normal Forces are the forces acting directly down on the cutter. Jet pressure was 5,000 psi and cutting angle was 45° with the jet parallel to the face of the cutter.*

It is worth noting that the force variation around this average was also considerably reduced during the test runs. Preliminary data from testing in harder igneous rocks has shown similar levels of improvement. It is also significant that, during the course of these tests, the test cutter chipped twice (due to thermal and mechanical loading) during the dry cutting tests, while no observable damage was received during jet-assisted cutting.

Preliminary bit design. Based on the results of the research effort, a new design of bit is proposed. This design has been developed with input from two potential percussion bit manufacturers, who will continue to work closely with Novatek through the remainder of the design process.

Figure 9 shows a new type of polycrystalline diamond cutter, which has been developed by Novatek for this bit. This cutter combines high impact resistance with a relatively sharp cutter profile. A key feature of this cutter is that it provides Novatek's highly abrasion-resistant diamond composite coating[8] completely around the cutter edge to minimize wear of the underlying cutter substrate. This improves the structural support of the diamond layer and is designed to improve the life of the cutter. Impact testing done at Novatek has shown that this cutter provides impact resistance that is superior to a standard commercially available flat PCD cutter by a factor of approximately two.

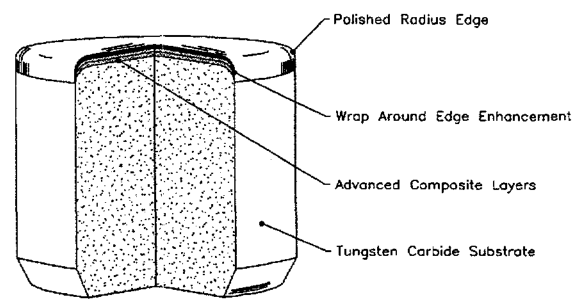


Figure 9. *New PCD Cutter for Rotary-Percussion Bit (patent pending).*

Figure 10 shows the physical implementation of the down-hole high-pressure jet intensifier. Key design features include: several intensifier pistons, which are actuated by the motion of a down-hole hammer; a bias shoulder, which returns each intensifier piston after the intensification stroke; and a valve set and several high-pressure nozzles for each intensifier piston. As shown, the nozzles are distributed over the face of the bit. Operation of this system is as follows. First, hydraulic pressure acts on the bias shoulder to move the pistons upstream. This opens a flow passage from the inside of the drill bit to the high-pressure nozzles. As this passageway is opened, mud at system pressure flows into the chamber below the pistons, and out the high-pressure nozzles. As the down-hole hammer approaches its impact position, it contacts the tops of the pistons and drives them downstream, closing the flow passage mentioned above. As the flow passage is closed, the fluid trapped in the chamber below the pistons is intensified in pressure and thereby exits the chamber through the nozzles at high differential pressure. Upon cycling of the hammer, the above procedure is repeated.

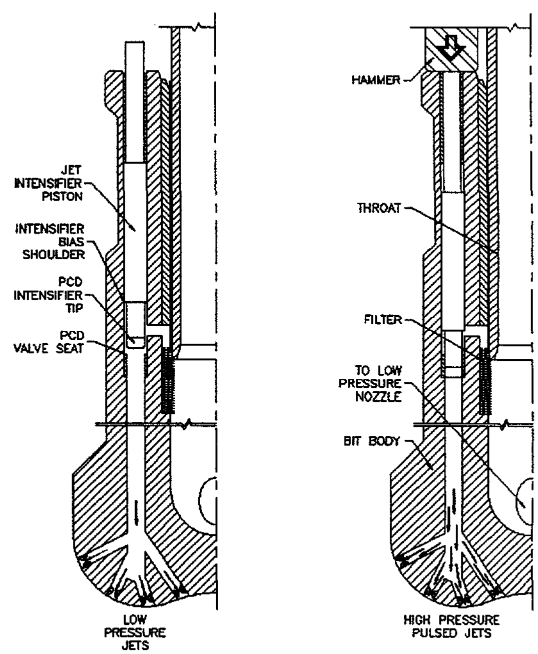


Figure 10. *Down-hole High-pressure Jet Intensifier (patent pending).*

In this way is a high-pressure pulse superimposed upon a constant lower-pressure jet. The timing of this jetting system is appropriate, considering the findings above, i.e., the high-pressure pulse is at its maximum as the bit is being driven into the rock by the impact of the hammer. This provides for maximal removal of crushed rock in front of the advancing cutter to increase penetration depth. The pulsed nature of the jet also minimizes the hydraulic horsepower that must be generated down-hole by providing high-pressure flow only during short intervals.

Conclusions

The basic premise under which the program was proposed has thus been validated, namely that adding a jet of fluid to a rotary-percussive bit will allow a significant increase in the ROP of the bit, at least in hard rock. The improvement can be anticipated to occur in both the percussive and rotary phases of rotary-percussive drilling. More particularly, the authors conclude that:

1) The crushed zone developed under a percussive drilling insert extends significantly beyond the zone penetrated by the tool.

2) The size of the crushed zone and the bit penetration is controlled by the energy imparted to the rock by the impacting tool.

3) Directing a 5000 psi fluid jet into the damaged zone during the cutter penetration provides a more effective method of removing the crushed material and allows the bit to penetrate through that zone, while cutting. This increases individual cutter penetration and thus rate of penetration by approximately a factor of 2 in hard rock.

4) Adding waterjets to a PCD cutter inclined at a positive rake angle into the face of 45 degrees will reduce the drag and normal forces required for penetration and rock removal by approximately 40%. Alternately, under equivalent loading the rate of penetration can be raised.

5) Adding waterjets to a PCD cutter reduces the damage incidence to the cutter when drag-cutting hard rock.

6) A high-pressure pulsed jet generator may be integrated into the body of a fixed-cutter rotary-percussion bit. This generator, when driven by a down-hole hammer, may be designed to produce 6000 psi differential pressure pulses which act at the instant the hammer drives the cutters into the rock.

7) By adjusting the presence, or absence, of a high-pressure fluid under an impacting cutter it is possible to control the depth to which the cutter will penetrate the rock. Thus by adjusting which jets operate over the face of a drill bit as the tool operates it will be possible to preferentially attack one side or the other of the face of the bit, thereby controlling the direction in which the bit will advance.

Future Work

A second phase of development work will focus on optimizing and reducing to hardware and practice the concepts proven to be feasible in this work. Second phase work will identify design specifics such as the optimal partitioning of energy between mechanical cutters and hydraulic jets, the optimal placement and orientation of cutters and jets, etc. Also the effect of pulsed fluid jets as opposed to continuous jets will be investigated. Concepts proven in the laboratory will be proven in actual field application.

Acknowledgement

The authors wish to thank the U.S. Department of Energy for their support of this project.

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Session 6:

Environment, Geothermal Heat Pumps and Direct Use

STATUS OF THE S.E. GEYSERS EFFLUENT PIPELINE & INJECTION PROJECT

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Lake County Sanitation District
Lakeport, California

ABSTRACT

A unique public/private partnership of local, state, federal, and corporate stakeholders is constructing the world's first wastewater-to-electricity system in Lake County, California. A rare example of a genuinely "sustainable" system, three Lake County communities will recycle their treated wastewater effluent through the Geysers geothermal steamfield to produce an estimated 625,000 MWh of electricity annually from six existing geothermal power plants. The concept is shown schematically in Figure 1. Construction was initiated in October 1995, and as of this writing, the system is approximately 85% complete. Operational start-up is expected in October 1997. The key to the project's success thus far has been its emphasis on cooperative action among affected stakeholders; and a broad, community-based view of solving problems rather than the traditional, narrower view of engineering-driven technical solutions. Special attention has been given to environmentally-responsive engineering design to avoid or minimize adverse environmental impacts.

PROJECT BACKGROUND

The project concept originated in the late 1980's with the convergence of two problems: 1) a need for augmented injection to mitigate declining reservoir productivity at The Geysers; and 2) a need for a new method of wastewater disposal for Lake County communities near The Geysers. A public/private partnership of Geysers operators and the Lake County Sanitation District (LACOSAN) was formed in 1991 to conduct a series of engineering, environmental, and financing studies of transporting treated wastewater effluent from the communities to the southeast portion of The Geysers via pipeline. By 1994, these evaluations concluded that the concept was feasible and the stakeholders proceeded to formally develop the project, including pipeline and associated facilities design; preparation of an environmental impact statement; negotiation of construction and operating agreements; and assembly of $45 million in construction funding from the stakeholders, and state and federal agencies with related program goals.

As finally designed, the project consists of a 29-mile, 20-inch diameter pipeline that will carry 7.8 million gallons per day of treated wastewater effluent and Clear Lake make-up water to the Geysers for injection at existing wells operated by NCPA, Calpine, and Unocal. Figure 2 summarizes the pipeline route from

Clear Lake to the Geysers. Make-up lake water will be used to take maximum advantage of pipeline capacity during the early years of the pipeline's life; as effluent flows increase over time with population growth, make-up lake water quantities will be reduced proportionately. To move the effluent and lake water the pipeline will use six pump stations totaling 7,370 hp, including a 1,600 ft. final lift from the Bear Canyon operator road entrance up to the injection area in the southeast Geysers. Depending on steam recovery rates for the injected effluent, the project is expected to create up to 70 MW of generating capacity at six existing power plants operated by NCPA and PG&E.

The project's total construction cost is $45 million, including $8 million in wastewater treatment plant improvements. Construction costs are being shared by the core group of participants, known as the Joint Operating Committee (JOC), with additional funding from the California Energy Commission, California Water Resources Control Board, U.S. Department of Energy, U.S. Department of Commerce, U.S. Department of the Interior, and the U.S. Environmental Protection Agency. Figure 3 summarizes this cost-sharing according to major policy-based categories. Additionally, the industry participants are investing several million dollars in secondary pipelines and controls that will distribute the effluent from the main pipeline terminus to injection wells in the steamfield.

The project's annual operating costs are estimated at approximately $1.5 to 2 million. The JOC members have signed a 25-year operating agreement wherein LACOSAN will operate the pipeline as far as the Middletown area, after which it will be industry-operated to its terminus in the steamfield. LACOSAN will pay an annual O&M cost share equivalent to a traditional surface discharge, with the industry participants paying the remaining O&M costs based on the quantity of effluent they each receive at their wellheads.

INSTITUTIONAL REQUIREMENTS

A major aspect of the project from the outset was its institutional complexity, and the need to reach legal and administrative agreement with multiple public and private stakeholders representing numerous environmental, regulatory, operator, and property interests. Initially, considerable effort was devoted to negotiating agreement among the JOC members to pursue project development. This was embodied in a 1991 agreement-in-principle that set out the project's basic goals and committed stakeholders to consensus decision making. Extensive effort also went into negotiating federal geothermal royalty reduction agreements that allow lower industry royalty payments in exchange for larger industry construction cost shares, plus a longer overall term of payments as a result of the effluent-extended reservoir life. A critical agreement also had to be negotiated with adjacent Yolo County for a portion of their water rights to Clear Lake for the make-up water needed during the project's early years when effluent flows will be relatively small in relation to pipeline capacity.

In order to structure the project's environmental review, a memorandum of understanding was negotiated between the BLM, who administers federal geothermal leases held by Calpine and NCPA, and LACOSAN as the primary local sponsoring agency. BLM was designated as the lead agency for federal environmental review and LACOSAN was designated as the lead agency for CEQA environmental review. Once underway, the EIR/EIS process focused on effluent injection-induced seismicity; possible groundwater contamination from effluent injection; sensitive plant impacts from pipeline construction; sensitive stream crossings by the pipeline; archaeologic site impacts; and Clear Lake water quality impacts. Analysis of these and other environmental issues revealed no significant adverse impacts that could not be adequately mitigated.

Permitting of the project was organized according to five segments, or reaches, of the pipeline. For each reach, a variety of local, state, and federal permits were required depending upon the urban or rural character of the reach and the presence or absence of sensitive environmental resources. Of the project's 25 total permits, the major ones included: federal and state archaeologic clearances; state fish and game authorizations for sensitive stream crossings and the Clear Lake intake; public highway and local road encroachments; construction stormwater pollution prevention; air quality management; and wastewater treatment plant discharge. Finally, in addition to public right-of-way encroachments, easements had to be obtained from 200 private land owners over the 29-mile pipeline alignment for construction and ongoing maintenance access.

PROJECT STATUS

Project construction was initiated with groundbreaking in October 1995. As of this writing, the following construction has been accomplished:

Pipeline: 139,000 feet (or approximately 91% of the total length) of main pipeline has been installed. The remaining 14,000 feet of pipe will be installed during the spring and summer of 1997. Of the pipe installed to date, approximately 52,000 feet have been successfully tested for hydrostatic acceptance.

Pump stations: Pumps for all six stations have been delivered to the sites. The pumps stations at the lake intake and Southeast Regional Wastewater Treatment Plant have been installed and wired. In addition, installation of motor control centers, wiring, compressors, priming systems, piping, valves, surge tanks and flow meters has been completed. The three pump stations in the Geysers are in various stages of construction; Geysers Stations 1 and 2 have completed buildings, and the above-ground piping has been completed in Station 1.

Flow control tank: A 250,000 gallon steel tank has been installed at the pipeline's mid-point. Leak testing for this facility has been successfully completed.

Steamfield distribution pipelines: Approximately 85% of the steamfield secondary distribution pipelines between the main pipeline and injection wellheads have been completed.

Control system: Initial site work for the telemetry system has occurred. Site testing and ordering of towers has been completed. The poles for the intermediate site between Lower Lake and the Geysers are being installed during March 1997. Computer hardware has been ordered and the RTU's are to be delivered by mid-April 1997. The software is currently being refined, and the draft start-up testing plan and operating strategy narrative are expected by the end of March 1997.

Environmental mitigation: All erosion control and seeded revegetation has been completed for the portion of the pipeline that has been installed. This included the collection, storage and replanting of sensitive serpentine and vernal pool plant species. A majority of reseeded areas of the pipeline corridor have grown quite well since they were planted three months ago. Long-term woody plant revegetation was initiated in late February 1997 and is expected to be completed by the end of March. To date, approximately 800 oak trees in five varieties have been planted. During winter 1997-1998, more oaks and coniferous trees will be planted, along with riparian trees at the 16 creek crossings affected by the project.

CHALLENGES AND ACCOMPLISHMENTS

Implementing the effluent pipeline project has been a major challenge in several respects. First, as something that has never been attempted before, it automatically raised a multitude of technical, legal, and environmental concerns among the public and regulators. Second, it was jointly undertaken by public and private organizations that have sometimes had adversarial relations in the past, but who now found themselves benefitted by a partnership where they could work together toward mutually advantageous objectives. Finally, the complexity of a 29-mile linear facility crossing multiple jurisdictions and dozens of sensitive environmental sites significantly increased the scope and amount of environmental and regulatory scrutiny.

The project's strategy for dealing with these challenges included: 1) an inclusive "open door" policy that emphasized information sharing and collaborative planning among all interested parties; 2) a community-based holistic set of objectives and problem-solving approaches that were broader than traditional engineering-driven technical solutions; 3) involvement of agency permitting staff in early feasibility studies to insure their familiarity with the project, and to solicit their input; 4) commissioning of special environmental studies to quickly analyze specific questions as they arose, before they could become publically problematic to the project development process; 5) aggressive information outreach to citizens and civic groups, particularly environmental organizations, to insure their familiarity with and support for the project (including about 35 information presentations to groups in the affected communities to date); and 6) use of consensus decision-making by the JOC members to insure that each step of the process had the full commitment of all stakeholders.

CONCLUSION

In an age of scarce resources, bureaucracy, and increasing competitive pressures, the Southeast Geysers Effluent Pipeline & Injection Project is a testament to the power of synergistic innovation and public/private partnering. In this case, the community liability of wastewater is being converted into the sustainable community asset of electricity. From a wastewater perspective, the significance is not necessarily the effluent-to-electricity concept itself, but rather the ability to solve community problems more successfully where they can be linked to convergent stakeholder needs. Rather than view sewage and other wastes as liabilities, communities may find that one stakeholder's problem is another's solution. Several cities across the nation have implemented wastewater reclamation for irrigating various lands. Others are using their wastewater to enhance wetlands and improve natural ecological systems. Seattle uses some of its effluent as a revenue-producing heat sink for cooling adjacent industrial facilities, thereby preserving inner city economic health in concert with environmental protection. The common elements in all of these examples are innovation and collaboration, which together can be a powerful means of securing both environmental quality and economic prosperity.

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Figure 1
WASTEWATER-TO-ELECTRICITY CONCEPT

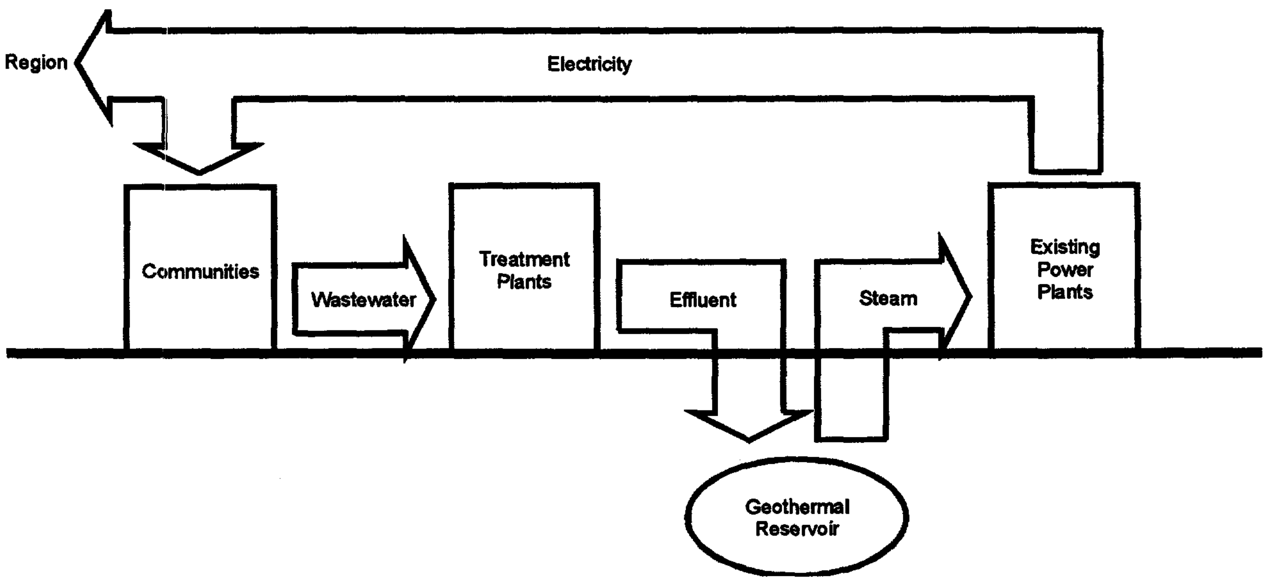


Figure 2
PIPELINE ROUTE

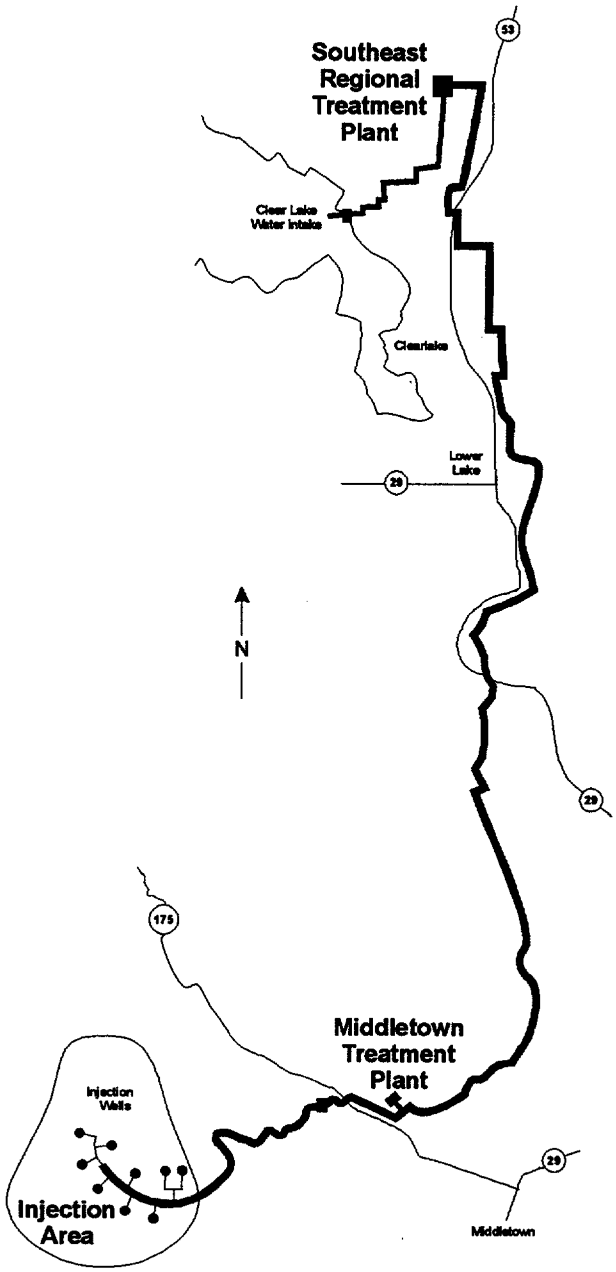
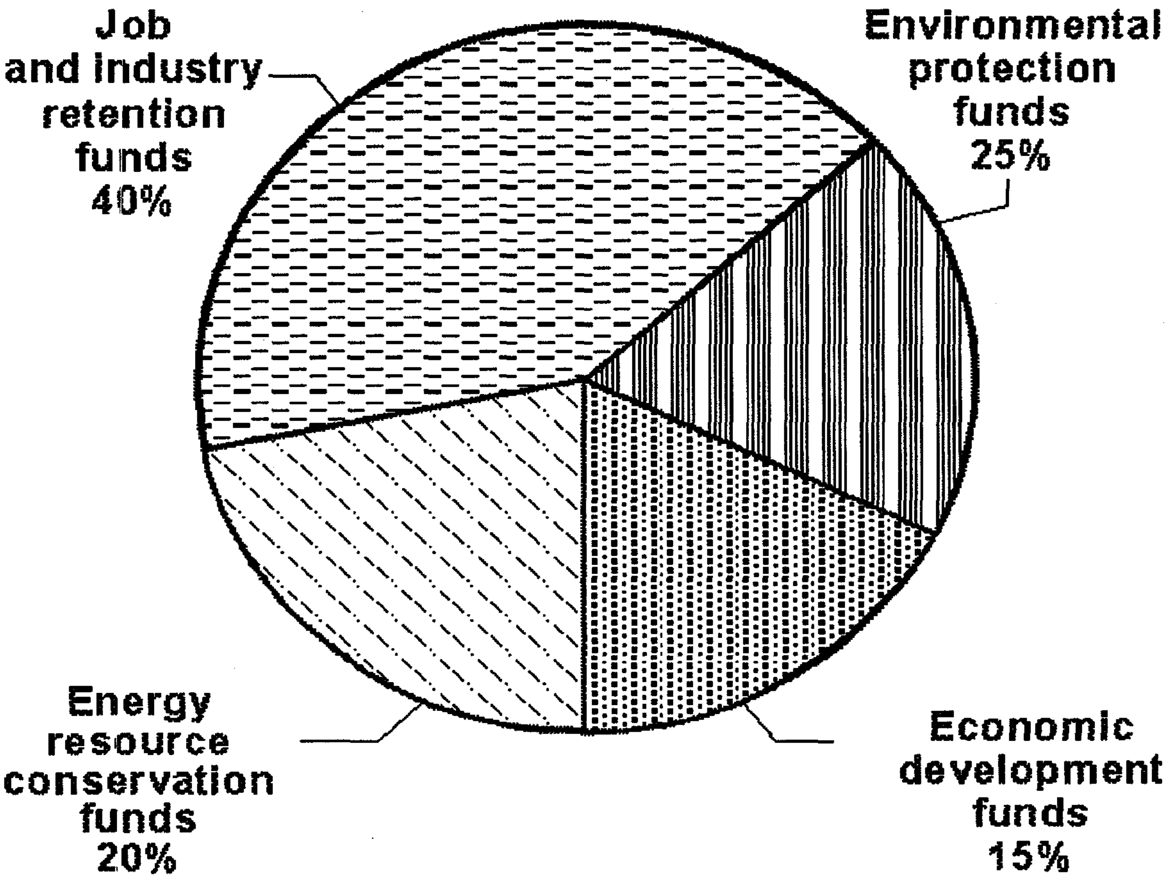


Figure 3
CONSTRUCTION COST-SHARING PLAN



The Geothermal Heat Pump Consortium's
National Earth Comfort Program

PAPER NOT SUBMITTED

GEOTHERMAL RESEARCH AT OKLAHOMA STATE UNIVERSITY: AN INTEGRATED APPROACH

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ABSTRACT

Oklahoma State University and the International Ground Source Heat Pump Association (IGSHPA) are active in providing technical support to government and industry through technology transfer, technology development, technical assistance, and business development support. Technology transfer includes geothermal heat pump (GHP) system training for installers and architects and engineers, national teleconferences, brochures, and other publications. Technology development encompasses design software development, GLHEPRO, in-situ thermal conductivity testing methods and verification of data reduction techniques, and specifications and standards for GHP systems. Examples of technical assistance projects are a Navy officers quarters and a NASA Visitors Center which required design assistance and supporting information in reducing the life cycle cost to make them viable projects.

INTRODUCTION

Researchers at Oklahoma State University and IGSHPA combine efforts in producing information directed to the growth and viability of the GHP industry. A significant amount of funding for these activities is provided by DOE. For the remainder of this paper IGSHPA will be used to denote the combined efforts at OSU. An integration of activities for the industry is provided in four categories: technology transfer, technology development, technical assistance and business development support. Sources such as utilities, manufacturers, distributors, contractors, service companies, and other universities are also strong contributors to these activities. Ideas and advancements from those working in the industry are most important to the final outcome.

When reviewing the integration of the projects supported by DOE it is seen that information is being disseminated through brochures, case studies, newsletters, national teleconferences, Geothermal Heat Pump Technical Conference, and the Annual Geothermal Heat Pump Industry Conference. Information is made available to keep the practitioners abreast of the technical tools, products, and methods used in the industry. Training is the transfer of technology to provide an individual the capability of applying the material to accomplish the task in the industry. Training is available for the installation as well as the design of GHP systems. All of this comes under the title of technology transfer.

Technology development is required if the industry is to remain viable. Part of the design and construction process is the use of tools to expedite work. DOE has supported the development of a software program that performs reliable designs quickly so that several options can be considered. To obtain reliable designs however, the input to the software must be reliable. Thermal conductivity, an important input, is a property of the formation (soil/rock) surrounding the ground heat exchangers. If this value is not known and a conservative estimate is used, the resulting heat exchanger field may be too large (costly) and the bidding therefore unsuccessful. On the other hand, the value of thermal conductivity can be estimated too high, and the heat exchanger field too small to satisfy the loads. This results in unhappy customers and additional costs. DOE is providing funding to develop accurate and economical methods of measuring the thermal conductivity. In addition, specifications and standards are being developed to save time producing documents which assist in providing quality systems. Another part of technology development is the subset we call application development. This is the provision to take GHP technology and apply it to specific projects to provide an advantage for the owner. One example is taking residential heat pump technology and applying it to school systems with appropriate modifications. Another is that of utilizing the benefits of strategically combining building loads, refrigeration loads, car wash, and ice melt systems in a convenience store with a heat pump system to move energy where it can provide the best overall efficiency. Another application is highway bridge de-icing, a system that connects buried pipe in the bridge deck with a GHP system.

Technical assistance is a DOE-funded project which provides information and services to specific qualified projects. Information gained from the activities discussed in the previous paragraphs are applied in this activity. In some cases training will provide the assistance needed to successfully complete a federally funded GHP project. At other times it might require a review of the design to determine the steps to be taken to make the building project have a favorable Life Cycle Cost. Telephone discussions and providing applicable manuals to cover the specific need will sometimes suffice. It is a matter of providing appropriate limited support regarding technical concepts or design to successfully save any viable GHP project.

The final integrated activity to be discussed is the business development support. In this activity the company is the primary funding source and our contribution is to provide suggestions, brief testing when applicable, technical guidance, and putting businesses in contact with influential people. An example is a company from Fairview, Oklahoma, Ewbank & Associates. The company privately funded the development of an in-situ thermal conductivity test trailer with technical support from OSU personnel. Their contribution to thermal conductivity measurements has resulted in more rapid development and commercialization with this technique than would have been possible otherwise. Because of this experience, several design improvements have already been determined with regard to data acquisition, instrumentation, fluid flow system, fluid heating and heat rates, insulation requirements, power input and data interpretation techniques. Ewbank & Associates has become very involved in GHP system training, design, installation, thermal conductivity equipment development, and commercial testing.

TECHNOLOGY TRANSFER

The transfer of technology related to GHP applications includes training and certification, books, manuals, video cassettes; brochures, case studies, newsletters, national teleconferences, and annual conferences.

Of these, DOE has supported development of brochures for schools, commercial, and residential applications, and utilities. Case studies were also done on the Galt House, Paragon ,and the Phillip Russell House. DOE has also supported a series of articles developed and distributed through *The Source* (IGSHPA 1996) to increase the awareness of GHPs. The approach was to search for information from across the industry and academia that would cover residential, commercial, and institutional GHP applications. Pertinent topics were written and then edited by both IGSHPA staff and external sources in pursuit of accuracy, clarity, and meeting the objectives of the publications.

Teleconferences have been produced to provide information through panels of experts whom the audience can ask questions of and receive immediate answers. Downsites are scheduled throughout the United States, often sponsored by utility companies and further used for promotion and training in their region. Some of the titles of more recent teleconferences are Geothermal Heat Pumps: The State of the Art, Geothermal Heat Pumps in Commercial Buildings, and Geothermal Heat Pumps for Residential Customers

GHP Training for Architects and Engineers was identified as a key element in implementing commercial GHP systems. The original training was developed for DOE/DoD and presented in the Washington D.C. area to personnel from

DOE, DoD, Army, Air Force, Navy and Marines. Topics included:

- "the state of the art" overview of geothermal technology;
- space heating, cooling, and water heating technology;
- the design of residential, commercial, and industrial applications;
- geothermal equipment (heat pumps, circulators, underground piping, etc.);
- design procedures and methods, software, design tools;
- installation methods and procedures, the associated equipment, types of heat exchangers, completion (grouting/backfill) choices;
- inspections, commissioning, performance monitoring, contracting, and federal. customers.

Additional work has been done on the training support material with funding from the Geothermal Heat Pump Consortium (GHPC). The coverage has been expanded to include ice makers and refrigeration, decision tree on system selections, complete design examples involving a school, motel and a convenience store, and other similar topics.

TECHNOLOGY DEVELOPMENT

Technology development involves the areas of design support, application development and specifications and standards. Recent research activities include each of these.

Design Support

Earlier design support activities involved the interfacing of GLHEPRO (Ground Loop Heat Exchanger Professional) with BLAST (Building Loads Analysis and System Thermodynamics). Currently, the design support focal area includes further development of the software design package called GLHEPRO (Spitler, 1996), the interfacing of GLHEPRO and TRANE System Analyzer, and experimental work in in-situ thermal conductivity testing. Other work in this focal area (funded by NRECA and EPRI) includes methods of backfilling horizontal ground heat exchangers and the design manual for the SLINKY™ ground heat exchanger.

GLHEPRO The original GLHEPRO software was funded by EPRI and NRECA. The software is used as an aid in the design of vertical borehole-type ground loop heat exchangers for GHP systems. The heat exchanger may be composed of any number of boreholes arranged in various configurations. Eskilson's method which depends on the use of "g-functions" was used for the design method. G-functions represent the response of a given borehole configuration to a step change in heat extraction or rejection rate. The g-function must be pre-computed, and this limits the user to borehole configurations that have been pre-computed. DOE has supported the development of a method for developing new configuration data on the fly. In order to accomplish this, several different approaches involving the use of transfer functions have been investigated. Two approaches have been moderately successful, a heuristic transfer function approach and a Box-Jenkins approach. The two approaches are discussed below.

With the heuristic approach the following has been taken to simulate the average borehole temperatures over an extended period of time: the average temperature of a given single borehole (output) at the end of a month is assumed to be a function of past average borehole temperatures (inputs), heat transferred (also inputs) within the borehole, and the constant far field temperature. At the start of the heat pump operation, the initial borehole temperature is set to be constant and equal to the specified far field temperature. A number of combinations of different numbers and types of transfer function terms have been evaluated. To date, the best results have been obtained by incorporating 13 coefficients into the transfer function. Figure 1 shows the close conformity of results obtained using the 13 coefficient transfer function with two more detailed methods (Line Source and GLHEPRO with g-functions).

The univariate Box-Jenkins auto-regressive integrated moving average modeling (UBJ-ARIMA) procedure is based on initially estimating the auto-correlation and the partial

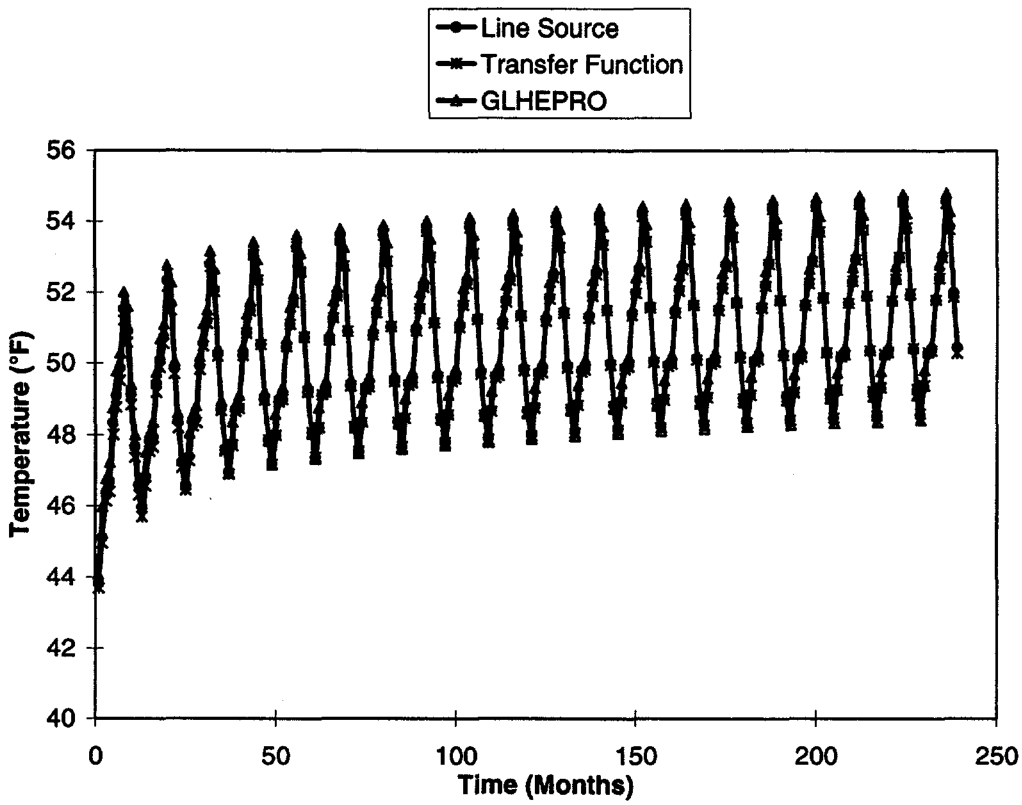

Figure 1. *Average borehole temperatures for a building heavily dominated by cooling using a transfer method in comparison to two standard methods.*

auto-correlation behavior of a given time series data set, and comparing these to theoretical auto-correlation and partial auto-correlation functions for auto-regressive and/or moving average models. Once a consistency is observed between the estimated and theoretical functions of auto-correlation, the error terms (the residuals) are investigated in regards to their auto-dependency and distribution behavior. If the error terms are in fact independent and normally distributed, the model is fitted to the data.

The multivariate transfer function model is based on a three-step procedure: identification, estimation, and diagnostic checking (Pankratz, 1983) (Box, Jenkins, 1976). In the identification stage, an UBJ-ARIMA model is identified to describe the input series. Based on this UBJ-ARIMA model, a preliminary transfer function model is identified that describes the output series (monthly average borehole temperature values) in the estimation stage. Finally, a transfer function model is determined using the statistical residuals of the preliminary model that describe the error structure of the preliminary model.

The multivariate Box-Jenkins transfer function modeling and the univariate Box-Jenkins ARIMA modeling were performed on all six different building load configurations using 48 monthly temperature observations obtained from the Hart and Couvillion line source solution.

The analysis of the multivariate model was compared with the univariate model. No significant deviations were observed. The modeling was performed using the SAS and SYSTAT software packages. The average borehole temperature forecast results of the Box-Jenkins analysis were compared to the Hart

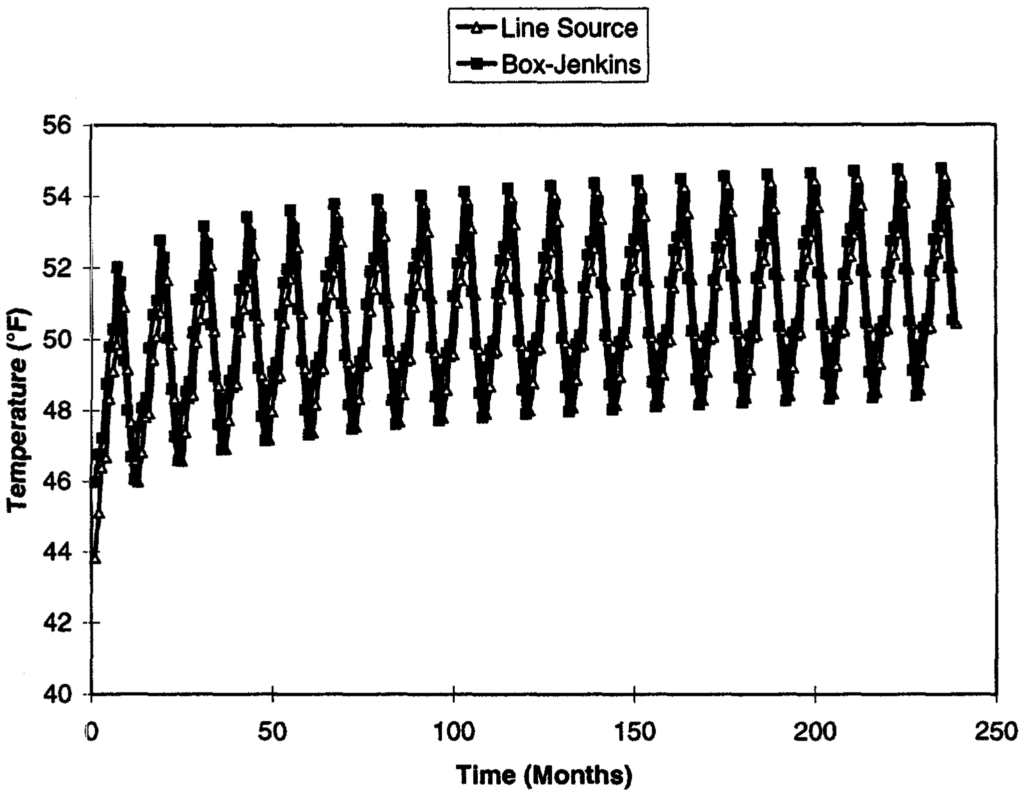

Figure 2. *Average borehole temperatures for a building heavily dominated by cooling using Box-Jenkins and Line Source methods.*

and Couvillion line source solution results and compared very well. See Figure 2.

A wide variety of industry interest has been expressed in the improved tools for design of ground loop heat exchangers. The methods have been transferred to the BLAST program through the BLAST support office. In addition, The TRANE Corporation has funded the interfacing of files between their commercial software programs and GLHEPRO. Industry use has demonstrated that the interface improves operator speed and confidence.

In-Situ Thermal Conductivity Testing In-Situ thermal conductivity testing activities are jointly supported by DOE, NRECA, EPRI and OG&E. The focus is the development of a hardware system and associated analysis software to determine soil/rock thermal conductivity of the total wellbore. Accomplishing this will result in more reliable designs with the accompanying strong potential to reduce first cost. Cost reduction is primarily associated with knowing a more accurate value of thermal conductivity to replace the conservative estimate which results in greater borehole depths and thus higher costs.

The DOE-supported experimental program includes the coring of selected well sites (primarily clays, shales and consolidated rocks) to extract the materials (soils/rock) in a consolidated form which is used to determine thermal conductivity by conventional methods. The cored wellbore is completed with a single U-bend loop and grouted, then tested with the in-situ thermal conductivity test system. The cored samples are cut into 12-inch sections and tested in a laboratory with a 6-inch probe to determine individual thermal conductivities. Those individual conductivities are used to determine a weighted average thermal conductivity for the formation around the borehole.

Cores have been extracted from two vertical wellbores, one each in Stillwater and Bartlesville, Oklahoma. The Stillwater site is primarily clay and shale while the Bartlesville site is hard shale and limestone. Also in Enid, Oklahoma a horizontal bore (a 200-ft U-bend path) was tested with the in-situ thermal conductivity test unit and the soil adjacent to the borehole was cored vertically at discrete locations along the U-bend loop. The depth and longitudinal pipe locations in the horizontal boreholes were determined with an electronic probe developed by Charles Machine Works.

In a test at the Enid site, the 6-inch probe was inserted into virgin soil so the top was at the 1-foot level. The soil appeared to contain some peat, and the thermal conductivity value for that location was determined to be 0.52 Btu/ft-hr-°F. Vertical core section samples were evaluated with the 6-inch probe in the laboratory. Interpolating the data curve (thermal conductivity versus depth) results in a thermal conductivity value for the 1 to 1.5 feet depth of 0.55 Btu/ft-hr-°F, which is compared to 0.52 from the 6-inch probe site test. The data from the cores were interpolated and applied to the locations along the U-bend with respect to depth and length (Figure 3). A weighted average value of 0.721 Btu/ft-hr-°F was obtained from these values. The value obtained using the in-situ trailer value was determined to be 0.722 Btu/ft-hr-°F. Given the variations in the data for both techniques, the closeness of the result is not expected. However, the point is made that for non-grouted boreholes the current technique appears to be sufficient if the data is interpreted properly.

Sections of the vertical wellbore cores are still being tested. With the effect of the grout in the vertical wellbores it is expected that a modification to the in-situ data reduction technique will be required.

A concurrent effort, funded by NRECA, is underway to refine the accuracy of the

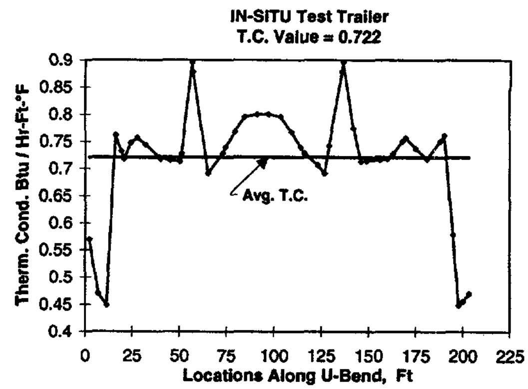

Figure 3. *Insitu thermal conductivity test method results compared to average values from core sample tests.*

theoretical model used to determine thermal conductivity from the measured energy input and fluid temperatures. The weighted average thermal conductivity determined from the core samples will be used to check the accuracy and validity of the refined theoretical models and provide data to "calibrate" the model where necessary.

<u>Specifications and Standards</u> Sample generic project specification materials for grouting, plastic pipe heat exchangers, heat pumps, circulators/pumps, and controls are being developed. Information has been assimilated from manufacturers, engineering firms, suppliers, contractors and regulatory and technical organizations. This material will also be integrated into DoD and HUD specifications. It will be compiled in a three-part format: general, products, and execution. Within the general part the items covered will normally be divided into sections entitled: related documents, description of work, quality assurance, and submittals. Products and materials will be described in the products part of the specifications. Basic information found in the execution part of the specifications will include inspection, installation, and reports.

Drafts of the five sections are entitled: Section 15512, Ground Heat Exchangers, Section 15512, Grouting Vertical Loops, Section 15540, Circulating Pumps and Related Components, Section 15786, Geothermal Heat Pumps, and Section 15901, Space Temperature Controls.

Research has shown that some GHP projects are not operating properly because certain design and construction features were not adhered to by the responsible entities. Most often it appears to be from inexperience or lack of knowledge. This project will incorporate information to lead to design and construction procedures which will be checks and balances for achieving satisfactory results.

An outline of some of the guiding concepts is listed in the following topics. These are to be incorporated within the appropriate sections with focus upon augmenting the design specifications.

The heat pump system must be selected to satisfy the heating and cooling requirements of a particular zone (load). The heat pump system may include auxiliary heating during winter loads and a cooling tower during summer cooling loads.

The heat pump must be ARI rated:

- for heat pumps operating with an entering liquid temperature range from 60 to 85°F, a unit rated under ARI Condition 320 must be used;
- for heat pumps operating with an entering liquid temperature range from 45 to 85°F, a unit rated under ARI Condition 325 must be used;
- for heat pumps operating with an entering liquid temperature range from 25 to 115°F, a unit rated under ARI Condition 330 must be used.

The heat pump selected must be compatible with the working fluid (corrosion-inhibited water or antifreeze.) The working fluid must:

- have acceptable fluid properties such as low viscosity;
- have good heat transfer characteristics;
- be non-corrosive to the heat exchanger;
- have acceptable flammability properties;
- be free of harmful particulate contaminants;
- not contain chemicals that will precipitate out or reduce the effectiveness of added corrosion inhibitors.

Ground heat exchanger field drawings are required. A drawing which details pipe size (diameter, wall thickness, material, placement, and length) for the headers and loops for the as-built condition is to be delivered to the owner upon completion of the project.

TECHNICAL ASSISTANCE

Technical assistance is expected to increase the number of federal and commercial projects involving GHP technology. Identification of projects which will be viable for demonstration of the benefits, direct assistance to designers which will produce cost-competitive outcomes, and technical training to enable more people to perpetuate the design process are all elements of technical assistance.

Guidelines for evaluating systems were produced through technical assistance to reduce costs on a NASA Visitors Center and a Navy officers quarters, provide information for the GSA design guide, and review operation problems with a school in Austin Texas, and other similar projects.

Most designers have experience with water loop heat pumps associated with cooling towers and boilers and try to transfer from this to water-source GHP systems which require different considerations. Cost estimates for the systems are often too high. To put it into perspective, a closed-loop GHP system will <u>not</u> have a cooling tower, circulation pump, boiler, cooling tower pumps, chemical water treatment, water bill for cooling tower fill and bleed, or controls for the listed items. Instead, it will have only a circulation pump(s) and pipe. Because of this, the maintenance and operating costs are lower for the closed-loop system than the standard water loop system. Pump rates and pressures are often sized too large for geothermal systems. Designers are not always aware of the differential pipe costs versus operating costs, so too small of heat exchanger pipe is designed, resulting in higher operating costs for just an incremental first cost reduction. ARI 330 heat pump ratings are not understood and the pumping penalty is added into the cost evaluation whereas the ratings already include the pumping energy.

The following are typical observations made during technical assistance activities:

1. Need to increase header pipe size to reduce system head loss so the pump can be down-sized.
2. Changing heat exchanger loops from 3/4" to 1" will reduce head loss with an economic benefit.
3. Reduce the heat exchanger fields and the equipment rooms from 2 to 1, thus reducing the number of pumps from 4 to 2, which results in lower first cost and better utilization of the field.
4. Use the correct pressure drops through the heat pump units for proper pump sizing.
5. Change to high performance heat pumps and increase the system efficiency.
6. Change calculations approach from using both ARI 330 EER values and the pumping penalty since ARI 330 already includes pumping energy.
7. The method used to determine loads was based on a bin analysis. Loads need to be determined from an analysis of the hourly block loads.
8. Wellbore depth was based upon the rule of thumb of 200 feet per ton, obtaining soil thermal properties and using GLHEPRO to design the heat exchanger field should reduce borehole length.
9. Drilling cost was originally estimated to be $13.50/ft, a better estimate for the project region would be $8/ft, which should include wellbore with heat exchanger and grout.
10. Reduce costs, specify individual digital programmable thermostats rather than a centralized system.
11. Heat pumps should be selected close to the loads in the conditioned space which provides better comfort and performance along with lower costs. If costs for 29 heat pumps was based upon 2 ton units or 58 total tons versus 33 tons required according to the heat pump schedule then estimates are too high.
12. Estimated maintenance costs are higher than current experiences with GHP systems.

ACKNOWLEDGMENTS

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OVERVIEW OF DIRECT USE R&D AT THE GEO-HEAT CENTER

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ABSTRACT

Geo-Heat Center research, during the past year, on geothermal district heating and greenhouse projects is intended to improve the design and cost effectiveness of these systems. The largest geothermal district heating system in the U.S., proposed at Reno, is describe and is one of 271 collocated sites in western states could benefit from the research. The geothermal district heating research investigated a variety of factors that could reduce development cost for residential areas. Many greenhouse operators prefer the "bare tube" type heating system. As facilities using these types of heating systems expand they could benefit from peaking with fossil fuels. It is possible to design a geothermal heating system for only 60% of the peak heat loss of a greenhouse and still meet over 90% of the annual heat energy needs of the structure. The design and cost effectiveness of this novel approach is summarized.

INTRODUCTION

The geothermal direct-use program of the Geo-Heat Center (GHC), among other activities, carries out research intended to improve the design and cost effectiveness of geothermal direct-heat projects. Two areas, based on technical assistance requests from project developers, which benefited from the programs are geothermal district heating and greenhouse heating.

In 1996 the Geo-Heat Center, along with the Energy & Geoscience Institute and State Geothermal Resource Assessment Teams, completed an inventory of western U.S. geothermal resources. This work (Lienau, 1996) resulted in the identification of 271 population centers collocated with geothermal resources. As an outgrowth of that work during Fiscal Year 1996 we completed an evaluation of residential district heating costs which indicated the feasibility of the use under certain circumstances. In December of 1996 plans for the largest U.S. geothermal district heating system, to be located in Reno Nevada, were announced. The project is expected to heat about 30 million square feet of commercial and residential structures. In many of these collocated sites, district heating would be the most useful application of the resource. In the past, district heating (geothermal or conventionally fueled) has not been widely applied to the single-family residential sector. Low-heat load density is the commonly cited reason for this. Although it's true that load density in these areas is much lower than for downtown business districts, other frequently overlooked factors may compensate for load density. In particular costs for distribution system installation can be substantially lower in some residential areas due to a variety of factors. This reduced development cost may partially compensate for the reduced revenue resulting from low-load density.

Greenhouses are a major application of low-temperature geothermal resources. In nearly all operating systems, the geothermal fluid is used in a hot water heating system to meet 100% of both the peak and annual heating requirements of the structure. Many growers, particularly cut flower and bedding plant operators, prefer the "bare tube" type heating system. Hot water is circulated through the tubes providing heat to the plants and the air in the greenhouse. Advantages include the ability to provide the heat directly to the plants, low cost, simple installation and the lack of a requirement for fans to circulate air. The major disadvantage of the system is poor performance at low (<60° C) water temperatures, particularly in cold climates. Under these conditions, the quantity of tubing required to meet the peak heating load is substantial. In fact, under some conditions, it is simply impractical to install sufficient tubing in the greenhouse to meet the peak heating load. As greenhouse facilities continue to expand, operators will increasingly encounter resource limitations, in some cases, necessitating the operation of new construction using effluent from existing construction. For a system operating from a 82°C resource, exit water (at say, 60°C) from the existing facility would be supplied to a new addition. In the new facility, the lower water temperature would reduce tubing system output to only about 60% of the required peak output. The difference could be made up from a conventionally-fueled peak load heating system.

GEOTHERMAL DISTRICT HEATING

Reno District Heating. "Reno Energy is proposing a massive geothermal district heating system that could supply up to 30 million square feet (equivalent of 15,000 homes) of commercial and residential space. The cost would be about half of what potential customers would pay for natural gas." This news item appeared in the Reno Gazette Journal, December 13, 1996 (Johnson, 1996). Reno is a big city with a large geothermal potential. It is only one of 271 cities in western states with low-to moderate-temperature geothermal resources in their backyard.

Reno Energy and Stone & Webster Engineering Corp. have worked together to develop the project and have signed agreements for the engineering and construction of the heating district. The estimated value of the project is currently $32 million (Burch, 1996). The University of Nevada, Mechanical Engineering Department has prepared an economic engineering analysis of the project which determined that the geothermal district heating system can deliver heat energy at 35 to 55 percent cheaper than natural gas or heating oil. Other independent research has confirmed that the clean, renewable resource from the Steamboat Hills Geothermal Field is plentiful and dependable enough to heat more than 30 million square feet of space. The project will be funded entirely by private funds; however, indirectly DOE has already assisted with the project through the GHC technical assistance program and the <u>Geothermal Direct Use Engineering and Design Guidebook</u> (Lienau, 1991). The Nevada Public Service Commission has contacted the GHC about regulatory considerations for the project. Developers hope to serve the first customers by the spring of 1998.

Wells within the Steamboat Hills Geothermal Field extract fluids from the fault zones 185 to 610 m below the surface. This water averages about 157°C and is used to run the turbines at the Steamboat Power Plants. The brine left over from the electrical generation process is currently injected back into the geothermal zone it originated from. Reno Energy will use this exit fluid and additional energy from geothermal wells to heat fresh water in a heat exchanger unit. The geothermal brine is then returned to the production zone as required by state law. The freshwater is heated to 116°C and circulated through a "closed loop" underground pipeline, supplying clean, economic and renewable heat energy to customers. A large industrial park is being developed on a 1200 acre area in close proximity to the geothermal plant. The 300 acre 1st phase of the park is already sold out, and the entire park is expected to be developed within the next 7 years. The Park will house mostly commercial buildings with some industrial facilities, a 200-bed hospital and a 525-room hotel. It is expected that buildings with 30,000,000 square feet (264 MW_t) of floor space will be connected to the geothermal grid for heating (100%) and air-conditioning (45%). Also, Galena High School located nearby and the UNR Redfield Campus which will be built in the area as well as a planned Casino across the street are likely to be major consumers of geothermal heat (Kanoglu, 1996).

Geothermal District Heating in Single-Family Residential Areas. In the past, district heating (geothermal or conventionally fueled) has not been widely applied to the single-family residential sector. Low-heat load density is the commonly cited reason for this. Although it's true that load density in these areas is much lower than for downtown business districts, other frequently overlooked factors may compensate for load density. In particular, costs for distribution system installation can be substantially lower in some residential areas due to a variety of factors. This reduced development cost may partially compensate for the reduced revenue resulting from low-load density.

This GHC examined cost associated with the overall design of the system (direct or indirect system design), distribution piping installation, and customer branch lines (Rafferty, 1996). It concludes with a comparison of the costs for system development and the revenue from an example residential area.

Distribution system installation costs were reviewed based on the use of double line (supply and return), preinsulated ductile iron piping. This material is currently the most widely used product for new distribution projects. Actual construction cost data were used along with cost calculations to desegregate gross costs ($/m) into 11 individual areas for lines in the 76 mm to 305 mm range. Among the savings identified were:

•Installation in unpaved areas can reduce costs 12% (305 mm) to 22% (76 mm),
•Uninsulated return lines use can reduce costs 9% (76 mm) based on the use of fiberglass in place of the preinsulated ductile iron,
•Elimination of active (flaggers) traffic control can reduce costs approximately 4% over the range of 76 mm to 305 mm lines, and
•Installation in areas unencumbered by existing buried utilities can reduce costs approximately 4%.

Figure 1 presents cost data for 76 mm, 152 mm and 305 mm line sizes in graphical form. The base case costs are those reflective of installation in downtown paved areas. The low case costs are those assuming that all of the above cost savings could be employed in a residential setting. The substantial reduction in the smaller sizes is especially beneficial for single-family residential areas since a majority of the distribution system would be in the 76 and 100 mm size.

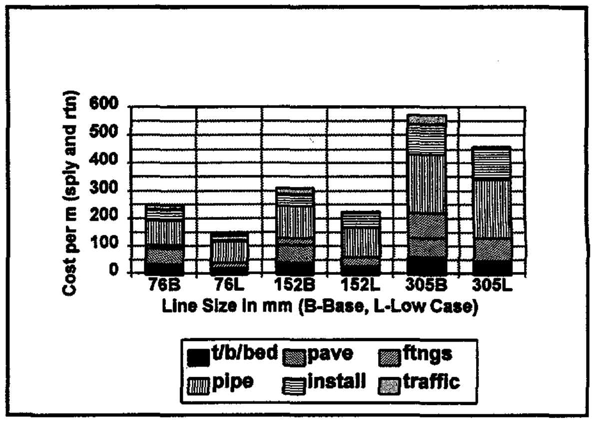

Figure 1. Installation cost of distribution piping for 76, 152 & 305 mm diameter, base and low case.

The location of heat exchangers between the geothermal fluid and the treated heating loop also has an influence on system total cost. There are two general approaches: an indirect system in which central heat exchangers are used and only treated water is delivered to the customer, and the direct system in which geothermal fluid is delivered to the customer and individual heat exchangers are located at each user. Use of the central heat exchanger approach (indirect system) allows the elimination of additional equipment from the individual user residence. Due to the economy of scale, there is a point at which the cost of the central equipment is less than the sum of the costs for individual equipment at each user. Based on the assumptions (Rafferty, 1996), the central approach results in lower costs above system capacities of approximately 878 kW_t (approximately 40 homes at 22 kW_t each).

Customer branch lines between the curb and the residence wall amount to a substantial expense to the homeowner when installed on a retrofit basis. Three types of piping for these branch lines were evaluated in this report: preinsulated copper ($92/m), field-insulated copper ($75/m) and preinsulated flexible polyethylene (PEX) at $102/m for installed supply and return of 25 mm pipe size. At an average length of 18 m per home, the cost of the branch lines would amount to approximately $1400 per home using field-insulated copper.

In order to evaluate the overall feasibility of geothermal district heating, an actual residential area of Klamath Falls, Oregon, was used for analysis. This area is representative of many small-to-moderate sized western towns where collocated resources have been found. An area of 16 blocks including 256 homes was selected. Costs were calculated for a complete system (construction costs only) including production wells, central plant, and distribution system. A range of costs for both the distribution system and the resource development was used. Resource development costs ranged from a single 152 m production well without injection to a system with a two 610 m production wells and one 610 m injection well. Distribution costs used the current base case costs (downtown/paved) and low case costs (residential/unpaved). Figure 2 summarizes this data.

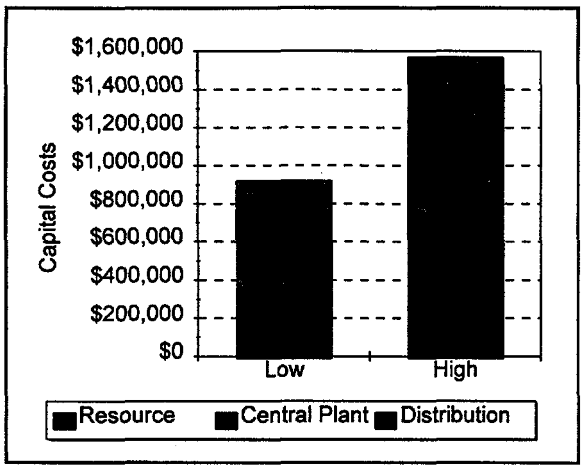

Figure 2. Expected cost range for 256 home geothermal district heating system.

Based on financing at 8% and a 75% customer connection rate, a revenue of between $452 and $771 per year per customer would be required to cover the system capital cost. Existing conventional space and domestic hot water heating costs in this area (6500 heating degree days, 102 m^2 average home size, primarily pre-1960 construction) ranges from a low of $440 per year (all natural gas) to $1050 per year (all electric).

Based on these figures it appears that geothermal district heating in existing single-family residential area could be feasible in situations where:

- Propane, fuel oil and electricity dominate the conventional heating used,
- Small lot sizes (<5,000 ft^2),
- Subdivisions where unpaved areas are available for installation of some or all of the distribution system, and
- Customer penetration rate is high (>75%).

This example suggests that for systems implemented with low-to-moderate cost resource and distribution costs, serving areas of propane, electric or fuel oil (or combinations of these with wood), that residential geothermal district heating can be possible.

GREENHOUSE PEAKING

Recent work with a large greenhouse operator who has expanded his facility by nearly 400% provided the impetus for this research task. As a result of injection well difficulties the consideration of other approaches to accommodating expansion, with reduced resource flow, became necessary.

Heating of greenhouses is one of the largest uses of low-temperature geothermal resources. In most cases, the existing projects use the geothermal heat in systems which supply 100% of the peak and annual heating requirements. As these facilities expand, some operators may encounter limitations in either the production or disposal of the geothermal fluids. Such flow restrictions can result in the necessity of operating new facilities (at lower temperatures) using effluent from the existing developments.

From an engineering standpoint, the obvious strategy is to select heating equipment (fan coil units or unit heaters) which perform well under low-temperature conditions. Unfortunately, this type of equipment is not acceptable to many growers, particularly cut flower and bedding plant operators. These operators prefer the so-called bare tube system in which the hot water is circulated through small diameter plastic tubes located under or adjacent to the plants. These systems are low cost, easy to install and unencumbered by the necessity for fans to circulate the air. On the negative side, however, they require substantial quantities of tubing to provide 100% of the heating needs at low outside temperatures.

The report (Rafferty, 1996) explored the cost of installing and operating a fossil fuel-fired (propane or fuel oil) peak heating system designed for 20 to 50% of a greenhouse peak heating load.

Due to climate related temperature occurrences, it is possible to design a geothermal system for only 50% to 60% of the peak heat loss of a greenhouse and still meet well over 90% of the annual heat energy needs of the structure. This is a result of the fact that the coldest outside temperatures (for which heating systems are normally designed) occur only a few hours per year. The bulk of the hours in a typical heating season occur at roughly halfway between the minimum temperature and the temperature maintained inside the greenhouse. As a result, a down-sized geothermal system is able to satisfy most of the annual heating requirements.

Two broad approaches to installing a peaking system are individual unit heaters or a central boiler. The unit heaters, because of the large number of individual pieces of equipment, tend to result in a higher capital cost for a given heat output than the boiler approach.

The boiler design (Figure 3), on the other hand, results in higher fuel cost in a given application than the unit heater system. This is a result of its incorporation into the heating loop and its negative impact on the capacity of the geothermal heat exchanger during peaking. To supply the required heat to the greenhouse, the boiler gradually raises the supply water temperature to the tubes as the outside air temperature drops. This results in a rising return water temperature to the geothermal heat exchanger which reduces it's capacity. In most applications this results in zero capacity for the geothermal heat exchanger at the design condition.

Consequently, the peaking boiler must be sized not for 60% but for 100% of the design load. The unit heaters, since they are a separate system, do not influence the capacity of the geothermal system during peaking.

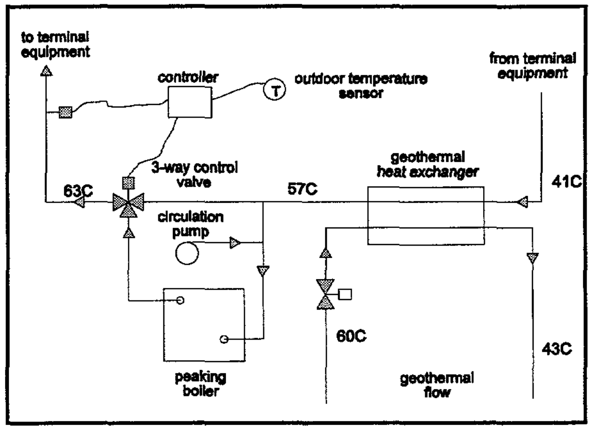

Figure 3. Design for installing a boiler on a circulating water loop.

Figure 4 provides information on the costs (ownership, maintenance and fuel) associated with the operation of a fossil fuel (propane and fuel oil) fired peaking system in a moderate climate assuming a 15.6°C temperature in the greenhouse. In general, the propane fired boiler system is the least total cost system for most applications due to its low installation cost. Only in the coldest climate where fuel consumption (rather than equipment cost) is the dominant cost factor does another system (oil boiler) provide for least cost.

Fossil fuel-fired peaking is unlikely to be used in applications where an acceptable geothermal system can economically meet the peak heating load. In applications where the geothermal resource flow is limited or a backup heating system is necessary, this approach permits the grower to use the heating system of choice for a reasonable increment in operating cost.

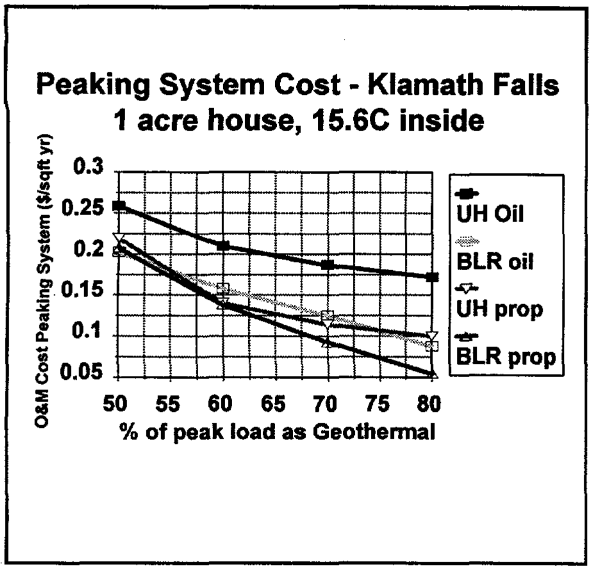

Figure 4. Peaking system costs include fuel oil and propane @ $1.00 per gal, 70% efficiency, electricity @ $0.07/kWh, 8% 15 yr financing, no night set back for a one acre double poly/fiberglass greenhouse

CONCLUSIONS

Geothermal district heating in the U.S. will more than double with the development of the Reno Industrial Park project. This is only one of 271 possible projects at collocated sites in 10 western states. Many of these sites could benefit from geothermal district heating, including residential areas where propane, fuel oil and electricity are used.

The novel approach of a fossil-fuel peak heating system for greenhouses allows the grower to continue using his preferred heating system design, retaining substantial conventional fuel savings and conserving the geothermal resource all for a small incremental increase in operating cost. In addition, the fossil-fueled peaking system offers a no-cost emergency backup in the event of a failure in the geothermal system.

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Session 7:

Panel Discussion

Panel Discussion:
Review of Geothermal Energy Association Workshops and Request for Further Input on Directions of the Geothermal Research Program

Chair: **Dr. Philip M. (Mike) Wright, Deputy Director, Energy & Geoscience Institute, University of Utah.**

Mike Wright: Welcome to the Geothermal Energy Association session on Industry Review of the Department of Energy R&D Program. We have a good panel up here. I think everybody knows the panelists, but I'd like to introduce them, and what I more or less expect each to concentrate on. They are:

Subir Sanyal — GeothermEx — "Reservoir Engineering"
Tim Anderson — Unocal Geothermal Division - "Exploration"
Lou Capuano — Thermasource — "Drilling"
Bill Livesay — Consultant — "Drilling"
Carl Paquin — Pacific Gas & Electric Company — "Power Plants"

We want to have an informal discussion, so feel free to break in at any point. The objective is to get candid comments on the DOE research program. We'd like to find out how this program can be improved, what are we doing right, and what are we doing wrong. I hope to get a lot of audience participation, and I'll call for it. If I put some of you on the spot, don't be surprised. Whatever is said up here, be ready with a question or answer. Now, I'm going to ask my colleagues on the panel, to take five to ten minutes to make a few statements regarding R&D, R&D needs, the geothermal program and how it's fulfilling those needs or not fulfilling those needs, and in general to get the discussion going. So, Subir, it's up to you.

Subir Sanyal: I have an important concern that I've been talking about the last seven or eight years. And that is about our losing ground vis a vis Japan and other countries in the R&D area. The reason I know this particularly well is that we have been working in Japan for the last 15 years, and I've seen the change.

In the early 1980's, for example, the Japanese were very interested in knowing what's going on in the way of U.S. R&D in reservoir engineering, geophysics, and geology and all the fundamental sciences, but then gradually the flow of information toward Japan stopped a few years ago.

If we don't start developing new technology, new ideas, and do some fundamental R&D, in the long run it will be bad for the U.S. industry. Right now it's bad for us consultants, but eventually it's going to hurt everybody, including the developers, because the respect the Japanese had for American technology gradually died out through the '80s.

Now every time I go to Japan, I find they have a new agreement with the Germans, the British, the French or somebody else. Specifically in the area of geophysics, we worked very closely with the Japanese government from the mid-1980s to early 1990s, and systematically they went after each aspect of each technology to the point, I think in some areas — such as CSAMT, they claim they have much more to offer than we do. In fact, in a limited way, they are beginning to compete in commercial markets in that area.

In reservoir engineering, for example, in the '70s, S-Cubed and LBL (Lawrence Berkeley National Laboratory) got into development of software for reservoir simulation. That kind of peaked by the mid-1980s. Now the Japanese have developed their own simulation software, with the help of S-Cubed, and essentially they have no more need for the kind of software we developed in the '80s. I look at the area of well testing, for example. A lot of the reports coming out of Japan, unfortunately in Japanese, are really quite sophisticated, and I don't think we have a lot of the technology.

Unlike the Japanese who can pick up DOE reports and find out what's going on, we can't pick up a Japanese report and understand what's going on. What frustrates me most is when I go to a Japanese office in a utility company or private developer's office, and I find the shelves are lined with U.S. DOE publications from all over — from LBL, Livermore, Los Alamos, just name it — and yet we cannot read their documents.

We shared our R&D readily in the '80s when we were doing it very well, and now that we are not generating new ideas or new processes or concepts, we can't find out what they are doing readily. Therefore my appeal is, first, for DOE to start seriously thinking about starting fundamental R&D once again and not just do only demonstration projects of small consequence, but something that will have fundamental impact. And, second, not make it so readily available to the rest of the world that they use it before we do. I had great difficulty getting, for example, the latest copy of some DOE software, and I found out that workers in some other countries already had it. The reason we couldn't get it was that, I was told, a National Lab cannot give you the software without proper documentation because you might sue them for some bug. Yet workers from other countries are not going to sue you, therefore, you can give them half-baked things.

That's why I think we really need to streamline the whole idea of geothermal R&D, and try to make it so that our taxpayers get to use it first.

Tim Anderson: Thanks, Mike, for the opportunity to say a few words. I've only officially been in geothermal about two years, although I've been watching it on the margins for about fifteen. I've had the interesting opportunity of plunging into this business and have just been getting an understanding of what's been done and what remains to be done.

On the subject of status: where are we today in geothermal exploration and development? My impression is that we're good at finding high temperature systems when we explore. But we have a poor success rate in finding (fluid) productivity. We need to make a lot more progress in targeting the wells and drilling in the right places in the field to maximize productivity. Because we sometimes fail to find productivity, we have some expensive failures where we have found high temperature and we believe there's a system present, but we haven't found commercial productivity.

What it also formulates for us is an economic handicap. We know in our fields we have wells capable of producing 30 megawatts. We also have sub-commercial wells. There's a certain percentage of failures in every field we work. We have an economic handicap on our projects because we cannot highgrade the drilling toward high productivity wells. I think all this is related to the fact that we don't fully understand the tectonic or lithological controls on production. We don't really have the knowledge of the geologic structure of the system that we need to predict these things.

As an aside, I would like to note that we have tremendous technical resources available to address these needs. We have the assets of the national laboratories and an excellent university system. I'm less concerned about competition abroad when I look at the caliber of people we have working on geothermal problems. What I am concerned about is that I think we're all spread out too thin. I think we have a lot of people putting 10 to 15 percent of their time on geothermal projects. What we really need to do is to take the expertise that we have and focus it and have people working full time on the geothermal needs and priorities. That may be a little controversial. How can we focus our assets and really put our people to work on the problems that must be solved?

Where to go from here? My sense of the times is that we're ready for another attempt at seismic reflection techniques. The reason I say that is that it's been a number of years since any work has been done on seismic methods in volcanic terrain. There was a lot of progress in the '70s and maybe early '80s. A lot of it was done under DOE funding, but it has not continued, and we need to get back to that. The people in Houston in oil and gas have made a lot of progress in distributed acquisition systems, 3D survey designs, vertical arrays, migration, and imaging. Those technologies are ready to be implemented in geothermal. We have to get out and see what they can do.

The second thing for the future is that we need to be able to target redrills. No matter what we do in our field, there's going to be some dry holes. We need to know what to do next. There are some good borehole geophysical techniques. Marshall Reed said that Mike Wilt is doing some EM work that has great potential for that need. We could be looking at VSP as another geophysical method to target redrills, so that when we do have a failure it's only one failure and it is followed by success.

Finally, I think we on the exploration side need to do a better job of fault-mapping in volcanic terrain. It's not an easy job because we have a lot of small offset normal faults related to the magma-induced extension, and we often have sites that are covered by a layer of volcanic ash which hides the fault exposures. And quite often there is rain forest and villages and rice paddies over the places we're working. So I think there should be some effort given to airborne techniques, airborne electromagnetics, and maybe some more work on remote sensing, low cost geophysical techniques to map the fault systems in volcanic terrain. Those are the technical priorities I see.

I think progress in this area would have a lot of benefits. We could see growth in our business and continued leadership in the field if we can make some progress in these things.

Lou Capuano: I'll talk a bit about where I think we should be going with R&D in the drilling field. I'm going to concentrate a bit more on drilling in the reservoir. Then, Bill Livesay will talk about actually reaching the target.

By way of an introduction, where do we think R&D should be heading now? Domestically, obviously, we're looking at more remedial work, more maintenance. We're trying to maintain the fields and wells by trying to be more successful in our workovers and remedial work on the wells, getting longer lives. There's been discussions today on setting up a new GRC (Geothermal Resources Council) courses on how to solve these problems.

A lot more of our time should be spent in diagnosis. We all have wells that have problems. How do we diagnose what the problem is? How do we solve it? What techniques and tools do we use? More work should, I think, be done on system analysis. How do we analyze the complete system of the well? When we start seeing wells decline in pressure and temperature, what diagnostic tool should we use that would minimize the time that the well is off production? How can we come up with answers, come up with quick solutions, and recommend quick remedial work?

In the drilling area, I think that system analysis can be utilized there. I say we need to "analyze the system," I'm talking about the type of resource we're penetrating, whether it be a dry steam, vapor dominated, or liquid dominated resource. What is the best way to analyze a complete system and put a package together that will penetrate the resource effectively?

Right now the hot place for geothermal is in Indonesia. There are five or six different exploration projects going on there now, and every one of them is penetrating the resource in a different manner. Some are drilling blind. Some are drilling with water, while some are drilling with air or mud. Which is the best way? I don't think we have quantitatively analyzed the system enough to be able to say what is the best way. We're drilling a lot of resources blind in those areas because we can't get enough air, or the resource is a two-phased system and we can't dispose of the fluids. If we're going to drill it blind, I don't like to sit on a well for two weeks for it to recover in temperature before we can find out if it's a good well. We shouldn't have to be doing that. There should be better ways to penetrate the resources.

And there should be better ways to identify the resource when we get to it. We're drilling into fractured systems and just assuming that once we reach a fractured zone, that's the resource, let's go through it and complete it. I don't believe that's the best way of handling it. I think we're drilling into this thing not only blind from the aspect of losing circulation or losing fluid, but we're going into it blind with respect to knowing where the tops or the bottoms are. Much better definition needs to be made in this area.

We also need to analyze our completion programs. There are many types of completion programs: big hole, small hole, whether or not we run a hang-down string of tubing. What's needed in these completions? What's going to be the optimum type of completion program to keep the well on line? I'd like to see the whole system analyzed so that we could determine what the resource is, and how we should complete it to prolong the production of the wells. More time should be spent analyzing the techniques of how we penetrate, how we drill, and how we solve the problems. We have the problem, as Tim was saying, of being very good at finding the high temperatures, but we've been not very successful in finding production.

I don't believe we're penetrating productive areas properly. I think in some areas we drill through production. That happens many times, I hate to admit. And I think we need to be more aware of it. We listened to the Drilling R&D session this morning and everybody's on the path of quickest drill, get down, get to Total Depth as soon as possible. I don't know if that's always the best. We need to take a better look at what we're penetrating. Make sure we're penetrating the appropriate zones. Make sure we case off the appropriate zones. Moreover, completion programs need to be designed so that there is flexibility as well as productivity.

One last note. We have been successful in finding good geothermal resources, but we've been unsuccessful in finding good power contracts. That's the next thing we need to start looking at. In effect, find better ways of getting rid of our resources, through power sales.

Bill Livesay: If you look at the wells we've drilled, from the top down, the list of problems has been the same for about the last 25 years: lost circulation, corrosion, temperature, hard rock, and now I think, borehole stability as sort of a part of the lost circulation problem. If you look at wells in the Philippines and Indonesia, we're revisiting some of the very same problems that the early wells at The Geysers had — we have very hard streaks and we have very soft streaks. You just couldn't pump enough of that stuff out of the hole to establish a well. So, those are still the main problems.

In the top part of the hole, no matter where we drill it, we see tremendous lost circulation. Trying to cement the surface casing in the same way that we have for years is very expensive and very slow. It's not unusual to have ten to fifteen cement plugs for lost circulation just in that surface section. So I think how you work the lost circulation problem is very important. Sandia National Laboratories under DOE geothermal funding has been working on that for a long time. Yet we still don't have good solutions. Please note that I am big proponent of the Sandia program.

And I should be a big proponent, since I have a project with Sandia on wellbore lining. I think that wellbore lining is going to be useful, even if it's temporary just to mitigate lost circulation. I think we can do that now in a manner that is very cost effective. Well bore lining is an important means to try to reduce the uncertainty of what we do. Uncertainty kills our investors' interest faster than the actual dollar value.

When Unocal was working in the Imperial Valley years ago, they did quite a bit on lining casings with polymer cement. They were fairly successful. If the life of that cement-lined casing could be increased — especially at the casing joints, where you see some degradation — it could be competitive with some very high-priced casing material, such as titanium. Usually, we've talked about lining the casing before we put it in the hole. But it may be that lining it after we put it in the hole is a better way to try to use carbon steel, simply because it may be easier to solve the problem at the joints.

There are other things out there that we don't use. You can put a 200-foot long patch in the wellbore right now if you want to; 200 feet is all the vendor will claim for length. This material is essentially corrugated in the radial dimension. You put it in place and pull the mandrel back through it to force it out against the wall. There ought to be some applications for that, especially when you can put a flowmeter at the bottom of the hole and measure the flow that's going across the well. I've never seen one of these used in a geothermal well, but I have seen them used in oil and gas. Another important thing to look at for the casing corrosion problem, I think, is non-metallics. Are there some new materials, composites, in our future? We have seen the first use of fiberglass in some wells. I think that we can go to 350° to 360° F with that.

I don't think we're ever going to get away from using carbon steel in the bottom of the hole. That's still a significant part of the well cost, because we use much larger diameters than in oil and gas wells.

Many of the things that we're going to need in the near future really have to do with remedial and monitoring work with the wells that are getting quite aged right now. We need to be able to monitor the condition of the casing without having to cool the well down. We need casing calipers that do not require you to shut the well down to run the tool in the hole. I think that should not be complicated to do. But somebody has to dedicate themselves to doing it. You people who pay the bills have got to quit shying away from signing the bill when it's a little higher than it is on a regular basis.

But all in all, I want to emphasize that the lost circulation and wellbore stability problems are still eating us alive. There are wells, especially in Asia, where we cannot get the well to bottom because if we pass one production zone, it takes fluid but it doesn't take cuttings. The next thing you know, we are pumping 1200 gallons per minute, and the drill pipe is stuck. Then you waste 10 days tugging on it and eventually you backtrack and sidetrack around. So lost circulation, as it affects completion is, I think, more difficult now in Indonesia and the Philippines than it is in the U.S. This is something we'll really have to work on. I think the temporary lining approach may be one way to get around it. We've pumped everything in the world down this hole trying to fill those cracks, and while we've made some improvements, we have not really been successful. I think other mitigative techniques where we actually block off that part of the well have some real capabilities that we haven't really explored fully.

Carl Paquin: I'll cover the energy conversion area. After you've gone through all the work of exploring, and drilling the wells, and getting steam production, the whole goal is to generate some energy, hopefully electricity, out of this. So the DOE Energy Conversion research is focusing on how to improve the efficiency of our power plants, and reduce their operating and capital costs. Currently, there is some good work you've heard about, like the turbo compressor at PG&E, Unit 11 where we're working with DOE and Barber Nichols. The steam suppliers are cofunding this work to improve the efficiency of our gas removal systems. There's a Biphase turbine project going on down in Cerro Prieto, Mexico, that will help improve the efficiency of those units. There's expansion research on binary fluids. And of course, there's conductive coating research and many other areas of research ongoing.

Some novel project ideas came out of our Geothermal Power Organization meeting yesterday. We talked about the need for steam scrubbing without desuperheating. For example, The Geysers plants might increase power by 20 megawatts just by not desuperheating the steam to remove corrosives. Several industry groups said that's a high priority. We'd like to also improve efficiency with a real-time stress-corrosion-cracking monitoring system. That might be an alternative for eliminating desuperheating.

Another problem is scaling. We'd like to be able to prevent scaling in our piping systems and power plants. We might also be able to improve efficiency by looking at ways to reduce flow loss in the steam gathering pipes and metering systems. Several firms think there's quite an opportunity there. Unocal mentioned that at their Tiwi field, in the Philippines, they gained close to 20 megawatts just by reevaluating their steam systems, because the steam flows had changed dramatically over the years from the original design conditions. Another area mentioned was the need for more research on two-phase nozzles and ejectors.

Another important area is cost reduction. We want to keep these plants competitive, especially now that we're facing deregulation here in the United States. One operating cost is corrosion and pitting. A real-time corrosion or pitting monitor would let us know when we should be adding corrosion inhibitors. There may also be opportunities to develop durable low-cost coatings for turbine casings, piping, condensers and pumps.

Hydrogen sulfide abatement is a major cost for many operators. We want better ways to remove hydrogen sulfide by improving its partitioning, so we can burn more of it instead of having to control it with costly chemicals. We also talked about ways of improving the existing hydrogen sulfide abatement systems. An idea from NREL (National Renewable Energy Laboratory) that we would like to explore further is to put oxygen directly into the condensate where it can react more efficiently with the iron chelate. Another idea we've been exploring is improving our existing Stretford processes by replacing the costly vanadium with a lower-cost iron chelate. Another issue, with some research ongoing, is various ways of removing hazardous wastes, especially mercury from the sulfur sludges.

Steam quality and impurity monitoring has been an issue at many plants. A slug of water can cause a lot of damage to the piping or turbine equipment. We also need a real-time hydrogen sulfide monitor. There's some work and support in several Labs for this. That research needs to proceed. We want to reduce our hydrogen sulfide abatement costs and still stay within compliance requirements.

The last area we discussed is the need to reduce capital costs. Unocal is saying that typical geothermal costs for plants run about $1,000 to $1,200 per kilowatt; that has to compete with $200 per kilowatt gas turbine technology. Look at every part of the plant to squeeze out capital costs. Another way in which we're reducing capital costs is by sustaining our geothermal field by injecting more fluids, via the Lake County Waste Water Pipeline to The Geysers. There are other opportunities to bring in treated waste water to The Geysers and other geothermal sites.

Mike Wright: "Thank You," to the panelists. I think we've got a lot to think about and a lot to talk about here.

To get things started, I'd just like to say that my observation of the Japanese program is much the same as Subir's. I think they are continuing to take a long-term view of R&D, and that they have a whole cadre of very good people, and they're working on the problems. And so we maybe have a chance to collaborate with them.

But on the other hand, I think that we all understand that the DOE program is for the benefit of the U.S. geothermal industry. So, how do we take advantage of what's being done in other parts of the world and enable our own industry to capitalize on that? Sabodh Garg, you've worked over in Japan a lot. Would you comment on some of these issues?

Sabodh Garg, Maxwell Technologies (formerly the "S-Cubed" firm mentioned above): We have, over the last decade and a half, worked with the Japanese and continue to do so in a collaborative fashion. They have funded several of our efforts and continue to do so in software development. In addition, they have been very forthcoming in supplying a lot of their well data for use as part of the slim hole study we've been doing for the last several years. I feel that there are opportunities for collaborative effort and we will all benefit if we could sort of look beyond the national efforts and not say, "This is ours — this is theirs," but see where we can collaborate with each other and promote geothermal worldwide.

Mike Wright: But how do we bring their results back to the U.S. and enable our industry to take advantage of it?

Sabodh Garg: Mike, I've gone to each and every major development in Japan, asked them to release their data, and they've done so. But with the understanding it's not a one-way street — that when we ask them to release their data and their results, we should not be shy about telling them what we know also. A collaboration takes two sides. It cannot be one-sided.

Subir Sanyal: Sabodh, I didn't mean to single out the Japanese. They are just an example. There are others like Icelanders. They are doing very good work. They're competing with us. But regarding the Japanese, it's OK, you can get a lot of data from them; you get a whole database. You can collaborate with them. They are willing to do that, providing it's a two-way street.

But if we don't have some DOE kind of funding, how are we going to do that? Now, if you are a private company, you don't have the time to have your staff do R&D and collaborate with the Japanese. There have to be groups like EGI (formerly UURI or ESRI) at the University of Utah who can do the collaboration, learn what the Japanese are doing, and take the research beyond that.

Also, look what's happened with the Italians. They have just dropped the ball on R&D, closed down their Center for Geothermal Research now. They know there's no funding, and suddenly you don't see any more publications from Italy. The same thing is happening in New Zealand. They privatized their government infrastructure, there are absolutely no papers coming from there. But look at the Japanese. At last year's GRC (Geothermal Resources Council) meeting in Portland, Oregon, for example, about 40 percent of the papers were from Japan. So, we are essentially now Number 2 in geothermal R&D. I think we have to reclaim the leading role that we had all through the 1970's and 1980's.

Lou Capuano: I think what you're saying, though, is that you're not going to discourage the Japanese from doing their R&D. You've got to compete with them. We're Number 2 probably because we're Number 2 or maybe 3 or 4 in funding R&D domestically. I think if we're going to compete, I think we need to fund our own R&D here at home so that we can compete with them on their own level. In other words, you're saying we need more money for R&D efforts here in the U.S. The reason why the Italians have shut down is that they're not putting any more money in R&D. They've quit, and they're going to drop right down to the bottom. If we want to compete with the Japanese, we've got to be there with the dollars.

Subir Sanyal: Here's another aspect. Recently, we developed a piece of software together with the Icelanders. It's a geochemistry package. We're finding that it's easier for a foreign client like the Japanese or the Indonesians to hire the Icelanders to come and train them because the Icelandic government subsidized such work. For $250 a day, Japan and Indonesia can get Iceland's best scientists. We have to charge $1,000 a day to send that kind of quality person. So the situation really is, not only are we losing our edge in R&D, but also our edge to market the R&D in the future. Right now this is not an issue for development companies like CalEnergy and Unocal. They don't feel it yet. But sooner or later, this is going to cause us problems. Because when I go into Indonesia or Philippines as a consultant, the perception has changed. They used to respect us because they knew we were the fountainhead of technology all through the '70s and '80s. They don't consider the U.S. as that any more. We just are bringing in capital. That's OK, but there's a limit to which capital alone can open doors.

Marcelo Lippmann, Lawrence Berkeley National Laboratory (LBL): Subir voiced his concern about gaining access to DOE-sponsored research. The way we get the research out is not only through publications, but also through collaboration. Several times we have asked U.S. companies to send somebody over to work with us. We found that it is very difficult for any person from the industry to spend time at LBL mainly because they don't have the funding to work with a National Lab or a University. That's my feeling.

The opportunities are there. We get visitors all the time from Japan, New Zealand, Iceland all the time. They spend weeks or months working with us. At the moment we have one fellow from the Geological Service of Japan who is spending two years working on nuclear waste storage. He is also listening to what we are doing in geothermal. So, I feel that there should be a commitment from industry to support R&D, or to have their people work closely with those involved in DOE-supported R&D. This would allow industry to get familiar with the results from the DOE program.

There is a feeling that we are losing our edge in R&D, but are also losing it in education. There are many foreign students in U.S. universities. Some of them stay here, others go back to their countries after completing their degrees. Several times we discussed with DOE the idea to create a geothermal school in the U.S. that would compete with those in New Zealand and Iceland, but there seems to be no interest. We should really be thinking about the concept of organizing a technical school of geothermics, funded by DOE and industry. The best way of influencing someone is by having close personal contacts. These are being developed by the New Zealanders and Icelanders through their geothermal schools. When a former student runs into a technical problem, he/she tends to call his/her teachers or colleagues asking for advice. We in the U.S., don't have many such opportunities.

We shouldn't "close-file" our publications. Rather, we should develop good contacts between industry, and DOE labs and universities by working together instead of closing the doors and saying, "Let's keep everything secret." We wouldn't get far.

Allan Jelacic, Director, DOE Geothermal Research Program: We should put some of that into perspective. The U.S. Department of Energy Office of Geothermal Technologies research budget has been in a rut at $30 million for the last three or four years, so the Japanese government indeed is spending more than we are, which may account for the feeling that they're ahead of us.

However, there's another side to it. From what I understand, Japan takes a different approach in the way they fund R&D. They pick their opportunities. They go after certain elements of technology that they want to focus on and put their resources into those particular projects. Our approach in the U.S. since the early days in the mid-70s has been a broad-based effort funding various projects across the board. So there's a difference of philosophy and approach between what we do and what the Japanese do. I think maybe this group should consider whether it's time for the U.S. to take a different tack in how it funds its R&D program.

Marshall Reed, Program Manger, DOE Geothermal Research Program: I sympathize with Subir Sanyal about the problem with communication with the Japanese. There are a couple of things that we could do about this.

Not too long ago I was at the Stanford geothermal reservoir workshop. About three months later I got a copy in Japanese of the entire proceedings of the workshop. We could do the same thing, I think, maybe with Government or industry funding, we could have a translation service. The Geothermal Resources Council or some other U.S. organization could take the proceedings of Japanese meetings and translate them into English and make them available to the industry. That would be a lot easier for me than trying to learn Japanese.

We have an International Energy Agency (IEA) agreement in which we are party to one part, the hot-dry rock part, as are the Japanese. But there are other opportunities in that IEA agreement. There's a possibility for U.S.-Japanese collaboration on exchange of information and data through a government-to-government exchange, where we would be able to make the information available to the U.S. industry. We need some direction from industry as to what you think would be best, what kind of information you would like, what things would be most useful. Sabodh Garg mentioned the collaboration that he and his company have had with some of the Japanese operators in getting slim-hole information. That is being paid for by the Department of Energy. We are funding that with the idea that within the U.S. community we don't have enough experiences in slim-holes. There are a lot of opportunities, but we need clear direction from industry.

Carl Paquin: I like your idea, especially where you're talking about looking at Japanese papers and papers from other countries. If you use your advisory organizations to identify the key areas of interest to the geothermal community, and then a couple of people who are fluent in other languages could look for abstracts that meet those areas of need, and translate those abstracts. And if there is somebody who finds it worthwhile to explore the whole paper, then they could pay for the paper to be translated.

Sue Goff, Energy Supply and Environment Program, Los Alamos National Laboratory: I want to address the panel from the point of view of the research institutions. The budgets that we're under are now on a two-year cycle with Congress. It's hard to do R&D on a two-year cycle. Often, after you just get started, that particular project gets cut off. That's one of the boundary conditions we have to work under.

The second piece is that Energy Efficiency (which encompasses Geothermal Research) and Fossil Energy, the two areas where I work for DOE, really do take their guidance for their R&D programs from industry. Across the board it is industry who is the driver. You guys are the driver for where the R&D direction is going. And in the last few years, the direction has been, "Here and now." We've had more than one trade association show up and say, "We've come here to find the low-hanging fruit." Well, it's all gone. You've picked it all. We have no low-hanging fruit left. We're trying to figure out at Los Alamos where we should be working across a number of industry sectors, and trying to identify what the right research might be. We started with oil and gas because we actually do have a fairly successful program in oil and gas. But if you look at where the research priorities are for the oil and gas industry, they're all things that they want very quickly.

And that's not where the National Laboratories should be working — in the here and now. That's not our role. That's not our job. Our role should be in the long-term piece. But if you don't have a plan for that long-term piece, then we're all competing for this "here and now." So there's this really kind of a fundamental problem here — a major disconnect. So instead we're competing with you guys to do things that are really <u>your place</u>.

Also what we see in the oil and gas industries is that the companies are ridding themselves of their R&D people. And yet it's really not the Labs that should pick up that piece that they need in the short term, that's probably going to be the role of the petroleum service companies. But then the service companies aren't going to pick up the long-term R&D. What you need to do is to establish a portfolio that's sort of broad-based and look at that and really use us correctly.

Because our role is the long-term high risk piece, you need to look at your priorities differently, think about how you are defining your priorities. For example, "drilling" is an area, but there are priorities within that are short and long-term. And that's really in my opinion how we can best figure what we can do to help you solve your problems, not, "Gee, this is what we do good. Why don't you take this from us."

Subir Sanyal: Sue, I totally agree with you. I think where we should be focusing more is on long-term problems. A lot of the DOE money is directed to shorter-term problems where the industry feels it needs things right away. For example, look at reservoir engineering. Right now, the crying need is better fracture definition. We have software now to do simulation, to do well tests, to do wellbore simulation. Nothing we do in those areas is going to be earth-shaking; it will only be refinement of what we already have.

What we need to do is to sit down and really look at: "Can we really improve our definition of fractures?" They're doing that in the nuclear waste isolation business. People are using fractals, for example. In Japan, there's been tremendous advancement in thinking of how to define a reservoir. We have gone up to the double porosity model and we stopped, simply because there isn't enough funding to really get into those fundamentals. And CalEnergy or Unocal wouldn't do that because they have more pressing business to do the drilling operation and get the project on line. So that's why I think I agree with Sue that there has to be longer term thinking in R&D.

Mike Wright: Al or Marshall, do you want to comment on the DOE role?

Bill Livesay: Yes: how do we sell the people who decide this on the fact that we're not trying to make next week's product?

Al Jelacic: That's a big part of the problem. Industry is our customer. We have avowed that, we have gotten up in public and stated that. Industry needs are near-term. We have made a concerted effort to focus the program to meet industry's needs which are on a time-span of say, one to three years. I wrestle with this myself, but I really don't have any answer. We're here to serve the customer. That's our job. The U.S. geothermal industry is our direct customer, and its needs are almost entirely short-term.

We also recognize, however, that there are other national interests that must be served and these fall in the long-term. We have tried to balance this over the years with things like the Hot Dry Rock research program, the Geopressured Geothermal program, and other longer-term outlooks on R&D. Industry, for the most part, has not been very supportive of our attention to those longer-term possibilities. I hear people saying, "Let's look at the long-term and look at the out years," but when it comes to spending dollars, real bucks, the industry says "Help me do my project within the next year or two." So, I'm hearing quite a bit of conflicting opinion here.

In the past we have tried to serve both masters by partitioning our budget. The heavy emphasis, certainly in recent years, has been on the nearer-term. If the industry, our customer, tells us that we should get out of the near-term business and look at long-term, we'll be happy to do that.

Bill Livesay: Sometimes I think you can influence the answer you get by the level of the person you ask the question to. If you asked the guy who has bellied up to a particular problem every day, he's going to tell you which problem is pounding on him that day. You go about three levels up in the company — this was my experience when I used to work at Exxon — you will find a more philosophical attitude toward expenditures. We really work mostly down with the guy who's got his toes getting hit with the hammer, rather than the guy who's two or three levels up from that and is trying to set company policy. And I think you can be influenced by that.

But it's absolutely a selling job. You have to sell a different level of the company the fact that long-term programs are harder to measure because often they don't have a piece of iron, or a product, or a computer code that's going to be the output. So in some respect, the longer-term R&D projects are a little more difficult to evaluate and look back and say, "Well, look what we did here!" And yet I think in the long run, the projects with a somewhat longer-term outlook end up being the most helpful.

We're just not geared to do short-term, six-month projects. We're just not. As Sue Goff said earlier, we're on a two-year funding cycle. In research, you can't even shift gears in two years. You can't really adjust the projects fast enough to really be supportive of a company who's looking at something that's 90 or 120 days downstream. So, I just think you have to do a selling job at a little higher level in the companies. Maybe that will help you get a different response.

Subir Sanyal: If DOE did not fund an experimental loop at the Salton Sea 20 years ago, today there wouldn't be 270 megawatts operating there. That is a classic example of "long-term" funding of R&D that had a direct practical consequence within 5 years. I remember in 1983, when the first Magma Company plant there had to be financed, I spent almost a year convincing the bank that particular experiment was the basis for the entire confidence you had in technology. After the first 40 megawatt plant was financed, it became routine. Ever since, you can any time go to the bank and get any project financed at Salton Sea. So, I would like to emphasize that long term R&D does not mean esoteric, hare-brained, or anything like that.

Carl Paquin: We need a balance between short term and long term. The industry has to survive and be competitive today, but we also have to be looking say 5, 10, or as much as 15 years out. One way is split your budget using a ratio of 80:20 or maybe 50:50. I would recommend, though, when you get the longer term research needs, think twice before doing a demonstration. That's where a lot of money gets poured into a technology that's maybe 15 years away from use, and it's harder for us in industry to really see the value in spending a lot of money.

Conversely, perhaps analytical studies or theoretical studies, where the opportunities are explored and analyzed without the great expense of pouring concrete and bending steel would provide us most of the benefit at reduced cost. Again, with us in industry facing deregulation, we do have to survive the present to exist into the future, so I do feel there's going to have to be a heavier weighting on short-term, but not at the exclusion of long-term.

Tom Sparks, Unocal Geothermal: I want to make two points. One is, it's very interesting to hear about the long-term look at this, and I think it's absolutely right. You have to have a long-term vision. If you look at the other energy technologies, from nuclear to solar, you can see that they've always had a long-term vision. I hear all the ingredients being mentioned today.

You don't jump into building a giant power plant on just theoretical concepts. You identify what things you have to overcome, where your hurdles are, and you break those up into doable packages and assign them to an R&D function, but you're looking for progress at the same time. You don't want to be just dabbling in science. We want to be looking at specifics and seeing that there is progress. I think the one thing we must recommend to the DOE as an industry is: what is the long-term vision; where do we want to be?

Yes, we have the Unocals and the Calpines that are working on projects today and are very busy developing business over there, but profit is the name of the game for us. Perhaps we don't spend enough time looking at the future a long time out, and I think that's a very important concept. So, let's try to get something put together that helps us in the short term. I also think many of the things that we're talking about for the vision of the future are very synergistic with what we need for the near term. For example, drilling. If we could reduce the cost of drilling, improve drilling productivity, by any measure, that would be very valuable.

Second, Allan Jelacic said it. Well, we, the industry, are the main customer of this research program. We're the people that should cast our vote on where things should be done, when and how. But we've got to help Allan and help ourselves by the grass-roots lobbying that we do up on Capitol Hill, because all of the funding for this effort — the roughly $30 million per year — is provided by Congress. We have to be heard in Congress and we have to go up and sell our program. So we have to have a vision, we have to have objectives and goals, and have to take those up on the Hill and sell them. We've been very successful in that the last two years. Government funding for geothermal research has been steady, while some other technologies have been cut severely in their programs, and have been criticized.

We need to remember that we need to do that and it can't just be the Calpines, the Unocals and the guys who are back in Washington a lot. It has to be all of us. We all have to contribute to this effort somehow. So Mike Wright and I have been working on ways to do this, and we now have an Executive Director for the

Geothermal Energy Association, placed in Washington, who will be helping us to do this. We just need to get a better effort to support these programs at the Hill coming from industry.

John Weare, University of California, San Diego: I'd like to add a little different perspective. I have the great pleasure of meeting and working with many of you in this room, at our chemistry modeling workshops. One of the things I've noticed, particularly in recent times, is that the people that have been contacting us — say from Japan in a recent collaboration there, and other countries, and the oil businesses — is that there's apt to be a more sophisticated R&D branch inside the company. So when you're talking to an oil firm, you're talking to someone who, as Marcelo Lippmann said, is a real expert in, say, geochemistry.

I think our geothermal industry is having a little more trouble because maybe there's less money out there, so the priorities are not in the R&D. I'd like to suggest that government consider spending a little money to industry to help support an internal person of that sort. I know that the industry can't fund an R&D person within the company, but maybe there could be some shared support there. That would create a little more expertise within the industry that would work on this R&D direction. I think that Marshall Reed has done a little bit of that in recent times with Caithness, but maybe more of that in other directions would be useful, too.

Allan Sattler, Sandia National Laboratories: There are two long-term projects. One is ongoing — the work at The Geysers, which has been going for ten years. And I think we're about to embark on another one, Dixie Valley. Tim, it's interesting you mentioned the seismic work. Some work is now being started in the solution-mining business where they're looking at the caprock over the salt domes. It's got voids that cause drilling conditions even worse than geothermal. But there are similarities. If they can find those voids in the caprock, perhaps they can find geothermal fracture systems.

Mike Wright: I'd like to ask Dick Benoit to comment on this business of technology transfer. Dick, you've done a lot of work recently with some of the DOE researchers, and I think part of what Subir was getting at is: How do we transfer technology from whatever source? How do we get this in use by our industry so that we're at the cutting edge.

Dick Benoit, Oxbow Power Services: Slowly and painfully. Part of the problem is that we have so many different technical aspects in geothermal. Within any company, for instance, take Calpine, Oxbow, or Caithness, you've got up to three guys to deal with the underground. And you've got to try to cover all the bases some way — from drilling, to permitting, to chemistry, physics, geology. And if you try to keep on top of something new happening, basically, you can't do it.

So, if you can find DOE, like we've done at Oxbow, to come in and get us real access to guys who are on top of specific things, that helps a lot. But there's no way there's enough money for everybody to get the sort of things that are going on in Dixie Valley now. The amount of money and effort going in there can't be spread throughout every company.

We also must think about this: Have we reached the point where we believe we've got a resource that's so foul, elusive, and difficult to deal with that we're never going to be competitive? I throw that out as a devil's advocate here. You could reach that conclusion listening to what's been said today.

You just can't be an expert in every thing. You have to try to find a niche and hopefully find other guys that you can rely on, and have access to, to help you sort out the details of some of the problems. We've had over 20 different people out in Dixie Valley in the last year doing various things — chemistry, physics, downhole, above ground, everywhere else. Nobody, no single normal-size geothermal company, can do that now. I don't know if Unocal can do it. I'm sure CalEnergy can't. They say you've got to survive today, bring some money in for tomorrow, and it's a very difficult problem. So much new stuff goes by that you just can't absorb it all. Look around at the prices you're getting for steam. You can't afford to have seven or eight guys sitting around, each one of them an expert.

Bill Livesay: Something that falls in what you're saying, Dick, is what Subir mentioned about producing power from the Salton Sea reservoir. That program was Unocal's problem, if you will, but there was a good R&D program, through DOE, on chemistry and the problems they had with high solids content. Whether it was a DOE success or Unocal's success, without those efforts, the Salton Sea reservoir would be non-productive, simply because it was too corrosive and there were just too much solids in the fluid.

But here's the point: Meeting the short-term goal of making the Salton Sea into a productive resource created a collection of new technologies that has since been used and reused in other places in the world other than just the Salton Sea. The longer range project of trying to learn how to generate power from a really lousy fluid generated a number of small projects. The larger project identified the smaller, shorter-term stuff that needed to be done. And so, and I know that in Exxon that's how, when we changed over from being sort of an academic kind of research organization to being a problem-oriented research organization, you found your short-term problems by finding what you couldn't do. That was where "research" came in.

Dick Benoit: Another important thing about the Salton Sea work is that you had an obvious goal there. You've got a nasty resource, and you want to make electricity from it. Do we have any similar goal like this in "fracture detection" or "reservoir sustainability" right now? I haven't heard anybody state goals clearly yet for those areas. You know, "This is exactly where we're trying to get five years from now." What are we trying to do? Maybe if we could reach some sort of consensus on that, we might see some things fall out of it.

Mike Wright: That leads me to a question that might change the direction of the conversation. It's an important one to discuss in a forum like this, and related to a point Tim Anderson made. The problem is something like this. In the National Lab System you have researchers who have access to probably the world's best facilities, and we have some very good people. Each of these researchers — not everybody, but to a significant extent — these researchers are cutting edge primarily because a lot of their work is funded through other programs, say the fossil program or the nuclear waste isolation program. So you could look at it like DOE, in using these people, is leveraging dollars. They're bringing this expertise in and paying for 10 or 20% of their time. And that buys a lot. On the other hand, you could also say that these people who are only spending 20% of their time, say working on a geothermal problem, lack the focus that I think Tim was talking about.

Does anyone here want to comment on that? Should we be using fewer good people somehow or is there a big advantage to using ten percent of somebody's time when their loyalties might be to some other program? I think this is a fundamental issue and a controversial one, but current for both the Geothermal Program, and the Labs.

Sue Goff: I think it really depends on what the problems are that people are working on. If somebody is working on corrosion, it cuts right across. If somebody is working 20% in oil and gas and 20% in geothermal and 20% on something else, it's still a fundamental corrosion issue that might be high temperature problems. So I think that the leveraging approach is often good.

I think part of the problem is that DOE itself is stove-piped and that I'm not so sure that the different parts of DOE take advantage of the R&D that might be going on in other parts of DOE. Let's use the NADET (National Advanced Drilling and Excavation Technologies) program as an example. The Geothermal R&D Program recognized that drilling is one of the fundamental issues, and it tried to engage other parts of DOE to come up with dollars for that particular program. And as far as I understand, it has not really been successful, has it? The importance of drilling R&D is something you hear from the oil and gas industry, yet DOE's Fossil Energy group isn't putting money into NADET. So, part of the fundamental problem sits with DOE itself.

I don't know if just all of a sudden now focusing a researcher 100 percent on geothermal really will end up solving fundamental problems. I actually think it won't. But it again depends on what that person is working on. I don't know how we help our DOE colleagues solve some of the problems that exist within DOE and how we take advantage of what's going on in other parts of DOE. This is something we deal with all the time. We could be building good programs if we cut across those stovepipes, but I don't quite know how to do it.

Marcelo Lippmann: I want to reinforce what Sue said. I feel that it is very advantageous for geothermal to have people from other programs working on geothermal-related problems. For example, we have very good numerical modelers at LBL and we apply their talents to geothermal. We could not get such experienced persons to devote 100 percent of their time on geothermal with the funding uncertainties with the Geothermal Program. Every year we don't know where we are going to be next year, so we cannot ask a person, "Put all your bets on geothermal," because in a year or so he/she might be on the street looking for another job.

The real advantage of having an experienced person like Karsten Pruess working on geothermal is that he has put together an excellent group of reservoir modelers and we are harvesting the effort and know-how of other DOE programs and incorporating them into the geothermal program. I believe that Karsten works about 20% on nuclear waste, 30% on environmental related programs, etc. It is unrealistic to think we could assign full-time persons on geothermal with the present budget uncertainties. In other words, at present we have the best people working on geothermal because they do not have to depend totally on funding from the Geothermal Program.

Mike Wright: I guess my own opinion of that issue is that for people who are well versed in geothermal energy, like Pruess is for example, where he doesn't have to get trained, there probably is an advantage for him to work on other problems and interact with a totally different bunch of people. But to bring someone new into geothermal at 10 or 20% of their time, I think you're going to be spending the first few years just bringing that person up to speed. Tom Sparks, we've talked about this; would you comment?

Tom Sparks: I think that's very true, but I don't think there are any strict rules you can apply to this. I agree with Sue's thought, that you have to analyze what the expertise is, and if it plays across a number of different fields, that's beneficial. But it occurred to me as I was listening, we've had a big success at Unocal, and perhaps we haven't mentioned it. Our oil and gas group overseas has reduced our cost of drilling by over 30% in the last couple of years. That's primarily the gas fields in Thailand, offshore. That was by just working and striving to make improvements and figuring out how to do things smarter, how to do it better next time. There was not really a lot of R&D effort in it. But we were able to achieve a better than 30% cost reduction through improved productivity. And I think that, with a little impetus from some of the R&D people, those kinds of things can be accomplished in the geothermal business, too. If we could get the cost of drilling in geothermal down by 30%-35%, we could really be competitive. I think so. Don't you think so, Mr. Benoit?

Dick Benoit: Yes, Tom, you can do it. But, how many wells in a year do you drill in Thailand?

Sparks: Oh, an awful lot.

Benoit: So, you guys are like baseball players in mid-season. You look at a company like Oxbow, we drill one well every other year. You just have to have some practice and do it regularly to get really good at it.

Sparks: There is value in quantity. That's right.

Benoit: That's part of a whole lot of things. We do a little chemistry, a little physics, a little drilling, a little of this and that, and you know, it doesn't make you an expert.

Sparks: That's very true. I think there's an opportunity here to look out and say there's more than just hydrothermal out in the future. Let's define what it is and then let's lay out a reasonable program to go after it. I think that's the road of the future for geothermal. My own personal opinion.

Mike Wright: I also agree with another one of Tim Anderson's comments. Somehow we've got to focus the R&D program more. Maybe you do it through management. I don't know. Maybe you can do it that way, but maybe you also really put an effort in by a very few good people. Maybe you spend your money hiring a few very, very good people to solve some of these problems. I think it's a fundamental question that we need to ask and we need to answer, because we do need to make progress if we're going to keep up with other countries, and keep from losing plants as they go over the PURPA cliff, and so forth.

Louis Capuano: My comment is about the difference between long-term and short-term. I think we need to focus a lot on long-term, but we need to handle and solve the short-term as well. I think some of the short-term obligation of DOE is not only for R&D, but also for short-term dissemination of the information that we do have available to us. And to facilitate the ability of individual operators to come together and exchange solutions, whether it be in DOE-sponsored forums, or other places. And also for maybe even subsidizing some of the work that the American companies can do abroad. It's very difficult for us to compete internationally with some of these other operators.

I think one of the places we need to be in the short-term is help to disseminate the solutions, help to disseminate the information that is being developed by U.S. operators. Now, the purpose of the GEA is to try to promote U.S. industry. Right? Is that why I think we're here in this meeting, and I think if we were to promote U.S. industry and U.S. technology that's been developed, I think it's our obligation here to try to <u>share</u> that. And if we look around the table right now, again I come back to the same thing we talked about years ago — how many industry people are here if we discount the labs and everybody else? There's not a lot: I see Oxbow, Unocal, and Calpine here. Everybody else here are consultants.

David Blackwell, Southern Methodist University (SMU). One of the things that's clearly happened in my own field, is that probably there is one-thousandth the manpower, manhours and womanhours going into it today than ten years ago. And you can't do even one-thousandth of what you did then with that amount of time focused on it. The capability we have lost is more than just a linear amount of the drop in the dollars. It's part of this focus that Tim discussed, having enough time. We used to be able to do the advanced research on overhead, on the extra money you got that you could squeeze out of getting the project done and then do the advanced research.

<u>I've never seen advanced research done in any kind of a coordinated fashion on a large scale by government or industry</u>. It's individual researchers, I think, that often pick out what's important in the long term, and work ahead of the game so they have a project ready to be funded when it comes to the next cycle. We can't do that anymore because there's no slack. We basically spend every penny we get for a contract doing the work that's on that contract. Contracts are cut back, there's a lot fewer people available, so all of the stuff we took for granted in the past is just gone. And I don't know how you build that back in to the system. We have to deal with it, and realize that all the flexibility we had we didn't recognize, but it's gone because of the structure that we have right now.

I also want to talk a little bit about size. I'm one that believes that bigger is not necessarily better, because if I look at some of the larger scale research projects, and I'm thinking really for example, NSF, there have certainly been some successes from DOE, but in NSF's large projects, I think they get a lot of less bang for the buck than they get with individual investigators. I'm very much one who thinks that managers ought to get the very best people to work on a project, regardless of where they come from or regardless of what their background is, rather than just picking a group of people to work on a project because they worked on similar projects in the past. You really need to keep an inflow of new talent, new ideas into any project.

Also, in listening to what people have said today, I don't hear a focus. Suggestions that say we could pick out a certain number of projects where we could really focus intelligently what we want. We've got too many kinds of problems to work on, too broad a span here to deal with. One of those things is the fracture detection problem. We have not defined fracture detection to the point that we can work on it.

Subir Sanyal: I think that DOE and GEA should cooperate much more closely because after all, both have the mandate to help the U.S. industry. Whether short term or long term, it has to be a much closer cooperation. That's why I was against the GRC and the GEA merging because that doesn't serve the purpose. The GRC is an international organization. It cannot promote just American industry, but both DOE and GEA can.

Tim Anderson: I'd like to touch back on the subject of concentrating personnel in the labs and also on long term versus short term. When we have a lot of scientists with a small percentage of their time applied to geothermal problems, we cannot effectively build teams to generate the interaction among professionals that bring forth ideas. A lot of good ideas are born in the hallway among people who have thought about problems long and hard and have shared concerns and experiences over time. When people are spread so thin in many different areas, that kind of spontaneity does not occur, and we lose a lot of creativity as a result. I also think that when a person has only a small amount of time to put in a given area, the amount of progress in that area will be small. We all know industry wants results right now. "We've got a rig spinning some where and we need help now. We don't need it 10 years from now." So we need to do something to accelerate the rate of progress in our laboratory research. There is a lot of benefit in crossovers and having somebody who's working in one area contribute a small portion of his or her time to geothermal. But I do think we need people who have geothermal as their first priority, who are involved in making this geothermal technology successful.

On the subject of long term versus short term technology, I agree with Sue Goff's comments. But I also have another point of view. To me the National Laboratories are a resource for all of us. They should be places that have the finest equipment, the greatest computers, the most amazing laboratory facilities. They should have state of the art in the areas that they cover, and they should have the people who know how to use those facilities and understand how they can be applied to solve problems, so that people from U.S. industry, or universities can go there and apply those things to short term questions. I guess I've viewed the long term role of the laboratory as a resource of the state of the art in the science, and an opportunity for industry to draw on those things to make progress solving problems.

Marshall Reed: I just want to make a couple of comments and ask that the industry folks think about them. I mentioned in the beginning of our "Geysers" session that because of the rapid decline in The Geysers in 1988, that by 1990 we were getting calls from industry at one of these Program Reviews to muster the DOE folks and try and help them out. This had a prehistory. I started working for the Department of Energy in 1984. When I got to Washington, I was told the current wisdom at the DOE was, "The Geysers geothermal field is a commercial operation, a going concern that nobody needs to worry about it. Everyone knows what's going on at The Geysers. All the industry people there really understand their reservoir, they don't need our help." I didn't believe it.

We had in place a low-level effort. We had some seismic people working with some of the companies, trying to figure out reservoir structure from that. We had a couple of other projects going on. In 1990, when we were asked to put much more DOE effort to help industry at The Geysers, we had some background, some people who had training, and we were able to bring in others working in geothermal. And we were able over 5 years with $12.5 million, to better define The Geysers, to define the problems better, and come up with potential solutions. So it really was a long term effort that was able to focus on short term problem. If we hadn't had the long term effort, we'd have had to start from scratch in 1990, we wouldn't have had the results.

Here's another important thing to think about. I think that even with the advantages of DOE's help, Dick Benoit is sitting out there in Dixie Valley mostly all by himself. Actually he has some help. But if he had a big organization out there of geologists, geophysicists, and geochemists, he wouldn't be interested in working with DOE. He wouldn't be interested in working with the scientists in the universities or Labs. But because he's out there pretty much by himself and has a difficult problem — he has a fractured system that is permeable in some places and impermeable in others — he's glad for our help. Moreover, in trying to attack that problem we've been able to bring in a number of research people with bright ideas, new ideas that hadn't been contaminated by association with traditional geothermal approaches. They are able to try out some of these ideas and try to attack that problem of determining why there is permeability in some places and not in others. This is, I believe, a long term research project. It's going to have some short term benefits to Oxbow, but it's going to have some long term benefits to the entire industry. This is the type of thing I think we should be working on. We don't have enough money or enough people to do that everywhere, but Dick has got a fundamental problem out there with permeability, and that is sufficient reason to put in a strong effort.

We have about $3 million a year going into exploration, about $4 million a year going into reservoir technology. That's not a lot of money. It's insignificant compared to what's going on in oil and gas. But we have problems that are every bit as difficult as oil and gas, and sometimes a lot more difficult. So, we're doing, I think, a reasonable job without strong definition from industry, and we're able to identify some of the problems ourselves and to get some people that are very good at it. Ken Williamson asked when we're going to get more new people in? He's tired of looking at the same old faces. I think because we've got some very interesting problems, that's going to excite and bring in some new research people. But it's going to have to be a concerted effort with industry to bring in these people and get their new ideas and approaches in solving some of our old problems.

Vince Zodiaco, Oxbow: I think this program is working very well, as evidenced by the discussion in this room. Dr. Jelacic, speaking for our company, we would like to continue in the direction that this program is going now. I don't want any fast-breeder-reactor-like visions in the geothermal industry. I've been there. We don't want that. What we want is good research aimed at solving near-term problems, whether they're downhole or in energy conversion. I think we'd want to go in the direction that we're going, and I don't think we'd want to change. I just think we need to work hard. I think we're willing to contribute and have demonstrated that. And Unocal certainly is. And I second the proposal that we need to get more people interested in the problem and working in the field.

Mike Wright: Jim Combs, what do you think of all this?

Jim Combs, Geo Hills Associates: I think we really do need to develop more geologists, geochemists, and geophysicists. And if they happen to be working in geothermal, to apply the basic knowledge that they have gained. I think one of the problems with UN-type schools is the people are trained only to do geothermal, and they don't see the other problems, they don't see the other interactions.

I think one of the reasons that the Japanese are ahead of us in some ways, is that they spent a lot of time looking over here. We haven't spent enough time looking over there. When we go over there to make a lecture, there are six or seven tape recorders, and 14 guys with their pencils going rapidly. How often do we have their scientists here and approach it in the same fashion? They have people that are working on some of the important problems but we never try to bring them here, try to learn what they are doing. As Subir said, we don't hear the sound of information flowing toward Japan as much any longer. Maybe we ought to turn that vacuum around and get it on this side to see some of their things, because quite frankly, their geothermal R&D budget is at $150 million a year, like our budgets in the '80s, when we were doing lots of things.

Another problem is that we're spending a lot of time working on some of the same problems they're working on, but we're not talking to them about it. They claim that geothermal is not economic. Of the many trips I've made to Japan, the last one is the first time that I found out they're getting paid 10 cents per kilowatt hour for steam. If we were over here as operators getting paid 10 cents per kilowatt hour for steam, not for electricity — 10 cents per kilowatt hour, not 10 yen — we would really love it. So there's a lot of things that we could learn from a lot more interaction. I think that it has to be sort of on a one-to-one basis at first, and then can develop into broader bases.

One of our big problems now is that there are too few people interested in geothermal. I think most of them in the United States are probably sitting in this room right now, unless they had to go do something else this week. But our numbers keep getting smaller. We used to fill a much bigger room. I think a lot of that comes from our not doing as much domestically. Most of the money looks like it's going to be made overseas for the short term. Quite frankly, there aren't a lot of people being involved in those projects. It's like Dick Benoit mentioned earlier, the three or so in each of the groups here in the United States. You know, there's not a whole lot more over there because firms are using consultants, they're hiring the New Zealanders, or Japanese, French, English, even the Australians. We're not even taking our own people to do some of these things because, "Well, we can get those people for $350 a day. It cost $650 a day for a U.S. guy to go there."

I think times are going to get tougher, but there are going to be some possibilities to do a lot of things differently. If deregulation of the electric industry really comes about, there's going to be a new window of opportunity. We're going to see some little entrepreneurial groups come around because the big guys already have a commitment. And that commitment is for the next several years, getting some large power plants on line overseas. And their overhead structures are probably such that they're not going to be interested in 20 megawatt, 30 megawatt power plants. Those may be the only kind we can finance in the U.S.

Bob Creed, Department of Energy, Idaho Field Office: My perspective is quite different from most folks in this room. I manage national security programs and environmental technology programs, as well as geothermal. The same sort of problems about how to get research and technology development meshed are apparent in those areas. In the environmental world, what Clyde Frank (DOE Deputy Assistant Secretary of Technological Development) finally did was separating his work into true research funded by Energy Research at DOE, and technology deployment, which basically is results that are ready to go.

I've been sitting here this afternoon thinking "Wouldn't it be nice if we could do that, if industry put up half the money and DOE put up half to actually deploy technology?" But we already do that in the Geothermal Technology Organization. "Well, why don't we free up money for pure research?" Well, we already have that in terms of the Research Solicitations.

So we already have many tools at our disposal to get at some of the problems we're talking about.

Why we don't have more fresh blood in this program? When I talked to the environmental people involved in fracture flow and explained some of the geothermal issues, they were real excited about it and would like to get involved with it. But it's very difficult to break into this geothermal research world. For example, if you bring a researcher in, and you're talking with business and industry folks who they want stuff they can use right now, the project has got to be business-oriented. Why would that researcher want to deal with those barriers, when he can get money from the environmental world for pure research and they just leave him alone to do what he wants?

So it's a difficult situation. The problems that we have are very attractive for people that want hard, challenging problems. But on the other hand, we don't seem to have the "culture" that encourages that kind of free-form approach to problem solving, with long-term goals and acceptance of different people and their ideas in the community here.

Gerry Huttrer, Geothermal Management Company: I am a firm believer that if you don't know where you're going, you'll end up somewhere else.

I think there can be a mix here of long term and short term goals. I think there always has been. Japanese culture as I know it is very focused on the long, long, long term, and they have a great deal of patience in everything they've attempted and done over the centuries. Americans are very "now" oriented with respect to business and profit, and we are all motivated to getting it done "in a New York minute." I do feel that we, in the geothermal industry, need to do a better job of our long-range planning and to actually identify and describe and characterize a few well chosen long term goals. By long term I mean four to six years for objectives. And these should be dynamic, changing, rolling objectives, but not dramatically changing objectives. However, we have to acknowledge the style and character of our business motives, that is, short term that we have problems that need to be solved tomorrow. And within our long term objectives, we need to identify milestones or focal points that need to be studied on a smaller range.

This is all very idealistic. I'm afraid that what I'm proposing probably is going to have major stumbling blocks because we don't have enough money or really enough people. We can and must mix the two. We need to have a very broad overall picture of where we want to be in five to ten years, and within that we need to continue with focused projects, and even <u>sub</u>-projects. But I don't know how to solve the problem of not enough researchers and perhaps not enough money.

Bill Teplow, TransPacific Geothermal: We're one of the few developers here along with Oxbow, and Unocal. I wanted to first of all say that the focus of the DOE funding for research for the small developer as far as TransPacific Geothermal's perspective has been very effective. We have participated with DOE in a number of geothermal exploration programs, including slim hole drilling and applications of advanced controlled source magnetotelluric exploration efforts. The DOE contribution has been absolutely critical to TransPacific as a small developer in progressing with particular projects that we would not be able to do on our own. And incidentally, as far as the MT-CSAMT program goes, we used some technology in collaboration with Zong Engineering which used a state of the art MT-CSAMT system that was developed in cooperation with the Japanese. So that's an example of direct application of Japanese technology for the benefit of American exploration efforts. So, the DOE program has been extremely effective in our specific exploration development projects.

I'd also like to ask a specific question. Mike, you and the panelists listed some very specific research topics that should be attacked. One item that I didn't hear which I'm curious about is whether horizontal drilling, so successful in oil and gas, could be applied to geothermal. As far as I know it's not been tried or pursued in the U.S. Is there a major increment of productivity that we could expect from horizontal drilling, and is it something that we as a group, including the DOE, should look into and pursue?

Lou Capuano: Well, my attitude in horizontal drilling is that in oil and gas it's great because it follows an oil bed or gas bed. In geothermal where temperature increases with depth, whenever you go horizontal, you've got to be happy with the temperature at that particular point. And if you're happy with the temperature, it's usually hot enough for geothermal uses, then you don't have any tools that can go horizontal at that depth. All the conventional horizontal drilling technique tools are good to only about 250 to 350° F, max.

Bill Livesay: One thing that may increase use of horizontal drilling in geothermal is the work that Kern Steel (or Geo-Cool, whichever name they want to use) is doing on insulated drill pipe. This may allow us to get tools to bottom, and operate in temperatures where they are at least comfortable. We can get temperatures at the bottom of the hole less than 270° F, which means we can use motors and uninsulated tools that at the present time we can't. The point is, if they're successful, it will allow us to do things in the hole right now that we cannot do. I think that has a chance to enable horizontal drilling. Or, if you think you have a laminated structure where you could penetrate more fractures by going horizontal or at least well off-vertical, I think that's going to be possible.

Bill Teplow: A lot of times in vertically-partitioned or geothermal reservoirs controlled by vertical structures, the horizontal gradients are much higher than vertical gradients, and so this would push in the direction of trying to apply horizontal drilling, as an exploration technique, of redrilling in case a first leg that is unsuccessful. Or as a technique of increasing productivity by following particular vertical fractures as opposed to the oil and gas strategy of following basically horizontal strata.

Larry Kukacka, Brookhaven National Laboratory: I'd like to speak as a researcher and as the manager of a research group. I'd like to address several of the topics mentioned so far.

One is the availability of foreign publications. There's a DOE publication that comes out on a monthly basis from the Technical Information Division at Oak Ridge. I don't remember the exact name, but basically it's a summary of all of the abstracts. All of the papers given at this meeting will be abstracted in English in that publication, and there are publications from Russia, Japan, Iceland, Australia, and New Zealand. I'm sure they're available to anyone here. There are instructions on how to get copies of the papers. This is a channel for getting access to some of these publications.

Second, regarding education. We've had three postdocs over the last four years. One was from New Zealand, one from Australia, and one from Iceland. Each summer over the last two or three years, we've had an industrial person from Japan who spent two or three months with us. Why don't we have any U.S. people? If one wants to make a commitment for a postdoc now, for starting in the fall, one has to be able to demonstrate support for that person over the next year. We really don't know what our budget is going to be for this fiscal year. How can we project — we prob-ably won't know what next year's going to be until at the earliest, October or November, so how can we make a commitment to a postdoc for a year, which is literally the minimum commitment you could make to an individual. Even then, we're subject to our budget being <u>changed</u> after we make that commitment, and that means you have to find alternate funding for that person. So that's a problem.

In the meantime, the foreign visitors we had during the summer will go back to their countries with the technologies that they worked on while our technology-transfer people are trying to figure out can we apply for a patent. Even if we do, we're not going to get foreign patent rights; the visitor has already patented this material in their country — I can show you some of the patented products.

We have seven people working on geothermal programs, none of whom is working on it full time. If we had to commit our budget solely to individuals, we would probably have only three people working on the program. Moreover, the roots of all the work we have done in geothermal — with regard to cements, lost circulation control materials, or elastomers — the roots came from other programs — other Department of Energy programs, Defense programs, Transportation programs. And people, both in our laboratory and in the DOE Geothermal Program, were able to see the potential for that work being extended to geothermal. For example, we were making cements for highway bridge decks, and now we're making CO_2 resistant lightweight cements that Unocal is going to use in Indonesia. Cross-fertilization is extremely valuable.

The problem of long term research: First, at our laboratory, some people question whether Brookhaven should be involved at all in geothermal because we're on the East Coast. It is obvious that there no geothermal energy other than heat pumps on Long Island. Secondly, the budgets. Our budgets come in one-year cycles, and the amounts go up and down. Our budget for materials research this year is 25% less than it was last year, even though the DOE Geothermal Program budget is relatively constant at $30 million, and Materials Research is given one of the higher priorities established by the GEA. Our budgets tend to fluctuate, and this is very difficult in trying to keep staff. We can't make commitments. Marcelo Lippmann mentioned this. How can we attract a Material scientist and tell him or her to risk his career on the basis of some Congressional action likely to happen in six months?

There's another stone I want to throw. This one at the geothermal industry. (You all know I normally don't talk like this.) I think we've worked with industry as much as any of the National Laboratory groups. When we first got involved with the industry, Jim Bresee was the director of the DOE Geothermal R&D program. One of the things he wanted us to do was to test materials in the field as quickly as possible, and I think that within a month we had made arrangements to test The Geysers, the Salton Sea, Taiwan, Iceland, Raft River. We covered the gamut, and I think that's basically how we got involved in geothermal: we impressed Jim on our ability to respond to some of these things. But over the years, we found that industry will come to us and say, "We have a corrosion problem with component A." Fine, they want to do some testing. And we will formulate some materials, send them samples, and they're going to test them.

And then, often, we don't hear a thing and never get the results back. Sometimes we've been told the company can't afford to have anybody go up and look at the samples. Now they've made a commitment, and they've also made a financial commitment. They've supplied test facilities, but quite often their priorities change. But we've spent a number of months doing something and we never get any response. Even if that information isn't valuable to that particular company, it may be of value to another company.

There's also a question of competitiveness between companies. We've talked to companies about cements. We thought maybe we could get a GDO program going between this company and that company, but they come say "No, we don't want to work with them — they may be a competitor." But both companies then still have the same common problem about which I hear people say we should pool information. I think that's good, but I don't think realistically it's going to happen. It will happen to a point, but once it gets down to, "I'm a competitor of yours," then I'm going to draw back into my shell. I think it's human nature.

There are a lot of concerns and problems, how one adjusts to them I'm not sure. But I do think we *need* more money. Secondly, we need more communication between the Laboratories. I think we have to market ourselves to Congress better. The fact that Brookhaven is an energy research laboratory, and Sandia is defense laboratory, and NREL is a renewable energy laboratory, should not necessarily be impediments for us to work together on a common problem.

Mike Wright: Now we have to wrap up. I hate to cut off the discussion. There've been a lot of good things here. But I'd like to just give the panel members a chance to respond for about three minutes each.

Subir Sanyal: My area is reservoir engineering. The main frustration is that while we have a lot of tools, software, and techniques, we don't have the field information from wells. There's nothing DOE can really do about it because DOE can't go around drilling wells for developers. But what DOE can do is invest money in better logging technologies so we try to learn whatever we can from the well we are drilling today.

Also, there are areas where some fundamental research should be done, for example, in definition of fractures and description of the fractures and fracture networks. The technology we use today is called the Warren-Root model, developed in the oil fields in 1960 or 1961. It is a set of cubic matrix blocks separated by fractures, which is very mickey-mouse. That's all we have to work with. But in the nuclear waste isolation business, they have developed better fracture definition and description techniques. Therefore, they are more confident in the projections they make. That's the kind of long term research that I think DOE could help us with, because no developer has the time or the manpower to do that. The question, "What is short term and what is long term?" really is a matter of judgment and the necessity of the moment. Therefore, I believe GEA and DOE could work together and keep a close watch on industry's needs both in the short and long term. Sometimes what is short term today may become long term tomorrow. For example, Unocal has a patent on pH modification technology. Without that, a lot of the fields in the world cannot be produced successfully. Like the Tiwi field, that has a lot of silica scaling problem. And yet, the idea for the pH modification technology came from Lawrence Livermore lab in 1976, when they were working on the Salton Sea project. Unocal developed the technology, patented it, and everybody benefits from that. So, I think DOE needs close cooperation with industry through GEA, in defining short term goals and long term consequences and setting priorities on what should be done today and what should be done tomorrow.

Regarding manpower and getting new blood in the business, I think it's tough luck. I cannot see young people coming out of college, joining the geothermal industry today. We don't have enough domestic growth and overseas, companies like Unocal, CalEnergy, and Calpine will find it cheaper to get local people, it's much easier. They're getting good education and they go to Iceland, New Zealand, and Italy where they're getting their masters degrees, and PhDs. Therefore, I don't think we have much hope to see a lot of new blood in this business. So we'll have to live with the people we have.

Tim Anderson: I would conclude by saying that the one thing that will address a lot of the problems we've talked about is growth in the industry. I think that industry is poised to grow. There's a lot of opportunity for new geothermal power generation and expansion in the power markets worldwide. Growth will bring benefits to all parts of the geothermal community.

I reiterate that one of the things that really holds us back is the inability to drill higher-rate, more productive, wells and to drill fewer low-rate, non-productive wells. There are good technical resources out there to address these needs. For example, many things have been developed in the years since we worked on seismic reflection, that are still waiting to be applied at geothermal projects.

On the long term, everyone agrees that there's a need for a long term strategy and a long term program. Our industry outlook is always, "What's going to happen tomorrow morning? We can't have the resources to address those short term needs unless there's someone out there with a long term point of view. The challenge on the long term side is accountability and how do we make sure that our dollars are being spent effectively and that we're building the right expertise on the long term side? I think that we should be optimistic. Growth in the industry will bring new people and will bring more stable funding for the long term.

Lou Capuano: I think what we need are long range goals, along with, hopefully, short term milestones that will help us see some success and help us get to the long range goals. I do think that the DOE and GEA need to associate more closely, so we can share more, to help educate all of us in industry to solve the problems that we have been encountering individually and collectively, so that we can pass the information on to each other and that way help the industry grow.

Bill Livesay: There is a service for delivering abstracts of foreign papers and things of that nature called the Tulsa University Abstract Service. They take papers from German, Japanese, and other languages, and deliver just abstracts in English. A number of your companies already subscribe to that service. It's both an online and a paper service.

The objectives we set may be based on dollars, but ultimately they must be brought down to technical questions you can work on. You analyze what your objectives are and then you identify the roadblocks. If you can't solve the biggest roadblock, then start to think maybe you have a bad idea.

No matter how good something looks it's new, don't get discouraged if it isn't picked up next week. The first PDC bit was built in 1971, and barely by the late 1980s was it really an accepted product. It takes about 15 years to accept a technology that has been proven. If you don't believe it, go back and look at some of the casing materials you have used, or some of the cementing practices you have used, that you now think are viable. It took a decade before people really started to pick up much of what we use. Part of this is that we have a habit of picking up a stone and polishing it about five years before we really accept it. An example of that is cement plugs done with foam cement. They have been doing foam cement jobs for 25 years in Bakersfield on a routine basis. But we in geothermal won't put a foam cement plug in the hole, because we screwed one up someplace along the line and it blew out.

Long ago I worked for Dresser. We were trying to find ways to build journal bearings in roller cone bits. I thought, "There has got to be somebody out there that really knows how to do this." So I went to Battelle, to the Franklin Institute, to a company called MTI in Albany, NY, to MIT. I went to eleven different places. I came back and told my colleagues, "Guys, we are the damn experts!"

There is not some holder of the magic wand out there who is going to come to wave the wand and make all our problems go. Because, like I told the guy at the Franklin Institute, "Well, it's an inch wide and two across for diameter. We put 40,000 lbs on that and run it at 150 RPM." And he said, "You can't do that." I said, "Well that's really unfortunate. We do it about 50,000 times a year. So somewhere between your answer and reality, we are not communicating."

We concluded that we at Dresser were the experts. We did it with brute strength and awkwardness, but it worked. Look at how long it took journal bearings to be accepted. Everything has a ramp-up period in this industry, where you have to sell to some of the most stubborn people in the world. (Much laughter.)

My last comment is based on what's going to happen in this industry over the next few years. Just make sure you keep your passport inside your breast pocket.

Carl Paquin: To conclude on the energy conversion area. I would like to commend DOE on their focus on The Geysers, for example. It has been a long-term effort that is paying off. We are seeing the difference at The Geysers. We understand the reservoir a lot better and the reservoir decline has been really helped. The innovative and creative ideas are working, such as bringing in the Lake County waste water.

I again want to emphasize the need for both long term and short term goals. I would also like to commend DOE and encourage them to continue to use their advisory groups and working groups. Where DOE can help the National Labs is to help them with a long term commitment in the longer term goals. And then on the other side, maybe we in industry, through co-funded projects, can focus on our shorter term needs. Larry Kukacka is quite right, that industry's issues change, if not by the month, then every year or two. The issues whip us back and forth. Industry should focus on the short term needs and working with DOE or the National Labs to get some problems solved. Then, help the National Labs be assured that there is going to be a tomorrow when they make multi-year commitments to interns or postdocs. That is where the longer term focus of DOE could have the best bang for the buck.

So we need a balanced program. I would encourage DOE to use its working groups to set specific short term <u>and</u> long term goals, preferably measurable goals, so that industry can work with Washington and show specific successes that we can all agree upon.

Mike Wright: A few more things and we will end. I would like to thank the panel. And, I want to thank everybody here. We have sat here now three hours, the discussion has been very lively, and I think very profitable. I really appreciate the time that everybody spent. Thank you. Allan Jelacic has a final wrap-up for us.

Allan Jelacic, Director, DOE Office of Geothermal Technologies: Thank you Mike. I promise I won't take very long. I have gotten some requests for copies of the presentation that I was scheduled to give yesterday, which we scrubbed for lack of time. It is unfortunate that I couldn't deliver the presentation yesterday, because it covered a number of the topics that were raised by this group. Conversely, today's discussion — which has been very lively and fascinating to me — would have helped to crystalize some the remarks that I would have made in my presentation. Let me just cover a few key items that I would have mentioned:

<u>I'm calling for working with industry particularly GEA, which speaks for the industry — to develop a strategic plan for geothermal research</u>. It is amazing to me that the DOE Geothermal Program has existed as long as it has without real concerted strategic thinking on the part of the stakeholders — you and I, industry and the National Labs and Universities — involved in the geothermal research. We don't have anything that I can give to my management, to pass out when I brief Congress or other public functions, as "The Plan for Geothermal" and what it promises for the future both in the near term and the long term.

The bottom line in my presentation was a call for cooperation, consultation, workshops in strategic planning to identify the problems that we need to focus on, goals that we need to set to make geothermal fulfill the promise that we all know that it has for ourselves and the nation. I'm pleased to hear a number of people in the audience, particularly Tom Sparks and Subir Sanyal, make those points over and over again. I think it is essential that we need to focus on what our immediate plans are for this research program and for geothermal energy as a whole.

<u>On the allocation of staffing resources</u>: We talked about using part of people's time at National Labs, trying to get more focused, getting new blood into the program, focusing more people for full time work within the research effort. This is an area of great concern right now. Our current system is a descendent of our approach that began in the 1970's, when the DOE Geothermal Program had a budget of about $150 million a year. We could afford to

spread the wealth around to a number of different places, especially to our National Labs. Today, we don't have that luxury. We don't have anywhere near that amount of funding, and yet we retain the same approach to doing the research. Right now we have eight National Labs involved in the Geothermal Research Program. By contrast, the Photovoltaics program, with approximately three times our budget, has three National Labs and basically just two that get the lion's share of that program's funding. So one has to look at whether we are approaching funding of the Laboratories in the proper manner. I have gotten a pressure from our higher management within DOE that we are not making the best possible use of the Lab resources.

One approach we could take is to focus on "centers of excellence," or "lead labs." We are seriously looking at that option. I would personally not want to cut the ties that exist with some of the Laboratories. We've built up a great deal of expertise with certain researchers who can provide strong support to our Research Program. We have to look at options to retain their services in the Program. That is a task that is going to take some delicacy on our part in maintaining some balance in approaches to getting the job done.

We need to focus the Geothermal Research Program on problem solving with definite goals. We need to work together more closely than we have in the past. We have started on that, with the series of GEA-sponsored workshops that Mike mentioned yesterday. We have had five of those with one more still to come. I think we need to go beyond that and perhaps set up permanent groups who meet and do the strategic thinking that will guide the program not only next year, but for many years to come.

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Finally, I want to remind you to fill out your evaluation forms. I really do value your opinion of the review and what we could do better. I would like also to recognize the efforts of the people who helped organize and conduct this Program Review, our support contractor Princeton Economic Research, Inc. (PERI), of Rockville, Maryland, and their staff who've been at the meeting, Cynthia Simonson and Dan Entingh. Thank you all for your attention.

Appendix

GEOTHERMAL PROGRAM REVIEW XV
Evaluation Comments

Suggestions for future conference topics/sessions (including keynote speakers and presenters):

- Although the geothermal industry is centered in California, there was too much emphasis on the effects of California deregulation on California geothermal.
- Focused session/invited speakers.
- Have sessions which respond to the items addressed in the panel discussions.
- Have/add a session on DOE's assistance to industry's international projects.
- Environmental monitoring, reservoir enhancement.
- Overseas applications, challenges, opportunities.

Suggestions to improve future conferences:

- Put DOE personnel in more of a leadership role in the conference to strengthen industry's regard for them and interaction with them.
- Develop "plans" for discussion and goal setting.
- Keep them in the San Francisco Bay area.
- Look into the quality of the rooms. I was not overally pleased with the quality of my room.
- Hold the meeting at a hotel near the BART System. This hotel was too far from a BART Station; one has to take a bus or cablecar to get here.
- Have tighter control of scheduled talks. Sessions did not begin on time; speakers often went way over their allotted time which is unfair to speakers who follow.

Other Comments:

- The Rockville, Maryland firm did an outstanding job in arranging the hotel, conference rooms, food, and registration. The staff managing the on-site logistics were superb.
- Loved the hotel - a very convenient set-up. Meeting rooms near lobby, good service, good food.

- Would like to see a goal of the geothermal program to be determined in a way to ensure decline in a vapor dominated resource is reduced to minimal or no decline, thus dramatically improving the economic viability of geothermal in competition against other technologies.

- Screens not high enough; rooms made too dark; strongly discourage concurrent sessions. Berkeley has better hotel accommodations.

- Food service was generally excellent but excessive (too much of a good thing, better to economize). The conference coffee was lousy.

- Future hotel facilities should have a business center with fax, pc docking, and printing capabilities.

- The pocket agenda was a great idea. Do it again next time.

- 20 minute presentations and slides are a proven method, continue it.

- This industry needs more interaction/cross-fertilization between different segments (reservoir, powerplant, drilling, etc.), not less. Parallel sessions makes this worse, not better.

- I was very happy and pleased with the presentations and the speakers.

- Try to avoid holding the meeting during Easter week.

- With concurrent sessions, a greater effort should be made to stay on schedule. The chair of one session spoke for 40 minutes in a 20 minute slot.

- Suggest you take credit cards for registration.

- The chairs were torture on my back.

- As someone who has been working in the geothermal industry for one month, the conference gave me an excellent overview and basic understanding of the field. Personally, I would have liked to hear more about the U.S. geothermal industry's international projects.

GEOTHERMAL PROGRAM REVIEW XV

"THE ROLE OF RESEARCH IN THE CHANGING WORLD OF ENERGY SUPPLY"

MONDAY EVENING, MARCH 24, 1997

7:00 - 9:00 PM	**OPENING RECEPTION AND CONFERENCE REGISTRATION**

TUESDAY, MARCH 25, 1997

8:00 AM	**REGISTRATION AND CONTINENTAL BREAKFAST**
9:00 - 11:45 AM	**OVERVIEW SESSION**
9:00 - 9:15 am	**Welcome and Announcements** Allan Jelacic, Director, Office of Geothermal Technologies, U.S. Department of Energy
9:15 - 9:35 am	**U.S. Department of Energy Office of Utility Technologies Keynote Presentation** Allan Hoffman, Acting Deputy Assistant Secretary, Office of Utility Technologies, U.S. Department of Energy
9:35 - 10:00 am	**Industry Keynote Presentation** Research to Die For: R&D Budgets in the Deregulated Electricity Markets R. Brent Alderfer, Commissioner, Colorado Public Utilities Commission
10:00 - 10:30 AM	**BREAK**
10:30 - 10:55 am	**Summary of GEA Workshops --** **Review of DOE's Geothermal Research Program** Phillip M. Wright, Senior Associate Director, Energy & Geoscience Institute, University of Utah
10:55 - 11:20 am	**Industry Keynote Presentation** Is Research Necessary? Dick Benoit, Resource Manager, Oxbow Power Services, Inc.
11:20 - 11:45 am	**Office of Geothermal Technologies Keynote Presentation** Allan Jelacic, Director, Office of Geothermal Technologies, U.S. Department of Energy
11:45 AM - 1:30PM	**GEA LUNCHEON - CALIFORNIA'S RENEWABLES PROGRAM AND THE ROLE OF THE CALIFORNIA ENERGY COMMISSION** Michal C. Moore, Commissioner, California Energy Commission

1:30 - 5:30 PM	EXPLORATION & RESERVOIR TECHNOLOGY	ENERGY CONVERSION
1:30 - 1:50 pm	**Overview**, Marshall Reed, Office of Geothermal Technologies, U.S. Department of Energy	**Overview**, Raymond LaSala, Office of Geothermal Technologies, U.S. Department of Energy
1:50 - 2:10 pm	**Borehole EM Tool**, Michael Wilt, Electromagnetic Instruments, Inc.	**Structured Packing in Unit 11 at The Geysers**, Desikan Bharathan, National Renewable Energy Laboratory
2:10 - 2:30 pm	**Isotopic and Noble Gas Geochemistry in Geothermal Research**, B. Mack Kennedy, E.O. Lawrence Berkeley National Laboratory	**Condenser Retrofit at Unit 11 at The Geysers**, Ken Nichols, Barber-Nichols, Inc.
2:30 - 2:50 pm	**High-Temperature Water Adsorption on The Geysers Rocks**, Miroslaw S. Gruszkiewicz, Oak Ridge National Laboratory	**The Biphase Project at Cerro Prieto**, Lance Hays, Douglas Energy

3:00- 3:30 PM **BREAK**

	EXPLORATION & RESERVOIR TECHNOLOGY (CONTINUED)	ENERGY CONVERSION (CONTINUED)
3:30 - 3:50 pm	**Volatility of HCl and the Thermodynamics of Brines during Brine Dryout**, J. Michael Simonson, Chemical and Analytical Sciences Division, Oak Ridge National Laboratory	**Binary Cycle Modeling**, Keith Gawlik, National Renewable Energy Laboratory
3:50 - 4:10 pm	**Tracing Fluid Flow in Geothermal Reservoirs**, Peter E. Rose, Energy & Geoscience Institute, University of Utah	**Geothermal Materials Development at Brookhaven National Laboratory**, Lawrence E. Kukacka, Brookhaven National Laboratory
4:10 - 4:30 pm	**Fracture-Matrix Interaction**, G. Michael Shook, Idaho National Engineering and Environmental Laboratory	**Design of the Geothermal Energy Conversion Facility**, Chuck Kutscher, National Renewable Energy Laboratory
4:30 - 4:50 pm	**Development of Inverse Modeling Techniques for Geothermal Applications**, Stefan Finsterle and Karsten Pruess, E.O. Lawrence Berkeley National Laboratory	**Metastable, Supersaturated Turbine Expansions**, Gregory L. Mines, Idaho National Engineering and Environmental Laboratory
4:50 - 5:10 pm	**Water Injection into Vapor- and Liquid-Dominated Reservoirs: Modeling of Heat Transfer and Mass Transport**, Karsten Pruess, Curt Oldenburg, George Moridis and Stefan Finsterle, E.O. Lawrence Berkeley National Laboratory	**Advanced Biochemical Processes for Geothermal Brines - Current Developments**, Eugene Premuzic, Brookhaven National Laboratory
5:10 - 5:30 pm	**Process Chemistry to Reduce O&M Costs**, Paul Kasameyer, Lawrence Livermore National Laboratory	**Geothermal Power Organization**, Kent Scholl, National Renewable Energy Laboratory

5:30 PM **ADJOURN FOR THE DAY**

WEDNESDAY, MARCH 26, 1997

7:30 AM **REGISTRATION AND CONTINENTAL BREAKFAST**

8:30 - 9:50 AM	**THE GEYSERS**	**DRILLING**
8:30 - 8:50 am	**Overview**, Marshall Reed, Office of Geothermal Technologies, U.S. Department of Energy	**Overview**, David Glowka, Sandia National Laboratories
8:50 - 9:10 am	**Geologic Research at The Geysers**, Jeffrey B. Hulen, Energy & Geoscience Institute, University of Utah	**Status of the NADET Program**, Carl Peterson, NADET Institute, Massachusetts Institute of Technology
9:10 - 9:30 am	**Steam-Water Relative Permeability in Geothermal Rocks**, Roland Horne, Stanford University	**Overview of the Sandia Drilling Program**, David Glowka, Sandia National Laboratories
9:30 - 9:50 am	**Decline Curve Analysis of Vapor-Dominated Reservoirs**, David D. Faulder, Idaho National Engineering and Environmental Laboratory	**Core-Tube Data Logger**, Joseph Henfling, Sandia National Laboratories

9:50 - 10:20 AM **BREAK**

	ENVIRONMENT, GEOTHERMAL HEAT PUMPS, AND DIRECT USE	**DRILLING (CONTINUED)**
10:20 - 10:40 am	**The Southeast Geysers Effluent Pipeline and Injection Project**, Mark Dellinger, Lake County Sanitation District	**A Self-Propelled System for Hard-Rock, Horizontal and Coiled Tube Drilling**, Denis Biglin, APS Technology
10:40 - 11:00 am	**The Geothermal Heat Pump Consortium's National Earth Comfort Program**, Paul Bony, Geothermal Heat Pump Consortium	**Superhard, Nanophase Cutter Materials for Rock-Drilling Applications**, Gary Tompa, Diamond Materials, Inc.
11:00 - 11:20 am	**Geothermal Heat Pump Research at Oklahoma State University: An Integrated Approach**, Marvin Smith, Oklahoma State University	**Nanocrystalline, Superhard, Ductile Ceramic Coatings for Roller-Cone Bit Bearings**, Fereydoon Namavar, Spire Corporation
11:20 - 11:40 am	**Direct Use Activities**, Paul Lineau, Geo-Heat Center, Oregon Institute of Technology	**Development and Testing of a Jet-Assisted Polycrystalline Diamond Drilling Bit**, David Pixton, Novatek

11:45AM - 2:45 PM **LUNCHEON/PANEL DISCUSSION: REVIEW OF GEA WORKSHOPS AND REQUEST FOR FURTHER INPUT**

2:45 - 3:00 PM **Closing Remarks**
Allan Jelacic, Director,
Office of Geothermal Technologies, U.S. Department of Energy

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