ANCR-1318

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A PLAN FOR DEVELOPING MODERATE TEMPERATURE/LOW SALINITY
GEOTHERMAL RESOURCES

by
Jay F. Kunze
and
Judson F. Whitbeck

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AEROJET NUCLEAR COMPANY

Date Published - May 1976

PREPARED FOR THE
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ACKNOWLEDGMENTS

The authors have generated this plan using the recommendations of numerous individuals. Those deserving particular mention are:

Dr. James Bresee and Dr. Louis Werner of ERDA, Division of Geothermal Energy;
Dr. Donald Pitts of Tennessee Technology University and consultant to ERDA;
John Griffith of ERDA, Idaho Operations Office;
Lowell Miller, Robert Schultz, and Roger Stoker of the Idaho National
Engineering Laboratory;
Edwin Schlender of Raft River Geothermal Development Corporation;
Henry Curtis and Kenneth Dyar of the Northwest Public Power Association.
George Freund of Stafco, Inc.

ABSTRACT

The approach to developing moderate temperature (150° to 300°F) geothermal resources so that these can competitively enter the energy market is herein described. The specifics discussed relate to experiments in the Idaho National Engineering Laboratory's program effort. These involve the energy supply and disposal systems, the surface conversion equipment for generating electricity, and supplementary uses of the heat directly for industrial and agricultural applications. The experimental facilities are located in the Raft River Valley area of southcentral Idaho, close to the Utah border, and the document describes the purpose and likely economic benefit to result from this experimental program.

APPROVED BY:

Dr. J. F. Kunze, Manager
Geothermal Programs

APPROVED BY:

Dr. F. H. Tingey
Assistant General Manager
Programs

SUMMARY

Geothermal energy can be utilized directly for its heat value, or be converted to electricity, generally using steam as the fluid to drive the turbine-generator. Direct heat uses offer a substantial potential for displacing consumption of scarce oil and gas and are generally within current technology. Electric generation from geothermal sources requires greater technical sophistication, particularly if economic use is to be made of the huge hydrothermal resource that exists in the moderate temperature range (say 260-340°F). This resource is equivalent to 500 times our present annual U.S. energy consumption. Direct heat uses can be considered either as a byproduct or supplemental use for energy associated with the electric generating plant.

The purpose of the medium temperature geothermal program (conducted for Energy Research and Development Administration at the Idaho National Engineering Laboratory) is to establish the technology and experience necessary to extend economic power production to the moderate temperature (hydrothermal or hot-water) resource. The purpose of the attached document is to provide the background achievement and the plan by which the above objective can be accomplished. The INEL program is part of the total ERDA Geothermal Energy Program.

The goal of the ERDA program is to stimulate greater utilization of U.S. geothermal resources by the private sector. Significant commercialization by 1985 (5000 to 20,000 MW of electric power) is the target range suggested during the last several years. The hydrothermal resources can make a significant contribution to this target if a vigorous testing and demonstration program is initiated immediately. The objectives of this program are as follows:

1. to establish the technical feasibility of an integrated energy supply and power conversion system, requiring essentially no component development;

2. to demonstrate economic viability by competitiveness with major existing sources (oil, gas, coal and nuclear) of electric generation; and
3. to implement transfer of hydrothermal technology to industry by continuing to increase industrial involvement in the program.

To show technical feasibility, it is proposed to continue the present well, resource, environmental, and materials and small components testing, and to begin immediately detailed design of a hydrothermal test facility, capable of carrying out full-sized component testing. The facility is to be located at Raft River, Idaho, site of on-going experimental hydrothermal work by INEL. It will include the following components:

1. producing wells,
2. re-injection wells,
3. connecting pipelines, and
4. all the components of a surface facility that transfer and remove heat and produce mechanical energy (i.e., drive a turbine).

This facility will be of sufficient size for an adequate test of techniques for managing geothermal reservoirs. The conversion equipment will be of a representative size for use in a commercial power plant. The base system of the facility will supply, with a binary isobutane system, 80 MW of thermal capacity; capable of generating 10 MW of electricity. This capacity represents two-thirds of the eventual total plant output. In this cycle, the geothermal brine is used to heat isobutane, a compound closely related to butane. This compound is used without combustion as the fluid to drive the turbine. This cycle provides the highest performance of any analyzed for the hydrothermal resource while operating at relatively low pressures. Except for the turbine, the components of the base system represent conventional chemical processing technology. However, their performance characteristics, over extended periods of operation on moderate temperature low salinity brine, have never been tested. Industrial organizations have expressed confidence that an appropriately sized, isobutane-driven turbine can be built with minimum research and development. This device also, has never seen long term use in service as a power producing machine. An artist's schematic of the test facility layout is shown in Figure A.

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Figure A - Artist's Concept of Test Facility and Its Applications

With this state of technology development, with immediate implementation of plans and funding for a test facility and with vigorous involvement by industry, it is believed that the facility can be in initial operation by early 1979. In addition to the base isobutane system, an additional 40 MW of thermal capacity will be provided in a flexible test facility arrangement so that other, more advanced concepts for converting hydrothermal energy to electricity can be tested and evaluated.

To demonstrate economic viability, the next step after a test facility, is the design, construction, and operation of a demonstration power plant. If the test facility is built on the proposed schedule and continues to show encouraging results, design of a demonstration plant could be phased for expeditious commitment to construction once preliminary results are obtained from the test facility. With this accelerated schedule, utility commitments to construction of commercial plants may be possible as early as 1982.

To implement technology transfer to the industrial segment requires continuing commitment by ERDA and INEL to foster industry involvement at every step of the program. Indeed industry involvement is the key to achieving the other objectives of technical feasibility and economic viability and to making a significant contribution to the ERDA 1985 commercialization target.

The INEL is dedicated not only to implementing of the research, development and demonstration efforts but to effective planning of the program management in order to foster the technology transfer to industry. Vital commitments to industrial involvement have already been made by both INEL and industry. Over 100 utilities are already involved in the Raft River Geothermal Program. These utilities represent literally hundreds of potential hydrothermal areas. If 20 to 50 power plants, of 50 or more MW, are committed early in the commercialization phase, hydrothermal resources in the Northwest alone could make a significant contribution of 1000 to 2500 MW to the 1985 ERDA target. Development of 10-15,000 MW (approximately equal to present hydroelectric capacity in the Northwest) would be possible by the turn of the century.

In the research phase of the INEL geothermal program, other national labs and universities have been asked to play a significant role, consistent with their capabilities and experience. Industrial organizations are participating in development of products and are supplying some of the services available in the industrial sector.

The test facility program can be considered to be a pre-demonstration phase, and should have even greater involvement of the industry, particularly by utilities who will be expected to carry on the subsequent demonstration and commercialization phases.

Accordingly, preliminary discussions have already been held with one organization to act as lead utility for the test facility. The respective roles of INEL and the lead utility are visualized as follows:

1. INEL-- responsible for:
 - a. conceptual design of test facility
 - b. selection and management of new technology
 - c. test program and evaluation, and
 - d. reporting technical results and economic evaluations to industry.
2. Utility--functions as owner of an experimental power plant to:
 - a. contract for and supervise architect engineer and construction manager, and
 - b. procure major equipment items.

In this way the utility would develop first-hand experience with hydrothermal power plants.

The research phase of the INEL program has thus far consisted of theoretical studies of the plant cycle and its economics and of supporting experimental work at Raft River. The results of these evaluations may be summarized as follows:

1. The energy available nationwide from hydrothermal resources is quite high compared to currently developed high-temperature resources. The success rate in tapping these individual hydrothermal resources is potentially much higher than in tapping high-temperature reservoirs. Further specific experience, such as obtained in the past year at Raft River in the drilling of geothermal wells, is necessary to confirm these preliminary findings.

2. The conversion efficiency from heat to electrical energy is somewhat lower than for existing geothermal systems which are economical. Experience with other methods, such as coal vs nuclear, indicates that efficiency is not the sole criterion of economics. Because the maximum efficiency attainable is low, every reasonable effort should be made to come as close as possible to that ideal efficiency as possible. For example, temperature lost between the geothermal fluid and the turbine fluid and between the turbine fluid and the heat rejection to the environment causes an important penalty in efficiency. Therefore, emphasis should be placed on improving the heat transfer equipment used at these two points in the conversion cycle.

3. The lower temperature and operating pressure, and the resulting smaller amount of dissolved minerals and gases, in these geothermal fluids offers potential savings in materials of construction for the power conversion equipment. This situation is analogous to low-sulfur, low-heat Western coal, which requires the burning of more coal for given power output but potentially less expensive pollution control equipment. Operating experience with equipment made from low-cost materials is a necessary part of any development plan for the hydrothermal source.

4. The potentially adverse environmental effects - discharge of waste heat and disposal of spent geothermal fluid - are solvable using conventional engineering. Because of the low efficiency, the amount of waste heat per unit of electric power is about five times as much as for a modern coal plant and about twice as much as for a 400°F geothermal plant. The total quantity per plant will be less than for a coal-fired plant because of the much smaller size of the geothermal unit, (50-150 MW(e) vs 500-1000 MW(e)). Re-injection into the

aquifer is a promising way to release both the waste heat and the spent geothermal fluid. Specific experience with this technique and with other methods of energy rejection is necessary to firm up the costs of this part of the cycle.

5. Target economic costs for hydrothermal sources are approximately as follows (in 1976 dollars without interest during construction):

- a. less than \$200/kW for the energy supply system to bring the geothermal fluid to the power plant equipment;
- b. less than \$500/kW for the energy conversion system;
- c. about \$100/kW to return spent geothermal fluid to the aquifer; or
- d. a suitable trade-off between these.

Postulated improvements in energy supply systems have the potential of reducing their cost well below the target costs. Current technology estimates indicate that conversion system cost of \$600/kW are already attainable. Since the power conversion system represents the largest portion of plant cost, the greatest cost incentives lie in improving the efficiency of the conversion process.

6. The small size of the optimum geothermal power plant offers some intangible advantages from a utility planning and financing standpoint. These advantages are not reflected in the base total costs of these plants. Continuing system studies and dialogue with potential users of geothermal plants are an essential part of developing these and other advantages of the hydrothermal process for power production.

The current thrust of the INEL program is a two pronged effort: 1) to continue to learn as much as possible from the resource now available, and 2) to simultaneously construct the test facility. While the test facility is being built, the existing three wells (as of this writing drilling has just begun on the third) will be utilized for testing purposes. Production and re-injection performance testing will continue, along with use of the hot water for small scale experiments on materials, heat transfer devices, and for environmental impact studies. This continual test program will provide information pertinent to the selection of improved components and techniques. Of those which show promise for improving the overall economics, provisions would be made for full scale testing during the second phases of the test facility operation.

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1.0 PURPOSE AND SCOPE

Geothermal energy can be utilized directly for its heat value, or be converted to electricity, generally using the standard Rankine Cycle (more familiarly known as the steam cycle). Direct heat uses offer a substantial potential for displacing consumption of scarce oil and gas and are generally within current technology. Electric generation from geothermal sources requires greater technical sophistication, particularly if economic use is to be made of the huge hydrothermal resource that exists in the moderate temperature range (say 260-340°F). Direct heat uses can be considered either as a biproduct or supplemental use for energy associated with the electric generating plant.

The moderate temperature hydrothermal resource is about 4000 Quad (1 Quad = 10^{15} Btu) recoverable according to a 1975 estimate by the U.S. Geologic Service⁽¹⁾ (the total annual U.S. energy consumption is now 75 Quad). The USGS picks 300°F (150°C) as an arbitrary dividing point. Above it applications will be mostly for electric generation. Below it most applications will be non-electric. Hence the target temperature of about 300°F for electric R&D efforts would be consistent with the USGS division of resources.

The purpose of the medium temperature geothermal program (conducted for ERDA at the Idaho National Engineering Laboratory) is to establish the technology and experience necessary to extend economic power production to the moderate temperature resource.

The purpose of this document is to present a plan by which the above objective can be accomplished. The document first provides technical and economic background information on moderate temperature utilization, then discusses the areas of promising technological advances associated with moderate temperature utilization and finally presents a plan to implement R&D in these areas.

2.0 TECHNICAL CONSIDERATIONS FOR PRODUCING ELECTRICITY

Except for hydropower, current systems for the production of electricity involve conversion of heat energy into electrical energy. The four essential elements of such systems are: (1) the energy source, (2) the power conversion equipment, (3) distribution of electricity to load centers, and (4) provisions for disposal of wastes, both materials and heat.

The energy source may be coal, oil, natural gas, or nuclear fuel elements containing uranium or plutonium - in all cases delivered to the power generation station. There the heat energy is released - either by a chemical process (combustion of a fossil fuel) or by a nuclear process (the fissioning of atoms in a chain reaction). In most instances the working fluid carrying this energy is steam or gas at high temperature. The working fluid drives a turbine linked to a generator. The generator produces electricity at moderate voltages (13,800 volts).

The distribution equipment involves (1) transformers to step up the electricity to a higher voltage (up to 500,000 volts) for more economic transmission over long distances, (2) the transmission lines for this purpose, and (3) the local substations and distribution equipment for delivery to the consumer.

Some of the waste heat can be put to beneficial use as in the heating of buildings or warm water irrigation. All of it eventually winds up in the environment either as heat up the stack during combustion or as heat rejected from the working fluid to water or air.

Handling of the material wastes depends upon the nature of the waste product, for example: (1) noxious gases released during combustion of coal are scrubbed out, (2) the large quantities of coal ashes are spread out, covered over, and the ground revegetated, and (3) the small quantities of radioactive wastes from nuclear power plants are concentrated further, converted to more inert forms, and will probably be buried in stable geologic formations.

Production of electricity from geothermal processes also involves the conversion of heat into electrical energy. The energy source is hot fluid delivered from underground to an energy conversion unit. This unit is also a turbine with steam or possibly some other material as the working fluid. Electricity is produced and transmitted as in the other processes.

Waste heat rejected by the working fluid must be disposed of. Because no intermediate process - either chemical or nuclear - is involved, no significant new waste products are generated. The waste material is the spent geothermal fluid and possibly some of the chemicals it contains, which are removed to improve operation of the power conversion equipment.

In order to set the stage for the program recommended in this document, this section deals with the technical and economic considerations involved in the use of moderate temperature geothermal resources for the production of electricity. The material is organized according to the four previously identified elements: (1) energy source, (2) power conversion, (3) electricity distribution, and (4) waste disposal.

2.1 Energy Source

The attractiveness of moderate-temperature geothermal fluids as a source of energy for the production of electricity stems from their relative abundance compared to higher-temperature geothermal sources and from their location, generally closer to the surface. This section deals with availability and with methods of delivery from underground to the surface.

2.1.1 Availability

Quantitative determinations have not been made on the estimated availability of geothermal fluids at various temperatures. The definition of these resources is traditionally left to the industrial sector. Cognizance for such activities by the government is outside the responsibilities of the Energy Research and Development Administration; rather it rests with the U.S. Geological Survey.

As a result, only qualitative arguments are presented here as follows: Nature has characteristic distributions, expressed mathematically as for instance the Gaussian distribution (Figure 1a). This distribution shows the deviations about a mean or likely value, with the deviations extending without interference in both the positive and negative directions. If one side is restricted by a physical limit (i.e. absolute temperature cannot be less than zero), then one obtains a skewed distribution, such as a Poisson Distribution (Figure 1b). One can postulate such a distribution for available ground water vs temperature (Figure 2). Here the left end of the X-axis (the origin) is the freezing point of water; the right end is an asymptote, leading to higher temperatures and approaching zero volumes. Of the total ground water within a reasonable distance from the surface, the most likely temperature may be 30 to 40°C. Since these temperatures are much too low for production of electricity, the upper end of the curve must be examined in detail.

Existing experience with higher-temperature geothermal sources has utilized reservoirs down to temperatures of 180°C (356°F), as shown by line A on Figure 2. If the curve can be extended even 30°C downward to line B (300°F), the quantity of available useful water is expanded by approximately an order of magnitude.

In terms of the total energy content of the available useful water, relative to some base temperature, the increased capacity is not as startling because the lower temperature water has a lower energy content (Figure 3). While both Figures 2 and 3 represent estimates and not necessarily the true shapes of the curves, it is apparent that significant increase in the geothermal energy source results if lower temperatures can be utilized.

The lower temperature resources should be easier to locate both because they are more abundant and because they are at shallower depths. A greater success ratio in drilling usable geothermal wells is to be anticipated. As discussed subsequently, this success ratio has an important effect on the cost of the geothermal resource.

Fig. 2. Postulated Curve to Represent "Available" Ground Water Volume vs Temperature

Fig. 3 Energy content (above 45°C) in the "Available" Ground Water

Fig. 1a Typical Gaussian Curve - Nature's "Normal Distribution"

Fig. 1b The Poisson Distribution

2.1.2 Delivery of Geothermal Fluid

In higher-temperature geothermal wells, fluid is brought to the surface primarily by letting the geothermal water flash as it rises to the surface. As a result, the temperature of the geothermal fluid drops. The well discharges a steam-water mixture that must be separated so the steam can be used. The steam fed to the geothermal power plant is thus several hundred degrees cooler than the temperature of the reservoir which feeds the plant. (Some geothermal reservoirs, such as the Geysers in California and Larderello in Italy, produce dry steam in contact with underground hot rock and bring the steam to the surface at nearly the steam reservoir temperature.)

Flashing in the higher temperature geothermal wells is a necessary process since no pumps are available that will operate at the temperatures and depths required to prevent flashing and release of dissolved gas. (R&D work to obtain suitable pumps is being sponsored by ERDA.)

A common pumping force, and one that is largely independent of the geology, is that caused by the density difference between hot and cold water. Figure 4 shows a sketch of a typical geothermal reservoir. The pressure in the reservoir is generally determined by hydrostatic conditions of the surrounding water table, that which is usually tapped for drinking and irrigation water. The geothermal water, at a higher temperature, is isolated, or prevented from mixing with these cooler waters, by strata of rock having poor permeability. The extent of the mixing varies from reservoir to reservoir. In general the hydrostatic pressure in the reservoir is established by a water column that is at a much cooler average temperature than the geothermal water. The geothermal water, entering the well bore and filling the casing, has a lower density than the water establishing the hydrostatic pressure of the reservoir. Table 1 lists the pressure difference per 1000 ft of (well bore) vertical distance, for water columns of various temperature, all with reference to a 21°C (70°F) cold water column.

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Figure 4 Hydrologic Model

TABLE I

PRESSURE HEAD AGAINST 70°F (21°C) HYDROSTATIC HEAD

<u>Geothermal Well Temperature</u>	<u>Pressure Differential Per 1000 ft of Height</u>
102° F	2.85 psi
153° F	8.7 psi
193° F	14.5 psi
212° F	17.8 psi
240° F	22.7 psi
281° F	31.0 psi
303° F	35.8 psi

If, for example, the domestic aquifer in Figure 4 is 2000 ft deep and at a temperature of 70°F (compared to 303°F for the water in the geothermal well), the resulting pressure difference would pump the geothermal water nearly 200 ft above the normal water table. As described subsequently, this pumping capability has been demonstrated as part of this program for some typical moderate-temperature geothermal wells in Idaho's Raft River area.

With a moderate temperature fluid (300°F) a pump need be set at a water depth of only 120 ft to suppress flashing. Such a pump can be used to provide additional lift if necessary to bring the fluid to the surface or to enhance the production from the well. The amount of enhancement possible depends upon the permeability of the formation and the amount of power one is willing to supply to the pump. Pumps for application at this depth are within current technology for shaft-driven or submersible pumps.

Once the fluid is brought to the surface, it can either be flashed to steam at the wellhead (losing some temperature in the process), or transmitted as liquid to the power plant. The selected method depends again on the fluid temperature and the ultimate application. For high temperature systems, steam at high pressure is a suitable fluid to be delivered to the power plant. For lower temperatures, the low density of steam makes it unsuitable. It is furthermore desirable to preserve as much heat as possible in the geothermal fluid until it reaches the power plant. When transmitted as water, pressure sufficient to prevent flashing in the pipelines is required. For the moderate temperature resource this pressure is in the order of 100-125 psi.

The high temperature systems require design to accommodate pressures in the order of 1500 psi or more. Thus, the lower temperatures, accompanied by lower pressures make possible the use of less expensive materials and construction practices.

This discussion of availability and delivery of geothermal fluids has dealt only with location in the vertical direction. Limitations are also imposed in a horizontal direction. If wells from too large an area feed the same power conversion unit, the piping costs become uneconomic. As a result the size of power conversion unit is limited to about 50-150 MW (e) (the lower values for the lower temperature system). The implications of this size limitation on costs, waste disposal, etc. are discussed in subsequent sections.

2.2 Power Conversion

The two important characteristics of the moderate-temperature geothermal fluid in regards to power conversion are the following: (1) the fluid generally contains fewer dissolved solids and gases; and (2) the efficiency of the process of converting heat to electrical energy is somewhat less - both in comparison to the higher temperature geothermal sources now in use.

2.2.1 Deposition and Corrosion

All geothermal fluids, whether steam or water, contain dissolved gases and minerals; the amount of dissolved solids tends to increase with temperature. As a result of extracting energy from the fluid, it is cooled and deposition of the minerals occur in the wells, piping systems, and energy conversion equipment. Corrosion results from an electric chemical process between exposed and unexposed metal surfaces. Metal surfaces require periodic changeout or use of expensive corrosion resistant materials. Prevention of dissolved gas release to avoid some forms of deposition can result in the need to maintain very high fluid pressures.

Moderate temperature resources tend to have much lower dissolved minerals and gases. Thus, the deposition and corrosion problem is less severe than in the higher temperature geothermal systems and more easily controlled.

2.2.2 Conversion Efficiency

The conversion of heat to electrical energy is performed by first creating mechanical energy in rotation of a generator. According to the basic physical principle (the second law of thermodynamics), this conversion is done most efficiently at high source temperature. Specifically the heat is extracted at a high temperature (T_{hot}), partially converted to work, and the remainder is rejected at a lower temperature (T_{cold}). The ideal or maximum possible efficiency is

$$E = \frac{T_{hot} - T_{cold}}{T_{hot}}$$

with both temperatures measured from absolute zero.

Fossil-fueled power plants operate their boilers at the maximum temperature that the materials of construction can withstand, typically superheated steam to 1000°F, and reject the heat at about 110°F (see Figure 5). Their ideal efficiency is 60% and their actual efficiency about 40% - both quite high.

Nuclear plants have thus far been limited to saturated steam temperatures (less than 600°F); their ideal efficiency is less than 50% and their actual efficiency about 32%.

Geothermal power plants currently in use around the world operate with source temperatures of about 350 to 400°F; accordingly, their efficiencies are considerably less than either fossil or nuclear; - about 27% ideal and about 18% actual. If the source temperature is reduced to 300°F, the actual efficiency would drop to about 12%.

What is the importance of conversion efficiency and what can be done to improve it? Efficiency is important on two counts: (1) economy and (2) waste heat. The higher the efficiency the greater is the amount of energy extracted for a given energy supply delivered to the conversion equipment. If the cost of the energy supply is small compared to the cost of the conversion equipment, as in nuclear plants, a somewhat lower efficiency may still result in a lower total power cost. This subject is developed further in Section 3.0 Power Costs.

Power Cycle Diagrams for Coal, Nuclear and Geothermal Power Plants

Figure 5

If the temperature of the source is fixed, the efficiency of the conversion process can be improved in three ways:

1. One can reduce the temperature of the ultimate heat sink, that final reservoir of the environment to which the waste heat is rejected.
2. One can develop methods whereby the efficiency more closely approaches those of the ideal (Carnot) cycle.
3. The working fluid of the turbine obtains its heat directly from the geothermal source fluid (without use of an intermediate heat exchange fluid) and rejects it to the fluid of the ultimate heat sink. One can therefore minimize the temperature differentials between the source fluid and the working fluid and the heat sink. Both these temperature differences contribute to the inefficiency of the conversion process.

The low thermal efficiency of the moderate temperature system implies large heat transfer surfaces per unit power generated. In addition, since the sink temperature of any conversion system is relatively fixed, the moderate temperature resource requires larger flow rates than a higher temperature resource, other factors being equal ($Q = wcp\Delta t$). Thus, efficient transfer of heat and maximum utilization of the available energy potential (source temperature minus sink temperature) is of particular importance with lower resources temperatures.

The heat transfer is depicted in Figure 6. The total heat transferred is depicted in Figure 6a. One half is shown as the heat added and the other half is shown as the work and heat rejected. Relative heat transfer areas are shown in Figure 6b. Now, the use of the temperature potential (source minus sink) is given in Figure 7. For the moderate temperature fluid (taken as 300°F) about 30% (and

Figure 6a and 6b

Fig. 7

TEMPERATURE RANGES OF THE VARIOUS
FLUIDS USED IN A 300°F DUAL BOILING
BINARY GEOTHERMAL POWER PLANT

possibly higher) of the available temperature potential (down to condenser conditions at 70° to 100°F) is expended in establishing the supply heat exchanger and condenser temperature differences, leaving only about 160°F for transfer from the brine. Although values may be varied somewhat they must be low to achieve the turbine work and at the same time keep the brine utilized to a minimum. The use of small pinchpoints to achieve the energy transfer across badly fouled surfaces result in extremely large brine heat exchangers, and the need to limit them on the condensing end results in large condensers.

These temperature differences are considered in the design trade-offs of all power plants. The consideration is particularly important as the heat source temperature is reduced. High performance heat exchangers which minimize thermal resistance are as essential to moderate-temperature, low-saline geothermal application as they are to the higher-temperature high-saline applications. A heat exchanger development and assessment program therefore is an essential element to a moderate-temperature program.

Maximizing the brine utilization (kW-hr/# of brine) is also important for the low temperature application. As noted, the lower temperature resources require larger flows to achieve the same energy transfer as higher temperature systems. Thus more wells are required or they must be made more productive. Since wells represent a substantial portion of the cost of electric power from a moderate-temperature system, they should be as efficient as possible.

Moreover, one must learn to manage the geothermal reservoir when extracting and re-injecting larger quantities of fluid than would be necessary with higher reservoir temperatures. Moderate-temperature geothermal reservoirs are expected to be nearer the surface and thus may have characteristics different from those more deeply seated in the earth.

2.3 Transmission and Distribution of Electricity

While coal and nuclear power plants in the very large sizes (500 MW and 1000 MW, respectively) are the most economical, geothermal plants in the 50 to 100 MW range have the optimum overall economics (see Figure 8). Much of the Western U.S., where geothermal energy is most easily found, involves long transmission lines, carrying small amounts of power to widely dispersed load centers and rural areas. Hence, transmission distribution costs become a significant factor in the potential economical advantages of geothermal power.

Presently, in the northwest Bonneville Power system, the transmission resistive losses cost approximately \$6000 of electricity per year per circuit mile. The trend has been to site new, large nuclear power plants near the major load centers (Seattle, Portland etc.) of the area. These areas also happen to be near the location of the major hydroelectric facilities utilizing the run-off from the western slope of the Cascades. The intermountain area receives its energy largely via transmission lines from these large hydroelectric and thermal generating facilities. To site large power complexes in the intermountain area would create large step changes in the energy supply. Smaller step changes are desired, and can be supplied in the area by geothermal power plant increments.

The siting of numerous such geothermal plants (50 to 100 MW each) in the intermountain area could in large part supply the needs of the area, better balancing the electric grid system as well as reducing transmission costs and losses.

2.4 Provisions for Disposal of Wastes

2.4.1 Heat Rejection

One of the often cited disadvantages of utilizing geothermal energy, with its low "efficiency" for conversion to electricity, is the companion high waste heat that must be released to the environment. A 12% efficient power plant will reject 7-1/3 times as much heat as it

300⁰F (150⁰C) GEOTHERMAL FLUID
TRENDS VS SIZE-DUAL BOILER BINARY

FIGURE 8

produces electricity. Because geothermal power plants have an optimum size in the 50 to 100 MW range, the rejected heat is also kept in relatively small packages, making the impact on the local environment less severe.

The most commonly used heat disposal method is the wet cooling tower. Though requiring make up water continually, the wet cooling tower provides a most efficient heat removal system, especially in hot, arid climates. Make up water is approximately 15% of the required geothermal flow, for an efficient 300°F geothermal plant, and could be supplied by tapping off the geothermal water loop.

The dry cooling tower represents a significantly higher cost impact to geothermal, because of the large waste heat to useful energy ratio. Advanced cooling tower technology (such as fluidized bed) is needed to bring this system to a competitive position in geothermal applications.

Once through cooling from rivers and streams is generally not practical because of the environmental impact. However, a related alternative is once through cooling from the near surface aquifer, with injection of the heat back to the aquifer. The environmental effects should be a minimum in most aquifers, and might well be beneficial where irrigation is performed from these aquifers.

Other alternatives, such as phased cooling, cooling pond storage, etc. could effectively remove the waste power cycle heat and at the same time lower the heat sink temperature, increasing power cycle efficiency.

2.4.2 Disposal of Wastes

Aside from the thermal pollution considerations, geothermal energy has two principal environmental concerns:

- (1) Disposal of the used (waste) geothermal fluids
- (2) Maintaining the integrity of the crustal layer of earth from which the geothermal fluid is drawn.

Both of these concerns can be mitigated, if not dismissed, by judiciously planned re-injection of the used geothermal fluid back into the ground. This approach obviously attends to the first concern, and nominally eliminates the second concern by maintaining the fluid pressure underground. Re-injection and withdrawal both must be done with careful monitoring and planning to avoid the slight possibility of affecting the slippage of fault planes.

There are other environmental concerns with geothermal energy, but these are largely shared with conventional power plants. One often cited issue is the land surface required for the well spacing. Land rights and geothermal leases from a large area are indeed required, but the actual land area disturbed by wells and pipelines is minimal, with virtually no irretrievable environmental effects.

Thus, the key to acceptable environmental impacts from geothermal energy is a satisfactory, economical means of re-injecting the fluids back into the ground. Little actual long term experience exists with geothermal fluid disposal. However, experience from oil field stimulation makes the prognosis for successful re-injection favorable, in almost all geological environments where geothermal energy is likely to be harnessed.

3.0 COSTS OF POWER PLANTS

The purpose of this section is to develop some typical costs for power plants in order to provide target costs to be achieved with moderate-temperature geothermal sources.

One need only review several independent analyses of electric power costs from the conventional type of plants to note the wide discrepancy between the various estimates, and even between the actual experiences with now operating plants (see Figure 9). The major items causing the wide variations are largely fiscal, inflation and interest rates. The broad category of environmental aspects also has considerable affect - i.e., Where will the coal or uranium be mined, and how? How will the waste heat be disposed of? What type of environmental regulations will be imposed?

In order to place the costs on a simple basis for technical comparison, the elements of inflation and varying interest rates are eliminated from the quoted cost values. All costs are therefore, given in terms of present day (1976) costs. When figuring net power costs, in terms of present day dollars, an arbitrary 15% factor for cost of capital investment is used. (This value is high for publicly owned utilities, and low for some privately owned utilities, but selected as a reasonable medium ground.)

The above arbitrary considerations do not, as one would expect, do full justice for comparing one choice of energy system with another. A coal plant, able to be placed in service in fewer years of construction than a nuclear plant, has an added advantage which will not show in the figures. A geothermal plant perhaps will not be built until the reservoir is proven, yielding no return-on-investment from the wells for many a year - an obvious disadvantage. However, the small optimum sized module of geothermal power compared to the large optimum modular size of coal or nuclear provides geothermal with an advantage, though an intangible one, in terms of cash flow, long-range planning decisions, and financing ease. These factors will vary from utility to utility, and obviously result in decisions tailored just to a particular utility.

Figure 9

Table II provides estimates of both energy supply and capital costs for fossil fueled and nuclear power plants.

As a guide, one can assume that costs of power based on direct comparisons in terms of 1976 dollars could vary as much as a factor of two among energy systems that are considered economically competitive for a variety of utilities. It is against this background of conventional power plant costs that the target area for geothermal power must be found. The target should be identified in terms of the temporal characteristics of the other fuel costs, particularly coal. And because of the varying financial aspects of interest during construction and arranging for financing, the target range is further obscured.

Based on these considerations, the following target costs were selected for the moderate-temperature geothermal systems: (1) \$600/installed kW for capital costs of the power conversion facility. For convenience, the energy supply system costs will be converted to equivalent capital costs as a target. The rate of which replacement wells must be drilled will vary from field to field. Normally, the replacement wells would be considered an operating and maintenance charge, and (2) 10 mills/kWhr for energy supply costs. The various factors influencing these costs in geothermal plants are discussed below.

3.1 Energy Supply System Costs

The energy supply system cost for geothermal is largely the result of well costs. Here, the success ratio will need to be included. That ratio should be larger for the moderate-temperature systems than it is for the high temperature ones, simply because of the greater abundance of the moderate-temperature water. Table II lists some characteristics of these geothermal energy supply system costs, for existing fields. All should be considered approximate numbers, for cost factors vary from locality to locality, let alone country to country.

What is a tolerable cost for the geothermal energy supply system? If a 25% minimum return on investment is necessary to attract speculative geothermal development, then for an assumed

10 mills/kW hr supply of energy at 80% plant factor, the allowable cost is \$280/kW for 25% Return on Investment.

TABLE II

CURRENT ENERGY SUPPLY COSTS, CONVENTIONAL POWER PLANTS (1976 dollars)

Coal	50¢ to \$1.40 per MBtu*	
	80¢/MBtu average, with heat rate of 9200 Btu/kWhr	
		7.4 mills/kWhr
Oil	\$13/barrel, delivered cost of \$2.40/MBtu	
	heat rate 8800 Btu/kWhr	
		21 mills/kWhr
Nuclear	current light water reactors	3 mills/kWhr**

CAPITAL COSTS, CONVENTIONAL POWER PLANTS (1976 dollars, no escalation or interest charges included)

	Installed Cost	Mills/kWhr at 15% cost of capital and 80% plant factor
Coal, with "normal" pollution control	\$ 460/kW	9.9
Oil	\$ 290/kW	6.2
Nuclear, light water reactors	\$ 550/kW	11.8

(Capital costs are from a mid-1975 tabulation of average costs compiled by Electric Power Research Institute)

* 1975 coal costs, which continue to climb significantly toward the level of gas and oil costs

**Future estimate (when new reprocessing costs, uranium at \$25/lbUO₂, \$72/SWU enrichments costs, and waste storage costs are included)

= 6 mills/kWhr

TABLE III
GEOTHERMAL ENERGY SUPPLY SYSTEM APPROXIMATE COSTS

A) <u>Geysers, USA</u>	
Gross MW of electricity per well (current)	5 MW
Gross MW of electricity per well (stretch capacity)	5 MW
Cost per well (6000 to 8000 ft deep)	\$500,000
Cost of pipeline per well	\$ 50,000
Success/(Failure + Success Ratio)	~ 0.7
Energy Supply System Cost	\$157/kW
B) <u>Cerro Prieto, Mexico</u>	
Gross MW of electricity per well (current)	6 MW
Gross MW of electricity per well (stretch capacity)*	10 MW
Cost per well (4250 ft deep)	\$300,000
Cost of pipeline per well, plus separators	\$100,000
Success/(Failure + Success) ratio	~ 0.9
Energy supply system cost (current)	\$ 74/kW
Energy supply system cost (stretch capacity)*	\$ 44/kW
*An additional flash stage is the likely means of stretching capacity.	
C) <u>Travali, Italy</u> (dry steam, 420°F)	
Gross MW of electricity per well (current)	15 MW
Cost per well (estimated)	\$300,000
Success/(Failure + Success) ratio	~ 0.4
Energy supply system cost (single wellhead, non-condensing units located at well)	\$ 50/kW
D) <u>Imperial Valley, California</u> (flash steam, reaching surface at 370°F)	
Estimated Gross MW per well, single steam flash	3 MW
Estimated MW per well, stretch capacity (binary)	6 MW
Cost per well*	\$400,000
Success/(Failure + Success) ratio	~ 0.8
Pipeline costs	\$ 80,000
Energy supply systems costs (single steam flash)	\$190/kW
Energy supply system costs (binary)	\$ 95/kW
*Based on East Mesa wells drilled by Bureau of Reclamation in 1974, plus 20% for inflation.	

E) Raft River, Idaho (295°F)

Estimated gross MW per well, double flash steam, standard	1.5 MW
Estimated gross MW per well (standard binary)	3.0 MW
Estimated gross MW per well (stretch binary or total flow)	
Cost per well	\$500,000
Success/(Failure + Success) ratio	~ 0.9
Pipeline cost per well	\$150,000
Supply and booster pumps and manifolds, per well	\$140,000
Energy supply system cost, steam	\$563/kW
Energy supply system cost, binary standard	\$281/kW
Energy supply system cost, stretch binary* or total flow	\$169/kW

*"Stretch binary" system would incorporate the improvements discussed

The energy supply system costs represents the wells, the pipelines, pumps, etc., plus any prior exploratory costs and credit for the unsuccessful wells.

From present experience at Raft River, (plus that at various producing electric plants shown in Table III), targeted \$280/kW supply system does not appear to be an unreasonable expectation, if each well can supply sufficient electric power. In the case of Raft River 3.0 MW per well is required, about what the present design and well production figures would yield. However, to this costs must be added the re-injection/disposal system costs.

3.2 Environmental Control System Costs (Reinjection System)

A companion part of the energy supply system is the waste material (geothermal fluid) disposal system. Both the supply and disposal system would be expected to be planned and operated as a unit. The costs are herein separated for comparison purposes, because none of the producing hot water geothermal operations to date have incorporated a disposal system involving re-injection wells.

Expected costs, based on extrapolation of the Raft River experience to date, is shown in Table IV. If one now adds the \$135/kW cost to the supply system cost, the challenge now becomes quite significant. The total supply plus disposal system costs must be reduced a third, or the power output of the plant increased 50%.

It should be recognized that the above analysis is based on present Raft River conditions, conditions which can vary substantially from field to field. The implication is, however, that significant improvements over the present design and costs are necessary, in general, if the moderate temperature resources in the range of 300°F (150°C) are to be competitive.

TABLE IV

ENVIRONMENTAL CONTROL SYSTEM COSTS (RE-INJECTION)

Wells	\$70/kW
Pipelines	\$47/kW
Pumps & Manifolds	\$ 8/kW
Environmental Monitoring (Capital Cost Only)	\$10/kW
	<hr/>
TOTAL	\$135/kW

3.3 Power Conversion Costs

The power plant costs, using nominally state-of-the-art technology for the binary organic cycle, total approximately \$640/kW. The following table lists the relative breakdown of this cost between the various components, so one can determine which aspects deserve the most attention and have the most potential for reducing costs of the overall plant⁽⁶⁾.

Land, improvements, buildings	\$20/kW	3%
Isobutane systems, storage, pumps	\$74/kW	12%
Heat exchangers (preheaters & boilers)	\$143/kW	22%
Condensers and hotwells	\$141/kW	22%
Turbine generator	\$64/kW	10%
Cooling supply system (wet cooling towers)	\$96/kW	15%
Electrical, controls, utilities, etc.	<u>\$102/kW</u>	<u>16%</u>
Total, 50 MW sized plant \$640/kW		100%

It is obvious that the heat exchange components (including the condenser) represents nearly half the power plant cost. The cooling supply system is the next most significant contributor, and could be more significant if certain additions to lower the heat sink were incorporated (dry cooling, fluidized bed towers, for instance). The other components represent essentially standard engineering practice, appear to offer little potential (if any) for reduced costs, and are relatively insignificant to the whole. Therefore, an overall target of \$500/kW seems to be the lowest realistic value likely to be achieved in the not too distant future.

3.4 Total Costs

The targeted costs for a geothermal power plant and energy supply/disposal system complex are approximately \$900/kW to be competitive with coal and nuclear plants (1976 technology, 1976 dollars without interest during construction). It would appear that this might typically be split 60/40 between the power plant and the energy supply/disposal system. The split will vary widely, from one situation to another. But these targets are used in the following sections to establish the RD&D program plan, the relative emphasis on the various sectors, and the time schedule and priorities for implementation.

4.0 REVIEW OF ERDA'S MODERATE TEMPERATURE UTILIZATION WORK

A program to explore the technical aspects that could improve the economics of moderate temperature geothermal fluids as a source of electricity was initiated at the Idaho National Engineering Laboratory in 1973. The program thus far consists of (a) power plant cycle and cost studies, and (b) exploratory field work in the nearby Raft River Valley. Each of the two phases of the program has produced significant findings:

1. the paper studies⁽⁶⁾ indicate that, with current technology, electricity from moderate-temperature geothermal resources can be cost competitive with electricity produced from oil as the energy source. Further technical development and experience leading to significant economic improvements will make this geothermal resource competitive with coal and nuclear power.
2. preliminary exploration at Raft River provided virtual assurance that the reservoir was extensive enough to provide the flow of 300°F geothermal water needed for test and pilot plant facilities. Further drilling should confirm adequate flow (25,000 gpm) for a demonstration plant with a net electrical capacity of 50 MW.

A summary of both the theoretical studies and experimental work is given in this section. More detailed information is found in published reports - a bibliography of these is given at the end of this section.

4.1 Theoretical Studies

Power plant studies were initiated at INEL in 1974. Three power conversion cycles have been studied in some detail for 300°F geothermal fluid: (2,3,4,5)

1. Flash steam. In this system, the pressure of the geothermal fluid is reduced and a portion of the fluid is allowed to flash to steam. The steam is expanded through a turbine to drive a generator to produce electricity. The steam is then condensed. In the so-called dual flashed steam system, flashing is allowed to occur at two pressures. The resulting steam is allowed to drive a high-pressure and a low-pressure turbine, or the high- and low-pressure sections of the same turbine. The dual flashing option increases the efficiency of the cycle and improves the utilization of the geothermal fluid.
2. Boiling binary. In both this and the third cycle studied, the heat of the geothermal fluid is transferred to a second fluid which is used as the working fluid in the turbine. The working fluid is preheated, vaporized (hence the term boiling), expanded through the turbine, and then condensed. In the dual boiling cycle, the working fluid is preheated at two different pressures and temperatures; and the same advantages accrue as for the dual option of the flashed steam cycle.
3. Supercritical binary. In this cycle, the working fluid is maintained at high (supercritical) pressure so it does not go through the normal boiling phase transition, instead it passes above the critical point on its way to turbine inlet conditions of the highest possible enthalpy.

Preliminary comparisons between the two binary cycles led to the selection of the boiling process for further study for the following reasons:

1. Working fluids for a supercritical process in the moderate temperature application generally.

- a. Result in high working pressures and higher costs for both the boilers and condensers, and
 - b. require a large amount of pumping power.
2. The performance of the two cycles is comparable but that of the supercritical cycle is drastically reduced if degradation of the temperature of the geothermal source occurs, i.e. the temperature drops below design value.

A preliminary comparison was made between the costs of power from the dual flash* and dual boiling binary cycles. The costs of the energy conversion systems were similar with a slight edge to the steam system. However, much better utilization of geothermal fluid - only about one-half as much is required in the binary system - causes that system's total power cost to be lower than those for the steam system. The cost advantage shifts to the steam system for low-cost high production wells because of the lower cost of the surface steam plant facility.

Further cycle studies resulted in selecting isobutane as the binary working fluid for detailed economic evaluation. Optimum vaporization temperatures were found to be 230 and 160°F for the dual boiling cycle with a flow split of 70% to the high-temperature and 30% to the low-temperature boilers when the geothermal fluid is initially at 300°F.

* The dual flash steam system used in the comparison was designed with the lower flash above atmospheric to prevent the introduction of oxygen into the system (recommended by turbine manufacturer). The condensing temperature was about 15° higher than that used in the binary system. While these differences penalize the steam system performance, they keep turbine inlet, turbine exhaust and condenser sizes smaller. Neither system has received complete economic optimization.

A detailed cost comparison of a 50 MW(e) geothermal plant with large fossil and nuclear plants led to the conclusion that moderate-temperature geothermal fluids are already competitive as an energy source with fuel oil. Results are shown in Figure 10. With proposed technical improvements this geothermal source will be comparable in cost to nuclear and coal.

4.2 Experimental Work Resource Related

The experimental work relative to moderate temperature geothermal utilization and concentrated on the resource in the Raft River Valley of south central Idaho, 6 miles from the Utah border. This valley intersects the vast tectonic split of the Snake River Valley, a recent volcanic rift zone. Intersecting this broad valley are many smaller valleys, typical of those found throughout the intermountain west. The Raft River Valley is typical of these valleys. It had no significant natural geothermal anomalies, except a few springs, very slightly warmer than normal 50°F spring water. However, since irrigation from deep wells (typically 400 ft) began in earnest in the 1930's, two such wells eventually developed a flow of boiling water. A geophysical-geological investigative effort, which focussed on these anomalies, was undertaken with the assistance of the Raft River Rural Electric Cooperative.

As a result of the preliminary work, the U. S. Geological Survey, in cooperation with the INEL (and several universities under contract to INEL) undertook a thorough geological-geophysical investigation for geothermal energy in the valley. In addition to surface measurements (deep resistivity, active seismics, magnetotellurics, magnetics, gravity, self-potential, microseismics, etc.) were made, some 34 hydrological wells (typically 100 ft deep) and five slim, intermediate-depth (1300 ft maximum), cored holes were drilled. Sufficient data were gathered in an attempt to make a geothermal case study, if and when the area would eventually be drilled to greater depth for geothermal energy.

FIGURE 10 POWER COST COMPARISON

For 300°F Geothermal Plant and Oil, Coal, and Nuclear Plants.

By the fall of 1974, most of the data was available for analysis. The conclusion was reached that the Raft River Valley appeared to be a typical Western valley. Though there was some hot water, the data could not reliably tell its quantity or source, none of the information indicated reservoir temperatures much exceeding 150°C (302°F). These conclusions prompted further exploration because developed information would have large-scale application if the Raft River Valley was typical of many areas in the Western United States.

Shortly thereafter, the State of Idaho provided for about one-fourth the cost of a deep exploratory hole ERDA provided the remainder, and the drilling began on January 4, 1975. It was decided to use only water as the drilling fluid in order to maximize the probability of developing geothermal flow and to minimize the chance of sealing small fractures with mud.

On January 31, the 4650 ft depth was reached in the predicted fracture zone. A complete set of geophysical logs was ordered before drilling deeper. During logging, flow spontaneously developed and eventually reached approximately 1400 gal/min (0.089 m³/sec). The 10-3/4 inch mud-line could not carry this flow without boiling water spilling onto the drilling platform. The well was shut off.

Since that time, the well has been enclosed with a 13-3/8 in. casing to 3700 ft, sealing off some of the cooler producing zones. Source temperature is 295°F (146°C) and artesian flow 600 gpm. Shut-in pressures are approximately 50 psi after injecting cold water, 165 psi after flowing hot water. Figure 11 shows the setting of this well.

A second well has since been drilled to 6000 ft, the bottom 1200 ft through basement quartzite rock. This well develops 900 gpm of artesian flow, with producing temperature apparently a few degrees higher than for the first well. Figures 12 and 13 are geological cross sections of the wells.

Reservoir drawdown testing was conducted in the fall of 1975, to establish the approximate reservoir parameters, at least producing the bulk of their flow from above basement rock. The first well, however, definitely penetrated a fault zone whence most of the flow seems to be coming. The second well developed most of its flow without any obvious contact with a fault zone (Figure 15).

The results of the reservoir testing were most encouraging. The permeability between the two wells is higher than typically expected in a reservoir, with an assumed producing reservoir thickness of 500 ft. The storage coefficient of water was about average. The testing also showed that only a small portion of the boundary to the reservoir was nearby, and that the reservoir extended at least several miles in some directions.

Of most significance is the long term effect of withdrawing and re-injecting water. Figure 16 shows the effect of producing 1000 gpm in one well and reinjecting it in the other. The model assumes no convection mixing, just blockflow. The first streamline from the injection well takes 60 years to reach the production well. Major dilution would not occur for nearly 100 years. The calculations are not directly comparable to the proposed demonstration plant. 1250 gpm per well is the design condition being used for cost estimating purposes for a demonstration power plant, but re-injection wells are anticipated to be somewhat more than 4000 ft from producing well.

This testing indicated that the reservoir was extensive enough to provide the flow needed for test and pilot plant facilities. Though two wells would hardly be sufficient to guarantee the flow needed for 50 MW (net) (25,000 gpm), the reservoir analysis provides positive indicators with regard to such an extrapolation.

Power Plant Components

Experimental work related to power conversion is primarily associated with corrosion and deposition and heat exchangers.

Test hardware has been designed and constructed which represent steam separators for flash steam systems and heat exchanger tubes used in a binary system. Fouling tests are currently being conducted on small diameter tubes in an attempt to accelerate deposition and thereby provide background data for plant design. Corrosion tests on many samples have been initiated to screen the materials suitable for use in the Raft River geothermal water and establish general corrosion rates which can be used as the basis of design trade-offs.

New heat exchanger concepts; a liquid fluidized bed and a direct contact boiler have been tested at Raft River and show great promise in geothermal applications for which they are being developed. The results of these tests have been published in the progress reports listed in the bibliography.

Figure 11. Photograph of the Drill Site Taken During One of the Very Brief Flow Tests Conducted Later Under Controlled Conditions

RRGE NO. 1

Fig. 12 Raft River Geothermal Exploratory Well No. 1

Fig. 13 Raft River Geothermal Exploratory Well No. 2

Fig. 14 Map of Well Locations

Figure 15 Formation and Location of RRGE-1 and RRGE-2

Flow = 1000 gpm from production well (on left) back into re-injection well on right

Aquifer thickness = 500 ft

Formation porosity = 10%

Production temperature = 147°C (296°F)

Re-injection temperature = 80°C = 176°F

Figure 16 Stream Lines Between Supply and Reinjection Wells

In the preceding sections, the status of moderate-temperature resources has been compared to that of other geothermal fluids and of other methods (fossil and nuclear) for production of electric power. A number of advantages and some disadvantages have been identified and the need to maximize the advantages and minimize the disadvantages has been established, as follows:

(1) The energy available nationwide from hydrothermal resources is quite high compared to currently developed high temperature resources. The success rate in tapping the individual moderate temperature resources is potentially higher than for high temperature wells. Further specific experience, such as obtained in the past year at Raft River, in the drilling of geothermal wells is necessary to confirm these preliminary findings.

(2) The conversion efficiency from heat to electrical energy is somewhat lower than for existing geothermal systems which are operating and have proven to be economical. Experience with other methods, such as coal vs nuclear, indicates that efficiency is not the sole criterion of economics. Because the maximum efficiency attainable is low, every reasonable effort should be made to come as close as possible to that ideal efficiency as possible. For example, temperature lost between the geothermal fluid and the turbine working fluid and between the working fluid and the heat sink causes an important penalty on efficiency, so emphasis should be placed on improving the heat transfer equipment used at these two points in the conversion cycle.

(3) The lower temperature and operating pressure, and the resulting smaller amount of dissolved minerals and gases, in these geothermal fluids offers potential savings in materials of construction for the power conversion equipment. In this regard the situation is analogous to low-sulfur, low-heat Western coal, which requires the burning of more coal for given power output but potentially less expensive pollution control equipment. Operating experience with geothermal equipment made from low-cost materials is a necessary part of any development plan for the moderate-temperature geothermal source.

(4) The potentially adverse environmental effects - discharge of waste heat and disposal of spent geothermal fluid - are solvable using conventional engineering. Because of the low efficiency, the amount of waste heat per unit of electric power is about five times as much as for a modern coal plant and about twice as much as for a 400°F geothermal plant. The total quantity per plant will be less than for a coal-fired plant because of the much smaller size of the geothermal unit (50-150 MW(e) vs 500-1000 MW(e)). Re-injection back into the near-surface aquifer is a promising way to release the waste heat without consumptive use of the water. Re-injection of the spent geothermal fluid back into its aquifer minimizes the environmental impact associated with it. Specific experience with this technique and with other methods of energy rejection is necessary to firm up the costs of this part of the cycle.

(5) Target economic costs for moderate-temperature geothermal sources are approximately as follows (in 1976 dollars without interest during construction):

- (a) less than \$200/kW for the energy supply system;
- (b) less than \$500/kW for the energy conversion system; or
- (c) \$100/kW to return spent geothermal fluid to the aquifer;
- (d) a suitable trade-off between these.

Postulated improvements in energy supply systems have the potential of reducing their cost well below the target costs. Current technology estimates indicate that conversion system cost of \$600/kW are already attainable. Since the power conversion system represents the largest portion of plant cost, the greatest cost incentives lie in improving the efficiency of the conversion process.

(6) The small size of the optimum geothermal power plant offers some intangible advantages from a utility planning and financing standpoint. These advantages are not reflected in the base total costs of these plants. Continuing system studies and dialogue with potential users of geothermal plants are an essential part of developing these and other advantages of the geothermal process for power production.

The goal of the ERDA Geothermal Energy Program is to stimulate greater utilization of U.S. Geothermal resources by the private sector. Significant commercialization by 1985 5000 to 20,000 MW of electric power-is the target. The moderate temperature geothermal resources can make a significant contribution to this target if a vigorous testing and demonstration program is initiated immediately. The objectives of this program, as described in this section are as follows:

- (1) to establish the technical feasibility of an integrated energy supply and power conversion system, requiring essentially no component development;
- (2) to demonstrate economic viability by competitiveness with major existing sources of electric generation; and
- (3) to implement transfer of geothermal technology to industry by continuing to increase industrial involvement in the program.

To show technical feasibility, it is proposed to continue useful experiments using the existing wells and to begin immediately the detailed design of a moderate-temperature geothermal test facility. The on-going testing phase will continue to gather the much needed, long term performance information on the following:

- 1) Well productivity, including methods of maintaining and enhancing it.
- 2) Re-injection effectiveness, including variation on re-injection schemes and methods of getting more water back into the ground with fewer wells and less cost.
- 3) Reservoir performance evaluation in connection with 1 and 2 above.
- 4) Long term effects on a variety of low cost piping, heat exchanger, and other primary loop materials.

- 5) Performance testing on small heat exchangers, both standard and advanced type, including methods of maintaining them in good, low cost operating conditions over long periods of time.
- 6) Experiments on reductions in heat sink temperature, spanning performance of these over a complete annual cycle.
- 7) Experiments on new concepts.

The test facility is to be located at Raft River. It will include the following components:

- 1) producing wells,
- 2) re-injection wells,
- 3) connecting pipelines, and
- 4) all the components of a surface facility that transfer and remove heat and produce mechanical energy.

This facility will be of sufficient size for an adequate test of reservoir management techniques. The conversion equipment will be of a representative size for use in a commercial power plant, approximately 10 MW of gross electric output. This base system of the facility will supply two-thirds of the eventual total facility output by using a binary isobutane system. As discussed previously, this cycle provides the highest performance of any analyzed for the moderate temperature resource while operating at relatively low pressures. Except for the turbine, the components of the base system represent conventional chemical processing technology equipment. However, this equipment (heat exchangers in particular) have never seen long-term extended performance testing on a moderate temperature, low salinity geothermal fluid. Neither have organic fluid turbines seen use as power producing devices for performance testing periods. Industrial organizations have expressed confidence that an appropriately sized, isobutane - driven turbine can be built without further development.

With this state of technology development, with immediate implementation of plans and funding for a test facility and with vigorous involvement by industry, it is believed that the facility can be in initial operation by early 1979. In addition to the base isobutane system, significant capacity will be provided in a flexible test facility arrangement so that the more promising advance concepts can be evaluated. Technical and schedule details of the test facility are provided in the next section.

To demonstrate economic viability, the next step after a test facility is the design, construction, and operation of a demonstration power plant. If the test facility is built on the proposed schedule and continues to show encouraging results, design of a demonstration plant could be phased for expeditious commitment to construction, once preliminary results are obtained from the test facility. With this accelerated schedule, shown in Figure 17, utility commitments to construction of commercial plants may be possible as early as 1982.

To implement technology transfer to the industrial segment requires continuing commitment by ERDA and INEL to hasten industry involvement at every step of the program. Indeed industry involvement is the key to achieving the other objectives of technical feasibility and economic viability and to making a significant contribution to the ERDA 1985 commercialization target.

The INEL is dedicated not only to implementing of the Research, Development and Demonstration (RD&D) efforts, but to effective planning of the program management in order to hasten the technology transfer to industry. Vital commitment to industrial involvement have already been made by both INEL and industry. Over 100 utilities are already involved in the Raft River Geothermal Program. These utilities represent literally hundreds of potential geothermal areas. If 20 to 50 power plants, of 50 or more MW, are committed early in the commercialization phase of Figure 17, moderate temperature geothermal resources in the Northwest alone could make a significant contribution of 1000 to 2500 MW to the 1985 ERDA target. The distribution of those resources in the northwest indicates that 10,000 to 15,000 MW capacity might be placed into operation over the subsequent 15 years.

FY-1974	FY-1975	FY-1976	FY-1977	FY-1978	FY-1979	FY-1980	FY-1981	FY-1982
Conceptual Ideas Program Planning	Resource Verification and Conceptual Design	Final Design and Specif. for R&D Testing Program	Fabrication and Construction of Test Facility and Pilot Plant			Testing and Evaluation		
			Demonstration Plant Preparation and Design		Construction of Prototype (Demonstration) Power Plant		Commercialization Plan	
							Operation of Demonstration Unit Evaluation and Dissemination of Information	

Figure 17 Industrial Participation Matrix

Other aspects of organizational involvement to date in the research phases of the INEL Geothermal Program are shown in Figure 18. In these activities, other national labs and universities have been asked to play a significant role, consistent with their capabilities and experience. Industrial organizations are participating in development of products and are supplying some of the services available in the industrial sector.

The test facility program can be considered to be a pre-demonstration phase and should have even greater involvement of the industry, particularly by utilities, who will be expected to carry on the subsequent demonstration and commercialization phases.

Accordingly preliminary discussions have already been held with one organization to act as lead utility for the test facility. The respective roles of INEL and the lead utility are visualized as follows:

1. INEL - responsible for
 - (a) conceptual design of test facility
 - (b) selection and management of new technology
 - (c) test program and evaluation, and
 - (d) reporting technical results and economic evaluations to industry.
2. Utility - functions as owner of an experimental power plant to:
 - (a) contract for and supervise architect engineer and construction manager, and
 - (b) procure major equipment items.

In this way the utility would develop first-hand experience with moderate temperature geothermal power plants.

IDAHO NATIONAL ENGINEERING LABORATORY GEOTHERMAL PROGRAM

Fig. 18

7.0 PROGRAM DETAILS

A variety of technical improvements aimed at enhancing the economic attractiveness of the moderate temperature geothermal resource have been identified. Figure 19 is a block diagram showing the various technical efforts in the development program planned by ERDA-INEL. These efforts have mutual interaction, in many cases; and that interaction is shown by the connecting lines. Not all of the technical improvements are expected to be successful. Indeed only a few are required to be successful to move the 300°F geothermal resource from a competitive position with oil-fired plants to being as competitive as coal or even nuclear plants.

This section provides a description of the proposed moderate-temperature facility, its components and programs.

7.1 Description of Test Facility

The basic characteristics of a minimum useful test facility are as follows:

1. Geothermal Fluid = 5000 gpm (2,500,000 lb/hr = 1,150,000 kg/hr
at a nominal 290° to 300°F, <2000 ppm

Expected well requirements are:

- 4 production wells
 - 2 reinjection wells
 - 1 spare well
2. Heat exchange capability of up to 120 MW-thermal
 3. Rotating machinery capable of generating up to 15 MW of electric power gross output, equivalent to approximately 10 MW(e) net output after captive requirements for operating pumps, fans, etc. of the facility are subtracted.

The base system will supply two thirds of the total output, using a binary-isobutane power plant with the following characteristics and components:

1. 80 MW thermal of tube- and-shell heat exchangers (preheaters and boilers)
2. 10 MW(e) turbine
3. 80 MW thermal of conventional tube- and-shell condensers
4. 80 MW thermal of wet cooling tower heat rejection capability

These components of the base power plant will have certain removal and substitution options built into the design, for ease of servicing-examination and of replacement with advanced concepts as these are developed.

Commercial size plants will require the use of multiple heat exchangers arranged in parallel (size limitations prevent use of single units). Figure 20 shows two parallel strings which will provide representative load sharing and control situations closely resembling that required in a typical power facility. The duplication will also provide for convenient substitution of new concepts, such as the fluidized bed heat exchangers. The arrangement allows modifications to permit each train to be operated independently for special tests, to be done at a relatively modest price.

Basic Systems

Program Basic Elements

Figure 20

S-9063

The other third of the total power capability of the total system (additional 40 MW thermal; approximately 5 MW, or more, electric) is reserved for those advanced components which are not compatible with the basic system and therefore cannot be incorporated into the basic loop via substitution of components. Examples of the latter are:

- (1) direct contact heat exchangers and condensers,
- (2) turbine with geothermal brine as the direct working fluid.

Figure 20 shows a partial concept for the test facility, showing a few of the many test options to be available. A schedule for design, construction and testing is shown in Figure 22. Details of various components of the facility and phases of the program are discussed below.

7.2 Wells

The area to be drilled for both production and re-injection wells will be confined nominally to a square four miles on a side. It appears that such an area is more than sufficient for withdrawing and re-injecting the required 5000 gallons per minute of fluid, with a minimum (virtually no) interference over a period of time approaching half a century. These 16 square miles roughly correspond to the 5000 acres retained as federal land withdrawal for the purposes of geothermal research, development, and demonstration, plus the adjacent privately owned ground on which lease or use rights might be obtained.

The two wells completed to date would serve as the initial two of the required six to seven wells. Each additional well would be drilled with a specific purpose and probably each with an experimental approach to the drilling operation. For instance, the third well is intended to be double channeled (or side-tracked, see Figure 23) should the first channel prove to be a successful producer. If it is not a successful producer, the hole would be converted to a re-injection well, possibly also including a double channeling operation. The overall goal is to develop and demonstrate means of obtaining the maximum amount of fluid for the least cost.

ACCELERATED SCHEDULE FOR THERMAL-LOOP, PILOT PLANT CONSTRUCTION

Phase I relates to the base facility using a binary isobutane system. Phase II incorporates variations and advanced concepts.

Figure 21

Figure 22

RRGE - 3 PROPOSED WELL CONFIGURATION

Subsequent drilling locations, casing, setting depths, etc. will be chosen based on both the drilling and down-hole logging information as well as the results of reservoir analyses from all the previous wells. Currently, it appears that production wells need be spaced no further than 1/2 miles, and the spacing from re-injection wells to the nearest production well could be as short as 3/4 miles.

7.3 Pipelines

Presently, it appears that pipelines could add as much as one-third to the base (well) cost of the energy supply-reinjection systems. Attempts at reducing these costs will involve the testing of different kinds of pipelines. Materials (including insulation), connections, and installation methods are the key areas to be addressed.

The present pipeline is concrete -asbestos with polymer connectors, buried to sufficient depth to be below the frostline. Future pipelines may be made of steel with quick disconnect devices. Such pipe would be appropriately insulated, and possibly placed on the surface or in trenches. Once enough wells are operable to assure continuous supplies of hot fluid, freezing of pipelines need not be a concern.

7.4 Pumps

Two aspects of pump design and performance will be addressed.

1. Corrosion, erosion, deposition, seal failure, etc. on all types of pumps caused by the dissolved solids in the geothermal water. The metallurgy - materials testing program described in Section 7.7 will attempt to identify the effects and find solutions.

2. Down-hole pumps to enhance flow.

Setting depths as great as 3000 ft could be employed before the pumping requirements exceed 20% of the eventual electric output from the well. In the case of the moderate temperature fluids, with their low flash pressure, such pumps also have the advantage of inhibiting flashing.

Currently, there are no pumps that have proven performance and reliability at depths exceeding several hundred feet in moderate temperature wells. Shaft-driven pumps at 150 to 200 ft have been in service successfully for many years in Iceland. Currently, a submersible pump is set at 650 ft in

the #1 well at Raft River and has seen limited service (2 months operation) to date.

ERDA has three experimental down-hole pump programs involving concepts other than those above (steam turbine drive, high frequency motor submersible, and a hydraulic turbine drive). The potential application of these pump concepts to hydrothermal fluid will be examined and tested as appropriate.

7.5 Reservoir Engineering

The reservoir engineering program is designed to involve a variety of aspects. For instance:

1. Sensitive down-hole pressure monitoring during production or re-injection of fluids.
2. Down-hole logging, using a variety of instruments.
3. Computer analysis, to establish reservoir models for (1) above, and correlation analysis to provide log interpretation for (2) above,
4. Isotopic analysis of waters, in an attempt to determine their source and age.
5. Chemical analysis, routinely, to monitor for changes that may reflect significant changes to the producing reservoir and the ultimate temperature and chemical characteristics of the fluid.

The reservoir engineering program has as its goal, the dual purpose of a generic analysis of how to manage moderate temperature geothermal fields in general, as well as to determine locations of the needed facility wells and assure the needed fluids for the surface experiments. It, quite naturally, includes routine environmental monitoring of those parameters most likely to be affected by fluid withdrawal and reinjection.

A related reservoir engineering question would involve the water needed for cooling of the power plant. If ordinary wet cooling towers are employed, it might be preferable to obtain the make-up water from the geothermal fluid. Thus, about 15% of the geothermal water would not be returned to the subsurface, creating a minor potential for subsidence. If once-through cooling using subsurface cool aquifer water were used in the condensers, with re-injection back into the same aquifer, the reservoir engineering problem has an added dimension. Reservoir management of both aquifers would be needed, with the related aspect

of possible interaction between the aquifers (which should be avoided to the extent possible).

7.6 Heat Exchange

The majority of the energy transferred within the power conversion system is handled twice, first in transfer from the source and then in rejection to the heat sink. Therefore, both portions of the system require nearly equal consideration.

7.6.1 Heat Exchange from the Geothermal Source

Further work is warranted on conventional surface-type heat-exchangers, as described in 7.6.1.1. In addition ERDA is currently conducting through the INEL two advanced heat exchanger programs:

- a) a fluidized bed in heat exchange (7.6.1.2)
- b) direct-contact heat exchange between the brine and a working fluid (7.6.1.3).

These heat exchangers development programs apply to all salinity geothermal brines and are as important to the low salinity applications (as a means to reduce heat exchange cost) as they are the high salinity applications. Both types of heat exchangers are currently under test at ERDA's Raft River Geothermal Facility.

7.6.1.1 Conventional Surface-Type Heat Exchangers

All geothermal fluids tend to foul surface heat exchangers by deposition of minerals on the heat exchange surface.

This scaling can be controlled to some degree if the dissolved carbon dioxide is low, by maintaining adequate pressure on the geothermal fluid. It appears that silica deposition can be controlled if the brine temperature is not reduced below the point that amorphous silica will be deposited. Because pressurization of the brine consumes power and increases design pressures, and because limitations placed on cooldown of the brine could restrict utilization, it is important to operate as closely to the minimum limits as possible. Operational experience with standard heat exchangers is necessary to determine actual performance.

Current designs utilize large fouling factors on the brine side ($\sim 0.003 \text{ hr-ft}^2\text{-}^\circ\text{F/Btu}$). This factor represents about 40% of the total thermal resistance. The ability to control brine side fouling to about $0.001 \text{ hr-ft}^2\text{-}^\circ\text{F/Btu}$ would result in about a 30% reduction in brine heat exchanger area. Therefore, it is necessary that conventional surface-type heat exchangers be tested with the low saline waters.

Heat exchange surface can be made from a high-cost material like titanium which virtually guarantees no corrosion or from a much lower cost material such as carbon steel (a factor of ~ 2 in cost between them) which will corrode at some presently unknown rate in the low saline brine. If the corrosion rate of carbon steel is sufficiently low, many years of service can be expected and the initial expense of high-cost material can be avoided.

Temperature can have a significant effect on corrosion rates. Therefore it is important that a materials corrosion program be an integrated part of the moderate temperature/low salinity geothermal program.

7.6.1.2 Fluidized Bed Heat Exchange

ERDA is currently conducting through the INEL two advanced heat exchanger programs which are directed toward use of a fluidized bed in heat exchange and of a direct contact heat exchange between the brine and a working fluid. These heat exchangers development programs apply to all salinity geothermal brines and are as important to the low salinity applications (as a means to reduce heat exchange cost) as they are the high salinity applications. Both types of heat exchangers are currently under test at ERDA's Raft River Geothermal Facility.

The fluidized bed heat exchanger consists of a bed of ordinary sand, fluidized by the geothermal brine. When fluidized, the bed circulates at random around the heat exchanger tubes and continually scrubs the tube surfaces. This scrubbing prevents deposition of minerals, and keeps the tube in a polished condition. Heat transfer coefficients in the order of 800 to 1000 Btu/hr-°F-ft² have been produced in small scale heat exchangers. This result offers great promise for reduction in heat exchanger size. The fouling factor may be reduced to nearly zero on the brine side (a reduction in heat exchanger size in the order of 40%). In addition, it permits use of the working fluid inside the tube on a preheater where increased velocities can be used to increase the film coefficient, further reducing the surface area required.

Small-scale testing operation has showed very encouraging results to date. A large-scale unit is planned for testing on a moderate-temperature low-salinity resource. Both preheater and boiler testing is desirable to develop a heat exchanger combination that would be used in a power conversion system.

Small-scale single-stage fluidized-bed heat exchangers are currently being tested at Raft River. The initial phase of this testing is directed at establishing bed particle size, maximum superficial velocity heat transfer coefficients and erosion. Following these tests testing will be conducted on a multi-staged bed. Concurrent with the testing preliminary design concepts are being developed for a full pilot-size unit which could be used in a large test facility.

7.6.1.3 The Direct-Contact Heat Exchange Mechanism

If two immiscible fluids are contacted properly, the rate of heat exchange is very rapid. There are no intermediate boundaries, such as a tube, upon which scale could form and inhibit the energy transfer. The heat exchanger is simply a tank, with trays and nozzles, and thus relatively inexpensive to build compared with a surface-type heat exchanger which requires thousands of tubes to provide the heat transfer surface. Research and testing of small-scale models is being performed by the University of Utah through the INEL. Results have shown direct contact heat exchange to work well with the moderate temperature low salinity fluids.

The design of energy conversion systems which use direct contact heat exchanger are different than those in which the geothermal and working fluids never mix. Water vapor is carried over, passes through the turbine and contributes substantially to the condenser heat load. Thus, turbine design must consider the water vapor (even though a small percentage) and the water must be separated from the working fluid after condensing.

The working fluid will be soluble to some extent in the brine. Therefore a means of stripping this working fluid from the geothermal fluid must be provided, as part of the power system, to prevent excessive loss of the working fluid. And finally, the selection of the working fluid must be optimized for the overall power conversion process and equipment and not merely for the best brine heat exchange performance.

These factors make it apparent that ultimately the direct contact heat exchanger must be tested in a complete power conversion facility. Application to the low-salinity geothermal resources puts it to a severe test from the standpoint of the overall process because of the need to minimize temperature differences (pinch points) and the fact that the working fluid will be more soluble in the low salinity than the high-salinity brines and will be in contact with a greater quantity of brine than would be necessary with a higher temperature resource. As a result, the economics of working fluid recovery very critical.

Carry-over of working fluid into the rejected geothermal water (in testing performed) to date appears near to the theoretical predictions, and within reasonable cost range for make-up fluids.

A small-scale direct-contact heat exchanger is current being tested at Raft River. The initial phase of this testing is to determine the performance of a "volume" boiler and a "surface" boiler. Following the testing of these two devices, a preliminary design of a pilot-size unit will be made.

Concurrent with the testing program is a system performance analysis effort to determine the overall characteristics of a system using the direct contact method of heat exchange.

7.6.2 Condensing of the Working Fluid by Direct Contact

Approximately 40% of the power plant cost is in equipment associated with heat rejection and therefore it is a prime target for cost reduction. The condenser is one component of heat rejection system and represents almost one-half the total heat transfer surface in the plant.

The size or cost of the condenser can be reduced by increasing the average temperature difference across the condenser or by incorporating a direct contact method. The former method is counter-productive because it very adversely affects the thermodynamic efficiency (and hence the power output) of these moderate-temperature geothermal power plants. The direct contact condenser offers the promise of much reduced cost, if the subsequent liquid-liquid separation can be performed efficiently and effectively. The technology of liquid-liquid separation of "immiscible" fluids is an established technology in a number of other fields, and hence may prove adequate for the direct-contact condenser development.

7.7 The Heat Sink Temperature Reduction

With a given resource the inlet temperature is fixed and the only way to increase the thermodynamic power output of a system is to lower the condenser temperature. This in turn is limited by the design heat sink temperature, that is the environment to which the heat must be rejected. Typically, river or sea water has been used as a coolant in once-through systems. Wet cooling towers have been used as closed systems. This latter mode is coming to most of today's geothermal power plants. Traditionally, power systems using cooling towers have been designed to produce full power at a specified worst condition that would only be rarely exceeded. The wet cooling tower requires consumptive use of water, which in many areas is not available. These factors, together with the relatively small size of any geothermal power plant (module sizes less than 100 MW) and its base load use, compared with large fossil and nuclear plants, permit consideration of more unorthodox design bases. These bases, which would potentially result in improved economics for any type of geothermal power plant are very significant to the moderate-temperature system.

Heat sinks can be classified as [relatively] constant temperature and variable temperature. The atmosphere which varies in temperature represents a variable heat sink for either wet-bulb or dry-bulb systems, whereas once-through cooling systems are essentially constant in temperature. Both type systems provide a potential for the geothermal power plant and are discussed with their variations in the following.

7.7.1 Ground-Water Once-Through Cooling

Ground water-aquifers provide a potential source of low-temperature cooling water. This water is typically at 50 to 60°F and when used for condenser cooling could allow (1) reduction of condenser size, (2) reduced cooling water flow (3) increased power output or (4) a combination of these depending upon system optimization.

The once through aquifer cooling water would be reinjected into the ground after passing through the condenser and therefore, would not result in consumptive use. The heat in effect would be dissipated to the earth. Volumes required are acceptable for a geothermal plant of say 50 MWe but could not be considered for a large 1000 MW plant, because of the large area from which this large quantity of water would need to be drawn.

7.7.2 Coolant Storage Variable-Temperature Systems

Large daily and seasonal variations in temperature below the design temperature means that for the majority of the time the cooling systems are oversized. If the condensing temperature was allowed to vary with the cooling towers capability to reject heat, then the power output of a theoretical turbine would vary accordingly and the total power output over a year would be substantially increased. The temperature is well below 50°F for a substantial period of the year in many parts of the nation.* The increase in annual power output from use of the atmospheric mean temperature would exceed the potential of the aquifer cooling system described above and would far exceed the output based upon a 65°F wet bulb design.

No real turbine would tolerate (without great loss in efficiency or insensitivity to higher pressure ratios) such large swings in condenser conditions that would occur throughout the year. The variations could be minimized by appropriate selection of the design temperature and storage conditions. Cold water made during the period of the day that the actual temperatures were less than design temperature could be stored. Then it would be used at other times to allow both a design temperature reduction and minimizing the variations in condenser conditions.

Allowing the power level to float will require special turbine design or cutting-in of low pressure stages. It has been estimated that about a 20 to 30% improvement in total kW-hrs generated could be achieved by a combination of these methods. As with aquifer cooling the gains that could be achieved could be taken in several ways. The method(s) selected would be based upon trade off studies.

*Annual mean temperature in the upper Snake River Valley is 40° to 50°F (47°F in the Raft River Valley).

Development of a variable temperature system, involves the requirement of an adequate storage system. Since a system usable on a 50 MW(e) "optimum" sized power plant is the nominal condition to be considered, whatever storage system is to be employed should be tested in a scaled version with the test facility. As an example, the 50 MW(e) facility might require a cooling pond of about 100 acre-ft capacity. The surface area and depth would be the important considerations for heat gain or loss. The test facility should be scaled accordingly.

7.7.3 Dry, Fluidized Bed Cooling Towers

An important consideration in taking full advantage of atmospheric temperature swings is that the use of dry cooling towers or fin-fan condensers with only short term augmentation by evaporation may be practical. Such a tower incorporating a fluidized bed to increase heat transfer to the air could substantially reduce the size of the dry tower, since heat transfer coefficients could be improved by a factor of about four.

7.7.4 Soil Dissipation

Because of their size, cooling towers traditionally dominate a power plant site. They must reject all the heat removed from the brine except for that used for power. Dissipation of heat into the soil (with or without transpirative cooling through trees or other plants) offers a method of minimizing the impact of a power plant in the area.

Rejecting heat into the soil requires, among other aspects, maintaining a moist, compacted soil for good heat transfer. The need for consumptive water use to maintain the soil moisture plus the presence of the heat prompts one to find a supplementary beneficial use for such ground, such as the year-round growing of trees.

7.8 Supplementary Direct Heat Uses

As discussed in Section 3.0 under costs of the energy supply system, a well that costs \$500,000 and produces only 3 MW(net) is only marginally competitive when one considers the associated costs of pipes, pumps, and re-injection wells. The combination cost is approximately \$900,000, and was assumed to produce ~ 1500 gpm of water. If one considers the same system combination cost and the associated value of heat in the water between 300°F and 200°F, a very favorable picture is obtained. Selling at 50¢/million Btu (5¢/therm, about 1/3 current wholesale natural gas prices in the Northwest), a 35% annual return on investment is realized. Since the value (5¢/therm) and the range of usefulness (only down to 200°F) are conservative, it appears that the direct heat has considerably more attractive value than its use for generating electricity.

However, the amounts of such heat available from several wells is much more than generally can be conveniently used in a given locality. Furthermore, the demands may vary radically during the year, particularly if space heating or food processing of local crops are major applications. Such a variable need significantly compromises the attractiveness of such an investment. But when coupled with a power plant operating many wells, the variable needs for direct heat may be but a minor perturbation on power plant operation.

The economic, institutional, and technical aspects of direct heat (non-electric) applications of geothermal energy are being examined in a parallel and closely coordinated project at the INEL. The advantages of a combined electric-utility heat utility operation will be given due consideration for demonstration in connection with the test facility.

7.9 Materials

A small facility has been designed and constructed that will permit screening and selection of materials for use in the power system. Basic data of all forms of corrosion anticipated in the geothermal system will be obtained. Preliminary projections of material life, particularly those considered for heat exchanger tubes will be performed and will form the base for the trade-off studies upon which the material selection is to be made.

Single tube heat exchanger tests will be performed to determine the ability to control scaling by selection of operating conditions. Where fouling occurs the rate and magnitude will be determined. From this data estimates of design fouling factors for the facility can be derived as well as establishing a preliminary idea of the cleaning schedule that will be required.

Reliable and efficient operation of the prime movers used to drive the generator are essential to any power plant. Down time due to blading corrosion and erosion have greatly reduced the output potential of many power plants. The turbo machinery used in a power plant is an integral part of the system and when new concepts and designs are employed, require on line evaluation and thus must ultimately become part of the test facility.

Binary systems use organic fluids as the working fluids, usually a hydrocarbon such as isobutane or a fluorocarbon (such as dichlorodifluoromethane). Turbines have not been built and operated which use these fluids. Although axial compressor technology applies to some extent, experience in the actual operating mode is required. Turbines systems designed for plants which use direct contact heat exchangers and/or which incorporate floating power levels most certainly require extensive testing and operation and must be considered within the overall program.

7.10 Total Flow Turbines

Total flow devices are under development at the Lawrence Livermore Laboratory. Although initially conceived as a means to extract energy from the hypersaline brines, these devices are also of interest to moderate temperature/low salinity system because they may result in a lower capital investment. When developed, it is anticipated they would be tested on a moderate temperature fluid in the Raft River facility. At this time, none of these machines has been specifically identified as offering either a capital cost reduction with equivalent output as the binary cycle or a greatly enhanced output for the same cost.

7.11 Testing and System Performance Analysis

Although it would be premature to provide a detailed test plan, an outline of how the 80 MW facility would be operated is appropriate.

1. Initial operational mode, turbine bypassed, steady state operation. Heat exchanger performance check. Calibration of computer model to actual plant performance. System performance mapping.
2. Turbine startup and operation. Turbine performance evaluations.
3. Steady state operation with periodic heat exchanger inspection. Shutdown of turbine on routine recommended by manufacturers.
4. Substitution of a fluidized bed heat exchanger for a low pressure pre-heater.
5. Set up system for operation in the floating-power and phased cooling mode. (Depending upon turbine design turbine may be bypassed.) Run at various simulated design conditions. Calibrate computer modeling of the system.

As a result of this program the following will be determined.

1. The ability to control scaling on the heat exchangers.
2. Turbine performance characteristics with isobutane.
3. The value of the fluidized bed heat exchanger.
4. The viability of floating power levels and phased cooling.
5. Operational and maintenance problems and how they will be reflected in power cost.

6. The technical base will be established upon which to make credible power cost estimates based upon actual operational experience.
7. System and reservoir reliability.

Design of a power conversion system requires many trade studies in the process of optimizing a given cycle. The complications in evaluating the potential floating power and various types of cooling further complicate the process. A system analysis code is being prepared that will permit these evaluations. It will utilize to the maximum extent possible the analysis already developed at the Lawrence Berkeley Laboratory.

8.0 POTENTIAL BENEFITS TO ACCRUE FROM THIS EXPERIMENTAL PROGRAM

The program and experiments planned for the moderate temperature development have a number of aspects, as discussed in Section 7.0. The ultimate goal is a reduction in capital and operating costs, and the resulting reduction in electricity produced.

Table 8.1 lists the various components of the power plant, its supply and disposal system. The costs of the present conventional type of binary power plant are listed, along with the estimated savings to result from successful development of the technical improvements discussed in this document. Note, all costs are presented in 1976 equivalent dollars, and do not include consideration for interest during construction. The possible savings are nearly 50% and bring the capital costs well within the current cost range of nuclear power, and much more attractive than coal. There is, of course, no assurance that all of these developments will achieve the success predicted, but the success of a few of the major contributions would effectively achieve the goal.

TABLE 8.1

POTENTIAL ECONOMIC BENEFITS

	PRESENT	POTENTIAL SAVINGS	NEW TARGET
A. SURFACE POWER PLANT (\$/kW)			
-ISOBUTANE SYSTEM	74	--	74
-ADVANCED HEAT EXCHANGERS	143	60	83
-CONDENSERS	141	60	81
-TURBINE-GENERATOR	64	10	54
-COOLING SUPPLY SYSTEM (WET COOLING TOWERS PRESENTLY)	96	--	96
-ELECTRICAL CONTROLS, ETC.	102	--	102
-LAND, ETC.	20	--	20
TOTAL	640	140	510
B. ENERGY SUPPLY SYSTEM (\$/kW)			
-WELLS	178	48	130
-PIPELINES	53	13	40
-PUMPS	50	10	40
TOTAL	281	71	210
C. ENERGY DISPOSAL SYSTEM (\$/kW)			
-WELLS	140	70	70
-PIPELINES	50	5	45
-PUMPS, MONITORING, ETC.	30	10	20
TOTAL	220	85	135
TOTAL OF A, B, AND C	1141	296	855
LOWERED HEAT SINK (30°F LESS)	17%	\$194	661

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