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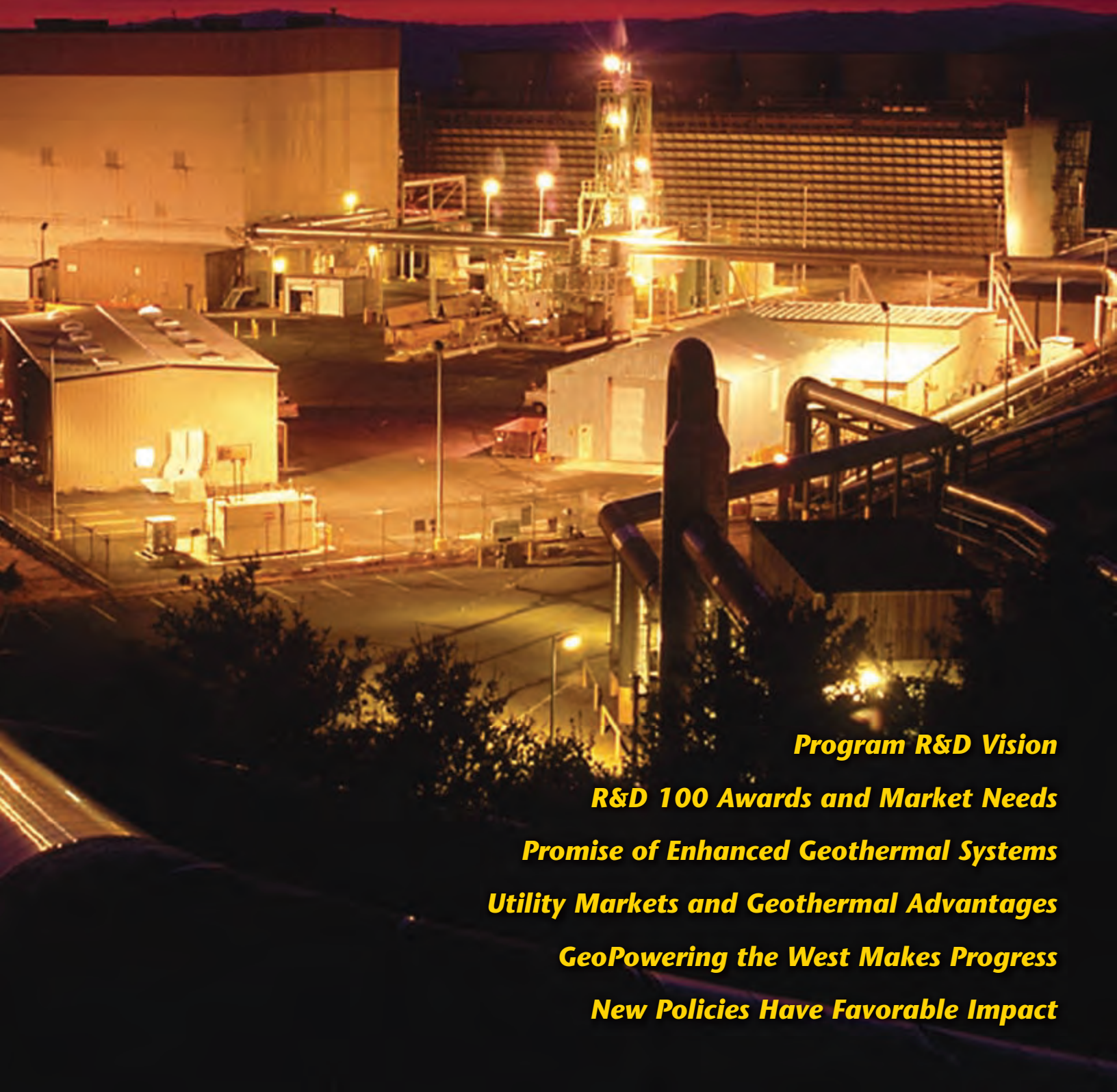
U.S. Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

GEOTHERMAL TODAY

U.S. Department of Energy *2005 Geothermal Technologies Program Highlights*



Program R&D Vision

R&D 100 Awards and Market Needs

Promise of Enhanced Geothermal Systems

Utility Markets and Geothermal Advantages

GeoPowering the West Makes Progress

New Policies Have Favorable Impact

Cover photo - Sonoma geothermal power plant at The Geysers. Credit - PG&E, now Calpine.

About "Geothermal Today"

The geothermal energy potential beneath our feet is vast. This tremendous resource amounts to 50,000 times the energy of all oil and gas resources in the world. And geothermal energy is clean; it represents a promising solution for the nation and the world as they become ever more concerned about global warming, pollution, and rising fossil energy prices. Furthermore, increased development of geothermal energy gives people the potential to gain better control of their own local energy resources and use a secure, safe, domestic source of energy.

Today's U.S. geothermal industry is a $1.5-billion-per-year enterprise involving over 2800 megawatts (MW) of electricity generation, about 2000 MW of thermal energy in direct-use applications such as indoor heating, greenhouses, food drying, and aquaculture, and over 3,700 MW of thermal energy from geothermal heat pumps. The potential for growth is substantial.

The international market for geothermal power development could exceed $25 billion (total) for the next 10 to 15 years. At the present time, U.S. technology and industry stand at the forefront of this international market.

However, the cost of geothermal heat and electricity remains higher than the least-cost conventional technologies and the near-term market for geothermal energy is uncertain, presenting a major challenge for the U.S. geothermal industry. Significant work is still needed to lower costs and create incentives to spur the market for geothermal heat and power. The U.S. Department of Energy (DOE) Geothermal Technologies Program (the Program) is committed to supporting the geothermal industry with research and development to reduce costs and help geothermal energy fulfill its potential. This issue covers highlights from 2003.

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DOE Geothermal Technologies Program R&D Vision

The Promise of Geothermal Energy

The Earth houses a vast energy supply in the form of geothermal resources. Domestic resources are equivalent to a 30,000-year energy supply for the United States. However, only about 2,800 megawatts of geothermal power is installed today. Geothermal has not reached its full potential as a clean, secure energy alternative because of concerns or issues with resources, technology, industry commitment, and public policies. These concerns affect the economic competitiveness of geothermal energy.

The U.S. Department of Energy (DOE) Geothermal Technologies Program (the Program) has a vision of geothermal energy as the nation's environmentally preferred baseload energy alternative. Geothermal power plants have a proven track record of performance as baseload facilities, with capacity factors and availabilities frequently exceeding 90 percent. Modern energy conversion technology enables geothermal facilities to operate with only extremely low emissions. These factors, combined with the considerable size of the resource, argue for a significant share of geothermal energy in the future U.S. energy economy.

Strategic Directions

Only a small fraction of the nation's identified geothermal resource is economic today, with the shallow, high-temperature resources typically first to be developed. Exploration and resource verification can be uncertain and expensive. Power plant development and capital costs are often greater than conventional alternatives. Exploration and drilling costs must be lowered to bring more resources into production. Discovering, accessing, and developing the deep geothermal resources with lower permeability and fluid content will require significant improvements in both the technology and economics of geothermal development. The Program's goals also require addressing institutional issues that affect costs and inhibit development, such as federal leasing practices, regulations, and public awareness.

PIX 08876, Courtesy of Brookhaven National Laboratory

Dr. Eugene Premuzic, a geothermal researcher (retired) at Brookhaven National Laboratory. His research led to an R&D 100 Award (see page 7).

PIX 06152, NREL, David Parsons

Dr. Desikan Bharathan, NREL, performing research and analysis on energy conversion improvements for geothermal power plants. His research led to an R&D 100 Award (see page 4).

PIX 09054, University of Utah

Researchers conducting tracer test on Southwest Geysers Wastewater Recycling System.

Consequently, the Program has shifted its emphasis to longer-term, high-payoff research with cost-shared field applications, as opposed to nearer-term incremental improvements in technology with laboratory-based studies. *The Program's mission is to work in partnership with U.S. industry to establish geothermal energy as an economically competitive contributor to the U.S. energy supply.* The Program's goal in support of this mission is *to reduce market entry cost of electric power generated from Enhanced Geothermal Systems (EGS) to an economically competitive level*. To achieve this, the Program will focus on EGS and related technologies, demonstrating the technical viability of EGS technology by 2011.

Research and Development Vision

Working in partnership with U.S. industry, the Program's research and development (R&D) activities are organized to support both technology development and application. These activities include EGS; exploration and resource characterization; drilling and reservoir management; and power systems and energy conversion.

The Program's R&D vision is to foster the continued development of hydrothermal resources (near-term) and expand the potential for development of enhanced or engineered geothermal resources (long-term). Achieving this vision will help enable geothermal energy resources to make significant contributions to clean, reliable power production and economically feasible energy use in the western United States.

DOE's Award-Winning Geothermal Technologies Find Commercial Success

In the presence of CO_2, and hence carbonic acid, ThermaLock (left) remains unaffected for a long time, while Portland cement (right) quickly degrades.

During just five years, DOE's national laboratories have received six R&D 100 Awards for technologies supported by DOE's Geothermal Technologies Program. *R&D Magazine* annually bestows R&D 100 Awards—also known as the "Oscars of Invention"—for the 100 most technologically significant new products of the previous year. Therefore, these award-winning technologies not only represent DOE's presence at the forefront of geothermal technology research and development, but also an opportunity for successful commercialization.

Here are the stories behind these award-winning technologies—from the problems they addressed at the beginning to their bright, commercial futures.

Working Both Sides of the Turbine

Steam power plants, including geothermal power plants, work by having steam under high pressure drive a turbine blade. The force on the turbine blade is a function of both the pressure of the steam on the upstream side of the blade and the lack of pressure on the downstream side. The downstream vacuum is created by condensation of the spent steam. The problem is this: you don't want to let the steam that has already passed through the turbine build up on the backside of the turbine. If it does, the result is a pressure increase on the backside (known as back pressure), which ruins the vacuum on that side and makes it harder to pull the steam through the turbine to produce electricity. The spent steam must be efficiently condensed to enhance power production.

For flash or dry steam geothermal plants, there is another key challenge—the steam also contains hydrogen sulfide and other noncondensable gases. If these gases build up, they create backpressure and reduce power production. If they dissolve in the condensation water, the hydrogen sulfide in particular is expensive to treat. That is the challenge that Pacific Gas & Electric managers at The Geysers—the world's largest geothermal complex and one of only two blessed with dry steam—faced in 1992 and brought to Desikan Bharathan of the National Renewable Energy Laboratory (NREL).

And Bharathan was the right man for the job. A fluid-flow and heat-transfer expert, he had already designed a similar system for a different power technology (ocean thermal energy conversion… but that's a different story). The system was called "advanced direct-contact condensation" or ADCC. "Direct-contact" because cooling water mixes directly with the spent steam as opposed to being piped through heat exchangers. "Advanced" because the

NREL National Renewable Energy Laboratory

PIX 06241, Ron Judkoff

NREL's Desikhan Bharathan (right) receives his R&D 100 Award in 1999. This technology innovation improved plant performance.

geometry of the packings—plastic or metal plates to provide surface area for the steam and cooling water to mix on—are designed for maximum surface area and effectiveness.

At The Geysers, the greatest problem was occurring at Plant 11. Although Plant 11 was built to generate 110 million watts (MW), steam-field pressure losses had reduced its capacity to approximately 65 MW by the mid-1990s. Gas buildup in the condenser aggravated that power loss. In designing ADCC for Plant 11, Bharathan and colleagues at NREL used computer modeling to predict not only the most effective packing design for the plant, but also the chemicals (and their amounts) that would be in the water and those that would stay in the vapor. This important step enabled them to design an effective two-passage system that separates the noncondensable gases from the water vapor, minimizing the amount of hydrogen sulfide dissolving in the condensed water to make abatement easier.

When the refurbished condenser was installed during a planned shutdown in 1997, it was an unqualified success. It increased energy production by 5 percent and plant capacity by 17 percent, from 65 MW to 78 MW. For a business that counts fractions of percentage points as great successes, this was extremely good news. The system effectively reduced steam carryover to the gas removal system, thereby reducing costly backpressure. It also reduced absorption of hydrogen sulfide into the cooling water condensate. As a result, the amount of iron chelate used to treat the hydrogen sulfide could be cut in half — saving the plant a considerable amount of money.

PG&E sold The Geysers to Calpine, and NREL licensed ADCC for geothermal power use to Alstom, an international power generation service company. In the intervening years, Alstom went on to design ADCC retrofits for Calpine for Units 5 and 6 at The Geysers. Alstom just recently sold its North American condenser business to Connell Limited Partnership, which will merge it with their Yuba Heat Transfer business. Yuba is looking forward to aggressively promoting ADCC to the geothermal industry.

ADCC installation is even more cost effective for new facilities than for retrofits, and takes up only about half as much space as conventional condensers. Alstom had also already built condensers for two projects in Mexico, a pair of 5-MW geothermal plants at Tres Virgenes in Baja California, and four 35-MW units at Los Azufres, near Mexico City. With new geothermal plants planned in the Philippines and Indonesia, there is potential for ADCC to make a major contribution to geothermal power development, and it clearly warranted its 1999 R&D 100 Award.

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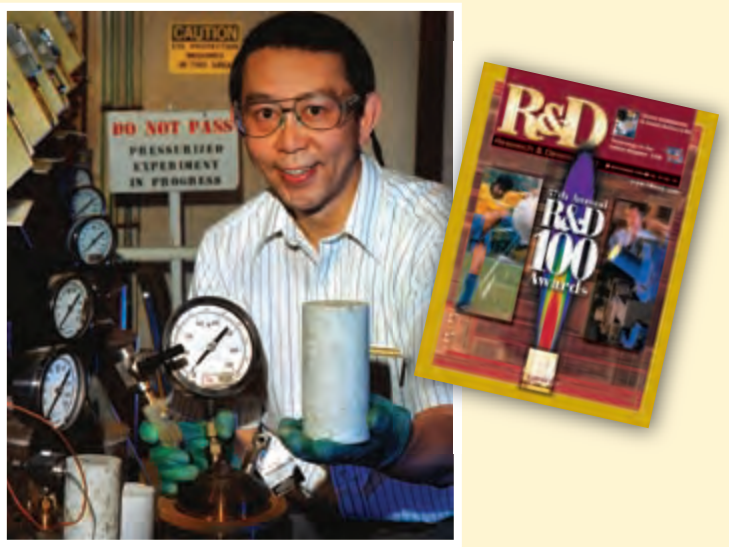

Toshi Sugama, Brookhaven National Laboratory, is shown with a sample of ThermaLock well cement.

Cementing a Growing Market

Before the turn of this century, drilling and cementing geothermal wells presented operators of geothermal facilities with a major problem. Using Portland cement—the industry standard for cementing oil and gas wells—just didn't work well for geothermal wells. The cement would not last more than a few months, and wells would have to be re-drilled and re-cemented.

This was the situation until Toshifumi Sugama of Brookhaven National Laboratory (BNL) got together with collaborators from Halliburton and Unocal to develop a new kind of cement. The cement they developed—which Halliburton has commercialized under the name of ThermaLock—not only won a 2000 R&D 100 award, it is becoming the preferred well cement for the geothermal industry, saving tens of thousands of dollars per well, and creating a growing market that today is worth many millions of dollars per year.

But why use cement in the first place? Drilling an oil, gas, or geothermal well requires drilling through different levels of rock and layers of sediment, which exist at different temperatures, have variable constituents (water, gas, brine, etc), and have different pressures and physical attributes. To isolate the wellbore from the rock and sediment, and the layers from one another requires steel casings—larger diameter pipe nearer the surface and piping of increasingly smaller diameter the greater the depth. To isolate and insulate the casings from the rock and sediment, and to keep the casings in place, cement is pumped through a feed pipe into the borehole surrounding the pipe, where it hardens to surround the casing.

There are several drawbacks to using Portland cement in wells that have the harsh environments common to geothermal wells, such as high acidity and high temperature. The first drawback is that Portland cement is based on calcium hydroxide ($Ca(OH)_2$) and calcium silicon hydrates (C-S-H), ingredients that chemically react with an acidic environment, disintegrating the cement and destroying its cement-like properties. Portland cement has low tensile strength and resiliency (i.e., is brittle, and so, it's less likely to deform without failure). Thus, under high stress, such as the thermal stress of high temperatures, it can crack and buckle.

But geothermal wells do not constitute the only hostile environment for Portland cement. Consider, for example, enhanced recovery techniques used at oil wells. For particularly viscous oils, steam is injected into an injection well to decrease the viscosity of the oil and increase the pressure on the reservoir. The temperature, however, often goes above 600°F (315°C), putting Portland cement under thermal stress and accelerating its deterioration. In other cases, carbon dioxide may be used in injection wells. This increases the pressure on an oil reservoir to force the oil to a recovery well to be pumped out. The carbon dioxide, however, will react with any water that is present to produce carbonic acid, which chemically reacts with the Portland cement and turns it into $Ca(HCO_3)_2$, which is no longer cement.

ThermaLock, on the other hand, is based on calcium phosphate hydrates, aluminate hydrates, and mica-like calcium aluminosillicates. With the appropriate slurry, this combination of materials forms a relatively hard cement with ceramic-like properties that withstands heat and that does not readily react with an acidic environment to lose its cement properties. The result is at least a 20-fold improvement for these harsh environments, with well casings being able to last up to 20 years.

ThermaLock has become a commercial success worth millions of dollars annually. Nonetheless, Halliburton considers it to be a success in a niche market. Niche because, compared with the main lines of Halliburton's well-cementing operations, geothermal use does not constitute a large market. Niche also with respect to enhanced oil recovery, because most of this recovery can safely use Portland cement. Still, this is a niche market with a growth potential that will correlate with the growth in demand for geothermal energy, and the need for enhanced oil recovery.

Thus far, ThermaLock has been used for:

- Geothermal projects in California, Indonesia, and Japan
- Enhanced oil recovery using carbon dioxide injection wells in Oklahoma
- Enhanced oil recovery using steam injection wells in Kuwait and New Zealand
- Casing repair and liner completions for a carbon dioxide flood field in Kansas
- Enhanced oil recovery using sour-gas injection wells in Wyoming (sour gas is a mixture of hydrogen sulfide and carbon dioxide, and is so-called because it is a by-product of "sour" hydrocarbon pools, which contain hydrogen sulfide and carbon dioxide
- Enhanced oil recovery using steam injection wells in California
- Off-shore oil recovery in the North Sea.

The last two of these projects used Halliburton's new foamed version of ThermaLock. To improve the original award-winning cement, Halliburton has added certain surfactants, along with the use of nitrogen gas, to produce the foamed version. This foamed version sets up the cement in a honeycomb configuration, giving it more air, making it lighter, increasing its insulating value, and making it more ductile. Thus, it is:

- Better able to withstand stress (largely because of greater ductility)
- Better applied to geothermal resources, because of greater insulating value, giving it the ability to retain geothermal fluids at higher temperatures for longer periods of time
- Less expensive, because it uses less raw material to fill the same space.

With this version of the technology, the cement and water are thoroughly mixed and forced through the feed pipe where, under a pressure of about

1,000 pounds per square inch, the mixture generates a foam with a structure akin to soap bubbles. Nitrogen gas is then forced down the pipe through a T-joint. When the nitrogen mixes with the foam, the foam flashes to a gas. The gas then sets up, creating the honeycomb cement structure.

For his part, Sugama is also improving the product in several ways, making it lighter, tougher, more ductile, and more resistant to stress and acid. In fact, he is working on improvements to make it resistant to acids down to a pH between 1.1 and 1.2. His goal is to make a cement that will enable casings of pipes to last 30 years or longer—a 100-fold improvement over Portland cement.

With these improvements from both Halliburton and BNL, we may not only see more facile geothermal applications and a growing market, we may also witness this superb concept winning another R&D 100 Award.

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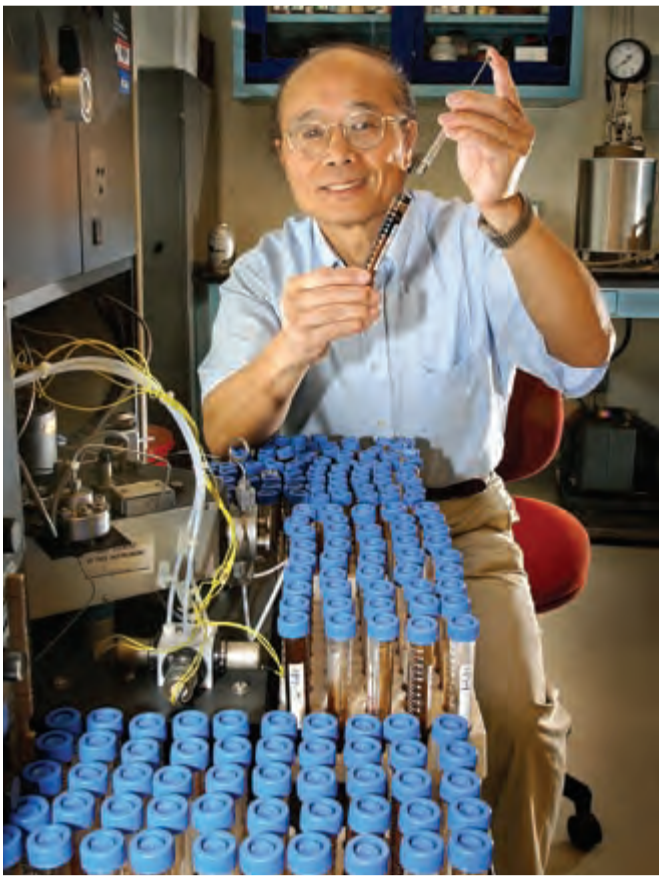

Brookhaven chemist Mow Lin, one of the inventors of the silica recovery process.

Where There's Muck, There's Money

Geothermal power potential is generally embodied in brines—hot saline water that can be brought to the surface and flashed to steam to drive a turbine. Without brine to bring the heat to the surface, the task of tapping geothermal energy is more challenging (see article on enhanced geothermal systems on page 12). But what do you do with the spent brine? Whether treating the brine for surface release or reinjecting it to help maintain the resource, as geothermal plants are increasingly doing, the brine carries with it an extra burden—dissolved minerals, particularly silica. As the brine cools, the silica precipitates out, scaling on and fouling the reinjection pumps, piping, and other equipment. Cleanup is costly and generates troublesome, frequently toxic, waste requiring disposal.

The Program turned to BNL scientist Eugene Premuzic, an expert in applying natural processes to technical challenges, for seeking a cost-effective and environmentally acceptable way to treat the precipitate waste and reduce its impact on geothermal equipment. Premuzic and BNL colleague Mow Lin, however, saw the challenge of this silica "mucking up" the equipment as an opportunity. In reviewing the options for treatment, they saw potential for producing commercial-grade silica, as well as valuable trace metals. High-purity silica is a commodity fine-chemical that is used for a wide range of products, some of which sell for as much as $100/gram.

Premuzic and his collaborator Lin started by looking at highly saline (300,000 parts per million or higher) geothermal brines, with their high-potential silica yields. The high salinity, however, also meant high content of other minerals, some toxic, as well as taking away from the purity of the desired silica. Premuzic and Lin developed systems to have groups of specialized microorganisms act on the minerals, converting them to water-soluble substances that could be easily removed. First, one consortium metabolized the arsenic and other toxics; then another the radioactive trace elements.

With DOE Program support, this system was tested on a side stream of spent brine at a Salton Sea geothermal plant in California. The system worked fine, but prompted the BNL team to expand their work, and they determined that lower-salinity brines (400 parts per million or less) might be more lucrative. Silica yields would be lower, but the purity would be higher, commanding a substantially higher price. Also, because silica's relative proportion of the mineral content was higher and the initial toxic contaminant levels were lower, the biochemical microbial treatment steps could

be skipped and the patented process could start immediately with chemical treatment of the silica.

At the recommendation of the Program, the scientists teamed up with geothermal industry economics expert Stuart Johnson to help in moving from the lab to the power plant and designed a process specific for lower salinity brines. The new low-salinity process includes a patented step for chemically inducing precipitation of the silica. This process starts with spent brine instead of sludge. And because silica is the main scaling problem for such brines, the remainder can be passed along for reinjection without concern for fouling.

The system was tested at the Dixie Valley Geothermal Plant in Nevada, and produced very impressive results—99.9 percent purity silica with higher surface area and porosity than the leading commercial product and a 60 percent yield from the available silica. The return from silica sale was calculated as being sufficient to reduce the cost of electrical production from the plant by $0.011 cents per kilowatt-hour—a nearly 20 percent reduction!

Such a return is sufficient to very significantly improve the economics of geothermal power plant operations. Also, the process was subsequently tested at two other Nevada plants, and turns out to be effective on mid-salinity-level brines, as well, so could be applied to a large proportion of geothermal power plants. Not gold from lead, but truly money from muck, silica recovery could prove a huge boon to geothermal power development and more than worthy of its 2001 R&D 100 award. The Geothermal Resources Council also awarded Premuzic a 2001 'Special Achievement' award for the work.

(Editor's note: Lin tragically died after receiving the R&D 100 Award; Premuzic has since retired from BNL, but still consults and is pursuing implementation of the silica recovery technology in the private sector; Johnson, with Caithness Energy at the time of development of the silica recovery technology, is now with ORMAT, another leading geothermal power developer.)

Survival in a Tough Neighborhood

Corrosive, scaling, and hot—geothermal brines present quite a materials challenge. Spas and geothermal power plants with relatively mild brines may get by with standard carbon-steel pipes and other parts, or simply resign themselves to frequent replacement. Power plants with stronger brines, however, call for some sort of protection to avoid continual component replacement. Cement-lined pipes are a relatively standard practice, but the cement cracks or corrodes itself, exposing the steel,

NREL National Renewable Energy Laboratory

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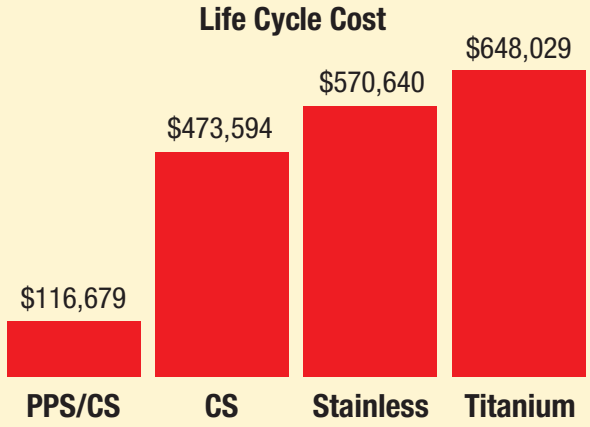
PPS coating on the left and a failed coating on the right.

limiting the duration of their usefulness. Other plants have gone to expensive materials, such as stainless steel, or titanium or nickel alloys. These resist corrosion, but are still subject to scaling. In addition to restricting flow, the scaling then promotes pipe corrosion beneath it and is hard to clean. For heat exchangers used in binary plants—in which longer-lasting materials are particularly desirable—stainless steel and alloys also have lower heat conductivity, reducing the effectiveness of the exchangers.



With his materials composition and bonding expertise, and geothermal experience, BNL scientist Sugama was the ideal researcher to take on the challenge of making geothermal plant equipment last longer. Early on, he explored various cement linings for steel pipe, but didn't find them effective. In the mid-1990s, he turned to looking for the best polymer coatings for the job. (Plastic

pipe and parts can be used in some geothermal and other corrosive environments, but not where there is high pressure or temperature, as is the case for most geothermal installations.) One polymer showed some promise, but then Sugama found that polyphenylenesulfide (PPS), which he had previously used for coating some military equipment, was the most resistant at high temperature and a highly effective choice as a coating for common carbon steel.

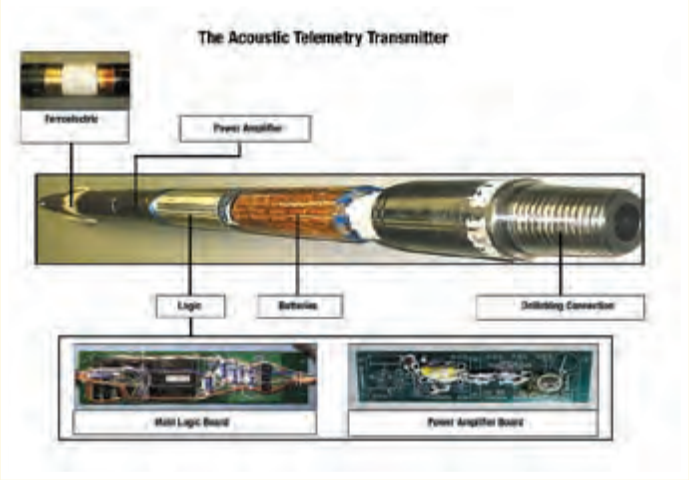
PPS is a 'thermoset' plastic, one that requires high temperature to form, and then takes on semi-crystalline structure. It can then withstand far higher temperatures than that at which it forms. It is highly resistant to oxidation, which means that it resists both corrosion and scaling. Whereas the oxide layer that protects stainless steel actually promotes scaling, very little will stick to PPS, and what little does washes off very easily. Unlike stainless and alloys, PPS-coated steel still has high thermal conductivity, so it's ideal for heat exchangers. The PPS matrix also readily accepts filler material, which can be used to enhance its properties. Sugama added carbon fiber to improve resistance to physical erosion, such as from rock particles in the brine, water droplets in high-pressure steam, or hydro-blasting—high-pressure water flow used to clean off scaling, though PPS-coated equipment needs that less often and at lower pressure than conventional materials.

Sugama first teamed up with Keith Gawlik at NREL for testing PPS, and then with Curran International for commercial application. With DOE Geothermal Technologies Program funding, Gawlik and Sugama tested PPS at several geothermal plants, including ones at Salton Sea—one of the most highly saline and corrosive geothermal resources—and Mammoth, both in California, with very good results. Based on the test results, they calculated that the life-cycle cost of PPS-coated steel would be one-fourth as much as uncoated carbon steel, one-fifth as much stainless steel, and one-ninth as much as titanium alloy.

Curran—which has provided epoxy- and phenolic-coated pipes, heat exchangers, and other components for the petrochemical industry—has added PPS to its offerings and is having excellent success with it. Most sales thus far have been in the larger petrochemical industry, but several geothermal uses are being tested and Curran has further refined filler formulations.

Sugama has continued his research and is currently developing use of nano-size particles of carbon fiber or other alternate fillers to further improve PPS composite's temperature tolerance, durability, and thermal conductivity. In particular, he expects to raise temperature tolerance above the 200ºC level frequently encountered in geothermal applications. At the same time, he is also exploring another promising polymer. Sugama clearly deserved his second R&D 100 Award in 2002, and PPS—already a commercial success—holds great promise as a standard for geothermal and other uses.

Sandia National Laboratories



Acoustic telemetry device quickly and reliably transmits data to the surface of a geothermal well to improve drilling, increase production, and lower well costs.

"Hearing" Where You Are Drilling

Picture drilling an exploratory well to tap geothermal or oil and gas resources. The drill bit might already be a mile away. It isn't necessarily where you are trying to reach, but how in …. do you know if you are heading the right direction, if you are reaching the formation containing the geothermal resources that you are seeking?

This is the challenge that Sandia National Laboratories' researchers Doug Drumheller and colleagues took on for DOE in 1988. Various sensors for temperature, pressure, orientation, and other useful information were available, but not necessarily able to withstand the high temperatures and other conditions for geothermal wells, and deeper oil and gas wells. And getting the data back to the operators at the surface was problematic to say the least—you couldn't exactly run a phone line down the hole with the drill bit.

The chief technology available at the time was to send data back to the surface in mud pulses. Mud is a combination of fluids introduced to aid drilling and removal of rock cuttings from the drilling, which is brought back to

the surface in the space between the outside of the drill pipe and the drill hole. Sounds daunting, but by mechanically pulsing that mud, data is sent to the surface. The mechanical sending units were subject to break down, and its effectiveness changed with the drilling fluid—it could not be used when gas rather than liquid was used for drilling—but 1 to 2 bits-per-second of data could be transmitted with this mud pulse telemetry.

The other possibility used to a limited extent was electromagnetic telemetry. Radio transmission through solid or semi-solid rock is not quite like tuning in your local talk-radio channel. In many kinds of rock formation, it would not work at all, but in the right situations 4 to 8 bits-per-second of data could be transmitted.

Drumheller envisioned another way—acoustic telemetry, a field that he was in essence developing. Instead of the returning mud flow or the surrounding rock, acoustic telemetry would use the drill pipe itself for the data transmission medium and sound waves for the transmission. The challenges, however, were formidable. There was the noise of the drilling, the flow of rock cuttings, and the fact that the data conduit would have to be a series of 30-foot (9.2 meter) drilling pipe segments rather than a continuous pipe or casing.

He set out to overcome the technological challenges of the drilling environment, later bringing in Sandia colleagues Steve Knudson for field work, then Scott Kuszmaul for electronics, and eventually Extreme Engineering, Ltd., of Calgary, Alberta, for real-world drilling experience. The result was the Extreme Acoustic Telemetry (XAcT) system that successfully transmits 10 to 30 bits-per-second of data to a surface decoder during drilling or flow testing. In the process, they also developed an innovative receiver for the system that Extreme Engineering offers as part of its product line for other uses as well.

The acoustic transmitter sits behind the drill bit along the drill string (i.e., pipe and connections). The system operates regardless of the fluid in the drill hole, the surrounding rock formation, or the noise of the drilling. Drilling noise is accounted for, and variations in it are even used to assess deterioration of the drill bit and the rock formation immediately surrounding the bit. The joints connecting drill pipe sections are perceived by the system as filters to the signal, reducing range, but not stopping the signal. Unlike mud-pulse telemetry, it has no moving parts to break down, and it does not require an operator. It also has the potential of sending data in both directions to operate any drill-end apparatus, such as directional or diagnostics sensors.

Extreme Engineering—which has joint patents and intellectual property of its own for the technology—licensed the rest of the technology from Sandia. It has joined with Shell Technology Ventures to set up XAcT Downhole Telemetry, a joint company that will act as a service firm to provide the acoustic technology to oil, gas, and geothermal drillers. Now near the end of the first year of three-year funding from Shell, Extreme Engineering is currently testing the system out on a 2,000-foot (610-meter) test length of drill pipe and will begin full drilling tests late in 2005. With consulting help from the recognized expert in the acoustic telemetry field—Drumheller, now retired from Sandia—Sandia is also developing repeater technology to extend the system's transmission range.

Back at Sandia, Kuszmaul is exploring electronics and materials capable of withstanding temperatures of 437ºF (225ºC) and higher. These kinds of temperatures are likely to be encountered in geothermal and deeper oil and gas drilling (system is currently built to withstand 302ºF or 150ºC), and he is anticipating applying the XAcT system to geothermal use as it becomes a standard tool for the drilling industry.

As drilling has become more sophisticated, data needs have evolved from measurement-while-drilling to logging-while-drilling to guide decisions and operations. Mud pulse telemetry has been unable to keep up with the need, and drillers often have to slow down to wait for the necessary directional or geoscience information to ensure that they get to the right place in the first place, and to know whether it is worth continuing and installing a well. The XAcT system is an invaluable telemetry device that should greatly reduce drilling and exploration time, and reduce investment risks, paying off handsomely for the oil, gas, and geothermal industries, and earning its 2003 R&D 100 Award.

Taming Geothermal Exploration

Explosive cauldrons of steam and toxic chemicals from the bowels of the earth—are geothermal resources a clean, sustainable energy source, or an infernal maelstrom of risk? Primarily, the great energy source, certainly, but even a family vacation to Yellowstone conveys that there is a dangerous as well as a beneficial side to geothermal energy.

The critical time for respecting the fire and brimstone side of geothermal energy is exploration, in particular the initial drilling, finding and tapping into the resource and bringing it to the surface. Water, steam, poisonous hydrogen sulfide and other chemicals can erupt with

volcanic force. If not controlled, this initial borehole can endanger project workers or cause serious environmental damage to the surrounding area when tapping, flow testing, and emission testing a new geothermal well.

Taming these risks is what Doug Jung of Two-Phase Engineering and Research, a California geothermal service company, set out to do. The result, Low Emissions Atmospheric Metering Separator or LEAMS, provides far better environmental control, worker safety, and noise reduction than previously available technology.

The previous technology and industry standard were cyclone 'blooie' mufflers, large cylindrical housings, typically built on site or used for projects of one drilling company. In a cyclone, the escaping geothermally propelled mix of liquids, gases, and rock is tangentially released—at jet-engine speed and noise levels—against the inside wall of the cyclone. This sets up a centrifuge effect, so that solids and liquids settle out along the walls for collection, and steam and vapors escape from the top. Caustic sodium hydroxide is added to neutralize the acidic hydrogen sulfide.

Sandia National Laboratories

The Low Emissions Atmospheric Metering Separator (LEAMS) helps geothermal well testing achieve "clean energy" status.

Cyclones, however, are by no means totally effective technology. Hydrogen sulfide, sodium hydroxide, and other noxious gases or liquids can escape, with the vapors and precipitate out, falling on the surrounding area. Mud and rock can also escape, and the tremendous pressure can knock holes in the walls or even blow the cyclones—as much as 15 feet (4.5 meters) in diameter and 30 feet (9 meters) high—off the drilling pads.

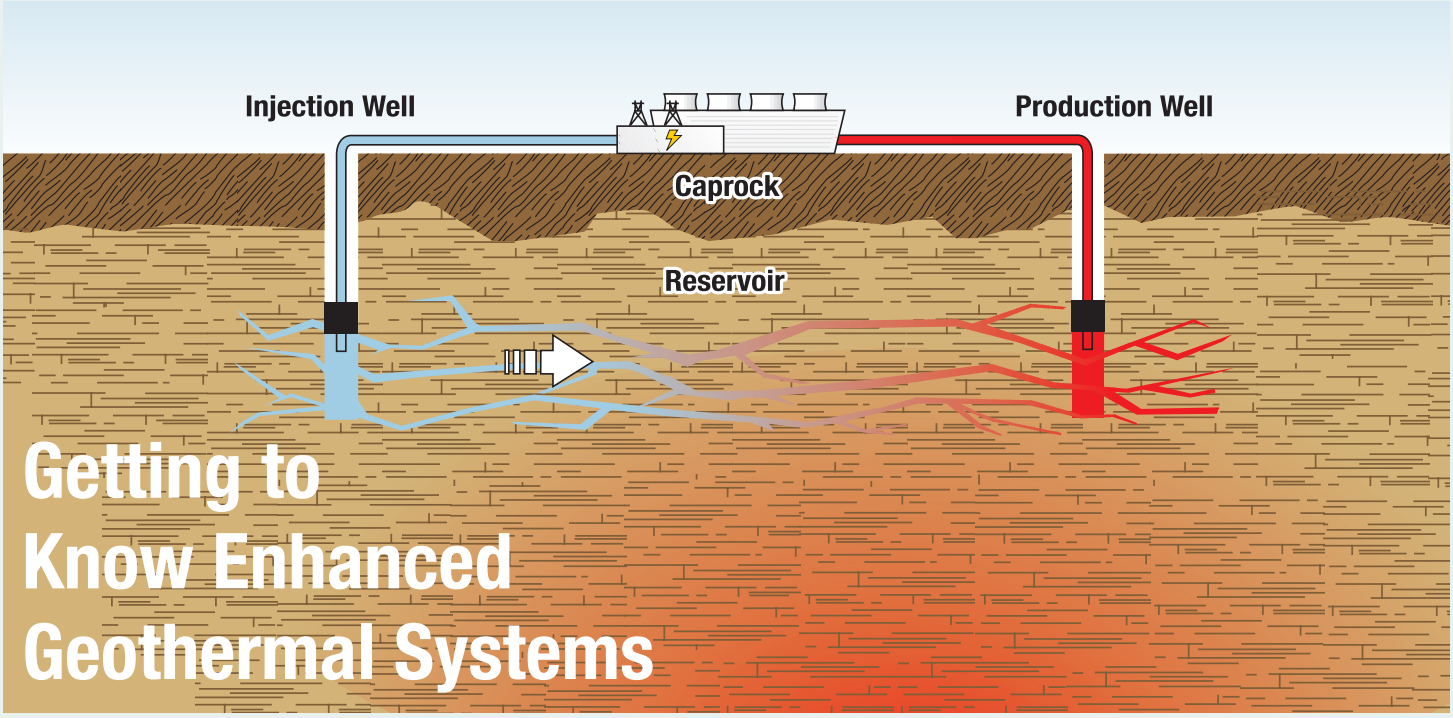
In areas with more stringent air emission standards, cyclones may have to be built as much as 100 feet (30 meters) high at far greater cost.

With LEAMS, Jung designed an inlet and a series of diffusers and diverters that slows the escaping geothermal mix down to manageable velocity, and then separates out the various solid and liquid components. Much less, if any, sodium hydroxide and other abatement chemicals are needed. Steam is pretty much just water vapor, but is ejected high into the air, so any residual toxics are safely dispersed. This is very important for worker safety, but also for preventing environmental damage to the surrounding area. Even clean steam can cause serious problems, such as freezing surrounding vegetation in the winter, breaking off limbs from the weight.

The sealed system with noise reducing cells is far quieter. With reduced velocity and without vacuum effects caused by the high velocity of the cyclones, emission-monitoring equipment built into LEAMS is far more accurate. LEAMS is also designed in segments so that it can be easily shipped by truck and reassembled at a new site.

Sandia brought Program funding support for the project and testing for the new technology. Side-by-side testing of LEAMS and a cyclone at Coso, California, showed dramatic differences with a "lake" of precipitated pollutants forming downwind of the cyclone, while the LEAMS remained totally clean. Sandia also brought Jung and Two-Phase together with Tom Champness at Drill Cool Systems, to have Drill Cool fabricate and rent LEAMS systems to the geothermal industry.

Drill Cool, a service provider for the geothermal and hot oil and gas well industries, scaled LEAMS down enough to fit on a single truck and provided their first unit to the Raft River geothermal project in southern Idaho, where old wells needed to be reestablished and flow tested. Developers of the Meager Project north of Vancouver, British Columbia, saw it and immediately asked for one just like it. Exploration and testing is nearly complete at both of these sites—with one, and probably both projects headed into production—so one or both LEAMS units will be headed to the Puna Project in Hawaii for redrilling and retooling existing wells. Even with investments in old cyclone units, geothermal drillers are seeing the clear advantages of LEAMS, and the technology appears to be off to a good start to commercial success, to helping the geothermal industry, and to proving the wisdom of its 2003 R&D 100 Award.



Getting to Know Enhanced Geothermal Systems

Fig.1 Conceptual illustration of a two-well enhanced geothermal system.

The Potential

The heat content of the Earth is virtually limitless—not exactly common knowledge to many energy decision and policymakers, or even the general public. Much of this vast thermal resource is contained in geologic areas not economically accessible for power production with present techniques. For cases in which reservoir flow rates are inadequate due to low fluid production from wells or lack of fluids, reservoirs may be engineered to increase productivity. Such engineered reservoirs are called 'enhanced geothermal systems' (EGS). With EGS, a candidate reservoir is targeted within a volume of rock that is hot, tectonically stressed, and fractured (see Figure 1). However, the fractures have closed or sealed over time, resulting in low productivity. Development of the technology for producing energy commercially from EGS is a top priority for the Program.

At present, only high-grade (shallow, hot, and permeable) hydrothermal reservoirs are economically feasible for the generation of electricity—this represents the 'low-hanging fruit' of geothermal resources. The Program estimates that the application of enhanced geothermal technology can more than double the amount of viable geothermal resources in the West in the near term. The technical potential is even greater in the long term. Coupled with less expensive drilling, EGS development will allow geothermal energy to be used more widely across the United States, including areas of the Midwest and the East that have experienced no significant geothermal development.

The EGS Concept

Through a combination of hydraulic, thermal, and chemical processes, the target EGS reservoir can be 'stimulated,' causing the fractures to open, extend, and interconnect. This results in the creation of a conductive fracture network and a reservoir that is indistinguishable from conventional hydrothermal reservoirs. This process can also serve to extend the margins of existing geothermal systems or to create entirely new ones wherever appropriate thermal and tectonic conditions exist.

At depths accessible with current drilling technology, virtually the entire country possesses some geothermal resources (see Figure 2). The best areas are in the western United States where bodies of magma rise close to the Earth's surface. Since temperature increases with increasing depth in the Earth, hot rocks can always be reached by deep drilling. At 20,000 feet (6 kilometers), a commonly accessible depth, temperatures exceed 300°F (150°C) under most of the United States, and temperatures above 480°F (250°C) occur in widespread areas. These temperatures are sufficient for generation of electrical power and for such direct uses of heat such as district heating, industrial processing, and heating homes and greenhouses. The practical drilling limit using today's technology is deeper still, about 33,000 feet (10 kilometers).

A preliminary characterization of the EGS resource base between the surface and a depth of 33,000 feet (10 km) indicates that enhanced geothermal systems could meet a

significant fraction of the U. S. electric power demand for many years into the future—this finding highlights the potential payoff of EGS research. Extensive drilling over the last century for petroleum, geothermal, and mineral resources has demonstrated that by far the largest heat resource in the Earth's crust is contained in rocks of low permeability. With today's costs and financial parameters, and with reasonable assumptions for continued progress from the Program's EGS research and development, more than 100,000 MW of developable power capacity exists in the continental United States.

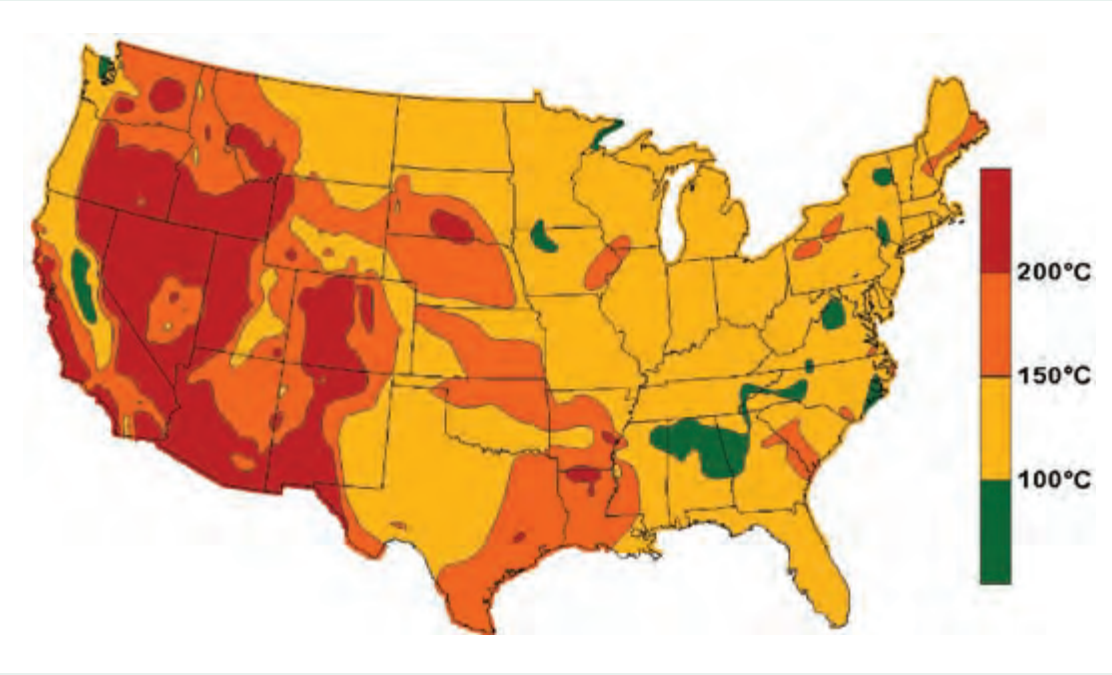


Fig.2 Map of estimated temperatures at a subsurface depth of about 20,000 feet (6 km)

The knowledge gained from EGS research in the United States and elsewhere forms a robust basis for the program. Current DOE-funded research addresses fundamental issues of technology development and demonstration to create fracture systems in low-permeability formations. Field-based studies currently seek to extend operating hydrothermal fields into adjacent rocks within the same thermal system. The EGS program will extend this work into less permeable rocks at increasing distances from known thermal systems to bring an ever-larger portion of the EGS resource base into economic use.

Although substantial progress has been made in developing and demonstrating certain components of EGS technology in the United States, Europe, Australia, and Japan, further work is needed to establish the commercial viability of EGS for electrical power generation. None of the known technical barriers to widespread use of EGS as a domestic power source is considered to be insurmountable. Therefore, this research program is a reasonably low-risk and potentially high payoff investment in the nation's future energy security.

Technical Goals and Objectives

The critical factor in demonstrating the feasibility of producing EGS energy at commercial rates is developing technology for creating and managing enhanced geothermal reservoirs over their lifetimes. Prime EGS research topics include defining and enhancing fluid pathways; detecting results of processes that form the subsurface heat-exchange system; and monitoring the engineered system for changes in physical properties over time. Initially, the EGS program will focus on high-grade resources—those in which temperatures of 390°F to 480°F (200°C to 250°C) can be found at depths of 7,000 to 13,000 feet (2 to 4 kilometers).

As the research progresses, technology will be needed for economically extracting energy from lower-temperature 257°F to 390°F (125°C to 200°C) resources, for developing EGS reservoirs in progressively deeper, 13,000 to 33,000 feet (4 to 10 kilometers) resources, and for working in higher-temperature (>480°F/250°C) resources. The ultimate aim of the program is to enable economic development of electrical power generation from geothermal resources throughout the United States.

Goals

The long-term (by 2040) goals of the Program are to:

- Decrease the levelized cost of electricity from Enhanced Geothermal Systems to less than 5 cents per kilowatt-hour.
- Increase the economically viable geothermal resource to 40,000 megawatts (MW).

The DOE Geothermal Technologies Program projects at least 30,000 MW of EGS geothermal power generation to be online by 2040 or sooner.

Credit: EEIG Heat Mining

Deep drilling for the European EGS project at Soultz, France.

Analysis of the hydrothermal resource base indicates the existence of about 10,000 MW power potential of economically viable hydrothermal resources with minimal reservoir enhancement. Together, the EGS and hydrothermal power generation can total at least 40,000 MW by 2040, with potential for expansion to 100,000 MW or more with a useful lifetime of centuries.

To guide the research effort in the near-term, the EGS program has adopted the interim goal to demonstrate the technical feasibility of creating EGS circulation systems that produce at commercial fluid-flow rates by 2011.

Once technical feasibility has been demonstrated, research will focus on increasing rates of fluid production from individual EGS reservoirs, and on reducing the costs and risks of EGS projects, both of which make the resource more attractive for commercial development.

Objectives

To further focus the near-term program, two technical objectives have been adopted to:

- Increase net thermal power extracted per production well
- Increase reservoir lifetime.

Net thermal power extracted is defined as the average heat recovery rate at the surface per production well over the lifetime of the reservoir, after deducting parasitic loads such as pumping power. Reservoir lifetime is defined as the length of time the reservoir can be operated before temperature drawdown exceeds 18°F (10°C), a value consistent with limits on the temperature tolerance of today's geothermal power plants. Larger temperature drawdown levels will be possible with future improvements in power plant design and efficiency.

Technical Approach

Research and technology demonstration under the EGS program will be carried out through a blend of computer, laboratory-scale, and field projects, all of which are essential for moving EGS technology forward. In past years, the Program has fostered specific geothermal expertise at national laboratories, universities, and private companies. Maintaining a strong research community focusing on EGS needs is essential to program success.

Results from research in related fields (e.g., drilling, reservoir stimulation, and enhanced recovery in the petroleum industry; drilling and rock fracturing in the mining and construction industries) will be incorporated, which will provide strong leveraging of the EGS investment. Working ties and collaborations with these industries are pursued as an integral part of the overall Program. To the extent practicable, the EGS program will also work with and incorporate results from other government-funded programs, such as those of DOE's offices of Science, Fossil Energy, Environmental Management, and Civilian Radioactive Waste; the National Science Foundation; the U.S. Geological Survey; and various state geological agencies and universities.

Field Projects

Field testing of technologies and equipment is essential for making progress in EGS research. Individual components of a commercial-scale EGS installation must be tested before being brought together in a final system. Options for field sites include: (1) continuing the present program of EGS activities at operating hydrothermal fields, (2) undertaking cost-shared projects with the private sector at sites in promising thermal areas, (3) supporting currently active projects in other countries, and (4) establishing a dedicated, DOE-operated and funded EGS field site. These options are, of course, not mutually exclusive, and may be conducted jointly.

PIX05948, Williams, Ken - U.S. DOE, Lawrence Berkeley Lab

Flow testing is among the field tests being performed in Soultz, France, in an attempt to better understand EGS potential.

Collaboration with Other EGS Research Projects

EGS experiments are currently underway in France, Switzerland, and Australia. These projects are aimed at end-use options for both electrical power and heat. The International Energy Agency (IEA) has an 'annex' for EGS research to foster cooperation among international groups, and the DOE Geothermal Technologies Program participates in this annex. The EGS program will support and participate in these research activities as appropriate to ensure that their results are incorporated into program activities. Further, EGS program priorities will be updated on an ongoing basis to eliminate duplication of effort and to build upon the results of others.

Collaboration with the Private Sector

Collaboration with the private sector is an important strategy for enhancing technology transfer, leveraging program funds, and fostering commercial development of EGS reservoirs. The present geothermal power-generation industry has very limited financial or technical capacity for moving significantly beyond the constraints of their immediate operations and into the more risky venture of EGS development. For the EGS program to succeed, it must stimulate the interest of large companies with substantial capital and expertise—companies undaunted by the risks posed in developing more complex geothermal resources. An obvious partnership from this standpoint would be with the oil and gas industry. Many aspects of petroleum drilling and production technology are applicable to EGS development. Exploration data from past drilling, such as downhole temperature logs, are widely used for resource evaluation. Moreover, several major petroleum companies are extending their business interests into renewable energies, including geothermal energy. This program is pursuing the development of strong working relationships with companies in the petroleum and mining sectors.

Current EGS Activities

DOE currently sponsors EGS studies at several sites within or near operating hydrothermal systems in the United States, as summarized below.

Coso, California

The Coso project is a collaborative effort between the University of Utah and the U.S. Navy at the well-known Coso geothermal area in southern California. The thermal anomaly covers about 200 square miles (520 sq km), with the producing hydrothermal system, which generates 236 MW of electrical power, situated in a small area in the northwest portion of the thermal zone. The area of EGS interest—characterized by low permeability and high rock temperatures of about 480°F (250°C)—is on the margin of the operating hydrothermal system. Research involves testing available low-permeability wells originally drilled for injection to determine if thermal, chemical, and hydraulic stimulation can create a viable fracture system.

Thorough geoscientific studies were undertaken by a diverse DOE-funded research team to characterize the area geologically and assess its potential as a site for stimulation. In 2005, one injector well was selected for deepening to access high-temperature, low-permeability rock. However, an unexpected, large natural fracture system was encountered at the bottom of the well, precluding its use for further EGS studies of the type originally envisaged. Another available well will be used in FY 2006 to complete the field experiment.

Desert Peak, Nevada

The Desert Peak hydrothermal field in north-central Nevada generates 50 MW of electrical power. It is

operated by Ormat Technologies, Inc., with whom DOE is collaborating on EGS research in the eastern portion of the field. Ormat has drilled a new well outside the area of hydrothermal production, but close to the existing power plant. DOE-funded researchers have been studying this well to assess its potential for hydraulic stimulation. Work completed to date includes geological, geophysical, and geochemical characterization of the new well and its environs. These studies have determined that the well seems ideal for an EGS stimulation experiment. Plans call for hydraulic fracturing of this well in FY 2006, with another well to be drilled subsequently, in an attempt to complete an EGS circulation loop.

The dedication of the Southeast Geysers Effluent Pipeline Project, where wastewater is used to recharge the geothermal reservoir. Shown are (left to right) Mark Dellinger, Ray Fortuna, and Allan Jelacic.

Glass Mountain, California

This project, a collaboration with Calpine Corporation, was planned to be carried out near the caldera at the Medicine Lake Volcano in northern California, in an undeveloped area known from oil and natural gas exploration drilling to have high-temperature, low-permeability rock. Opposition to geothermal development by an Indian tribe and several public interest groups has stymied the project, as well as planned construction of a separate hydrothermal power plant. This may be resolved very soon.

The Geysers, California

The Geysers is a well-known field in northern California that produces nearly 1,000 MW of electrical power. The northern portion of the field is underlain by a thermal region moving from magmatic intrusions that are younger than the intrusions that created most of the field. Although the rocks are very hot at ~572°F (~300°C), permeability is low. Fluids produced from this so-called "high-temperature zone" are laden with corrosive gases and a high proportion of noncondensable gases. The objective of the project is to determine if fracturing could be used to enhance permeability, and whether dilution of existing fluids with injected water would lower corrosivity enough to allow economic production of power. A significant source of injection water will become available to this portion of the field with the planned extension of a pipeline that now brings municipal wastewater to the central portion of the field. This EGS project has already registered early success by increasing power generation at The Geysers.

Technical Challenges

Important technical obstacles to attaining near-term and long-term EGS goals and objectives exist in the areas of resource characterization and exploration; reservoir design and development; and reservoir operation and management. *Resource characterization and exploration* includes research in geothermal gradients and heat flow; geologic structure; lithology; tectonics; and induced seismicity potentials. *Reservoir design and development* includes research in fracture mapping and in-situ stress determination; isolating stimulation zones; reservoir stimulation design; reservoir stimulation; and fracture propping. *Reservoir operation and maintenance* includes research in reservoir performance monitoring, hydraulic management, short circuit mitigation, fluid loss control, reservoir properties determination, and fluid chemistry and permeability control.

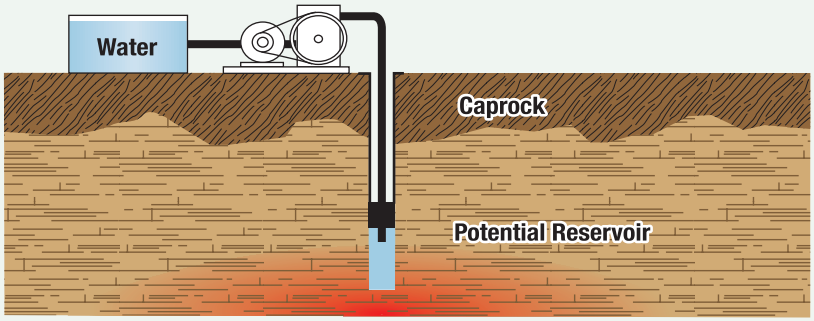
New technologies in these areas, especially the latter two, are crucial to demonstrating the feasibility of developing EGS. Similar research in the past on hydrothermal resources has been successful in developing new tools and technology now being applied by industry. The technology developed will also set the stage for eventually recovering the abundant heat contained in areas not associated with commercial hydrothermal fields, but with huge resource potential. This broadening use of geothermal resources throughout the United States will strengthen regional and national energy self-sufficiency, and develop needed clean, domestic energy resources.

How

an Enhanced Geothermal System works

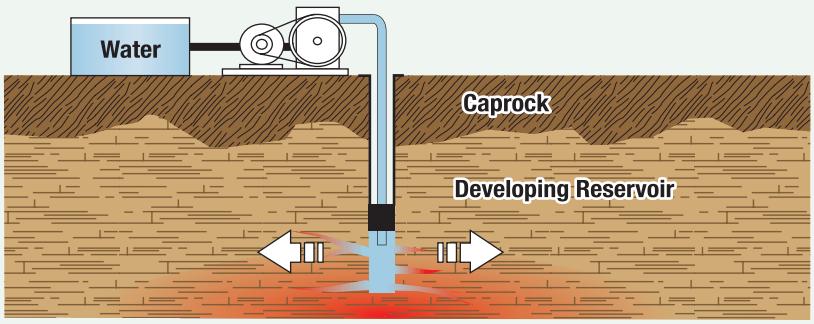
1 Injection Well

An injection well is drilled into hot basement rock that has limited permeability and fluid content. All of this activity occurs considerably below water tables, and at depths greater than 5000 (1500m) feet. This particular type of geothermal reservoir represents an enormous potential energy resource!



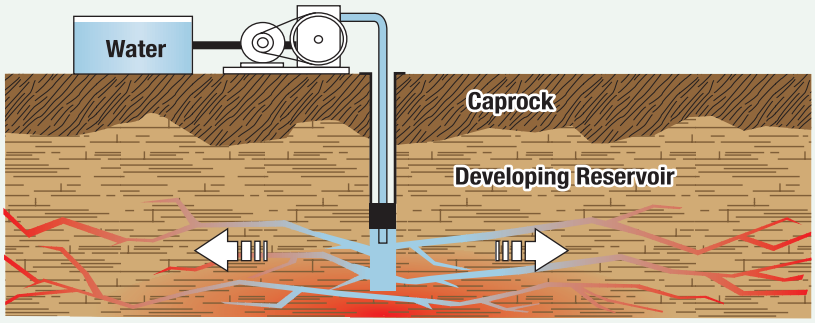
2 Injecting Water

Water is injected at sufficient pressure to ensure fracturing, or open existing fractures within the developing reservoir and hot basement rock.



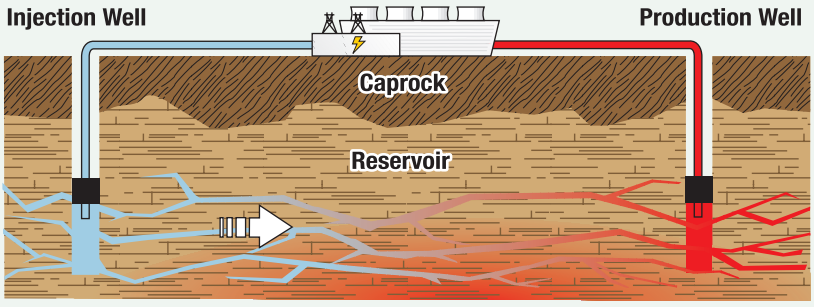
3 Hydro-fracture

Pumping of water is continued to extend fractures and reopen old fractures some distance from the injection wellbore and throughout the developing reservoir and hot basement rock. This is a crucial step in the EGS process.



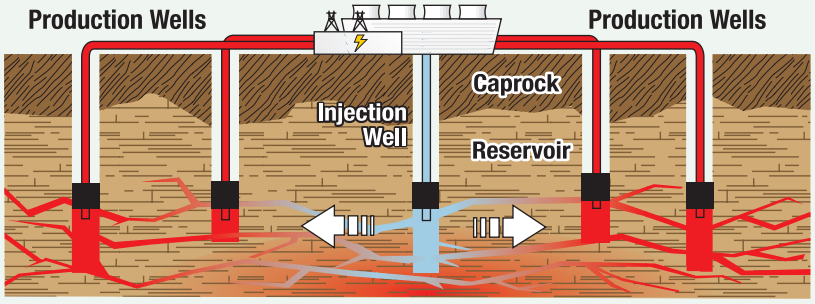
4 Two Wells

A production well is drilled with the intent to intersect the stimulated fracture system created in the previous step, and circulate water to extract the heat from the hot basement rock with improved permeability.



5 Multiple Wells

Additional production wells are drilled to extract heat from large volumes of hot basement rock to meet power generation requirements. Now a previously unused but large energy resource is available for clean, geothermal power generation.



Raft River—Coming On-Line in Idaho

Tucked between mountain ranges in southern Cassio County, Idaho, the Raft River has carved a wide valley that is populated with the sagebrush and grass indigenous to arid climes, but with very few people. Yet, this remote, thinly peopled area just north of the Utah border is about to make geothermal history—again. The Raft River Valley will soon be home to the first commercial geothermal power plant in the Northwest (Washington, Oregon, Idaho, and Montana).

This valley has already had a fleeting taste of geothermal fame. In 1979, it became the site of the world's first binary-cycle geothermal power plant. A binary-cycle plant is used when the geothermal resource produces no steam and has water temperatures typically less than 360°F, but greater than 212°F (182°C and 100°C). The temperature of the geothermal resource in the Raft River Valley varies between 275°F and 295°F (135°C and 146°C) at depths between 5,000 and 6,500 feet (1,500 and 2,000 meters). In a binary-cycle plant, heat from the geothermal water heats a working fluid, usually an organic compound with a lower boiling point than water, and vaporizes it to turn a turbine. The water is then injected back into the ground to be reheated.

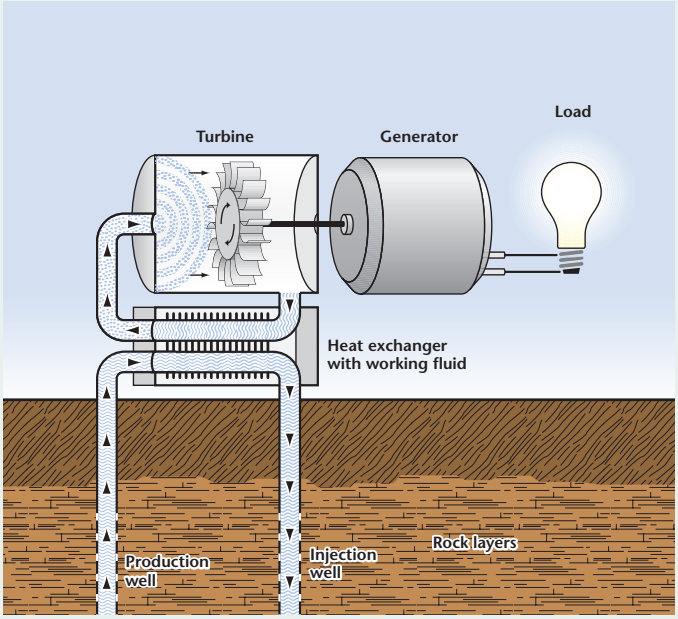
DOE (and its predecessor, the Energy Research and Development Administration) developed the field and built the 7-megawatt (MW) demonstration plant. The project came about largely due to concerns about developing alternative energy sources and technologies because of the energy crunch of 1973-1974. The project, which began in 1974 and ended in 1982, proved the feasibility of the technology at the time. But in southern Idaho, such a geothermal plant would not have been commercially viable. At the time, growth in the area was relatively static; the Northwest already had sufficient electric power for its needs, with plenty of hydroelectricity. There was no growing demand for electricity and no upward pressure on its price, and many of the environmental problems—especially that of CO_2 emissions—had not yet become well known or much of an issue. Consequently, there was no market and no incentive to favor the construction of an alternative energy plant in the area. So the plant was removed and shipped to Nevada, where there was another proven geothermal field and a growing market.

The Raft River Valley is defined by three mountain ranges—the Black Pine Mountains to the east, the Jim Sage Mountains to the west, and the Raft River mountains to the south. Map url ***geothermal.id.doe.gov/maps***

Pitfalls and Utility Issues

Market timing is just one of the many pitfalls awaiting geothermal developers to detour their intention on the road from drilling the first exploratory hole in a geothermal field to generating and transmitting the first kilowatt-hour for an electric utility. There are many others:

- Exploration and drilling costs alone, for example, can constitute up to one half the cost of a project.
- Leasing and siting a project involves a lot of uncertainty and can take years because of conflicting concerns of interested parties and disagreements over vying uses for the land.
- Transmission lines may not be readily available because of the remoteness of a site, and even if they are available, they may have to be upgraded.
- The productivity of geothermal wells may decline over time.



Schematic showing how a binary-cycle power plant works. This technology will be used at the Raft River geothermal field.

- Financing may be difficult to secure unless the project can be shown to be a generator of revenue for its prospective investors.

Finally, and of paramount importance, there are utility issues that a developer must face, which are vital to address if a project is to generate revenue.

According to Guy Nelson, Director of the Utility Energy Forum, the most important issue between utilities and producers of geothermal power is *reliability*. This can be taken in more than one sense.

First, there is the reliability of the geothermal field. Is it a proven field? Will it sustainably yield a promised amount of electricity for a reliable period of time? If a utility signs a power purchasing agreement (PPA) with a geothermal power producer, the utility needs to be assured that the field will produce the power the utility will depend on to meet the demand of customers. This is especially so for geothermal power plants because they typically serve as baseload, not peak plants. As baseload, geothermal power plants should be able to generate their projected power day in and day out, '24/7.' Baseload plant capacity is highly valued by utilities because it is the most steady, reliable, and economical in its generation portfolio.

A second sense of reliability is that the developer be reliable. This, in turn, can be understood in several ways:

- First, that the developer knows what it's doing. That it understands the technology and can guarantee plant construction and design for at least the life of a PPA.
- Second, that the developer not only proves the viability of the geothermal field, but that it not overuse it—'not stick too many straws in the soda.'
- Third, that the developer knows the market, and can get appropriate financing to see the project to fruition.
- Fourth, that the developer exhibit perseverance, and not give up on a project without effort, especially when promises have been made and the power will be depended on to fit demand.

Besides reliability, Nelson feels that cost of generated electricity is also an important issue for utilities, not surprisingly. And given that gas prices have been so volatile—jumping back and forth from less than $4.50 to greater than $9.30 per MMBTU (a thousand, thousand or million BTUs) during the last year—utilities may be quite willing to negotiate an agreement to purchase firm geothermal electricity for a levelized price of between $60 and $70 per megawatt-hour (MWh). Such volatility in natural gas prices adds considerable risk to a long-term investment, making a stable and reliable geothermal source much more enticing for utilities and investors. Under these circumstances, geothermal can then be a preferred source, not just because of its reliable baseload capability, but also because geothermal baseload plants are well known to have the industry's highest power factor—approximately 95 percent.

The Raft River geothermal site looking south across the Raft River Valley. In the distance is the Raft River mountain range, just over the Idaho border in Utah.

Credit: U.S. Geothermal

As part of the process of verifying the reliability of the Raft River geothermal field, workers prepare to test production well #5.

An Object Lesson?

Nelson maintains that one of the reasons there are no up-and-running geothermal power plants in the Northwest is because prospective developers of the plants have not had a good track record in addressing these utility issues. Up until now, that is. The Raft River geothermal project, he says, appears to be a looming success story, and has become an important test case for geothermal energy in terms of reliability and cost. It may even prove to be an object lesson in how to avoid pitfalls inherent in developing a geothermal project and in addressing utility issues.

Although the spot price of natural gas has been on an inexorable climb during the past year or so, it has zigzagged on its journey from less than $4.50 to more than $9.30 per MMBTU (million BTU).

With how smoothly things seem to be progressing, it certainly appears that the developer of the project—U.S. Geothermal, Inc.—is doing things right. At this time, a 10-MW plant is scheduled to go online in December 2006. For this so-called phase I of the project, the company has already signed a 20-year PPA with Idaho Power—the utility that services southern Idaho and eastern Oregon. The agreement calls for a price schedule that starts at $51.50/MWh and that increases at 2.3 percent per year to a maximum of $81.25 per MWh over the term of the 20-year contract. The company is also planning phase II of the project, which calls for two more 10-MW facilities that will go on line in December of 2007. For this phase, the company has signed a power purchasing agreement with Idaho Power that starts at $53.90 per MWh and increases by 2.3 percent per annum to $85.04 after 20 years.

According Daniel Kunz, CEO of U.S. Geothermal, the 30 MW of phases I and II of the project will generate enough electricity to supply 25,000 to 30,000 typical homes. The power purchasing agreements for both phases will bring in approximately $15 million per year for the electricity generated. Over the 20 years of the contract, this would come to about $300 million, just for the power. The company also negotiated rights for green tags, renewable energy credits that the company has the right to sell to customers for anywhere between 1¢ and 4¢ per kilowatt-hour (kWh). These, together with revenue from selling carbon credits, will make the Raft River geothermal project a profitable venture and an enticing investment.

The Right Time and the Right Place

Today, the Northwest energy market is dramatically different from that of the early 1980s. Demand is growing substantially in Idaho and the Northwest, and is projected to continue to grow. No new hydroelectric plants are being built in this area (hydroelectricity dominates the baseload capacity in the Northwest). As indicated earlier, natural gas prices are volatile and rising. And, just recently the 2005 Energy Bill that was passed by the Congress and signed by the President, extends production tax credits to all qualifying renew-

Transmission of new power can often be a challenge, but fortunately, a 138-kVA transmission line with plenty of spare capacity was available to U.S. Geothermal along the northern boundary of the Raft River geothermal field.

able energy technologies; and geothermal power plants qualify under the new law (see *New Policies Have Favorable Impact on Geothermal Development*). A production tax credit of 1.9¢/kWh will be granted for 10 years of production for every qualifying facility that comes online by the end of December 2007. U.S. Geothermal plans to bring both phase I and phase II of the Raft River project online by that time. So now is the time to build new plants, especially those that offer renewable sources and can also take advantage of green tags and carbon trading.

And the right place is the Raft River geothermal field:

- In 1985, the Bonneville Power Administration (BPA) had ranked this field as the top high-temperature geothermal resource in the Pacific Northwest and projected that the field had the potential to produce 100 to 200 MW of geothermal power.
- DOE had already proved the field viable with its demostration plant.
- The field already had five production wells, 2 injection wells, and other assets worth more than $11 million.
- And when U.S. Geothermal incorporated in 2002 to begin its geothermal venture, Vulcan Power Company of Bend, Oregon—the owner of the property that held the wells and other assets—was willing to negotiate a sale of those assets.

With these original and subsequent purchases, U.S. Geothermal now owns 660 acres (640 acres is a square mile) of the Raft River geothermal field. The company has also leased nearly 3,200 additional acres adjoining the property, for a total land package of 6 square miles with geothermal rights and a proven geothermal field.

Déjà Vu—All over Again

Having purchased and leased the land it needed, U.S. Geothermal did not take DOE's word for granted that the geothermal resource in the field was viable and sustainable. Nor could the company do so. It had to prove the reliability of the field beyond question. So the company retained the services of GeothermEx Inc., a world-recognized geothermal engineering consulting firm, to analyze the field and the production capacity of the existing production wells. The analysis performed by GeothermEx found that the existing wells could sustainably produce between 14 and 17 MW, enough for the first phase of the project.

The analysis also indicated that the Raft River geothermal field could produce 15.6 MW of geothermal power per square mile. So, with the 6 square miles U.S. Geothermal currently owns and leases, there is a potential for about 90 MW of generating capacity. But according to Kunz, there is also the possibility that the company could eventually extend the development area to 13.6

PIX07212, Credit: Sierra Pacific

Desert Peak geothermal power plant, located about 65 miles northeast of Reno, Nevada.

square miles, giving the field the ultimate potential for producing about 200 MW. Thus, the analysis not only verified DOE's original findings and confirmed the estimate made by the BPA, it also more than substantiated the reliability of the resource to produce the 30 MW called for in the first two phases of the project.

Stand and Deliver

Power transmission can be an important issue for geothermal power plants, especially if the field is remote, as is the Raft River field. Part of the beauty of this field, however, is that there is a 138-kVA (kilovolt-ampere) transmission line running along the northern boundary of the property and a substation—the Bridge Substation—only two miles from the planned phase I plant. The Raft River Rural Electric Cooperative owns both the transmission line and the substation.

The line itself has the capacity to transmit 120 MW of electric power. The BPA leases the transmission line from the Cooperative and has 60 MW of excess line capacity available. Because U.S. Geothermal needs only 12 MW of transmission capacity for phase I and 24 MW for phase II, there is plenty of carrying capacity available. The company will simply have to build a short interconnect line and a step-up transformer to transmit its generated power from the plant to the Bridge Substation. The 138-kVA line will then be used to transmit the power from that substation to the Minidoka Dam Substation, part of the Idaho Power grid.

All of this seems pretty straightforward. The complications set in with the fact that the 138-kVA transmission line belongs to the Cooperative but that the capacity is leased by BPA. This is abnormal for BPA. It is the only transmission capacity that BPA leases; it owns the rest of the transmission lines they use. So even though U.S. Geothermal negotiated with BPA for transmission capacity, it may eventually have to sign agreements with the Raft River Rural Electric Cooperative. This may not happen, however, because it has been normal practice for the Cooperative to simply extend its lease to BPA when the lease expires.

Nonetheless, the negotiations with BPA were straightforward. BPA was quite supportive of the project, particularly because it was a renewable energy project, and BPA has a policy of encouraging electricity production using renewable energy sources and technologies. The only requirement that BPA made of U.S. Geothermal was that the company conduct (and pay for) studies on interconnection and transmission for its electricity, and demonstrate that there would be no technical issues or problems with the interconnection and transmission. Once U.S. Geothermal performed the study and established that there were no technical issues, BPA and the company signed an agreement for firm point-to-point power transmission of up to 12 MW of capacity.

BPA and U.S. Geothermal also agreed that U.S. Geothermal could reserve an additional 24 MW of transmission capacity for phase II of the project. In this case, all parties benefit from 'Green Power' purchases.

Easy Does It—Getting Permission

With geothermal plants, as well as with other generating plants, getting the right to develop the field and build the plants, roads, and transmission lines can often take years. With U.S. Geothermal, however, it only took 3 or 4 months, counting the required public hearings. There are several reasons for this:

- First, Cassia County was extremely supportive of the project, and eager to accommodate the process for

public hearings and the granting of a conditional use permit.

- Second, the project will not leave a large 'footprint.' DOE had already developed part of the site, with 5 production wells, 2 injection wells, security fencing, and road access and line power for all seven well sites. Plus, the geothermal generation plants themselves will not leave a large footprint, in terms of land and resource use, and other environmental impacts.
- Third, the electricity generated by the project is a commodity needed by Idaho and the Northwest, and it would provide jobs and have a beneficial economic impact on the area, as well as additional county revenue from royalties.
- Fourth, there were no identified conflicting uses for the land and resource in question—neither economic, recreational, nor cultural.
- Fifth, Raft River Valley is a relatively remote area that has very few neighbors who, on grounds other than those stated above, would object to the use of the land for a geothermal project.
- Sixth, the company already owned the prime property where the wells are and where the phase I geothermal plant will be built, and has leased rights to surrounding property for possible development, all without objection to the planned use.

A Fly in the Ointment

No matter how smooth things seem to be going, and no matter how smart you seem to have been in foreseeing problems, there always seems to be something that crops up to make the going a little rougher than anticipated. The issue that hit U.S. Geothermal involved the power purchasing agreements and, in part, had to do with reliability.

In this case, the utility—Idaho Power—did not question the reliability of the developer to provide the stated power. Nor did it really question the reliability of the field. These were not a problem in the utility's eyes. U.S. Geothermal had proven the reliability of the field, and its own reliability—it had technical capability and a good business plan, and had secured the financial backing that would enable them to see the project through to a successful conclusion.

Rather, for the utility, the question of a power purchase agreement revolved around three issues. The first issue concerned whether the nominal 10-MW power plants being proposed under both phase I and phase II of the project should be considered as 'qualifying facilities'

Wellhead with spool and blowout preventer in foreground at Raft River.

under Public Utility Regulatory Policies Act (PURPA) of 1978. This law requires that a utility buy the electricity generated from such a qualifying facility—a facility that is generally owned by an independent producer and that is 10 MW or less—at a rate based on a price structure known as 'avoided cost.' The avoided cost is cost that the utility would incur to produce extra power. A qualifying facility can generally produce power for less than the avoided cost, so such a rate structure tends to be quite favorable to the producer. Plus, under PURPA, the producer will be locked into that favorable rate structure for 20 years, with yearly increases to accommodate inflationary pressures.

According to the utility, the problem with considering the nominal 10-MW geothermal plant as a qualifying facility is that design of the plant entails it often produces more than 10 MW of power—as much as 12.9 MW. This is due to how the generating capacity of a thermal power plant is determined. Generally, a given design for a thermal power plant is rated for a moderate temperature and humidity, and will produce different quantities of power depending on the ambient atmospheric conditions. Waste-heat rejection efficiency affects a plant's overall generating efficiency.

This is the case with the geothermal plants for phases I and II of the Raft River project; they are designed to produce 10 MW of delivered power (beyond parasitic loads, etc.) at 48°F (9°C). Electricity production goes up in colder weather and down in warmer, due to waste-heat rejection efficiency changes. This dependency is especially true of plants that use air-cooled condensers—as do the great majority of geothermal plants. So in the eyes of U.S. Geothermal, it is reasonable to expect that Idaho Power should accept power that is greater than the design is rated for, in given periods.

PIX03698, NREL, Warren Gretz

Geothermal resources are prevalent in the western United States.

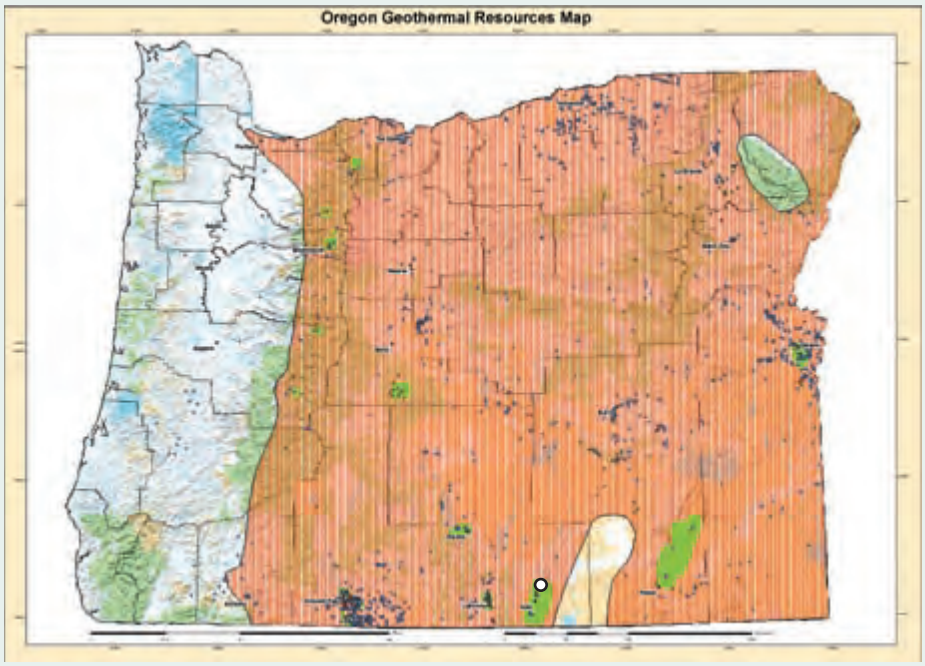
The second issue, which hinges on the first, revolves around the definition of 10 MW of delivered power. The utility's contention was that it should be considered as *10,000 kilowatts (kW) in any given hour*, and that if the geothermal plants were to be considered as qualifying facilities, then the utility should not be required to buy electric power greater than 10,000 kW in any given hour. In contradistinction, because of the plant design and the variance in output to be expected at different times of the year, U.S. Geothermal felt that the definition should be considered as *10,000 kW of delivered power averaged over a year.*

The third issue did concern reliability—the reliability of the delivered power. That is, Idaho Power wanted U.S. Geothermal to guarantee that the power delivered to the utility would reliably be between 90 percent and 110 percent of the projected power, thus asking for what is known as a firm '90/110 band.' Moreover, to ensure this firm delivery, the utility wanted penalties for not meeting the projected power band. It certainly makes sense, from a utility perspective, that it would want a firm amount of power guaranteed from the producers so that the utility may make accurate assessments on how to meet its customers' demands. From the producer's point of view, though, it may be difficult to meet too stringent a band because of the exigencies of weather. If the temperature for a given month varies significantly from the norm, the predicted power delivered will vary accordingly.

Resolution

Because Idaho Power and U.S. Geothermal could not come to terms on these issues through their face-to-face negotiations, they took the issues to the Idaho Public Utilities Commission (PUC) for arbitration. After hearing and considering arguments from both sides, the Idaho PUC decided that:

- Each of the three 10-MW generating plants of the Raft River project were to be considered as qualifying facilities under PURPA.
- The definition of the 10 MW of delivered power was to be a *10,000 kW monthly average*.
- Idaho Power was to pay the avoided-cost rate.
- The plants were to deliver firm power to Idaho Power within the 90/110 band of the projected monthly capacity, and never more than 10 average MW in any one month. However, if the plants produced outside the band, then Idaho power would not have to purchase the power at the agreed avoided-cost rate. Rather, if the energy delivered was in excess of 110 percent or less than 90 percent of the projected power, then U.S. Geothermal would be paid 85 percent of the wholesale market price or of the contract rate, whichever is less.



The next area for geothermal development? The Crump Geyser area in Lake Count, southern Oregon has the potential for producing 85 MW of geothermal power. Web url ***geothermal.id.doe.gov/maps***

In response to the decisions by the Idaho PUC, Idaho Power and U.S. Geothermal settled on the two PPAs that were described above.

However, the decisions by the Idaho PUC also entailed that U.S. Geothermal slightly alter the design of its plants to be able to meet the firm 90/110 band requirement. Rather than depend on the typical air-cooled condensers in the plants, the company decided to design for water-cooled condensers. This design change would make the output of the plants less susceptible to the exigencies of ambient air temperature, and would provide greater control of plant output.

One more change needed to be made. Because the plants would now use water-cooled condensers, U.S. Geothermal negotiated for water rights so that water would be available to keep power production on target in cold, moderate, and warm temperatures.

Because the PPAs were crucial to the success of the project, the PUC decisions were also crucial—they unblocked the dam to further progress and enabled U.S. Geothermal to move forward to secure the essential financial backing, and to bring in the appropriate experts to design and construct the plants, wells, and accompanying infrastructure. And they provided the further impetus needed for phases I and II to go on line in 2006 and 2007, as planned.

Just the Beginning

As noted above, the 30 MW of phases I and II is just a beginning for tapping the potential of the Raft River geothermal area, which could produce at least 90 MW and maybe as much as 200 MW of power. But more than that, it may be just the beginning of geothermal power in the Northwest, and the Raft River project may be able to serve as the object lesson that Nelson suggested it could.

Nevada Geothermal Power, Inc. recently announced that it had acquired leases on 6,500 acres of private land covering the Crump Geyser geothermal area. Crump Geyser is an extensive hot springs area located in the Warner Valley, Lake County, just north of Adel, Oregon. In 2003, the U.S. Bureau of Land Management ranked Crump Geyser, a 'known geothermal resource area,' as highly favorable for near-term development of geothermal power, with an estimated potential of 85 MW. And with the production credit in the new federal energy bill, this area appears even more favorable for development.

The Crump Geyser project has much in common with the Raft River project, including a reliable field and a reliable company—one with known expertise in the field and sound financial backing. If Nevada Geothermal Power can cross the hurdles to development—including those set up by the needs of the utility industry—as smoothly and quickly as U.S. Geothermal has done, the Pacific Northwest will soon be enjoying electricity from its second geothermal site. Perhaps, a harbinger of things to come.

GeoPowering the West Initiative Makes Progress

Sonoma power plant, a 72-MW geothermal facility located in The Geysers area, northern California. Other geothermal power plants can be seen in the background. Credit - Calpine Corp.

GeoPowering the West

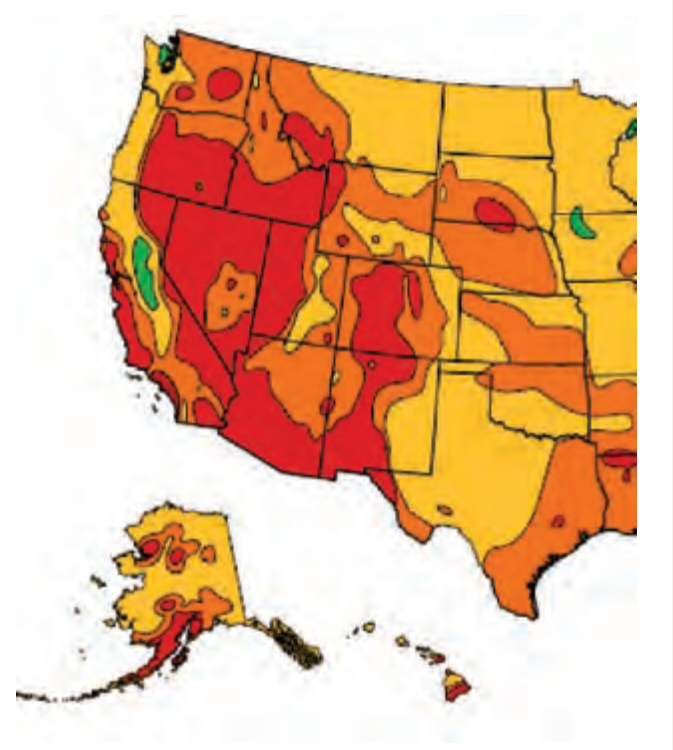
The GeoPowering the West (GPW) initiative was established in 2000 to identify barriers to geothermal power development and pursue strategies for overcoming them at the regional, state, and local levels. The GPW team has developed and delivered technical assistance and outreach activities aimed at key user communities—state government officials, power developers, utilities, industry, Native Americans, economic development agencies, and other potential partners. The team approach to GPW includes partners from DOE, DOE's national laboratories (e.g., Idaho National Laboratory, National Renewable Energy Laboratory, and Sandia National Laboratories), State Energy Offices, industry partners, as well as regional associations, tribes, and various states and local groups.

In 2004, the GPW initiative achieved the highest rating among EERE outreach efforts by providing a customer friendly, partnering approach, relevant information, and by interactively working with the geothermal industry, regulators, and state stakeholders. In 2005, the initiative is applying peer review recommendations and undergoing refinements to reflect the realities of the evolving marketplace and needs of the geothermal industry.

Market Factors and Barriers Overview

The domestic power market has continued to be volatile, with factors such as rapidly rising natural gas prices creating the most recent concerns. These market conditions represent a substantial development opportunity for the geothermal industry due to environmental, baseload, development scale (e.g., small plant 'footprint' and smaller generating facilities compared to fossil and nuclear), and time frame (e.g., smaller generating facilities typically require less construction time) advantages and benefits, but numerous other market factors combine to thwart deployment of geothermal power technologies.

Transactional Costs – Institutional barriers increase the transactional costs of projects, such as permitting, siting,



Map showing the distribution of geothermal resources in the western U.S. showing the prominence in the West.

and leasing approvals; royalty payment accounting; and other institutional requirements. Delays also add to costs, affect project timelines, and can seriously impact and often even prevent development. When these costs and delays increase, investment advantages and timeliness decrease.

Technical Unfamiliarity –Most regulators, policymakers, decision makers, and possible users are unaware of geothermal's potential, where it can be found, and its benefits. Targeted information products, as well as working with advocates in the states and utility sectors, will address this issue. Technical assistance and training helps eliminate unfamiliarity and uncertainties about adopting new technologies.

Power Market Expectations – Most utilities, power marketers, and regulators do not regard geothermal energy as a viable alternative today because of their lack of awareness and experience, and perceived risk. Geothermal acceptance depends on understanding the constraints and opportunities, and on the level of interest by public officials responsible for regulation of the power sector. Public utility commissions and consumer-utility boards are not adequately informed about economic and environmental benefits, and do not ask utilities and power companies to include geothermal resources in planning scenarios. Additionally, the on-again and off-again history of the production tax credit (PTC) impacts investment in geothermal power technologies, although the 2005 Energy Bill helps rectify this situation. Failure to adopt 'field-leveling' policies results in high thresholds for geothermal market development, and hence, is regarded as a critical barrier.

Leasing, Permitting, and Public Policies – In some cases, land use plans; federal and state agency permitting requirements and regulations; and public policies constrain the development of geothermal projects. Many of these regulatory and permitting processes have not been as conducive and timely as needed for expeditious geothermal progress, limiting development.

Environmental, Tribal, and Public Perception – Geothermal energy is erroneously identified with environmental problems, such as air and water emissions (see *Clean Energy Award sidebar on page 36*). This affects development on tribal reservations and historic (non-reservation) tribal lands. Environmental, tribal, and consumer issues are being characterized for benchmarking, which will address these barriers.

GPW Approach

Minimizing and overcoming these market challenges can greatly aid in realizing the substantial potential of geothermal energy resources and the adoption and deployment of geothermal power technologies. This is the aim of the GPW Program element.

GPW efforts are focused on identifying and resolving market-related issues inhibiting geothermal resource use, and creating and fostering partnerships to resolve these issues. Directly addressing these barriers through interaction with stakeholders brings those who are concerned about and those who can benefit from increased geothermal resource use into the process.

The operating principles are to:

- Prioritize states with undeveloped, high-quality geothermal resources
- Leverage and build institutional partnerships
- Develop innovative pilot applications
- Share and replicate successes, and learn from failures
- Use and coordinate existing national, regional, and local expertise
- Coordinate with established institutions
- Work with industry and the public
- Promote R&D elements of the DOE Geothermal Technologies Program.

Big Geysers, Unit 13, a 75-MW geothermal power plant located in northern California. Credit - Calpine Corp.

GPW builds state-level support for increased use of geothermal energy. A state-focused strategy acknowledges the critical role states play in geothermal development through policymaking, incentive adoption, R&D involvement, outreach and education, and demonstrations. This state-based strategy is complemented by high-level national and regional efforts to align policies, remove barriers, and facilitate the communication of experience-based and specific information. Also, the peer review recommended state partnering and activity coordination.

GPW tasks are now organized along the following categories:

- State-based activities
- Geologic assessments
- Interagency facilitation and collaboration
- Utility sector support
- R&D technology transfer.

State-Based Activities – One essential task for the states is to track policy development efforts and communicate progress and results among partners (i.e., to facilitate sharing of strategic plans, legislation, and industry outreach methods). State agencies also:

- Aggregate stakeholders
- Identify and catalog geothermal barriers
- Facilitate development of policies that remove barriers
- Increase awareness of geothermal benefits among decision makers, policymakers, regulators, investors, and consumers.

Presently, policy approaches to valuing renewable energy differ from state to state. These range from tax credits, to renewable portfolio standards, to voluntary programs that allow customers to make individual procurements (e.g., 'Green Power' programs). State policies and administrative requirements affect power markets, production costs, preferences for alternatives, and other factors relevant to development. Laws established in one state may affect laws being considered by other states.

The GPW state working groups (SWGs) serve as the locus and key organizers for state efforts. The SWGs form the network of energy professionals, policymakers, industry partners, and interest groups needed to facilitate communication, activities, and outcomes. A geothermal SWG can identify and address state-specific needs and translate them into focused plans and actions.

Geologic Assessments – Geothermal development depends on resource availability and understanding of the resource characteristics. The first step is to collect all available information from the states so this information can be used for analysis of geothermal potential of a given area. This requires identification of geologists and other experts in all of the GPW states who can collect and provide this information to interested developers. It will also be necessary for them to prepare the data in a form suitable for use by the U.S. Geologic Survey (USGS) in an updated national assessment

The USGS will analyze the data used to update the geothermal resource estimates previously published in the 1978 assessment (USGS Circular 790). The Program is providing staff to the USGS to facilitate this work.

Interagency Facilitation and Collaboration – The interagency facilitation approach will directly address barriers to geothermal development by engaging government agencies and institutions with policies and procedures that inhibit development to remove, reduce, or mitigate these barriers. Support efforts include:

- Cataloging and assessing key impediments and institutional issues
- Engaging various agencies, such as the U.S. Bureau of Land Management, U.S. Forest Services, U.S. Department of Agriculture, U.S. Department of Defense, and the U.S. Environmental Protection Agency
- Engaging high-level utility organizations
- Engaging high-level industrial organizations
- Engaging high-level tribal and other organizations
- Facilitating investor and interagency interactions
- Communicating results among stakeholders.

Transactional costs involving permitting of geothermal power plants, land leasing and royalties, siting of related infrastructure, and the time (and cost) needed to accomplish these things can often be reduced, given the engagement and cooperation of key participants.

PIX 07215 Credit – Sierra Pacific

Hot springs in the Steamboat Springs area, Nevada.

PIX01125, NREL, David Parsons

Workers install new piping at one of the geothermal power plants at The Geysers in northern California.

The new 2005 Energy Bill has streamlined a number of issues relating to leasing and royalties in revisions to the Geothermal Steam Act.

Utility Sector Support – Gaining increased utility sector acceptance for geothermal is based on ensuring that its intrinsic value as a clean, safe, secure, domestic, and reliable energy source is considered in the utility evaluation and planning process. The approach will be to:

- Identify or target likely geothermal energy-buying utilities or other potential utility sector stakeholders
- Assess geothermal performance with utilities or stakeholders currently buying geothermal energy, obtain testimonials, identify champions, and facilitate interaction and exchange of experience.

As a result of this utility sector approach, the GPW program seeks to:

- Increase awareness of the competitiveness of geothermal power with other generation technologies, especially the baseload advantage
- Create greater utility and retail customer acceptance of geothermal technologies
- Parlay new environmental regulations into winning solutions for the power sector
- Align large, capable and well-capitalized companies with the power sector to facilitate investment in geothermal power generation and direct-use technologies
- Identify and mitigate transmission barriers
- Remove technology acceptance barriers through deployment-driven strategies.

Because there is a growing need for clean, diversified, secure, dependable, and domestic energy, the results of the power sector efforts will be evident in opportunities for geothermal development. This would be evidenced by such activities as requests for proposals, renewable portfolio standards, inclusion in integrated resource plans, regional commitments (e.g., the Western Governors' Association renewables initiative) and state and national tax credits, and other incentives.

R&D Technology Transfer – GPW also seeks to match new innovative technology to market and project needs and assist the geothermal industry to be more competitive in developing markets. The state framework is important because of individual state policies, local

utility purchasers of renewable energy, and state-based federal agency needs. Industry often participates in a public review process, and this affords the opportunity to address R&D needs through both market pull and technology push.

Where the Program has demonstration needs, industry is typically recruited to implement new technology into installations. Where developers and power producers have technical issues, the GPW team strives to solve these problems and to determine if technology solutions can be transferred from Program R&D. GPW strives to act as an interface between industry needs (market pull) and Program technology innovations, products, and services (technology push).

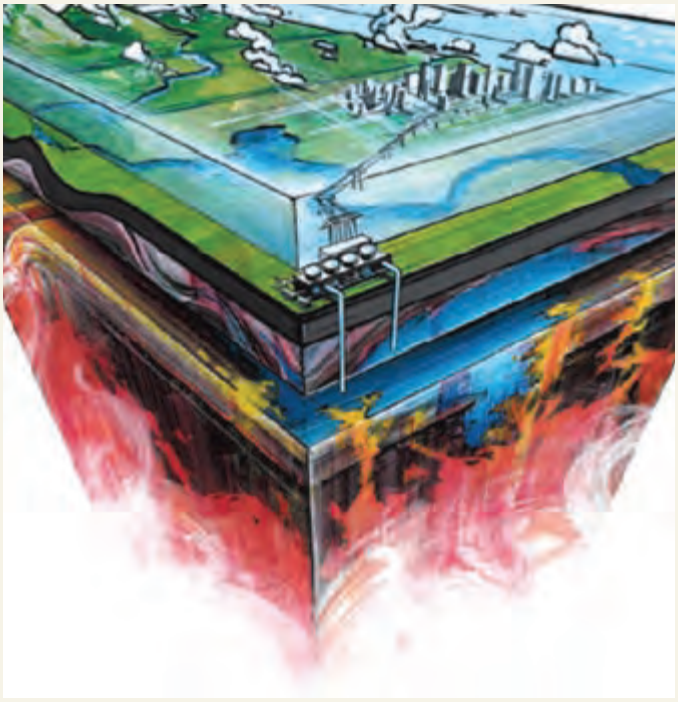
Time for a 'Check Up'

In 2004, GPW underwent a peer review that provided a critical, formal, documented evaluation of early activities. This process used objective criteria and external independent peer reviewers to judge the merits, results, direction, and effectiveness of the GPW program. The peer review panel also assessed program strengths, weaknesses, and gaps, and provided recommendations for improving the effectiveness of GPW activities.

The peer review team noted that after four years of GPW activity, the geothermal industry is facing a future with greater opportunities resulting from a number of key factors, including the passage of legislation mandating minimum renewable energy contributions in the supply portfolio of investor-owned utilities in several western states (see *New Policies Have a Favorable Impact on Geothermal Development*). The consistent and positive message about geothermal's potential and benefits from the GPW team staff has likely contributed to creation of the current market and potential for future expansion.

Federal Role

In its federal role, GPW serves as a catalyst and coordinating body that assists in bringing geothermal technologies to wider market acceptance and greater realization of geothermal energy potential. Knowledge and technology transfer is an essential facet of GPW, with staff facilitating access to the newest and best geologic and resource data and evaluation tools, and helping couple market needs with DOE Geothermal Technologies Program R&D results. Winning six R&D 100 awards within five years is a noteworthy indicator of the value the Program's R&D delivers (see *R&D 100 Awards and Market Needs*).



Imagine utility load-growth needs being helped by new geothermal power.

GPW works at all levels of government: local, state, regional (e.g., state energy offices and Western Governors' Association), and federal (e.g., U.S. Departments of Interior and Agriculture). Knowledge and technology transfer constitute a prime goal of GPW activities, with particular focus on resource integration, transmission and distribution issues awareness of geothermal technology benefits and advantages and institutional barriers, such as leasing and permitting time frames and costs.

Success in this program area contributes to the DOE Office of Energy Efficiency and Renewable Energy mission by enhancing energy productivity, bringing clean, reliable, and affordable energy technologies to the marketplace, and making a difference for Americans by enhancing our energy choices. Success also contributes to the nation's energy security, environmental, and economic development initiatives.

PIX13100, NREL, Bruce Green

The Idaho State Capitol Building and adjoining office buildings are heated by the state Capitol Mall geothermal district-heating system.

New Policies Have Favorable Impact on Geothermal Development

National, state, and local energy policy and this has been a rapidly evolving area recently. Within the last few years, numerous policies and regulatory actions have had a profoundly positive impact on the development and market acceptance of renewable energy technologies, including geothermal.

There are many policy options for geothermal energy development, such as grant and loan programs; corporate, sales, and property tax incentives; and 'green power' purchasing and mandatory utility requirements. Two policy concepts being implemented at the state level are renewable portfolio standards (RPS) and public benefit funds (PBF).

State Activity and Interest

RPS policies create mandates for states or specific utilities to generate a percent of electricity from renewable sources. Typically, a state decides how to fulfill this mandate using a combination of renewable energy sources, including wind, solar, biomass, and geothermal, or other renewable sources. Some RPS policies specify the technology mix, while others leave it up to the market. States may even include energy efficiency improvements as part of their 'clean power' requirements. Hawaii, Illinois, and Minnesota apply voluntary RPS policies, as another option.

To date, 21 states and Washington, D.C., have implemented minimum RPS or generation targets, including several in western states with known geothermal potential. For example, California, with the fifth largest economy in the world, has enacted a requirement of 20 percent by 2017. In fact, a recent RPS integration study done for the California Energy Commission indicated that geothermal resources would contribute the most toward reaching this goal. Nevada, called the Saudi Arabia of geothermal resources by U.S. Senator Harry Reid, has a 20 percent requirement (which

includes energy efficiency) by 2013. Some of the other western states with RPS policies are Montana with a 15 percent requirement by 2015 and New Mexico with a 10 percent requirement by 2010.

Senator Harry Reid, Nevada.

PBF policies are typically state-level programs developed through the electric utility restructuring process to assure continued support for renewable energy resources, energy efficiency initiatives, and low-income support programs. These funds are also frequently referred to as a system benefits charge. Such a fund is commonly supported through a charge to all customers on electricity consumption, e.g., 0.2 cents/kWh. Examples of how the funds are used include: rebates on renewable energy systems, funding for renewable energy R&D, and development of renewable energy education programs. To date, 15 states and Washington, D.C., have PBF policies, including several western states with known geothermal potential, such as Arizona, California, Oregon, and Montana.

National Activity and Interest

The new 2005 Energy Bill recently passed by Congress and signed by President Bush on August 8, 2005, previously included a 10 percent national RPS, however, it was removed in a joint conference committee vote. Measure sponsors will reintroduce RPS legislation, and we may yet see a national RPS.

This new legislation contains some noteworthy and substantial incentives for geothermal development. These will be briefly described below.

Production Tax Credit – A 1.9 cents/kWh credit is in place, and developers may claim this credit for ten years instead of only five years, as was the case until the new energy legislation went into effect. The generation facility must be "placed in service" by December 31, 2007.

Utility Cooperatives – This provision allows cooperatives to pass any portion of the renewable electricity production credit to their members, thus sharing financial incentives with investors. An eligible cooperative is defined as a cooperative organization that is owned more than 50 percent by agricultural producers or entities owned by agricultural producers.

Clean Renewable Energy Bonds – This provision creates a new Clean Renewable Energy Bond (CREB) to provide cooperatives, other not-for-profit electric companies, and Indian Tribal governments incentives for building new geothermal and other qualified energy projects. Provision is effective for bonds issued after December 31, 2005.

President Bush signed the energy bill on August 8th. Credit: Eric Draper, White House

The bill streamlines some of the most bureaucratic aspects of the law. It simplifies the royalty payment requirements, provides clear direction for the agencies to make geothermal use a priority, gives local governments more funding to mitigate impacts, and ensures that the federal agencies will have the resources needed to implement the new law and quickly work-off a backlog of unfinished studies and lease applications.

In regards to royalties, before this new law, the federal and state governments equally split royalty payments that companies pay when they lease public lands for geothermal power. Now, the states will receive half the royalty income, with the federal and county governments each receiving 25 percent. And as Churchill County (Nevada) Commissioner Norman Frey says, "For a small county like Churchill, it's a big deal." The new 25 percent split could mean about $1.5 million for Churchill County, which could go toward the library or senior center, according to Commissioner Frey.

Direct users of geothermal energy (non-electric uses) may also use a simpler procedure for leasing on federal lands and establishing a fee schedule instead of royalty payments. State and local governments are now allowed

PIX07662, INEEL, Joel Renner

Brady Power Project, a 27-MW geothermal power plant, at Brady Hot Springs, Churchill County, Nevada. Churchill County will gain revenue from new royalty arrangements and geothermal power development.

to use geothermal resources for public purposes at a nominal charge. This could lead to substantial geothermal direct uses, such as district heating, while achieving significant financial savings on supplanted conventional energy costs.

Geothermal Heat Pumps – One of the highlights of the new bill addresses homeowners, who are granted up to $300 in tax credits (Sec. 1333) for the cost of new geothermal heat pump (GHP–sometimes called a ground-source heat pumps) systems. To be eligible, certain performance and energy efficiency standards must be met. However, the system must include a 'desuperheater' or integrated water heating to meet the credit's criteria. There are also provisions for residential tax credits and commercial tax deductions for energy efficient building, and this could include the use of GHPs. According to the Geothermal Heat Pump Consortium, an industry group, there are 22 states that offer tax incentives for GHPs. You can check to see if your state offers incentives at: ***www.geoexchange.org/incentives/incentives.htm.***

The section covering renewable energy security offers a 25 percent rebate, up to $3,000, for renewable energy systems that "(i) when installed in connection with a dwelling, transmits or uses- (I) solar energy, energy

PIX06537, NREL, Warren Gretz

Residential application of a geothermal heat pump in Colorado.

PIX08827, Geo-Heat Center

In Klamath Falls, Oregon, the city applies direct-use geothermal for keeping sidewalks and bridges clear and dry after a snowfall.

derived from the geothermal deposits, energy derived from biomass, or any other form of renewable energy which the Secretary specifies by regulations, for the purpose of heating or cooling such dwelling or providing hot water or electricity for use within such dwelling…" The GHP industry is now working to ensure GHP technology is not excluded from this definition, which could bring an even greater interest to geothermal technology.

R&D Direction – The 2005 Energy Bill's Title IX, *Research and Development*, includes provisions directing DOE to continue a geothermal research program, providing specific goals for that effort. The bill language stipulates:

"GEOTHERMAL. The Secretary shall conduct a program of research, development, demonstration, and commercial application for geothermal energy. The program shall focus on developing improved technologies for reducing the costs of geothermal energy installations, including technologies for:

(1) Improving detection of geothermal resources

(2) Decreasing drilling costs

(3) Decreasing maintenance costs through improved materials

(4) Increasing the potential for other revenue sources, such as mineral production, and

(5) Increasing the understanding of reservoir life cycle and management."

Further, the 2005 Energy Bill revised the Geothermal Steam Act and directs the U.S. Geological Survey to submit an updated nationwide geothermal resource assessment to Congress within three years. There hasn't been a nationwide geothermal resource assessment in nearly 30 years.

Senator Pete Domenici (New Mexico), chairman of the Senate Energy and Natural Resources Committee, in recently describing the importance of the new energy bill, said, "Renewables will go faster and farther with this bill than they ever have." Also in regards to the new bill, the Senator said, "Instead of begging OPEC to drop its oil prices, let's use American leadership and ingenuity to solve our own energy problems." Senator Larry Craig (Idaho) added: "This Bill represents a framework for energy independence in the future through the use of cleaner technologies today, and the development of clean energy technologies for the future."

Senator Pete Domenici, New Mexico

Senator Larry Craig, Idaho

Upon signing the 2005 Energy Bill, President Bush said, "The bill offers new incentives to promote clean, renewable geothermal energy. When you hear us talking about less dependence on foreign sources of energy, one of the ways to become less dependent is to enhance the use of renewable sources of energy."

Karl Gawell, executive director of the Geothermal Energy Association, calls the new geothermal provisions in the 2005 Energy Bill "a dramatic improvement in the law that will encourage the rapid expansion of geothermal energy use in the West." Congress' decision last year to include geothermal power in the Production Tax Credit has generated significant interest in new production. Between January and May 2005, there were 483 megawatts (MW) of new geothermal power purchase agreements signed. These new projects are located throughout California, Nevada, Arizona, Utah, Hawaii, and Idaho. Also moving forward are small-scale projects in California, New Mexico, and Alaska not included in this total.

Regional Activity and Interest

Adding even more encouragement to this changing policy landscape, the Western Governors' Association (WGA) passed a *Clean and Diversified Energy Initiative for the West* resolution and has set a goal of generating 30,000 MW of electricity from clean, renewable energy sources, such as geothermal, by 2015. To ensure that newer, clean energy sources play an important role in meeting this goal, this resolution is specifically concerned with identifying ways to increase the contribution of renewable energy, energy efficiency, and clean energy technologies within the context of the overall energy needs of the West. The growing prevalence of wind energy applications and the prominence of geothermal resources should be two substantial early contributors to reaching this WGA goal.

The Next Frontier

Many scientists believe carbon dioxide and other greenhouse gases cause global warming that is affecting coastal areas, icebergs, and wildlife. Around 40 percent of U.S. carbon dioxide emissions come from fossil fuel power plants. A recent *National Geographic* (September 2004) article said, "There's little doubt that greenhouse gases released by industry, agriculture, automobiles, and coal-fired electric generation are a key factor in changing Earth's climate."

An overwhelming majority of Americans—94 percent—supports U.S. limitations on greenhouse gas emissions at least as much as the other developed countries do on average (July5, 2005, PIPA, University of Maryland). The "Sense of the Senate on Climate Change" amendment states, "There is a growing scientific consensus that human activity is a substantial cause of greenhouse gas accumulation in the atmosphere, and mandatory steps will be required to slow or stop the growth of greenhouse gas emissions into the atmosphere."

Nine northeastern U.S. states are working on a plan to cap and then reduce the level of greenhouse gas emissions from power plants—the first U.S. deal of its kind. It's somewhat noteworthy that Republican New York Governor George Pataki brokered the deal. The so-called 'Regional Greenhouse Gas Initiative' would explore a market-driven cap-and-trade system where businesses must trim emissions under set limits or buy credits from companies that have complied with the limits. The move comes as California, Washington, and Oregon are considering a similar pact. This may be the next major activity area concerning energy and environmental policy deliberations.

Clean Energy Award

Calpine Corporation has received an award from the California Department of Conservation for environmental stewardship, safety, infrastructure maintenance, and resource conservation of its Geysers geothermal operations. The award marks the fourth consecutive year Calpine has received such recognition. "Calpine has continued its outstanding record for lease maintenance and environmental stewardship in The Geysers Geothermal field," said Hal Bopp, State Oil and Gas Supervisor for the California Department of Conservation. Calpine is one of only two geothermal operators to ever receive the award.

Use of geothermal resources benefits local and regional economies—often in rural areas—and creates and brings jobs and income with development. And use of geothermal resources has valued environmental benefits, while offsetting the need for conventional fossil-fueled power generation with all its emissions issues. The proven array of geothermal technologies—power plants, direct-use applications, and geothermal heat pumps—stand ready to make a substantial contribution to reducing greenhouse gas emissions. Why wait?

PIX00560, NREL

Pollution from a power plant using coal to generate electricity.

Geothermal Energy Uses

Typical uses of geothermal energy at different temperatures

700˚F

400˚F
204˚C

350˚F
177˚C

300˚F
149˚C

250˚F
121˚C

200˚F
95˚C

150˚F
66˚C

100˚F
38˚C

70˚F

60˚F

50˚F

40˚F/4˚C

Flash & Dry Steam Geothermal Power Plants Hydrogen Production* & Minerals Recovery

Binary Geothermal Power Plants Hydrogen Production*

Fruit & Vegetable Drying

Mushroom Culture

Soft Drink Carbon-ation

Geo-thermal Heat Pumps

Cement & Aggregate Drying

Onion & Garlic Drying

Food Processing

Snow Melting & De-icing

Pulp & Paper Processing

Aqua-culture**

Lumber Drying

Concrete Block Curing

Bathing

Refriger-ation & Icemaking

Fabric Dyeing

Green-housing & Soil Sterilization

Building Heating & Cooling & Water Heating

Soil Warming

Ethanol, Biofuels Production

Beet Sugar Evaporation & Pulp Drying

Blanching, Cooking & Pasteur-ization

Biogas Process

*Geothermal electricity can be used to produce renewable Hydrogen.
**Cool water is added to make the temperature just right for the fish.

A Strong Energy Portfolio for a Strong America
Energy efficiency and clean, renewable energy will mean a stronger economy, a cleaner environment, and greater energy independence for America. Working with a wide array of state, community, industry, and university partners, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy invests in a diverse portfolio of energy technologies.

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