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DISCLAIMER

FOREWORD

I wish to thank Portland General Electric, the Warm Springs Indian Reservation, and the State of Oregon for their superb hospitality during our Geothermal Workshop at Ka-nee-ta. I also want to express my appreciation to the session chairmen, speakers, and panelists for an excellent job, and also to all of you who contributed your ideas to the many discussions.

Geothermal energy is the kind of resource whose development is dependent on close coordination and cooperation between electric utilities, resource companies, regulatory agencies, and researchers if we are to recover it and deliver it to the market at prices the consumer can afford. It was with this thought in mind that our purpose for this workshop was to promote an exchange of ideas and information that will help chart future directions for our efforts, collectively and individually, that will hasten the development of geothermal energy. In retrospect, the high level of participation by all attendees during the course of the workshop contributed most toward achieving this purpose.

Any comments that you may have concerning the workshop, its format or content, or these proceedings are invited, and I hope that you will join us again at our annual workshop next year.

These proceedings contain all the presentations for which papers were submitted, and summaries of the workshop sessions. It was not possible to transcribe all of the discussions; however, they were reviewed and the more significant issues noted.

Vasel W. Roberts
EPRI Program Manager
Geothermal Energy

ABSTRACT

The Electric Power Research Institute sponsored a Geothermal Workshop in July 1977 at Warm Springs, Oregon. The purpose of the workshop was to:

(1) Expose details of the EPRI Geothermal Program to the geothermal community

(2) Exchange information and ideas on projects and important issues among all segments of the geothermal industry

(3) Gain insight and recommendations for future planning

The participants included representatives from the utility industry, geothermal resource industry, suppliers, academic institutions, local and state governments, environmental groups, DOE, and other interested persons.

This report attempts to capture the main flow of ideas that transpired at the meeting and is organized to include reports on individual EPRI and utility projects as well as results of workshop sessions on reservoir engineering, geothermal energy pricing concepts, and future directions of geothermal R&D.

CONTENTS

Section 1

WELCOME AND KEYNOTE ADDRESS

WELCOME

J. Lynn Rasband
Southern California Edison Company
Chairman, EPRI Geothermal Program Committee

Because of the utility funding constraints and difficulty in obtaining R&D funding, EPRI's budget in general has not been able to grow quite as fast as we had envisioned. In fact, in several of the program areas including the Geothermal Program, there have actually been some decreases. However, in the meeting which we are initiating this morning, we have been charged to put together the need of the industry, both the utilities and the geothermal producers, to establish a meaningful program whereby we can identify the items that need to be done--that have to be done--to move the geothermal industry ahead at a more rapid rate than before. As there are members of the Geothermal Program Committee present, we are going to define a program at the conclusion of this meeting which we think must be done and give the reasons thereby. We are then going to work to gain additional funding to go ahead with this program.

As you know, the key project of the EPRI Geothermal Program is the hydrothermal demonstration plant in the Heber area and we are looking forward to its successful implementation. However, we want to accomplish the other things in the research and development program that need to be done to satisfy the utilities and the geothermal producers so that utilization can go forward at a greater rate. I want to refer to 2 or 3 sentences from the preliminary report on geothermal energy to the World Energy Conference prepared by Vasel Roberts, his staff, and consultants. It estimates the geothermal resource base in the world today as about 5.8×10^{14} MWh thermal. Now that's a lot of energy, but only about 2% of the resource base is high enough in temperature to be considered for electric power generation, and only about one part in ten thousand can be converted to electric energy with our present technology. Our purpose for being here is to identify what things we need to do so that greater amounts can be converted to electric energy and also we can identify institutional and other constraints for utilizing geothermal energy. I hope that we can go forward and work together to accomplish this as a group of interested people caught up in geothermal energy.

KEYNOTE ADDRESS

Frank M. Warren
Portland General Electric Company
Chairman of the Board
Electric Power Research Institute

I guess I wear two hats today. One as Chairman of EPRI, and one as Board Chairman of Portland General Electric Company.

It seems particularly fitting that a workshop of this caliber is being held at a resort area which has been built adjacent to one of Oregon's 200-plus surface manifestations of geothermal energy. We are, as they say, "where the action is."

Kah-nee-ta's Hot Springs is somewhat of an enigma to those who are attempting to understand the nature and occurrence of Oregon's geothermal resources. It is the only known hot spring that issues along the eastern margin of the Oregon Cascades, and discharges over 30 miles from the nearest major Cascade volcano. In view of this large distance from an obvious potential heat source, one is left with the problem of explaining the origin of Kah-nee-ta's hot waters, which according to the U.S. Geological Survey may be derived from a subsurface geothermal reservoir with temperatures approaching 150°C.

So you readily see that the task of locating and testing a potential resource associated with Kah-nee-ta Hot Springs to determine its suitability for electric power generation is beset with the numerous problems and uncertainties that in general plague the geothermal industry today. Many of these problems will undoubtedly be highlighted later in the week, as one of the two major workshop sessions will be devoted to geothermal reservoir detection and verification. This subject is of fundamental interest to those of us in the utility industry, and those of you representing resource companies or other private geothermal interest groups.

The theme of this workshop sponsored by the Electric Power Research Institute, or EPRI, is "Geothermal Milestones 1977." And I think it is most appropriate. Webster's dictionary defines milestone as "a significant point in development," and let us hope as we look back to this conference and the events of this year, 1977 will indeed be a milestone in the development and utilization of this country's indigenous geothermal resources. It very well could. Certainly a meeting of this magnitude, which enables exchange of information between the probable resource developers and the ultimate resource consumer - the utility industry - is not insignificant in this regard. Those of you representing legal, environmental and regulatory interests also have an important role to play, as the ultimate disposition of many key issues under your domain will directly impact both the growth and vitality, and public understanding and acceptance of the geothermal energy option.

We have already jumped over several important hurdles this year in the development of the geothermal industry. On May 6, ERDA signed the first Geothermal Loan Guarantee of $9.03 million with Republic Geothermal and its lender, Bank of

America, thereby committing the federal government to share both the financial and technological risks in the development of the East Mesa, California, geothermal resource. That is most encouraging. Similarly, the Carter Administration's endorsement of tax advantages for the geothermal industry will hopefully provide impetus for federal tax legislation that will make geothermal competitive with the petroleum industry in attracting high-risk venture capital from the investment community.

In the area of resource investigations, we in Oregon are particularly pleased about the recently initiated joint federal/state three-year program to evaluate the geothermal potential of the Mount Hood Known Geothermal Resource Area (KGRA). Finally, from the standpoint of an electric utility, the most noteworthy event of 1977 to date was ERDA's recent request for industry interest in, and an apparent intent to fund, a commercial-sized demonstration facility to utilize a low-salinity, moderate-temperature hot water geothermal resource for power generation. Such demonstration will provide information required by the utility decision maker in evaluating the desirability of the geothermal alternative, namely fuel supply longevity, capital and operational costs, and construction lead times.

To help meet this request, the Electric Power Research Institute has joined with the San Diego Gas & Electric Company and a consortium of other utilities, including Portland General Electric Co., in cosponsoring the Heber Geothermal Demonstration Plant for consideration by ERDA. This participation by EPRI, which is the research and development arm of the electric utility industry, is consistent with the overall objective of the EPRI Geothermal Program - to adapt current technology and develop new technology required for early commercial utilization of geothermal energy. To attain this objective, the program is concentrating a major share of its effort on the development of hydrothermal hot water resources. We in the utility industry believe that this resource type has the best prospect for power generation in the near term.

Well, what is EPRI doing? Where is it coming from? Where is it going? Before highlighting some of the studies presently under way at EPRI in support of hydrothermal resources development, let me take several minutes to place the Geothermal Program in perspective with the overall research and development activities presently being conducted at EPRI. By doing so, I think the utility industry's present viewpoint concerning the potential contribution of geothermal resources in meeting this nation's future demand for electrical energy will become apparent.

As most of you know, the Electric Power Research Institute came into being in 1973 under the voluntary sponsorship of the nation's electric utility industry - public, private and cooperative. Its assigned mission is to conduct a broad, coordinated program of research and development with the aim of improving electric power production, transmission, distribution, and utilization in an environmentally acceptable manner. Given the many requirements and the broad interests of the electric utility industry, the potential for valuable R&D is unlimited.

The EPRI Program for 1977 is based on anticipated contract expenditures of $180 million. Nearly half the total amount is earmarked for the Fossil Fuel and Advanced Systems and Nuclear Power Divisions. This allocation reflects the present consensus of the electric utility industry, and the Federal government too, as a matter of fact, that during the next several decades major emphasis for base-load power generation must be placed in the use of coal and nuclear power.

EPRI's activities in new energy resources development has been allocated $10.3 million for 1977. It stands to reason that as the cost of exhaustible fuel resources goes up and the supply dwindles, it is imperative that the electric utility industry make a significant commitment now to the R&D of inexhaustible and renewable energy resources. We all know the lead times required for development from scientific, engineering, and commercial feasibility demonstration to utility integration and market penetration of these new energy resources are long. We must plan far enough ahead to permit a smooth transition from exhaustible to inexhaustible energy resources deployment. This is not easy, but it must be done. Our obligation and duty is to have power available for the people, now and in the years to come.

Our New Energy Resources Department is focusing primarily upon central station applications for electric power generation with fusion, solar, and geothermal. Although research and development of these alternatives is dominated by very large federal programs under ERDA, this effort would benefit greatly from early utility participation. This partnership support is not only necessary to provide broad support for new energy resource R&D, but it is essential to our having a voice in the development of those options that reflect utility requirements. Together, we can do a far better job of evaluating and weighing the pros and cons, the impacts and constraints. The dollars will be invested more wisely, and hopefully the results will be better and ready more quickly.

Projected funding for the EPRI New Energy Resources Department programs over the five-year period 1977-1981 is $51 million. Fusion and solar will each receive roughly 40 percent of the allocated funds, while geothermal receives the remaining 20 percent. These proportions are obviously subject to change should conditions change. Since the funding of New Energy Resources Department R&D is small in comparison with the federal effort, the main EPRI emphasis is to identify, assess, and relate utility requirements and impacts to the federal program for consideration. Thus, the EPRI effort is complementary to that of the federal program, by assuring the development of a number of preferred system concepts and alternatives, thus ensuring the availability of a combination of new energy resource options to supply the nation's future energy demands. It gives the program much-needed "practical direction."

It should also be pointed out that the total funding committed by the electric utility industry to new energy resources R&D is much higher than that channeled through EPRI. Significant investigative programs are carried out independently by many individual utility companies. The dollars come from a number of corporate money belts - and all are needed and welcome.

Now with that background, I would like to focus on the Institute's activities in geothermal, which is really why you are here. It is surprising to me how many people think that all you have to do to harness geothermal is to drive a pipe down wherever you see ground steam. They are amazed when you tell them that the nature of geothermal resources varies widely, complicating the problems of identification and utilization.

Temperatures range from 100°C to over 300°C and the geothermal reservoir fluids exhibit a wide variability in chemical and thermodynamic characteristics. Each geothermal resource type imposes certain requirements on the choice and design of the energy extraction system. For instance, in <u>fluid-dominated reservoirs</u>, the heat will be extracted together with the natural geothermal fluid. If the <u>fluid is steam</u>, conversion is straightforward. If the <u>fluid is in liquid phase</u> and the reservoir temperature is sufficiently high, spontaneous well-flow can be used (by flashing to steam). For low-temperature fluids, in many cases it will be necessary to preserve the temperature by suppressing flashing in the well or reservoir by maintaining the pressure above the flash point, in which case down-well pumping will be required.

Induced fracturing and circulation of a working fluid will be necessary in dry heat reservoirs. Well stimulation, in one way or another, may be required for formations wherein the permeability is low. Furthermore, systems for drilling into high-temperature formations will be needed if the higher temperature hot rock and magma resources are to be developed.

As utility people we have to say to ourselves, "Geothermal is certainly an energy source to evaluate. But just how much potential is there, and where does it fit into our system needs?"

Present geothermal reserves, producible and convertible to electricity at costs competitive with other energy sources, amount to roughly 4000 MWe-centuries. Another 50,000 MWe-centuries appear to be producible with near-term technology and to be commercially interesting. Therefore, one of the positive attributes of geothermal energy is that it can add to generation capacity with adaptions of current technology in the near term. Other portions of the resource are producible in the intermediate term of 1985-2000 with improvements in technology, while the advanced geothermal energy systems such as hot dry rock must await the development of new technology.

Plant size? Geothermal power plant size will be small, in the 25-MWe to 150-MWe range, and associated construction time is expected to be from 3 to 5 years. For these reasons, geothermal is expected to penetrate the market where small-increments, base-load energy, and short construction times are required.

An important part of EPRI's role in R&D is to help bridge the gap between technical feasibility and reduction to commercial practice. In this context it is appropriate for EPRI to participate, and even take the lead, in projects that are needed to develop models for replication and to increase the level of confidence in a particular set of technologies or a particular resource type.

Geothermal energy is essentially a sole-source commodity and therefore commitments to power plants, once constructed, are irreversible regardless of success or failure, since fuel substitution is not likely. Utilities must have detailed knowledge about the reservoir from which they will derive the energy. It is appropriate, then, that EPRI be involved in R&D associated with reservoir assessment and reservoir management. This position is reinforced by the fact that some utilities have or plan to take lease positions, and are likely to become owners or part-owners of the resource.

Power plant technology? Geothermal has some requirements that certainly can be improved with research. Unlike most generating methods, the geothermal power plant cannot be isolated from the energy source. The plant and the reservoir will operate together as a system and some of the problems, such as scale and corrosion control, may well overlap both parts of the system. In any case, the fluid conditions must be accepted as delivered at the plant and, likewise, the reservoir must accept spent geothermal fluids as delivered from the power plant, although some intermediate treatment is possible in the latter case. Brine treatment, heat transfer, phase separation, machinery rotation, and scale control, as well as in-process instrumentation, fall into this category.

Environmentally acceptable power generation systems are essential, and environmental control technology is certainly an appropriate EPRI R&D candidate. And of course, economic feasibility is extremely important to the industry and is yet another area for EPRI investigation.

So with this background in hand, and to put it very simply, the goal of the EPRI Geothermal Program is to adapt current technology and develop new technology for early commercial utilization of geothermal energy.

The specific objectives of the program over the next five years are to

- participate in construction and testing of a commercial-size geothermal power plant for the purpose of demonstrating the adequacy of technology, environmental acceptability, and economics of generating power from a moderate-temperature, low-salinity hydrothermal resource
- develop an information base on the chemistry, scaling characteristics, and corrosion potential of geothermal fluids, in order to provide design criteria for second generation power plant equipment
- start critical component development and tests
- initiate a subprogram in the development of geopressured resources

The EPRI program places high priority on the development of hydrothermal hot water resources, as these are the best prospect for power generation in the near term. Emphasis in the near term will be on the development of low-salinity hydrothermal resources. Our major objective will be to assemble all of the technology available and develop an operational data base for binary cycle power conversion using geothermal hot water as the energy source.

To meet this objective, and to get the necessary "actual-operation ingredients" we all need, EPRI has agreed to provide over $4 million funding in support of the Heber Geothermal Demonstration Plant to be constructed near El Centro, California, by mid-1980. We in the utility industry are hopeful that successful commercial demonstration of the binary cycle will provide the necessary technology to produce economically competitive electricity from hot water geothermal reservoirs in an environmentally acceptable manner. We think it is a significant step in the right direction.

I would like to touch briefly upon two topics to be discussed in later sessions of this workshop - the pricing of geothermal energy and reservoir verification. Both are extremely important. With respect to pricing, a contract for the sale of geothermal fluids by a producer to a utility is like a marriage in which divorce is impossible. Neither party has the practical option of changing to a new seller or a new buyer, yet each has different business objectives and philosophies. Each party is subject to somewhat different government action and regulations, which will often have a profound effect on their respective costs. The producer's cost of supplying fuel is affected in a major way by government regulations respecting resource depletion allowances, intangible drilling deductions, federal and state income tax rates, property tax rates, and income tax credits. Power plant costs are affected by all of the foregoing, with the exception of percentage depletion and intangible drilling deductions, and utility income is regulated by the Public Utility Commission. Clearly, there are many variables that influence pricing.

Certainly, it seems to me the geothermal fuel supply contract should begin with a good-faith negotiation as to the initial fuel selling price between the parties. It should be based upon the cost of making fluid available, useful energy content, and chemical quality. This negotiated selling price should be adequate to cover the costs of finding, confirming, and producing the energy with appropriate allowances for a fair return to the producer in proportion to the risks he must face. The pricing mechanism should also provide for an efficient trade-off between the interests of the field and power plant operators.

And, of course, some method of coping with the inflation factors must be developed. It might be achieved by tying price to recognized cost indicators. It might be through scheduled periodic renegotiation. It can be evaluated in many ways. One thing is sure: the derivation of a fuel pricing strategy that is comprehensive, yet fair and equitable to both the producer and utility, will indeed be challenging.

One of the key questions the utility industry must get an answer to is "How much energy is down there?" Predevelopment verification of a reservoir's capability to sustain fuel production for 20-30 years is essential. This time period is required for the utility to recapture its power plant capital expenditures and realize a reasonable rate of return on the initial investment. But geothermal is a fairly new technology, and we need to know a lot more about its life expectancy. The long-term reliability of geothermal reservoirs to supply fluids to a power plant is difficult to substantiate because of limited experience in geothermal reservoir engineering and the lack of long-term case history data on which field longevity predictions can be based. There appears to be a serious need to correlate geophysical data with reservoir depth characteristics and to develop test methods that allow prediction of reservoir longevity without waiting until the field is exhausted.

One protection suggestion is that the federal government could initiate a "resource longevity insurance" to help minimize the risk to utilities which choose to utilize geothermal resources for electric power production. This insurance could take the form of expedited depreciation in the event of resource failure, reimbursement of additional expenses incurred as a result of early field depletion, or other similar mechanisms. Hopefully, these are the types of ideas that will be developed and analyzed during this EPRI-sponsored workshop.

Finally, potential geothermal areas exist in the eastern United States, including portions of the Appalachians, the White Mountains of New Hampshire, and the Gulf Coast states. In view of this apparent widespread occurrence nationally, and of the significant near-term generation potential from hydrothermal resources in the western U.S., I urge that the EPRI program planning workshop consider a stronger R&D effort in hydrothermal conversion technology and expanded investigations of other resource types including geopressured and hot/dry rock.

Research is indeed our key to tomorrow's energy. One of the most damaging things that can happen to a nation is to stop searching ... to stop looking ahead. And one of the most serious concerns to the utility industry is to show our customers and our nation that we aren't hiding our heads in the sand and saying, "Coal and nuclear is our answer for evermore. We need nothing else." But rather that people realize that we are ever searching for new ways to do things better.

And we must move ahead with speed. We cannot tarry. As Alan Valentine said, "Whenever science makes a discovery, the devil grabs it while the angels are debating the best way to use it."

Section 2

CURRENT EPRI PROJECTS

FEASIBILITY STUDY OF A LOW-SALINITY HYDROTHERMAL DEMONSTRATION PLANT

EPRI Research Project 580-1

Ben Holt
Edward L. Ghormley
HOLT/PROCON
(A Joint Venture of The Ben Holt Co. and Procon Incorporated)

INTRODUCTION

The objective of this study was to assess the feasibility of constructing a 25 MWe to 50 MWe geothermal power plant utilizing a low-salinity hydrothermal fluid as the energy source. Holt/Procon, a joint venture of The Ben Holt Co. and Procon Incorporated, was the prime contractor, with Geonomics, Inc., providing technical support as a subcontractor in the geotechnical and socioeconomic fields. The hydrothermal (i.e., liquid-dominated) geothermal reservoirs are located largely in the eleven western states. Most of the known reservoirs are relatively low salinity (less than 15,000 ppm TDS) and relatively low temperature (less than 200^{o}C). This type of reservoir appears to be widespread geographically and to represent a large proportion of the known geothermal resources in the United States. Accordingly, it was felt that a comprehensive study of the type undertaken herein would accelerate the commercial development of this important resource.

The first phase of the work led to the selection of a recommended site and a recommended process for the demonstration plant. The second phase included design studies of the proposed plant together with the preparation of an implementation plan.

During the first phase of the work, several parallel activities were carried out, including geotechnical, environmental, socioeconomic, and energy conversion economics.

GEOTECHNICAL ASPECTS

An evaluation was made of sixteen hydrothermal reservoirs in the United States. The reservoirs were selected for comparison on the basis of available data, development potential, and representativeness of known hydrothermal reservoirs in the United States. Six reservoir and fluid criteria were considered the most important in determining the development and power conversion potential: depth and lithology, reservoir temperature, tested flow rate per well, fluid chemistry, magnitude of the reserve, and reinjection potential. These criteria were evaluated for each of the selected reservoirs.

Geothermal reservoirs are classified by origin and occurrence into three types: those associated with unusual artesian or thermo-artesian conditions, the volcano-tectonic type, and the volcanic type. Two conceptual models for hydrothermal reservoirs were developed: sedimentary and volcanic. An imaginary or hypothetical reservoir representative of the mean of the majority of commonly occurring hydrothermal reservoirs in the United States was defined as an aid in assessing the representativeness of the actual reservoirs. The properties of the hypothetical reservoir were derived by comparative study of reservoirs, statistical data, and reservoir engineering calculations from which performance was estimated. The hypothetical reservoir appears to have a reasonable prospect for economic development using current technology. Nine minimum criteria to determine whether a hydrothermal reservoir has development potential were proposed.

The conclusion was reached that the Heber reservoir in the Imperial Valley of California and the Valles Caldera reservoir in New Mexico were representative of the hypothetical reservoir, and subsequent attention was directed towards evaluating these two sites as locations for the demonstration plant. Of the two the Heber reservoir was recommended because it met substantially all of the criteria and much more information was available on which to base its longevity and productivity. It was determined that the reservoir was capable of producing at least 200 MWe for a period of thirty years.

Following this determination additional studies were made investigating the geology, geophysics, hydrogeology, seismicity and subsidence in the Imperial Valley, with particular reference to the Heber site. The findings were:

- Geothermal development at Heber is not likely to have any adverse impact on the shallow groundwater resource of the area.

- Corrosion, scaling and presence of noncondensable gases should prove to be minimal for the Heber geothermal project.

- The Heber area lies in a general region of high seismicity and strain release.

- No fault has yet been mapped directly under the Heber area. The stress condition and the strength of the rocks at Heber are not known. Until such data are available, it is difficult to assess the possibility of increased seismicity due to geothermal activity.

- The Heber area is subsiding and tilting northeastward due to tectonic causes. The fluctuating subsidence rate is not great and should present no serious problems.

- Geothermal development activity at Heber should have a small effect on subsidence compared to that due to existing tectonic causes.

- Design of the structures should incorporate acceleration and resonance spectra that are available for the Imperial Fault 1940 earthquake located five miles northeast. A combined local soil test analysis and seismic structural response should be made as part of any detailed structural design. The design acceleration should not be less than 0.375 g.

- Baseline data should be obtained by monitoring the Heber area for seismicity and subsidence before power production begins. It is also desirable to have a permanent monitoring system throughout the life of the power plant.

ENVIRONMENTAL ASPECTS

This part of the work was directed towards the Imperial Valley broadly and the Heber reservoir in particular. The environmental impact of a geothermal development on climate, topography, soils, hydrology, air quality, biology, land use, aesthetics, and sensitive areas was examined. No significant environmental constraints were found, especially for the first plant.

Adequate Colorado River cooling water is available for the first plant. An ultimate Imperial Valley development (4000 MWe) would require the use of agricultural drainage water for cooling water. There are ample supplies of such water, but the effect of large-scale use on the Salton Sea should be evaluated.

The effect on air quality appears negligible both for the first plant and a large-scale development. Noncondensable gases will be reinjected completely in case the recommended binary cycle plant is built.

SOCIOECONOMIC ASPECTS

The study examined the socioeconomic impact of the geothermal development at Heber. It was concluded that development of Heber will create a limited number of new jobs, but is not likely to reduce unemployment to a significant extent. The county is expected to remain predominantly agricultural. The value of the land is expected to appreciate, and additional tax income will accrue to the county, which will serve to improve the quality of life in Heber and the Imperial County.

ENERGY CONVERSION ASPECTS

The final task in Phase 1 was the energy conversion study. Attention was focused on two principal sites, Valles Caldera and Heber. Raft River, Idaho, was also included, not as a candidate site, but as a representative of a low-temperature reservoir.

Nine cases were analyzed to show the effect of reservoir temperature and conversion processes on the cost of power produced. These cases examined flashed steam, binary cycle and hybrid processes for the three reservoirs. The reservoirs have bottom hole temperatures of approximately 260°C, 180°C and 150°C, respectively. The flashed steam cycle employs two stages of flashing, the steam from each stage driving a double-entry condensing turbine. The binary cycle is a closed-loop Rankine cycle using light hydrocarbons as working fluids. The hybrid cycle is a combination of the flashed steam and binary cycles.

The approach in determining technical and economic feasibility was to examine the three conversion options at the three sites at a net power output level of 50 MWe using wet cooling towers. Net power is the generator output less the parasitic power required for pumps and cooling towers, but excluding the power required to pump and reinject the geothermal fluids.

Preliminary engineering designs were prepared for each of the nine base cases as a basis upon which to prepare realistic estimates of the capital cost for the power plant, the field installation, and the transmission lines for each plant. Detailed capital cost estimates were prepared for the field, plant, and transmission costs at Heber. These estimates were then adjusted for the Valles Caldera and Raft River cases to reflect differences in design and location. This work was followed by the preparation of operating and maintenance cost estimates for field, plant, and transmission lines.

Fuel costs were estimated using a cost-of-service approach. Power conversion and transmission costs were estimated as the sum of fixed charges applied against the initial capital investment plus estimated operating and maintenance expenses.

The summarized results of the foregoing work are presented in the accompanying table, which sets forth pertinent design and cost data relating to the reservoir, the power plant, and transmission system. Capital cost estimates per kilowatt and estimates of fuel, conversion and transmission costs per kilowatthour are presented.

The cost of power delivered to the load center is least for the binary process at all three sites (i.e., 35 mills/kWh at Heber, 34 mills/kWh at Valles Caldera, and 55 mills/kWh at Raft River). The flashed steam process power costs exceed these amounts by 3 mills at Heber, by 5 mills at Valles Caldera and by 15 mills at Raft River. The higher costs of the flashed steam process are due to the higher brine consumption of the process.

Near-term alternative new power available in the Southwest will probably be based on either coal-fired or oil-fired power plants and will cost in the range of 30-35 mills/kWh. It appears that a 50 MWe binary cycle plant can be built at Heber to supply power at a cost within this range.

The conclusions reached as a result of the Phase 1 activities were:

- The geothermal reservoir at Heber is technically, economically, and environmentally feasible for location of the geothermal demonstration plant.
- The binary conversion process is technically, economically, and environmentally feasible for producing electric power using fluid from a hydrothermal reservoir. At the Heber site this process converts geothermal energy into electrical energy at a lower cost than does either the flashed steam process or the hybrid process.
- A 50 MWe binary conversion plant at Heber can produce electric power at a cost that is comparable with other new sources of power. A smaller plant would experience higher operating costs, which would reduce the profitability of the plant operation.

PRELIMINARY DESIGN

In the second phase of the work, design studies were continued covering a binary conversion plant at Heber. These studies included the following information:

Process Flow Diagrams
Piping and Instrumentation Flow Diagrams
Equipment Specifications
Piping Layout Drawings
Electrical Single Line Drawings
Electric Classification Drawing
Site Layout Drawings

Trade-off studies to optimize the geothermal plant process systems were included. The following conclusions were reached:

- Operational economy is favored by a low pinch temperature between the reservoir fluid and the working fluid.

- Operational economy and the cost of energy produced are only slightly affected by the approach temperature between the cooling water and the ambient wet bulb temperature.

- The cost of energy is affected by cooling water temperature rise. An intermediate temperature rise of about 11.7°C (21°F) gives the lowest cost of energy.

- A study was made of the major process pumps to determine whether turbines or electric motors should be used for motive power. It was concluded that electric motors should be used to drive the hydrocarbon circulating pumps and the cooling water pumps.

An economic analysis was made in which the following costs were developed:

- The capital cost of the conversion plant is estimated to be $29,634,000 or $592/kWh.

- The cost of electrical energy produced by the plant is estimated to be 35.84 mills/kWh.

IMPLEMENTATION PLAN

An implementation plan was developed in which it was concluded that a geothermal demonstration plant can be constructed and operating by 1980 if permits are obtained without delay and construction proceeds according to schedule.

ENERGY CONVERSION STUDY SUMMARY

	HEBER			VALLES CALDERA			RAFT RIVER		
	BINARY	FLASH	HYBRID	BINARY	FLASH	HYBRID	BINARY	FLASH	HYBRID
THE RESERVOIR									
Reservoir Temperature, °F	360	360	360	500	500	500	300	300	300
Producing Well Capacity, K lbs/hr	650	650	650	250	250	250	650	650	650
No. of Wells, Start of Production	12	16	13	11	16	12	19	27	20
Injection Well Capacity, K lbs/hr	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
No. of Wells, Start of Production	6	8	6	2	4	3	9	13	10
Production and Injection Well Cost, K $	300	300	300	700	700	700	600	600	600
Total Field Capital Cost, M $	11.8	14.35	12.2	16.8	21.4	19.4	29.5	42.3	38.3
O&M Cost, Field, K $/yr	1,973	2,486	2,050	1,068	1,302	1,228	2,953	4,181	3,808
THE POWER PLANT									
Wet Bulb Temperature, °F	80	80	80	62	62	62	65	65	65
Brine Consumption, M lbs/hr, Start	6.942	10.01	7.25	2.62	3.96	3.00	11.00	16.30	11.9
lbs/kwh	139	200	145	52	76	60	220	331	238
Brine Temperature, Out, °F	154	217	162	110	218	154	145	208	163
Thermal Efficiency, %	11.75	12.09	11.89	15.91	14.86	13.79	9.86	11.19	11.28
Generator Output, MW	64.3	55.0	62.0	56.3	55.0	56.0	67.5	55.0	66.0
Pumping Work, MW	9.5	3.2	10.7	3.6	1.9	4.6	15.9	3.7	13.5
Cooling Tower Work, MW	4.8	1.1	1.3	2.7	1.1	1.4	1.6	2.1	2.5
Net Power, MW	50.0	50.7	50.0	50.0	52.0	50.0	50.0	49.2	50.0
Plant Cost, M $	28.5	26.8	36.6	26.5	28.1	37.6	32.3	35.9	39.8
Plant O&M Cost, K $/yr	1,200	1,171	1,360	1,085	1,239	1,312	1,331	1,366	1,468
TRANSMISSION COST, M $	0.500	0.500	0.500	1.900	1.900	1.900	3.600	3.600	3.600
OVERALL COSTS									
Field Development, $/kw	236	287	244	336	428	388	590	846	766
Power Plant, $/kw	570	536	732	530	562	752	646	718	796
Transmission, $/kw	10	10	10	38	38	38	72	72	72
Fuel Costs, mills/kwh	16.69	20.53	17.26	16.03	20.65	18.99	32.80	46.61	42.42
Plant Fixed Charges, mills/kwh	15.03	14.13	19.30	13.72	14.53	19.45	16.83	18.70	20.73
Plant O&M, mills/kwh	3.22	3.14	3.65	2.91	3.33	3.52	3.57	3.67	3.94
Transmission Cost, mills/kwh	0.28	0.28	0.28	1.03	1.03	1.03	1.97	1.97	1.97
TOTAL POWER COST, mills/kwh	35.22	38.08	40.49	33.69	39.54	42.99	55.17	70.95	69.06

Note: M = Millions, and K - Thousands.

HEBER GEOTHERMAL DEMONSTRATION PLANT

EPRI Research Project 580-2

C. R. Swanson
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San Diego Gas & Electric Company

The purpose of the Heber Geothermal Demonstration Plant project is to determine the feasibility of producing economical electric energy from this moderate temperature, low-salinity resource.

There are significant risks associated with the development of this first-of-a-kind power plant. For this reason, SDG&E has invited numerous entities to participate in this project and share the burden of the risks as well as the information produced by the project. In particular, the support of the Energy Research and Development Administration (ERDA) is necessary for this project to proceed to completion. On June 20, 1977, SDG&E and its participants responded to ERDA's Request for Expression of Interest for federal cost-sharing in a geothermal demonstration plant. The project participants will also respond to ERDA's Program Opportunity Notice when it is issued later this year. The Program Opportunity Notice is the last step required in the competitive process for the selection of the successful geothermal demonstration plant to receive ERDA support.

The Heber Geothermal Demonstration Plant will be the first U.S. commercial-scale geothermal power plant utilizing liquid-dominated resources. The plant will have a 65-MW (gross) and 45-MW (net) capacity. It will utilize the binary-cycle energy conversion process. The plant location is Heber, California, in the Imperial Valley.

The project is based upon the EPRI feasibility study for a hot water geothermal demonstration plant that was conducted by The Ben Holt Company during 1975 and 1976. The objective of the first part of this study was to make a technical, economic, and environmental analysis of a commercial-scale power plant. If supported by the findings, this portion of the study was to recommend a site for the construction of a 25- to 50-MW geothermal power plant and a power conversion cycle on which to base the design. Sixteen sites in the western United States were analyzed by this study. The three most promising sites were analyzed and compared in depth. These were Heber, California; Raft River, Idaho, and Valles Caldera, New Mexico.

Three energy conversion processes (i.e., flash, binary, and hybrid) were examined on the basis of:

- Reservoir development
- Technical feasibility of the power conversion process
- Power conversion system requirements
- Economics
- Environmental impact
- Identification of technology weakness

The first part of this study was completed in April 1976, with the following conclusions and recommendations:

1. The Heber site appears to have the best qualifications for the demonstration project in the early 1980s. The reservoir temperature, 182°C (360°F), is close to the average of the identified resources in the western states. The geothermal fluid composition is the most representative of other hydrothermal resources in the United States.

2. The salinity of the Heber brines (approximately 14,000 ppm) is slightly higher than average. However, the preliminary heat exchanger test at Heber, conducted by SDG&E in 1974, indicated there should be no great difficulty in using these fluids. Any system which could handle the Heber fluids should be capable of handling fluids of lower salinity.

3. The binary conversion process has the potential for technical, economic, and environmental feasibility in producing electric energy from a liquid-dominated reservoir. The binary cycle may be more economic than the flash cycle for this temperature reservoir and for those with lower temperatures. It may also be more environmentally acceptable.

4. A binary conversion plant at Heber has the potential to produce electric energy at a cost competitive with power from other economic generating sources.

The binary energy conversion process to be employed in this plant is an advanced concept that has the major advantage of being capable of converting a greater amount of geothermal heat into electrical energy than can the flash steam process. Much of the technology is now in existence; however, it has not been proven on a large scale. The major plant component, the hydrocarbon turbine, has never been constructed in this size.

The objectives of the project include the following:

- Determine technical and economic feasibility of generating power from liquid-dominated geothermal reservoirs
- Prove binary cycle technology on a commercial scale
- Achieve plant operation by mid-1980
- Document the results of engineering design, construction, and operation
- Accelerate the installation of additional geothermal power plants

The project will be conducted in six separate phases. Phase I is the feasibility study discussed earlier, which was completed in late 1976. Phase II includes the preliminary engineering design. Work on this phase is currently underway. Phase III will involve the detailed engineering design, equipment procurement, and site preparation. Construction will be accomplished during Phase IV. Phase V will include plant startup and the initial test period. Phase VI will include long-term operation and performance evaluation.

The EPRI/SDG&E funding agreement for the project was executed during June 1977. The Phase II statement of work provided for in this agreement includes the following general activities:

- Obtain utility participants
- Contract for
  --Participation
  --Geothermal Heat
  --Cooling Water
  --Power Sales
  --Engineering Design (A/E)
- Obtain ERDA funding support
- Conduct preliminary engineering design
- Obtain permits and conduct environmental studies

In December 1975, EPRI awarded a contract to SDG&E to manage an environmental baseline data acquisition study of the Heber area. This study has as its primary goal the collection and compilation of available data on the environment surrounding the Heber reservoir. The results of this study program will establish a foundation for environmental assessment of future geothermal development.

The Heber reservoir is located at the southern end of the Imperial Valley (Figure 1). An artist's rendering of the plant is shown in Figure 2. The major plant components include the cooling towers, turbine-generator and electrical equipment, brine working fluid heat exchangers, working fluid condensers, accumulators and condensate pumps. The production and reinjection well islands are also shown.

The project is being managed by SDG&E. EPRI, the California Energy Commission, and five other utilities have committed to participation.

The plant owners include:

- San Diego Gas & Electric Company (77%)
- Imperial Irrigation District (10%)
- Los Angeles Department of Water and Power (10%)
- Southern California Edison (3%)

EPRI's total contribution to the design and construction of the plant will be approximately $4.6 million. The California Energy Commission will contribute $50,000 per year for five years. Two additional utilities, Portland General Electric Company and Nevada Power Company, will each contribute $50,000 to the project. The California Department of Water Resources is considering making a contribution to the project.

As project manager, SDG&E will have overall responsibility for the design, construction and operation of the plant. The reservoir will be developed by the Chevron Resources Company and New Albion Resources Company, a subsidiary of SDG&E. Chevron will be the field operator. The Imperial Irrigation District has agreed to provide the cooling water needed during the early years of plant operation and has offered to purchase the electric power generated. Since the project must carry the burden of research and development expenses, the cost of power from the geothermal demonstration plant will be substantially higher than the cost of power from conventional resource alternatives (nuclear and fossil).

The project organization is shown in Figure 3. The project will include a management committee, an engineering committee and a technical advisory committee. The management committee will approve the scope and funding of work to be performed. Its members include the utility owners and EPRI. The engineering committee will provide engineering expertise to assist in solving any problems that may arise

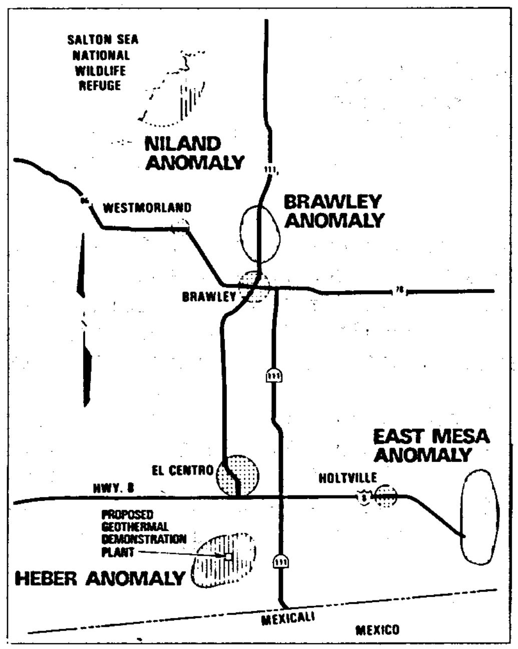

Figure 1

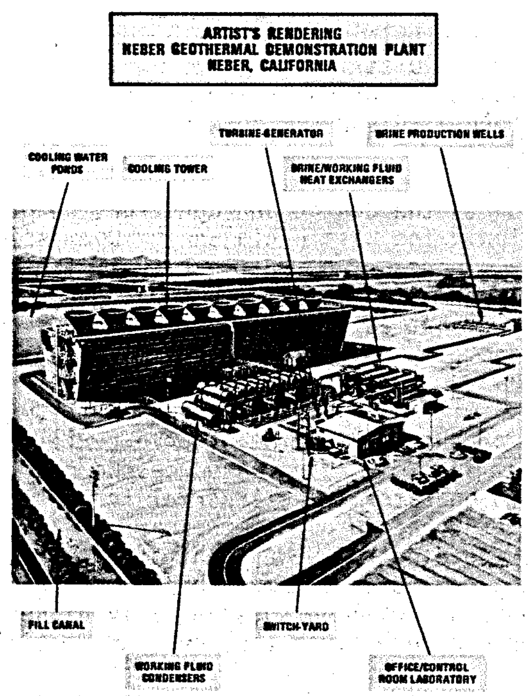

Figure 2

during the course of the project. This committee will review the engineering design as needed to assist in the successful completion of the project and will submit recommendations to the Project Director. It will be composed of one representative from each of the owners and each of the contributors. There will also be a technical advisory committee which will meet quarterly to exchange information on project status, discuss solutions to possible problems, and serve as a mechanism for dissemination of information regarding the project. It will consist of all project participants and other interested groups whose input would prove helpful to the project outcome.

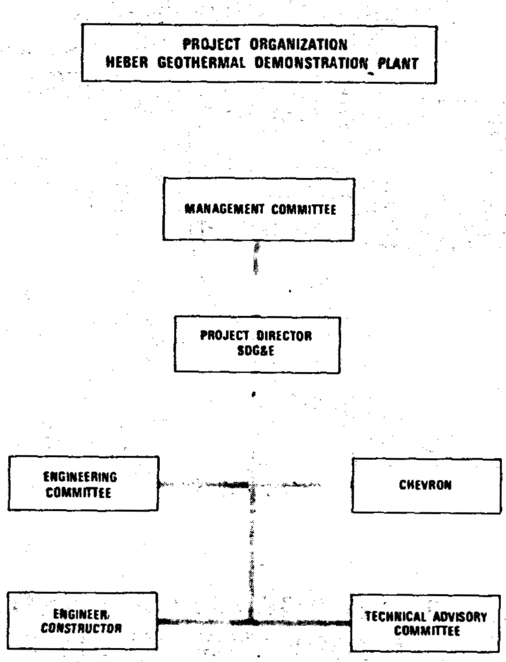

Figure 3

The total capital cost for the demonstration plant is estimated to be $42.8 million. The basis for the capital cost estimate and cash flow was the EPRI feasibility study plus SDG&E factors related to contingency, escalation rates, and plant availabilities. SDG&E's estimate is based primarily upon its own experience in construction and operation of power plants.

The plant will occupy an area approximately 122 m (400 ft) by 122 m (400 ft), or just under four acres. The total land required for the plant, sedimentation ponds, production well island and a buffer zone around the entire site is approximately 20 acres.

The brine production wells will be located adjacent to the perimeter of the power plant, clustered on production islands with directional drilling into the reservoir (see Figure 5). Brine reinjection lines will be routed from the site to reinjection wells some two miles away.

In the binary cycle, hot brine will be pumped from the wells and converted into mechanical work by means of a heat exchanger/secondary working fluid/turbine system. The cooled brine will be reinjected into the reservoir. The proposed working fluid will be preheated and vaporized by heat exchange with the brine and pumped to a pressure of 4137 kpa (600 psia) and a temperature of 149°C (300°F). The vapor would expand through the turbine and exhaust to the condensers and accumulators and then be pumped back through the brine heat exchanger, completing the circuit (see Figure 6).

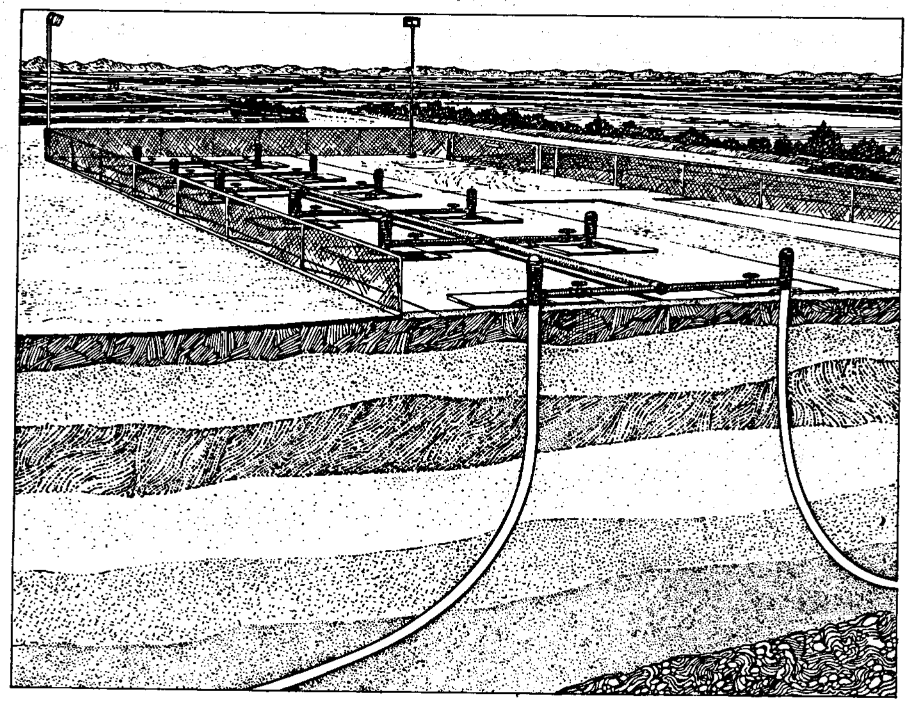

Figure 5

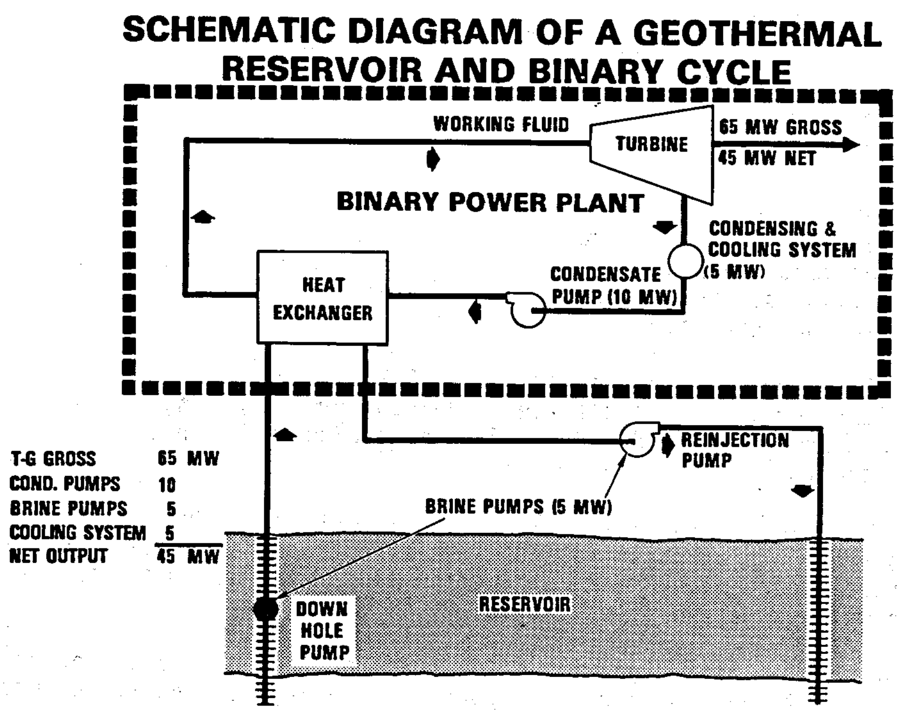

Figure 6

The schedule (see Figure 7) has critical events which must be completed on time to maintain a 1980 startup date. Vendors predict that 18 to 24 months will be required to design and build the turbine-generator. To meet this schedule, the purchase date of the turbine-generator is scheduled for around late 1977. The overall schedule is believed to be realistic. Some flexibility is included in the schedule to allow for unknowns. The actual lead time required for the first demonstration plant will serve as a basis for scheduling future plants.

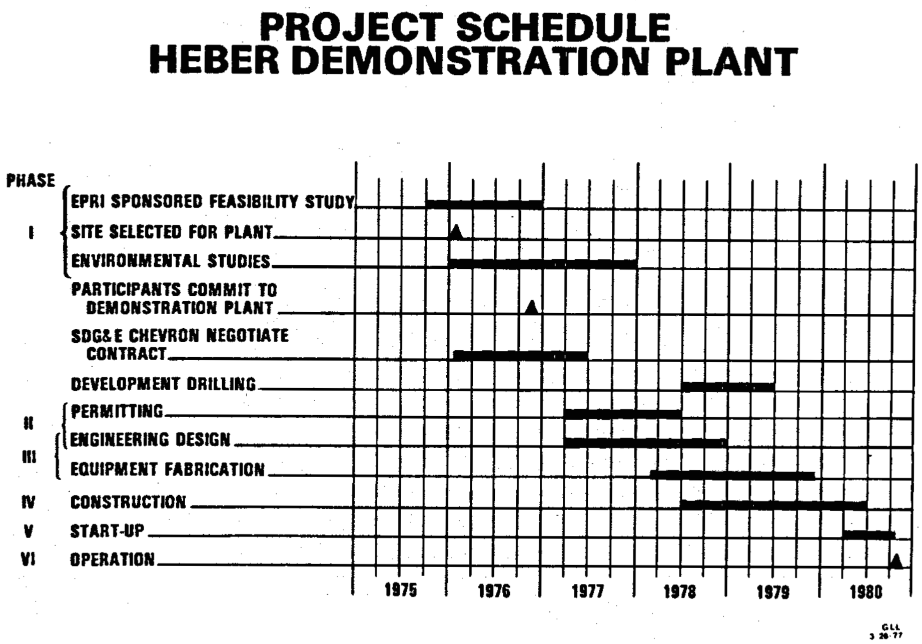

Figure 7

Fluor-Pioneer has been the corporation selected to design the demonstration plant. Fluor will subcontract portions of the design to The Ben Holt Company.

Primary objectives for Fluor in 1977 will be to (1) develop an implementation plan for the project, (2) establish an engineering schedule, (3) implement interface procedures with The Ben Holt Company, (4) develop the plant design criteria, and (5) complete most of the preliminary engineering design. The plant design will be based on the feasibility study. However, Fluor will be requested to check the accuracy and approach of the feasibility study and to conduct additional optimization studies. Among the early engineering tasks will be the development of a specification for the turbine-generator. Other engineering activities include development of drawings and specification for other equipment.

In conclusion, the Heber site appears to have the best qualifications for a geothermal demonstration plant utilizing the binary cycle. The installation of a plant at Heber would lead to an early demonstration of large-scale utilization of liquid-dominated reservoirs in the United States. Last, this demonstration would assist in the accelerated development of this new resource alternative.

BRINE CHEMISTRY/COMBINED HEAT AND MASS TRANSFER

EPRI Research Project 653-1

D. W. Shannon
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INTRODUCTION

One of the major concerns in geothermal development today is the extent of the resource base. Will a "geothermal fuel supply" last the 20 to 30 years needed to obtain a satisfactory return on the investment of an electric generating plant? If the plant investment is to be successful, we must also assure reliable plant operation, a high plant factor, and the disposal of the spent geothermal fluids in an environmentally acceptable manner.

There have been a number of studies trying to optimize a geothermal power plant cycle (such as multistage flash versus binary fluid) for various geothermal reservoirs. So far these studies have not taken into consideration that the power cycle chosen, and the engineering details of temperatures, pressures, and flows can profoundly alter the extent of scaling and corrosion, and the potential for plugging the waste injection wells. <u>Scaling is not an inherent characteristic of a geothermal fluid; it results from the process used to extract the energy</u>.

This program has as its objectives:

- develop a data base on the chemical factors affecting scaling
- develop computer models to estimate scaling rates in plant components
- develop computer models of the impact of scaling on long-term plant electric output and maintenance requirements

We recognize that such computer models have limitations and can only give back what has been programed. Obviously, at the present level of the state of the art, our understanding is still incomplete; therefore, our models will be incomplete. We must accept that these are first generation models.

However, computer models can be useful:

- The massive memory allows consideration of many facts simultaneously. An important fact is less likely to be overlooked.

- The models will be useful educational tools to scientists and engineers new to geothermal technology.

- The models provide a framework within which to plan field work and define test data to be gathered.

- The models will permit comparison of one reservoir with another and with various power cycle concepts.

Our program centers around the development of four computer codes:

EQUILIB - an equilibrium chemistry code that takes a brine model and calculates what minerals would become insoluble and how much would precipitate with changed temperatures, pressure and volumes in a power cycle

FLOSCAL - a code to estimate the buildup rate of scale on pipes and components

PLANT - an extensive thermohydraulics code that optimizes a typical multistage flash plant or binary cycle plant for a reservoir and then calculates plant degradation due to scale buildup

GEOSCALE - a time-dependent code to combine the above codes to assess when and how the performance of a geothermal power plant will degrade with time as a result of scale buildup

EQUILIB

Why Does Scale Form?

When a geothermal brine flashes, the gases fractionate to the steam phase (Figure 1). This process causes pH changes that affect calcite solubility (Figure 2) and sulfide solubility. As temperatures drop, the solubility of quartz, cristobalite, or amorphous silica can be exceeded, and one or more forms of silica can be precipitated (Figure 3). Other factors are shown in Table 1.

What Process Parameters Affect Scaling?

When we examine the factors affecting scaling we see that there are many (Table 2). Precipitation of a mineral does not necessarily lead to scale formation, because mass transport must take place towards a pipe wall and sticking must occur in order for a scale growth to form. Thus it is the interplay of chemical and thermohydraulic factors that controls scale growth.

Table 1

WHY DOES SCALE FORM?

TYPE	CAUSES
Silica and silicates	Temperature drop decreases solubility Steam loss concentrates brine pH changes affect kinetics
Calcite	CO_2 loss increases pH Steam loss concentrates brine
Sulfides	Temperature drop decreases solubility CO_2 loss increases pH
Iron deposits from corrosion	Fe^{+2} ion precipitates on surfaces and in other scale deposits
Carry-over	Incomplete steam separation results in aerosol carry-over of salts
Sulfates	Temperature or pressure changes decrease solubility Mixing different fluids - barium in one stream and sulfate in another = $BaSO_4$ scale

Table 2

IMPORTANT FACTORS AFFECTING GEOTHERMAL SCALING

- Brine composition
- Gases present and pH - CO_2, H_2S, NH_3, HCl, H_2, O_2
- Temperature in reservoir
- Fluid produced single phase or 2 phase
- Degree of flashing and steam fraction
- Distribution of gases between liquid and vapor
- T and P
- Oxidation-reduction potential
- Brine concentration from steam loss
- Nucleation-growth phenomena
- Deposition surface
- Velocity, Reynolds number and other flow effects

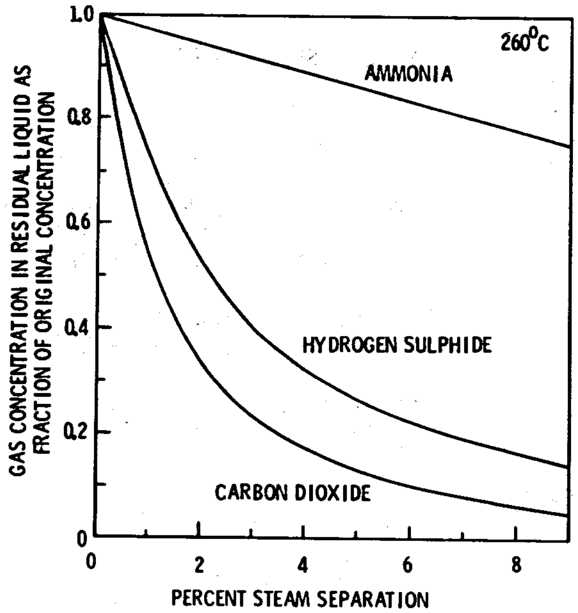


Figure 1. The Concentration of Gases in the Water Phase Remaining after the Equilibrium Separation of Steam
Source: A.J. Ellis (1-4)

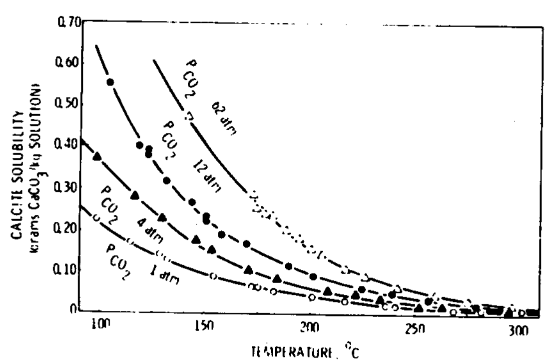


Figure 2. The Solubility of Calcite in Water up to 300° at Various Partial Pressures of Carbon Dioxide Source: A. J. Ellis (1-2)

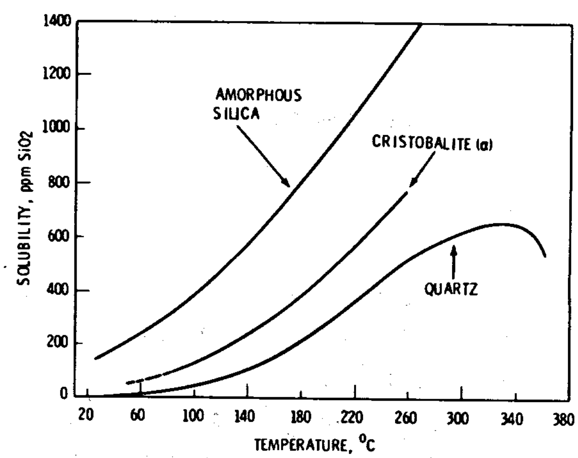


Figure 3. Silica Solubility in Water Source: Barnes and Rimstidt

The code EQUILIB only looks at part of the problem - the chemical driving forces affecting precipitation. This is very important to assess what minerals are thermodynamically possible. The concept of EQUILIB is illustrated in Figure 4. Some of the important chemical factors are considered in Figure 5.

SYSTEM HAS 1 kg OF BRINE

CONCEPT OF EQUILIB

- CALCULATIONS ARE DONE ON 1 kg OF BRINE AT ANY TEMPERATURE 25 TO 300°C
- GAS VOLUME CAN BE ANY VALUE - ZERO TO X EXPRESSED AS LITERS OF GAS VOLUME /kg OF BRINE
- THE GASES CO_2, H_2S, HCl WILL DISTRIBUTE BETWEEN GAS PHASE AND LIQUID AS FUNCTIONS OF T, pH, SALT CONTENT
- TWO PHASE MIXTURES SIMULATED BY INSERTING PROPER VALUE OF V TO SIMULATE STEAM VOLUME
- DURING A FLASHER CALCULATION BRINE PHASE CONCENTRATIONS ARE CORRECTED FOR WATER LOSS
- IF ALL WATER FLASHES CODE STOPS AND TELLS YOU
- CODE CALCULATES AQUEOUS PHASE CONCENTRATIONS, ACTIVITIES, pH AT TEMPERATURE, GAS PARTIAL PRESSURE, AND IDENTIFIES TYPE AND QUANTITY OF INSOLUBLE MINERALS AT CHEMICAL EQUILIBRIUM

Figure 4. Concept of EQUILIB

- TEMPERATURE
- CONCENTRATIONS OF ALL BRINE CATIONS AND ANIONS
- pH
- PARTIAL PRESSURES OF GASES
- ACTIVITY COEFFICIENTS
- IONIC STRENGTH WHICH AFFECTS CHEMICAL ACTIVITIES
- COMPONENTS THAT CONTROL OXIDATION POTENTIAL
- SOLUBILITES OF SOLID MINERALS THAT COULD FORM
- AQUEOUS PHASE EQUILIBRIA THAT DISTRIBUTE COMPONENTS AMONG MANY SPECIES AND COMPLEXES
- TOTAL MASS BALANCE BETWEEN AQUEOUS AND GAS PHASES

Figure 5. Factors to Be Included in Equilibrium Chemistry Model

The code EQUILIB is presently operational using a data base originally developed by H. C. Helgeson for another purpose. We have used the code to verify a mineral stability diagram (Figure 6) where the code correctly identified the stability fields of siderite, pyrite and hematite. We used EQUILIB to calculate what corrosion products would form on carbon steel and compared the result with actual experimental results (Table 2A). The code has also been used to compare scaling in a HEBER heat exchange tube where sulfides and silica were predicted to deposit. When the same brine was flashed in a code calculation, calcite, silica, and iron silicate were predicted to deposit. We are presently expanding the data base to include more species of interest to geothermal power plants.

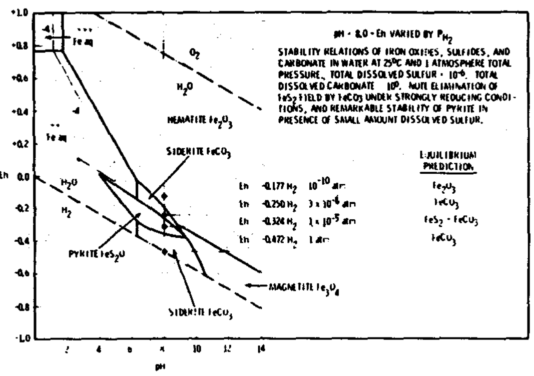


Figure 6. EQUILIB Calculations Compared to Published Stability Fields of Fe Phases at 25°C Eh-pH Diagram from Garrels and Christ (1-3)

Table 2A

EQUILIB CODE PREDICTIONS OF CORROSION PRODUCTS ON CARBON STEEL

T °C	1% NaCl, pH 7.5 EQUILIB	1% NaCl, pH 7.5 Experimental	1% NaCl, pH 4.8 EQUILIB	1% NaCl, pH 4.8 Experimental	1% NaCl, pH 4.8 + H_2S EQUILIB	1% NaCl, pH 4.8 + H_2S Experimental
50	$FeCO_3$	None detected	Fe^{++}	85% Fe	FeS_2	FeS
				10% $FeCO_3$		
150	Fe_3O_4	Fe_3O_4	$FeCO_3$	$FeCO_3$	$FeCO_3$	80% $FeCO_3$
					FeS_2	10% FeS
						5% FeS_2
250	Fe_3O_4	Fe_3O_4	Fe_3O_4	70% Fe_3O_4 + 30% $FeCO_3$	Fe_3O_4	Not run

FLOSCAL

FLOSCAL is a code in its beginning stages of development. It will take the output of EQUILIB (which predicts what minerals will precipitate) and estimate how fast scale will build up on walls. The computational approach for FLOSCAL is given in Figures 7 and 8. The FLOSCAL data base is presently the most inadequate because we need equations to describe scaling kinetics mathematically. We are concentrating on the species in Table 3, recognizing more specimens must be added at some future time (sulfides, silicates, sulfates, etc.).

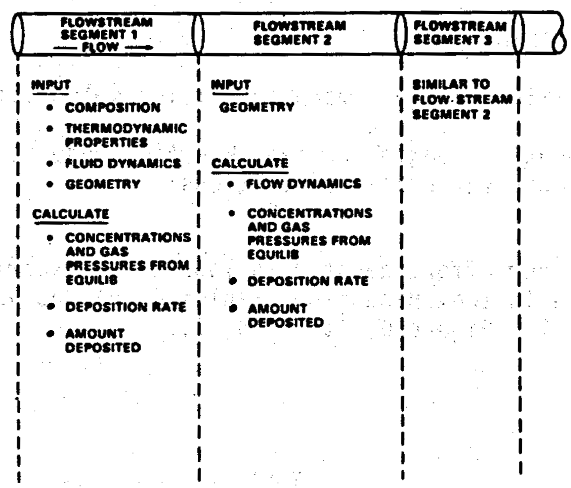


Figure 7. Computational Approach

INPUT

- FLOWSTREAM SECTION GEOMETRY
  - FLOW AREAS
  - LENGTHS
- FLOW DETERMINING PARAMETERS
  - FRICTION FACTORS
  - ELEVATION CHANGES
- FLUID CHARACTERIZATION AT UPSTREAM END
  - TEMPERATURE
  - PRESSURE
  - QUALITY
  - MASS FLOW RATE
  - SOLUTE CONCENTRATIONS
  - GAS PARTIAL PRESSURES
  - pH

OUTPUT

- DOWNSTREAM FLOW VARIABLES
  - P, T, X, V
- DOWNSTREAM SCALE FORMATION RATES
- DOWNSTREAM CONCENTRATIONS

Figure 8. FLOSCAL Characteristics

Table 3

DEPOSITION FORMULATIONS

CALCIUM CARBONATE

- Attenuation length model
- Correlation for attenuation length to be developed

QUARTZ

- Reactor rate model (H. L. Barnes)

AMORPHOUS SILICA

- Deposition only if amorphous silica solubility exceeded

- Attenuation length or mixed kinetics model to be developed for scale correlations

We have a portion of our effort devoted to laboratory experiments on the kinetics of calcite and silica in two-phase flow (Tables 4, 5) and analysis of real scale deposits from the field (Figure 9, Tables 6, 7).

Table 4

KINETIC EXPERIMENTS

TEST OBJECTIVE

- Define the interactions of temperature, salinity, chemistry, and hydraulics on scaling rates during flashing in two-phase flow

TEST PARAMETERS

- Reservoir Temp / Flash Temp / % Steam

Reservoir Temp	Flash Temp	% Steam
290C (554F)	171C	28
235C (455F)	143C	19
180C (356F)	116C	13

- Salinity 0.58% and 5.8%

- Chemistry Saturated with $CaCO_3$, SiO_2 at reservoir temperature and 1 atm CO_2 overpressure

Table 5

INITIAL OBSERVATIONS FROM SCALING KINETIC TESTS

- $CaCO_3$ deposits in both calcite and aragonite forms
- $CaCO_3$ deposits very rapidly and is in chemical equilibrium a few cm downstream from flash point
- $CaCO_3$ scaling increases as reservoir temperature drops
- $CaCO_3$ scaling decreases as salinity increases
- SiO_2 scaling is much slower - 20-30 hours to equilibrium
- SiO_2 scaling occurred only in 290°C test
- SiO_2 scaling increases as salinity increases

Table 6

ATOMIC PERCENTAGE OF MAJOR CONSTITUENTS OF THE SCALE DEPOSITS IN HEBER TUBES

ELEMENT	E1-IN (173°C)	E2-OUT (116°C)	E2-OUT (84°C)	E3-OUT (66°C)	E4-OUT (56°C)
S	19.8	31.7	42.7	46.4	67.0
Sb	7.0	3.8	27.5	7.7	23.8
Fe	44.3	27.8	2.1	17.7	0.4
Si	5.4	10.5	9.0	23.1	4.4
As	8.9	1.9	3.2	0.6	1.2
Zn	5.1	9.3	0.7	0.9	0.2
Ca	4.6	8.8	0.7	0.2	0.3
Pb	0.1	0.8	2.2	0.2	0.3
Tl	-	-	-	0.4	1.3

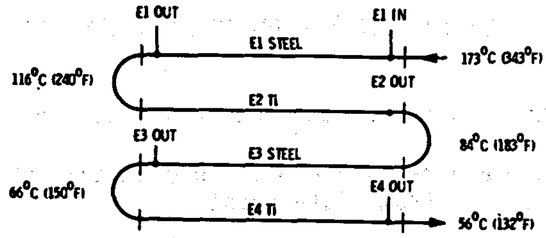


Figure 9. Samples Taken from Heber Heat Exchanger Tubes

Table 7

PHASE IDENTIFICATION BY X-RAY DIFFRACTION FOR SCALE DEPOSITS IN HEBER TUBES

Diffraction Method	E1-IN (173°C	E1-OUT (116°C)	E2-OUT (84°C)	E3-OUT (66°C)	E4-OUT (56°C)
As-received deposits					
Diffractometer	-	-	A-Phase*	-	A-Phase
Guinier photograph	A-Phase (FeS)	A-Phase (FeSbS) ($Fe_{0.95}S$)	A-Phase	A-Phase (FeSbS)	A-Phase
Deposits heat-treated at 350°C for 12 hours	A-Phase and (FeS)	A-Phase (FeS, Sb)	Sb_2S_3	A-Phase (Sb) (FeSbs)	Sb_2S_3

*A-Phase: Amorphous phase or fine grain crystalline phase with grain size below 50 Å

( ): Small quantity of crystalline phase

PLANT

A computer model has been developed to simulate two types of geothermal power plants, the flashed steam plant and the binary cycle plant. This computer model not only establishes a baseline description of the power plants, but also simulates the performance of these power plants as scale buildup occurs.

The two typical power plant flow diagrams are given in Figure 10 and Figure 11. Up to four stages of flashing can be accommodated. The inputs to the code, general process information provided the user on the code, output, and components modeled are given in Tables 8 through 13. In Figures 12-16 some of the component models are diagrammed.

We have the code PLANT running with manual input of scale thicknesses. Two such cases are given in Table 14 and Figures 17 and 18, where the impact of scale buildup on power output is illustrated.

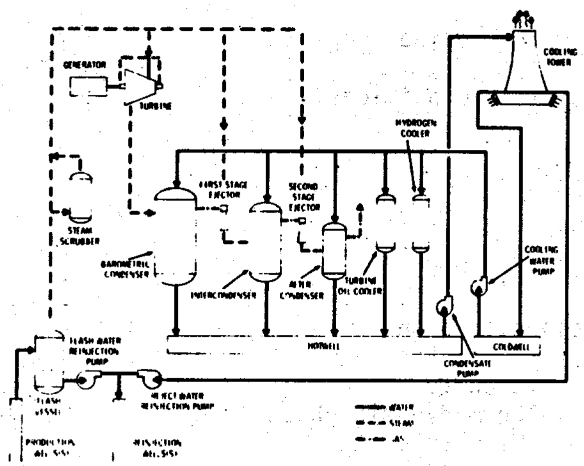


Figure 10. Flash Steam Plant

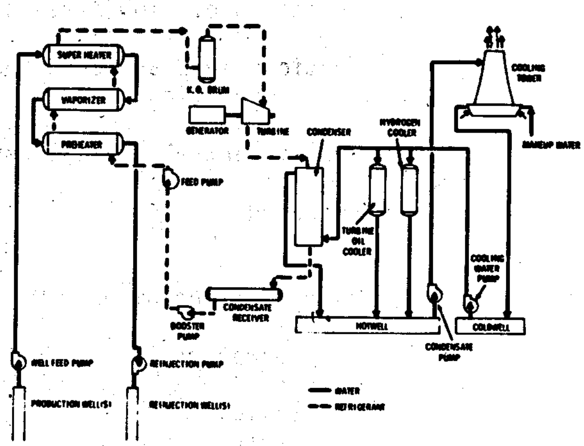


Figure 11. Subcritical Binary Fluid Cvcle Power Plant

Table 8

INPUT TO PLANT CODE

RESERVOIR PROPERTIES
- Thermodynamic properties
- Composition
- Well flowrates

PLANT PARAMETERS
- Binary or flash steam
- Size
- Plant component options

METEOROLOGICAL CONDITIONS

Table 9

GENERAL PROCESS INFORMATION

Geometry of Specific Plant Components
- Diameter
- Length
- Cross-sectional area
- Description of internal configuration

Degradation of component efficiencies due to scaling

Pressure and heat losses in system

Heat transfer coefficients where appropriate

Scaling conditions at key plant locations

Descriptions of flow streams other than brine

Alterations in plant baseline operating conditions due to deposition

Internal plant electrical consumption

Power output

Brine conditions at over 90 locations in plant

Temperature	Velocity
Pressure	Thermodynamic phase
Enthalpy	Flow rate
Density	Viscosity
Wt% of dissolved solids (and species)	Reynolds number

Table 10

COMPONENTS WITH STATE POINTS

Well and Transmission System

Wells	Elbows
Valves	Tees
Pumps	Pipes

Flashed Steam Plant

Flashers	Valves
Separators	Turbine
Steam scrubber	Condenser

Binary Fluid Plant

Heat exchangers
Valves

Table 11

INFORMATION GIVEN AT EACH STATE POINT

Temperature (°F)
Pressure (psia)
Enthalpy (Btu/lb)
Density (lbm/cu ft)
Weight percent of NaCl
Weight percent of 7 other species
Flow velocity (ft/sec)
Phase or steam fraction
Instantaneous scaling rate
Instantaneous corrosion rate
Scale thickness (mills)
Percent reduction in component efficiency due to scale (-%)
Mass flow rate (10^3 lbm/hr)
Corrosion limit
Design diameter (ft)

Table 12

LIST OF MODELS FOR FLASHED STEAM SYSTEM COMPONENTS
THAT ARE IN CONTACT WITH GEOTHERMAL FLUID

- Production wells (reservoir not included)
- Brine pump
- Transmission lines
- Flasher separator
- Steam scrubber
- Turbine
- Condenser
- Gas ejector

Table 13

LIST OF COMPONENT MODELS FOR BINARY SYSTEM
WHICH ARE IN CONTACT WITH THE GEOTHERMAL FLUID

- Production wells (reservoir not included)
- Brine pumps
- Transmission system
- Geothermal/working fluid heat exchanger(s)

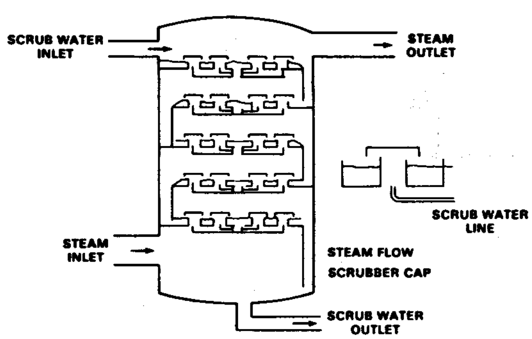


Figure 12. Ben Holt Steam Scrubber

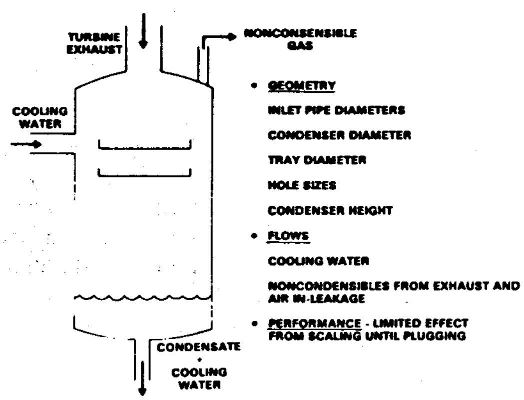


Figure 13. Direct Contact Condenser

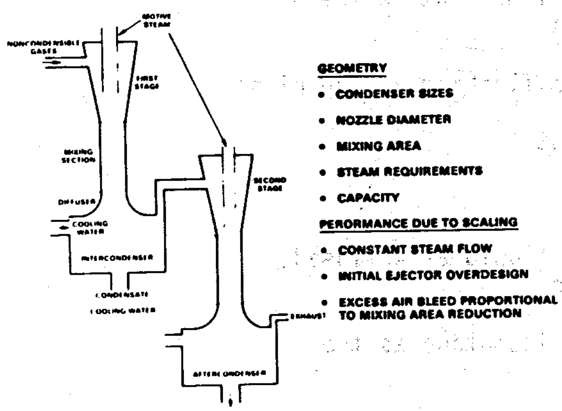


Figure 14. Steam Jet Ejection

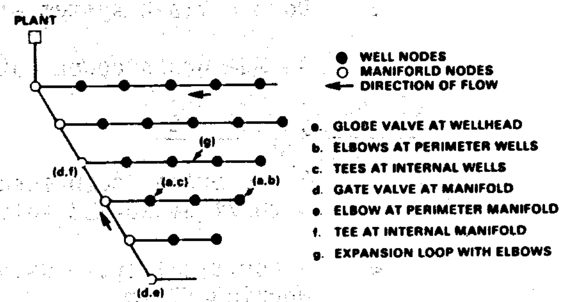


Figure 15. Transmission System Matrix

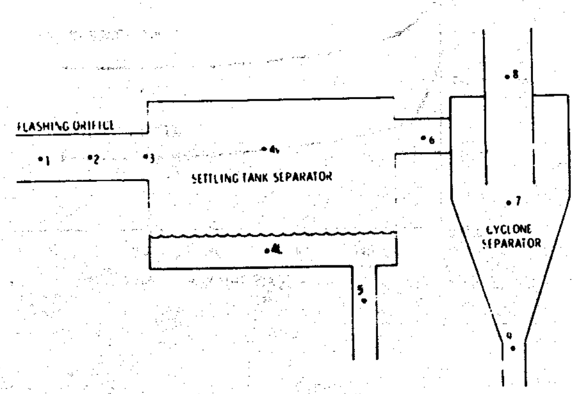


Figure 16. Flasher Separator System

Table 14

EFFECT OF SCALE ON POWER OUTPUT

INPUT CONDITIONS:

Flashed Steam Plant

- 200°C brine, compressed liquid at wellhead, with 7% dissolved solids
- Double-flash system with flashing at the plant
- 44 MWe gross power output

Binary Cycle Plant

- 205°C brine, compressed liquid at wellhead, with 7% dissolved solids
- Subcritical cycle using isobutane as the working fluid
- 55 MWe gross power output

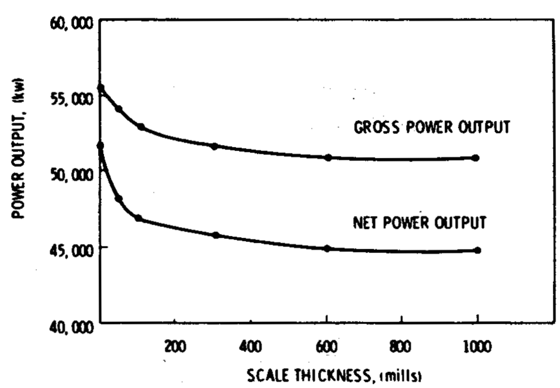


Figure 17. Plant Power Output Flashed Steam Plant

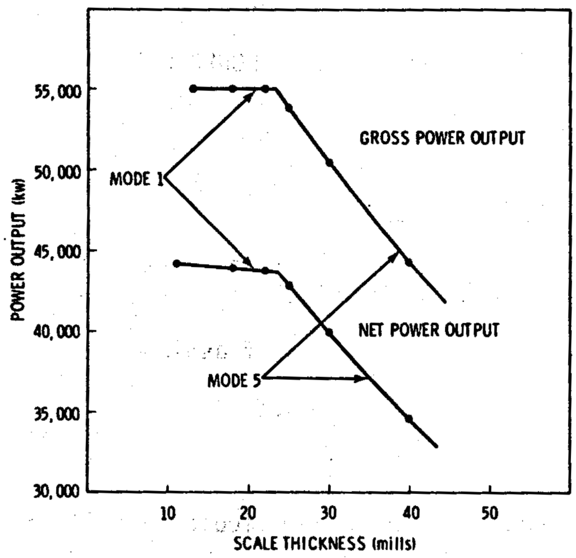


Figure 18. Power Output Binary Cycle Plant

GEOSCALE

All of the above material will be integrated into a large code called GEOSCALE, which will permit assessing the time-dependent performance of a geothermal power plant. The general flow logic of GEOSCALE is illustrated in Figure 19.

CONCLUSIONS

At the present time we are about 50% complete with this program and expect to have the codes available for use by August 1978.

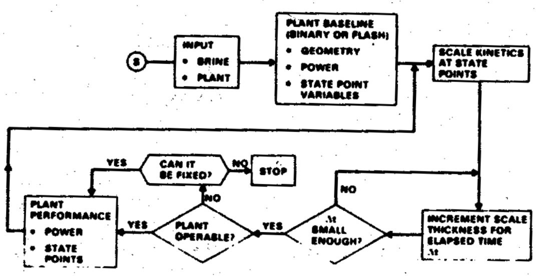


Figure 19. GEOSCALE Calculation Flow

ROCK-BRINE CHEMICAL CORRELATIONS

EPRI Research Project 653-2

Frank W. Dickson
Stanford University

INTRODUCTION

Geochemists at Stanford University are reacting powdered rocks with various kinds of aqueous solutions, at temperatures ranging upward to 500°C and pressures up to 2000 bars. The experiments yield information on the compositions of the fluids as they modify during the reaction and the mineralogical changes that take place in the rock materials.

EPRI project RP653-2 specifically utilizes these techniques for geothermal systems. The objective of this project is to examine the interactions of rock and geothermal fluids, with the purpose of understanding the relationship of geothermal fluid and host rock composition, as well as gaining insight into reactions occurring during reinjection.

Rock-solution data are needed to clarify scientific questions on geochemical cycling, rock alteration and metamorphism, origin of specific mineral assemblages, the genesis of hydrothermal ore deposits, and the compositions of natural fluids. From the data, reaction kinetics and the equilibria toward which the system is moving can be deduced.

The research is relevant to geothermal development in several ways. The chemical and isotopic data provide a basis for understanding compositions of natural materials as they relate to underground factors of fluids from hot springs and drill-holes, such as bulk composition, temperature, pressure, and reaction times. This information is particularly useful in the early stages of geothermal exploration, when typically only a sparse supply of material is available to assess underground temperature, sources and residence times of the fluids, and the rock units from which the fluids have been migrating. It increases the probability that predictions can be made of the deposition or dissolution of minerals in the rocks or in pipes during withdrawal, recharging, or plant processing of hot waters. Finally, the kinetic and equilibrium data are needed in computer modeling of the processes involved in producing geothermal energy.

RESEARCH METHODS

We have been reacting rock powders and granules with aqueous solutions (seawater, $NaCl-H_2O$, H_2O) mostly in the range from 100 to 300°C at 500 bars, for times of about 30 days. The rocks we have used have been glassy basalt and rhyolite, crystalline rocks (diabase and granite), and a carbonate sedimentary rock.

The reactions are done with Dickson-type gold cell hydrothermal equipment designed to provide inert and deformable containers for the experimental mixtures. A gold cell suspended in a steel pressure vessel is connected to an exit tube, which permits internally filtered liquid samples to be withdrawn from the cell during the experiment. Pressures in the cell are controlled by adjusting the pressure of water in the volume around the cell. A great advantage of the design is that it permits samples to be taken at regular intervals without disturbing the experimental conditions. The furnace-pressure vessel assemblies are rotated, in a rocking device, from vertical to upside-down several times a minute, keeping the powder and liquid well mixed and greatly increasing the reaction rate as compared to static arrangements.

The samples of fluids withdrawn from the cell during experiments (about ten 4-gram samples for a 30-day experiment) are analyzed by atomic absorption and emission spectographic approaches for about 30 major, minor, and trace elements. Other constituents, such as sulfide, sulfate, and carbonate, are determined by special methods. The isotopic exchanges (^{18}O, D, and ^{34}S) between solution and solid phases are determined by cooperation with Dr. R. O. Rye, U.S. Geological Survey, Denver. Each experiment, therefore, requires a large amount of analytical work, and much of the time of the research personnel is consumed in doing the analyses.

DISCUSSION

Although the principle of the Dickson hydrothermal equipment is simple, in practice considerable experience is required. Each experiment is a major investment in time and funds, and careful planning of experiments is necessary to ensure maximum return of useful information.

Rock-solution studies are comparatively new and not much is known about the kinetic behavior or the equilibria. Each experiment done so far has produced unpredictable results, which require follow-up studies to clarify. For example, some sulfide was unexpectedly solubilized in our original reaction of basalt with seawater at 200°C and 500 bars. The sulfide was produced by two possible mechanisms: extraction directly from the basalt or reduction of seawater sulfate. Subsequent experiments at higher temperature with normal seawater and sulfate-free synthetic seawater revealed that most of the sulfide could be accounted for by extraction from the rock.

The solid phases produced by the reactions tend to be fine-grained and difficult to separate for identification and chemical analysis. Processing the solids requires techniques similar to those traditionally used by sedimentary petrologists and soil scientists: disaggregating by ultrasonic vibrators; separation by differential settling of suspensions in aqueous media; X-ray diffraction identification of minerals; microscopic examination of textures and structures; and microprobe determination of compositions.

The project currently being carried out with EPRI support is directed by Mr. Jared Potter, in collaboration with Dr. James Rytuba of the U.S. Geological Survey. It involves the reaction of basalt and rhyolite with H_2O and 10% NaCl solution at 300°C and 500 bars. This work has just begun, and no results are yet available.

The major rock-water study done so far in the laboratory over the past three years, the basalt-seawater reaction sponsored by the National Science Foundation, was done under conditions of 100 to 500°C temperature and 500 to 1000 bars pressure. The effects of variations in crystallinity and rock to solution ratios have been worked out. Synthetic seawater without sulfate and simple $NaCl-H_2O$ solutions of similar ionic strength to seawater have provided comparisons. Dr. W. E. Seyfried and Mr. David Janecky are currently doing the research.

One of Dr. Seyfried's projects has involved reacting powdered basalt glass with 2.57% NaCl solution (near the ionic strength of seawater) in a one to 10 mass ratio, at 300°C and 500 bars for 600 hours (25 days). Fine-grained, poorly crystalline minerals were produced by breakdown of the glass; these consisted of albite ($NaAlSi_3O_8$), clay (Ca-Mg hydrated aluminosilicate with subordinate K,Na). Zeolite (wairakite, $CaAl_2Si_4O_{12}\cdot 2\ H_2O$) and trusscotite (Ca hydrated silicate). All these minerals have been reported in geothermal systems, although trusscotite is rare.

The reaction was comparatively rapid; most of the solution components reached 90% of their final values in 200 hours or less. SiO_2 increased to about 610 ppm and slowly dropped to about 570 ppm, presumably because it was consumed by growth of silicate phases. The quartz saturation level was not reached. Na dropped from the initial 10,100 ppm to less than 9260 ppm at 50 hours, then rose to a steady value of about 9620 ppm. Na was initially consumed by exchange reactions, probably for Ca and to a lesser extent for K, but then released during growth of the mineral assemblage. Cl increased from 15,400 ppm to a constant value of 15,750 at 200 hours, reflecting release of Cl from the rock or the increase in ionic strength resulting from hydration of the glass. Ca rose to a maximum of 700 ppm in 50 hours but dropped steadily thereafter to about 500 ppm at 600 hours, reflecting albite formation mostly. K grew on rapidly to about 145 ppm. Mg remained low, but increased steadily to 1 ppm at 600 hours. The heavy metals Fe, Mn, Cu, Zn and Cr, and Al, remained below 0.1 ppm.

The pH rose from 6.0 to 7.0 at 50 hours and then dropped to about 6.3 at the close of the experiment. The reason for the initial rise is not clear, but it is probable that hydrolysis of silicate is involved.

Two components commonly found in geothermal fluids, H_2S and CO_2, were generated by the reaction. CO_2 rose to about 30 ppm and H_2S to 12 ppm. A rock-water reaction source for some of the CO_2 and H_2S in natural waters is suggested.

MOBILE GEOTHERMAL FLUIDS, MATERIALS, AND COMPONENTS TEST LABORATORY

Research Project 741-1

G. Hajela
Atomics International Division
Rockwell International

STATEMENT OF THE PROBLEM

Although data pertaining to many of the physical, chemical, and thermodynamics characteristics of fluids from a variety of geothermal resources have been collected for many years, and selected power cycle tests have been performed at several locations, there is an increasing need for detailed, comprehensive, and consistent data from existing and new wells to establish technical and economic feasibility of electric power production. In addition, there is a paucity of information that can be used as a data base for verifying the analytical procedures that are now being developed to predict the behavior of geothermal fluids in the power production process (scaling, corrosion, steam production, etc.). These problems have been caused, in part, by the fact that many different individuals and organizations have been and are now involved, each using a different method and each concerned only with a particular aspect of the overall problem, and by the fact that the required measurements are frequently complex and time-consuming to make.

SOLUTION

The most practical solution to these problems is to design and build a mobile geothermal laboratory that can be used at any given well site to conduct comprehensive, standardized, and systematic tests that constitute a prerequisite to the development of power plant performance specifications, power plant design criteria, scale control methods, and material selection criteria. A mobile laboratory is needed that has the capability of providing, in a short span of time at the site, information sufficient for the power cycle process to be identified for any given geothermal resource. Also, a mobile laboratory that can identify the major problem areas and that can be used to define the basic requirements for permanent, or semipermanent, large-scale test facilities, if needed, is desirable.

JUSTIFICATION FOR A MOBILE LABORATORY

Although, in principle, a centrally located laboratory can be used to generate much of the required data, some fluid properties must be measured on site, since the properties may change significantly if the elapsed time between collection and measurement is long. Furthermore, the compatibility of materials of construction and of selected components with the geothermal fluid must be verified under conditions that are representative of actual operating conditions. Finally, because of the statistical nature of many geothermal parameters, multiple sampling, which can cause serious logistics problems can be avoided when the laboratory analysis is on site.

OBJECTIVE OF THE PROJECT

The long-term objectives of the project are to provide an inventory of baseline geothermal data from a variety of geothermal sources and to provide an economical method for site-specific testing. This testing is to be carried out with sufficient detail for the financial risk in developing any given geothermal reservoir site to be significantly reduced. In order to meet this objective, the immediate goal of the project is to develop, design, and construct a mobile geothermal fluids, materials, and component test laboratory.

CURRENT STATUS OF THE PROJECT

Part A of the project consisted of six tasks, all of which have now been completed. Task 1 dealt with an assessment of the state of the art of geothermal test facilities. In order to accomplish this task, numerous site visits were made, the literature was reviewed, and the capabilities of the various mobile, as well as stationary, facilities were compiled. For Task 2, the range of the variables that characterize geothermal fluids was established so that the mobile laboratory could be designed to handle the vast majority of fluids likely to be encountered. Under Task 3, the on-site testing requirements were developed on the basis of discussions with personnel at various laboratories and organizations and on the basis of geothermal studies that have been performed at Atomics International. From the results of Tasks 1, 2, and 3, which were conducted more or less simultaneously, conceptual designs of four basic processes making up the laboratory were developed. This work, which was designated Task 4, was combined with conceptual designs of equipment and a set of system specifications, in order to derive a set of detailed designs of the mobile laboratory. The detailed design work (Task 5) consisted of the preparation of engineering drawings, a preliminary construction specification, a preliminary instrumentation and control specification, and a detailed system design description. Preliminary operating instructions and test procedures for the mobile laboratory were also prepared. Finally, under Task 6, a detailed cost estimate of the materials and labor to construct the laboratory was developed, along with an estimate of operating expenses. Design work is sufficiently complete for procurement and preliminary construction to commence.

DESIGN DESCRIPTION

In order to meet the objectives described above, a mobile laboratory consisting of two units was designed. One of them, the Chemical Analysis Trailer, will consist of an enclosed, commercially available, 2.4 m (8 ft) wide by 12 m (40 ft) long, double axle, air suspension unit that will be used to form a three room, essentially self-sufficient, versatile chemistry laboratory and office for on-site work. The Chemical Analysis Trailer, which is depicted in Figure 1, contains such major analytical instruments as an atomic absorption spectrophotometer, a gas chromatograph, a flame photometer, a UV-visible spectrophotometer, and an automatic titrator. Also built into the laboratory will be a drying oven, a vented hood, balances, sinks, a furnace, vacuum lines, compressed air, cabinets, and storage space. The laboratory will be air conditioned and will contain bottled gases for the various instruments, a supply of distilled water, as well as water for general purpose operations.

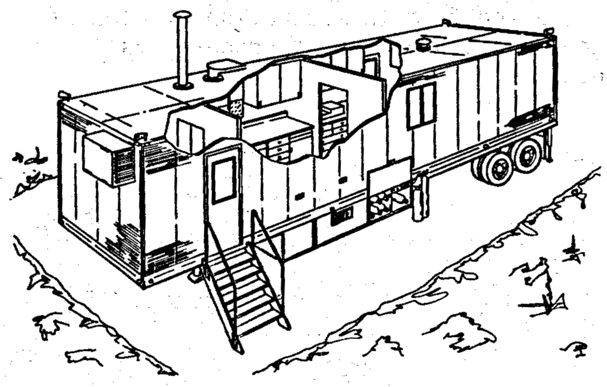


Figure 1. Chemical Analysis Trailer (CAT)--
EPRI Mobile Geothermal Laboratory

As with any well-equipped laboratory, there will be glassware, chemicals, a conductance meter, pH meters, a dissolved oxygen meter, coulometric chloride meter, and turbidimeter. Fire extinguishers, a combustible gas detector, and a safety shower will also be included.

The second unit, a Component and Materials Test Trailer, utilizes a commercially available, open, flatbed trailer, 2.4 m (8 ft) wide by 13.7 m (45 ft) long. This trailer will contain the basic process equipment for handling the geothermal fluids, for characterizing the behavior of the fluids, for testing components and processes, and for collecting samples for analysis in the Chemical Analysis Trailer. Four basic unit operations or subsystems (flash separator, corrosion test, scaling/heat exchange test, and noncondensible gas analysis) comprise the trailer, which is shown in Figure 2.

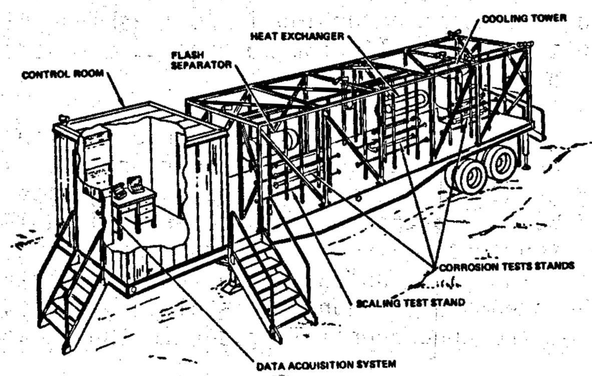


Figure 2. Component and Material Test Trailer (COMATT)--
EPRI Mobile Laboratory

Unit analyses were carried out on each of these subsystems in order to define the ultimate data required, the principal variables, the concept block diagram, the equipment design, test procedures, and control methods. Other data that might be useful and can be extracted from the operation of each of the units were also identified. From this basic approach, a process system of the type shown in Figure 3 was designed.

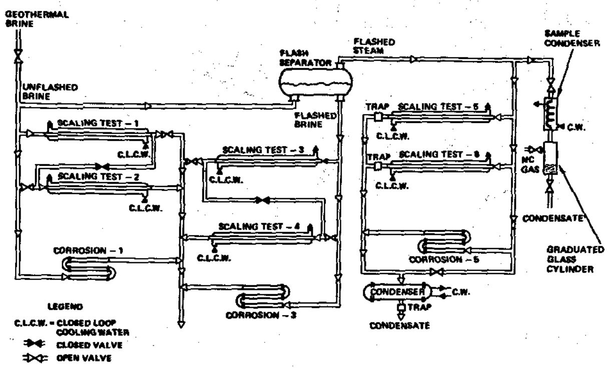


Figure 3. Flashing Process Schematic

In a geothermal fluid in which flashing is allowed to take place, three fluid types - unflashed brine (well flow), flashed brine (separator underflow), and flashed steam - are produced. Thus, three corrosion test units and two scaling/-heat transfer test units are provided for each fluid type. Each corrosion test unit consists of three sections so that corrosion test coupons from the three sections can be removed, one at a time, at different time intervals without disturbing the other two. Each section can hold up to about 36 single coupons of various types or 18 U-bend specimens, or 18 prestressed tensile specimens, or combinations thereof. The scaling test unit consists of a simple 12.7mm-OD (1/2-in) by 2.13m-long (7-ft) tube inside a 20.93mm-ID (0.824-in) shell. Brine flows along the inside of the tube and cooling water along the outside. Thus, the scaling will take place only on the inside of the inner tube which can readily be removed for detailed study of the scaling process. Since, in general, a temperature drop must occur in a brine in order for scaling to take place, a transfer of heat energy from the brine to the cooling water must occur. This heat transfer process is one of the principal processes occurring in nonflashing, binary power cycles; therefore, the scaling test unit will also be used to characterize in detail the heat transfer process in geothermal fluids.

The cooling water for the scaling test units is circulated in a closed loop so that its chemistry can be controlled to prevent corrosion or scaling within this loop. The heat energy gained by the closed loop cooling water is dumped via a heat exchanger to a 13.62-MW (15-ton) cooling tower located in the trailer. A separate cooling water source can also be used to condense the flashed steam in a tube-and-shell-condenser that is mounted on the trailer. This cooling water also is used to condense the steam in the noncondensible gas analysis unit. This condensation process allows the noncondensible gases in the steam to be collected and analyzed.

A data acquisition system, including a calculator that is capable of collecting, storing, and manipulating data, has been included in the design of the Components and Materials Test Trailer. This unit will continuously monitor the various processes and provide alarm signals or shutdown as required.

Both of these mobile laboratory trailers can be transported from one site to another over relatively unimproved roads by hookup to shortbed, commercial trucks. Both trailers also meet state codes with regard to weight, height, width, and length so that no special permits are required to transport them.

MOBILE LABORATORY CAPABILITIES

The mobile laboratory has been designed to be as versatile as possible. The inlet valving on the Component and Materials Test Trailer can accept fluids at temperatures up to 260°C (500°F) at pressure up to 3.4 MPa (500 psi). In the brine-side scaling test unit, nominal brine flow rates of 152 m/s (1100 lb/hr) and an inlet temperature of up to 232°C (450°F), temperature drops of from -18°C (0°F) up to 38°C (110°F), and nominal flow velocities of 1.5-2 m/s (5 - 7 ft/sec) can be achieved in the brine. In the corrosion test unit, fluid velocities can be varied over about a factor of 10 (up to about 4.6 m/s [15 ft/sec]) with brine inlet pressures of about 2 MPa (300 psi) and brine inlet temperatures of about 232°C (450°F). Lower inlet temperatures can be achieved by running the brine through one or more scaling test units before allowing it to enter the corrosion test unit, thus permitting the corrosion process to be studied as a function of temperature.

For geothermal resources of potential use in nonflashing processes, heat transfer characteristics are of great importance. In investigating brine reacting to this type of process, many variations in the hookup of corrosion test units and of scaling/heat transfer units can be achieved to meet particular test requirements. For example, all six of the scaling/heat transfer units can be run in series. In this case, if the brine inlet temperature is assumed to be 232°C (450°F), the outlet brine temperature will be 77°C (170°F). Heat fluxes will vary from as low as 59,888 W/m^2 (19,000 $Btu/hr \cdot ft^2$) to as high as 349,872 W/m^2 (111,000 $Btu/hr \cdot ft^2$) in the various heat transfer units. If lower heat fluxes are desired, Dowtherm A can be substituted for water in the closed-loop cooling system.

If the corrosion process is to be emphasized in a nonflashing process system, a test stand arrangement of the type shown in Figure 4 can be used. Corrosion phenomena can be studied at three different controllable temperatures. For example, Figure 4 shows the three different temperatures to be 190°C, 133°C, and 96°C (374°F, 272°F, and 204°F).

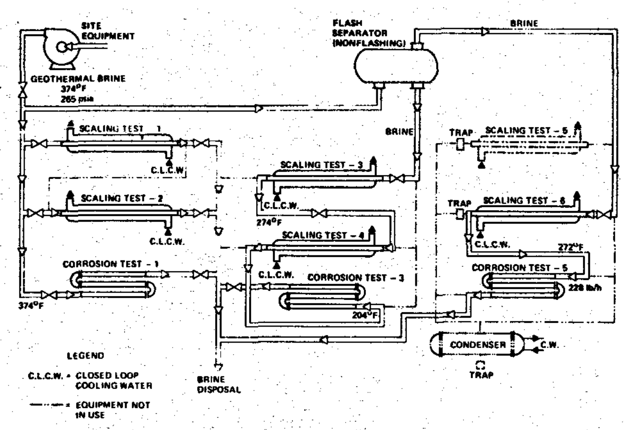


Figure 4. Simulating Pumped Brine Organic Binary Process

RELIABILITY/SAFETY

The mobile laboratory has been designed to achieve a high degree of operating reliability. A double inlet has been provided so that one inlet system can be overhauled if necessary while the other is working. Test stands can be readily isolated from the rest of the system, and test stands can be readily removed and replaced by spare units carried on the trailer. Commonality among the valve types has been adopted so that a few spare valves can meet the needs of the entire system. Pipe lines are relatively short, and have flange connections that can easily be taken apart. Tubing connections use a ferrule-and-lock-nut system that will allow easy replacement. Finally, all functions are monitored and recorded continuously by the data acquisition system. Thus, off-normal operation can be detected, and situations that can lead to shutdown can be anticipated and avoided.

Personnel safety in the operation of the laboratory has been considered throughout its design. Burst disks are provided to prevent overpressures, and detectors are provided to close off the inlet and outlet valves under certain abnormal situations on the Component and Materials Test Trailer. The Chemical Analysis Trailer has safety showers and alarms to indicate potentially hazardous conditions.

METHODS FOR GEOTHERMAL BRINE TREATMENT

EPRI Research Project 791

Sidney L. Phillips
Ashwani K. Mathur
Lawrence Berkeley Laboratory
University of California

OBJECTIVE AND METHOD

The objective of the project was to compile methods useful for treating geothermal brines. Geothermal brines are primarily treated to prevent or control scaling and corrosion but are also treated for environmental and injection purposes. The approach used was a critical survey of current data covering brine treatment methodology, in which the geothermal literature is covered in a comprehensive manner, with selected literature from the oil field, waste water, and boiler water industries included to provide data where the geothermal data were either lacking or insufficient. The project work involved screening the world literature for data dealing with brine treatment methodology and storing the references on computer tapes. The results were used to provide information for a report listing methods of brine treatment.

Table 1 shows a record stored in our computer file. It is identified by data elements (e.g., the title of the report, the author(s), author(s) affiliation, and date of publication). Selected data elements are machine retrievable terms that can be used for automatic generation of indexes for all the records listed in the database. Besides these data elements, records are annotated with descriptors taken from a controlled thesaurus. Descriptors describe the data or information content of each record and can be used to retrieve all the records in the database containing a specific topic or subject of interest. For example, if one is interested in obtaining a listing of all the records in the database dealing with scaling in the Salton Sea geothermal field, then one would key in the descriptor "Scaling" and "Salton Sea Geothermal Field."

The work was organized into two sections, one dealing with the treatment methods for fresh geothermal brines (i.e., treatment of the brines issuing from geothermal producing wells prior to their utilization for electric power production) and the second with the treatment of the spent geothermal brines (treatment of the fluids prior to their disposal to some option, such as injection, after they have been used for electric power production).

Treatment methods designed for fresh geothermal fluids should be such that the temperature or flow rate of the production fluid is not affected. Fluids have varied compositions, according to their site-dependent location; treatment methods for fresh geothermal fluids must therefore be designed for the specific type of fluid. Also, in treating either fresh or spent geothermal fluids, one must keep in mind the disposal option (for example, injection into the ground or agricultural irrigation use) because treatment of the fluid may result in a change in its composition and thereby affect the disposal option.

Table 1
COMPUTER RECORD FORMAT

BOHLMANN 76B
BRINE TREATMENT/SCALING

TITLE- PRECIPITATION AND SCALING IN DYNAMIC GEOTHERMAL SYSTEMS.

AUTHOR- BOHLMANN, E.G.;SHOR, A.J.;BERLINSKI, P. [OAK RIDGE NATIONAL LAB., TENN. (USA). CHEMISTRY DIVISION].

REFERENCE- PRECIPITATION AND SCALING IN DYNAMIC GEOTHERMAL SYSTEMS. ORNL/TM-5649, OAK RIDGE NATIONAL LABORATORY, OAK RIDGE, TENN., OCT. 1976, 48 P.

DESCRIPTORS- PRECIPITATION; SCALING; GEOTHERMAL SYSTEMS; DYNAMIC SYSTEMS; EXPERIMENTAL RESULTS; LABORATORY EQUIPMENT; HEAT EXCHANGERS; SILICA MINERALS; GRAPHS; FIGURES.

The disposal options normally listed for brine or other waste water (not specifically limited to geothermal fluids) include the following: the ocean; inland saline lakes; holding ponds; subsurface injection; agricultural uses. For example, agricultural irrigation uses are being investigated in Idaho for brines of the Raft River geothermal project.

Table 2 lists treatment methods commonly used for removing unwanted characteristics from waste waters in general. Some of these, as will be indicated later, have been applied to geothermal water treatments. For example, solids and colloids are commonly removed by chemical coagulation, followed by filtration. Corrosiveness can be removed either by pH control or by removal of corrosive gases. Gases can be removed by aeration, purging, or degasification.

Scale Prevention and Control

Some typical methods that have been used to control scale formation in geothermal systems are given in Table 3. The table shows that silicate scale at Niland was controlled and its formation prevented by acid injection into fresh fluid. The silicate scale formation in Iceland geothermal waters was controlled by dilution of the unflashed geothermal fluid with makeup water. In the boiler water industry a commonly used treatment involves addition of alkaline phosphate. The addition of alkaline phosphate precipitates any dissolved calcium as calcium phosphate. The calcium phosphate formed is less likely to adhere to the walls in boiler water applications than is calcium carbonate. The method of adding dispersing agents along with alkaline phosphate to keep calcium phosphate sludge dispersed in the water, rather than depositing and causing scaling on the walls of the container (tank or pipe), can be applicable to geothermal fluids.

Table 2
UNDESIRABLE GEOTHERMAL AND OTHER WASTE CHARACTERISTICS AND TREATMENT OPERATIONS

Undesirable Characteristics	Treatment Operations
1. Suspended Material:	
a. Solids, colloids, etc.	Chemical Coagulation Sedimentation Centrifugation Gravity Sand Filtration Pressure Sand Filtration Diatomite Filtration
b. Biological growths (e.g., slime forming algae and bacteria)	Chlorination Filtration
2. Dissolved Substances:	
a. Gases (e.g., H_2S, CO_2)	Aeration Purging Vacuum Degasifier
b. Undesirable ions (e.g., Fe, As)	pH Adjustment Neutralization Precipitation, Chemical Coagulation Ion Exchange Membrane Process (Reverse Osmosis) Aeration
3. Corrosiveness	Removal of Gases pH Control
4. Deposited Scale	Acidization Scale Inhibitors (e.g., Dearborn 8010, Calnox 214 DN, Calgon SL-500)

Table 3
TYPICAL TREATMENT METHODS TO CONTROL SCALE FORMATION IN GEOTHERMAL SYSTEMS

Scale Type	Treatment Method	Comments
Silica	pH adjustment (acid injection)	Tested at Magmamax No. 1 well, Niland, California
Silica	Injection of base (NH_3 or NaOH)	Sinclair wells, California
Silica	Dilution of the unflashed geothermal fluid	Namafjall,Iceland
Mixed	Application of electrical potential	Sinclair Well No. 4., California
Calcium Carbonate	Maintain CO_2 pressure	Tested at East Mesa Well 6-1, California
Calcium Carbonate	Sulfuric acid addition	Precipitates barium sulfate, pH changes
Calcium Carbonate	Phosphate addition	Laboratory tested on $10^{-7}\underline{M}$ concentrations
Calcium Sulfate	Phytic acid addition, organic phosphates	Laboratory tested on $10^{-7}\underline{M}$ concentrations
Mixed (Silica/Carbonate)	Nitinol material	Proposed method

Typical treatment methods used for scale removal in geothermal plant systems were also included in our study (Table 4). We considered both methods now in use and those in the process of being developed.

TREATMENT OF SPENT FLUIDS

Examples of treatment methods that have been used or are proposed for use in treating spent geothermal fluids are shown in Table 5. In Wairakei and Broadlands Field, New Zealand, removal of arsenic from spent geothermal fluids was accomplished by a combination of sedimentation and coagulation. Silicates from spent geothermal fluids in Japan and El Salvador were removed by plain sedimentation, wherein the water was held in a retention tank for a period of time to permit the silicate to deposit preferentially on the inner walls of the tank rather than in the disposal system. A non-geothermal example is the boiler water treatment to clean up deposited scale from boiler water. Calcium carbonate formation was inhibited or removed by using a sequestrant, for example, EDTA. The function of EDTA was to form a soluble complex with calcium thus preventing formation of calcium carbonate and thereby reducing the likelihood of formation of calcite scale. This method may have application in geothermal fluid treatment, for example, adding EDTA to the spent fluid.

Table 4
TYPICAL TREATMENT METHODS FOR SCALE REMOVAL IN GEOTHERMAL SYSTEMS

Scale Type	Treatment Method	Comments
	CURRENT METHODS	
Silica in borehole	Pump NaOH solution into the well	Used at Matsukawa, Japan
Calcite in borehole	Reaming or redrilling	Used in New Zealand, Hungary, and Mexico
Mixed scales in turbine components	Spaced injection of heavy diesel oils	Used at Lardarello, Italy
Mixed scales in injection and brine drain lines	Hydroblasting followed by water flush	Used at Niland Geothermal Test Facility, California
$CaCO_3$ in borehole	Pump inhibited HCl into the well	Acidizing used at East Mesa Well 5-1 and Otake, Japan
Calcite in well casings	Wash with inhibited HCl	Used in Hungary and Kawerau, New Zealand
Silica in flow control equipment and heat exchangers	Wash with ammonium biflouride	Acidizing used at Hveragerdi, Iceland
	DEVELOPING METHODS	
Mixed scales in heat exchanger tubing and piping	Cavitation descaling	Laboratory experiments
Calcite scale (test probe)	Application of thermal shock	Laboratory experiments

Table 5
TREATMENT METHODS FOR SPENT GEOTHERMAL FLUIDS

Removal of	Treatment Methods	Comments
Silica	Sedimentation and coagulation (addition of slaked lime, hypochlorite, flocculant)	Used at Wairakei and Broadlands, New Zealand
Silica	Plain sedimentation; retention tank	Used at Otake, Japan, and Ahuachapan, El Salvador
Calcite	Addition of sequestrants	Chelating agent used at East Mesa; effective but expensive
Silica, Calcite	Magnesium oxide and slaked lime	Used at East Mesa; generates large amount of sludge
Barium Sulfate	Chelating agent	Investigated at East Mesa; not effective
Mixed Scales	Polyphosphates, phosphonates, methacrylic acids	Effective for East Mesa

A pilot plant treating spent geothermal fluids from Wairakei and Broadlands Field is in operation in Broadlands, New Zealand. In one portion of the plant the waste water was mixed with hypochlorite which oxidized arsenic from the +3 to the +5 valence state, the +5 state being more readily settleable than the +3 state. Calcium oxide (slaked lime) was then mixed with the fluid causing precipitation of solid calcium silicate and arsenic. The solid material was filtered from the water and the cleaned-up water was then disposed. Table 6 is an analysis of discharged water from Wairakei after the slaked lime treatment. The table shows that as calcium oxide concentration was increased, the silicate and arsenic concentrations fell, indicating that the method apparently is effective for removing both silicate and arsenic from treated brines.

There are at least two issues that must be considered when evaluating this treatment method. First, the method of disposal of the solid calcium silicate and arsenic is important, because substantial quantities of these solids are created. Second, as the calcium oxide concentration increases both the total calcium oxide in the fluid, and the pH increase. This change may have a deleterious effect on the disposal method. For example, if one is interested in injecting the fluid into a disposal well, an increase in pH and calcium oxide content may make the fluid incompatible with the receiving formation and undesirable precipitates may form. Therefore, the fluid may require additional treatment to lower either the pH or the concentration of the calcium.

Corrosion Control Methods

Treatment methods for corrosion control involve two aspects. First, the group of corrosive species, such as hydrogen sulfide or oxygen, must be reduced or removed from the system. Hydrogen sulfide and other dissolved gases, for example, carbon dioxide, can be removed by aeration, that is, air is bubbled through the water. However, this process has the disadvantage of adding oxygen to the system, the oxygen itself becoming a corrosive dissolved constituent. Chemical degasification for removal of oxygen can be accomplished by addition of sulfite or hydrazine, which reduce the oxygen. In Iceland sulfite was added to the system to reduce the corrosivity of geothermal fluid.

A second method of controlling corrosion in geothermal fluids involves material selection. There is currently an active research program centered on the development of corrosion-resistant alloys and concrete-polymer materials that would be suitable for use in geothermal fluids at high temperatures and other hostile environments.

Table 6
ANALYSES OF DISCHARGE WATERS FROM WAIRAKEI AFTER SLAKED LIME TREATMENT
(in grams per tonne)

Added CaO	Added NaOCl	Added Floc.	Total SiO_2	CaO	As	B	pH
0	0	0	560	32	4.30	28	7.9
350	0	0	136	210	2.50	na	11.2
350	10	0	117	221	0.45	na	11.3
410	0	0	87	216	2.03	25	11.4
425	0	1	73	210	1.55	na	11.5
580	0	0	33	255	0.51	22	11.6
780	0	0	15	435	0.13	na	11.7
985	0	0	6	575	0.06	na	11.9
1000	0	1	10	545	0.12	20	12.0

na = not analyzed

SUMMARY

Generally, current methods for controlling scale deposition and materials corrosion in the geothermal power industry are mainly cleanup and replacement of parts on an as-needed basis. Scales are commonly removed by several methods including acidizing, reaming, scraping, and hydroblasting. Efforts have been made to treat geothermal hot water to minimize scale deposition and to remove such materials as arsenic and silicate from spent fluids prior to disposal of the waste water. Corrosion can be controlled by removal of corrosive species from the fluid system, chemical reaction, or selection of corrosion-resistant materials for use in the system.

2000-HOUR HEAT EXCHANGER STUDY

Research Project 846-1

Edward L. Ghormley
Jay L. Stern
The Ben Holt Co.

In 1976 the Electric Power Research Institute commissioned The Ben Holt Co. to study the heat transfer characteristics of a shell-and-tube exchanger in geothermal brine service. The Heat Exchanger Test Unit (HETU) used in this test had been previously used by San Diego Gas & Electric Company in 1975 in a preliminary series of tests. The objective of the current program was to test both steel and titanium tubes for 2000 hours in geothermal brine service to obtain reliable information on corrosion of heat exchanger tubes and exchanger fouling that could be used to design a commercial plant.

The HETU is made up of four 6.1 m (20-ft) long exchanger sections connected in series. Each section contains four 19-mm (3/4 in), 16 gauge tubes. The unit operates by exchanging heat from the incoming brine to a recirculated stream of treated water. The exchanger sections are arranged as follows:

SECTION	DESCRIPTION	MATERIAL	ASTM SPECIFICATION
E-1	Brine inlet	Steel	A-179
E-2	Second in series	Titanium	B-338
E-3	Third in series	Steel	A-179
E-4	Brine outlet	Titanium	B-338

The HETU was cleaned and instruments and controls were overhauled prior to startup of the test program.

The test was started 1 November 1976 and continued for 2034 hours' operation with only minor shutdowns such as for power failure. During the test, brine and treated water temperatures were recorded continuously at the inlet and outlet of each heat exchanger section. Heat transfer coefficients were calculated at two-hour intervals for each section. These data were plotted, and equations derived to describe the change in the coefficients.

The equations which fit the data best are tabulated below:

ITEM	EQUATION	
E-1	$U = x/(0.00184\ x - 0.0363)$	(1)
E-2	$U = x/(0.0019\ x - 0.0268)$	(2)
E-3	$U = x/(0.0028\ x - 0.1203)$	(3)
E-4	$U = x/(0.0027\ x - 0.0881)$	(4)

where $x = (n + 86)$ days

At the completion of the test the tubes were removed from the HETU and examined using a scanning electron miscroscope. Photomicrographs of the scale were taken which showed the structure and thickness of the scale. Analyses of the scale were obtained using the scanning electron microscope in conjunction with an X-ray analyzer. Typical photomicrographs of the scale are presented in Figures 1 and 2.

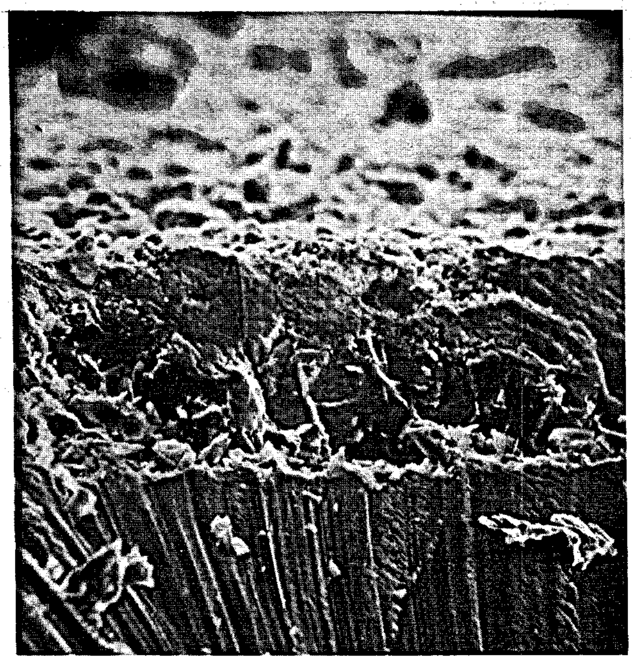


Figure 1.
(600X) E-1 Inlet
Cross section of scale on steel tube

Figure 2.
(1,000X) E-2 Outlet
Cross section of scale on titanium tube

Table 1 presents analyses of the scale recovered from the tubes.

Table 1

ANALYSES OF SCALE SCRAPED FROM TUBE WALL

STEEL TUBES

Constituent Element, Weight Percent

	S	Zn	Si	Fe	Cu	Ni	Cr	As	Sb	Other*
E-1										
IN	5.8	2.1[a]	13.2	34.9	1.1	0.5	0.4	9.0	1.0	30.3
OUT	8.6	-	14.0	37.4	0.9	0.4	0.2	-	-	38.4

Table 1 (Continued)

TITANIUM TUBES

	S	Zn	Si	Fe	Cu	Ni	Cr	As	Sb	Other*
E-2	INSUFFICIENT MATERIAL OBTAINED									
E-3										
IN	4.9	4.8[a]	16.2	30.9	0.2	0.3	0.3	-	2.0	51.3
OUT	6.7	-	10.5	24.4	3.0	1.2	2.8	0.5	-	50.0
E-4										
IN	19.0	1.7[a]	1.6	0.8	2.6	-	0.2[a]	2.5	55.0	17.9
OUT	12.7	-	0.4	-	0.5	-	-	2.5	41.2	42.8

*This value is obtained by difference. It represents constituents with a molecular weight less than 23, such as carbon or oxygen.

[a]Not universally detected.

Table 2 presents the thickness of the scale that was measured from the photomicrographs.

Table 2

SCALE THICKNESS, MICRONS*

EXCHANGER	INLET	MIDDLE	OUTLET
E-1	51.7	92	93.1
E-2	5	8	12
E-3	48	96	110
E-4	12	26	24

*Average estimated thickness, variation ± 10 percent.

Chemical analyses of the Nowlin No. 1 well brine and the noncondensable gases present in the brine were obtained as a part of the investigation.

Overall heat transfer coefficients were calculated as follows:

HEAT TRANSFER COEFFICIENT, Btu/(hr) (ft^2) (F)

SECTION	CLEAN TUBE COEFFICIENT	365 DAY COEFFICIENT
E-1	890	569
E-2	639	542
E-3	741	395
E-4	553	402

From these data the following fouling factors were calculated for the exhangers:

SECTION	365 DAY FOULING FACTOR (F) (ft^2) (hr)/Btu
E-1	0.000576
E-2	0.000280
E-3	0.001182
E-4	0.00679

Table 3 presents the thermal conductivity and the density of the scale deposits.

Table 3

SCALE PROPERTIES

EXCHANGER	THERMAL CONDUCTIVITY Btu/(hr) (ft) (F)	DENSITY GRAMS/CC
E-1	0.490	0.526
E-2	0.160	0.186
E-3	0.343	0.516
E-4	0.143	0.198

No pitting or crevice corrosion was observed on either the steel or the titanium tubes. The scale deposits on the steel tubes contained about 30 percent iron whereas the deposits on the titanium tubes contained no iron. If this iron is a corrosion product from the tube wall, the corrosion rate would be 7.62 μm/yr (0.3 mils), which rate would be acceptable in a commercial plant.

The conclusions reached in this study are as follows:

1. Either steel tubes or titanium tubes could be used in a commercial geothermal plant. Scale deposition would be more rapid on the steel tubes.

2. The scale deposited on the steel tubes contains silicon, iron, antimony, arsenic, and sulfur. The scale is brittle and can be easily scraped from the tube surface.

3. The scale deposited on the titanium tubes is primarily antimony sulfide. This scale is a loose amorphous deposit that can be easily scraped from the tube surface.

4. An analysis of the noncondensable gases in the Heber brine showed that the gas constitutes only 0.0049 weight percent of the brine. The gas contains 0.36 mol percent hydrogen sulfide. This concentration of hydrogen sulfide is sufficiently low that it would not constitute a hazard if a brine spill should occur.

WASTE HEAT REJECTION FROM GEOTHERMAL POWER PLANTS: REVIEW OF DATA BASE AND METHODOLOGY

Research Project 927-1

Randy D. Horsak
Rodger O. Young
R. W. Beck and Associates

Although geothermal energy is capable of significantly contributing to our nation's energy supply, the development of many geothermal resources may be limited by cooling water supply. For instance, most of the known geothermal resources in the United States are located in the arid western states where water resources generally are either scarce or highly allocated. The constraints imposed by climatology are reinforced by the fact that local meteorological and hydrological conditions will influence the type and performance characteristics of the plant/cooling-system combination, and consequently the expected electrical energy production cost from the resource.

The eleven western states are characterized by many phenomena which suggest anomalously high heat concentrations at shallow depths in the earth's crust. In order to delineate those regions with potential for electrical energy production, nine geothermal regions have been defined according to a combination of geological features and upper mantle and crustal processes. For purposes of this report, only the hydrothermal (water and vapor-dominated geothermal) systems with temperatures in excess of 150°C (302°F) are considered. For analytical purposes, these systems are further classified as low temperature (150°-200°C), intermediate temperature (200°-250°C), and high temperature (>250°C) resources.

The approach used in this report to estimate hydrothermal reserves is based upon the statistical data available from heat flow determinations which have been made throughout the continental United States. Assuming that the heat flow determinations are randomly distributed, these data can be used to estimate the hydrothermal resource base in each of the nine regions. The recoverable energy from hydrothermal sources in each region can therefore be estimated as a function of heat flow by using developed information on fluid production, electrical energy production, and the area assumed to be available for hydrothermal development. By determining electrical energy production rates, the electrical production capacity for each region can be estimated for a nominal 30-year facility lifetime as shown in the following table.

These estimates are roughly equivalent to other conservative estimates, which foresee the ultimate development of several tens of thousands of megawatts of geothermal generating capacity in the western United States.

The hydrothermal resources in each region can then be correlated with climatic regions (tundra, forest, steppe, semidesert, and desert) in order to provide general guidelines for the selection of plant-site design combinations to be analyzed in detail in the second phase of this study. Correlation of resources with climatic regions indicates that there are apparently no significant occurrences of developable resources in tundra climates. Low, intermediate, and high temperature resouces may occur throughout the remaining climatic types, however, with the majority of the resources occurring in a semidesert climate.

ESTIMATES OF NOMINAL 30-YEAR ELECTRICAL PRODUCTION CAPACITY(MWe)
FOR THE MAJOR HYDROTHERMAL REGIONS AS A FUNCTION OF HEAT FLOW

	Heat Flow, hfu		
	3-4	4-5	>5
Hydrothermal Region			
Central California Coast Range	1,450	1,740	850
Cascade Range	200	120	30
Snake River Plain	2,050	3,420	3,000
Northwestern Basin and Range	5,600	7,560	3,780
Central Basin and Range	150	70	20
Eastern Basin and Range	880	620	160
Salton-Imperial Valley	480	800	700
Southern Basin and Range	960	420	90
Rio Grande Rift System	1,840	2,050	1,100
TOTAL	13,610	16,800	9,730

It is therefore reasonable to conclude that the availability of water for cooling system makeup may be an area of concern in many of the areas of hydrothermal interest. In many regions, water resources are either scarce or highly allocated, or are influenced by regional institutional and legal considerations. Moreover, use of groundwater resources in some areas may further deplete already dwindling reservoirs. The use of geothermal fluids may be feasible at some sites, depending upon their mineral content and the necessity to reinject fluids to prevent subsidence or maintain reservoir integrity. Regardless of the type of water used for makeup, however, site-specific analyses must carefully consider the costs associated with water acquisition, transportation, and treatment.

A number of processes have been devised for converting the thermal energy of water-dominated geothermal resources into electrical energy. The principal conversion processes are the flash steam process, the binary process, and the hybrid process, which is a combination of the flash and binary processes. These processes operate on the principle of producing a vapor either directly from the hydrothermal resource (flash steam process) or by transfer of energy from the hydrothermal resource to a suitable working fluid (binary process). The vapor is then expanded through a turbine or expander to produce mechanical work which, in turn, is used to drive an electrical generator.

The economically optimum conversion system for a particular application represents a trade-off between system capital and operating costs and the cost of the hydrothermal resource. The required hydrothermal resource flow rate depends upon the amount of energy extracted from each unit mass of resource and the efficiency with which the extracted thermal energy is converted into electrical energy.

A flash steam system generally is the simplest and least expensive of the principal conversion systems to build and operate. However, the energy extracted from each unit mass of hydrothermal resource typically is less for a flash steam system than for either a binary or hybrid system. Therefore, even though the thermal conversion efficiency may be slightly higher for a flash steam system than for the other systems, the hydrothermal fluid rate generally is higher for the flash steam system.

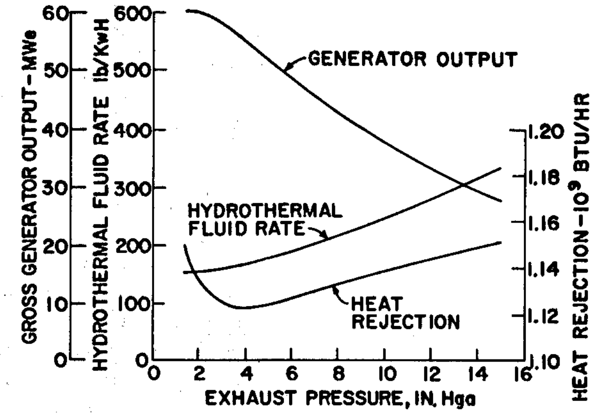
Because of the relatively low temperatures of hydrothermal resources, the thermal efficiencies of geothermal conversion cycles are quite low, being on the order of 10% to 15%. Thus, the waste heat rejection from the turbine exhaust flow of a geothermal power plant typically will be 20,000 to 30,000 Btu/kWh of electrical generation at design conditions, compared to approximately 5000 Btu/kWh for a modern fossil-fueled plant. If conventional evaporative cooling methods are to be used for geothermal power plants, large quantities of cooling water will be required. Therefore, advanced-concept as well as conventional waste heat rejection systems should be considered in evaluating the development potential of hydrothermal resources.

Wet, wet-dry, and dry cooling towers appear to be the principal cooling systems for rejecting the waste heat from a hydrothermal power plant. If sufficient surface or groundwater is available, or if the hydrothermal fluid can be used for cooling tower makeup, the conventional wet cooling tower can be used.

Dry cooling towers, which transfer the waste heat from a power plant directly to the atmosphere by means of air-cooled, finned-tube heat exchangers without any consumptive use of water, afford much greater flexibility in power plant siting than do other methods of waste heat rejection. This can be an especially important factor in considering the development of hydrothermal power plants. By combining wet and dry cooling methods in a single system, the makeup water requirements associated with all-wet systems may be reduced significantly, usually with a considerably smaller increase in electrical energy production costs than would result from the use of an all-dry system. With this type of cooling combination, the wet tower provides the additional cooling that would be required to maintain a low back pressure, thus reducing the amount of capacity lost during high ambient air temperature operation.

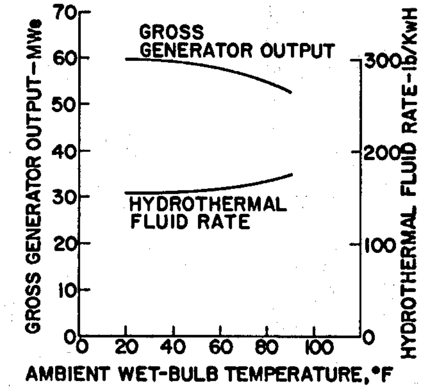
The available energy from hydrothermal resources is low compared to conventional power plant conditions. Typical performance characteristics of a geothermal steam turbine-generator are shown in Figure 1 for a dual flash steam system with a 180°C (360°F) hydrothermal resource. The turbine, a tandem-compound, four-flow unit designed to produce 55 MW (e) at 13.5 KPa (4 in. Hg), will experience a loss of capacity of approximately 50% over the expected range of operation (2-15 in. Hg). Similarly, the hydrocarbon turbine used in the binary conversion process (designed for a 180°C resource temperature) also experiences a significant loss of capacity over the expected range of operation, as shown in Figure 2.

Typical combined performance curves for the dual flash steam turbine-generator using wet and dry cooling systems are shown in Figures 3 and 4, respectively. The generator output and the hydrothermal fluid rate are significantly affected by the performance of the cooling system over the anticipated range of occurrences of wet bulb and dry bulb temperatures. The dry tower, however, has a far greater effect on generator output and hydrothermal fluid rate.



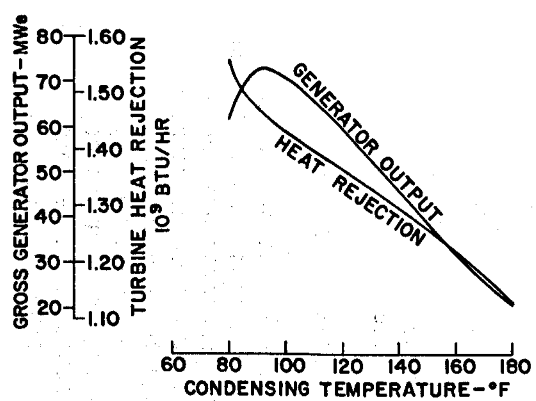
TYPICAL HYDROTHERMAL STEAM TURBINE PERFORMANCE

FIGURE 1



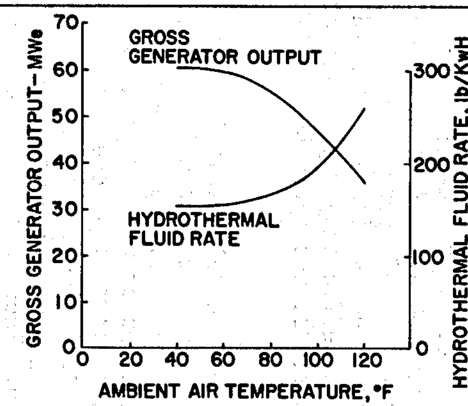
TYPICAL HYDROTHERMAL STEAM TURBINE PERFORMANCE (WET COOLING SYSTEM)

FIGURE 3



PRELIMINARY HYDROCARBON TURBINE PERFORMANCE

FIGURE 2



TYPICAL HYDROTHERMAL STEAM TURBINE PERFORMANCE (DRY COOLING SYSTEM)

FIGURE 4

In analyzing waste heat rejection systems for hydrothermal power plants, the following factors are considered:

- Size of cooling system (heat rejection capability)
- Capital cost
- Fixed charge rate
- Ambient air temperature and durations
- Resource cost
- Turbine-generator performance
- Auxiliary capacity and energy costs
- Replacement capacity and energy costs
- Makeup water costs
- Operation and maintenance costs

A computer model which considers the above factors is used to perform economic analyses of waste heat rejection systems for the various resources (high, intermediate, and low temperature) for both the flash steam and binary conversion processes. The optimum system can therefore be determined for a given hydrothermal resource at a certain location.

ACKNOWLEDGMENTS

R. W. Beck and Associates wishes to acknowledge the assistance of Dr. G. V. Keller and Dr. L. T. Grose of the Colorado School of Mines in the preparation of the discussion of hydrothermal resources.

PRELIMINARY DESIGN OF AXIAL FLOW HYDROCARBON
TURBINE-GENERATOR SET FOR GEOTHERMAL APPLICATIONS

Research Project 928-1

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The purpose of this study is to demonstrate the feasibility of a large 65-megawatt axial design, double flow turbine generator unit for use with a variety of hydrocarbon mixtures. The project objectives are as follows:

- Evaluate the present state of the art for the design and construction of an axial double flow turbine
- Establish a conceptual design for a 65-megawatt axial flow turbine
- Evaluate off-design performance for seasonal variations and long-term thermal depletion conditions
- Establish a conceptual system control scheme

To achieve these objectives, a hardware-oriented design was initiated. Turbine design parameters were specified by EPRI. For a specific mixture of 80% iso-butane, 20% iso-pentane, the inlet temperature was specified as 146°C$\pm$ (295°F $\pm$5°), the inlet pressure 3447 kPa $\pm$34.4 kPa (500 psia $\pm$10 psia) and the discharge pressure was specified as 496.4 kPa +0 and -68.9 kPa (72 psia +0 and -10). In addition, conditions for a 90% iso-butane, 10% propane and commercial iso-butane were specified.

Overall objectives of this project have been achieved in that a 65-megawatt axial double flow turbine concept has been proposed and the design is within the present state of the art.

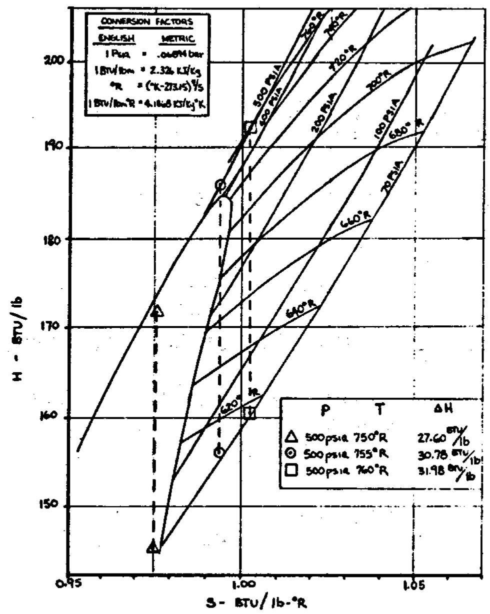
THERMODYNAMICS

The gas properties used for the design of this unit were calculated by Elliott Company from modified Benedict-Webb-Rubin (BWR) equations of state. Mollier charts for each gas mixture were prepared.

Figure 1 is a portion of the 80/20 mixture Mollier chart. The selected design point lies very close to the vapor dome. The isentropic ideal expansions for the design point, as well as points of $\pm$5°F in the temperature, are shown. With the 80/20 mixture, a 5°F decrease in temperature pushed the entire operation of the unit within the vapor dome and caused a loss of turbine-available energy of about 10%.

A further study was also done to establish the sensitivity of the process to changes in mixture purity. Shown in Figure 2 are Mollier charts of three mixtures of iso-pentane and iso-butane. The middle vapor dome shows the 80/20

ISENTROPIC HEAT DROP -



80% ISOBUTANE - 20% ISOPENTANE

Figure 1

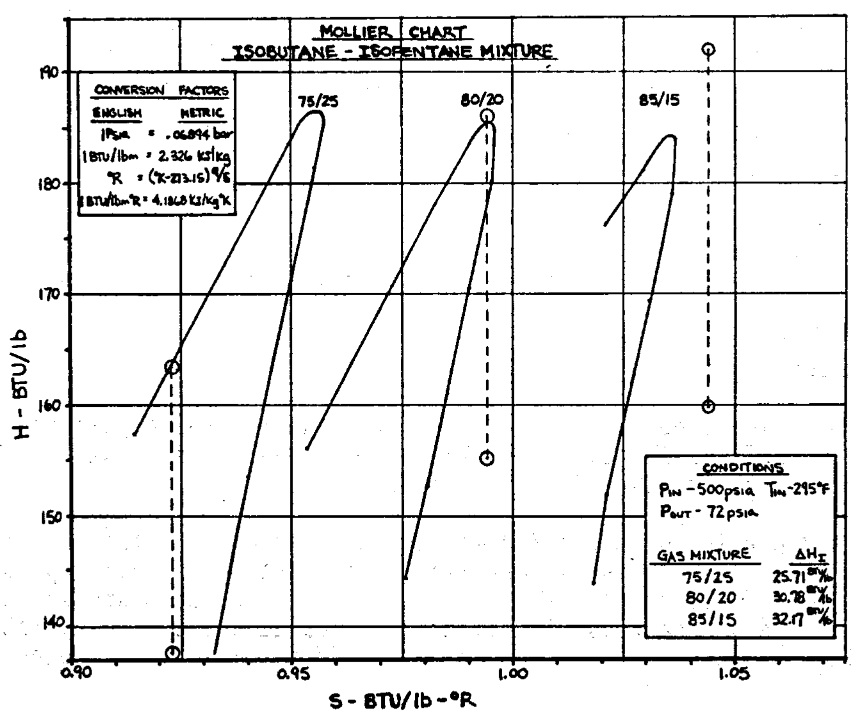


Figure 2

mixture as in Figure 1; to the right is an 85/15 mixture and to the left is a 75/25 mixture. As the mixture changes to greater percentages of iso-butane, the same pressure and temperature point moves further away from the wet region. As the mixture has an increasing proportion of iso-pentane, then this same position of 146°C, 3447 kPa (500 psia, 295°F) moves down to the wet region. This particular mixture is extremely sensitive to purity. Note that the isentropic paths shown are identical for each mixture case. Purity will have to be measured continuously as part of the normal plant operation.

A review of methods other than BWR for computing the gas properties was conducted. It is our opinion that the gas mixture properties should be verified to prove the turbine design assumptions. This verification should be by experimental methods.

AERODYNAMICS

EPRI specified three mixtures to be used for the design of this turbine. It was found that the conditions for the 80/20 mixture required the largest flow area in the turbine of all the mixtures to obtain the 65-megawatt conditions. It was therefore decided that this mixture would be the design mixture for the turbine.

Shown in Figure 3 is the final blade path utilizing a 0.7 m (28 in) base diameter. A flow of 1099.5 kg/s (2424 pounds per second) is required to produce 65.9 megawatts at a blade path efficiency of 0.8766. The inlet blade height is 81.28 mm (3.2") and the last stage blade is 228.6 mm (9"). This is reaction-type staging with 40% to 50% reaction in the buckets. The final blade path was computed using real gas properties and not ideal gas relationships. The 88% efficiency is for the blade path and is not the overall turbine efficiency.

The losses associated with a turbine design are shown in Figure 4. For any given condition, there is a total available energy capable of being converted to mechanical power. We assumed there will be a throttling valve for turbine control; therefore, there is a throttle loss. From the inlet flange to the start of the blade path, there is an inlet loss, after which there is the blade path loss, and finally the exhaust loss. All of these losses tend to lower the efficiency of the unit from 88% at the blade path to approximately 82% for the overall turbine with a throttle valve. If there were no throttle valve, the overall turbine efficiency would be on the order of 84% to 85% at design point. Mechanical losses are included in the overall efficiency values.

Figure 5 is the turbine shaft output in megawatts versus the overall unit efficiency. This is based on constant inlet conditions at the inlet throttle valve and constant discharge pressure at the exhaust. For this specific design geometry, the 80/20 mixture has an 82% efficiency, commercial iso-butane has an 80% efficiency and the 90/10 mixture a 79% efficiency.

Table 1 shows turbine performance under a variety of conditions. The first column demonstrates the turbine without a throttle valve, that is, no throttling drop. The inlet temperature and pressure are the same value upstream as the inlet blade path. The power developed for this condition is 77.5 megawatts and requires 1247.4 kg/s (2750 pounds per second) of flow. Column 2 shows the performance with the throttle valve added for control purposes. We have assumed a 344.7 kPa (50 pound) drop for this throttle valve. The inlet temperature, assuming an isenthalpic throttling across the valve, is 139.4°C (283°F). The power developed is 67 megawatts for a flow of 1099.5 kg/s (2424 pounds per second). Column 3 demonstrates the effect of increased supply temperature to 167.7°C (334°F), as is the case for the non-fouled condition on the heat exchanger. The turbine inlet has to be throttled to 2937 kPa (426 psi) to develop the same 67 megawatts, but requires only 2100 kg/s (2100 lbs) of flow. This is due to the higher available energy at this superheated point than is available closer to the vapor dome.

A further study was made on the effects of back pressure on this three-stage unit. Figure 6 is the blade path efficiency versus pressure ratio. As the pressure ratio decreases (increasing back pressure), the unit becomes more and more inefficient for the three-stage design. At approximately a pressure ratio of 3.5, the last stage actually became parasitic, in that it was absorbing power and not creating it. There is a decrease in peak blade path efficiency going from three stages to two stages. Basically, this decrease reflects the overall available heat drop becoming smaller, esentially going from 69.73 kJ/kg (30 btus per pound) at a pressure ratio of 6.5 to 46.49 kJ/kg (20 btus per pound) at a pressure ratio of 3.5. Therefore, the losses illustrated in Figure 4 become a greater proportion of the available energy.

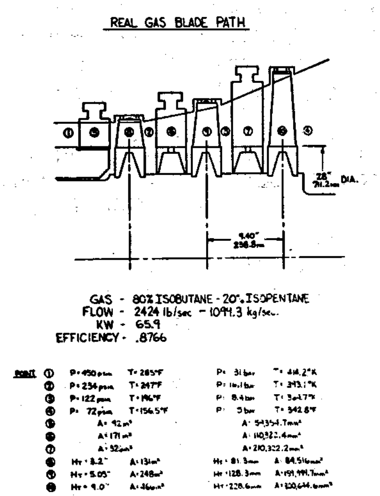


Figure 3

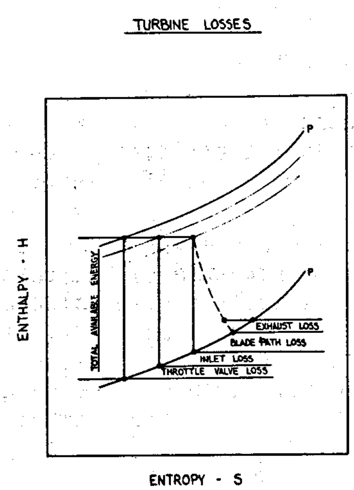


Figure 4

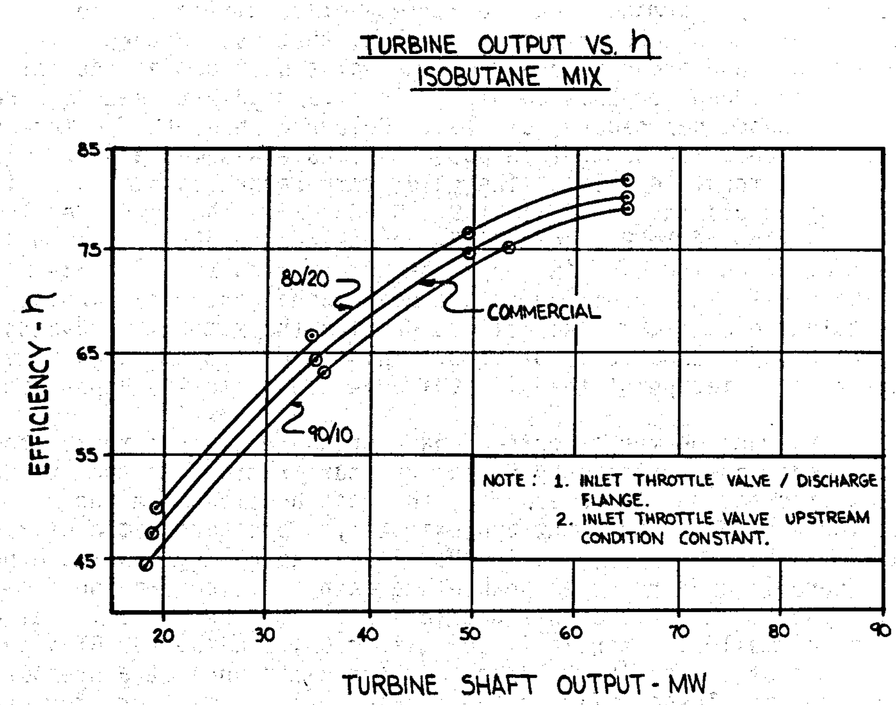


Figure 5

Table 1

TURBINE PERFORMANCE

80 - 20 Mixture

SUPPLY			
Pressure psia	500	500	500
Temp. °F	295	295	334
BLADE PATH INLET			
Pressure psia	500	448	426.9
Temp. °F	295	283	324
DISCHARGE FLANGE			
Pressure psia	72.0	72.0	72.0
Temp. °F	155	157	220
TOTAL FLOW LB/SEC	2750	2424	2100
TOTAL POWER MW	77.5	67.0	67.0

Table 1 shows turbine performance under a variety of conditions. The first column demonstrates the turbine without a throttle valve, that is, no throttling drop. The inlet temperature and pressure are the same value upstream as the inlet blade path. The power developed for this condition is 77.5 megawatts and requires 1247.4 kg/s (2750 pounds per second) of flow. Column 2 shows the performance with the throttle valve added for control purposes. We have assumed a 344.7 kPa (50 pound) drop for this throttle valve. The inlet temperature, assuming an isenthalpic throttling across the valve, is 139.4°C (283°F). The power developed is 67 megawatts for a flow of 1099.5 kg/s (2424 pounds per second). Column 3 demonstrates the effect of an increase in supply temperature to 167.7°C (334°F), as is the case for the non-fouled condition on the heat exchanger. The turbine inlet has to be throttled to 2937 kPa (426 psi) to develop the same 67 megawatts but requires only 2100 kg/s (2100 lb/s) of flow. This is due to the higher available energy at this superheated point than is available closer to the vapor dome.

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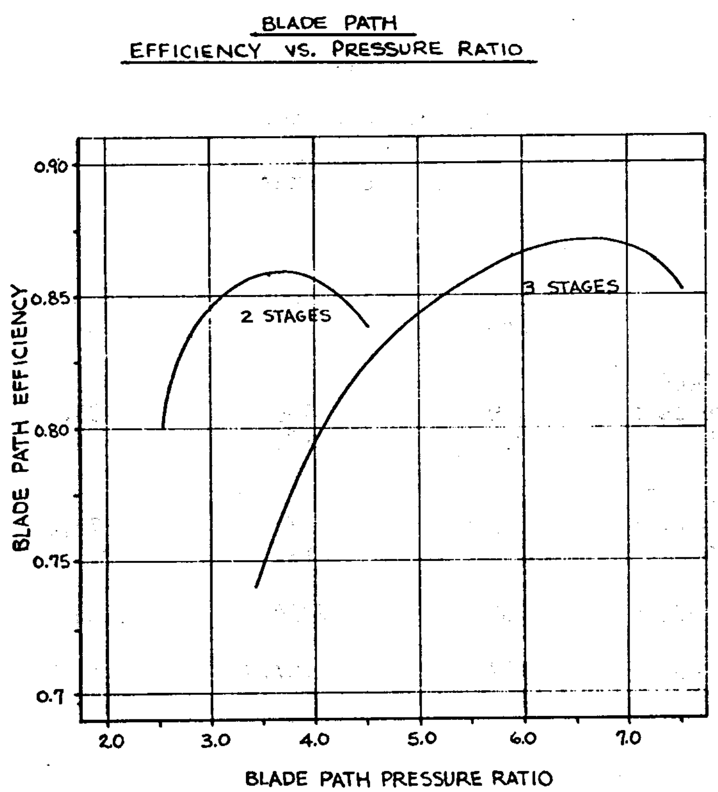


Figure 6

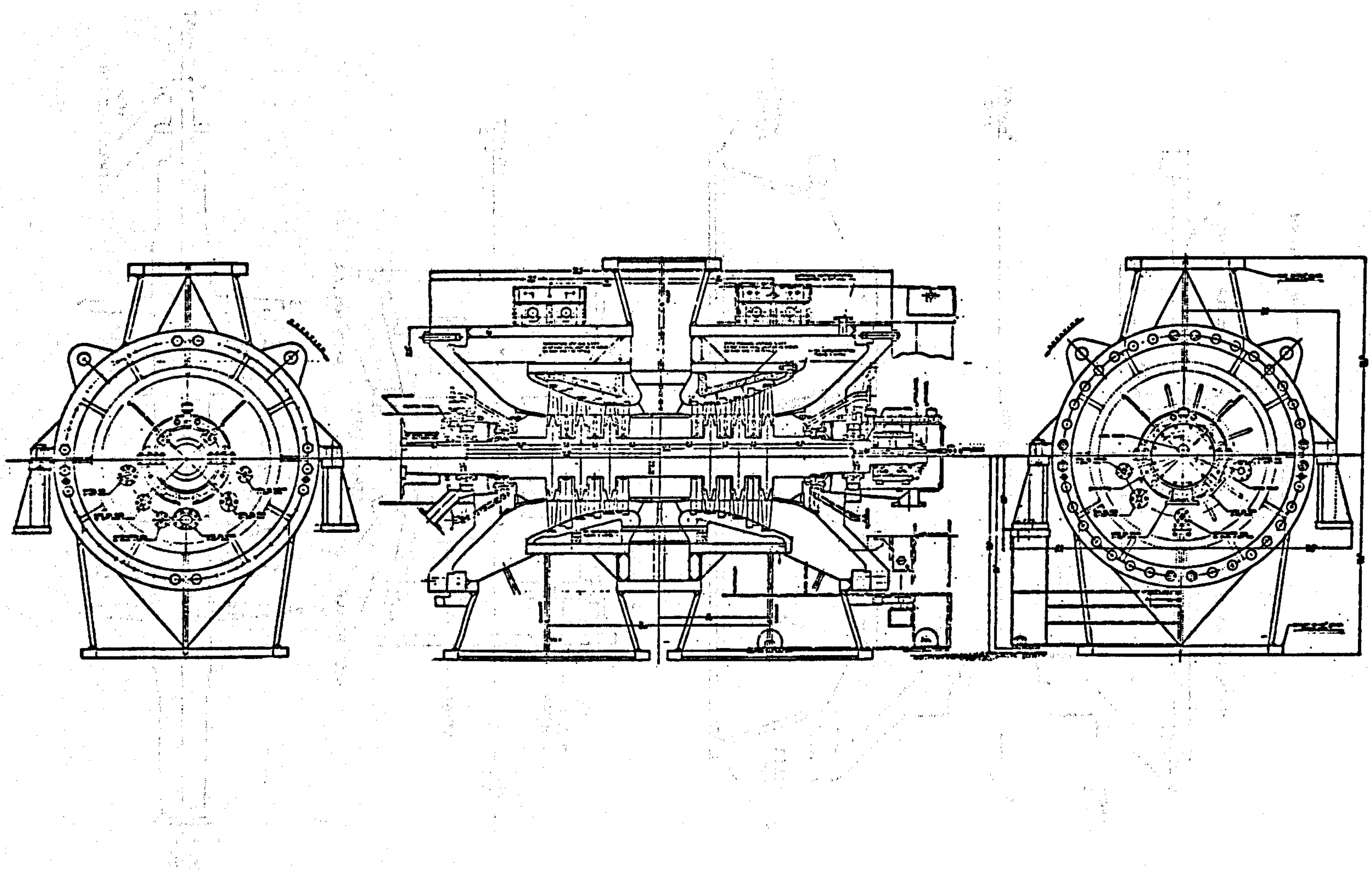


Figure 7

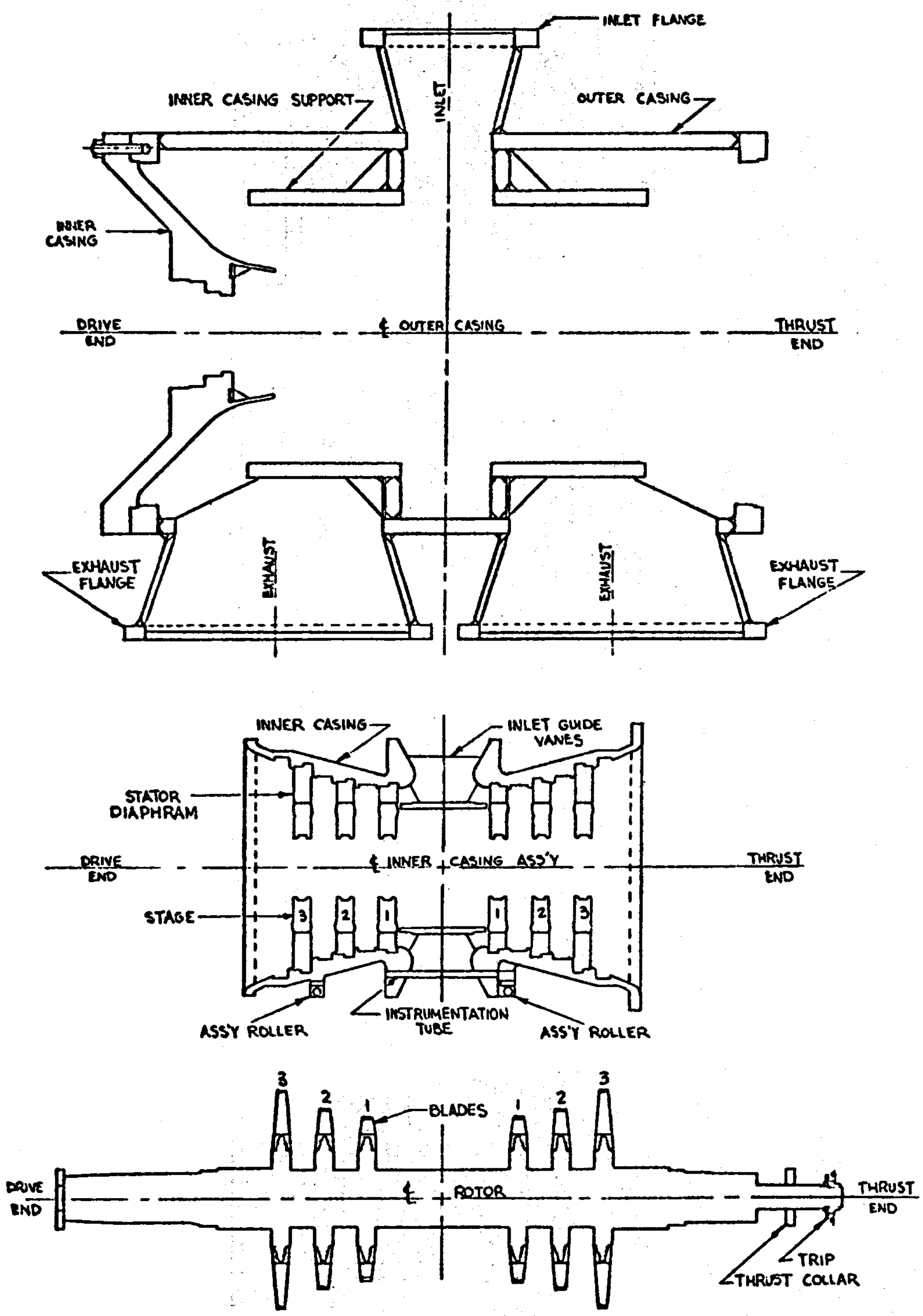

INLET FLANGE
INNER CASING SUPPORT
INLET
OUTER CASING
INNER CASING
DRIVE END
℄ OUTER CASING
THRUST END
EXHAUST FLANGE
EXHAUST
EXHAUST
EXHAUST FLANGE
INNER CASING
INLET GUIDE VANES
STATOR DIAPHRAM
DRIVE END
℄ INNER CASING ASS'Y
THRUST END
STAGE
3
2
1
1
2
3
ASS'Y ROLLER
INSTRUMENTATION TUBE
ASS'Y ROLLER
3
2
1
BLADES
1
2
3
DRIVE END
℄ ROTOR
THRUST END
TRIP
THRUST COLLAR

Figure 8

MECHANICAL DESIGN

Figure 7 shows the complete outline of the unit. Figure 8 is an expanded view of the major components. This is a barrel type, axial double flow, hydrocarbon turbine. The outer casing is 2.21 m (87") in outside diameter, 0.89 m (3-1/2") thick, and 3.25 m (128") long. The inlet flange is 0.76 m (30") and the two discharge flanges are 1.52 m (60"). This barrel contains two welded internal rings, which guide the flow to the inlet portion of the casing and also provide the support for the inner casing assembly. The inner casing positions the stator blade diaphragms and is a horizontally split casing. Incorporated in the design is full instrumentation for both pressure and temperature measurements at each stage for performance evaluation. The rotor is an integral shaft forging. It will be operating as a flexible shaft with the first critical frequency of approximately 2400 RPM and the second at 5300 RPM, as derived from unbalance response analyses. The bearing span is 3.24 m (127.7") and the overall length of the rotor is 4.19 m (165"). The shaft seals are a mechanical contact oil seal. This design has been proven in hundreds of compressors for this type of service under more severe operating conditions (i.e., temperature, pressure, rubbing velocity).

As shown in Table 2, the rotor weighs 4540 kg (10,000 lb); the inner casing assembly, including the rotor, weighs 12,800 kg (28,2000 lb), baseplate 3180 kg (7000 lb) and the total turbine unit (114,000 lb). The generator, rotor and stator weights are shown here, and the total generator and excitor weight is 141,000 kg (311,000 lb), making the total string 192,800 kg (425,000 lb).

Table 2

TURBINE GENERATOR COMPONENT WEIGHTS

	Lb	Kg
TURBINE		
Rotor	10,000	4,540
Inner casing assembly	28,200	12,800
Baseplate	7,000	3,180
Total unit	114,000	51,700
GENERATOR		
Rotor	45,200	20,500
Stator	200,000	90,700
EXCITER		
Rotor	2,500	1,130
Casing	9,000	4,080
TOTAL GENERATOR AND EXCITER	311,000	141,000
TOTAL STRING	425,000	192,800

Figure 9 is a conceptual design of the placement of this turbine generator set above the condensers and accumulators. The unit would have to be placed approximately 17 m (55 ft) above ground level to accommodate the condensing system based on the information supplied by EPRI. Figure 10 demonstrates the arrangement utilizing these down exhausts with the plenum concept. This arrangement will require the turbine to be mounted approximately 6 m (20 ft) above ground level. It must be noted that we are recommending down exhaust for this type of turbine. The motive fluid being used is normally a liquid at ambient temperature and the pressures of the system. For safety reasons, the turbine should always be draining, to avoid the possibility of its filling with liquid. If the problem is recognized and steps taken to prevent it, then the flanges can be designed for any direction - side exhaust or up exhaust.

Figure 11 is the control scheme that we would propose for this type of unit. Basic components, of course, are the condenser, pumps, vapor generator and the turbine. We would also require a storage and make-up tank to allow for load changes within the confines of the closed loop. The recommended pressure control is based on bypass of liquid. A temperature controller is also required to sense the gas temperature coming off the vapor generator and regulate the the brine flow. The bypass around the turbine would be used for start-up, to circulate the gas without the turbine on-line.

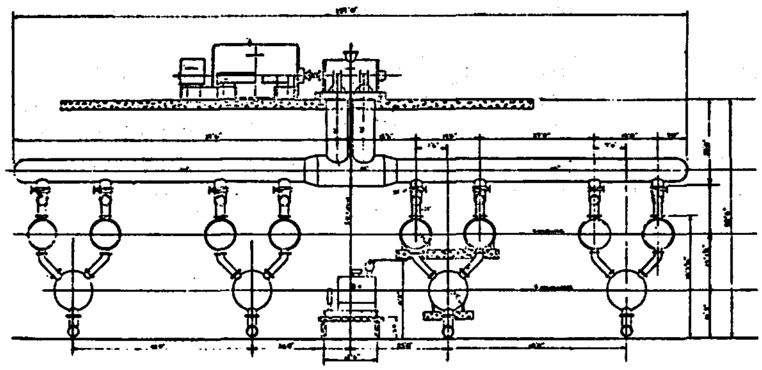


Figure 9

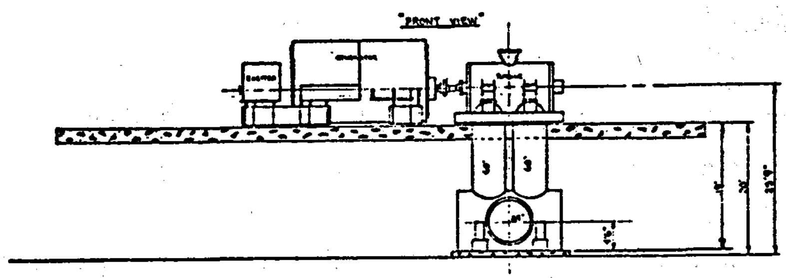
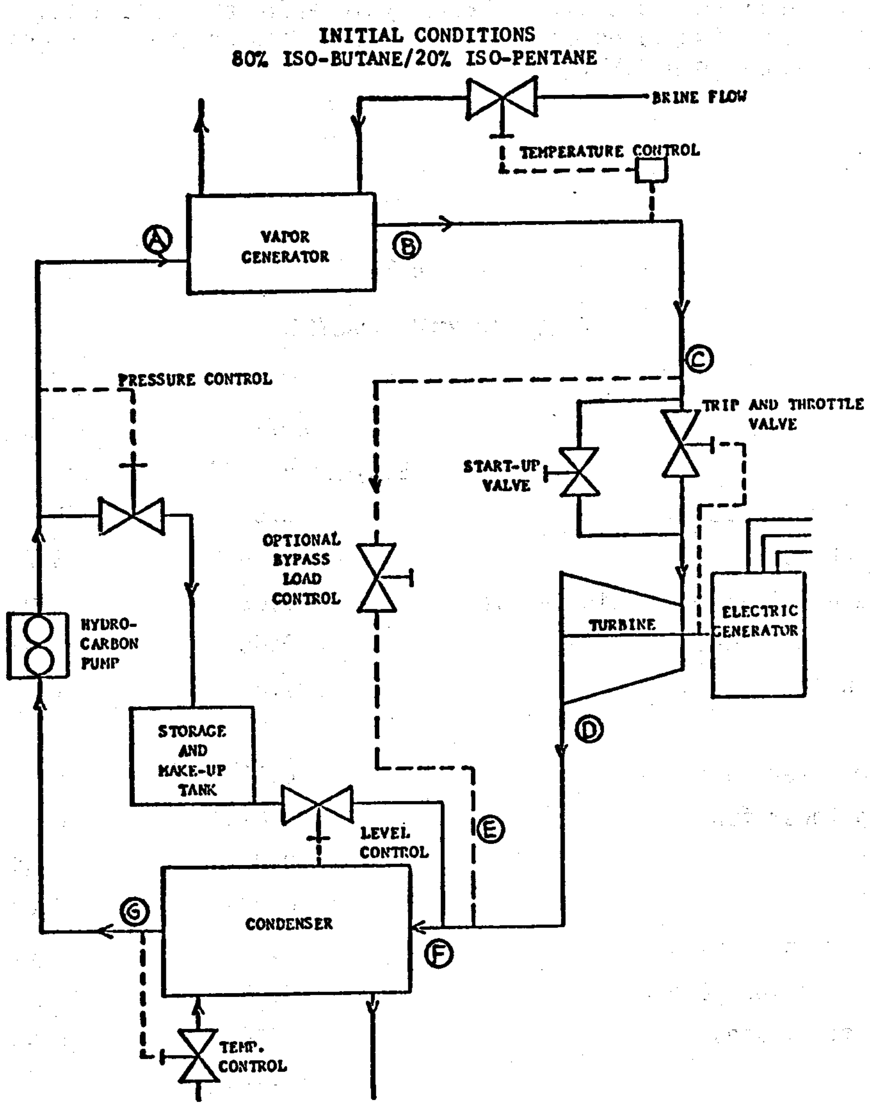


Figure 10



CONDITIONS AT POINT:

Ⓐ 555 psia (38.24 bar)
120.8°F (322.92°K)
14 Btu/lb (32.55 KJ/K_g)

Ⓑ 505 psia (34.79 bar)
296°F (420.34°K)
186.1 Btu/lb (432.68 KJ/Kg)

Ⓒ 500 psia (34.45 bar)
295°F (419.78°K)
186.1 Btu/lb (432.68 KJ/K_g)
2424 lb/sec (1100.5 Kg/sec)

Ⓓ 72 psia (4.96 bar)
156.5°F (342.77°K)
160.6 Btu/lb (373.4 KJ/K_g)

Ⓔ 67 psia (4.62 bar)
207.8°F (371.3°K)
186.1 Btu/lb (432.68 KJ/Kg)

Ⓕ 67 psia (4.62 bar)
155.4°F (342.16°K)
160.6 Btu/lb (373.4 KJ/K_g)

Ⓖ 64 psia (4.41 bar)
102.2°F (312.58°K)
10 Btu/lb (23.25 KJ/K_g)

Figure 11

Shown in Table 3 is the cycle thermal analysis for the 80/20 and 90/10 mixtures. The 80/20 mixture cycle would have a 12.4% cycle efficiency and a 10.6% plant thermal efficiency. Estimates of parasitic losses and of the vapor generator "heat in" were supplied by EPRI.

Table 3

CYCLE THERMAL ANALYSIS

	80/20 Btu/min x 10^{-6}	90/10 Btu/min x 10^{-6}
Vapor generator - heat in	25.0	25.0
Turbine - work out	3.75	3.75
Mechanical-electrical conversion - loss	0.05	0.05
Circulating pump - work in	0.60	0.62
Condenser - heat out	21.8	21.8
Parasitic losses		
Cooling water pump	0.15	0.24
Cooling tower fans	0.07	0.09
Make-up	0.03	0.04
Miscellaneous	0.02	0.02
Brine down-hole pump	0.13	0.20
Brine injection pump	0.05	0.07
Total parasitic losses	0.46	0.66
Cycle efficiency	12.4%	12.3%
Plant thermal efficiency	10.6%	9.7%

As shown in Figure 12, the overall pricing for the turbine generator set for 65 megawatts would be $3.3 million and delivery would be approximately 22 to 24 months, consistent with the delivery of the generator. For a single-flow unit, the pricing would be somewhat different, as shown in the figure. There is a band between 30 to 35 megawatts where there would be an overlap to go from a single-flow unit to a double-flow unit, depending upon cycle requirements.

To summarize:

- There are no new materials being utilized.
- The turbine aerodynamics are subsonic, and the stages are adapted from proved gas and steam turbine vane profiles.

- The turbine shaft seals will keep the gas within the system to avoid hazardous conditions, and they are well-proved components.

Therefore, the turbine-generator unit is well within the present state of the art.

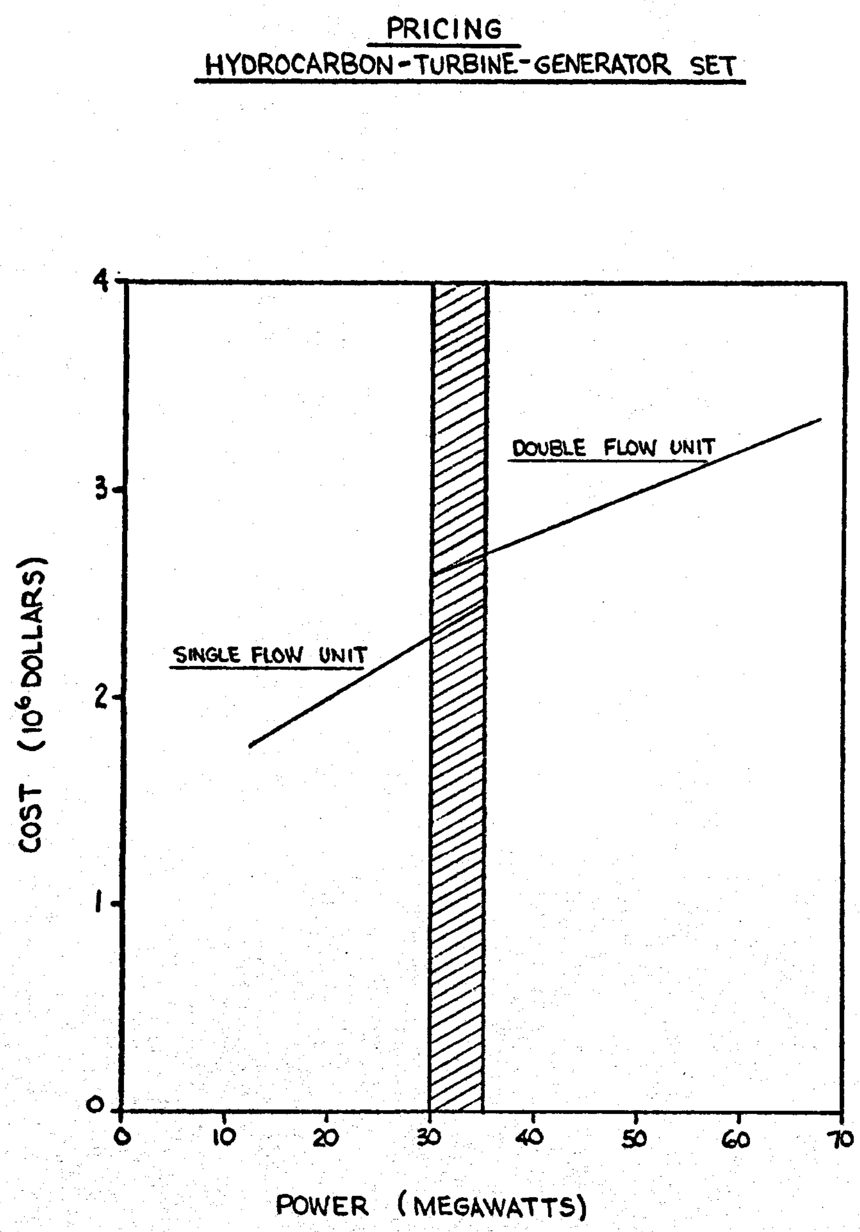
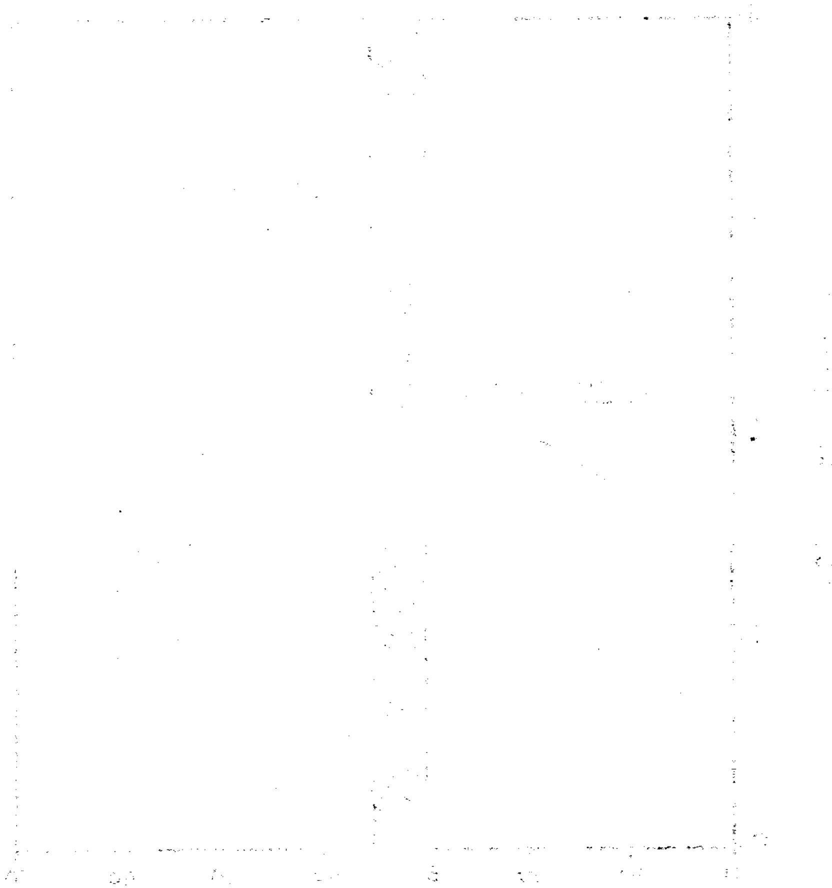


Figure 12



RADIAL HYDROCARBON TURBINE STUDY

EPRI Research Project 928-3

Robin Dakin
Rotoflow Corporation

The objective of this project is to evaluate the radial inflow turbine as a hydrocarbon expander for geothermal application. The report presents an outline of Rotoflow's conceptualization and calculations on the project at this time.

DESIGN CONSIDERATIONS

EPRI requested that Rotoflow perform the following tasks: (1) prepare a preliminary design for an approximately 65 MW(e) turbine-generator set, (2) investigate the 65 MW(e) design to assure that it is capable of maintaining 65 MW(e) output under the varying geothermal fluid wellhead temperature conditions, (3) investigate the possible range of sizes of turbine-generator sets that could be extrapolated from the 65 MW(e) baseline design and that can meet the needs of a range of resource wellhead temperatures and wellfield productivities, and (4) generalize the results obtained so that turbine design conditions can be calculated from a multiparameter plot for any reasonable working fluid and turbine inlet and exhaust conditions. This last task is to provide data that is useful for concept design studies by or on behalf of electric utilities.

HYDROCARBON MIXTURES ANALYZED

Table 1 presents the range of gas mixtures analyzed. Rotoflow has prepared Mollier Charts for each of these mixtures. The 80% isobutane/20% isopentane mixture was selected by the Ben Holt Company as a suitable working fluid for a geothermal system having a wellhead temperature of about 182°C (360°F). The second fluid, 90% isobutane and 10% propane, is suitable for wellhead temperatures of about 163-182°C (325-350°F). Commercial isobutane was selected as a suitable "backup" fluid capable of operating over the entire range but with somewhat reduced power plant and turbine efficiencies.

For a geothermal resource whose wellhead temperature declines from, say, 182° toward 163°C (360°F toward 325°) during economic life of the power plant (30 years), a changeover from the 80/20 mix to the 90/10 mix appears appropriate. The changeover time, of course, will be highly dependent on the particular resource being considered. For the specific problem posed by EPRI, the changeover would come at approximately seven to ten years after plant startup.

GENERAL ARRANGEMENT - BASELINE DESIGN

In selecting a suitable choice of hydrocarbon turbine for geothermal secondary working fluid (binary) cycle application, the important factors are size, wheel shape, and speed. For the working fluids presented in Table 2 the wheel size for for a 3600 rpm direct drive falls in the range of 1.02-1.27 m (40-50 in).

Table 1
GAS MIXTURES AND FLANGE STATE POINTS INVESTIGATED
65 MW(e) BASE CASE

Gas Mixture	P_{in}(mPa/Psia)	T_{in}(°C/°F)	P_{out}(mPa/Psia)	T_{out}(°C/°F)
80% Isobutane,	3.52/510	149/300	.365/53	63/146
20% Isopentane			.496/72	72/161
			1.14/165.5	99/211
	3.45/500	143/290	.365/53	57/135
			.496/72	63/146
			1.140/165.5	94/202
90% Isobutane,	4.14/600	143/290	.579/84	65/149
10% Propane			.765/111	72/161
			1.65/239	103/217
	4.00/580	138/280	.579/84	57/134
			.765/111	64/148
			1.65/239	97/207
96.4% Isobutane, *				
3.2% n-Butane,	3.52/510	149/300	.517/75	81/177
0.4% Propane			.689/100	87/189
			1.45/210	117/242

*Typical composition of Commercial Isobutane.

For a convenient specific speed ratio of

$$\frac{\text{(Speed)x(flow rate)}}{\text{(Enthalpy Drop)(3/4)}}$$

and wheel shape, the optimum horsepower is around 30,000. Thus, for 65 MW of generation capacity, this size leads to the use of three wheels on one shaft in one double (back-to-back configuration) and one single unit.

Figure 1 shows the relative size of the baseline double wheel expander casing and a 65 MW(e) alternator. Note the relatively small size at the turbine. Figure 2 illustrates the general configuration in profile and side views. Note the piping sizes in relation to casing size. The generator selected for coupling to the turbine is rated at 65 MW at 0.9 power factor and is hydrogen cooled for optimum efficiency and cooling potential in hot climates, as found in the Imperial Valley, California. In present geothermal areas, seismic activity must be considered. It is, therefore, desirable to avoid high structures with large weights on top. The proposed arrangement, Figures 1 and 2, is similar to many other radial inflow expander power installations and results in minimum excavation, structure, and installation costs. It also permits easy movement to another site, if necessary.

In order to minimize the overall length of the machine, volute type entry and exit casings are used with the exit volute enclosing most of the inlet and minimizing internal stresses. Figures 3 and 4 show the difference in internal casing configuration between a double and single rotor. For the single rotor machine of Figure 4, a seal rotor is used in place of a second bladed rotor.

The wheels are all similar, as are the shafts, bearings, and shaft seals. Such design minimizes spare parts inventories and tool requirements. Seals will be labyrinth-type, and a Rotoflow patent-protected recovery system will be used to minimize loss of secondary fluid and seal gas at the seals. Nitrogen or propane can be used as a seal gas.

EXTRAPOLATION FROM BASELINE DESIGN - MODULE CONCEPT

Table 2 summarizes the flexibility of the module concept, which allows for the use of the same casings, shaftings, and generator arrangement in various installations. This is especially important, as wellhead temperatures and field productivity vary from field to field. It is possible, for example, to couple modules together, drive at either end of the generator, or allow expansion in 2 stages. It is also possible to use a secondary and tertiary fluid system.

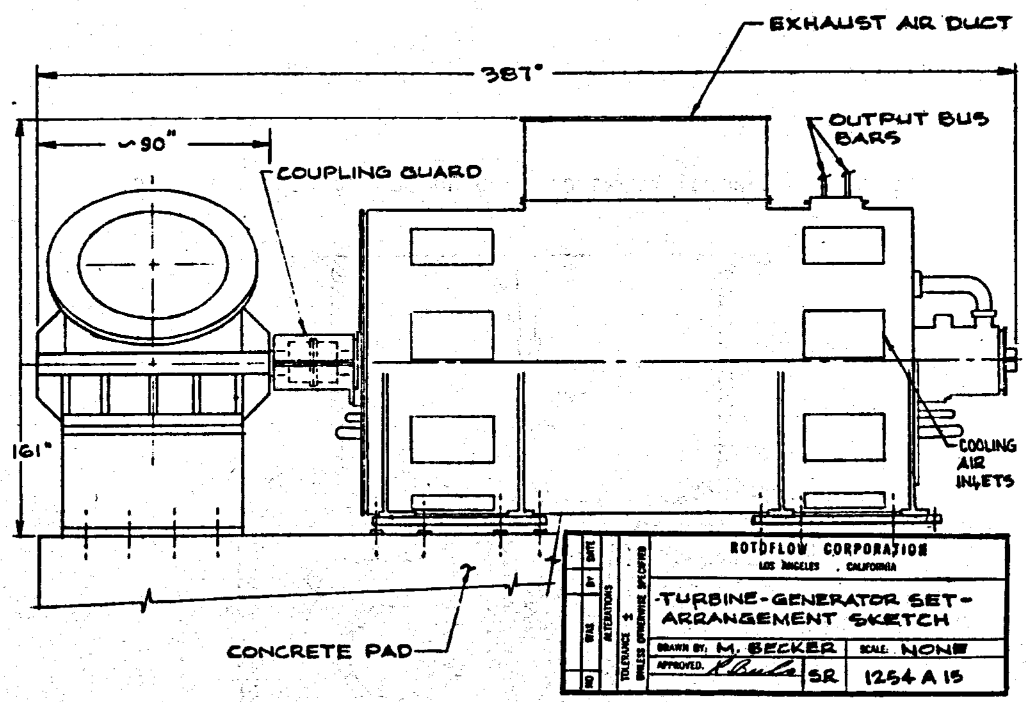


Figure 1. Turbine-Generator Set Arrangement and Relative Size.

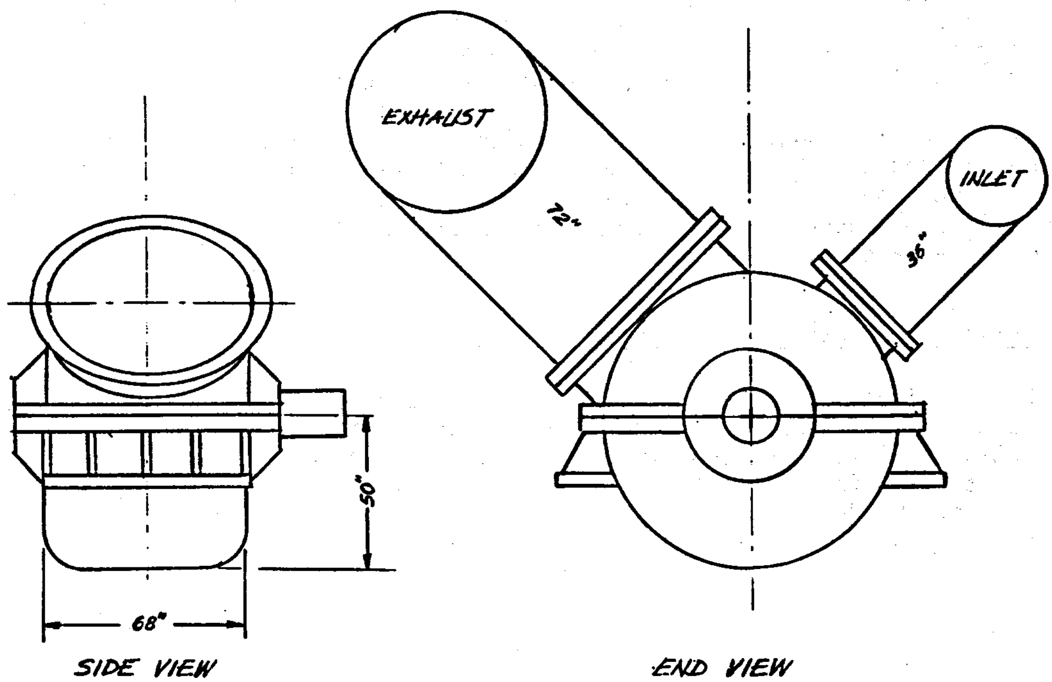


Figure 2. General Views of Turbine Casing Configuration.

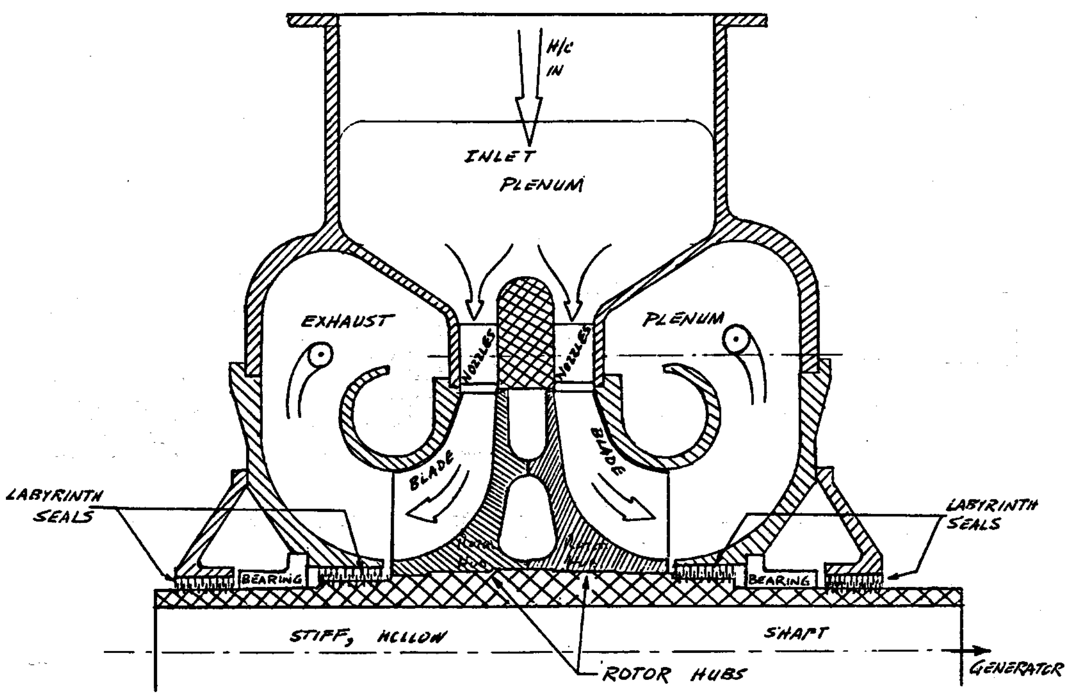


Figure 3. Internal Configuration of Double Wheel, Double Flow Casing.

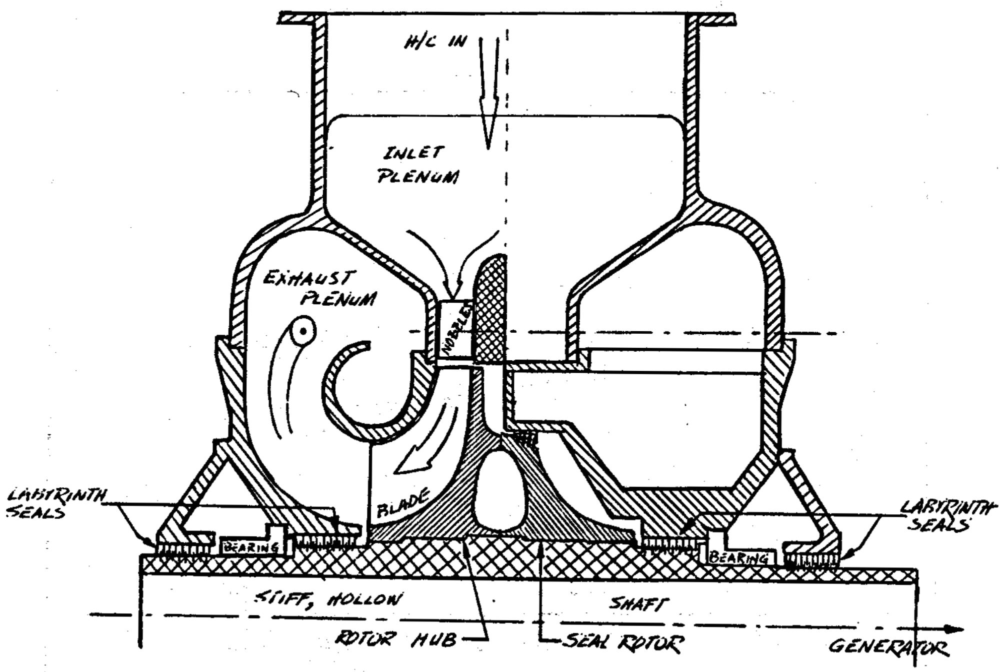


Figure 4. Internal Configuration of Single Wheel, Single Flow Casing.

Table 2
VERSATILITY OF RADIAL INFLOW GEOTHERMAL HYDROCARBON EXPANDER DESIGN

Number of Rotors on String	Number of Casings	Number of High-Pressure Rotors	Number of Low-Pressure Rotors	Number of Gas Streams (Parallel)	Shaft Horsepower Range
1	1	1	0	1	Up to 30,000
2	1	2	0	1	Up to 60,000
2	2	1	1	1	Up to 60,000
3	2	3	0	2	Up to 90,000
3	2	1	2	1,2	Up to 90,000
4	2	4	0	2	Up to 120,000
4	2	2	2	1	Up to 120,000

GAS DYNAMICS

Figure 5 shows the effect on efficiency of long term variation in wellhead fluid temperature. The working fluid temperature is assumed to decline from 149° to 138°C (300° to 280°F) in a 10 year period. After about six or seven years, the working fluid would be changed, which in turn would change the available enthalpy drop across the machine. The volume flow would then be adjusted to maintain the power. The Rotoflow variable nozzle system is able to maintain a relatively constant efficiency over the entire time period that the machine is likely to remain in service, without requiring a wheel change.

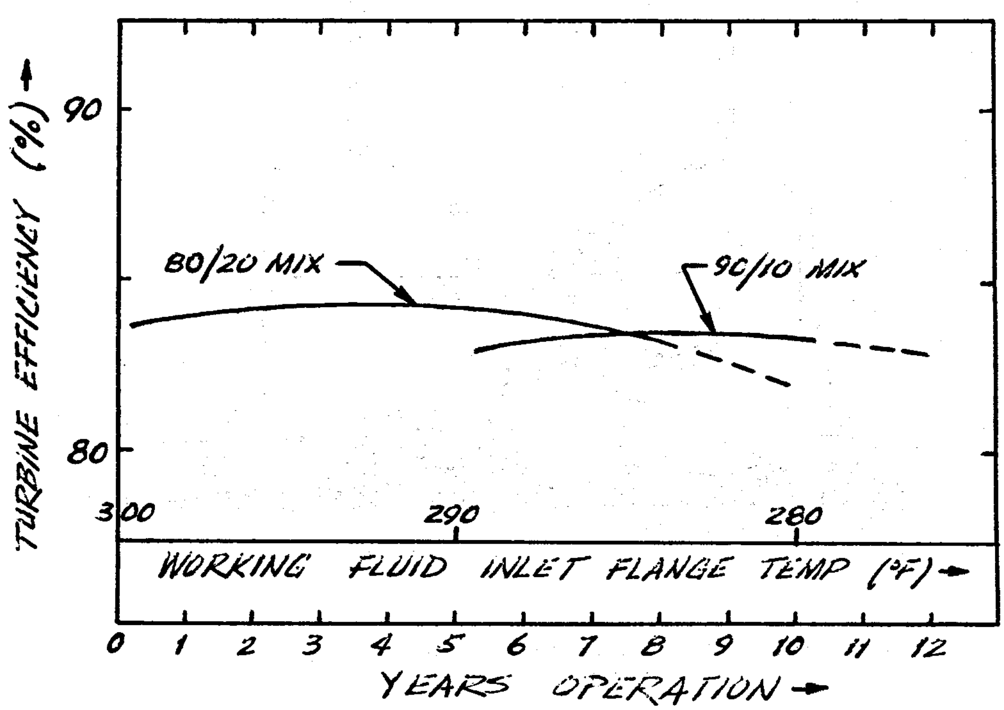


Figure 5. Impact of Long-Term Variation of Wellhead Fluid Temperature on Turbine Efficiency.

The short-term effects of ambient temperature variation have also been considered, using a wet and a dry tower condensing system. The principal effect of rising ambient temperature is an increase in the condensing pressure and, therefore, in the back pressure on the wheel. On most turbines, this rise produces a typical parabolic efficiency curve, as shown in Figure 6. In studies completed thus far, the thermodynamic cycle has been selected as shown in Figure 7.

However, the radial inflow turbine has a unique characteristic in that it can operate within the two-phase part of the envelope with no performance penalty. This characteristic exists because the trajectory of a liquid droplet, passing radially inwards through the wheel, follows the profile of the blade without impinging on the blade. This characteristic permits an unusual solution to the varying back pressure conditions. The inlet pressure could be allowed to increase at the turbine exhaust flange regardless of whether two-phase flow develops in the blade path. In this manner, a relatively constant enthalpy drop across the machine and a relatively constant efficiency might be achieved. The feature may allow consideration of dry cooling towers because the economic penalties associated with them may be decreased.

Another important characteristic of the radial inflow turbine is that at the end of the expansion process, with zero superheat, or with up to 20% or more liquid at the discharge (as on many existing radial inflow expanders) some useful savings can be made in the condenser surface areas and, consequently, in plant cost, especially in systems using dry cooling towers.

During seasonal high ambient temperature, evaporative cooling would be necessary, since the inlet pressure would be excessive in order to maintain relatively constant enthalpy drop across the machine. This type of cooling would be a supplement to the dry cooling towers. Wet towers benefit from higher temperatures in that higher temperatures are normally associated with reduced humidity. The resultant greater cooling effectiveness tends to reduce the range of back pressure within which the expander must operate.

MECHANICAL DESIGN

Having established the basic performance data for a machine, the next step is to optimize the wheel rotor design, in order to establish the mechanical reliability and practicability of the unit. The results of rotor and blades analysis and some component selections are shown in Table 3. Obviously, there are no stress difficulties with the rotor design, and stresses are well within the state of the art.

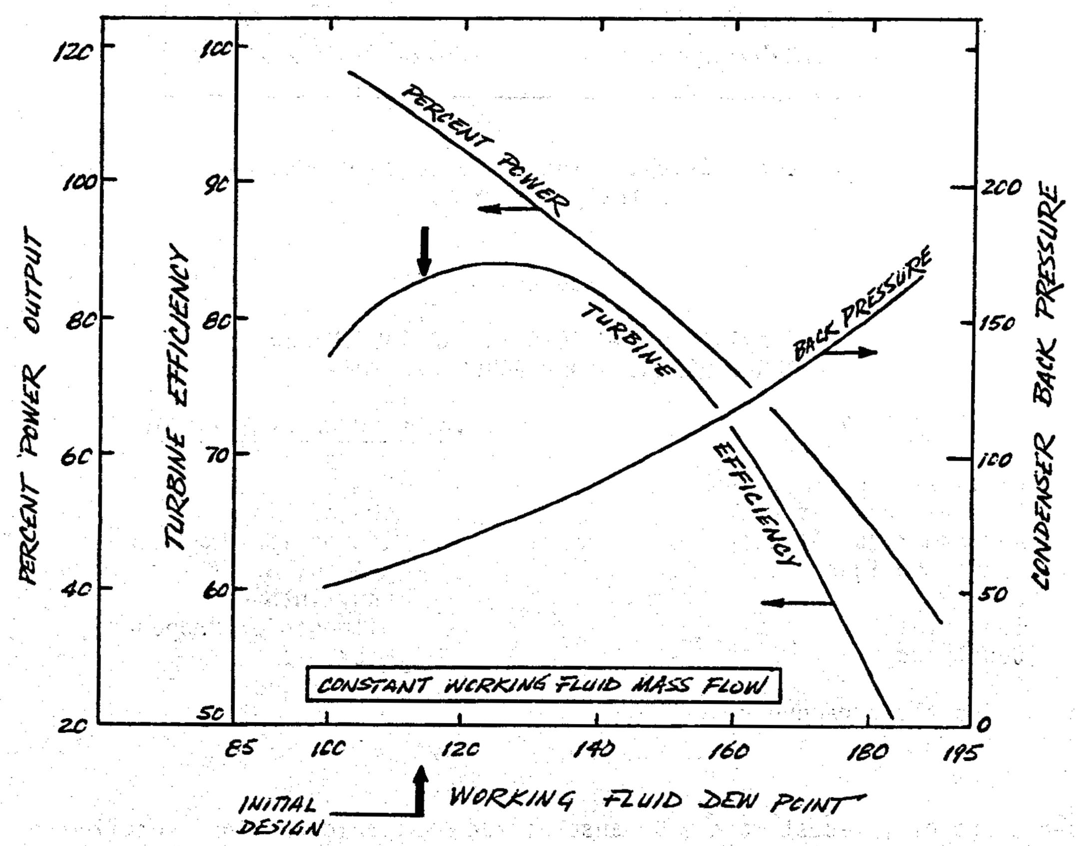


Figure 6. Turbine Efficiency, Condenser Back Pressure, and Percent Power as a Function of Working Fluid Dew Point

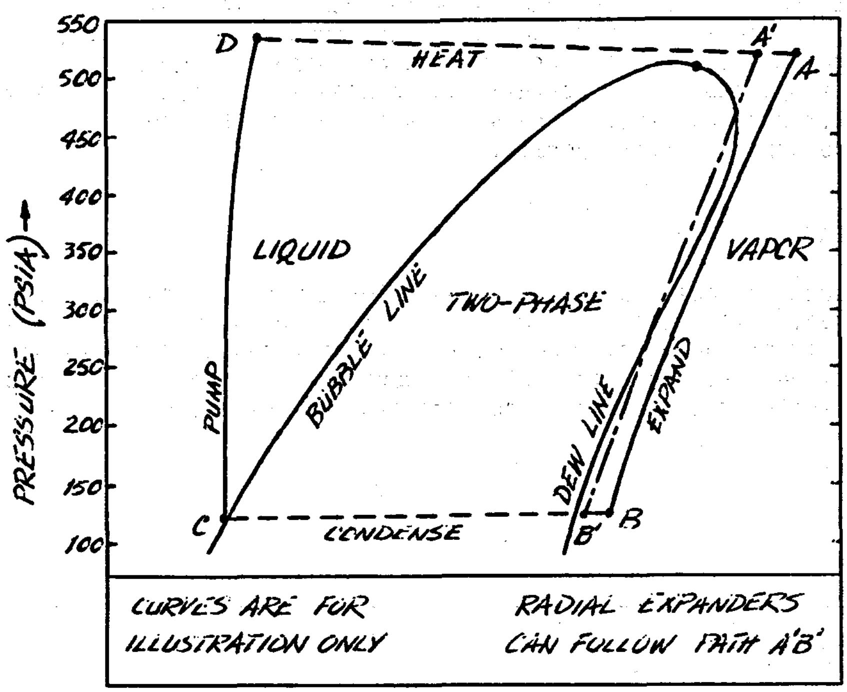


Figure 7. Illustration of Cycle on Pressure-Enthalpy Diagram.

Table 3

MECHANICAL PARAMETERS FOR RADIAL INFLOW GEOTHERMAL HYDROCARBON EXPANDER

PARAMETER	VALUE OR CHARACTERISTIC
Critical Speed Margin	50%
Maximum Wheel Stress	40% of Yield
Maximum Blade Stress	14% of Yield
Shaft Configuration	Hollow, Stiff
Seals	Labyrinth
Seal Fluid	Nitrogen or Propane*
Couplings	Flexible

*with working fluid recovery system

The seals are of interest mainly because of the available choice. Rotoflow prefers the labyrinth seal for long-term use. This seal has the greatest reliability factor. The seals would allow a minimal quantity of cycle gas to enter an interstage seal area, where the hydrocarbon gas can be recovered and returned to the loop. Nitrogen would be used as an inert cover to the oil system, which can be pressurized, as in many such seal systems, or vented to ambient, with a subsequent loss of seal gas. A different system under examination uses propane as a seal gas. Still another system analyzes the use of positive carbon face-type seals.

TORSIONAL ANALYSIS

Torsional analysis shows that, in terms of configuration, three arrangements are possible with the least complex torsional modes of vibration, illustrated by arrangements 1 and 3 in Figure 8. The couplings will be the nonlubricated type manufactured by either Bendix or Zurn, or an equivalent. The Bendix coupling has distinct weight advantages and safety features, which assist in flexibility of application.

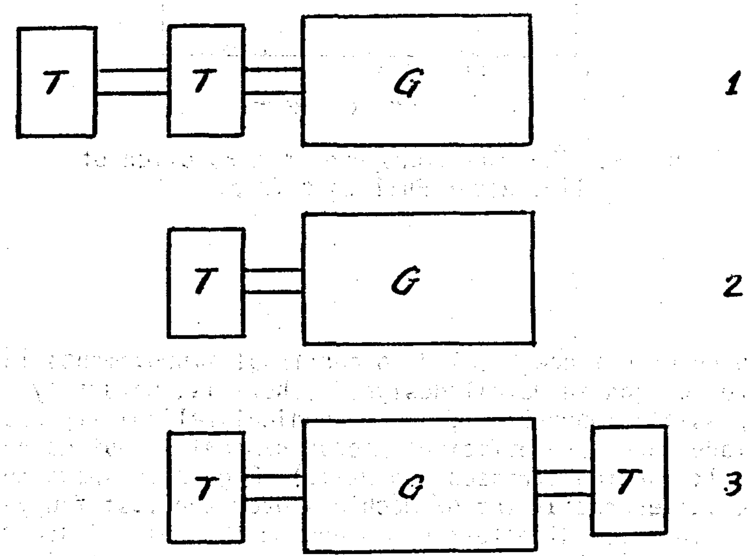


Figure 8. Configurations Used for Torsical Analysis.

FULL LOAD REJECTION

One of the more interesting aspects of this study concerns full load trip of the generator. Calculations show that the rate at which power has to be shut off is comparable, in such a situation, to that of the light-weight gas turbine generator. However, in the latter instance, the control is on fuel, and a relatively small valve is required. In this case, the inlet lines can be of the order of 610 to 720 mm (24-30 in) in diameter, depending on working fluid used.

The patented Rotoflow variable nozzle system provides a means for rapidly closing off the working fluid flow. The situation here is analogous to closing a venetian blind instead of a swing window. The inertia is much less, and the calculated overspeed after a power trip is as shown in Figure 9. A stop valve may be required to prevent gas leakage after the flow has ceased.

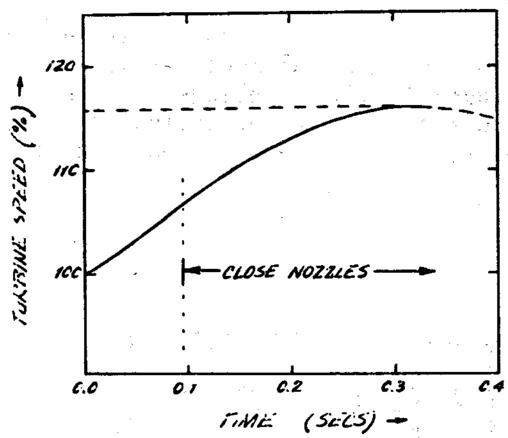


Figure 9. Turbine Overspeed as a Function of
Time After Full Load Trip.

TECHNICAL MATURITY

Radial inflow turbine experience has led to continual improvements in efficiency (as shown in Figure 10) and in detail design. (There is, naturally, a thermodynamic limit to possible improvement, and mechanical reliability has its place, too. Very thin blades are more efficient, aerodynamically, but do not survive gas bending loads and alternating stresses too well.) Figure 10 shows the trend in efficiency for the larger radial inflow machines over the last few years. This data is for units with rotor diameters up to 660 mm (26 in). Since radial inflow rotors as small as 38 mm (1-1/2 in) in diameter have been built, it is thought that the scaling factors are well understood.

At this time work is underway in certain energy recovery fields to design rotors and casings similar in size to those considered for the geothermal machine. Investigation of castings and machinery and ancillary equipment is already under way in order to provide quotations for these similar units.

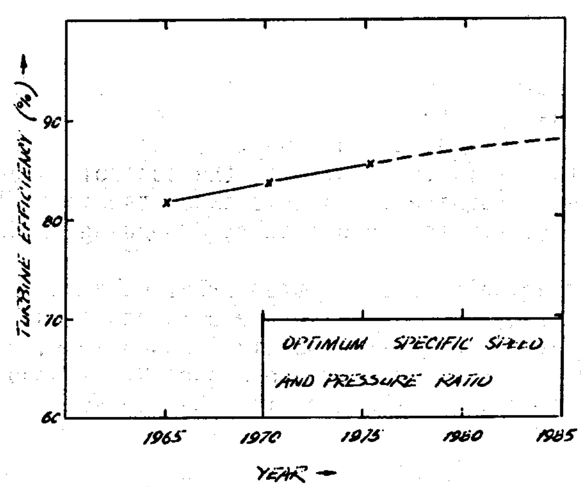


Figure 10. Efficiency Improvement for Radial Inflow
Turbines (Optimum Specific Speed and Pressure Ratio).

GEOTHERMAL RESERVOIR ASSESSMENT TECHNIQUES MANUAL

Research Project 929

S. K. Sanyal
H. J. Ramey, Jr.
H. T. Meidav
Geonomics, Inc.

INTRODUCTION

The advent of geothermal energy as a viable source of electrical power has drawn a number of utility companies to the field of geothermal power generation. Many more utility companies are apparently contemplating such a move. However, the techniques of assessing the power generation potential and economics of development of a geothermal reservoir are neither standardized nor well documented. Only sketchy accounts of assessment of geothermal reservoirs have appeared in isolated publications among diverse disciplines, such as petroleum engineering, geophysics, well logging, hydrology, geology, and so on. The problem is not so much a lack of technology as a lack of communication among the various scientific disciplines that have developed the technology. In the exploration and development of geothermal resources in the United States as well as abroad, many costly failures and inefficient operations have resulted from this lack of information. Not having standardized assessment techniques makes it difficult to compare the assessments of a geothermal resource by various groups. This project is intended to fill these gaps by providing guidelines for geothermal reservoir assessment and management from the point of view of the utility companies. This is particularly important in view of the unique nature of the geothermal industry. Unlike other fuels, geothermal water cannot be transported; the power plant has to be built at the resource site. This requirement has prompted some utility companies to explore, develop, and operate a geothermal field themselves or share the operation with a resource company. This trend is expected to continue. Even if a utility company is not involved in exploration, development, or operation of a geothermal field, it needs a knowledge of the reservoir assessment and management techniques for efficient planning and management of the power generation operation.

The goal of this project is to prepare a geothermal reservoir assessment manual with the help of which a utility company can make a quick, preliminary evaluation of the reservoir characteristics that have direct bearing on the power generation potential. Relevant information is being collected from various scientific and engineering disciplines. A reader will need no specific training in reservoir engineering in order to use this manual. The manual will discuss the techniques of estimating heat and fluid reserves, reservoir performance, well production capability, and so on. The data utilized for such an estimate may include geological, geophysical, and geochemical data; well logs; core analysis reports; and well test data. These estimates will provide the most important input in the feasibility study for a geothermal power project. If a reservoir has been selected for power generation, the preliminary assessment will provide a basis on which to plan for the development and operation of the reservoir and the associated economic analysis and optimization and environmental impact studies. Such an assessment may point out the need for further geophysical survey, well test, or drilling. A preliminary reservoir assessment should provide an insight for a more detailed reservoir study if warranted. The manual should serve as a comprehensive handbook for the management and the engineers in a utility company.

FEATURES OF THE PROPOSED MANUAL

Assessment of geothermal reservoirs is accomplished in several stages, each stage being connected with a specific phase of exploration and reservoir development activity. At every stage of the field activity, a specific type of analysis procedure is applied for reservoir assessment. As field activity and corresponding data analysis continue, the reservoir assessment is continually refined. Figure 1 illustrates this concept. Essentially, five types of data analysis and calculation are applied in geothermal reservoir assessment:

1. Exploration Data Analysis
2. Well Log and Core Analysis
3. Well Test Data Analysis
4. Reservoir Performance Prediction
5. Well Bore Engineering

Hence, the manual will be divided into the seven sections listed below.

Section 1. Introduction & Assessment Rationale

Section 2. Exploration

Section 3. Formation Evaluation

- a. Well Logging & Core Analysis
- b. Well Testing

Section 4. Reservoir Performance Prediction

Section 5. Well Bore & Production Engineering

- a. Flow Metering
- b. Multiphase Flow in Pipes

Section 6. Reservoir Development & Management

Section 7. Executive Summary

Each section will consist of a concise text describing the scientific principles and calculation procedures required in each step of reservoir assessment, illustrated by practical examples. To reduce to a minimum the number of calculations required for assessment, the manual will present a set of parametric charts for each type of calculation, covering a range of expected values of the variables. The charts will be presented in terms of dimensionless variables so that a limited number of charts can be used for a large range of reservoir conditions. Direct readings from tables, charts, and monograms, supplemented by a few calculation steps on an ordinary calculator, will be sufficient for an approximate assessment. The manual will also include tables of conversion factors for units, tables of relevant mathematical functions, and a selected bibliography. This volume will present mainly the state of the art in geothermal reservoir assessment, with substantial improvements in some areas. All areas of deficiency in assessment technology will be pointed out.

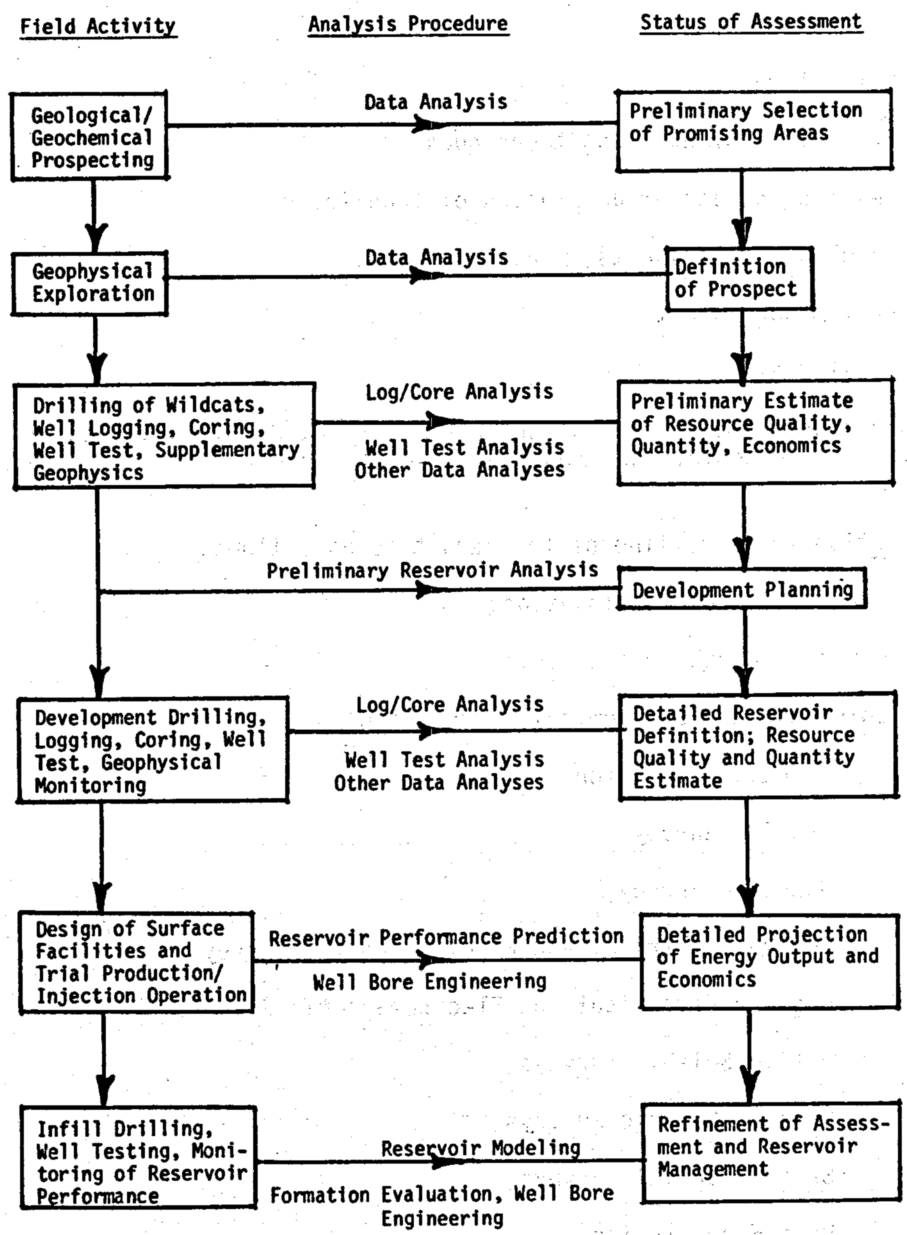


Figure 1. Flow chart of geothermal reservoir assessment

This manual will be the first effort toward providing guidelines for a comprehensive reservoir assessment for geothermal reservoirs. Various industries have developed design manuals for their use. For example, the American Gas Association sponsored a gas well test analysis manual. We feel that the manual will be valuable to utility companies because it will provide a step-by-step systems approach to geothermal reservoir assessment from the viewpoint of electrical power generation.

SECTIONS OF THE MANUAL

- Formatting
- Literature Survey
- Evaluation of existing techniques
- Development and/or adaptation of techniques
- Development of charts, monograms, etc.
- Preliminary draft
- Final draft

1. Introduction & Assessment Rationale - Dr. H. J. Ramey, Jr., and Dr. S. K. Sanyal will write this section. Subtasks 1 through 5 are complete for this section.

2. Exploration - The outline of this draft is as follows:

   Introduction and Exploration

   Models of Geothermal Systems

   Geological and Geochemical Prospecting

   Geophysical Exploration

      Gravity Survey

      Magnetic Survey

      Active Electrical and Electromagnetic Surveys

      Passive Electrical and Electromagnetic Surveys

      Active Seismic Surveys

      Passive Seismic Surveys

      Self Potential Surveys

      Heat Flow Studies

   Dr. H. T. Meidav will write this section. Subtasks 1 through 5 are essentially complete.

3. <u>Formation Evaluation</u> - The outline of this section is as follows:

Introduction

Core Analysis

Well Log Analysis

Self Potential Log

Gamma Ray Log

Electric Logs

Acoustic Logs

Nuclear Logs

Temperature Log

Production Logs

Miscellaneous Logs

Well Test Analysis

General

Pressure Buildup

Pressure Draw Down

Well Interference Tests

Multiple-Rate Flow

Pulse Tests

Drillstem Test

Gross Reserve Estimate

Dr. S. K. Sanyal will write the draft of these subsections. Subtasks 1 through 5 have been completed for all but Well Test Analysis subsection. Dr. H. J. Ramey will prepare the Well Test Analysis subsection.

4. <u>Reservoir Performance Prediction</u> - This section will consist of the following subsections:

Introduction

Empirical Approach

Analytical Approach

Lumped Parameter Approach

Dr. S. K. Sanyal will write this section. Subtasks 1 through 5 have been completed for the first three subsections. Subtasks 1 and 2 have been completed for the last two subsections.

5. Well Bore & Production Engineering - This section will consist of three broad subsections:

   Flow Metering

   Multiphase Flow in Pipes

   Well Stimulation

   This section will be written by Dr. H. J. Ramey, Jr., and Dr. S. K. Sanyal.

6. Reservoir Development and Management - This section will consist of the following subsections:

   Planning

   Optimization

   Forecast Updating

   Performance Matching

   Remedial Measures

   Maintenance

   This section will be written by Dr. H. J. Ramey, Jr., and Dr. K. S. Sanyal.

7. Executive Summary - This section will provide an overview of the manual for the management of utility companies.

UTILIZATION OF U.S. GEOTHERMAL RESOURCES

Technical Planning Study TPS 76-638

John Reitzel
Systems and Energy Group of TRW Inc.

The objective of this study was to develop information about the potential of geothermal energy and the technology required for its use, so that utilities can assess its importance in preliminary planning for the next 25 years. The main questions addressed are these: How much generating capacity can be supported by those hydrothermal geothermal resources of the U.S. that are in reach of development by the year 2000? How much generating capacity is available in what cost range? Where will it become available, and when? There are no firm answers to these questions yet, but the range of possible answers has been much narrowed by recent work in assessing the resource and evaluating the costs and conditions of its use.

Previous estimates of U.S. geothermal resources, which used varying definitions and differed among themselves by two orders of magnitude, have been largely superseded by the estimates of the U.S. Geological Survey, published in USGS Circular 726. In this publication, the most promising near-term resources are identified, catalogued, and individually evaluated, where possible, in terms of electrical generating capacity. The two main types of resource that have been quantitatively assessed are in hydrothermal systems, all located in the western states, and in hot geopressured reservoirs, all located along the Gulf Coast.

For our purposes, the geothermal resources of interest are those that may become economically competitive within the next 25 years. This restriction focuses our study on hydrothermal resources, which have the highest temperatures, mostly related to intrusions of magma within the earth's crust, and which are found at the shallowest depths. Hydrothermal resources also provide an efficient natural medium for transferring heat to the earth's surface, in the form of hot water (or steam, in rare occurrences) supplying geothermal wells. Geopressured resources stand second in line, with the main disadvantage that they nearly all lie deeper than 3000 meters (10,000 feet).

This study reviewed the geological basis for hydrothermal occurrences, to show that they are localized in narrow zones where the crust of the earth is deeply fractured. In these zones, magmatic heat originating beneath the crust can rise high enough in the crust to interact with circulating groundwater and form hydrothermal systems. These fracture zones are marked by the surface traces of major faults, by young volcanic systems, and by earthquake epicenters. Such tectonic indicators show that the fracture zones are essentially continuous boundaries between distinct crustal blocks or plates.

We have compared the characteristics of 77 hydrothermal systems, whose reservoir volumes were evaluated by the USGS, to those of larger samples of hot springs in the western states, in order to estimate the amount of undiscovered resources associated with hot springs. Our conclusion is that the total hot-spring resource has a capacity of about 50,000 MWe x 30 years, which is about twice the amount in the identified systems hotter than 149°C (300°F) currently evaluated by the USGS (excluding Yellowstone National Park).

Nearly all the presently identified hydrothermal systems are to be found within contour lines that enclose regions where all hot springs are hotter than 49°C (120°F), so these 49°C contours make convenient hydrothermal indicators. These contours generally define elongated areas within the belts of tectonic indicators that mark the major fracture zones. Some of the places where there are gaps in the hydrothermal indicators, but no gaps in the tectonic indicators, may well be the results of low water tables and active groundwater flow toward large low-lying rivers, preventing the near-surface expression of any deeper hydrothermal systems that may exist. Such hydrological gaps in continuous fracture belts are the most hopeful target areas in which to explore for "blind" geothermal resources. We judge from the mapped indicators that the blind gaps are about equivalent in area and richness of tectonic indicators to the patches bounded by the 49°C spring contour, and are probably comparable in their resources. By these extrapolations from identified to undiscovered hot-spring resources, and from hot-spring to blind resources, the evaluated hydrothermal resources are increased by a factor of about four, to give a total of approximately 100,000 MWe x 30 years for all hydrothermal resources, identified and undiscovered. The evaluated resources are highly concentrated in a few very large systems, however, and the number of such systems still to be discovered is a major uncertainty. The locations of the identified systems and the tectonic belts that are the source areas for new discoveries are mapped together with the service areas of individual utilities, in Figure 1. This map provides a basis for judging the relative importance of geothermal energy for the future planning of particular utilities.

To consider the probable costs of producing energy from various hydrothermal resources, we have compared the results of a number of cost analyses, ranging from very generalized studies to conceptual plant designs for specific sites. These analyses agree well on the conversion efficiencies that can be attained by optimum use of current technology. The capital cost estimates for power plants (not including wells and field piping) show a scatter of about $100/kW to either side of a central estimate that rises from $400/kW for a fluid temperature of 260°C (500°F), to $520/kW for fluid at 149°C (300°F) (Figure 2). This central estimate is for average plant costs as they depend on fluid temperature and is not intended to predict costs of individual projects at specific sites. The scatter takes in some allowances for differences in fluid salinity and condensing temperature, but most of it probably arises from differences in the approaches to costing by different estimators. For most resources, the well cost per unit of flowrate is the most important single factor in overall unit cost.

Assuming that 25 percent of the thermal energy is extractable as hot fluid, and that wells and field piping cost $1.25 per lb/hr, we have estimated the electrical energy available from currently evaluated resources as a function of capital cost. This near-term supply curve shows about 20,000 MWe x 30 years potentially available at direct capital costs of $800/kW or less, most of it in five large systems.

Reviewing the current lines of technology improvement in geothermal systems, we have concluded that at low geothermal fluid temperatures (T 149°C [300°F]) reductions in well cost per unit of flow are likely to be the determining factor in utilization. At higher fluid temperatures, technology improvements in plant components are likely to be as important as well cost improvements, especially those improvements that also improve the plant availability factor. We estimate that these technology improvements will have an important effect on increasing the

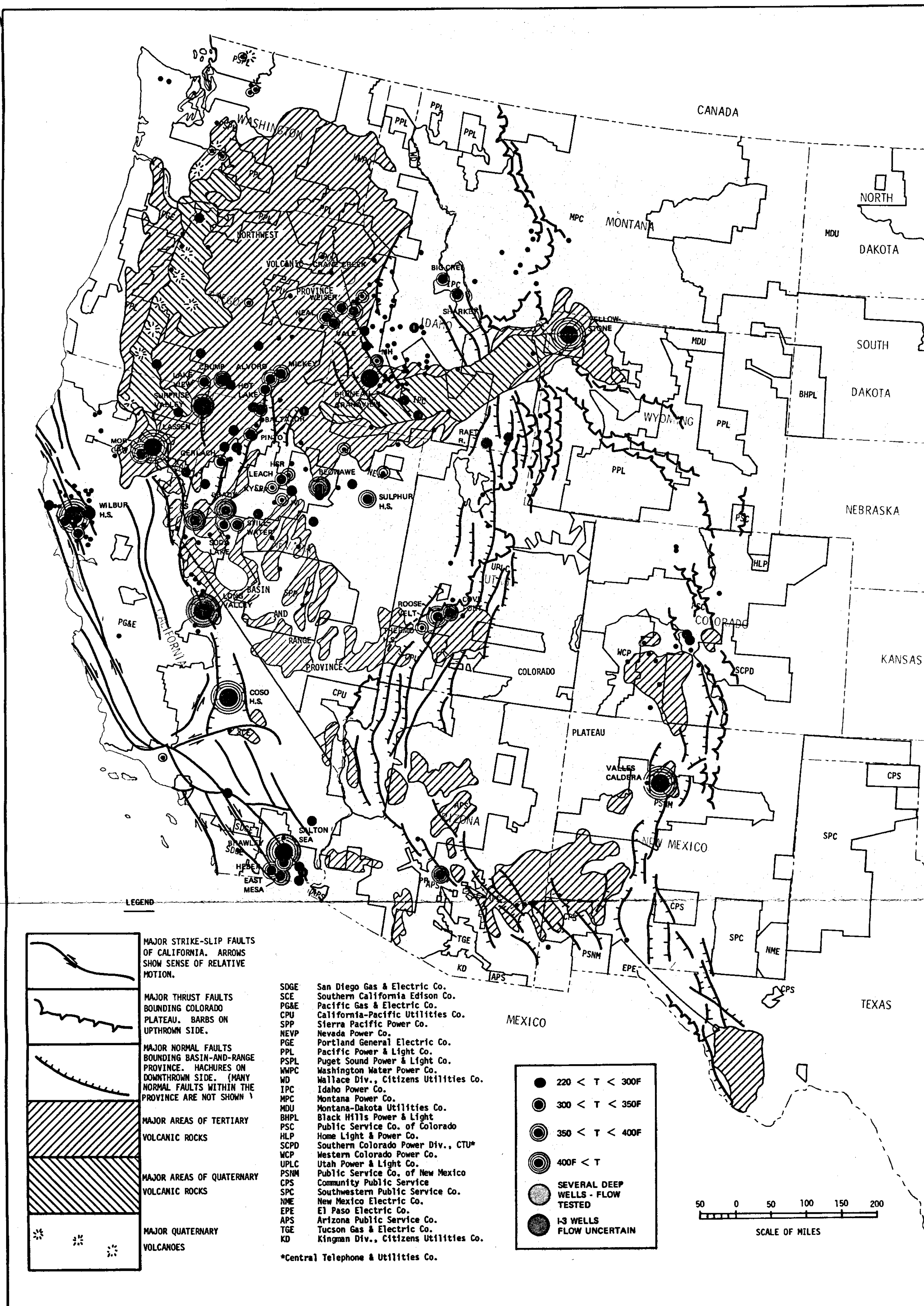


Figure 1. Utility Service Areas and Hydrothermal Resources

supply of geothermal energy to the year 2000, but less than the fourfold increase we have estimated for new discoveries.

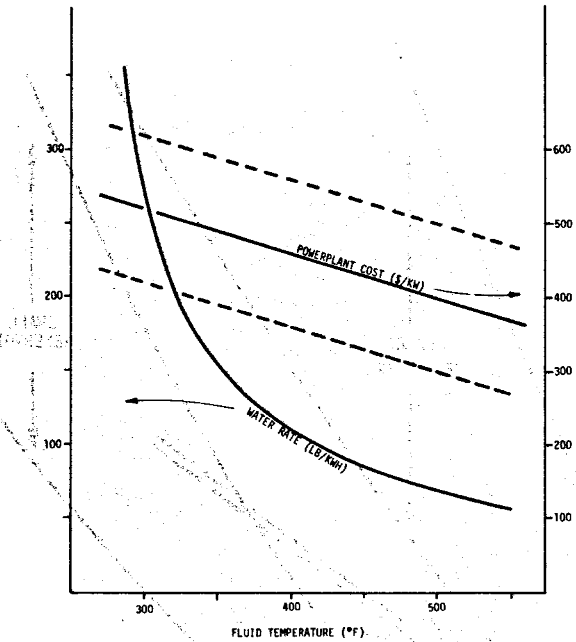


Figure 2. Values of Water Rate and Plant Cost

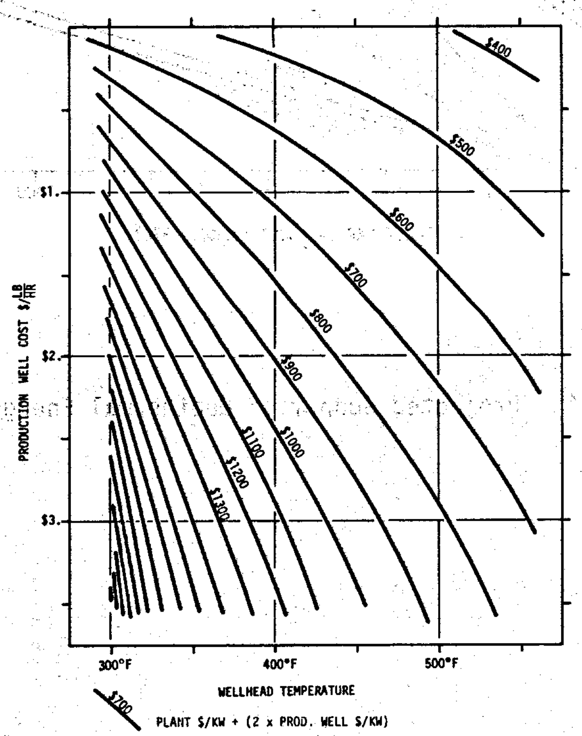


Figure 3. Direct Capital Costs for Wells and Plant, on Plot of Fluid Temperature versus Well Cost per lb/hr

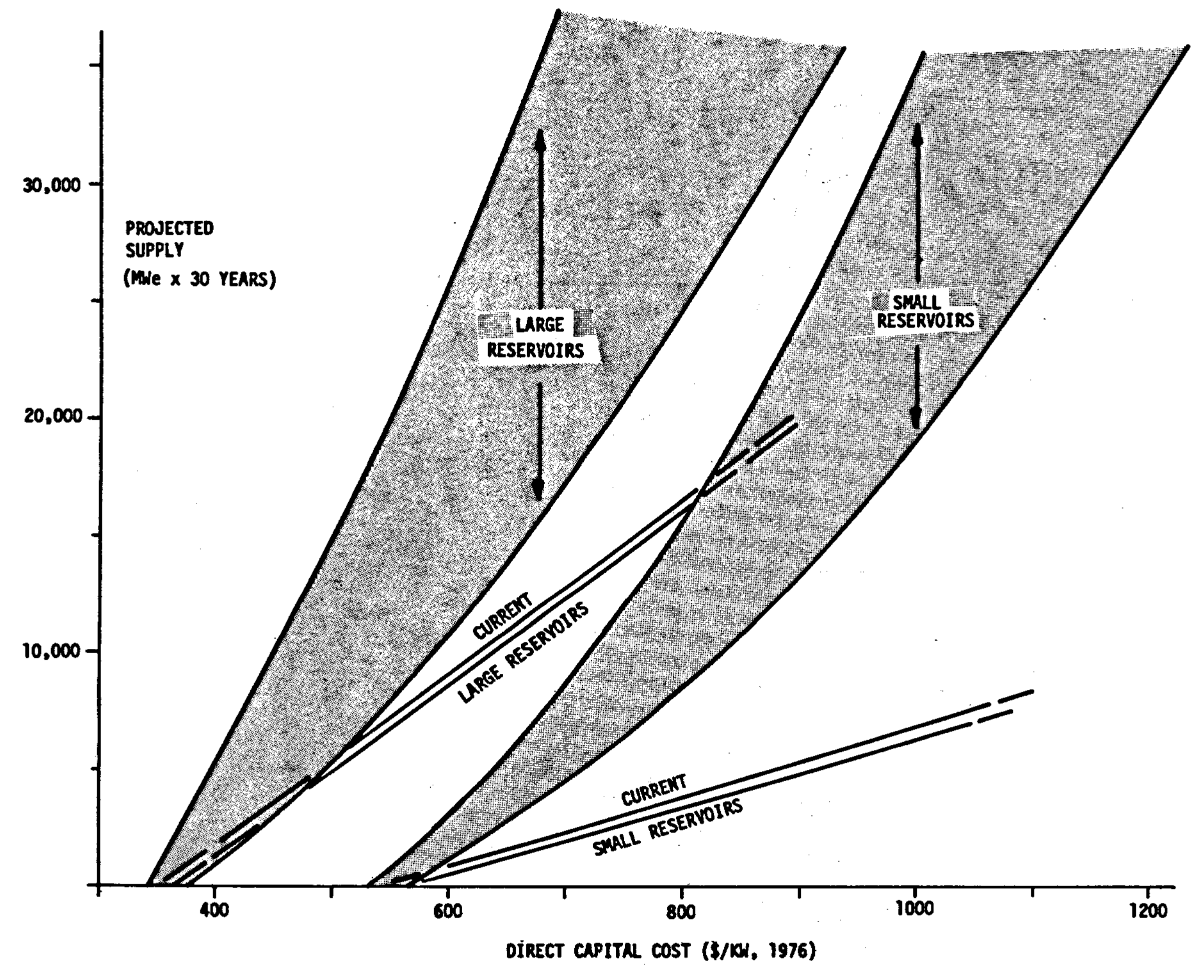


Figure 4. Projected Supply of Geothermal Energy

Section 3

PROJECTS BY UTILITIES

GEOTHERMAL DEVELOPMENT IN MEXICO

P. Mulâs
Instituto de Investigaciones Eléctricas
J. Rivera
~~Comisión Federal de Electricidad~~

Since 1973, geothermal electrical generation has been a reality in Mexico at the Cerro Prieto field. Two units of 37.5 MWe have been operated successfully by the Comisión Federal de Electricidad. Total production through the end of 1976 was 1,953,375 kWh. The prospects for geothermal generation in the future are good. The Cerro Prieto field will be exploited in increasing amounts as indicated by the new units that are being planned.

UNIT	CAPACITY (MWe)	YEAR OF INITIAL OPERATION
CP-I-3	37.5	1979
CP-I-4	37.5	1979
CP-I-5	30.0	1980
CP-II-1	55.0	1981
CP-II-2	55.0	1981
CP-II-3	55.0	1982
CP-II-4	55.0	1983

By the year 1983, there will be 400 MWe installed at Cerro Prieto. The well drilling program for Cerro Prieto calls for 14 new production wells during 1977 and 22 new production wells and four exploration wells in 1978.

In the central volcanic region of Mexico, an exploration well was drilled this year at Los Azufres, Michoacán, down to 2184 m. The well is producing and the temperature is on the order of 300°C. Exploration at other sites in the same region will be increased during the next few years.

In the research and development area, the recent establishment of the Instituto de Investigaciones Eléctricas has created a stimulus to geothermal energy research. Under contract from the Comisión Federal de Electricidad, research and development projects are being carried out related to scaling, two phase-flow, separator efficiencies, microseismicity techniques, reinjection feasibility of the disposed water, and recovery of chemical byproducts. The Organization of American States is partially supporting a study of the viability of desalination and geothermal power generation process coupling. A greater number of projects is expected to be carried out next year, since the utilization of geothermal energy is to increase in the future.

OREGON GEOTHERMAL RESOURCE ASSESSMENT

Rodney D. Wimer

Portland General Electric Company

GEOTHERMAL SYSTEMS IN OREGON

The state of Oregon contains over 200 surface thermal manifestations of geothermal energy, including hot springs, fumaroles, mud pots, and warm water wells. Those with estimated minimum subsurface reservoir temperatures above 90°C (194°F) are shown in Figure 1. Most of these hotter systems are within the Basin and Range and Cascade Range Provinces; several are also in the Blue Mountain Province in the northeastern corner of the state. To date, the U.S. Geological Survey (USGS) has established 13 known geothermal resource areas (KGRA) in Oregon, 5 of which are in the Cascades and the remaining 8 in the Basin and Range.

In early 1976, the senior management of Portland General Electric Company (PGE) directed that a comprehensive study be undertaken to evaluate the geothermal energy potential of these areas, and of Oregon in general. The ensuing study involved nearly a man-year's effort by three principal investigators. Our initial efforts in resource appraisal involved a detailed compilation, review, and assessment of all available published and unpublished geological, geophysical, geochemical, and hydrological data on each of these 13 KGRAs and on the area around Glass Buttes and LaGrande, as shown in Figure 2. An additional area in the southern Washington Cascades, the Indian Heaven KGRA, was also included because of its proximity to PGE's Northwestern Oregon service territory. A large portion of this initial effort was devoted to development of an in-house understanding of the geologic occurrence and nature of geothermal systems in Oregon to provide a foundation from which to develop and evaluate possible future Company resource positions. Primary data sources included published journals, federal and state bulletins, and geologic maps, with augmentation by unpublished thesis, USGS open-file reports, and personal communication with other geothermal investigators. Where suitable, relevant data was plotted on 1:250,000 AMS sheets, thus enabling discernment of spatial and temporal patterns.

During the course of this literature investigation, it became evident that geothermal systems in Oregon and southern Washington might be subdivided into four generalized types of occurrence based upon their geological and hydrological setting. These are identified in Figure 3 as the Basin and Range resource type with the Brothers Fault Zone sub-type, and the High Cascade resource type with the Western Cascade sub-type. Each of these resource types differs somewhat with respect to geologic age, rock lithologies, age and style of deformation, age and type(s) of volcanism, and availability of subsurface water. These differences will probably ultimately be reflected in the physical nature and producibility of individual geothermal reservoir systems.

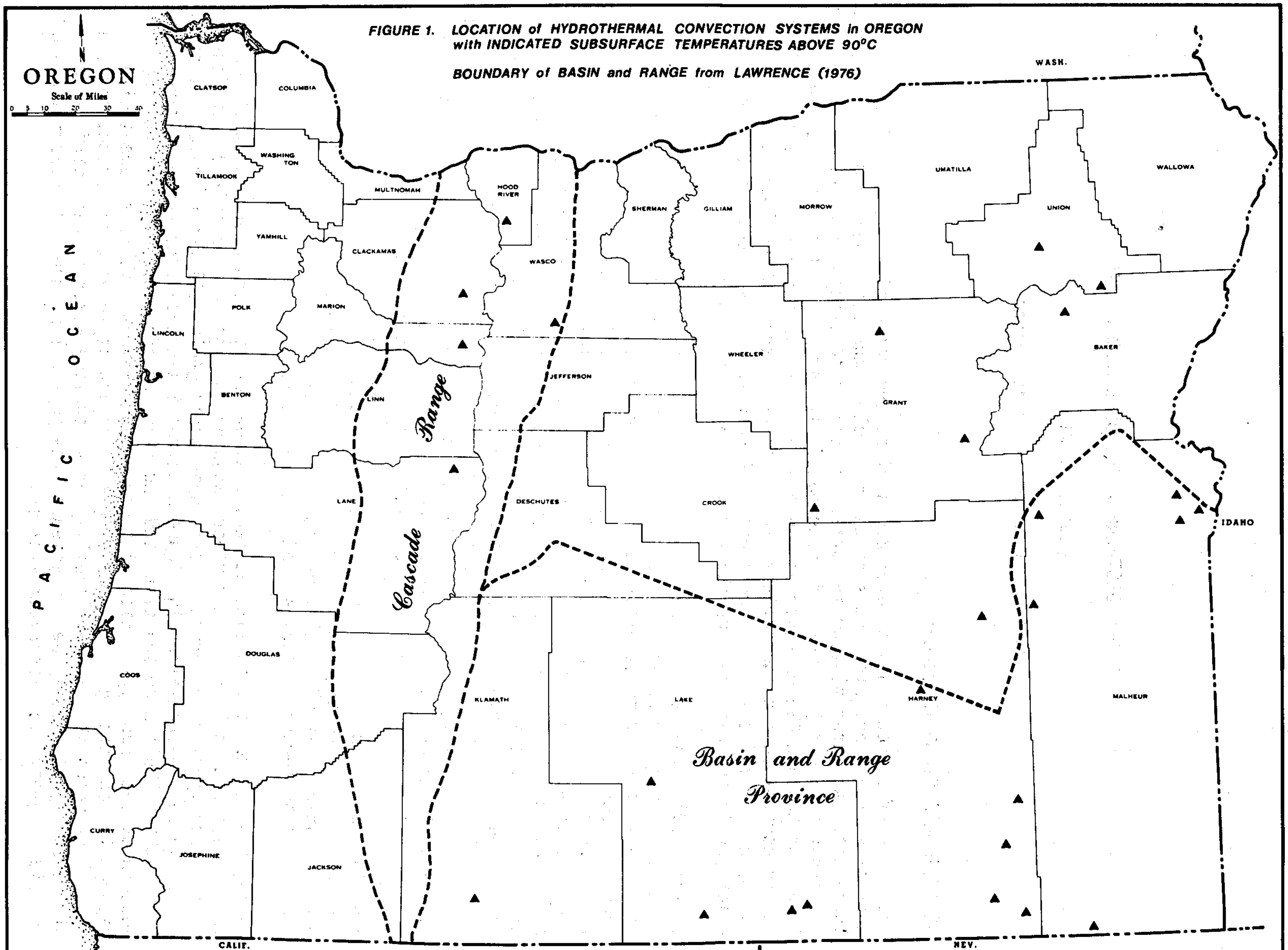


FIGURE 1. LOCATION of HYDROTHERMAL CONVECTION SYSTEMS in OREGON with INDICATED SUBSURFACE TEMPERATURES ABOVE 90°C

BOUNDARY of BASIN and RANGE from LAWRENCE (1976)

SOURCE: U S GEOLOGICAL SURVEY CIRCULAR 726 (1975)

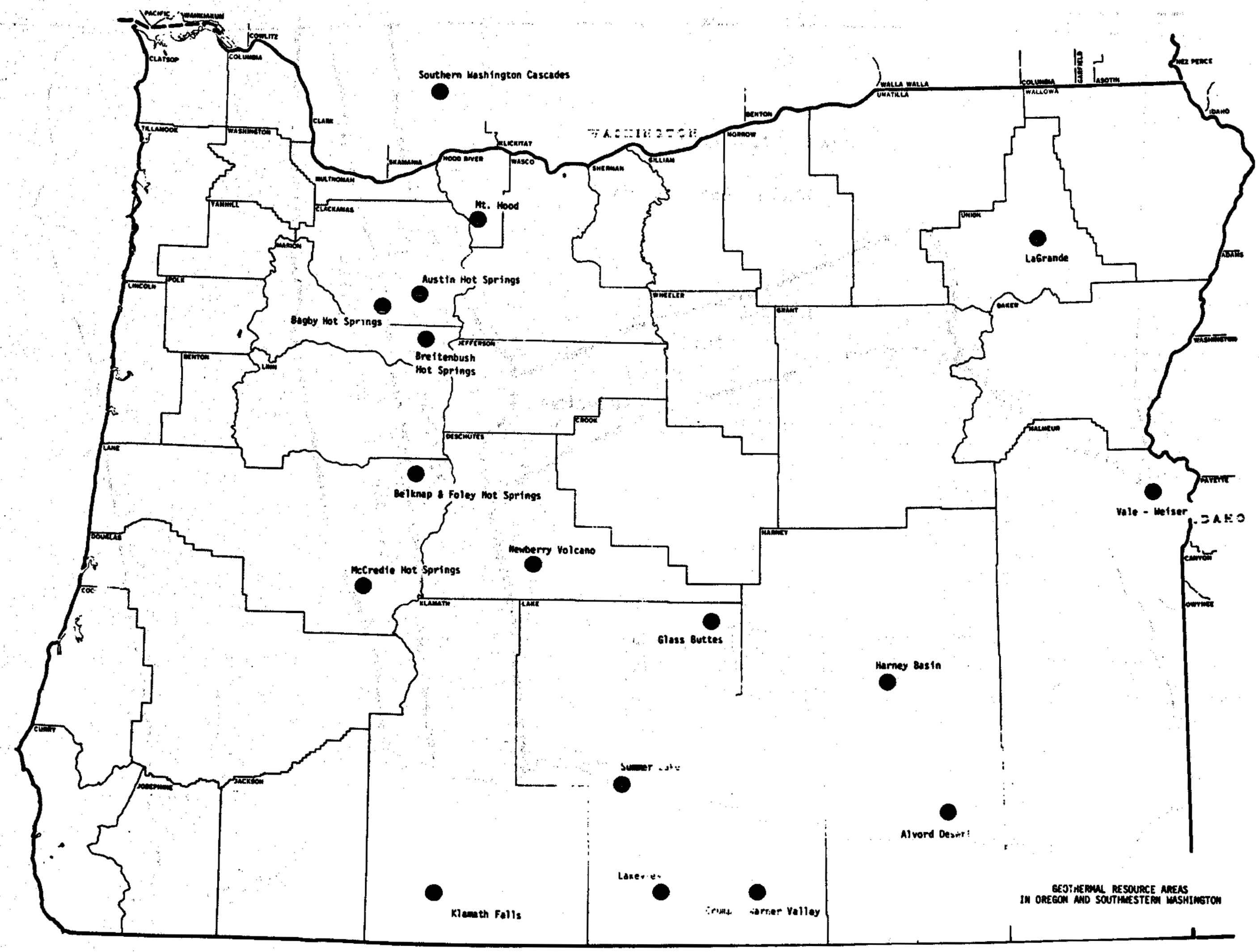


Figure 2. Geothermal Resource Areas in Oregon and Southwestern Washington

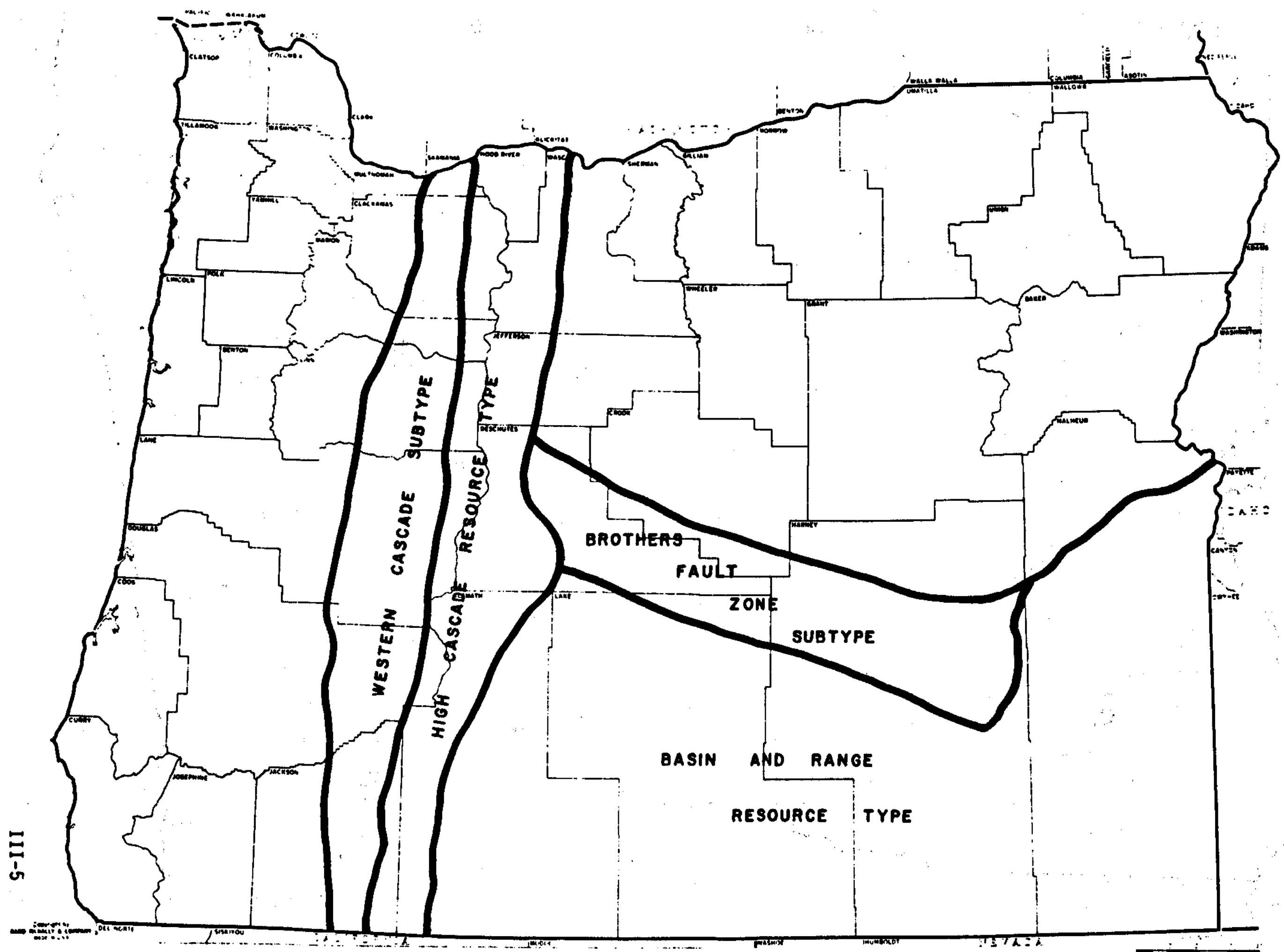


Figure 3. Generalized Geothermal Resource Types in Oregon

In order to perform a preliminary assessment of the relative merits of individual resource areas in Oregon and southwestern Washington, a list of 25 geological, geophysical, and geochemical indicators of potential geothermal systems was developed. This group of indicator criteria, which is shown in Table 1, was developed through review of exploration case histories for producing geothermal fields. Of these criteria, several occurred at most of the producing reservoirs and are, therefore, considered key indicators. These include:

- Presence of hot springs with discharge temperatures greater than 70°C (158°F) and geochemically-determined subsurface temperatures greater than 150°C (302°F)
- Presence of geysers, fumaroles, or mud pots
- Rhyolite and dacite domes and flows less than 2 million years old
- At or near the intersection of two or more major structural trends
- Hydrothermal alteration and extractable quantities of mercury
- Holocene volcanism

The presence of other criteria in conjunction with these key indicators enhances the possibility of locating a potentially commercial geothermal resource by deep drilling. It was our contention during this investigation that regional screening utilizing these 25 unweighted indicator criteria would greatly facilitate locating target areas for application of various geoscience exploration techniques, and possible result in the delineation of property for which PGE might wish to secure a lease position.

In performing the regional screening utilizing these 25 indicator criteria, and subsequently manipulating indicators experimentally within a given resource type, consistent groupings of areas became apparent. Those areas displaying the greatest number of favorable indicators were assigned highest priority for possible additional detailed investigation to assess their geothermal potential. Whereas this rather simplistic screening methodology contains obvious inherent biases, it was a relatively cost-effective way for an electric utility to attain current knowledge of the occurrence and possible controls of geothermal resources in Oregon and begin establishing the relative potential of each prospect area. This type of analysis is of necessity dynamic, as the data base is continually expanded and refined, and obviously the relative priorities for future investigation might change accordingly.

PGE GEOTHERMAL PROPERTY POSITIONS

As an outgrowth of the literature review and assessment work, and through independent discussions with a geologic consultant to PGE, Dr. Paul E. Hammond of Portland State University, four prospect areas in Oregon were identified for consideration as possible Company resource positions. Subsequently, in November 1976, PGE filed noncompetitive geothermal lease applications on two of these prospects with the Bureau of Land Management. Both are within national forest lands in the High Cascade Range - one totaling approximately 87,008 sq m (21,500 acres) is on the east flank of Mt. Hood, and the second comprises roughly 115,336 sq m (28,500 acres) immediately east of and adjacent to the Three Sisters in the vicinity of Three Creek and Melvin Buttes. Both of these two major andesitic stratovolcano complexes have been active during the Pleistocene and exhibit other characteristics which make them favorable geothermal exploration targets. In addition, both are within areas designated as "suitable" for the siting of geothermal power plants by the Oregon Energy Facilities Siting Council, which has the statutory authority to regulate siting and construction of all thermal power plants with installed capacities of greater than 25,000 kW in the State. Prospective sources for power plant cooling water makeup also exist in both areas.

PGE considers these two land parcels as research areas in which to test some of our ideas regarding the nature and occurrence of geothermal systems in the Cascades. As yet, detailed exploration programs have not been developed to evaluate these specific properties. Our ultimate strategy for assessment of these lands will, in part, be dictated by the results of a cost-benefit/risk analysis presently nearing completion, the results of which will also provide the basis for determining if, and to what extent, a regulated electric utility should become involved in a high risk geothermal exploration venture.

Nevertheless, PGE is in the midst of a geologic mapping program of the Three Sisters area, which is being undertaken by Dr. Edward M. Taylor of Oregon State University, who is employed by the Company under a summer faculty internship program. This mapping will provide geologic control for the eventual location and drilling of temperature gradient and heat flow holes, as well as enhance the interpretation of geophysical data from surveys which might be conducted at a later date. The Company is presently in a holding pattern with respect to evaluation of our Mt. Hood property position pending completion of a recently initiated three-year investigation of the Mt. Hood volcano being performed jointly by ERDA, the USGS, U.S. Forest Service, and the Oregon Department of Geology and Mineral Industries. The outcome of this investigation will not only afford a test of Mt. Hood's geothermal potential, but also serves as an exploration case history from which to design programs to evaluate the potential of other Cascade Range volcanoes.

OREGON GEOTHERMAL RESOURCE QUANTIFICATION

During presentation of the results of our Summer '76 program to PGE's senior management, we were instructed to develop a detailed rational quantification of Oregon's geothermal potential to serve as a planning guide from which management could base an initial decision regarding the potential long-range contribution of geothermal energy to the Company's generation resource inventory. Previous estimates of Oregon's geothermal potential for electric power generation range from the USGS preliminary estimate of 400 MWe-centuries in Circular 726, "Assessment of Geothermal Resources of the United States - 1976," to the 6500 MWe-centuries from dry steam resources alone, as proposed by one Oregon geothermal explorer.

To assist in the actual task of subjectively quantifying Oregon's geothermal potential, and to provide overall technical guidance to the future direction of PGE's geothermal program, the Company retained a four-man panel of geothermal consultants. This panel is composed of highly qualified and respected experts from the geothermal community: Dr. Gunnar Bodvarsson, Dr. James B. Koenig, Dr. H. Tsvi Meidav, and Dr. L. Trowbridge Grose.

The methodology we are considering for implementation in our resource quantification effort is a refined version of the USGS approach for assessing hydrothermal convection and igneous-related systems, as presented in Circular 726. Many of the generic assumptions developed by the USGS have been modified to portray better our present understanding of Oregon's geologic and hydrologic environment. In addition, an expanded geophysical and geochemical data base over that available to the USGS two years ago, and the recent availability of both published and unpublished new radiometric age dates, should enable upward refinement of the results tabulated in Circular 726.

As part of this quantification effort, hypothetical models of geothermal reservoir systems in the Basin and Range Province and Cascade Range will be developed by the panel, based upon experiences gained in similar geologic environments and upon case histories of producing geothermal fields in analogous settings. These models will be used to put physical constraints on individual reservoir systems for the quantification task, and will also aid in the design of exploration strategies to evaluate geothermal occurrences in these two resource types.

Initially, each panel member's input to quantification model development is being obtained through individual responses to technical questionnaires designed to allow development of concepts regarding the occurrence, probable physical and chemical nature, and geologic controls of geothermal systems in Oregon. As each member's response is of necessity subjective and based upon his own experience in geothermal prospecting, we presently envision utilization of the Delphi technique to attain the unanimity eventually required in model development and subsequently in the quantification task.

We realize that resource quantification is an inexact process wrought with many inherent uncertainties - not the least of which is a poor understanding of geothermal systems in general and an inadequate data base specifically. Nevertheless, we and our panel of consultants agree that a great deal can be learned in going through the quantification procedure and that the validity of any resource estimate is not in the final answer itself but in the detailed and carefully conceived methodology employed in deriving the estimate. It is anticipated that our initial subjective quantification will be refined as additional data becomes available and our models are tested through exploration. Ultimately, this process will be replaced by objective and measured reservoir data as individual geothermal systems are discovered and developed.

Hopefully, a utility effort, such as PGE's, in Oregon geothermal resource development will encourage others in the industry to undertake more active programs in this state. Furthermore, we are hopeful that such a combined and cooperative effort will lead to the delineation and testing of a medium-temperature, low-salinity hydrothermal resource on a time scale that will enable construction of a demonstration unit by the mid-1980s. In the long run, if costs are competitive with other generation alternatives and if the resource is available in commercial quantities in Oregon, PGE can envision adding geothermal capacity to our resource mix; perhaps by the early 1990s.

Table 1

REGIONAL GEOTHERMAL INDICATOR CRITERIA

- Hot spring or well with surface discharge temperature of >70°C (158°F)
- Estimated reservoir temperature of >150°C (302°F)
- Hot spring depositing quartz, chalcedony or siliceous sinter
- Hydrothermal alteration
- Hot spring with flow >150 l/min and chloride content >500 ppm
- Hot spring with lithium content >1.0 ppm and/or boron >10 ppm
- Mercury production >25 flasks (quantity is arbitrary)
- Presence of geysers, fumaroles, or mud pots
- Hot springs and/or warm wells covering >2.59 sq km (1 sq mi) and/or along a 8.05-km (5-mi) linear zone
- Rhyolite or dacite domes and flows
- Rhyolite or dacite domes and flows <2 million years old
- Collapsed caldera of late Tertiary or Quaternary age
- Holocene volcanic activity
- Proximity to regional tectonic feature
- At or near offset of a tear fault
- At or near intersection of two or more major structural trends
- Temperature gradient >80°C/km and/or heat flow >2.5μcal/(cm^2 s)
- Gravity anomalies (high or low)
- Low magnetic values within volcanics
- Magnetic lineament >8.05 km (5 mi) in length
- Microseismic or ground noise anomalies
- Unusual seismic activity
- Electrical resistivity anomalies
- Quaternary basaltic field of >64.8 sq km (25 sq mi) area
- Faults with cumulative displacements of greater than 1.5 km (5000 ft) or individual faults with greater than 305 m (1000 ft) of displacement
- Presence of near-surface thermal insulation layers

OPERATIONAL EXPERIENCE AT THE SAN DIEGO GAS & ELECTRIC ERDA NILAND GEOTHERMAL LOOP EXPERIMENTAL FACILITY

Gilbert L. Lombard

San Diego Gas & Electric Company

Nearly one year of operational experience at the San Diego Gas & Electric/ERDA Geothermal Loop Experimental Facility (GLEF) has been generally very successful. The thermal energy of the high-salinity, high-temperature resource has been successfully extracted. Simplified control and handling of the brine and flashed steam/condensate has allowed scale to be removed, plant operators to anticipate problems, and maintenance costs to be limited. Plant modifications have included replacement of on-off controls with proportional elements, revision of pump bearings, and replacement or modifications to valves.

Remaining tasks to be accomplished are (1) defining operating and maintenance costs, (2) gathering long-term operational and engineering data, and (3) improving plant reliability.

San Diego Gas & Electric (SDG&E) has been operating the Geothermal Loop Experimental Facility since May 1976. The facility utilizes the high-temperature, high-salinity (HT/HS) brine resource of the Salton Sea (or Niland) Geothermal Anomaly. The purpose of the facility is to investigate the technical and economic feasibility of generating electric power from this type of resource. The facility is sized to generate approximately 10 MW of electric power using a flash/binary cycle, except that the turbine and generator are not present. A flow diagram is shown in Figure 1. The operating experience to date of the three major systems (brine, steam/condensate, and binary) will be reviewed here.

BRINE SYSTEM

The primary design and functional intent of the brine system is to simplify brine handling. A major underlying reason for this approach is the large quantity of scale that is generated, tending to bind valves and other moving components, obstruct flow passages, and block control and data transducers. Other reasons for this approach are to limit the variety of components exposed to the brine and minimize maintenance costs. The large, easily accessible, gravity separator vessels operate very well and also simplify scale removal. The original control system (essentially limited to on-off level controls on each separator vessel) was replaced with proportional elements. Some valves were replaced with types chosen to minimize flow restrictions and sealing interfaces.

Operating experience has indicated that this approach is successful in reducing brine handling problems. The brine system must be periodically cleaned of scale. Continuous operating time appears to be limited by scale accumulation at the reinjection pump. Scaling of guide, seal, and bearing surfaces is still a problem in the operation of valves and pump, but significant improvements have been made.

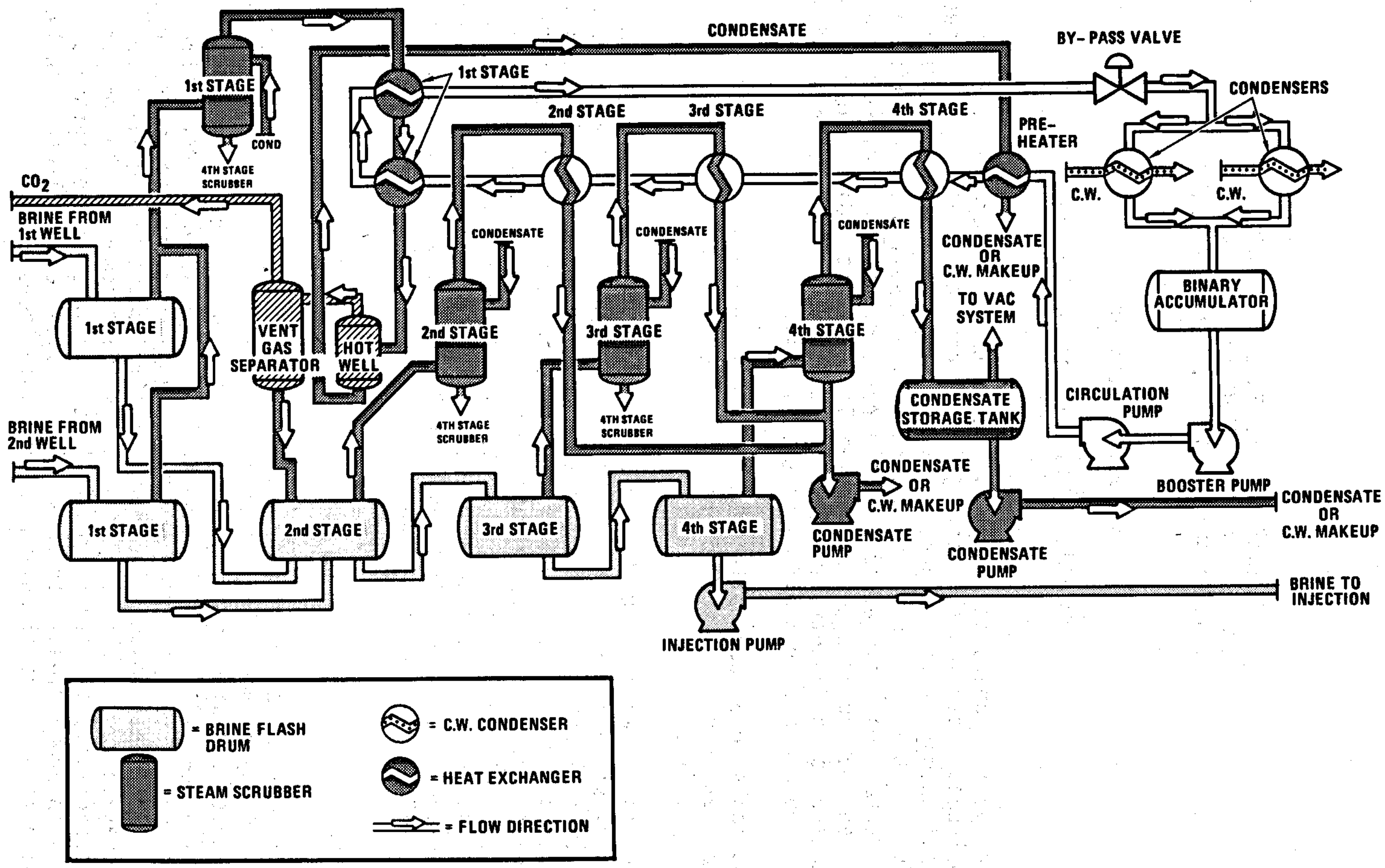


Figure 1. Geothermal Loop Experimental Facility

Areas that remain to be investigated after gathering of engineering design data are the economics of scale control and removal, improved reliability of components, and long-term effects on reservoir and plant.

STEAM AND STEAM CONDENSATE SYSTEM

The design and functional intent of the steam and steam condensate system was also to simplify operation and minimize scaling difficulties. Operating experience has generally been very favorable.

The control system is essentially limited to hot well liquid level controls plus a pressure control on the first stage. Pressure and temperatures of the other stages "float." This type of operation has the advantage of anticipating problems by small changes in pressure and temperature. One disadvantage is that plant upsets and/or transients are easily transmitted throughout the plant.

Scaling of the steam and steam condensate system has been minimal. Separator and scrubber operations have generally kept total dissolved solids to less than 20 ppm. Heat exchanger surfaces have not required cleaning to date.

BINARY SYSTEM

Distilled water has been used in the binary system as the working fluid to date. Water is being used to determine baseline system characteristics. Operating experience has been good.

The facility was designed to use isobutane as the working fluid. The use of water as the working fluid in the binary system has required several plant modifications. Booster pump impeller and case were replaced with components suitable for water, and the main pump was taken out of service, since it was not required for water. A bypass of one of the first stage heat exchangers was accomplished in order to reduce the heat transfer surface area, since the excess area for water in binary system was generating unrepresentative data and performance. Returning these modifications to isobutane conditions, in addition to operational differences in pressures (accumulator operates under vacuum with water) and temperatures, will have uncertain effects on system performance.

Physical properties of isobutane are not as well defined as are those of water. The operation with water will attempt to define system characteristics with water, particularly heat exchanger coefficients for a known baseline. Later operation with isobutane will then be compared where applicable. This comparison should improve the ability to predict future isobutane system performance.

Prior to starting operation with isobutane, a safety analysis of the plant will be conducted.

FACILITY OPERATION

The facility has accumulated over 3500 hours of operation as of July 1, 1977, using the total flow from one geothermal well (50.4 kg/s [400,000 lb/hr]). Availability has gradually improved from 40% to 85%. These values do exclude scheduled periods for inspection of this experimental plant. Major problems have been with injection pump seals, scale deposition, and injection well plugging.

BRINE CHEMISTRY

The geothermal fluid available from this reservoir is a hypersaline brine containing approximately 200,000 ppm total dissolved solids (TDS), mostly in chloride form (see following table). These chlorides remain in solution during the heat extraction process and are subsequently injected back into the reservoir. Certain minor species, however, such as silica, lead, and iron, have limited solubility and, as the brine is cooled during the heat extraction process, they precipitate from solution and deposit on pipe and vessel surfaces.

Table 1
GEOTHERMAL FLUID COMPOSITION

NILAND RESERVOIR (MAGMA MAX NO. 1)

Element	Mg/1
Sodium	40,600
Potassium	11,000
Calcium	21,400
Chlorides	128,500
Iron	315
Manganese	681
Zinc	244
Silicon	246
Barium	142
Lead	52
Strontium	440
Lithium	180
Magnesium	105
Copper	3
Ammonia	360
Total Solids	219,000
pH	5.3
Oxidation Reduction Potential	+25

Gas Analysis

Element	Percent
Carbon Dioxide	98.14
Methane	0.68
Nitrogen	0.02
Oxygen	N.D*
Hydrogen	N.D*
Hydrogen Sulfide	0.18

*N.D. -- Not Detected

The principal noncondensable species is carbon dioxide. Small amounts (up to 30 ppm) of hydrogen sulfide are also found in the geothermal brine. Ammonia is also present in the geothermal brine and has a significant effect on the brine chemistry.

The pH of the brine (5.6 to 5.8) is such that a carbonate-type precipitate is not normally observed in the geothermal brines from this reservoir, in spite of the high carbon dioxide level (up to 3% by weight) observed in the geothermal brine.

In this process, the available energy in the geothermal brine is extracted in the form of steam. The drum separators and scrubbers are capable of producing high quality steam with a TDS content of less than 10 ppm. However, accompanying this steam are the noncondensable gases (carbon dioxide and hydrogen sulfide). A portion of the ammonia in the geothermal brine is also driven off with the steam. The resulting removal of the noncondensable gases causes the pH of the brine to increase to approximately 6.0. The pH of the geothermal steam, as observed in the condensate, varies with the ratio of carbon dioxide and ammonia. This rather complex relationship produces a slightly acid (pH 6.5) steam condensate from the first stage, where carbon dioxide concentration in the steam is the highest. The steam condensate produced from subsequent stages is more influenced by the ammonia evolved and exhibits a pH of 9 to 10.

SCALE DEPOSITION

Scaling was observed on all surfaces in contact with the geothermal brine. As noted in the above paragraph, the geothermal steam was generally quite pure and as a result no significant scaling was observed on the heat exchange surfaces. The GLEF has been operated in three modes:

- cascade mode: the condensed steam from the preceding stage is added to the next stage
- condensate reinjection mode: the condensate from all of the stages is collected and injected into the last stage
- the noninjection mode: none of the condensed geothermal steam is injected, but instead is used as cooling water makeup

The scaling deposited in the first stage is predominately a galena-crystaline phase interspersed in an iron-rich amorphous silica matrix (1). The presence of the lead sulfide at this point is attributed to its very low solubility, which would cause it to precipitate first as the temperature of the geothermal brine decreases.

Scale deposition in subsequent stages is dependent upon the mode of operation. In the cascade mode, the reintroduction of the carbon dioxide-saturated steam condensate caused significant deposits of carbonates in the vessels and lines. When the condensate from each stage was collected and introduced into the fourth stage, calcite deposits were observed in the fourth stage vessel and injection line. The formation of a calcium carbonate scale is attributed to a reaction between carbonate in the condensed steam and calcium in the geothermal brine. At the point of mixing, it is postulated that the pH is sufficiently high to allow the formation of calcium carbonate. Thus, when the steam condensate is directed to the cooling pond, rather than combined with the brine, no carbonate deposition is observed.

The major constituent of the geothermal scale in the absence of steam condensate recombination is silica. The solubility of amorphous silica is rapidly exceeded as heat is extracted from the geothermal brine. Initially, the deposit is in the form of a hard iron silica scale, which is observed in the second and third stage vessels and piping. A precipitate of a silica gel-like material develops in the fourth stage and injection lines, which forms a soft silica scale. In some areas, such as the injection pump, this deposition has almost the consistency of mud.

Scale deposition has been particularly troublesome in close tolerance operating equipment within the facility, such as valves and pumps. Valves have been reworked to increase the clearance between the mating surfaces, and specialized valves, such as Kymar ball valves, have been used whenever possible. Positive lubrication of injection pump bearings with condensed geothermal steam has almost eliminated scaling on bearing surfaces.

In the injection lines the silica scale can be removed by high-pressure water jets (34.5 MPa [5000 psia]). However, in the GLEF itself, chemical softening has been found to be necessary before scale removal can be affected. Scale removal within the GLEF has been successfully accomplished utilizing an acid-based softening solution, followed by high-pressure water.

Scale deposition rates range from 0.01 mm/hr in the first stage to 0.08 kmm/hr at the injection pump discharge. Scaling deposition rates subsequently decreased to 0.01 mm/hr at the injection well.

CORROSION

Only light to moderate corrosion of the mild steel surfaces in contact with the geothermal brine and steam was observed. This was attributed to the reducing nature of the geothermal fluid and possibly to some protection from the scale deposits. Some of the corrosion observed, particularly in the scrubber vessels, appeared to be iron oxide caused by frequent opening of the vessels for inspection.

TEST PROGRAM

A detailed test program has been developed to document the operation of the plant and overcome the mechanical and chemical problems. The goal of this test program is to provide the engineering data needed to design future commercial geothermal power plants.

SUMMARY AND CONCLUSIONS

The operation of the Geothermal Loop Experimental Facility to date has been very successful. The facility has been able to handle the HT/HS brine and extract thermal energy with high plant availability. Long-term operating, economic, and engineering data remain to be determined.

REFERENCE

1. R. Quong. "Scale and Solids Deposition in the SDG&E/USERDA Geothermal Loop Experimental Facility at Niland, California." In Transactions of the Geochemical Resources Council Annual Meeting, San Diego, California, May 9-11, 1977.

FOUR POSSIBLE GEOTHERMAL PROJECTS

Arthur Martinez
Public Service Co. of New Mexico

Public Service Company of New Mexico (PNM) has been reviewing geothermal development both in the western region of the United States and, more specifically, New Mexico, for the past several years. Discussion today will concentrate on the major geothermal activities the Company has been involved in. The activities can be categorized into four areas: the Valles Caldera/Union Oil geothermal development, the Diablo Exploration, Inc. (Diablo) geothermal project, early communications with field developers, and continuing review of the Los Alamos hot/dry rock project.

VALLES CALDERA/UNION OIL DEVELOPMENT

PNM has been involved in an information exchange relationship with Union Oil on the Baca Location No. 1 (the actual private property the Valles Caldera is situated in) for five to six years. Extensive deep well drilling and reservoir assessment have been performed in the area by Union Oil, one of the world's largest developers of geothermal energy. Visits by PNM personnel to the site have enabled the company to observe Union activities and to follow development.

PNM has performed plant economic and preliminary alternative transmission routing studies for the Baca location. We are currently involved in contractual negotiations concerning pricing philosophy, escalation, liabilities, and so forth. Both companies have also replied to the ERDA "Expression of Interest Request" for a 50-MW demonstration plant at the Baca location. PNM fully supports the EPRI and SDG&E 50-MW demonstration facility. We believe this will be a significant milestone in geothermal development. However, in the Jemez Mountain (the Valles Caldera) also lies a significant geothermal reservoir. To simply let this reservoir lie without attempting plant development will not further either New Mexico's geothermal development or the demonstration of geothermal development in California and the entire nation. We hope ERDA will realize this and support demonstration projects in at least the better known reservoirs.

The Baca location is definitely the most developed geothermal area in New Mexico. Utilization of this site for geothermal electrical production would definitely help demonstrate geothermal potential in the state of New Mexico.

DIABLO EXPLORATION INC.

Diablo and PNM signed a preliminary agreement in which Diablo will obtain and develop a site and construct a 50-MW plant. PNM will build the transmission line and purchase capacity and energy at an agreed price. The preliminary agreement is basically subject to economic feasibility, permit acquisition, and environmental restraints.

Diablo is currently assessing New Mexico geothermal anomalies and talking to developers and lease holders. PNM and Diablo are also discussing possible PNM involvement in earlier phases of the project.

Diablo is seeking an ERDA geothermal loan guarantee for the field development phase and is completing the required paperwork. PNM may perform the initial environmental work required for the loan guarantee.

EARLY COMMUNICATION WITH FIELD DEVELOPERS

As part of PNM's budgeted geothermal R&D program for 1977, we have contacted various field developers and lease holders in the state of New Mexico to ascertain their development status, impediments to development, and projected plans for future development work. We felt that discussions between the utility and developer early in the field development phase were essential for planning purposes for all parties concerned.

Generally, what developers ideally would like to see, in order of preference, is front end utility capital in field development, contractual commitment as early as possible with as little field verification as required, a general letter of intent, and information on when the utility will be ready to purchase steam or power, and at what price.

Alternately, what the utility ideally would like to see, in order of preference, is full field verification as soon as possible with as little contractual commitment as required, information on the developer's anticipated cost of production and escalation, and information on the anticipated commercial availability of the geothermal field with projected steam or electrical power pricing, with escalation.

It does appear that two of the key criteria on contractual pricing are an assessment by the utility on what it can economically pay and in what year (specific transmissions cost should be included) and an assessment by the developers as to the price of their product and the anticipated escalation of that price.

DRY/HOT ROCK PROJECT REVIEW

Los Alamos Scientific Laboratories (LASL) and PNM have established an information exchange program. Specifically with geothermal, PNM personnel have met with LASL geothermal people, visited their drilling site, and are continually reviewing their project achievement. Current breakthroughs in water recovery (approximately 92% of water injected) and upcoming heat exchanger tests are activities PNM is definitely following with interest. Although joint venture between LASL and PNM is not beyond an expression of interest stage, it is anticipated that LASL electrical generation from hot/dry rock will occur.

DEVELOPMENT OF GEOTHERMAL ENERGY AT CHANDLER, ARIZONA

Harold Bell
Arizona Public Service Company

Geothermal Kinetics, Inc. (GKI) was convinced that potential for geothermal did exist in Arizona. A consortium of three utilities, Arizona Public Service Company, Salt River Project, and Tucson Gas and Electric, joined to support GKI in their efforts to locate and develop potential geothermal in Arizona. The business arrangement was that GKI would determine the optimum site and drill a well. The consortium would provide some financial incentive on the first well drilled. This gave the consortium the opportunity to obtain use of any resource that was obtained.

GKI determined the most beneficial location of this activity was in an area of south central Arizona. This area is typical Arizona desert that is currently in use as farmland for the production of cotton and fruit. The location is 30 miles southeast of the city of Phoenix, and it is in the electrical service area of the Salt River Project. From a geological standpoint it is in the Basin and Range Province about 60 miles south of the Colorado plateau area. The general structure appears to be an ancient valley that was surrounded by active volcanos. Eruption had filled the valley with high-silica, acid-type volcanic ash. This was subsequently covered with various clay and sediment layers. It would appear to be typical of a batholith formation, with intruding magma providing heat to the fluid that is contained in the porous volcanic ash. This sedimentation basin has fault formations at the edge that allow percolation of runoff water from the adjacent mountain range. The exploration techniques used were primarily that of satellite photograph and deep resistivity. Some work was also done with passive seismics. In this particular area there are no obvious surface manifestations such as hot springs, geysers, or fumaroles. However, some of the ground water wells that are used for crop irrigation are abnormally warm. Wells 43° to 54°C (110° to 130°F) have been observed.

Drilling on the Power Ranch's No. 1 well was started in early 1973. The casing schedule was:

- 340 mm (13 3/8 in) down to 884 m (2900 ft)
- 217 mm (9 5/8 in) down to 1646 m (5400 ft)
- 178 mm (7 in) down to bottom depth

Down to 1829 m (6000 ft) normal drilling mud was used. Below that depth a mixture of air and water was used. Before the 178 mm (7 in) casing was set, the normal suite of logs were run. A liner was put in from the 1829 m (6000 ft) to bottom depth of 2804 m (9200 ft). This liner was perforated selectively from the 1829 m to 2438 m (6000 to 8000 ft) level.

The second well, Power Ranch's No. 2 well, was started in mid-1973 and was located 402 m (1320 ft) north of Well No. 1. Drilling mud was used all of the way to bottom depth. A core sample was taken at the 2408 m (7900 ft) level. Casing was done much in the same manner as with Well No. 1, except that slotted liner was used rather than perforations. Also, a few hundred meters at the bottom of the hole were completed without slotted liner. Total depth of the hole was 3185 m (10,450 ft). Drill cuttings did indicate correlation between wells, with No. 2 showing some upward displacement. Results from these wells did indicate the typical upper formation sands, shales, anhydrites, gypsum, silt stones and conglomerates. The lower formation is essentially volcanics with some layers of welded tuff. No granitic basement was reached in either well. Properties of the core samples indicated about 20 to 30 percent porosity with a permeability of a few millidarcy. Gas was liberated from the drilling fluid. An analysis indicated N_2 and H_2 as the major components, with a trace of hydrocarbons and ammonia. No CO_2 or H_2S was observed. Equilibrium formation fluid temperatures were indicated in the order of 160° to 171°C (320° to 340°F).

Formation pressure was sufficient to produce fluid from the perforations or slots up to a few hundred meters below the surface. At this point the cold-fluid hydraulic-head matched formation pressure. Attempts were made to remove the cold fluid leg by air blowing at various depths. An attempt was made to reduce density of the hydraulic leg by froth techniques, using detergents followed by air blowing. This also was unsuccessful. Down hole pumping was tried at the 884 m (2900 ft) level and also at the 1524 m (5000 ft) level. Pumping was able to remove fluid in the wellbore as well as that produced by the formation, but this did not result in warming of the wellbore. Thus, when pumping was stopped, the fluid would cool off as it came up in the well. During pumping operations the surface flow temperature equilibrated between 93° to 99°C (200° to 210°F). An attempt was made to warm up the wellbore by circulating the formation fluid up in the annular area rather than in drill pipe. Warm surface discharge fluid was repumped down using the mud tank as a storage. Heat added to the upper formation wellbore was not enough to lighten the hydraulic leg or get flashing.

During a period of several months while shut-in, the well temperatures were rechecked, little difference was noted. The wells were left in this shut-in condition.

Because some of the problems associated with lack of self-production may be associated with formation of stimulation and well completion techniques, a proposal was made in 1974 to National Science Foundation through TRW's research activity in this area. The present status is that the wells are still shut-in waiting disposition of further tests. If ERDA's priorities will permit these tests, it may be that natural flow can be produced. Additional exploration work done in the Chandler area field, using improved geophysical techniques, does give positive results. Although the present wells, in their current conditon, are not considered commercial, the reservoir still appears to have good potential.

MAMMOTH GEOTHERMAL DISTRICT HEATING SYSTEM

George Crane, Research Engineer
Southern California Edison Company

BACKGROUND

Southern California Edison (SCE) has been interested in geothermal prospects in the Long Valley area of California for a number of years; Long Valley appears to be a large reserve containing perhaps 30% of the known geothermal reserves in California. It apparently contains low total dissolved solids (TDS) brines, temperatures in the order of 350°F, and part of Long Valley lies within Edison's service territory, so any power generated there could be tied directly into Edison's net.

In 1971, SCE, through an affiliate company, entered into a joint exploration venture with Getty Oil. Two wells were drilled on the shores of Mono Lake in Long Valley, both of which turned out to be unsuccessful.

South of Mono Lake, Magma Power Company owns in fee 90 acres of land at the Casa Diablo Hot Springs area near Mammoth Mountain. Nine wells have been drilled on the site, and a number of well flow and heat exchanger tests were performed during the period from 1959 to 1975.

In 1974, a preliminary design was completed for a 15-MW geothermal binary cycle power plant to be installed at Casa Diablo. It was subsequently determined that there was insufficient resource potential on the privately owned land to support a major generating facility there. This project is being delayed until geothermal leases on the surrounding federal lands become available.

In August 1976, ERDA awarded a contract to the Ben Holt Company, with SCE and Magma Power Company as participants, to perform a 12-month study to assess the technical environmental, and economic feasibility of a geothermal district heating system serving the village at Mammoth Lakes and utilizing the Casa Diablo Resource. This study is now about 75% complete. The majority of the technical and economic work summarized here has been performed by the Ben Holt Company, under the direction of W. C. Racine.

INTRODUCTION

Mammoth Lakes Village is located on the eastern slope of the Sierra Nevada Mountains about 483 km (300 miles) north of Los Angeles, California (Figure 1). The Village is a winter skiing and summer fishing resort with a permanent population of about 3000. On peak winter weekends, the population of the Village has reached 18,000. The houses, condominiums, motels, and commercial buildings in the Village use electric energy for most of their space and water heating demands. The purpose of the work described in this paper is to determine if a geothermal district heating system can be utilized as an alternate means of providing heating.

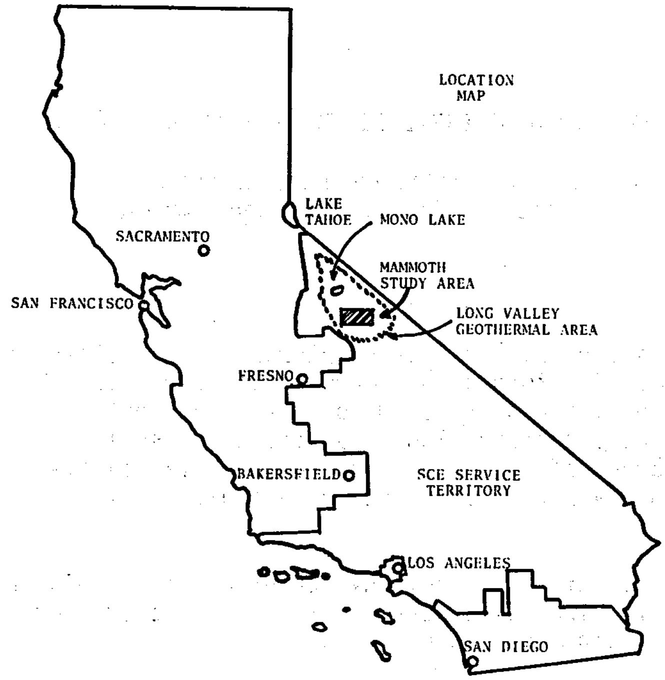


Figure 1

The study is divided into six tasks as follows:

1. Literature Search
2. Load Surveys
3. Reservoir Analysis
4. Heating Unit Selection and Retrofit Study
5. System Design and Cost Estimate
6. Environmental Evaluation

The results of work completed to date on tasks 2, 3, 5, and 6 will be summarized here.

LOAD SURVEYS

SCE performed a number of load surveys in order to establish the characteristics of heating loads in Mammoth Lakes Village. The data sought from the surveys include the peak heating load, heating load factor, monthly heating energy consumption, potential market for retrofit of existing facilities to geothermal heating, and a geographic distribution of connected load within the town. The surveys and source data included a door-to-door survey of 122 facilities, a review and analysis of SCE's billing records, SCE's local substation load demand charts, the Mono County Plan, utility association load studies and data from a metering program initiated under this study.

Results of the survey work indicate that the Village is characterized as tabulated below.

2800 Condominium units in 60 developments

1200 Motel/Lodge rooms in 40 developments

1200 Single family homes

24 Restaurants

150 Other commercial/institutional facilities

The total connected heating load is comprised of 84% electric resistance type and 16% liquid petroleum gas type units. In addition, of the total connected space heating load, only 14% is of the forced air type, which is the least costly type of unit to convert to geothermal district heating. The monthly energy consumption varies by a factor of 12:1 between the winter and summer months (Figure 2). Based on projections of total load growth and potential market penetration of the geothermal system, a geothermal system demand vs. time curve was developed (Figure 3).

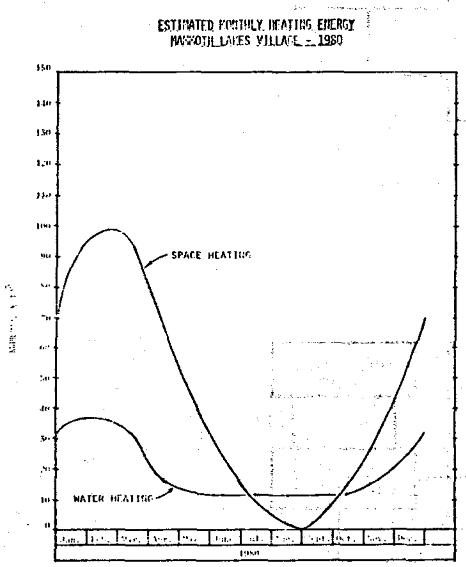


Figure 2

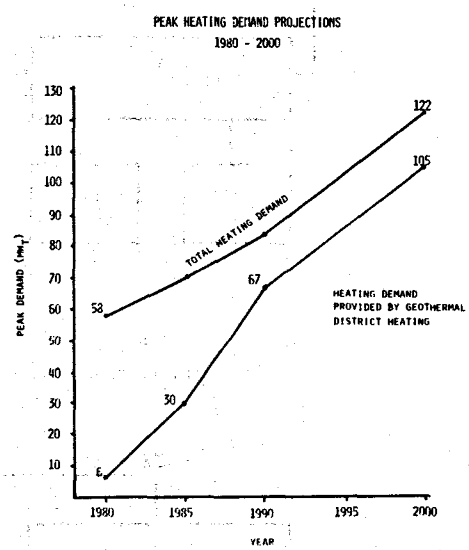


Figure 3

RESERVOIR ANALYSIS

Information obtained from the United States Geological Survey (USGS) and data from flow tests on seven of the nine wells drilled indicate that the Casa Diablo geothermal area has the capacity to provide the space and water heating needs of the town of Mammoth Lakes. USGS estimates suggest the potential of a 200-year supply of heating energy beneath the 90-acre Casa Diablo site. Wellhead temperatures of 166°C (330°F) to 171°C (340°F) and flow rates of 38-63 kg/s (300,000 to 500,000 lb/hr) per well have been measured during short-term testing.

SYSTEM DESIGN AND COST ESTIMATE

Based upon the heating demand characteristics and expected geothermal water temperatures and flow rates determined above, two alternate geothermal district heating system configurations were defined (Figure 4). In Alternate 1, a low temperature (LT) system, fresh water at about 93°C (200°F) is stored in tanks at atmospheric pressure and flows through hydronic space and water heaters in buildings upon demand. Alternate 2 is a high temperature (HT) closed loop system in which 149°C (300°F) fresh water is supplied to the heat exchangers of closed hydronic heating systems in each building being served. The design parameters, capital costs, and annual costs of the two alternatives are indicated on Tables 1, 2, and 3, respectively.

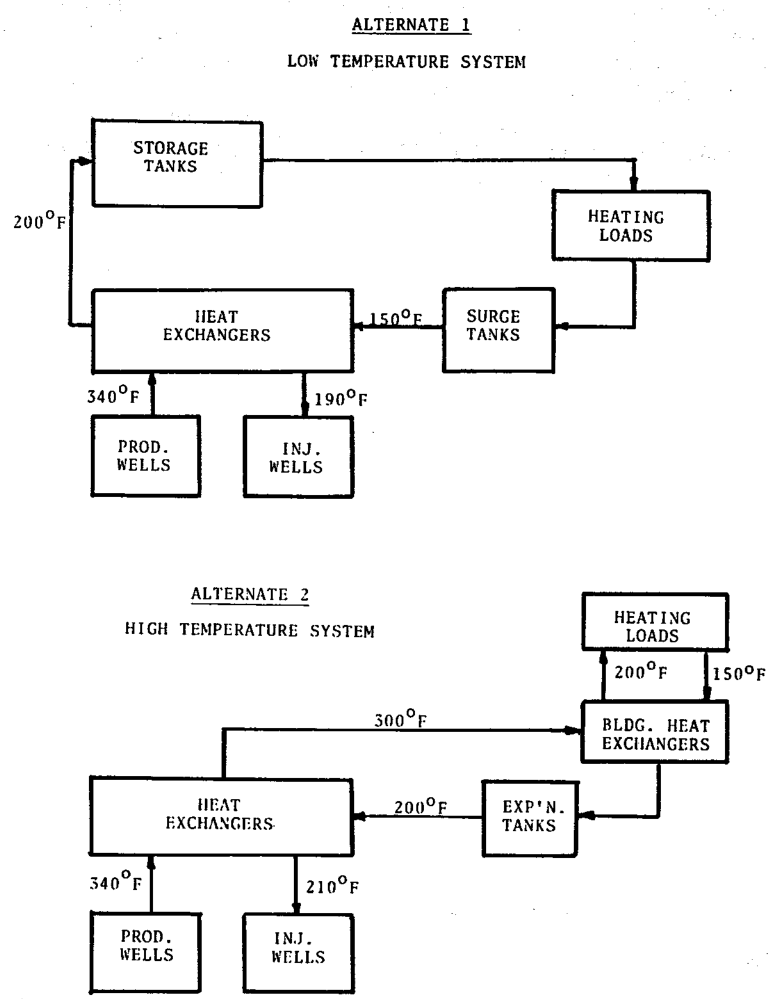


Figure 4

Table 1
DESIGN PARAMETERS

	LT System	HT System
Main Supply Pipeline Diameters	.4 m (16 in)	.3 m (12 in)
Hot Water Peak Flow Rate	.37 m^3/s (5900 gpm)	.24 m^3/s (3800 gpm)
Geothermal/Fresh Water Heat Exchanger Surface Area	1672 m^2 (18,000 sq ft)	5017 m^2 (54,000 sq ft)
Geothermal Water Peak Flow Rate	.18 m^3/s (2900 gpm)	.25 m^3/s 3900 gpm
Number of Building Heat Exchangers Required	None	

Table 2
CAPITAL COST COMPARISON
(Thousand Dollars)

	LT System	HT System
Piping Mains	1800	Base
Wells	Base	200
Well Pumps	Base	300
Heat Exchangers	Base	700
Tanks	Base	1200
Circulating Pumps	200	Base
Building Heating Systems	Base	3600
TOTAL	Base	4000

Table 3
ANNUAL COST COMPARISON
(Thousand Dollars/Year)

	LT System	HT System
Carrying Charges on Capital	Base	800
Operating Costs		
Labor and Material	Base	40
Electric Power	120	Base
TOTAL	Base	720

Table 3 clearly shows that Alternate 1, the low temperature geothermal district heating system, offers superior economics for the case of Mammoth Lakes Village.

ENVIRONMENTAL EVALUATION

SCE has completed a preliminary assessment of the environmental feasibility of the geothermal district heating system. The areas specifically addressed included the biological setting, rare and endangered species of vegetation and wildlife, aesthetics, population, transportation, and archaeology. The environmental impacts of the heating plant, the underground transmission and distribution piping and the storage tanks were considered. The scope of the preliminary assessment did not include air quality, water quality, land use, geology and seismicity, or climate.

The data sources for the study include two field trips to the site by representatives of SCE's Environmental Planning Department, the Final Environmental Impact Statement for the Geothermal Leasing Programs by the Department of the Interior, the Mono County Plan Draft Environmental Impact Report, and environmental reports prepared for an earlier proposed geothermal power plant at Casa Diablo, and for a SCE transmission line.

In general, there have been no potential adverse environmental impacts identified to date of sufficient consequence to preclude the construction and operation of the proposed district heating system.

REMAINING/FOLLOW-ON WORK

The completion of the feasibility study will include optimization of the low temperature system configuration, completion of the system preliminary design, and comparison of geothermal heating costs with alternatives.

In addition to the ERDA-funded feasibility study, two other programs at Mammoth are underway.

SCE has contracted the Ben Holt Company to look into the technology and economics of a system combining power generation, using a binary cycle, with a district heating system as a bottoming cycle.

The State Energy Commission recently awarded a contract to the same team of Holt/SCE/Magma to design, construct, and operate a geothermal district heating pilot project at the Casa Diablo site. This project will include installation of a well pump on existing well, a heat exchanger plant, and a heating loop serving hydronic heaters in a hardware store and a lumber shed located on the Magma property.

At the conclusion of these programs, the results will be reviewed by SCE to determine how such a district heating system might fit into SCE's service system.

SITE-SPECIFIC ANALYSIS OF HYBRID GEOTHERMAL/FOSSIL POWER PLANTS

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INTRODUCTION

Liquid-dominated geothermal resources must be extensively used if geothermal energy is to provide 10,000 to 15,000 MW of electrical power by 1985. The conversion of this resource relies upon the development of new and, for the most part, commercially unproven technology.

Present electric power generation and distribution technology is directed at large plants -- 3000 to 5000 MW -- to ensure the most economical delivery of electric energy to the consumer. The advantages of using this technology for conversion and distribution of geothermal energy are readily apparent. However, the properties of geothermal energy in terms of temperature, pressure, and quantity are far different from the properties of the heat energy produced from fossil fuels.

In 1975, the City of Burbank suggested that fossil fuel and geothermal energy could be combined to mutual advantage in a single power plant. By 1976, the city, Pacific-Sierra Research Corporation (PSR), and other investigators suggested that geothermal energy and fossil fuels could be used to advantage in a hybrid cycle. Geothermal energy could provide low-temperature heat to the boiler feedwater of a Rankine steam cycle, reducing the need for regeneration. The fossil fuel could provide the high-temperature heat at a more efficient level of use. A recent study by Brown University(1) revealed several important advantages of the hybrid cycle.

- Thermodynamically, the hybrid system is superior to a combination of the two state-of-the-art systems, one using only fossil fuel and the other using only geothermal energy. Therefore, to achieve a given generating capacity, the hybrid plant would require less fossil fuel than a conventional steam plant.

- Equivalent geothermal energy conversion efficiencies are substantially higher in feedwater heating than in a state-of-the-art binary fluid or flash plant.

- Geothermal fluids with marginal temperatures (150°C/300°F) can be used in a hybrid cycle to produce electricity. This advantage is especially important because lower temperature geothermal resources are much more abundant than those with high temperatures. In a purely geothermal plant, low-temperature fluids cannot produce power economically under present technology.

Because piping high-temperature geothermal fluid over distances greater than 1.6 km (one mile) is impractical, the hybrid plant must be located within the geothermal resource area. In general, the resource is not optimally located with respect to sources of fuel, fresh water, or transmission networks. Therefore, while the thermodynamic advantage of the hybrid plant had been established, its economic competitiveness remained an open question. Could the economic advantages gained from the geothermal resource overcome the economic penalties owing to the location of the resource?

The Utilization Technology Branch (UTB) of the Energy Research and Development Administration (ERDA) undertook the task of determining the economic viability of a hybrid power plant. ERDA contract E(0-4-1311), "Site-Specific Analysis of Hybrid Geothermal/Fossil Power Plants," was awarded to the city late in 1976 and was completed in the Spring of 1977. Pacific-Sierra, the major subcontractor to the city, was assigned the analytical modeling.

STUDY OBJECTIVES

The objectives of this work are:

- Develop the analytical techniques for rough parametric design of hybrid geothermal/fossil fuel plants for various geothermal resource characteristics
- Develop the analytical techniques for approximate evaluation of hybrid geothermal/fossil fuel plants for given hydrothermal resource characteristics, fossil fuel location, consumer locale, plant size, and environmental restraints
- Evaluate the merits of a hybrid geothermal/fossil fuel plant at four known geothermal resource areas (KGRAs):
    - -- Roosevelt Hot Springs, Beaver County, Utah
    - -- Coso Hot Springs, Inyo County, California
    - -- East Mesa, Imperial County, California
    - -- Long Valley, Mono County, California
- Prepare a preliminary plan for implementing geothermal energy in hybrid cycle plants

To achieve these objectives, the city assembled a team primarily from the staff of its Public Service Department. The objectives were achieved through the following task sequence:

- Execute the basic hybrid power plant synthesis
- Analyze the geothermal characteristics of each of the four KGRAs
- Conduct a site-specific analysis of power production and delivery
- Prepare preliminary plant designs optimized for each site
- Compare the optimized plant designs against each other and a reference coal-fired plant design

- Compile the report

STUDY CRITERION

Utilities strive to provide electric energy to their customers at the lowest practical cost. Therefore, the selected criterion for this study is to establish minimum cost of delivered electric energy through optimizing the use of coal and geothermal resources within environmental constraints and legal requirements. All regulations presently known, including environmental protection, safety, and water usage, are to be met. Throughout the study, care also is taken to ensure that performance characteristics are readily achievable within the current state of the art.

The site-to-site cost comparisons are made by the general costing method outlined by ERDA (2). The economic assumptions conform to the ERDA method.

FOCUS ON COAL

By focusing on coal as the fossil fuel, this study recognizes the nation's goal to reduce its dependence on oil and natural gas. A hybrid geothermal/coal plant would use two energy sources of great abundance within the United States. Its electrical power would be secure and reliable, immune from any gas shortage or oil embargo.

Another important attribute of coal is its status as the least expensive of the fossil fuels. Because oil and gas are more costly, geothermal energy in a hybrid cycle will show even greater savings than would the use of coal alone.

Because minimum cost of electric power is the study criterion for the design of a hybrid plant, a reference all coal-fired plant is needed in order to provide a standard for measuring the economic viability of the hybrid plant and a guide for the costing of major power plant components.

Ideally, the reference plant should be a state-of-the-art design and optimally sited.

The Intermountain Power Project (IPP) plant was selected as the all coal reference. This plant is to start power production in 1984, which corresponds to the time period a hybrid plant could be ready for operation. Therefore, the IPP and the hybrid plants would face similar requisites relative to federal, state, and local regulations; cost of land, components, and labor; environmental restraints and requirements; and market considerations. The preliminary design of the IPP plant is available to the city because of its participation in the design study. The preliminary design for the IPP plant has not been completed at this time, although the work has been in progress since July 1974, and considerable analyses have been made on the design.

RESULTS AND CONCLUSIONS

Site Evaluation

The energy cost comparisons of a 750-MW hybrid plant at each of the four geothermal sites are presented in Figure ES-1. The principal conclusions drawn from the comparisons are:

- The Roosevelt Hot Springs site has the potential of producing electric energy delivered to Burbank at 10 percent less cost than a well-sited reference all coal-fired plant.
- The Coso Hot Springs site shows slightly greater cost than the all coal-fired plant for delivered electric energy to Burbank.
- The East Mesa and Long Valley sites did not show economic advantage for hybrid plants.

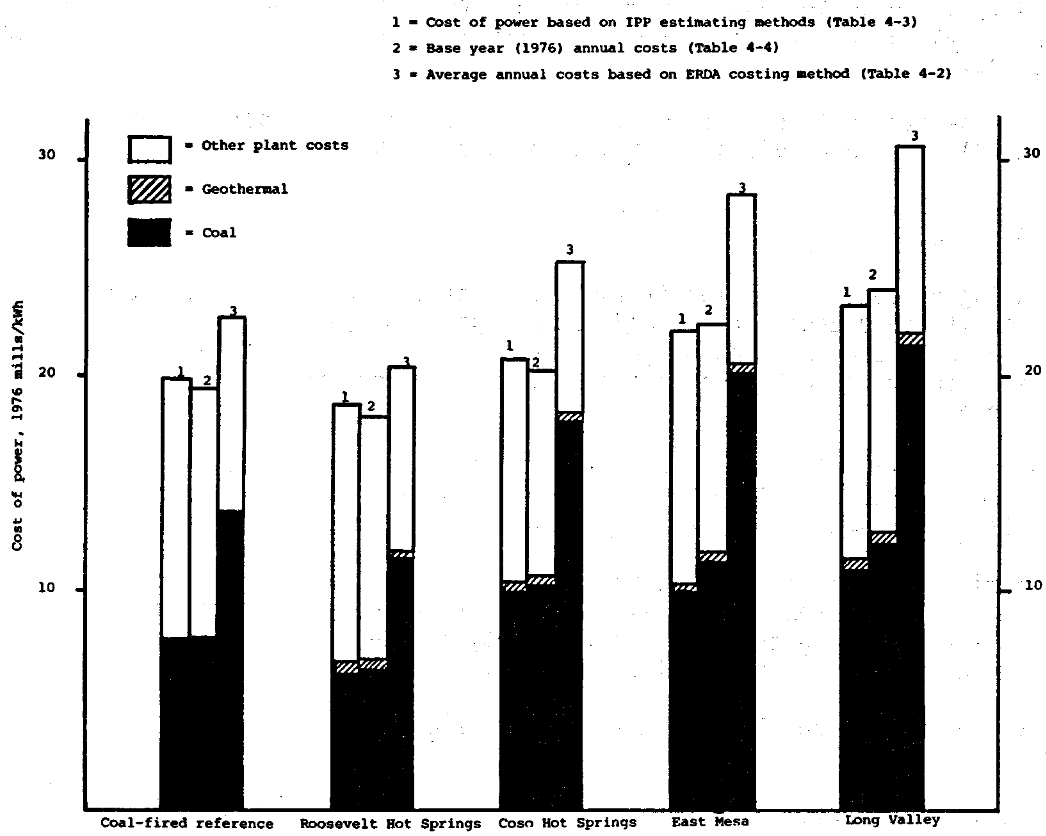

Figure ES-1. Energy Cost Comparisons for a 750-MW Hybrid Plant

Although comparisons were not explicitly made between hybrid and all coal-fired plants located at Coso Hot Springs, East Mesa, or Long Valley, the hybrid plant would be competitive with any all coal-fired plant at the same site.

Figure ES-2 shows why Roosevelt Hot Springs and Coso Hot Springs are more competitive than either East Mesa or Long Valley. With fewer geothermal wells, hybrid plants at Roosevelt Hot Springs and Coso Hot Springs would reduce the coal requirement. For example, the amount of coal could be reduced by at least 46.3 t/h (51.0 tons/h) at Roosevelt Hot Springs. East Mesa and Long Valley have larger cost penalties owing to their greater distance from the coal source.

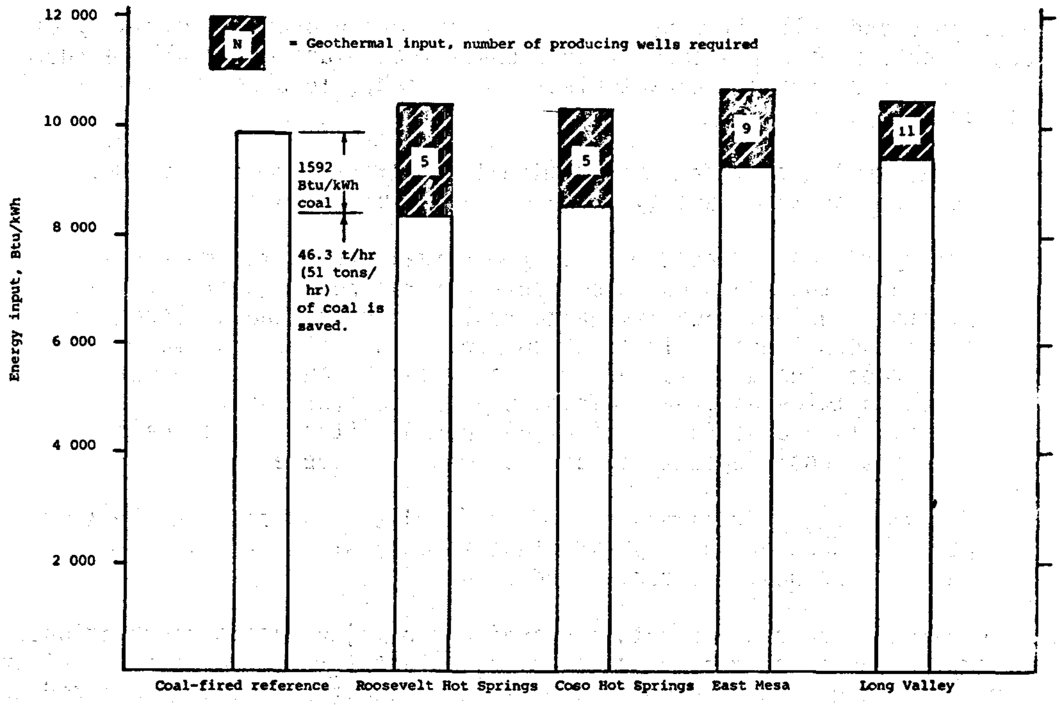

Figure ES-2. Energy Input for a 750-MW Hybrid Plant

Cost Results

Table ES-1 shows the annual costs, based on the ERDA costing method. The cost of coal delivered to the geothermal site is the principal economic factor that impacts upon the cost of delivered electric power from the hybrid plant. In comparison, well cost and well operation and maintenance are less than five percent of the coal costs for each of the four sites; and they are roughly equal to the cost of cooling water. These data indicate that feedwater heating is indeed a most significant application of the geothermal fluid, by its replacement of coal.

Additionally, using the geothermal fluid to dry coal or to supply power to an auxiliary boiler would further increase its ability to replace coal. Further savings would result if the geothermal fluid is used to supply cooling water.

It should be noted that well costs do not include royalties or profits, since they cannot be reliably estimated. If royalties or profits are large enough, they could affect site selection.

The capital cost of geothermal wells, larger condenser, and turbine-generator is more than offset by the reductions in the capital cost of the boiler for an all coal plant. At Roosevelt Hot Springs or Coso Hot Springs, the cost of a hybrid plant would be slightly less than the cost of an equivalent size all coal-fired plant. The development cost of the geothermal resource in East Mesa or Long Valley would more than cancel the reduced cost of the boiler.

Hybrid Plant Design

A well-designed and well-sited hybrid power plant can produce electricity at a lower cost than can either a conventional coal-fired plant or an all geothermal plant. Several performance characteristics of the hybrid plant account for its economic viability:

- Geothermal energy could economically contribute more than 20 percent of the total energy consumed in a hybrid plant.
- The hybrid plant would utilize geothermal energy far more efficiently than do present concepts for future all geothermal plants. For high-quality geothermal resources, the utilization of geothermal energy is about 20 percent greater. For marginal resources, the utilization efficiency can be one-and-one-half times to twice as great. Thus, the hybrid cycle would be especially useful for marginal geothermal sites located near enough to coal deposits to be economically viable.
- The thermodynamic efficiency of the coal contribution to electric power production in a hybrid plant is only slightly less than that of the best all coal-fired plant.

These conclusions were reached notwithstanding two major design restrictions, as well as some lesser ones imposed on the hybrid plant for this analysis. First, the geothermal energy was used only to heat the feedwater before it entered the boiler. Second, the boiler feedwater was heated in a subcritical cycle. Present judgment is that an actual hybrid design would encompass the following features:

- In addition to feedwater heating, the geothermal energy could have other applications, including coal drying and beneficiation, air preheating, flue gas reheating, auxiliary boiler heating, and general heating.
- The water balance in a hybrid plant is such as to allow for complete consumption of the geothermal fluid in evaporative cooling wherever the chemical and local environmental conditions would allow.
- The restriction to a subcritical cycle holds the steam at just below the critical temperature and pressure. It appears that a supercritical cycle could be utilized, with maximum pressures of about 240 bars (3500 psia).
- More than one turbine extraction point probably would be used. This allows flexibility to accommodate variations in the geothermal resource, as well as high-temperature steam for auxiliary station equipment. The hybrid plant is designed to accommodate some well shut-downs.

In view of the above considerations, the hybrid plant shows even greater promise than that revealed in the present study. Moreover, all the components in the hybrid cycle are state-of-the-art. The use of coal ensures a guaranteed plant life, even if the lifetime or quality of the geothermal resource is overestimated.

RECOMMENDATIONS

The results of this present study and the Brown University study show that the hybrid cycle can combine the two abundant national resources, coal and geothermal energy, to advantage. The general recommendation is to design, construct, and operate one or more hybrid power plants at suitable geothermal sites as soon as practicable. An operations target date of 1984 would be a good goal. Supporting recommendations are given below:

ACKNOWLEDGMENTS

This study was supported by the Energy Research and Development Administration Division of Geothermal Energy. Clifton B. McFarland was the Program Manager for ERDA. The work was performed by the City of Burbank's Public Service Department, with the analytical modeling being done by the Pacific-Sierra Research Corporation. Richard E. Roxburgh was the Program Manager for the City of Burbank and was assisted by Acey L. Floyd, Science Advisor to the city.

The study is based on theory developed at Brown University by Professors Ronald DiPippo, Joseph Kestin, and H. Ezzat Khalifa. This theory provided a clear and organized method of analysis of the hybrid geothermal/fossil fuel power plant.

The cost calculations are based upon modification of the computer simulation "A Thermodynamic Process Program for Geothermal Power Plant Cycles" developed by M. A. Green and H. S. Pines of the Lawrence Berkeley Laboratory. This simulation provided the basis for the cost optimization process used for the geothermal portion of the study.

The analysis required an optimally sited coal-fired power plant of the latest state-of-the-art design as a reference in order to provide realistic design and cost considerations for the hybrid plant analysis. The Intermountain Power Project (Joseph C. Fackrell, President) power plant was selected as the reference because of its siting, size, design, and schedule for first operation in the mid-1980s. The use of this ideally sited, cost efficient reference plant greatly enhanced the realism of the analysis.

REFERENCES

1. R. DiPippo, J. Kestin, and H. E. Khalifa. Hybrid Fossil-Geothermal Power Plants. Providence, Rhode Island: Brown University, 1977.

2. Energy Research and Development Administration. Comparing New Technologies for the Electric Utilities. ERDA-76-141 (Discussion Draft). Washington, D.C., December 1976.

MEAGER CREEK GEOTHERMAL INVESTIGATION SUMMARY

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British Columbia Hydro and Power Authority

BACKGROUND INFORMATION

In 1973 the Government of the Province of British Columbia passed the Geothermal Resources Act by which all the rights to geothermal resources, defined as waters of 121°C (250°F) or higher temperature, are reserved for the Crown.

The British Columbia Hydro and Power Authority (B.C. Hydro) is a Crown Corporation responsible for investigation, generation, and distribution of electric power in the Province of British Columbia and as such has an interest in exploring and developing geothermal resources in this province.

B.C. Hydro at the present time generates and distributes approximately 28,000 GWh of electric energy annually.

Sources of energy supply: Hydroelectric generation - 5500 MW
Other - 1300 MW

Further, approximately 20,000 MW of water power and 20,000 MW of thermal (coal) power are available for development.

INTRODUCTION

Approximately 60 hot springs have been identified in western Canada, of which approximately 90% are located in British Columbia. B.C. Hydro commissioned its first geothermal study program in 1973. The terms of reference for this first study called for identification and assessment of the geothermal potential of southwestern British Columbia.

Five areas within Garibaldi and Pemberton volcanics were identified as having potential for a commercial geothermal development:

1. Meager Creek, 55 km northwest of Pemberton
2. Mt. Cayley and the east side of the Elaho River, 25 km west of Alta Lake
3. Bridge River headwaters, 50 km west of Gold Bridge
4. The Lillooet fault zone, beginning at the north end of the Harrison Lake and extending northwest up the Lillooet River and Billy Goat Creek
5. Wasp Creek, 15 km west of Pemberton

Based on the geological evidence of the geothermal potential, specifically an occurrence of hot springs partially circumscribing a Quaternary volcano, the Meager Creek area was identified as the most promising area and was selected for more detailed study.

Meager Creek - Geography

Meager Creek area is centered on a recent volcanic complex approximately 20 kilometers in diameter and 2000 meters high. Thick forest cover, permanent snow fields, glaciers, and glacial outwash characterize the area. Annual precipitation is up to 500 centimeters. Rugged mountainous terrain and, until recently, no road access influenced the overall exploration cost.

1974-75 STUDY

The principal objectives of this study were to conduct a geophysical program, mainly resistivity surveys and temperature profile measurements in shallow drill holes, sufficient to determine whether or not the area is of continuing interest for geothermal power. Geological mapping of the area was also initiated.

Resistivity Survey

Altogether approximately 50 line miles were surveyed, mostly on the southeast side of the Meager volcanic complex. A dipole-dipole electrode array method was used with an electrode spacing of 152.4m, 304.8m, and 609.6m (500, 1000, and 2000 ft), giving an effective depth of penetration from 52.4 to 2438.4m (500 to 8000 ft).

Drilling

The first well, 74-H-1, was the deepest well drilled, to 347 meters (1140 ft), during the winter of 1974-75. The drill used was a Longyear 34 diamond drill. The following three wells, 75-H-1, 2, and 3, were drilled during September and October 1975, using a Boyles Bros. B BS-1 drill. The diameter of all four holes was 5 cm with a core sample of 2.5 cm in diameter. Bottom hole temperatures were monitored throughout the drilling.

One of the results of the study was to identify a possible geothermal reservoir whose top was within 300 meters of the surface, dipping north towards the heat source, believed to underlie the volcanic complex. Only the southern and southeastern limits of the possible reservoir have been identified.

1976 STUDY

During 1976 the study was limited to a reconnaissance geophysical survey of the eastern and northern parts of the Meager volcanic complex to test for the presence of subsurface geothermal fluids using the electrical self-potential method.

1977-78 STUDY

This and the next year's work will likely involve a more detailed electrical resistivity survey of the northern and eastern parts of the complex, followed by shallow drilling, in order to select the location of one or more possible deep exploratory test wells.

GEOTHERMAL RESOURCE REGULATION: AN IMPERIAL COUNTY PERSPECTIVE

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Director of Public Works
Imperial County, California

The purpose of this presentation is to clarify Imperial County's approach to the policy guidance and regulation of its geothermal resource development by means of an element of the County General Plan.

In the recent past, the states have required that individually enacted zoning and other ordinances must conform with a more inclusive policy or overall plan. This type of master policy plan has come to be known as a general plan. Most people would agree with a definition of general plan as being a comprehensive long-term outline that sets forth major policies concerning desirable future physical development for the locale.

All counties in California must create a general plan of their projected physical development that clarifies the relationships between physical development policies and social and economic goals. A general plan frequently addresses major activities and capital improvements that affect the physical character of a community.

A county general plan in California must have nine mandatory elements and is permitted to have further optional elements as necessary. The mandatory elements are land use, circulation, housing, conservation, open space, seismic safety, noise, scenic highways, and safety.

While the law mandating the development of general plans comes from the state, the intent of the enabling legislation was for the exercise of local control over local destiny. Subsequent state and federal legislation has reinforced this concept of stipulating that outside agencies - whether regional, state, or federal - take the local general plan into account before preempting that plan. The general plan is legitimately viewed as having the most valid mandate, since the people involved must live with the consequences of their decisions.

Two general rules apply to a general plan: first, any zoning must conform to the general plan, and second, the nine mandatory elements must be consistent. The first of these two rules explains why the County of Imperial determined to have a geothermal element to guide development of the resource: any zoning for geothermal resources would have to be consistent with the general plan. A coherent hierarchy of policies, zoning, and regulations is required to fulfill and implement the general plan concept. The geothermal element must also be consistent with the other elements of the County General Plan.

Perhaps the most important aspect of the general plan concept is that the citizens of a county have a unique knowledge of the various value relationships existing within the county, which would be missed by legislation imposed from, say, the state or federal level. While the general plan is obviously a planning instrument, it is--more importantly--a manifestation of responsible self-determination or democracy at the most sensitive and accountable level.

The foregoing is intended to clarify why and how a county uses an element of its general plan to provide a vehicle for decision making concerning the destiny of an area. The regulations that implement the general plan are a natural derivative of it. Both can be altered or amended by standard procedures.

In May 1971, the Imperial County Board of Supervisors adopted an interim set of regulations to guide geothermal development pending the creation of the geothermal general plan element. This interim regulation is called, "Terms, Conditions, Standards and Application Procedures for Initial Geothermal Development, Imperial County."

In 1973, the county sought funding to make a comprehensive study to develop a geothermal element of the Country General Plan. The county was subsequently awarded a grant of $365,000 by the National Science Foundation for that purpose. The county subcontracted to the University of California at Riverside and California Institute of Technology to perform research in seven disciplines: resource assessment, engineering, geography, environmental aspects, sociology, economics, and political science/law. The purpose of the research was to acquire sufficient background material to develop a comprehensive geothermal element.

The research commenced in November 1975 and was completed in February 1977. The geothermal element is nearing completion. We anticipate that it will be adopted during the summer of 1977.

The resource assessment research determined the size of the recoverable resource in each of the four economic anomalies: Salton Sea, Brawley, Heber, and East Mesa as well as the possibility of new areas being developed. Engineering research proved the feasibility of using the irrigation drainage water as a cooling medium; determined the amount of surface land use for plants and wells; addressed the problems of transmission pipeline burial, disposal of blowdown sludge, drilling in the Salton Sea; and determined the fact that cooling tower drift should not be a problem.

Geographical and environmental studies concluded that geothermal resource development should not significantly affect the county's agricultural resources. The major environmental considerations appear to be potential subsidence, possible seismicity, and long-range water availability. Sociologically, the county has been characterized as being almost unanimously in favor of development of geothermal resources, and having a growing population that will likely grow slightly faster because of geothermal resource development. Creation of a skills training center was recommended to provide an appropriate labor pool.

The economic research determined the capital costs of geothermal development, the fact that the county would gain some employment and tax revenues of approximately $5,000.00 per installed megawatt, and the multiplier, or ripple effects, that would occur throughout the county's economy. The economic risks are still the major deterrent to geothermal resource development.

In the political science/law areas we have received an articulated set of policy recommendations relating to the regulation and administration of the resource development and relations with other agencies and groups.

Based on the research results and a multitude of meetings with various industry and government groups, we have developed preliminary policy recommendations in the areas of social and environmental concerns, industry and resource concerns, and county-oriented concerns.

Understandably, these policies will strive to maintain or preserve the values of the citizens of the county, such as a healthy economic climate, as well as make the regulations as equitable as possible.

We have some recommendations based on our geothermal element project:

- The more ministerial an accountability mechanism is, the better. That is, if performance standards can take the place of discretionary permitting processes, the industry is encouraged and the bureaucracy is minimized.

- Geothermal energy needs better public relations to educate the general public, as well as decision makers.

- Since water for cooling may be a critical constraint in the long run, its assured supply should be studied.

- To ensure avoiding problems deriving from secondary geological consequences, the existing monitoring systems (a vertical survey net for subsidence detection, and diverse seismographic stations) should be expanded and coordinated into a coherent system.

- The timing seems right for a study of effective economic incentives to accelerate the development of geothermal resources.

Section 4

WORKSHOP:
RESERVOIR VERIFICATION

RESERVOIR VERIFICATION WORKSHOP
PANEL OF SPEAKERS

CHAIRMAN: S. K. Sanyal
Geonomics, Inc.

PANELISTS:

W. E. Brigham
Stanford University

D. R. Butler
Chevron Resources Company

G. W. Crosby
Phillips Petroleum Company

A. G. Duba
Lawrence Livermore Labs

J. H. Howard
Lawrence Berkeley Laboratory

G. Lombard
San Diego Gas and Electric Company

A. Martinez
Public Service Company of New Mexico

H. T. Meidav
Geonomics, Inc.

T. D. Riney
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O. J. Vetter & Associates

W. Youngquist
Eugene Water and Electricity Board

RESERVOIR VERIFICATION WORKSHOP PANEL REPORT

Subir K. Sanyal, Chairman

INTRODUCTION

Before geothermal energy can be commercially developed for electric power, the utility companies need to have the assurance that the geothermal resource at a particular site can be produced at an adequate rate and with an acceptable quality over the life of the power plant, that is, over 25 to 30 years. Thus, the utilities need two basic assurances:

- That the reservoir has sufficient reserves and flow capacity to produce for 30 years at an adequate rate
- That the reservoir characteristics are such that the produced fluid will have acceptable quality as regards enthalpy, chemical composition, and so forth, over the 30 year period

The abovementioned assurances will have to be provided primarily by the reservoir engineer, who specializes in estimating the nature of a subsurface reservoir and the reserves it contains, as well as in forecasting its performance. Reservoir engineering is a well-developed discipline in the petroleum industry. However, in the geothermal industry the application of reservoir engineering is a relatively new development and is fraught with problems arising from the lack of a substantial data base and the inherent idiosyncrasies of a geothermal reservoir.

The lack of a substantial data base is a serious handicap. Worldwide, only three geothermal reservoirs have been produced for sufficiently long periods to provide case histories of major significance. These reservoirs are Larderello geothermal field in Italy (producing since the early 1900s), Wairakei geothermal field in New Zealand (producing since the late 1950s), and The Geysers geothermal field in the United States (producing since the early 1960s). Of these only Wairakei is a hydrothermal (hot water) system; the other two are dry steam reservoirs. Because of the inherent operational and economic advantages of dry steam wells and the two well-known case histories (Larderello and The Geysers), dry steam reservoirs are the most attractive sources of geothermal power. The Pacific Gas and Electric Company has been producing commercial geothermal power at The Geysers for over a decade and has thus developed, among the utilities, a sense of confidence in the viability of dry steam geothermal resource. The utility industry does not appear to have such confidence in the viability of hydrothermal resource. Hence, this workshop.

The other difficulty in applying reservoir engineering to geothermal reservoirs is the inherent complexity of geothermal systems. In the petroleum industry, the resource sought after (oil or gas) has a definite, assessable mass. In a geothermal system the resource is heat energy, the resource carrier being water and steam. Estimating the total amount of heat contained in the rocks and fluids in a reservoir is relatively simple. However, how much of that heat is practically recoverable depends primarily on the amount of available water and how extensive the contact is between rock and water. The amount of available water depends on the water stored in the reservoir, artificial recharge (injection of power plant waste water), and natural recharge of water. It is relatively easy to estimate the water-in-place and the extent of artificial recharge, though not of natural recharge. Until a reservoir has produced for a number of years, the extent of recharge, or the absence of it, cannot be precisely estimated. As more case histories of geothermal reservoirs accumulate, inferences on the nature of natural recharge in geothermal systems can be drawn. However, a reservoir engineer can estimate the lower limit of available water by assuming no recharge. If any recharge takes place, the net energy recovery will be higher. Another uncertain factor is the degree of interconnection between pore-spaces in the reservoir. This aspect of a geothermal system sometimes cannot be precisely estimated from the state-of-the-art of well testing, well logging, and surface geophysical or geochemical methods.

The uncertainty of our knowledge of the nature of a geothermal system and the lack of case histories makes it difficult to estimate the reserve and flow capacity of the reservoir, or to forecast the performance of the reservoir with a high degree of confidence.

PURPOSE

A utility company will like to know with reasonable accuracy the answers to the following vital questions:

- Do we have sufficient reserve for a certain power plant capacity?
- Can the reservoir produce at an adequate rate to supply 'fuel' to the power plant for 25 to 30 years?
- How will the enthalpy of the produced fluid vary over the life of the power plant?
- How will the chemical composition of the fluid vary over the life of the power plant?
- How will the operational problems (amount of noncondensible gases, salinity, and corrosivity of the fluid, etc.) vary over the life of the power plant?

As discussed before, the answers to these questions are uncertain.

The purpose of this workshop was to bring together experts in geothermal resource assessment and representatives of geothermal resources producers, as well as the users (utility companies), with the aim of discussing the present uncertainties in geothermal resource assessment, its impact on the growth of the geothermal power industry, and the future trend. The participants consisted of representatives of the utility companies, EPRI, academia, government, and the service industry. An open and informal exchange of ideas took place between the panel of speakers and the other workshop participants.

DISCUSSION

This summary is followed by the transcripts of the talks presented by various speakers at the workshop. Transcripts have not been received from some of the speakers. The following outline summarizes the discussion at the workshop.

Exploration

H. T. Meidav pointed out both the assets and the shortcomings of the various geophysical and geochemical exploration techniques as they pertain to reservoir verification. He concluded that the risk in geothermal resource assessment can be reduced by judicious and synergistic combination of geophysical and geochemical survey techniques, tempered by local experience in an area. He pointed out that some failures in geothermal field development in the past were the result of undue reliance on any one survey or interpretation technique to the exclusion of others.

Laboratory Study of Rock Properties

A. G. Duba pointed out that the current state of knowledge of geothermal rock-fluid properties at elevated temperatures and pressures is limited. Yet such knowledge is indispensible in deciphering well log and test information and interpreting geophysical surveys, and in general reservoir assessment. He pointed out the need for some basic laboratory research into geothermal rock-fluid properties.

Well Logging

S. K. Sanyal underscored the urgent need for developing well logging tools that can safely withstand the hot, corrosive environment of a geothermal well; the existing tools are inadequate. He also discussed the inadequacy of the existing interpretation techniques for geothermal well logs. It was pointed out that in spite of these impediments, a reasonable assessment of geothermal reservoir fluid and rock properties can be made from the existing well logging techniques by innovative and synergistic analysis of data.

Well Testing and Reservoir Performance Prediction

W. E. Brigham discussed the various uncertainties in well testing and reservoir performance prediction. For example, he pointed out that while fairly reliable well test interpretation is possible in single-phase reservoirs (dry steam and hot water without any steam saturation), there is no simple analytical technique for well test analysis when both steam and water coexist in the reservoir. He pointed out that there are some basic uncertainties in reservoir performance prediction, because of the reasons mentioned in the Introduction section of this report. However, he did point out the advances made in geothermal reservoir engineering during the past few years and the consequent improvement in our confidence in geothermal reservoir assessment.

Use of Tracers in Reservoir Assessment

O. J. Vetter discussed how introduction of tritium tracer in the injected water and monitoring of the tritium level in producing and observation wells can be powerful tools in geothermal reservoir assessment. He concluded that the use of tritium tracer in geothermal field operations can not only reveal some basic reservoir characteristics (flow patterns in reservoir; location, orientation, and extent of fractures, etc.) but also provide an early warning of breakthrough of cold, injected water in producing wells and allow time for prevention of coldwater breakthrough.

Use of Computer Simulation in Reservoir Assessments

T. D. Riney discussed the use of numerical simulation of a geothermal reservoir as a tool in various aspects of reservoir verification and development. He showed how various forms of reservoir and well bore simulators can answer some of the basic questions posed by utility companies. Thus, computer simulation can help reduce the uncertainty in geothermal reservoir assessment.

Resource Companies' Views

D. R. Butler and G. W. Crosby discussed the various aspects of the risks and uncertainties involved in the assessment and development of geothermal reservoirs as perceived from the point of view of the resource companies. Butler classified the risks to the geothermal resource producers into six groups: prospect risk, drilling risk, evaluation risk, sales risk, development risk, and reservoir risk. He described these risks and pointed out how the resource companies and utilities can work together with a reasonable amount of federal help to reduce their risks and develop a geothermal industry. Crosby pointed out that the resource operator makes every effort to reduce risks because he has to make a large investment in field development, just as the utility has to be concerned about the risks because of the large capital costs involved in power plants. He emphasized that both the utility and resource company should work in close cooperation to reduce these risks and that the time is ripe for decisive cooperation to build a geothermal power industry.

Utility Companies' Views

G. Lombard and A. Martinez voiced the dilemma of the utilities that while on the one hand they would like to promote a geothermal power industry, yet on the other hand it is difficult to make large financial investments in power plants based on a resource that is yet to be proved entirely reliable. They were concerned about the economic viability of the geothermal resource, as well as the assurance of adequate supply over the life of the power plant. In the near future they foresee the basic role of geothermal energy as a supplement to, and not a replacement of, the baseload capacity. However, as the geothermal industry matures, it is likely that geothermal energy may assume a significant portion of baseload supply.

Youngquist expressed the opinion that for the small utilities a small geothermal power plant (10 MWe) may be practical. Even wellhead generators can be used as supplements to the baseload capacity.

ERDA's Reservoir Engineering Management Program

J. H. Howard described the program now being planned that is to be implemented by Lawrence Berkeley Laboratory for ERDA for support of research in geothermal reservoir engineering.

CONCLUSIONS

The basic conclusions of this workshop can be summarized as follows:

- There are basic uncertainties in geothermal reservoir assessment:

  -- lack of data about the reservoir
  -- lack of a data base about geothermal reservoir assessment
  -- lack of knowledge about the "geothermal system" of a reservoir

- These uncertainties can be substantially reduced by proper engineering and basic research.

- Resource and utility companies can work together with some federal help to reduce the risks and uncertainties.

- While the utilities are interested in a geothermal power industry, they are yet to be convinced about the economics and the assurance of future supply of the resource.

- For the near future, geothermal energy will be a supplement to, not a replacement for, baseload energy.

- Small utilities may utilize small geothermal power plants, even though these may be uneconomical for large utilities.

GEOTECHNICAL METHODS IN GEOTHERMAL RESERVOIR EXPLORATION

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INTRODUCTION

The purpose of this brief presentation is to discuss a number of commonly employed geochemical and geophysical methods in geothermal reservoir identification, both their assets and shortcomings. The latter must be discussed explicitly, because lack of appreciation of the pitfalls of each of the employed methods may lead to unwarranted conclusions regarding the existence of a geothermal reservoir, and its expected temperature and volume.

The term reservoir in itself must be cautiously employed. A geothermal reservoir, especially a liquid-dominated reservoir, cannot be likened to a petroleum reservoir, where the resource itself has a definite mass and fairly well-defined boundaries. Petroleum cannot be replenished at a rate that has any meaning in terms of a life of a power plant. On the other hand, a geothermal reservoir may receive very significant contributions of both heated fluid, colder water and heat during the life span of a power plant (one-third of a century). Hence, the definition of reservoir must be made more explicit and must state whether the dynamics of the system (i.e., recharge region of heat and water, and recharge rate) are included in the area defined as a reservoir.

GEOCHEMICAL METHODS

Surface geochemical methods provide important clues as to the nature of the geothermal system in a region, whether liquid-dominated or dry steam (vapor) dominated, whether saline or brackish, whether single reservoir system or a mix of two systems or a dry steam system leaking into a liquid-dominated system. However, assertions based upon geochemical data are fraught with pitfalls due to unfulfilled conditions.

Sampling of hot springs at the surface provides means for determining the base temperature of liquid-dominated reservoirs, and for identifying the presence of vapor-dominated reservoirs. A geothermal reservoir at any given temperature will dissolve a known amount of silica at that temperature. As the reservoir fluid cools from its original temperature to a much lower temperature as it travels towards the surface, it may retain most of the dissolved silica in solution. Thus, the dissolved silica in solution becomes a fossil thermometer, indicating the minimum reservoir temperatures.

One problem with silica thermometry, which may tend to cause an overestimation of reservoir temperature, is that of assuming quartz solubility vs temperature as the calibration curve. If other types of silica, such as opal, cristoballite or amorphous silica are present in an abundant amount in the host rock, the quartz solubility geothermometry would provide an unduly optimistic reservoir temperature estimate.

An unduly pessimistic estimate of reservoir temperature, based upon silica thermometry, may be arrived at when there has been dilution of the original reservoir liquid with shallower, colder ground water; when the actual reservoir temperature is above 180°C (356°F); when the rate of movement of the geothermal liquid to the surface has been very slow, and when a high-solubility of silica (e.g., amorphus silica solubility) has been assumed while quartz solubility would have been more appropriate.

The solubility ratio of Na/K is another often-employed geochemical thermometer. The Na/K ratio in geothermal water is inversely proportional to temperature, for the temperature range of geothermal water. The advantage of the Na/K ratio is that, like any other ratio, it is not affected by dilution by pure water. Yet, many problems may occur in the use of the Na/K geothermometer. The solubility of Na and K in cold ground water is quite different from that in the geothermal range, or alternatively, no equilibrium with temperature is normally attained at normal surface water temperature. However, advance knowledge of equilibrium conditions in the source rock is not known. Hence, other verification approaches are required. Another possible thermometer is the Ca/K thermometer, inasmuch as Ca solubility is inversely related to temperature. Some workers (Fournier and Truesdell) have recommended combining Na-K-Ca into one single thermometer, by using certain empirically derived relationships.

Discrepancy between different geothermometers may serve as a warning that the simplest rules of chemical thermometry are not necessarily fulfilled. Furthermore, an agreement between independent geothermometers in themselves does not provide assurance against fortuitous coincidence.

GEOPHYSICAL METHODS

Electrical resistivity methods, both active and passive, may provide important information on the location of reservoirs and their dimensions, or the occurrence of a heat source nearby and its geometry. Under especially favorable conditions, resistivity data may be employed to provide semiquantitative data on relative salinities, relative temperatures, and relative porosity. Without exception, all known liquid-dominated reservoirs anywhere in the world are characterized by electrical resistivities that are lower than those of the surrounding rocks. Most liquid-dominated geothermal reservoirs are characterized by resistivities less than 5 ohm-meters, no matter how high the resistivity of the surrounding country rock.

Electrical resistivity is affected by five different factors:

(1) Temperature. At temperature ranges of 20-300°C (68-572°F), the electrical conductivity of the electrolyte, the water, provides the main conductive component of the system. Electrical conductivity of electrolytes increases by about 2.5% per degree centigrade. At temperatures near melting (500-1000°C [932-1832°F]), matrix conductivity becomes important. The resistivity of some silicate rocks at melting is 1-2 ohm-meters.

(2) Salinity. Electrical conductivity varies almost linearly with salinity of the pore-fluid.

(3) Porosity. Electrical conductivity increases approximately with the square of porosity.

(4) Formation Factors. Tortuosity of the pore space decreases its electrical conductivity (increasing the 'formation factor').

(5) Clay Content. The higher the clay content, the higher the matrix conductivity of the rock.

Were these five factors totally independent of each other, resistivity studies would be useless in geothermal exploration. In reality, many of these factors vary together, amplifying the effect of temperature very significantly. Thus, as temperature increases, salinity increases, because of the higher dissolving power of warmer water. Porosity may increase because of the higher solubility of rocks at elevated temperature, and hydrothermal alteration may increase the clay-like mineral content of the rocks.

Yet, undue reliance on electrical resistivity alone may result in drilling expensive holes into cold brine pools or large clay bodies. Resistivity must be corroborated by other geological, geophysical, or geochemical data before commitments for deep drilling are made.

Gravimetry has often been employed for mapping of the geological structure in the given area. Gravity lows have been assigned to the effect of melting on density (The Geysers, California), collapsed caldera effects (Mono Lake, California) and increase in sedimentary column thickness. Gravity highs have been related on rare occasions to densification of sediments by hydrothermal fluids and to cold magmatic intrusions. Gravimetry has been employed primarily as an auxiliary structural tool, rather than a direct exploration tool. On one occasion (East Mesa, California, field), gravity data was employed for estimating convective heat flow rates, by ascribing the densification of the rocks to depositioned effects from a cooling convective plume (1). In another case (Wairakei, New Zealand), changes in gravitational attraction over the producing field were converted into a mass-loss estimate and compared to the actual mass loss due to production of geothermal fluids (2). That comparison showed that the gravimetrically-determined mass loss is about one-third lower than the actual mass loss, indicating that significant recharge is taking place. A similar use of gravimetry is being presently made of gravity in The Geysers by the U.S. Geological Survey (USGS).

Microearthquake seismology has enjoyed an increasing utilization as a geothermal exploration tool. Westphal and Lange have observed the empirical correlation between higher microseismicity in The Geysers area and the area of dry steam occurrence (3). Similar reports have been made by investigators in Iceland, Kenya, El Salvador, and elsewhere (see, for example, 4). However, it is important to note that microseismicity can occur extensively in non-thermal areas. Thus, microseismicity is a necessary but not a sufficient condition for geothermal reservoirs.

An even less definite statement may be made with regard to ground noise, the continuous vibration of ground at any point. While some correlation has been shown to exist between ground noise and some productive geothermal areas, the number of high-amplitude ground noise areas has been so large that any statement relating ground noise to geothermal reservoir occurrence must be treated with the greatest caution.

Temperature gradient measurements can be most valuable in delineating promising structures. Yet, the utilization of thermometric data must be treated with the greatest of caution, if any extrapolation is attempted. No extrapolation is ever safe, as data from Marysville, Montana, Dunes, California, San Miguel, Azores, would show. In the first two mentioned examples, a very steep shallow gradient changes into a flat or even negative gradient at depth. In the last case, a very flat gradient changes into a very steep one at a depth of about 100 meters (330 ft). In drilling in highly pervious strata, it is most important to drill to a depth below the zone of desaturation or extensive downward ground water flow. Temperature gradient data in itself is reliable only to the depth that the hole has been drilled and no more. Extrapolations must be always supported by other data.

Integration of a number of techniques, such as resistivity-plus-geochemistry-plus-thermometry will always lead to results that are superior to those from the application of a single method. Judgment and regional experience will determine the degree of success in finding economically viable geothermal reservoirs.

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ROCK PROPERTIES RELATED TO ASSESSMENT METHODS*

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In order to interpret the data obtained from field geophysics measurements as well as well-logging tools that exist or may be developed for geothermal wells, laboratory data under relevant conditions must be available. Since the conditions of the laboratory measurement must closely simulate the reservoir environment, parameters that should be considered independent variables in relevant experiments include, but may not be limited to, rock type, mineralogy, structural state (cementation, fracturing, etc.), temperature, confining pressure, pore pressure, and pore-saturant chemistry. Correct interpretation of field data should provide information on the heat and fluid conductivity and capacity of the reservoir. The ideal situation would be one that provided spatial resolution of these properties in three dimensions.

Laboratory measurement of physical properties at the relevant conditions for a given reservoir should allow interpretation of routine and specialized field measurements. In order for these experiments to be useful, however, samples must be carefully characterized as to pore structure, chemistry, and phase relationships before and after laboratory experiments are performed. Most meaningful physical property measurements need to be supported by petrographic studies, including optical and scanning electron microscopy, chemical characterization by the electron microprobe, and definition of pore structure.

Laboratory measurements of physical properties of rocks under conditions that are relevant to most geothermal reservoirs are either sparse or non-existent at present. The situation for electrical properties typifies the problem. A recent workshop on geothermal exploration concluded, "Most strongly endorsed was a need for comprehensive, high quality, laboratory studies of the electrical properties of rocks under temperatures, pressures, and solution chemistries pertinent to the geothermal environment. Unless we can move off square one in this basic area, the very foundations of electrical methods are in question." (1)

Some data do exist and are useful to gain "first cut" answers to questions concerning permeability, heat capacity, thermal diffusivity, and porosity. A good recent summary of the petroleum literature on these topics, which seeks to apply them to the geothermal problem, is found in (2). However, very few of the results summarized can be applied directly to a particular geothermal system. No complete data set in which pressure, temperature, and pore fluid composition and pressure are varied is available. One has to rely on extrapolation and analogy to get an estimate of the value of a parameter in a geothermal log. And when large expenditures of time and dollars depend on the proper interpretation of such logs, extrapolation and analogy will not suffice. The large reversible decrease in permeability of sandstone to water in the temperature range 21°-150°C (70°-302°F)

*Work performed under the auspices of the U.S. Energy Research & Development Administration under Contract No. W-7405-Eng-48.

which is attributed to "... unsuspected fluid-solid surface attractive forces between water and quartz..." (emphasis mine) exemplifies the problem (3).

Compressional wave velocity (V_p), shear wave velocity (V_s), and compressibility have been measured to about 100 MPa (15,000 psi) and 200°C (392°F) on sandstones and siltstones, some of which were saturated with a KCl brine (4). In addition, they also determined the thermal conductivity at 133°C (271°F) and 3 MPa confining pressure on some of these rocks. Electrical conductivity to 200°C (392°F) and an effective stress of about 7 MPa has been measured on shaly sandstones as a function of brine composition (5).

However, these studies have limited application to geothermal well-log and field survey interpretations. The paramount shortcoming is that the rock types studied have been limited to petroleum reservoir rocks. Igneous and metamorphic rocks have been studied over a much more limited range of pressure-temperature-saturant chemistry (6-9). Another shortcoming is the lack of simultaneous measurement of several physical properties on the same core. Cycling the sample in laboratory experiments produces permanent changes in crack structure, so that sequential information is unreliable for correlating changes in different physical properties when stress or temperature is cycled (10). Such correlations are essential if information on the permeability, porosity, or salinity of a geothermal reservoir is to be inferred from sonic and resistivity logs.

Laboratory data on the variation of the physical properties of reservoir constituents as a function of pressure, temperature, and saturant salinity would be invaluable in the interpretation of field measurements. If such data were available, we would be able to interpret geophysical data in terms of parameters the reservoir engineer needs to know -- the permeability and available porosity of the reservoir. In addition, these data could be useful for designing and interpreting monitoring tools to detect changes in reservoir properties during production. This information would be vital if reservoir stimulation schemes are evolved and employed in geothermal systems.

Specific measurements that need to be performed on typical reservoir rocks as a function of temperature, pressure, pore pressure, structural state of the rock, and pore fluid composition include but should not be limited to:

- ultrasonic velocities
- electrical conductivity
- permeability
- compressibility
- thermal conductivity
- heat capacity
- thermal expansion

Simultaneous measurement of several properties for various durations would be useful.

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COMMENTS ON GEOTHERMAL RESERVOIR VERIFICATION

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Utilities are currently in a dilemma as to establishing a policy with developers which will both promote geothermal resource assessment and yet reduce, as much as possible, abundant financial commitment to an as yet unproven reservoir. Early communication between utility and developer, I believe, is necessary for long-range planning purposes for all parties concerned. Early utility planning will basically view an unproven reservoir as a potential supplement to planned baseload units, such as coal and nuclear.

It is well known that a developer with a yet unproven field does not have all the ideal information a utility would like to see, such as reservoir life, steam price, participated operational performance, price escalation, and so on. Yet the developer can provide the utility, in the early stages of field development, with his long-term plans, such information as the basic location of his efforts, and requests for information he would like to see from the utility, such as utility growth rate, existing and planned transmission routes, and so on. As field assessment is occurring and a better understanding of drilling costs, reservoir extension, and so forth is evolving, contractual terms and degree of utility involvement can better be quantified.

By law, a utility is required to (1) meet load requirements, and (2) do this as economically as possible. Therefore, reservoir assurance is viewed by the utility not only as an economic concern, but also and more importantly, as an availability concern.

It is anticipated that geothermal energy will serve initially as a potentially viable energy supplement and not a replacement. As geothermal growth proceeds and as various field developments occur, confidence will increase and consideration of geothermal energy as a significant portion of baseload supply may eventually take place.

TRITIUM TRACER AS A MEANS FOR RESERVOIR VERIFICATION IN GEOTHERMAL RESERVOIRS

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ABSTRACT

Naturally occurring or man-made tritium can be used to obtain information on reservoir characteristics not available any other way.

Determination of naturally occurring tritium may allow conclusions about a) age of fluid in reservoir, b) flow patterns within the reservoir, and c) natural recharge of reservoir. The shortcomings of utilizing natural tritium for these purposes are explained.

Man-made tritium as a tracer for geothermal reservoir studies is an extremely powerful tool. Tritiated water as a tracer added to the reinjected brine will indicate a number of reservoir heterogeneities such as fractures (number of fractures, fracture directions, fracture conductivities, etc.), other high permeability zones (streaks with higher permeability than the majority of the reservoir) and communications across "impermeable layers" (shale breaks, flow channels behind pipe, etc.).

Tritium tracers will not replace common reservoir engineering methods such as pressure test work. However, it must be seen as a verification method and as a supplement to the common reservoir engineering methods. Its greatest value during actual field operations lies in the extreme sensitivity and accuracy of the tracer determinations. This will allow constant reservoir monitoring at a very low cost. If cold brine (from reinjection) should break through the reservoir, a financial disaster can occur. Tritium tracers will indicate this damage long before the actual cold front arrives at a producer. This would allow remedial measures to be taken before larger financial losses have occurred.

NATURALLY OCCURRING VS. MAN-MADE TRITIUM TRACERS

Tritium (T) is a naturally occurring radioactive hydrogen isotope. Its half-lifetime is comparatively short (12.26 years), and, therefore, the concentration of T in most reservoir fluids is so low that it cannot be detected even with the most sensitive instrumentation. If the reservoir is being charged by waters that have been "recently" in contact with surface waters or the atmosphere (rain), the reservoir water may contain T at various concentrations. Theoretically, and--in a few instances--practically, the precise analytical measurement of these T concentrations can be used to determine a few important reservoir parameters:

1. Age of the reservoir water

2. Natural recharge of the reservoir

3. Flow patterns within the reservoir

Age Determination

An age determination of the reservoir fluid could be made provided all of the four following conditions are met:

a) When recent water (containing T) has entered the reservoir, no mixing between recent (entering) and the old (previous) water is allowed, i.e., a 100% displacement must have occurred.

b) No subsequent mixing of water containing different T contents has occurred.

c) The T content of the recent water at the time of entering the reservoir must be known.

d) The age of the recent water cannot be older than approximately 60 years.

The first two conditions are unlikely to be found in any reservoir.

The original T content of the recent water cannot be known for sure because of the varying T concentrations in the biosphere during the recent history (30 years). Due to atmospheric testing of nuclear devices after World War II and a subsequent stop in the 1960s, the T content in the biosphere went through a steep maximum and is presently leveling off. Pre-bomb T concentrations in the biosphere are not known, due to the lack of sensitive instrumentation during that time. The upper limit of an age determination is approximately 60 years at the very most. Even extremely accurate measurements will leave large uncertainties at older ages, as indicated in Figure 1.

For these reasons, age determinations of reservoir fluids seem to be questionable at the very most.

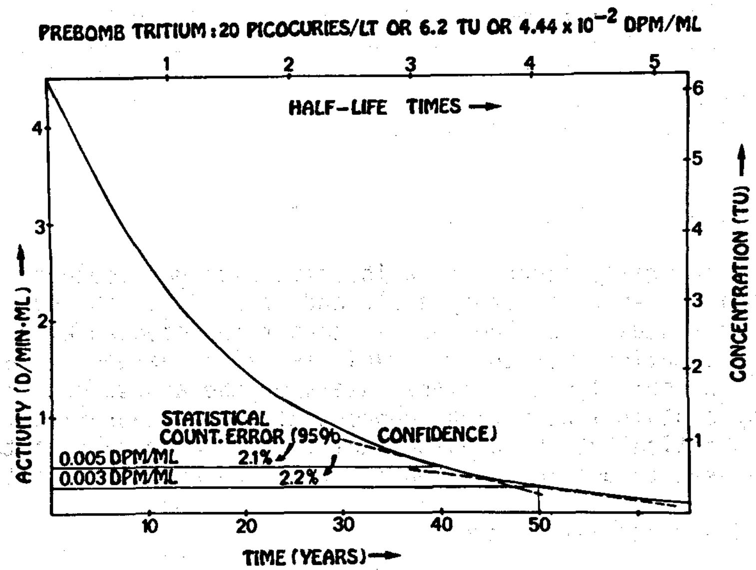

Figure 1. Age Determination by Tritium Measurements

Natural Recharge of the Reservoir

Because of the problems outlined above (mixing of formation fluids, age of brine, and pre-bomb T contents), a recharge of the reservoir could be determined by low-level T measurements only in a very qualitative way. Conclusions as to the precise degree of the recharge cannot be drawn.

Flow Patterns Within the Reservoir

Determination of the flow patterns within a reservoir can also be made only in a very qualitative manner. This data may, however, be sufficient for certain geological or reservoir evaluations.

MAN-MADE TRITIUM TRACERS

The basic objective in the use of tritium as a reservoir tracer in reinjection systems (as opposed to a "huff and puff" type of tracer method) (1) is to find heterogeneities in a reservoir. Many publications have been written on the use of these tracers in water, oil and gas reservoirs (2-6). Only a very few studies have been performed in geothermal reservoirs (none is published). To our knowledge, there has been no tritium tracer study in a liquid-dominated field even though this tracer is perfectly suited for the situations found in these reservoirs. If we assume that the tritiated water will follow the injected water and behave like regular water in the reservoir, a number of reservoir characteristics could be determined in a very elegant way. Heterogeneities such as fractures and high permeability streaks can be found, and many of their parameters can be quantitatively determined. Fracture conductivity, fracture directions, number and size of fractures, or other high permeability streaks are just a few examples.

However, the great value of using tritium tracers lies elsewhere. In order to recover most of the reservoir heat and also to satisfy regulations regarding environmental preservation, we must reinject the brine into the reservoir. Even if this reinjection is planned "properly" using advanced reservoir engineering methods, an early breakthrough of injection fluid can occur, due to unknown high permeability zones in the reservoir or to changes of a number of reservoir characteristics caused by the injection of relatively cold fluid. If the cold fluid advances toward the producer at an "unreasonably" high rate, it will leave behind a "cold front" in the most valuable and critical portions of the reservoir. The problems are recognized when this lagging cold front arrives in the producer. At this time, the major reservoir damage has already been done and the value of the reservoir (recoverable heat) has decreased considerably. Theoretically, all the high permeability zones, that is, the most critical and vital flow channels in the reservoir between injectors and producers, can be cooled down and may render the power plant unoperable. Observation wells between injector and producer will somewhat decrease this risk, but will not eliminate it.

If tritium tracers are injected, they will provide an almost perfect means for reservoir monitoring in this regard. These tracers are not affected by heat or pressure. As soon as they are detected in the produced fluid (observation well or producer), the entire field operations can be evaluated before a major damage has occurred. Rearranging of the injectors and producers must then be considered to prolong the life and yield of the field. Due to an extremely high accuracy of the quantitative T determinations, very little guesswork is involved. The present damage and the future operations could quantitatively and very exactly be determined by using this tracer method. This method may save large investments by prolonging the life of the reservoir and by optimizing the recovery of the reserves within the reservoirs.

SAMPLING AND ANALYTICAL METHODS

Depending on the objectives of the T tracer test, a sampling schedule must be provided. The samples can be collected by any field person according to the sampling schedule. No radiation hazard is involved in the sampling procedure.

To decrease the considerable cost of the analytical work, the samples will normally be stored for a longer time and then mailed to the laboratory where they are analyzed in larger labs. First, a "spot check" is performed, that is, every fifth or tenth sample is analyzed for its T content. The decision as to which samples to analyze for the final reservoir analysis will be made after this "spot check" is completed.

The analytical procedures to determine the inherently low levels of T in the samples call for extremely sensitive instrumentation. Most samples are analyzed with a "Low Level Beta Scintillation Spectrometer." Only a recent and advanced model should be used because of the problems caused by rather complicated chemiluminescence and quench reactions during the actual measurement. Geothermal fluids can be especially bothersome in this respect. In addition, to keep the analytical cost low and the precision of the analyses as high as possible, the instrument itself and the applied procedures must be extremely efficient. A good overall measuring efficiency should be on the order of 65%. The instrumentation should have provisions for the automatic correction (or at least indication) of chemiluminescence or quench problems.

The accuracy of the data is another problem. It will mainly depend on the counting time in the spectrometer which in turn may boost the cost for the analytical work. No data should be accepted unless the "counting error" is stated in the analytical report. Low level T counts can be off by order of magnitudes if the analytical laboratory measures the samples for too short a counting period in order to save on the actual expenses for the analytical work. In most instances, an error limit of $\pm 5\%$ of the total T concentration can easily be achieved with the more sophisticated scintillation counters and if the tracer test is designed properly.

PROBLEMS OF AND INCONVENIENCES WITH TRITIUM TRACERS

Even though the actual injection of tritiated water into a reservoir is a simple and straightforward procedure, certain legal and technical requirements must be met for each tracer job.

Legal Requirements

Only a qualified and licensed person can perform the handling of the T tracer before and during the actual injection. A good knowledge of the legal and technical aspects and extensive practical experience in applying the tracers in the field is absolutely required to avoid the inherent risks in handling the radioactive materials.

The Nuclear Regulatory Commission (NRC) and/or state rules require that handling of liquids (water) containing more than 3×10^{-3} u Curie/ml T demands a special license. Only a general license is required if the T concentration in the water drops below 3×10^{-3} u Curie/ml. This means that every T tracer injection job will be designed so that the "high level" injection fluid will be handled by a licensed person who is fully and personally responsible to the proper governmental authorities for the actual injection and meeting of all legal regulations, including safety measures. The legal authorities (e.g., State Health Department and Division for Industrial Safety) must be notified by the licensed person before any test is performed.

The jobs are normally designed so that the required dilution is achieved immediately after discharge (injection of the "high level" tracer fluid). The "discharged" fluid or the fluids to be sampled can then be absolutely safely and legally handled by any unqualified person. The salt content of the produced brine will pose a much larger health hazard than the T content.

Unfortunately, this procedure requires a thorough knowledge of the tracer injection equipment itself and the operating conditions of the fluid handling in the field (injection rates, pump equipment, wellbore geometry, etc.).

Technical Procedures

The technical procedures for applying the T tracer will vary from test to test, depending upon the field conditions and the objectives of each individual test. The only general rule is the duration of the actual T tracer injection period: it will seldom last longer than 36 hours. However, in a few instances, the field conditions and test objectives may require a deviation from this rule. Some objectives may require a long duration tracer injection (at low T concentrations) as opposed to the more common slug method (using a tracer fluid with high T content for a short time). Sometimes it may be difficult to decide which method (short or long duration) to use. This decision will depend on the type of reservoir, field conditions, and objectives of the study. The slug method is preferable in most cases.

Interpretation

The interpretation of the rough test data can be rather tricky. The job is not done by just injecting the tracer and supplying the reservoir engineer with a plot of data.

Figure 2 indicates a very simple tracer behavior not normally expected in reservoirs, particularly not in a sandstone reservoir such as most reservoirs in the Imperial Valley. Three fractures are indicated in Figure 2. The interpretation of Figure 2 must take into account a) shape of the curve, b) area underneath the curve, c) tracer behavior as a function of surface area contacted by the tracer, and d) contact time. Proper interpretation of Figure 2 will allow conclusions regarding fracture conductivity and fracture dimensions.

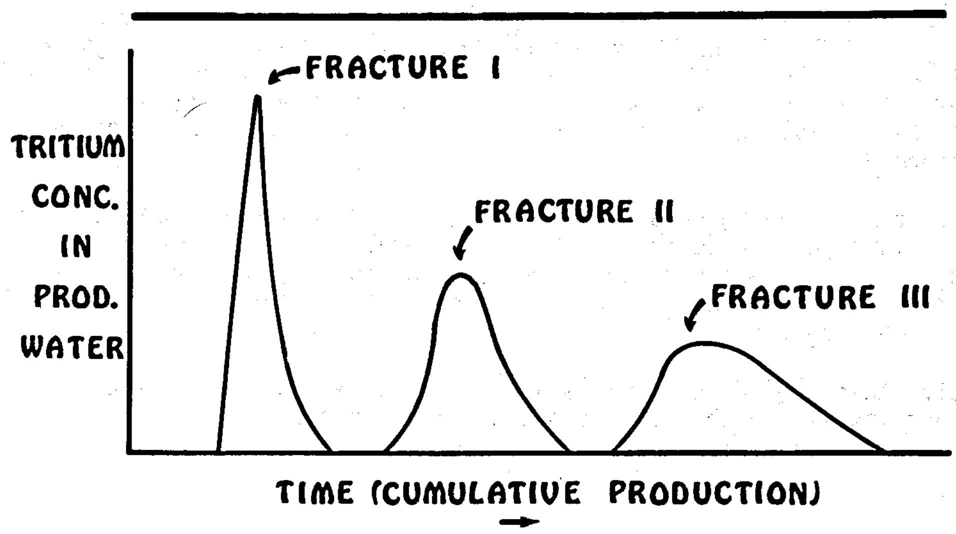

Figure 2. Return Profile of Tritium Tracer from Different Fractures (Same Conductivity, Different Path Length)

The interpretation of Figure 3 is much more difficult and reflects not only certain reservoir characteristics such as high permeability streaks, but also the very special reactions of the tracer itself (7,8). The adsorption-desorption sand isotopic reactions of the tracer (tritiated water) itself must be recognized and properly evaluated. Unfortunately, no precise data of these high temperature reactions of this tracer are published. Fairly simple lab studies could easily resolve some of these problems. For example, the adsorption isotherms could easily be measured (1) and some isotopic effects could be calculated from simple lab tests. The data from these lab studies could be included in the interpretation of actual field data. Thus, additional information will be retrieved from the actual tracer test in the field.

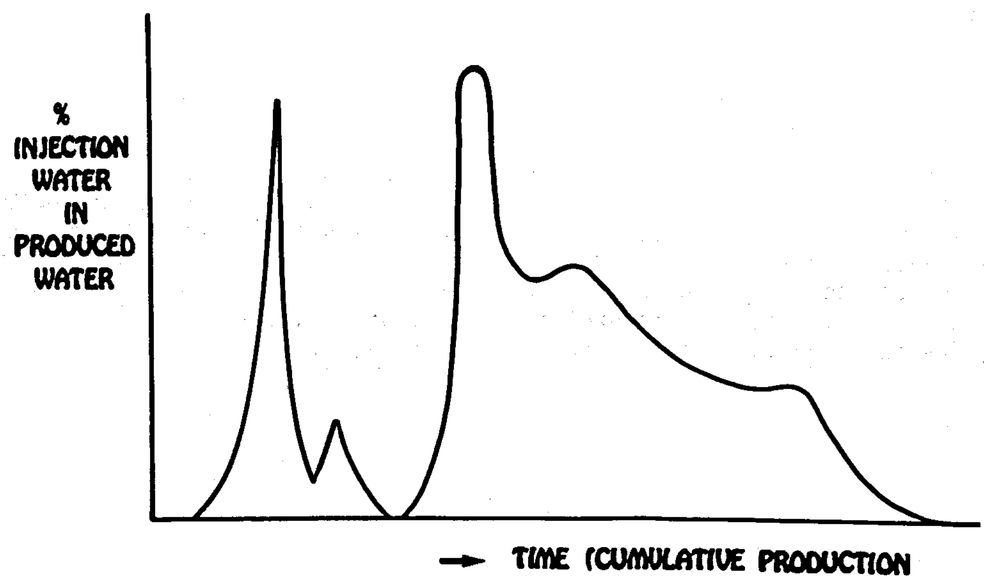

Figure 3. Tritium Tracer Profile in "Stable" Reservoir

CONCLUSIONS

1. Determination of naturally occurring tritium in reservoirs gives only limited information as to a) age of fluid in reservoir, b) natural recharge, and c) flow patterns within reservoir.

2. Tritium injection into the reservoir is an extremely powerful tool to determine certain reservoir characteristics: fractures and high permeability streaks (conductivity, dimensions, direction, etc.).

3. Tritium tracers can give early warning of a cold front breaking through from the injectors. This early indication can be used to prevent major damage to the reservoir by restimulating the injectors in the early periods of reinjection.

4. The high-temperature behavior of any tracer in water-saturated porous media is not well known. Fairly simple lab studies are required to shed some light on the surface reactions at the solid phase.

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GEOTHERMAL RESERVOIR MODELING NEEDS FROM EXPLORATION TO UTILIZATION

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Systems, Science and Software

INTRODUCTION

The decision to proceed with full scale development of a geothermal field will be determined primarily by the confidence that can be placed in its satisfactory long-term productivity. A continuously updated numerical simulation of the geothermal system, based on physical principles and the indirect measurements of the characteristics of the reservoir available at the various stages of development of the resource, can be a key tool in making realistic long-term forecasts. For example, during the exploration and development stage, the natural preproduction flow of the fluid within the system will be dominant, except in the immediate vicinity of any exploratory wells. During the full-scale extraction and utilization stage, however, the effect of the natural flow system will likely be swamped by the flow imposed by the production and injection wells.

PREPRODUCTION RESERVOIR SYSTEMS

For geothermal reservoirs it is necessary to predict both the quantity of fluid that can be produced and its temperature, in order to estimate the total usable energy of the resource. In the case of hydrothermal geothermal systems, the resource is a flowing convective fluid heated at depth and rising towards the surface as a result of the reduced density. The system is not only non-isothermal but also a dynamic system, as a consequence of buoyant flow. The three-dimensional temperature field is profoundly affected by the heterogeneity of the reservoir porosity and permeability (e.g., rock types, geologic structure, faults, etc.).

For realistic simulation of hydrothermal reservoir performance, it is necessary first to establish the preproduction temperature and flow fields. Figure 1 depicts a vertical section of a region within the Salton Sea Geothermal Field (SSGF) that is being modeled at Systems, Science and Software (S^3). By using a reservoir simulator to synthesize the available information, a model has evolved that contains cold groundwater influx upstream into the dipping and thickening upper reservoir and a hot fluid convective source from the hotter lower reservoir. The preproduction velocity field in the upper reservoir calculated from the model is shown in Figure 2. Since the model is only as good as the input physical data, and only very limited information is available, it will need modifying as more information is generated.

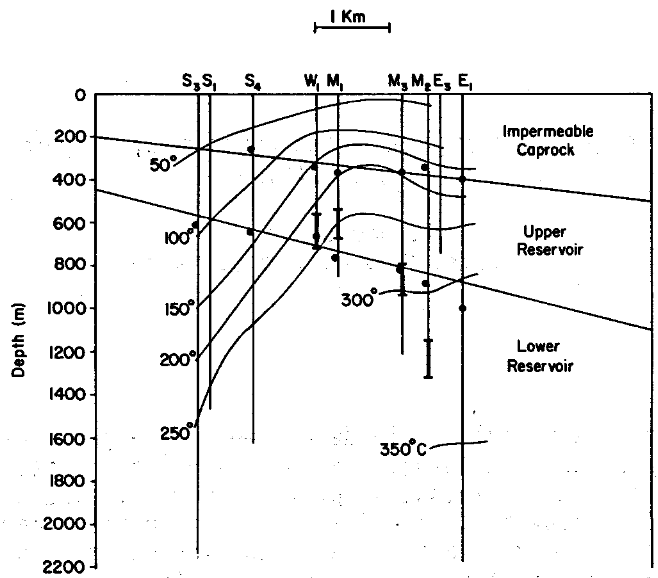

Figure 1. Vertical Section of Reservoir Model and Projected Data from Wells in Portion of SSGF Chosen for Study

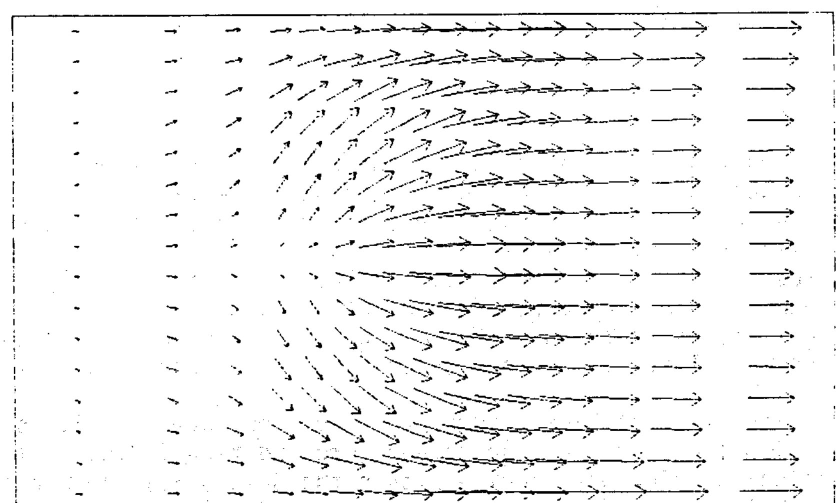

Figure 2. Preproduction Velocity Field in Upper Reservoir of a Portion of SSGF Studied

Geopressured geothermal aquifers in the U.S. Gulf Coast area are isolated by impermeable shale above and below and segmented and isolated laterally by growth faults. The preproduction temperature and pressure head are nearly uniform, and the system is essentially static. Although the initial conditions for reservoir performance calculations are simpler than for a dynamic hydrothermal system, simulation of the reservoir response to extraction is not at all simple. Basically, there are four driving mechanisms which tend to expel fluid from the aquifer (water compressibility, pore collapse, evolution of methane gas, and clay dehydration or "shale dewatering") and two which tend to impede fluid flow (decrease in permeability, which accompanies pore collapse, and relative permeability effect due to evolution of free natural gas).

RESERVOIR RESPONSE SIMULATION

There has been excellent progress at S^3 and elsewhere (1) in developing computer programs, such as QUAGMR, which solve the equations of heat flow and unsteady Darcian fluid flow in geothermal reservoir systems described in one, two, or three spatial dimensions. The work at S^3 appears to represent the current state of the art and has been summarized in Figure 3.

QUAGMR (1975 - 1977)

- Unsteady fluid and heat flow
- Compaction effects on porosity, permeability
- 1-D, 2-D, or 3-D
- Arbitrary stratigraphy, grid shape, boundary conditions
- Multiphase (water and steam) systems

MUSHRM (1976 - Present)

- All of the above
- Also treats multispecies pore fluid mixtures:
    - H_2O (Water-Steam - equivalent to QUAGMR)
    - H_2O/Methane (Water-Dissolved Gas-Free Gas)
    - H_2O/NaCl (Water-Steam-Dissolved Salt-Precipitated Salt)

Figure 3. Summary of Capabilities of Two Reservoir Simulators Developed at S^3 Over Past Five Years. QUAGMR has been superseded by More General MUSHRM Simulator

The numerical method used in QUAGMR properly treats the effects of phase change (liquid $\rightleftarrows$ vapor) within the pores of the reservoir rock (2). Each computational zone in the finite difference mesh may contain a different rock type characterized by density, porosity, directional absolute permeabilities, relative permeability functions, heat capacity, thermal conductivity, porosity-pore pressure relation, and permeability-porosity relation. Provision is made for all practical boundary conditions. QUAGMR was used in a history match study of the Wairakei field in New Zealand (3).

The MUSHRM simulator is a generalization of QUAGMR to include species mass balance and constitutive relations for water/species mixtures. One version includes a methane mass balance relation and constitutive relations for water/methane mixtures. It includes treatment of all the important drive mechanisms in geopressured geothermal aquifers and has been employed to study such systems (4). A second version includes a sodium-chloride mass balance relation and constitutive relations for single- and two-phase water/sodium-chloride mixtures. It also includes provisions for salt precipitation within pores and is being applied to a portion of the SSGF. T_{max}, in Figure 4, corresponds to the hottest part of the vertical section in Figure 1. The corresponding pressures and flash temperatures are shown for water ($s = 0$) and two brines ($s = 0.20, 0.25$). Since the presence of a vapor region within a system strongly affects reservoir behavior, it is clear that the salinity of the brine is an important input to a model, and an adequate constitutive package is essential for realistic modeling.

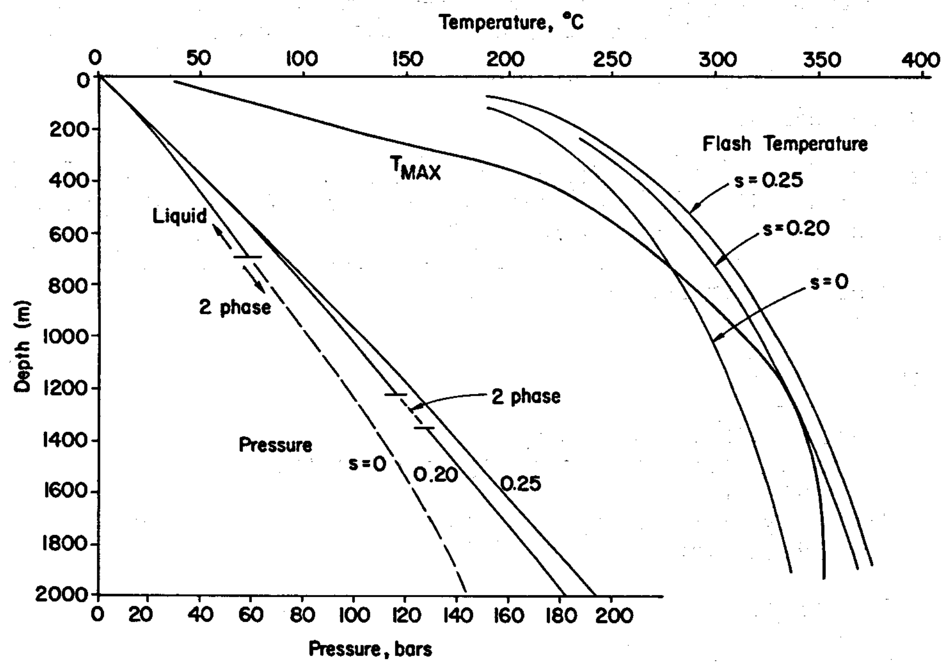

Figure 4. Pressure-Depth and Flash Temperature-Depth Curves Calculated assuming T_{max} Versus Depth Profile and Using S^3 Brine Equation of State for Fluids of Indicated Salinities

WELLBORE/RESERVOIR SIMULATORS

Reservoir simulators provide the average pressure, temperature, and so forth, within each computational zone of the finite difference mesh. To make meaningful predictions of the production at the wellhead of a wellbore perforated within the grid block, it is necessary to relate both the simulator grid block pressure to the sandface pressure and the sandface conditions to the wellhead conditions at the surface. Analytic techniques for calculating the sandface conditions are straightforward for single-phase flow. Since the temperature drop is small and the pressure drop large, however, the actual flow within the grid block may be two-phase even though the grid block conditions infer single-phase flow. The procedures that are commonly used for calculating the sandface conditions for two-phase gas/oil mixtures do not adequately treat this anomaly. At S^3 we use a technique involving subzoning of grid zones containing wells and solving the appropriate relations governing two-phase flow. The procedure accounts for the anomalous case as well as the case in which two-phase flow occurs throughout the grid block.

Several empirical correlations to calculate holdup and frictional pressure drop in vertical two-phase flow have been developed, primarily for gas/oil mixtures. The correlations are based on insufficient data and lead to serious errors when extrapolated to other flow conditions (5); data on flowing geothermal wells is needed. At S^3 we have written a program for wellbore flow of water-steam and water-methane gas mixtures. It is being incorporated into the MUSHRM simulator, along with the procedure for determining the sandface conditions from grid block values to treat coupled reservoir-wellbore systems. Application of such coupled reservoir-wellbore simulators can help interpret short-term pressure tests conducted in exploratory wells.

SUBSURFACE/SURFACE SYSTEMS

Once a hydrothermal field is under significant production, the natural groundwater and convective fluid transport will decline in importance relative to the flow associated with production/injection wells, and the temperature and pressure of the produced fluid will decrease. For example, the production of 500 kg/sec of fluid (corresponding to $\sim$ 50 MWe) from the SSGF upper reservoir would change the preproduction velocity field shown in Figure 2 to that shown in Figure 5. Assessment of the suitability of a site includes estimating the long-term producibility of the reservoirs and the conceptual design of a suitable power plant matched to the changing characteristics of the "fuel" supplied by the reservoir over the design life of the plant.

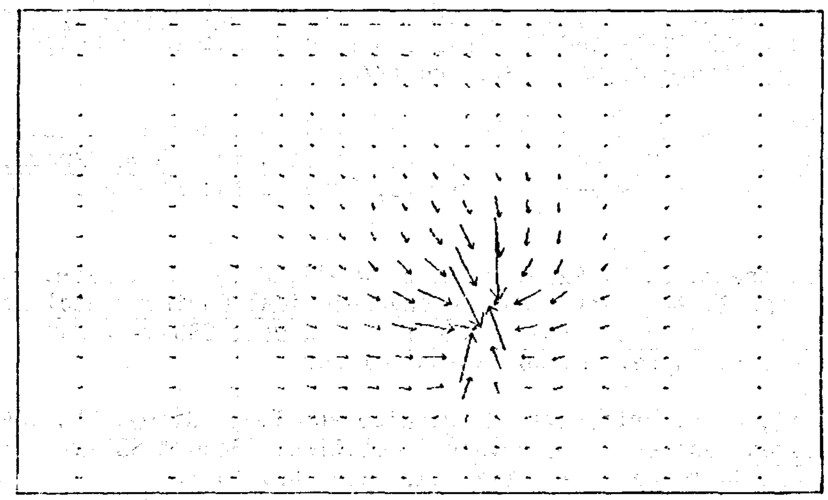

Figure 5. Velocity Field in Upper Reservoir of Portion of SSGF Studied. Simulation Depicted after 6 Months Production of Fluid at the Rate of 500 kg/sec.

Once a site is selected for a demonstration plant and a final design is initiated, it is essential that a more detailed analysis be made of the continuous interaction between the quality of the fuel supplied and the plant design. For example, the detailed power plant design, capital cost estimates, and engineering construction schedule over the design life will be sensitive to changes in the temperature and pressure of the geothermal fluid supplied to the plant. The quality of the geothermal fluid delivered and the quantity required could be forecast by simultaneously considering the reservoir flow, production wellbore flow, and the flow in the surface gathering lines. The treatment of the integrated system requires coupling of computational procedures for analyzing the individual segments.

CONCLUDING REMARKS

It is the author's opinion that numerical simulators for studying reservoir response to fluid production/injection are in fairly good shape. An immediate fruitful area of research is the development of preproduction models for specific geothermal resources. In the exploration and assessment stage of development, uncertainties in the model could be used to suggest sites for exploration wells. Planning of well tests for reservoir verification could be based on resolving major uncertainties in the evolving model. Response of the reservoir under large scale exploitation could be predicted with more credibility if the preproduction situation were matched prior to forecasting its behavior under various production/injection strategies. Such studies may form the basis for operators of adjacent leases to unitize the exploitation of a reservoir system.

Application of coupled reservoir/wellbore simulators to interpret well test data for specific sites is clearly needed. In the near future, the author believes the requirement for managing the fluid production/injection strategy to the needs of a specific power plant will lead to the development of integrated models coupling the subsurface/surface flow system to the power plant processing of the fluid.

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RESOURCE RISKS IN GEOTHERMAL DEVELOPMENT

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Risks that concern geothermal resource producers can be put into these general categories:

- Prospect Risk. For each commercial geothermal field discovered, some large number of prospects must be evaluated geologically and geophysically.

- Drilling Risk. Some percentage of the prospects evaluated geologically and geophysically will be drilled to result in the one commercial discovery.

- Evaluation Risk. Likewise, some percentage of the prospects drilled will require some greater or lesser amount of additional drilling and testing before the producer knows for sure which prospect comprises the commercial discovery.

- Sales Risk. At present, most producers do not intend to generate electricity. Therefore, before development can proceed, a purchaser must agree to buy the resource produced for a price that will allow an adequate return to the producer

- Development Risk. In the full development of a commercial discovery, some unsuccessful wells will be drilled. It is believed this risk will be quite low.

- Reservoir Risk. This can be an area of uncertainty, and the magnitude of risk will probably vary considerably, depending on the specific circumstances.

These simple categories are those which are of immediate concern to producers and do not reflect political, social, economic, and other risks in the real world that are less amenable to quantification.

Natural resource producers are accustomed to prospect, drilling, evaluation, and development risks and are willing to assume the high risks inherent in the prospect, drilling, and evaluation stages if they can expect a return commensurate with the risk.

However, sales and reservoir risks associated with geothermal development are relative unknowns at the present time. It appears that sales risk is highly dependent on reservoir risk, purchasers seem reluctant to enter into a sales contract with producers unless it can be shown that there is little or no reservoir risk. In fact, it appears that most prospective purchasers want some form of guarantee that the geothermal reservoir will produce at acceptable conditions for a period of 25 to 30 years.

Natural resource producers in many instances have geological, geophysical, and engineering staffs that are capable of assessing the reservoir risk, so the producer can decide if the risk justified his considerable investment in wells and the other producing facilities necessary to develop and produce the geothermal field.

Normally, producers will make their assessment of the reservoir risk available to prospective purchasers. However, purchasers are not likely to have in their organization the technical capability to evaluate this information in a manner that will enable them to commit to the considerable investment for construction of power plants and related facilities. Thus, the tendency has developed for purchasers to demand indemnification of the reservoir risk.

Producers are reluctant to indemnify the reservoir for two main reasons. First, producers are taking all the exploration and development risk and assuming a considerable portion of the reservoir risk by their investment in producing facilities intended to last for the life of the reservoir. Second, indemnification represents a long-term liability on the producer's books.

I would like to suggest for consideration a means whereby the risk to the purchaser can be ameliorated. ERDA has in effect a loan guarantee program for geothermal exploration and development. This is one of the vehicles by which the federal government encourages geothermal development during the early higher risk phases. Ideally, as private industry gains confidence through experience, federal participation should phase out.

As regards reservoir risk, ERDA has, or can retain, technical personnel who can assess the degree of reservoir risk inherent in a geothermal development project from reservoir data acquired by the producer. Based on their assessment, ERDA can indemnify the purchaser's reservoir risk by means of loan guarantees for power plant construction. Based on assessment of reservoir data, these loan guarantees would carry considerably less risk of default than guarantees for exploration ventures. Furthermore, the amount of loaned capital at risk under the guarantee would decline progressively as the reservoir proved to be capable of sustaining adequate production over the years of amortization.

The foregoing suggestion would seem to be an acceptable solution to the problem of reservoir risk as it pertains to monetary indemnification of the purchaser's investment in the geothermal power plant. A more perplexing problem is the makeup of lost capacity in a purchaser's supply grid in the event the geothermal reservoir should fail. In this instance, ERDA or other federal participation in the indemnification of reservoir risk would be further required to assure that alternate sources, swaps, and/or purchases of electricity would be made available such that the purchaser would not suffer loss of service or loss of return anticipated from the geothermal installation.

With time and experience in reservoir prediction in a particular province, it is likely that the need for federal guarantees of reservoir risk will diminish. This situation seems to offer one of the few ideal situations under which federal participation is warranted - large commitments to begin with in terms of both provinces and projects, but phasing out completely with time and increased experience on the part of producer and purchaser.

PROVING THE VIABILITY OF THE GEOTHERMAL RESOURCE

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Phillips Petroleum Co.

A comparison is often made between geothermal resource companies and utility companies in which the resource company is cast in the role of engaging in high-risk venturing, and the utility company in the role of making more conservative investments. There is some basis in fact for making this contrast, and for obvious reasons. Nevertheless, utility representatives would no doubt seize on any opportunity to remind us that they are acquainted with risk taking and that no one guarantees their financial success. On the other hand, applying capital to prove the existence of a natural resource that is deeply buried will always be fraught with grave risks. We in exploration learn to accept it and formulate rules designed to win in spite of it. But we are never comfortable with it, and <u>the first point to be made is that the resource operator makes every effort to reduce risks</u>.

We do this by applying state-of-the-art and cost-effective exploration methods, drilling techniques, and reservoir assessment methods. We also apply statistical models and attempt to predict the future in economic analyses. These methods have been reviewed in previous sessions of this conference.

The investment prior to coming on stream with a field and plant is comparable for the resource and utility companies, in the order of $25,000,000 each for a 55 MW plant. To this cost the resource company must add the earlier exploration costs of those unsuccessful prospects that had to be evaluated on the way to that one prospect that is destined for commercial development.

<u>A second point to be made, then, is that it is just as much in the operator's own self-interest to be assured of the viability of the resource before proceeding with field development, as it is for the utility to be assured prior to proceeding with plant construction</u>.

Manifestly, a marriage of the fuel supplier and the utility must be consummated to produce kilowatts. The courtship should begin as soon as the resource company has a discovery that has commercial possibilities. The wedding may take place at the time <u>both</u> are convinced that the resource is durable enough to amortize their respective facilities. <u>Like any marriage, it only works when both win. Negotiating for anything less spells failure, and that is my third point</u>.

<u>Point number four is - - - - the sooner the better</u>. The resource company is in a <u>somewhat delicate position in that it is investing</u> in the resource years before the utility comes on board. We spend today's dollars, which are seriously eroded by interest and inflation by the time cash flow starts. The longer it takes to come on stream, therefore, the more costly the fuel, if the project goes at all. A negotiated steam price must reflect these sunk costs that rise in time with the leaven of inflation and the time value of money. Both of us, along with the consumer, are interested in a lower, competitive, product price.

The greatest single source of delays stems from governmental regulation. Geothermal fields in the Philippines, for example, are going on stream in four to five years, whereas in this country seven to eight years or longer separates first exploration surveys and first kilowatt produced. Ideally, the resource and utility companies should combine forces at an early stage to streamline a program to grapple with the excessive body of regulations and the multiple agencies and to assure that there are no delays in addition to the legal and institutional barriers.

But because of these inevitable delays economics demands that sunk costs, that is, costs incurred in proving the resource in the ground, be kept to a minimum until the latest possible moment. This means that the geothermal operator will drill only enough holes and perform only those reservoir tests adequate for demonstrating the quantity and quality of the resource to his own satisfaction and to inspire the confidence of the utility. The final holes and surface facilities are made ready while the plant is under construction. A fifth point, then, is let us decide what kind of information and how much of it is necessary for a clear demonstration. That's why we are here.

Nothing said so far purports to be profound. These simple axioms are part of economic reality. And the whole point is, we can cope better together. The resource company is ready, indeed eager, to furnish what information you need and to make the utility a party to the demonstration when an interest in participating in development of the new resource is shown.

PROVING THE RESOURCE

The viability of the geothermal resource, measured in terms of quantity, quality, recoverability, longevity, and economic constraints, is a prime consideration from the time first exploration activities are planned and continues through deep exploratory drilling and reservoir testing. The exploration program is designed to generate information bearing not only on the existence or nonexistence of subsurface heat but also on the nature of permeability and porosity, the dominant phase, temperature, and chemical aspects of reservoir water, depth and areal extent of the reservoir, and recharge characteristics. Preliminary economics are run out on the basis of these findings before the second and third phases, exploratory drilling and reservoir testing, are entered.

Exploration Program

Phillips Petroleum Company's geothermal exploration program is based on three core surveys; namely, water chemistry, magnetotellurics, and heat flow. All prospects that continue to show promise are investigated by these three methods. Any additional tools that might be run on a given prospect are ad hoc surveys designed to answer specific questions for that prospect.

Water Chemistry. Water is sampled, where available, from springs, wells, and perennial streams in an extensive region surrounding a locality where surface indicators, recent volcanics, and hot springs, for example, suggest the possible existence of a reservoir. Unstable compounds and the physical properties of the water that are apt to change under the new P-T conditions at the surface are measured in the field. Samples are then brought to the laboratory for additional analyses (3). Altogether some eighteen different measurements and analyses are carried out on a routine basis, and other analyses are undertaken as the local situation dictates.

The appropriate compounds are plotted in Piper diagrams to determine the chemical populations extant in the region. Each sample location is then plotted on a map with a symbol designating the population to which it belongs. This distribution is interpreted in terms of possible origin of its chemistry, with particular emphasis placed on man's activities in the basin and known subsurface geology, as well as anomalous shallow crustal heat. Maps are also prepared showing distribution of concentrations of certain marker compounds or elements. These interpretations are made with the aid of a map of the piezometric surface in the basin.

Various combinations of compounds, ratios of compounds, and physical properties are graphed against each other to study mixing of waters originating as distinct family types, among other things. Various statistical tests are carried out on the combinations. Finally, geothermometers are calculated (5) and interpreted, often applying subjective judgment prompted by the above findings. Thus, information on focus of a possible heat source within the basin, the dominant phase of the water, lithologic aspects of the reservoir, and temperatures are revealed in the water chemistry.

Magnetotellurics. The magnetotelluric (MT) method determines electrical conductivity distribution in the subsurface from surface measurements of natural transient electric and magnetic fields. The time variations of the earth's electric and magnetic fields at a site are recorded simultaneously over a wide range of frequencies, commonly .001 to 8 Hz, on digital tape. Later, in the office, the variations are analyzed with the aid of a computer to obtain apparent resistivities as a function of frequency contained within the wavelength spectrum.

Electric field measurements are made by determining meter differences of potential between two mutually perpendicular sets of electrodes a few hundred feet apart. The electrodes are small lead plates buried to a depth of about one foot. Magnetic field measurements are accomplished with three mutually perpendicular induction coils, approximately three feet long and four inches in diameter. These are commonly buried just below the surface so that wind shaking the coils will not generate magnetic "noise."

Interpretation consists of matching the computed plots of apparent resistivity against frequency to curves calculated for simplified models. The MT method depends on the penetration of electromagnetic energy into the shallow subsurface. Depth control is a natural consequence of the greater penetration of the lower frequencies.

Conductivity increases with increasing temperature of reservoir water, salinity, and shaliness. Thus, not all conductive regions in the subsurface express the presence of heat. Anomalies must be interpreted with caution, applying what is known about the subsurface. As a general rule, however, salinity increases with temperature. Moreover, if thick shale sections and/or evaporites occur in the regional stratigraphy, the geologist is apt to be aware of it.

Ideally, then, the areal extent of the geothermal reservoir and its approximate depth and thickness are reflected in the MT field. In some cases, information on a deep seated heat source is revealed in the MT data.

Heat Flow. Shallow holes, averaging 91 m deep (300 ft), are drilled on the prospect for the purpose of making temperature measurements. Normal crustal gradients in the western United States are approximately .66°C/30 m (1.5°F/100 ft). We look for something in excess of this value by five to ten times, or more. Initially, ten holes, more or less, are drilled, but as a thermal anomaly develops, additional holes are drilled to define it adequately. This requires that temperatures be measured and gradients determined concurrent with drilling, except for a small lag time to allow rebound from the temperature disturbance caused by drilling. If hydrologic or other problems are suspected, a 600 meter-deep (2000 ft) observation hole may be drilled.

Temperature gradients are plotted and contoured to show the extent of the anomaly. Where viable geothermal reservoirs exist, it is common for hot reservoir water to leak into shallow aquifer(s) and spread laterally. Thus, shallow gradient holes bottoming above the hot aquifer may have anomalously high gradients, yet be offset from the reservoir. It is important, therefore, to check correlation between gradients and the magnetotelluric conductivity anomalies to arrive at the best estimate of the reservoir size and to determine the most probable cause of the MT anomaly.

Thermal conductivity measurements are not routinely undertaken by Phillips. Where the refinement that accrues from heat flow determinations, as opposed to gradients alone, answers critical questions, these measurements are made by either the needle probe or the divided bar apparatus.

Additional Surveys. Other surveys that may be undertaken, including gravity, magnetics, active and passive seismics, soil gas surveys, isotopic studies, petrologic investigations, and other types of electrical surveys, may provide information on gross stucture of the geothermal occurrence, distribution of igneous rocks, active tectonics, convective systems, fracture systems, hydrology, alteration, phase relations, and geologic ages.

Ideally, the progressive assimilation of new data narrows the field of working hypotheses and allows them to converge on the best geologic interpretation (1). If this model includes a geothermal reservoir with commercial parameters, a drill site is selected, and a recommendation is made to test the model by deep drilling.

Exploratory Drilling

Deep drilling, 1220-3050 m (4000 - 10,000 ft), is undertaken with oil field-type drilling rigs and drilling procedures (4), modified slightly to accommodate anticipated high temperatures. Drilling is a continuous problem solving exercise, and no two holes are drilled the same way. Commonly, a conductor pipe, surface pipe, and a production string are successively run and cemented in the borehole as drilling proceeds. The blowout prevention stack is installed on each string in turn. Below the production string, terminating at depths in the order of 457-1372 m (1500 - 4500 ft), the hole is, more often than not, completed open hole.

During drilling, the mud returns are continuously monitored for temperatures and gases, including CO_2, H_2S, and combustibles. Filtrate resistivities are measured, chemical analyses are carried out for elements that have distinct affinities with geothermal reservoirs, a lithologic log is kept current with drilling, and drill rates are logged. The complete drilling history includes a record of lost circulation and all measurable fluid loss or gain. At projected depth, a suite of electric and temperature logs are run. From time series measurements, equilibrium temperature, which will be attained after rebound from the drilling disturbance, is calculated.

Thus, having generated a large mass of information during the drilling operation, the presence of a reservoir and the quality of the resource is indicated. A short flow test is carried out with the rig in place to characterize the production from the reservoir encountered through the prepared borehole. With favorable data from all these sources, one or more confirmation hole is drilled.

Reservoir Testing

With several holes drilled into the reservoir, an interference test is initiated in which one well, commonly, is flowed, while instruments in the others monitor pressure drawdown during flow and buildup after the well is shut in (2). These time series data reveal the transient wave that moves through the reservoir from the disturbance at the production well. Computational and graphical methods have been worked out whereby reasonably close estimates can be made from these data for permeability-thickness product of the reservoir, distance (and sometimes direction) to boundaries, reservoir volume, recharge, and well productivity. Phillips has used a variety of pressure measuring devices; the Hewlett-Packard quartz pressure transducer, however, is judged to provide the greatest accuracy at approximately $\pm$ 1379 Pa ($\pm$ 0.2 psi) resolution.

While these transient data are being obtained, a variety of information is gathered at the flowing well. Wellhead flowing pressures and temperatures are logged, flow rates versus back pressure and through various orifices are determined, mass flow and steam fraction are measured, steam quality is determined by calorimetric methods, and fluids are sampled and analyzed to determine detailed chemistry and types and amount of noncondensable gases.

Phillips has used two systems to obtain flow data; namely, a steam-water separator with measuring devices in each line and a lip-critical apparatus that permits measurements of mass flow. The method utilizing the separator is standard; however, we have tested both systems connected in series to check comparability. The results are within ten percent of each other with mass flows up to 126 kg/s (10^6 lb/hr). This favorable comparison justifies the use of the simpler lip-critical apparatus in testing exploratory wells, and Phillips has fabricated a single-unit, skid mounted, integrated test module that can be trucked to any well site.

The exploratory, drilling conclusions flow test programs thus provide reliable data on which reservoir size, longevity, production characteristics, and steam quality can be estimated. This data base permits sophisticated economic analyses to be carried out by both the geothermal resource company and the utility. The data are adequate to estimate the life of the field and establish both design criteria for the plant that will utilize the steam and optimum well spacing, which dictates the layout of plant and gathering facilities.

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THE ERDA-DGE/LBL GEOTHERMAL RESERVOIR ENGINEERING MANAGEMENT PROGRAM

J. H. Howard
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INTRODUCTION

Lawrence Berkeley Laboratory (LBL) has been assigned responsibility by ERDA/Division of Geothermal Energy (DGE) for developing and then implementing a plan for support of research in geothermal exploitation engineering. Although historically refered to as REMP (Reservoir Engineering Management Program), the scope of the activity encompasses many aspects of geothermal exploitation engineering; and reservoir engineering (as traditionally defined to include well testing and modeling mass and energy transport) is, in fact, a subset of the whole program.

A diagram showing the elements that make up the program is shown in Figure 1. The elements are shown in boxes on the figure.

PURPOSE OF THE ACTIVITY

The ultimate purpose of this activity is to establish a higher level of capability than currently exists in all the elements shown in Figure 1. The figure shows the key questions facing an exploiter of geothermal resources. The elements for which planning for research is being done form the basis for answers to these questions. Of fundamental importance are the questions:

- How large is the resource?
- What is the spatial distribution of temperature, porosity, permeability, and other parameters that are important to understanding the resource?

Knowing the answers to these, the question of primary importance then becomes: How will the resource behave in the future, as it is produced to service the needs of an electric generating power plant or a nonelectrical application?

Ultimately one would like to have a reliable plan for exploiting a given resource - reliable in the sense that the plan can be done technically in an environmentally acceptable way and that it is a financially attractive thing to do.

PROCEDURE IN DEVELOPING THE PLAN

In order to improve existing capabilities--to conduct and interpret borehole geophysical surveys, for example--it is necessary to understand first of all what an existing capability really is, then envision a desired status, and finally generate and implement a way "to get there."

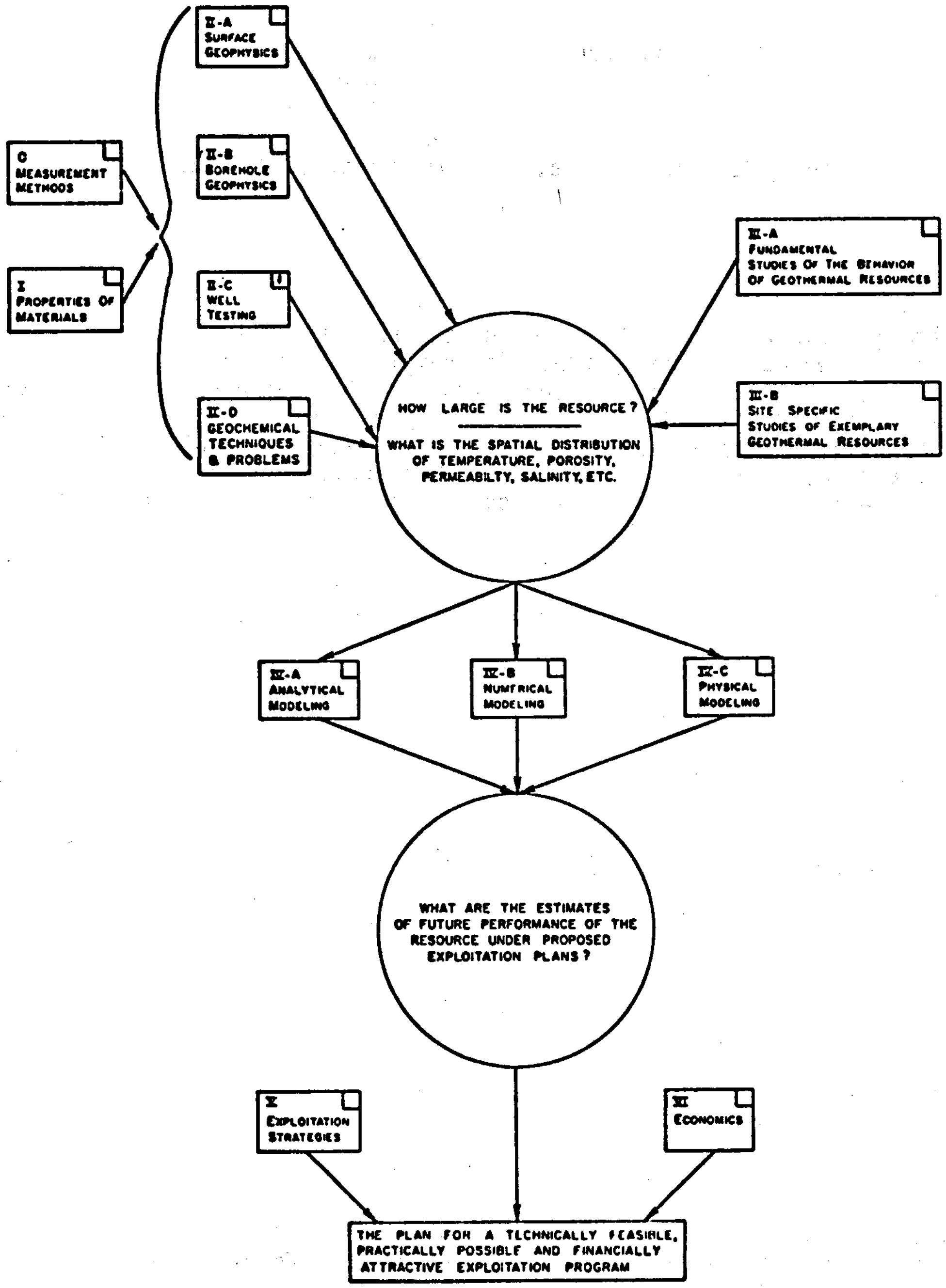

Figure 1. Overview of Geothermal Reservoir Engineering Program

The procedure used by REMP is similar to that used by another LBL management activity to develop a research plan for subsidence due to production of geothermal resources (1). The procedure involves an iterative method between a planning group and a review task force.

The planning group, on the one hand, develops various draft plans. The review task force, on the other, is responsible for commentary on the drafts and for a statement in general terms regarding the completeness of the plan and the priorities of the tasks identified in the plan. The final form of the plan will incorporate improvements resulting from exchanges between the planning group and review task force. The document will include a statement of all tasks that should be carried out and an assignment of priorities to each of them. The product of all this activity is a document to be used as a guide in supporting research in geothermal exploitation engineering.

IMPLEMENTATION OF THE PLAN

Development of a planning document is only a part of the overall program. Implementation of the plan is also the responsibility of LBL. It must be done in view of the constraints imposed by the following factors:

- availability of ERDA/DGE budget for this purpose
- existence of ongoing federally funded research on certain tasks
- the availability and suitability of contractors to carry out various research tasks

Items identified as first priority items will be supported as funds allow in fiscal year 1978, which will be the first year of implementation of the plan. Contracts for various research tasks will be determined by public announcement of requests for proposals (RFPs). Technical personnel and administrative personnel, principally but not exclusively from LBL, will be called upon to review the proposals and negotiate acceptable contracts for research work.

It is expected that the plan will evolve with time and that after fiscal year 1978 needs for research and availability of qualified researchers will guide the budgetary needs of the program.

LBL is also expected to monitor progress of the contracts and to assist in dissemination of research results.

The review task force has been asked to continue its service into fiscal year 1978, to provide commentary of the way in which the plan is actually being carried out, and to suggest new directions of effort, as appropriate.

BUDGET

During fiscal year 1977, the principal implementation activity under this plan has been to assist in the continuation of support to geothermal projects initiated under the National Science Foundation's RANN program. These responsibilities were assigned to ERDA/DGE upon formation of ERDA. The budget for such continuations was approximately $500,000. Work at Stanford, University of California - Riverside, Princeton University, University of Colorado, and Systems, Science and Software were supported.

During fiscal year 1978, the budget for implementing the plan is anticipated to be in the range of 1 to 2 million dollars.

INTERACTIONS WITH OTHER GROUPS

It is important to realize that although this entire activity is under the supervision of ERDA/DGE, its implementation will take place with cognizance of activities of other groups. The work being supported by EPRI is included among these other activities. It is clearly ERDA/DGE's desire to work effectively with EPRI to enhance the establishment of the capabilities noted in Figure 1 and to disseminate new knowledge.

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Section 5

WORKSHOP:
PRICING OF GEOTHERMAL ENERGY

Pricing of Geothermal Energy Workshop
Panel of Speakers

Chairman: Paul Kruger
Stanford University

Panelists:

David Anderson
California State Energy Resources
Conservation and Development Commission

Harold Bell
Arizona Public Service

Ann Corrigan
Portland General Electric Company

William Dolan
AMAX

Harry Falk
Magma Power Company

Robert Grieder
Chevron Resources Company

PRICING OF GEOTHERMAL ENERGY
WORKSHOP PANEL REPORT

Paul Kruger, Chairman

The panel convened to review the various philosophies and approaches to the pricing of geothermal energy for the generation of electric power. In most countries of the world, the price of the electricity is set by many factors, among them the economy of the nation and the costs associated with the general national energy situation. In those countries where the energy resources and the facilities for electricity production are state-owned, the breakdown of costs between resources and generation may be internally decided. In the United States, the energy resources and the electricity generating and distributing facilities are generally owned by different entities. The electric utilities purchase the energy resources as independent operators. The price of major fuels, such as oil, gas, coal, and uranium, are generally set in the international marketplace. Because of the nontransportability of geothermal heat and the limited extent of its utilization by utilities, the price of geothermal fluids for electrical energy production must be arranged on an individual, local basis. Further creating a complex arena in which such arrangements can be executed are the institutional differences among the concerned parties, that is, a utility, generally considered to be highly regulated, an energy resource company, accustomed to high-risk resource development, and the levels of federal, state, and local government agencies involved in licensing and regulation. Thus many possibilities exist in the quest to find a suitable policy for the pricing of geothermal fluids. The panel, consisting of three members of the resources industry, two members of the electric utilities, and one member of a state energy commission presented the following views.

The price of energy delivered to a geothermal plant should be dependent on the thermodynamic properties of the fluid as well as such factors as reliability of supply and price of other available fuels. The price could be determined by the net quantity of heat delivered (e.g., in millions of Btus above some negotiated reference temperature). This method puts the cost of energy to the utility in the same framework as other fuels and encourages the utility to improve its efficiency in terms of the number of geothermal Btus required per kWh. (See details in the Summary of Greider.)

An alternate concept considered pegging the price of geothermal energy to a stable resource, such as coal, in order to allow for changes in generating efficiency over the life of the "fuel" contract. Provisions for reduced or improved performances, such as changes in fluid enthalpy or turbine efficiency, would be added to allow the producer and the utility to share in the resultant change in total electricity cost. A formula to relate such changes relative to the cost of producing electricity by coal was proposed. (See details in the Summary of Dolan.)

A third concept, for pricing geothermal fluids, especially for the more technically uncertain hot-water resources, is adaptation of the pricing policy used at The Geysers steam field, in which the return to the supplier is determined by formula of the costs of alternate fuels available to the utility, adjusted for the differences in plant costs. Under such a contract the return (in mill/kWh) is determined by the output and efficiency of the plant, which would be required to be operated "as close to full capacity and as continuously as practical . . . ." (See comments in the Summary by Falk.)

A fourth concept is making the geothermal resource producer responsible for the generation of electricity, in which the price of the electricity at the busbar becomes the subject of the negotiation between supplier and utility. This method could be useful to the utility short in capital or with little experience in the production and conversion of geothermal energy and useful to the producer who can manage the production/conversion cycle with greater efficiency. (See details in the Summary of Bell.)

A fifth alternative among these field-plant relationships is for the utility to purchase part or full ownership of the geothermal resource. In this system the utility has greater control over resource development and availability but incurs greater risk. The acceptability of such risk under present public utility commission systems is uncertain. (See details in Summary of Corrigan.)

The possibility of governmental regulation of wellhead prices for geothermal steam has been raised by the state of California. An early study recommended that wellhead price regulation of geothermal energy would not provide more equitable pricing in the public interest, nor would it accelerate the use of geothermal energy in any way. However, the possibility of regulated pricing remains as one of the philosophies and methods of the pricing of energy. (See details in Summary of Anderson.)

Several approaches to the pricing of geothermal energy were raised by the panel. There are others. In the U.S. framework of a resource producer providing a "fuel" for conversion to electricity by a utility, the possible arrangements for pricing are large in number. The costs of producing geothermal fluids are uncertain and vary by resource type. The costs of generating electricity are also uncertain and vary by conversion technology. Cooperation between producer and utility is evidently needed. Arrangements can range from utility ownership of the resources to electrical energy conversion by the developer. Advantages and disadvantages are apparent for any combination. Therefore, pricing arrangements also require a high degree of cooperation and trust between producer and utility with the general concurrence of the pertinent regulatory agencies. The panel has made a first step in bringing this complex problem into the public forum. EPRI should be encouraged to continue the dialogue between the interested parties.

BUSBAR CONTRACTS FOR GEOTHERMAL

Harold Bell
Arizona Public Service Company

One relatively simple and convenient method for a utility to obtain geothermal electric power is to buy it as busbar power. In this situation, the utility contracts with a developer/supplier of geothermal power who has taken all of the risks of developing and producing the power and then simply sells it as busbar power. In this case, the utility can be relieved of the responsibilities of operating in areas in which it may not be familiar and of making capital outlays in the areas of high risk. The interaction with state and federal regulatory agencies relative to the cost of the resource and its utilization may also be simplified. Generally, the contract is based on a take-or-pay basis, contingent upon a reasonable geothermal energy source being found and developed.

Several organizations are taking this generic approach to marketing a geothermal project. One such company is Diablo Exploration of Oakland, California. It has approached many of the western utilities and is actively working with some. A commitment by Public Service Company of New Mexico is the basis for an application under the federal geothermal loan guarantee program.

In a typical contract for this type of project there are specific responsibilities for the resource/power vendor. These usually include:

- Find resource and drill wells
- Test resource
- Get lease or ownership of property
- Do design and engineering of production field and power plant
- Get permits and regulatory approval
- Arrange financing for plant
- Obtain construction contractor and build plant
- Start up production field and electric generation plant
- Test run electric plant
- Make electric power available at plant boundary

The utility company also has some responsibilities. These usually include:

- Obtain necessary regulatory approval for contract

- Provide interconnection and step-up transformers to accept power; operate and maintain this facility

- Work closely with the vendor on design, construction, and operation of the plant

- Buy plant electric output

This type of contractual arrangement has many advantages and disadvantages both to the vendor and to the utilities. The following is a list of some of the advantages to the utility:

- Interface with only one vendor or contractor

- Minimum risk if no resource is available

- Minimum capital risk

- No obligation on field or plant development or construction cost

- Minimum plant size (i.e., 50 MW)

- Site compatibility (i.e., service territory vs. long transmission lines)

- Fixed price plus fixed or controlled escalators

- Regulatory roll-in of price; off balance sheet handling of cost

- Predictable cost increases for plant and field operation and maintenance. An agreeable economic indicator can be used. Changes in ad valorem and income taxes are more difficult to predict.

- Long-term contracts (i.e., 30 years, then year to year renewal)

- Right of refusal on lease or purchase of power plant after five years

- Right of first refusal on additional capacity from expanded resource base

Some of the possible disadvantages to a utility are as follows:

- Higher total electric power costs, due to the lack of utility financing and the higher return necessary for risk capital

- Lack of control of fuel costs

- Lack of control of operating and maintenance costs

- Requirement to use output on take-or-pay basis for 30-year contract. Load may shift or cost may become noncompetitive.

- Limited lead time on acceptance of electricity (i.e., 36 months to build substation and transmission lines)

- Limited use of specific technology (i.e., inability to build utility's own plant using some technology incorporated in vendor-built plant)

- No termination liability protection (though could be factored into contract)

- No guarantee of available electric output from plant (a penalty factor could be incorporated into the contract, however)

- No overall control of plant with total system interaction (i.e., cycling, voltage control, power sales to other utilities, etc.)

- Limited opportunity to obtain complete control of resource or power plant

The power purchase contract does have some advantage to specific utility companies. When they lack staff or expertise to be able to explore, develop, and build geothermal plants, the contractor or vendor may supply this need efficiently. It is possible that utilities may be experiencing difficulty in arranging large capital outlays. This approach can significantly reduce their capital requirements. In any case, it allows the utility company to get into the business of using geothermal energy when it may not be able to do so under the normal business constraints of fuel supply and power plant construction.

ESTIMATING THE VALUE OF A GEOTHERMAL RESOURCE TO AN ELECTRIC UTILITY

Ann E. Corrigan
Portland General Electric Company

INTRODUCTION

The decision of an electric utility to accept a particular price for a geothermal resource depends on the "value" placed upon that resource by the utility. This "value" includes a variety of factors, some of which consist of different portions of the cost or price of the resource, but many of which are not directly related to the cost of the resource, and some of which are intangible and thus difficult to quantify. A decision whether or not to invest in a geothermal resource would depend upon all of these factors. The facts considered by a utility in evaluating and comparing alternative sources of electricity are presented below, and an evaluation of geothermal energy is given with a view toward identifying some of its advantages and disadvantages, and some of the difficulties that would have to be resolved in a pricing arrangement. The particular viewpoint taken is that of an investor-owned utility in the Pacific Northwest - Portland General Electric Company (PGE).

CHARACTERISTICS OF GEOTHERMAL ENERGY

Several characteristics peculiar to the geothermal industry are considered important in an evaluation of geothermal energy. The most often noted of these characteristics is the requirement that geothermal energy be used where it is produced, and, therefore, that a power plant to convert geothermal fluids to electricity must be built at or near the reservoir. This results in a relationship between field producer and power plant operator that has been characterized as a "one market-one supplier" situation; this relationship poses certain constraints on the types of field-plant arrangements that are viable.

Another significant characteristic of geothermal energy is the relatively small optimal plant size - on the order of 50-100 MW. While this characteristic is disadvantageous from a utility's viewpoint because economies of scale are not possible, this property of geothermal power plants also has advantages in terms of greater flexibility of scheduling and reliability of operation.

The nature of geothermal reservoirs is such that in most cases wells will have to be run continuously, resulting in decreased flexibility in the operation of the power plant. Geothermal power plants are not expected to be load-following. It may be possible to operate wells continuously while at times bypassing the power plant and directly reinjecting the fluid into the reservoir; however, the extent to which this practice is possible and the effect of such a practice on the quality and longevity of the reservoir is difficult to predict at the present time. It may also be possible to control the flow rate of wells, particularly pumped wells, or to turn off the wells during seasonal periods of low energy demand. However, our current state of knowledge is such that the feasibility of these options is uncertain.

The relative youth of the geothermal industry, compared with more traditional forms of generation, also must be considered when estimating the value of a geothermal resource to an electric utility. Large uncertainties exist with respect to the cost of the resource and to the size, reliability, and longevity of the field. Because of the unique relationship between field producer and utility noted above, uncertainties with respect to the size and life of the resource are especially significant. Utilities will need to have some assurance that the fuel supply exists and is reliable, or else must factor this aspect of risk into the revenue requirements for a geothermal power plant. On the other hand, geothermal energy is one new fuel alternative that appears to be commercially viable now or in the near future and as such should be given serious attention by utilities.

For an Oregon utility, geothermal energy has a special attractiveness in that it is one of few fuel resources indigenous to that state (besides hydroelectric power; Oregon has only a few minor coal deposits). Finally, although some environmental difficulties exist, these difficulties appear to be surmountable and, on the whole, geothermal energy appears to be an environmentally acceptable resource. These characteristics may help to make it an attractive fuel alternative to government and the general public.

OPTIONS FOR OBTAINING GEOTHERMAL ENERGY

Three basic options exist for a utility considering investment in geothermal energy. The "classic" arrangement is where a resource company explores, develops, and operates the field, and sells the fuel to an electric utility which builds and operates the power plant and transmission lines. Alternatively, a utility might purchase part or full ownership of the field and thus be responsible for development and operation of both field and power plant. A third possibility is for the utility to purchase busbar power from some company who owns and operates a power plant producing electricity from geothermal energy. In this third alternative, the utility would still be responsible for transmitting the electricity to the load center. The costs, benefits, and risks to a utility (and consequently the "price" acceptable to the utility) differ for each of these three alternatives.

CRITERIA USED IN COMPARING GENERATION ALTERNATIVES

The financial criteria used to evaluate generation alternatives can be summarized as follows. The major goal is to minimize the cost or the revenue requirements, levelized over the life of the plant, for the generation of electricity, usually expressed in $/kW-yr or mills/kWh. Given a "best estimate" for the levelized revenue requirements, a second major goal is to minimize the risk associated with the cost of the resource; that is, to consider the range or the probability distribution of the revenue requirements for each alternative resource. While an analysis of the expected revenue requirements and the risks associated with various generation alternatives usually determines which alternative should be selected, a third criteria exists, which may override the results of analyzing the first two criteria. This third consideration is the impact of an option on the near-term future of the utility in terms of revenue requirements, rate adjustments, capitalization structure, and so on. An option which appears most desirable over the long-term may be rejected because of unacceptable impacts in the near future.

Therefore, when evaluating a geothermal resource and determining what price would be acceptable, PGE would analyze: (1) the busbar price of the electricity, (2) transmission system capital and operating costs, (3) total fixed (or "ownership") costs versus operating (or "incremental") costs, (4) long-term levelized costs versus initial year costs, (5) costs/kWh versus absolute cost in $/yr revenue requirements, (6) impacts on near-term rate adjustments, and (7) existence of tax incentives and the ability of the company to take advantage of them. The importance of each of these criteria will vary for different alternatives; again, the decision would be based on minimizing the expected revenue requirements subject to the existence of unacceptable risks or near-term impacts.

In addition to the factors noted above, several important considerations exist that do not directly involve the cost of the generation resource being evaluated. Perhaps most obviously, the acceptability of a price for a particular resource depends on the prices of competitive resources. Whether or not a pricing strategy for electricity from geothermal energy is indexed to the prices of competitive fuels, PGE will consider the prices of competitive fuels when evaluating geothermal opportunities. Not only current prices must be considered but also the expected future prices of competitive fuels. It may be desirable to invest in a resource which is currently higher in price but which may be expected not to escalate as rapidly as its competitors or whose future price may be less uncertain. Additionally, the expected plant operating factors (number of hours operating per year) can have a significant impact on the relative economics of competitive resources.

A critical consideration is that of availability. As is well known, this issue of availability, often determined politically rather than otherwise, has become crucial over the last several years. In addition to current availability, the assurance of future supply is important. Flexibility in adding generation capacity of a particular type of resource is another somewhat intangible consideration. In particular, relative lead times for different types of power plants can be a critical factor.

The larger picture of a balanced resource mix and the availability of different options for generating electricity are also important considerations. Geothermal energy should be evaluated according to the part it will play in a mix of baseload, intermediate, and peaking resources. It is also useful simply as an additional option for generating electricity; in this sense it helps to provide the variety of resources necessary to provide security in an uncertain environment.

Finally, public acceptance of a resource, much of which revolves around the question of environmental suitability, is becoming increasingly critical. Public acceptance of a resource not only eases the implementation of that particular resource, but may also improve the general attitude of the public toward a utility which then impacts on the success of other utility projects.

The importance of these less tangible criteria for the pricing of electricity from geothermal energy is that these considerations will enter into an estimation of its value as a resource alternative, and thus into the determination of what would be an acceptable price for geothermal energy.

EVALUATING GEOTHERMAL ENERGY

The following discussion provides a background for an evaluation of geothermal energy, and the three options for obtaining geothermal energy, from the viewpoint of an electric utility.

Assuming that the field producer sells the geothermal fluid to a utility, the price of the fuel for a hot water resource is estimated to run from half to significantly more than half of the total busbar cost of electricity. This relatively high incremental cost would tend to suggest that electricity from geothermal energy be used as a peaking or, more likely, an intermediate resource (similar to coal); however, the requirement that wells be run continuously seems to restrict it to a baseload resource. The degree to which some flexibility may be gained so that the power plants need not operate continuously is uncertain. From a utility's viewpoint, some degree of control over maintenance downtime of field equipment would be desirable in order to schedule such downtime with periods of low energy demand. These factors will have to enter into any pricing arrangement between field producer and utility. Where geothermal energy is used as a baseload resource, its record of high plant operating factors may have a positive impact on its economics relative to competitive fuels.

The "one market-one supplier" property of electricity from geothermal energy results in significant uncertainties in field size, reliability, and longevity that must be worked into any arrangements between a field producer and a utility. The field producer will want to assure a buyer for a future field that is not yet proven, while the utility may not wish to commit its funds until a field of adequate size is proven. The utility will also wish to require insurance in the event of decline of fluid quality or early depletion of the field. Hopefully these uncertainties will become less critical as the geothermal industry matures. In addition, the unique field-plant relationship makes the location of the field with respect to load center and transmission facilities especially critical. A field of lower quality close to a major load center may be more valuable than a field of higher quality far away from load centers or existing transmission facilities.

The small size of a geothermal electric plant, while not providing economies of scale, may prove to be more reliable and may provide greater flexibility in scheduling small additions of generating capacity. In addition to the greater reliability of small power plants, failure of a small plant will have far less impact on the total generating system. The economics of a smaller plant will have less impact on total utility revenue requirements; thus a somewhat higher price in mills/kWh might be acceptable for a smaller plant if other advantages accrue to that plant.

The indigenous nature of geothermal energy, besides enhancing public acceptance, also provides greater reliability of supply and possibly greater control and, hence, less uncertainty with respect to the price of the resource. Finally, as noted, although geothermal energy is still an emerging resource, it is hoped that it will provide significant quantities of commercially competitive power within the near or middle term future. Therefore, it is a resource that utilities should support.

No absolute preference exists at the present time for any of the three options for obtaining geothermal energy outlined above. Nevertheless, some of the advantages and disadvantages of each of these options, and the difficulties that would have to be resolved in each case, are summarized below.

PGE does not currently foresee a large availability of geothermal busbar electricity produced by non-utility companies. It is believed that a utility would be able to generate electricity cheaper and more reliably; therefore, the price of purchased electricity is expected to be higher than the busbar cost would be if the utility generated the electricity. This option, however, does possess certain advantages that may offset the expected higher price. These advantages mostly involve a low capital outlay with consequently low risk (although some risk to the utility is involved in constructing transmission facilities for a power source that may prove unreliable). On the other hand, this option provides the least degree of utility control over the amount and timing of electricity generation and over production reliability. The fact that the cost of this busbar electricity is totally incremental - and may be expensed to offset revenues - may or may not be an advantage, depending on the individual utility.

The "classic" arrangement provides the utility with costs that are divided between fixed and operating. Capitalization is significant in this case, although incremental costs (mostly fuel) are also high. The utility would not bear the risks associated with field exploration and development, except as they are reflected in the fuel costs. The utility's major concern lies with the uncertainties in field size, reliability, and longevity. The uncertainty in field size impacts on the question of when power plant construction should begin, and when and what size of transmission facilities should be constructed. These factors will need to enter into the agreement between field producer and utility, including the amount and timing of prices. The utility will also wish to have some insurance with respect to field reliability and longevity; several suggestions for resolving this uncertainty have been offered, including federally funded insurance and accelerated depreciation methods. Finally, as has been noted, it may be desirable to include provisions for obtaining flexibility in capacity expansion and plant operating schedules. Any such provisions for flexible field expansion and plant operation will also have to enter into the pricing agreement.

The third option in reality encompasses many options consisting of various degrees of utility participation in field development. This option results in a higher percentage of fixed costs and lower incremental costs, since field capital costs would be assigned to fixed charges. The attractiveness of this option stems mainly from the greater control over field development and operation that the utility would possess. Whether this option would be economically advantageous for the utility is uncertain at this time, as the rate of return required by a utility depends upon the perceived risk of a project. Much depends upon whether or not the Public Utilities Commission would allow the ratepayers to bear the risks of such a venture (this is particularly true if the utility participates in field exploration as well as development). The willingness of the PUC to allow the risks of field development to flow into the rate base will depend largely on how great these risks are perceived to be in terms of the probability and magnitude of loss. It is likely that the PUC would look more favorably upon joint ventures, for example, between a utility and a resource company. Even if the risks of field development are born by the stockholders rather than the ratepayers, the PUC will have control over the rate of the return to the stockholders by controlling the price the utility is allowed to pay (itself) for the fuel. In addition to these difficulties, this option includes administrative headaches, due to a new type of utility project, which are lacking in the other options.

It is hoped that the preceding discussion will give resource companies and others an idea of the type of analysis performed by one utility in evaluating and comparing alternative sources of electricity, and how one utility might evaluate different options for obtaining geothermal energy.

CONSIDERATIONS FOR THE PRICING OF GEOTHERMAL ENERGY

William M. Dolan
AMAX Exploration, Inc.

1. Utilities insist that the cost of electricity from geothermal energy be competitive with alternate methods of generating electricity.

2. Most producers consider it appropriate that they receive compensation on the basis of delivered fuel rather than kilowatthours at the busbar. This posture corresponds with the sales practices involving alternate fuels, for example, coal. It also provides an incentive for utilities to operate their geothermal plants efficiently.

However, several problems require attention:

(a) Geothermal power conversion experience is limited and still improving. Accordingly, plant performances might vary substantially from design criteria.

(b) Noncondensible gases may affect a plant's performance adversely and hence limit the value of the resource to the utility.

(c) Producers require assurance that the utility will employ state-of-the-art plant designs that are appropriate to the resource.

The following procedures can be justified for dealing with the above-mentioned problems:

(a) The utility will assure that its design efforts will satisfy such well accepted criteria as:

(1) Thermal efficiency for liquid resources > 232°C (450°F) will be $\geq$ 0.10.

(2) Thermal efficiency for dry steam resources will be $\geq$ 0.15.

(b) The plant hot water rate or steam rate, depending on the resource, will be determined by the first 180 days of operation, during which time the producer will be paid at the busbar on the basis of design hot water rate.

(c) Thereafter, the producer will be paid for the geothermal energy delivered to the plant inlet with the price having been established on a busbar basis during the first 180 days of performance.

(d) In the event that the resource changes properties (e.g., enthalpy, noncondensible gases) necessitating plant revisions resulting in either a reduced <u>or</u> improved plant performance, then the producer and the utility <u>will</u> share in the resultant change in total electricity cost, subsequent to the utility's recapturing investments necessary to such plant revisions.

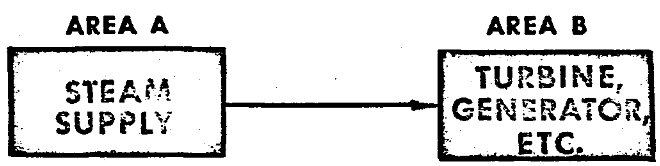
(e) In the event that the utility is able to improve plant performance in the instance of no change in the resource, then the producer and the utility will share the resultant incremental changes in the cost of electricity, providing that the utility may first recapture the investment necessary to such improvements.

(f) In the event that the plant performance declines through no reduction in resource quality, appropriate plant revisions will be absorbed by the utility.

(g) In the event that changes in resource properties adversely affect the plant performance in a manner not resolvable by plant revisions, then the utility will be obliged to revise the price of the resource appropriately.

(h) In the event that the plant operation by the utility necessitates revisions in the producer's production practice, but that the requirement for such revisions is not through fault of the producers, the producer will be appropriately compensated by the utility.

3. The fixed costs for a coal-fired plant plus the price of the coal to fuel it less the geothermal fixed costs equal the equivalent price of geothermal energy, all else remaining equal (load factor, operating costs, etc.) (Figure 1).



$$[COST_A + COST_B] - [COST_B] =$$

GEOTHERMAL PRODUCER PRICE

Figure 1

4. Due to utility-producer accounting differences, the initial price for electricity from geothermal energy might exceed the aforementioned equivalency price, providing that the geothermal price escalates at a lesser rate than that for coal.

5. The producer price involves total service (i.e., steam delivery to the plant inlet), which, of course, incorporates effluent disposal by the producer.

6. Most utilities are not disposed to risk the entire plant investment in the initial plant, in view of the question of reservoir longevity. The producer might consider escrowing a portion of the price for electricity from geothermal energy during the initial years as a means of accommodating that concern.

7. The producer must be concerned about the utilization schedule for a geothermal plant (well throttling is undesirable). Hence, a reward for increased utilization is contemplated.

8. The foregoing considerations are reflected in the following formula for pricing geothermal energy:

$P_g = K_o + B_o$ when $L = 80\%$ where:

P_g = geothermal steam price based on coal equivalency

K_o = the fixed costs for a coal-fired plant (Fc) less the fixed costs for the geothermal plant (Fg) in mills/kWh (common time base)

B_o = the true cost for coal plus average coal-fired operating costs minus the average geothermal power plant operating costs.

L = load factor

For load factors other than 80% the formula becomes:

$P_g - h(K_o + B_o)$

where:

$$h = \frac{0.8}{0.6} = 1.33 \text{ for } L \leq 0.6$$

$$= \frac{0.8}{L} \quad \text{for } L > 0.6$$

This system provides incentive for the utility to maintain a high load factor (Figure 2).

Inflation is a real concern in any long-term contract. Figure 3 shows how inflation would affect the price of geothermal energy (P_g) over time.

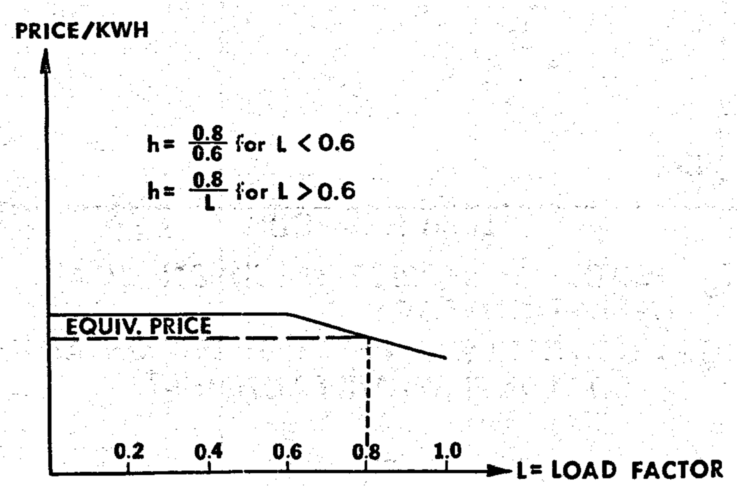
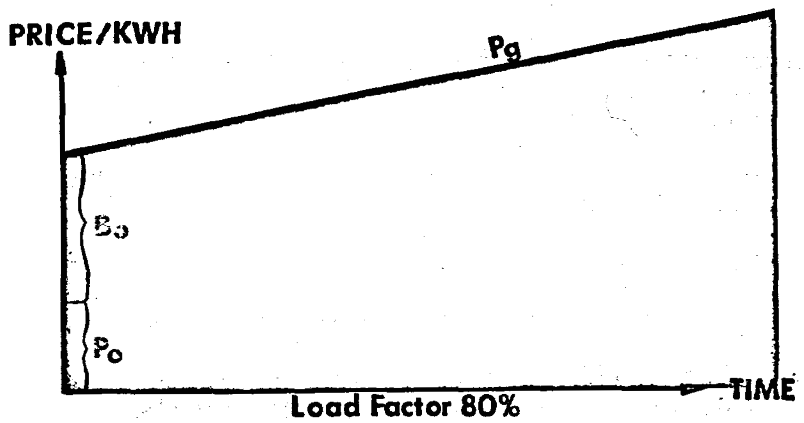


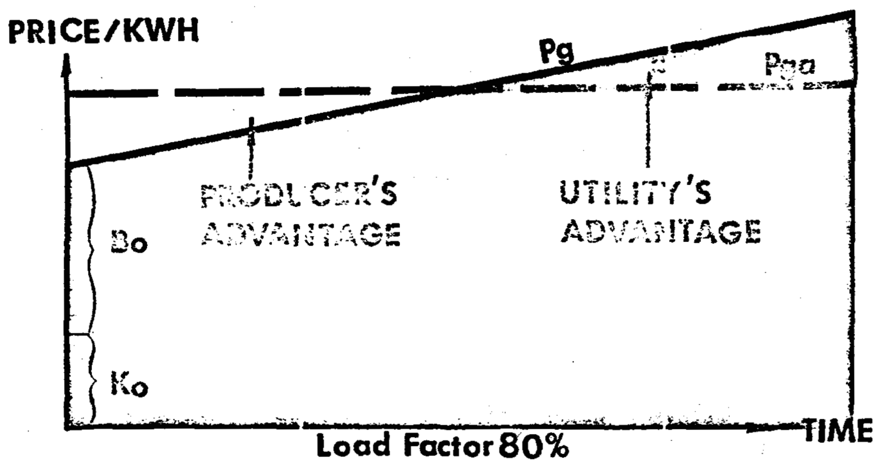
Figure 2



P_g-GEOTHERMAL PRICE BASED ON COAL INFLATION FACTOR

Figure 3

Due to the producer-utility accounting differences (the producer needs early income for a high rate of return, while the utility is concerned with total cost to its customers), both entities might be in a better position if the initial price for geothermal exceeded the equivalency price with the geothermal prices (P_{ga}) escalating at a lesser rate than that for coal. Figure 4 shows the advantage to both the producer and the utility.



P_g-GEOTHERMAL PRICE BASED ON COAL INFLATION FACTOR

P_{ga} - GEOTHERMAL PRICE BASED ON ADJUSTED COAL INFLATION FACTOR

Figure 4

The following equation, provided only for your edification, is one representation of the line P_{ga}:

$$P_{ga} = h\{ K_o + nB_o \ [(E_{t-1}1)\ (2-n)\ +1]\}$$

where:

P_{ga} = geothermal price based on decreased coal inflation

n = a factor to be negotiated $1 < n < 2$

$$E_{t1} = \frac{C_{t-1}}{C_o}$$

where: C_o = the average true cost of coal plus the average coal-fired operating costs

C_{t-1} = average coal cost plus operating cost in the previous time period, probably quarter

Reservoir risk, which seems to be the paramount utility concern, is not covered by the equations or graphs. The producer can share the utilities' reservoir risk through the following escrowing arrangement:

> X percent of P_{ga} will go to the producer while Y percent of P_{ga} will go to an escrow account for time 0 to time M. The escrow account will be capturable by the producer if the reservoir is satisfactory at time M. Otherwise, it will be capturable by the utility, serving as partial compensation.

The increased utility security provided by this arrangement depends on the values of Y and M. The real utility security is that the producers are not going to risk investments in wells and piping until they are satisfied with the reservoir parameter.

A FEW THOUGHTS ON PRICING GEOTHERMAL ENERGY

Harry W. Falk, Jr.
Magma Power Co.

My remarks will primarily be directed towards the pricing of geothermal energy produced from the "hot water" reservoirs, because it is those reservoirs that give promise of the greatest potential. However, there are a couple of points about The Geysers' "dry steam" field that should be stressed.

The first is that the purchaser of the steam at The Geysers, Pacific Gas & Electric Company, is currently producing most of its electricity by burning oil. On today's market it costs about 25 mills for the oil used to generate one kilowatthour of electricity. This compares to only 14.18 mills currently being paid for geothermal energy at The Geysers (including .5 mills for reinjection).

The second point to be stressed is that The Geysers contract requires the plants to be operated "as close to full capacity and as continuously as practicable..."

Engineers usually argue that energy should be priced on a Btu basis, or, in the case of geothermal energy, on the basis of pounds of steam or hot water, instead of on the basis of mills per kilowatthour as is done at The Geysers.

If 100,000 pounds of steam at The Geysers were priced at $70.00, one would find that such a price roughly equates to the busbar price now being paid. The pounds of steam basis would appear to give the user an incentive to improve its efficiency and minimize service station use; on the other hand it also involves some complications such as changes in temperature, pressure, quality, and quantity over a long period of time.

My personal opinion is that there would be no major advantage in changing the formula we are using at The Geysers at the present time; but that subject is worthy of continued study and perhaps additions to value because of increased efficiency, or otherwise, should be shared by the developer and the utility.

Turning to the hot water fields, there is considerable dispute as to the value of hot water. What is the value of 150°C hot water? 200°C? The only figure that we really can grasp at this time is that utilities will pay a kilowatthour price that is competitive with alternate sources of energy that are available. From the utility company standpoint, initial calculations will be made in mills per kilowatthour.

Our short or intermediate term goal is to see developed a system whereby 100 pounds of 180°C hot water can be converted into one kilowatthour of electricity. Assuming plant costs are the same, and it costs 25 mills for the oil that will make one kilowatthour, then it would be competitive to charge 25 mills per 100 pounds of 180°C hot water. However, we know that until we can demonstrate that the goal can be reached, no utility will agree to pay such a price for hot water.

Accordingly, we can hardly expect a contract at this time based upon Btu content or pounds of hot water. However, like at The Geysers, such a method of pricing is worthy of continued study, and when we can more clearly establish what can be done with hot water we can discuss a pricing method that will be in the best interest of all concerned.

I want to join with the many others who stress the unknowns involved in producing geothermal energy from a hot water reservoir. Discovering a field, testing it, and getting into production involves indeterminable millions of dollars, and a timetable that often seems to stretch out forever. Nobody knows what it will cost to operate such a reservoir. We believe that the typical case will involve the use of expensive downhole pumps; pump life has been variously estimated by different experts as being from one to ten years. Nobody knows how long temperature and volume will be maintained at a specific site; accordingly the need for replacement wells or additional wells is not known. I could proceed at length with such uncertainties.

The risks I have just described are sometimes called "geologic risks," and explorers for natural resources are not unaccustomed to taking such risks. The far greater problem, and the primary obstacle to an accelerated geothermal program, is the ridiculously costly and time-consuming bureaucratic red tape. Imaginary environmental problems require money and time beyond belief. Regulations often appear to be incomprehensible. Tax incentives are minimal. There is just no way for industry to evaluate the risk involved in what we now call these "institutional problems."

In the face of all this, there are those who urge government price regulation. It should be clear that where costs are not subject to being ascertained, price regulation is impossible; attempts at such regulation would increase the developers costs, the price, and create another bureaucratic staff that would find itself running in circles.

Likewise, there are those who urge that pricing be based on cost plus a reasonable profit. This is similarly impossible. No purchaser in his right mind would agree to pay the costs, whatever they might be.

Moreover, I fail to comprehend why such concepts should be urged for an emerging industry. If there is a sincere desire to hold down energy costs, it would certainly be far more meaningful to adopt policies involving coal, oil, gas, and uranium. And this perhaps raises questions about the cost of food, construction, clothing, and so on. Usually, attempts at price control have resulted in higher prices.

In conclusion, as of this time, it is my personal opinion that there is no practical way to price energy from hot water fields other than on the basis of mills per busbar kilowatthour, subject to some requirements calling for the user to be efficient and to operate continuously.

PRICING OF GEOTHERMAL ENERGY

Bob Greider

Chevron Resources Company

This opportunity to discuss pricing concepts with the utility industry is one that is needed. The utility fuel purchasers may discuss together how much they will pay for fuel. The fuel finders cannot discuss among each other how much they will charge nor how they will develop a price to charge. Federal law will allow us individually to discuss these questions with our customers. My presentation will be limited to that which is a part of the formal testimony given before the State of California Geothermal Task Force of 1977.

The price of any fuel is the amount of money a willing buyer and a willing seller can agree upon. Posted prices for commodities are a visible gauge of a seller's desired price, and reports on fuel costs by the utility are evidence of the final fuel costs. To derive the actual price for the fuel at the producing facility requires a careful analysis of fuel transportation, preparation, and handling charges. In a free economy the fuel producer, in establishing his price, has strong constraints established by his costs, the price of competing fuels, and the desire of potential customers to use his fuel. The supplier and user of geothermal energy has to consider carefully if the price provides a reasonable return on investment. A company with limited funds to invest must select the investment opportunities with the best chance of having the most favorable return from these finite funds. The customer must select the fuel to buy that will reliably provide a product at an attractive price. The amount of money needed to construct and operate plants to use the fuels is a strong component of how much the customer will pay per unit of fuel.

The pricing system used in the past at The Geysers was directly related to the number of kilowatthours of electricity produced. The disadvantage of pricing energy by the kilowatt produced is that there is no incentive for the utility to invest money in making its plants more efficient. An increase in efficiency, resulting in more kWh per kilogram (pound) of steam, results in the steam producer, not the utility, being paid more. The dry steam system of The Geysers is relatively low-cost, so an increase in efficiency is not needed to be strongly competitive. Dry steam reservoirs are at a nearly constant temperature so there is little incentive for the producer to conduct research and explore new depths for higher-temperature reservoirs.

The costs in the hot water systems that will be developed in California are of such magnitude that incentives must be provided to encourage increased efficiency in generation and increased search for hotter water reservoirs at depth. Both are necessary if these systems are to compete successfully (commercially) with other fuels.

A way of structuring price is shown below.

PRODUCT PRICING CONCEPTS

SALE OF GEOTHERMAL ENERGY TO BE BASED ON COST PER KILOJOULE (PER 10^6 BTU) OF "USEABLE HEAT" DELIVERED TO PLANT INLET OR PLANT'S PIPELINE.

"USEABLE HEAT" IS THE TOTAL ENERGY DIFFERENCE BETWEEN THE DELIVERED FLUID MIXTURE AND THE FLUID RETURNED TO THE PRODUCER AT A SPECIFIED TEMPERATURE FOR DISPOSAL.

ENERGY SALES AGREEMENT SHOULD INCLUDE CLAUSES THAT PROVIDE FOR ENERGY SALES AT A FAIR MARKET VALUE WITH ESCALATION DETERMINED BY NEGOTIATIONS BETWEEN BUYER AND SELLER.

The pricing concept for geothermal energy includes the price and the structuring of the price, as this may be a strong template for future generating units in the field. The basic structure of price must provide an attractive rate of return to the prospector. To achieve this, the prospector's capital investment must be minimized.

PRICING CONCEPT

DEVELOP METHOD TO COMPETE WITH FOSSIL FUELS

1. ENVIRONMENTAL ACCEPTABILITY
2. LOWER CAPITAL REQUIREMENTS
3. BUSBAR PRICE

The utilities participate in the lowest risk segment of the business. The lower risk segments should require a lower rate of return on investment than the higher risk. Therefore, the busbar price for each kilowatt generated will be more competitive if equipment to transport and convert the geothermal energy to electricity is built by the utility. The fuel price should provide for delivering fuel to a productive site manifold and receiving the fluid at a disposal well island site.

PRICING CONCEPT

DELIVER FUEL TO:

A. MANIFOLD AT PRODUCTION SITE
B. A PLANT SEPARATOR

RECEIVE SPENT FLUID AT:

A. DISPOSAL ISLAND SITE
B. PLANT CONDENSER

PLAN "A" IN EACH, RESULTS IN LOWER FUEL COST AND BUSBAR PRICE.

It is good business to consider the revenue stream for the producer as being composed of two parts. The first is money for providing useful heat to the utility, and the second is money for disposing of the fluid after the useful heat utility, and the second is money for disposing of the fluid after the useful heat has been extracted by their machines. By buying fuel on a kilojoule (Btu) basis, incentive is provided for continued improvement in the electricity generating system. The more kilowatts produced per kilojoule (million Btu), the more competitive the geothermal busbar price becomes.

FUEL PRICE

(BASIC CONCEPT PAY FOR USEFUL KILOJOULES [BTU])

A. PAY ON BASIS OF ALL KILOJOULES (BTUS) DELIVERED ABOVE A "REFERENCE" TEMPERATURE
B. PAY FOR KILOJOULES (BTUS) DELIVERED AND DISPOSAL AT X DOLLARS PER KILOGRAM (MILLION POUNDS) DISPOSED

The producer of fuel is stimulated to find and produce the highest heat content fluid from his system. This lowers his operating costs for production and disposal, since volumes of fluids to be moved are minimized.

The joules (Btu) provided should be priced on joules (Btu) delivered above a reference temperature. These will be known as "useful joules" ("useful Btu"). A useful kilojoule per kilogram of brine (Btu per pound) is the remainder of the difference between the enthalpy of the fluid at delivery temperature and the enthalpy of the fluid at a reference temperature such as 93°C (200°F). (Reference temperature depends upon agreement with purchaser and is limited by composition of the geothermal fluid.)

USEFUL JOULE (BTU)

DELIVERY TEMPERATURE	C (F)	185° (365°)	171° (340°)	166° (330°)
ENTHALPY (INLET)	KJ/KG (BTU/LB)	784.5 (337.5)	723.1 (311.1)	698.9 (300.7)
ENTHALPY @ REFERENCE TEMPERATURE	93°C (200°F)	390.5 (168)	390.5 (168)	390.5 (168)
ΔH = USEFUL KJ/KG OF BRINE	 (BTU/LB)	394 (169.5)	332.6 (143.1)	308.4 (132.7)

BRINE KG (LB)

DELIVERY TEMPERATURE	C	185°	171°	166°
	(F)	(365°)	(340°)	(330°)
FLOW FOR 50 MW	KG/S	955	913.4	1285.1
	(10^6 LB/H)	(7.58)	(9.25)	(10.2)
NET MW PRODUCED		45.5	45.2	45.0
BRINE REQUIRED:	KG/NET KWH	75.7	93	103
	(LB/NET KWH)	(167)	(205)	(227)
USEFUL KJ/NET KWH		29,826	30,932	31,765
	(BTU/NET KWH)	(28,300)	(29,300)	(30,100)

(CALCULATION: BRINE REQUIRED TIMES
USEFUL KJ/KG [BTU/LB])

COMMENTS ON PRICING OF GEOTHERMAL ENERGY

T. R. Fick
Bechtel Corporation

Bechtel has just concluded a study that included the effects on power plant design and busbar electric energy costs of the anticipated decline in geothermal brine temperature of the Heber reservoir. A two-stage flashed-steam energy conversion process was used, and two operating modes, constant brine flow and constant power output, were considered. Plant net capacities were taken at 50, 100, and 200 MW (e) as multiples of 50 MW (e) units.

The "cost of fuel" was estimated as a direct function of the cost of developing and operating the well field, including the cost of drilling more wells as the reservoir cools with time. Any connection between previous less direct costing bases, such as the cost of oil or nuclear fuel, was avoided. Capital costs for the well field and the power plant were estimated by the usual methods. Cost and power plant energy output were both expressed in levelized annual terms, and a plant capacity factor of 85% was assumed. Power plant cost calculations included the following assumptions:

- Operating and maintenance (O&M) at 2% of plant capital cost
- Administrative and general expense at 25% of O&M
- Insurance at 0.1% of plant investment
- Ad valorem taxes at 2.5% of plant investment
- Rate of return (ROR), 10.8%

The well field cost calculations included the following:

- Well cost at $425,000 per well
- Well annual maintenance at $50,000/well for production wells and $80,000/well for reinjection wells
- Operating cost at $70,000 annually, plus a factor varying with number of wells
- Royalties, 10% of gross field income
- Ad valorem taxes at 6% of field income
- Exploration, confirmation, and engineering as $2 million plus 5% of gross field income (only with 10.8% ROR)
- Administrative and general, 10% of O&M

- Investment tax credit, 10%
- ROR, 10.8% or 20%, depending on assumption of low or risk-adjusted financing.

As a result of the several concepts considered, estimates of a number of different busbar costs of electric energy were obtained. The lowest cost was 35 mills/kWh, assuming a 50-MW (e) plant without reservoir temperature decay and a 10.8% rate of return. The highest cost was 53 mills/kWh, assuming reservoir temperature decay and a 10.8% rate of return for the power plant and 20% for the well field. In all cases the well field costs were nearly equal to or greater than the power plant costs.

The results of the study emphasize that realistic "cost of fuel" and the effects of reservoir temperature decay are important and should be included in the pricing of geothermal energy.

ACKNOWLEDGMENT

The work reported herein is the result of a study funded by the U.S. Energy Research and Development Administration under Contract E(04-3)-1124. It should be noted that this report has not yet been approved by ERDA, hence the foregoing information should be considered preliminary.

Section 6

WORKSHOP: FUTURE DIRECTIONS

Chairman:
Val Finlayson, Utah Power and Light

Panel of Speakers:
Ira Adler, Energy Research and Development Administration
Dave Anderson, California State Energy Resources Conservation Development Commission
Bert Barnes, Energy Research and Development Administration
Harry Bishop, San Diego Gas and Electric Company
Priscilla Grew, California State Geothermal Task Force
Hamilton Hess, Sierra Club
Robert Mallis, United States Geological Survey
George Sylvestri, Westinghouse Electric Company

Synopsis

Val Finlayson addressed the group assembled and indicated that the purposes of this session were to:

1. Identify what needs to be done in geothermal energy research and development so that EPRI can better plan its geothermal program

2. Develop better communication between all segments of the geothermal community about their needs and requirements

Each member of the panel then spoke to the group describing current efforts in geothermal energy R&D. Robert Mallis described the USGS geothermal research program. Ira Adler presented information on ERDA geothermal organization and goals. Bert Barnes followed this up with discussion of ERDA's geothermal programs. Dave Anderson then described CSECDC's geothermal program.

Priscilla Grew gave a preliminary report on the deliberations of the geothermal task force about the future development of geothermal energy in California.

Hamilton Hess described the environmentalist point of view on geothermal development. He felt that there are three present and future priorities for development:

1. A clean environment (water, land, air)

2. The preservation and protection of other resources, e.g., wildlife habitat, scenic and esthetic values, thermal phenomena, archeological resources, etc.

3. Consideration of enhancement of competitive or alternate land use

George Sylvestri discussed equipment for geothermal energy utilization. Harry Bishop's discussion was deferred until the next day because of time limitation. The group then adjourned until the next day.

Section 7

WORKSHOP: EPRI GEOTHERMAL PROGRAM PLAN AND DIRECTION

Alan Grant, Chairman
Portland General Electric

Synopsis

The discussion continued from where it left off at the conclusion of the Future Directions Workshop. The majority of the continuing discussion centered on two topics:

1. The proposed 50-MW binary hydrothermal demonstration plant at Heber
2. The mobile geothermal test lab proposed by EPRI to develop a geothermal data base and evaluate utilization options from specific resources

The group supported both concepts completely and indicated that they were highest priority projects.

Additional important research topics were discussed. The inputs from this discussion resulted in the EPRI Geothermal Program Committee later recommending the following list of "Must Do" research projects for geothermal development.

MUST DO RESEARCH PROJECTS AND SUBPROGRAMS LIST GENERATED BY GEOTHERMAL PROGRAM COMMITTEE AT JULY 29, 1977, MEETING

1. 50-MW hydrothermal demonstration plant
2. Mobile geothermal test lab and subsequent development of geothermal data base
3. Alternative waste heat rejection systems
4. Plan and arrange more meetings for educational purposes (inter-industry exchange of views on specific topics)
5. Environmental control systems--initial emphasis on H_2S abatement
6. Geopressure
7. Collaborate and coordinate with other groups that design and build first-of-a-kind pilot or demonstration power plants in the U.S.
8. Reservoir assessment (resource verification)
9. Conversion equipment development, including fluid handling and processing
10. Flashed-steam power plant performance and reliability
11. All current EPRI projects not specifically called out in 1 through 9, e.g., brine chemistry and others

Appendix A

GEOTHERMAL MILESTONES 1977 - July 25-28, 1977

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Appendix B

PROGRAM AND SPEAKERS
"GEOTHERMAL MILESTONES 1977"
EPRI GEOTHERMAL PROGRAM PROGRESS REPORT AND WORKSHOP

Kah-nee-ta, Oregon
July 25-28, 1977

July 25 - Monday	Speaker
Meeting Opening and Introduction	Vasel Roberts, General Chairman
• Welcome	Lynn Rasband (SCE)
• Keynote Address	Frank Warren, Chairman of the Board and Chief Executive Officer, Portland General Electric
Session 1, Current EPRI Projects	Lynn Rasband (SCE), Chairman
• RP580-1 Heber Demonstration Plant Feasibility Study	Ben Holt (The Ben Holt Co.), Subir Sanyal (Geonomics)
• RP580-2 Heber Demonstration Plant Development	Rich Swanson (SDG&E) Gil Lombard (SDG&E)
• RP846 2000-Hour Heat Exchanger Study	Ed Ghormley (The Ben Holt Co.)
• Geothermal Regulator-Local Government	Dave Pierson (Imperial County)
Session 2, Current EPRI Projects	Harold Bell (APS), Chairman
• RP741 Mobile Geothermal Laboratory	Tom Springer (AI), Raly Schilling (EPRI)
• RP927 Waste Heat Rejection from Geothermal Power Plants	Robert Mitchell (R. W. Beck), Randy Horsak (R. W. Beck)
Session 3, Luncheon Session	Vasel Roberts (EPRI), Chairman
• A Legislator's View of Geothermal Energy Development	Lawrence Kapiloff, Assemblyman, State of Calif.

<u>Session 4, Geothermal Projects by Utilities</u>	John Arlidge Chairman
• Geothermal Development in Mexico	Pablo Mulás, Mexico
• Geopressure	Fred Repper, Central Power & Light
• Oregon Geothermal Resource Assessment	Rod Wimer, PGE
• Operational Experience at the San Diego Gas & Electric ERDA Niland Geothermal Loop Experimental Facility	Gil Lombard, SDG&E
• Four Possible Geothermal Projects	Arthur Martinez, PSCNM
• Development of Geothermal Energy at Chandler, Arizona	Harold Bell, APS
• Mammoth Geothermal District Heating System	George Crane, SCE
• Site Specific Analysis of Hybrid Geothermal/Fossil Power Plants	Greg Sinay, Burbank
• Meager Creek Geothermal Investigation Summary	J. Stauder, British Columbia Hydro & Power Authority

<u>July 26 - Tuesday</u>

<u>Session 5, Current EPRI Projects</u>	John Arlidge (NPC), Chairman
• TPS76-638 Utilization of Geothermal Resources	Phil La Mori (EPRI)
• RP929 Reservoir Utilization Manual	Subir Sanyal (Geonomics)
<u>Session 6, Reservoir Verification Workshop</u>	Subir Sanyal (Geonomics), Chairman

Panel:
- Dave Butler (Chevron)
- Gary Crosby (Phillips)
- Al Duba (LLL)
- Jack Howard (LBL)
- Otto Vetter (Vetter Associates)
- Art Martinez (PSCNM)
- Tsvi Meidav (Geonomics)
- Bill Brigham (Stanford)
- Dave Riney (SSS)
- Gil Lombard (SDG&E)
- W. Youngquist (EWEB)

Session 7, Current EPRI Projects	Phil La Mori (EPRI), Chairman
• RP653-1 Brine Chemistry/Combined Heat and Mass Transfer	Don Shannon (BNW), Duane Faletti (BNW)
• RP653-2 Brine Rock Chemical Correlations	Frank Dickson (Stanford)
• RP791 Study of Brine Treatment	Sidney Phillips (LBL)

July 27 - Wednesday

Session 8, Pricing of Geothermal Energy Workshop	Paul Kruger (Stanford) Chairman

Panel:

- Harold Bell (APS)
- Ann Corrigan (PGE)
- Bill Dolan (AMAX)
- Harry Falk (Magma)
- Bob Greider (Chevron)
- Art Martinez (PSCNM)

Session 9, Current EPRI Projects	Gary Underhill (EPRI), Chairman
• RP928-1 Axial Hydrocarbon Turbine Study	Norm Samurin (Elliott)
• RP928-3 Radial Hydrocarbon Turbine Study	Robin Dakin (Rotoflow)
Session 10, Future Directions	Val Finlayson (UPL), Chairman

Panel:

- Robert Mallis (USGS)
- Ira Adler (ERDA)
- Priscilla Grew (Calif. Geo. Task Force)
- Hamilton Hess (Sierra Club)
- George Sylvestri (Westinghouse)
- Dave Anderson (CSERCDC)

July 28, Thursday

Session 11, EPRI Geothermal Program Plan and Direction Workshop	Alan Grant (PGE), Chairman
• EPRI 5-Year Program Plan	Rasband/Roberts
• Critical Problems	Maddox/Schilling
• R&D Priorities	Ridgway/La Mori
• Recommendations for Research Projects	Bell/Underhill

Participation limited to utilities or by invitation.

Session 12, EPRI Program Committee Meeting