Geothermal Resources Council
Special Report No. 7

DIRECT UTILIZATION OF GEOTHERMAL ENERGY: A TECHNICAL HANDBOOK

GEYSER, CALISTOGA, CA

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DIRECT UTILIZATION OF GEOTHERMAL ENERGY: A TECHNICAL HANDBOOK

*A Joint Project of the
Geothermal Resources Council
and the
Geo-Heat Utilization Center
Oregon Institute of Technology
1979*

MASTER

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NOTICE

The views and conclusions contained in this document are those of the participants and should not be interpreted as necessarily representing the official policies or recommendations of the Geothermal Resources Council, the Oregon Institute of Technology or the Department of Energy.

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INTRODUCTION

Man has utilized the natural heat of the earth for centuries. Historical records reveal its use as a direct source of heat for cooking, bathing, space heating and medicinal purposes in many areas throughout the world. Early in the 1900's in Italy, geothermal energy was used for the first time as a prime energy source for the generation of electricity. These two uses of the resource are commonly referred to as "direct use" (non-electric) and "electric." These terms usually appear in the literature as Megawatts thermal (MWt) and Megawatts electric (MWe).

Worldwide direct use of geothermal currently amounts to about 7000 MWt as compared to 1500 MWe now being used in electrical power generation. By the year 2000, the estimated worldwide utilization will be 190,000 MWt. The U.S. growth rate is estimated to be 10-15% per year or 32,000 MWt by the year 2000.

Since the early 1970's, dwindling domestic reserves of oil and gas, continued price escalation of oil on the world market and environmental concerns associated with coal and the development of nuclear energy have created a growing interest in the use of geothermal energy in the United States. This relatively clean and highly versatile resource is now being used on a limited basis in a multitude of diverse applications, e.g., space heating, vegetable dehydration, agriculture, aquaculture, light manufacturing and other applications requiring a reliable and economic source of heat.

Although used in direct applications for centuries, geothermal resources were not seriously considered a modern energy source in the U.S. until the late 1960's. Because of the relative youth of resource development, no single, comprehensive publication covering geothermal's numerous aspects was ever previously developed. This was not because the information did not exist, but because it occurred in a myriad of publications and papers not readily available to most libraries or to interested individuals. Furthermore, a large amount of information exists in unpublished reports, notes and in company files available only to those with the contacts to obtain it. Finally, much of the data needed for a comprehensive publication was developed only in the last few years.

It was to the development of such a comprehensive direct-use publication that this project was directed. Essentially, this report is a single, technical volume that provides a background into the nature and occurrence of the resource, its development, utilization, economics, financing and regulation. In addition, it is documented with bibliographies of both major reference works and unpublished reports.

In order to make maximum use of the information developed in the technical report, a non-technical version has also been produced. The non-technical version will be useful for both the junior-high and high-school levels as well as for the general public.

In addition to the above documents, a pamphlet on pricing parameters for the direct use of geothermal energy was also included as one of the tasks of the project. The pricing document has not been published separately, but is included as Appendix B of Chapter 5 in this publication.

The project was jointly developed and managed by the Geothermal Resources Council and the Oregon Institute of Technology and sponsored by the U.S. Department of Energy. It was directed by a steering committee made up of the chairpersons responsible for each of the seven chapters, the principal investigators and four other persons with varied responsibilities. The names and addresses of the project participants are listed in this section.

Most of the work was done during a workshop at Diamond Lake, Oregon, in February 1979. The

chairperson of each chapter convened a group of experts in various fields to assist in the development of chapter outlines. The chapters were later more fully developed by the chairpersons and submitted to the principal investigators and the technical committee for review and editing.

For your convenience, the key reference documents for the discovery, development and utilization of geothermal energy and their publishers are listed below.

Armstead, Christopher H., 1978, Geothermal energy: New York, NY, Halstead Press (Div. of John Wiley and Sons), 357 p.

Geo-Heat Utilization Center, Quarterly Bulletin, May 1975 to date: Klamath Falls, OR, Oregon Inst. of Technology.

Geothermal Resources Council, 1977, Transactions Vol. 1, Geothermal: State of the Art: Davis, CA, 310 p.

Geothermal Resources Council, 1978, Direct Utilization of Geothermal Energy: A Symposium (San Diego, California, Jan. 31-Feb. 2, 1978: Davis, CA, 145 p.

Geothermal Resources Council, 1978, Transactions Vol. 2, Geothermal Energy: A Novelty Becomes Resource: Davis, CA, 747 p.

Geothermal Resources Council, 1979, A Symposium on Geothermal Energy and Its Direct Uses in the Eastern United States (Roanoke, Virginia, April 1979), GRC Spec. Rept. No. 5: Davis, CA, 100 p.

Geothermal Resources Council, 1979, Transactions Vol. 3, Expanding the Geothermal Frontier: Davis, CA, 808 p.

Howard, J.H., ed., 1975, Present status and future prospects for non-electrical uses of geothermal resources, Reports UCRL-51926: Livermore, CA, Lawrence Livermore Laboratory, 162 p.

Kruger, Paul and Otte, Carel, eds., 1974, Geothermal Energy, Resource, Production, Stimulation: Stanford, CA, Stanford University Press, 360 p.

Lienau, Paul J. and Lund, John W., eds., 1974, Multipurpose Use of Geothermal Energy: Proceedings of the International Conference on Geothermal Energy for Industrial, Agricultural and Commercial-Residential Uses: Klamath Falls, OR, Oregon Inst. of Technology, 239 p.

Muffler, L.J.P., ed., 1979, Assessment of geothermal resources of the United States--1978: U.S. Geol. Survey Circ. 790, 163 p.

Petroleum Information Corporation, 1979, The geothermal resource: Denver, Colorado, 200 p.

Proceedings of the (First) United Nations Symposium on the Development and Utilization of Geothermal Resources (Pisa, Italy, 22 September to 1 October 1970), 1974: Geothermics, Special Issue 2, 2 volumes (the second in 2 parts), 1725 p.

Proceedings of the Second United Nations Symposium on the Development and Use of Geothermal Resources (San Francisco, California, 20-29 May, 1975), 1976: Washington, D.C., U.S. Govt. Printing Office, 3 volumes, 2466 p.

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Wahl, Edward F., 1977, Geothermal Energy Utilization: New York, John Wiley and Sons, 302 p.

Wehlage, Edward F., 1976, The Basics of Applied Geothermal Engineering: West Covina, CA, Geothermal Information Services, 211 p.

OTHER SOURCES OF INFORMATION

Geothermal Resources Council
P.O. Box 98
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General information on electric and non-electric uses of geothermal energy.

Geo-Heat Utilization Center
Oregon Institute of Technology
Klamath Falls, OR 97601
(503) 882-6321

General and specific information on direct uses of geothermal energy.

National Water Well Association
500 W. Wilson Bridge Road
Worthington, OH 43085
(614) 846-9355

Information on water-well drilling and groundwater heat pumps.

This technical handbook and the non-technical version are available through the National Technical Information Center, U.S. Department of Commerce, Springfield, VA 22161, and for a limited time at the Oregon Institute of Technology, Geo-Heat Utilization Center, Klamath Falls, OR 97601 and the Geothermal Resources Council, P.O. Box 98, Davis, CA 95616.

RELATED PUBLICATIONS

In addition to this technical handbook, the contract included as separate tasks the development of a non-technical version of this report and a special pamphlet on the pricing of geothermal energy for direct uses. A reference to the non-technical version can be found below; however, it was decided to include the special pamphlet on pricing as an appendix to Chapter 5 instead of publishing it separately. This action was taken because the pricing pamphlet and Chapter 5 (Economics of Direct-Use Development) are related in subject material and the pamphlet by itself would not provide a total picture of the pricing situation.

Anderson, David N. and Lund, John W., 1980, Direct Utilization of Geothermal Energy: A Layman's Guide, Geothermal Resources Council Special Report No. 8: Davis, California, the Geothermal Resources Council and Klamath Falls, Oregon, the Oregon Institute of Technology.

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CONVERSION FACTORS

The geothermal community is an international one; thus all units are given in the U.S. system with metric in parenthesis, i.e., 140°F (60°C). Every attempt was made to use the same number of significant figures in both systems. Thus, for example, 300°F would be converted to 149°C when used as an exact number (three significant figures), and to 150°C when used as an approximate number (two significant figures). In two cases, conversion to metric was not attempted: (a) in the detailed economics calculations of Chapter 5, as this would confuse the explanation of the engineering economics principles, and (b) in the details of the leasing information in Chapter 7, as this information is peculiar to the U.S.A.

The following English and SI (metric) relationships and abbreviations were used:

<u>English</u>	<u>International System (SI)</u>
1 pound mass (lb)	= 0.4536 kilograms (kg)
1 pound force (lbf)	= 4.448 newtons (N)
¹ 1 ton (short = 2,000 lb) (tn)	= 0.9072 tonne (metric = 1,000 kg) (t)
1 ounce (oz)	= 28.35 grams (g)
1 pound per square foot (psf)	= 0.04788 kilo Pascals (kPa) = 0.04788 kN/m ²
1 pound per square inch (psi)	= 6.895 kilo Pascals (kPa)
1 mile (mi)	= 1.609 kilometer (km)
1 foot (ft)	= 0.3048 meters (m)
1 inch (in)	= 2.540 centimeters (cm)
1 gallon (gal)	= 3.785 liters (l)
1 gallon per minute (gpm)	= 0.06308 liter per second (l/s)
1 British thermal unit (Btu)	= 1055 Joules (J) = 1.055 kilo Joules (kJ)
British thermal unit per hour (Btu/hr)	= 0.2930 watts (w)
1 acre (A)	= 0.4047 hectares (ha) = 4047 square meters (m ²)
² 1 degree Fahrenheit (°F)	= 1.8 x degree celcius (°C) + 32°
1°F/1000 ft	= 1.823°C/km
1 barrel (petroleum)	= 42 gal (159 liters)
	10 ⁻⁶ = micro (μ)
	10 ⁻³ = milli (m)
	10 ⁻² = centi (c)
	10 ³ = kilo (k)
	10 ⁶ = mega (M)
	10 ⁹ = giga (G)

¹ Since references to this unit were only approximate, the two terms were considered equal and some have not been converted in the text.

² If only a change in temperature is required, then $\Delta^{\circ}\text{F} = 1.8 \times (\Delta^{\circ}\text{C})$.

CHAPTER 1

NATURE AND DISTRIBUTION OF GEOTHERMAL ENERGY

Work Group

L. J. P. Muffler (Chairman), J. K. Costain, Duncan Foley,
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ABSTRACT

Five major factors, either alone or in combination, are responsible for geothermal anomalies: 1) differences in regional heat flow, 2) range in value of thermal conductivity, 3) differences in concentrations of radioactive elements, 4) young magmatic intrusions, and 5) hydrothermal circulation. Geothermal exploration involves searching for positive geothermal anomalies, and geothermal production involves extraction of thermal water or steam from holes drilled into these anomalies. Favorable geothermal reservoirs require rocks of high natural transmissivity, but artificial fracturing shows some promise of allowing energy to be produced from hot rocks of low permeability. Important types of geothermal systems include 1) hydrothermal convection systems related to young igneous intrusions, 2) fault-controlled systems, 3) radiogenic heat sources beneath insulating sediments of low thermal conductivity, 4) geopressured-geothermal reservoirs, and 5) deep regional aquifers. The geologic environments of geothermal systems in the United States include volcanic belts, extensional environments, the northern Gulf of Mexico Basin, and the Atlantic Coastal Plain. The accessible resource base and the geothermal resource of the United States have been estimated in recent publications of the U.S. Geological Survey.

GEOTHERMAL GRADIENT, HEAT FLOW, AND GEOTHERMAL ANOMALIES

It is well known from drilling, observations in mines, and various geophysical studies that temperatures in the Earth increase with depth. This increase of temperature (T) with depth (Z) is termed the geothermal gradient ($\Delta T/\Delta Z$). At depths accessible to drilling (currently less than 6 miles--10 kilometers), the geothermal gradient usually is in the range of 5-25°F per 1000 ft (9-45°C per km), but in many areas of the United States it exceeds 25°F per 1000 ft (45°C per km). Differences in rock type, geologic setting, and hydrologic regime account for the wide range in geothermal gradient.

In response to this geothermal gradient, thermal energy moves toward the Earth's surface, either by conduction of heat through solid rock, by movement of molten rock (magma), or by movement of water. The vertical movement of thermal energy by conduction is termed heat flow (q) and is related to the geothermal gradient by the equation

$$q = K (\Delta T/\Delta Z) \quad (1)$$

where K is the thermal conductivity.

A geothermal anomaly is an area beneath which, at some depth, temperatures are elevated or depressed relative to adjacent terrain; these areas may range in size from the environs of a single hot spring to a region of thousands of square kilometers. Because of the high cost of drilling, developing, and maintaining wells that will produce warm or hot water, geothermal exploration involves searching for positive geothermal anomalies--locations where relatively high temperatures will be encountered at the shallowest possible depths. Accordingly, it is important to understand the five major factors that cause geothermal anomalies in various geologic settings:

1. Differences in regional heat flow: Regional "heat flow provinces" have been defined (Birch et al., 1968; Diment, et al., 1975) and explained in terms of fundamental differences in heat flow at depths of up to 20 miles (32 km; the base of the continental crust). For example, heat flow near the base of the crust (commonly termed the "reduced heat flow") is very low beneath the Sierra Nevada (Figure 1), intermediate in the eastern United States, and high in the Basin and Range province.
2. Range in value of thermal conductivity: Conductive heat flow (in the absence of heat sources such as radiogenic heat-producing elements) must be the same at any depth in a

stratigraphic section. Hence, according to equation 1, the geothermal gradient must increase if thermal conductivity decreases. The thermal conductivity of common rocks ranges over a factor of at least 6 from unconsolidated clay to quartzite (essentially all SiO_2 ; Clark, 1966). Correspondingly, at constant heat flow, geothermal gradients can range over a factor of at least 6 owing to different thermal conductivities alone. Lateral changes in rock type from high to low thermal conductivity thus can produce striking geothermal anomalies.

3. Differences in concentrations of radioactive elements: Within a heat-flow province, additional factors influence the magnitude of the geothermal gradient. Radiogenic elements are concentrated in the upper crust and tend to be concentrated even further in granitic intrusive rocks. Such concentrations increase the magnitude of heat flow at shallow crustal levels. It is now known that up to two-thirds of the heat flow in some granitic rocks is the result of heat continually released from these rocks by the decay of radioactive isotopes of the elements uranium, thorium, and potassium (Birch *et al.*, 1968). Of these, uranium and thorium are about equal in importance and contribute approximately 80-90 percent of the heat associated with radioactive decay. It is worth noting that only modest amounts of uranium (5-10 parts per million) and thorium (20-80 parts per million) in granites have a significant effect on the elevation of subsurface temperatures, if the volume of granite is large enough. Thus, within a given heat flow province, lateral variation in concentration of radiogenic elements will result in differences in the geothermal gradient, even in crystalline rocks of uniform thermal conductivity.
4. Young magmatic intrusions: The theory of plate tectonics (Le Pichon *et al.*, 1973) has successfully explained, for the most part, the geographic occurrence of centers of magmatic activity. Magma generation takes place along spreading ridges, along zones of plate convergence, and at intraplate melting anomalies (such as Hawaii or Yellowstone). Upward movement of magma transfers heat toward the Earth's surface and can result in very high geothermal gradients. The positive geothermal anomalies produced in this manner by recent intrusion of magma may represent substantial geothermal resources. However, intrusive bodies older than several million years have had the chance to cool to ambient temperatures and no longer sustain a positive geothermal anomaly.
5. Hydrothermal circulation: In many areas of the United States, heat is transported relatively rapidly by fluid flow along permeable sedimentary beds, faults, fissures, or fracture zones. This hydrothermal circulation may be driven by heat from a young intrusive mass or may result merely from deep circulation of water in a region devoid of young igneous rocks. In either case, thermal energy is transported to shallow depths in the crust, and major positive geothermal anomalies can result. At places where the thermal waters rise to the land surface, hot springs occur. At other places, the thermal waters may be within reach of shallow wells.

PRODUCTION OF GEOTHERMAL ENERGY

Geothermal energy of the Earth's crust is stored predominantly in rock and only subordinately in water, steam or other fluids that fill pores or fractures within the rock. This diffuse energy must be collected from large volumes of rock and transported to a discharge point in order to make the energy available for practical uses. The water contained in nearly all rocks within the upper few kilometers of the Earth's crust provides the transfer mechanism by which this collection and discharge is accomplished.

In order to permit the economic extraction of water and its contained thermal energy, the rocks through which the water moves must store significant amounts of water and transmit it freely.

The capacity of a rock to store water is termed the storage coefficient, and the ability of a rock to transmit water is termed the hydraulic conductivity or permeability. Rocks such as fractured quartzite and limestone, brecciated volcanic rock, or uncemented sand and gravel generally have moderately high storage coefficients and hydraulic conductivities and may be expected to produce fairly large amounts of water per unit cross-sectional area. Where these rocks have large thicknesses, they are said to have high transmissivity (the product of the hydraulic conductivity and the thickness of the cross-section of flow). Rocks of high transmissivity form the principal aquifers in groundwater systems and constitute the most productive geothermal reservoirs.

The long-term productivity of a geothermal reservoir is dependent on many interrelated factors. In addition to the aquifer transmissivity and storage coefficient, these factors include the volume and temperature of the reservoir, type of heat source, magnitude of regional heat flow, chemical nature of the geothermal fluid, and the presence or absence of recharge and discharge boundaries. Reliable evaluation of several of these factors may not be possible prior to actual production of fluid from the geothermal reservoir.

The productivity of low-permeability reservoirs theoretically can be enhanced by various fracturing techniques (for example, hydrofracturing, explosives, or chemical treatment). To date, such techniques have been used only rarely in geothermal settings, and their economics and common applicability remain to be demonstrated.

Extraction of energy from rock of very low porosity and permeability can be accomplished by the establishment of a confined circulation loop consisting of two wells connected by a network of fractures induced by hydraulic or other means (Smith, 1978). Cold water is pumped down one well, heated by conduction as it flows through the induced fractures, and extracted as hot water through the second well. Implicit is the requirement that rocks adjacent to the fractured volume remain impermeable, so that the fluid losses from the circulation loop are minimal. This procedure, commonly referred to as "hot dry rock technology," is presently in the experimental stage. Its widespread applicability and its economics have yet to be demonstrated. Hot dry rock is one end-member of a series of hydrologic environments that extend, with increasing permeability, to conventional reservoirs or aquifers (Muffler, 1979, p. 160). Indeed, most rock in the Earth's crust is likely to be intermediate in this series; that is, too permeable to support a confined circulation loop but not permeable enough to produce contained fluids at economically acceptable rates.

TYPES OF GEOTHERMAL SYSTEMS

Hydrothermal convection systems related to young igneous intrusions

The most spectacular evidence of the heat of the Earth is a volcanic eruption. Although the lavas that may be extruded from such an eruption will cool on the Earth's surface in a relatively short time, the chamber in the Earth's crust from which these lavas came will contain molten or still hot rock for many thousands of years. At present it is not practical to tap these magma chambers directly by drilling. However, fractures and faults around the intrusion commonly allow the development of a hydrothermal convection system--that is, circulating ground water that reaches down to or near the cooling intrusion, absorbs some of the heat, and returns to or near the Earth's surface. The density difference between hot and cold water causes the heated water to rise, thus concentrating thermal energy in a near-surface geothermal reservoir (Figure 2). Geothermal reservoirs related to young igneous intrusions can have very high temperatures (300-660°F, 150-350°C) and have been developed for electrical generation and direct uses in a number of localities throughout the world.

FIGURE 2. Schematic model of a hydrothermal convection system driven by an underlying young igneous intrusion (modified from White, 1968).

Fault-controlled systems

Most hydrothermal convection systems are not located in areas where young igneous intrusions have been identified. Instead, these geothermal systems derive their heat from large volumes of rock by deep circulation of water along permeable zones, which may be either stratigraphic beds or networks of faults and fractures (Figure 3). The temperature attained by the water is primarily dependent upon the magnitude of the regional heat flow and the depth to which the water circulates. Recharge to the downward-circulating limb of the hydrothermal convection system may occur over both mountain areas and adjacent valleys. The types of fractures and faults could differ from those shown in the generalized model of Figure 3; the only requirement is that the faults or fractures be permeable enough to transmit the rising hot water.

FIGURE 3. Schematic model of a hydrothermal convection system related to deep circulation of meteoric water without the influence of young igneous intrusions.

Deep regional aquifers

Down-warped troughs in the crust form sedimentary basins that collect and transmit groundwater from recharge areas in adjacent highlands. This water moves down-dip through the sedimentary deposits and is heated in the Earth's geothermal gradient (Figure 4).

FIGURE 4. Schematic model of a geothermal reservoir in a deep regional aquifer.

At places in these basins where hydraulic conductivities are unusually high or where fractures allow water to move vertically under artesian pressure, geothermal water may occur within economic reach of drill holes. If artesian pressures are sufficiently great, the thermal water may flow at land surface. As shown in Figure 4, the upwarping of isotherms in sediments of low thermal conductivity may also aid in making geothermal water available at fairly shallow depths.

Deep regional aquifers have been developed extensively for direct uses in France, Hungary, and the USSR. In the United States, deep regional aquifers having geothermal potential are known to occur in the Williston Basin in the northern Great Plains and may also occur in other large basins of the north-central and western United States. In the eastern and midwestern United States, areas such as the Allegheny, Michigan, and Illinois Basins (Figure 1) appear to offer similar opportunities for geothermal exploration.

Geopressured-geothermal reservoirs

Geopressured-geothermal reservoirs are aquifers whose fluids are under pressure exceeding the pressure of a water column (hydrostatic head) and approaching that caused by the weight of the

FIGURE 5. Generalized sedimentary model of the northern Gulf of Mexico basin, showing the relation of gross lithology to fluid-pressure gradient and growth faulting (modified from Wallace *et al.*, 1979).

overlying rocks (lithostatic head). Less porous sediments that lie on top of geopressured-geothermal reservoirs prevent upward leakage of water that ordinarily would transport and lose the heat to the surface (Figure 5). Water in the geopressured sediments thus contains an anomalous amount of heat as well as substantial amounts of dissolved methane (the chief constituent of natural gas).

The technology for producing geothermal energy from geopressured-geothermal reservoirs, along with the dissolved methane, is still being perfected, but basically it involves the use of the same tools and techniques required in very deep oil drilling. This is a costly undertaking. Therefore the development of these sorts of reservoirs will be restricted to organizations with substantial financial backing and will not be an endeavor into which smaller firms or individuals can readily enter. Also, at present the hot water alone does not seem to be an economically justifiable target; but combined with the associated methane, the development of these geopressured-geothermal energy reservoirs may become economic.

Radiogenic heat sources beneath insulating sediments of low thermal conductivity

Granitic plutonic rocks are relatively enriched in uranium and thorium. Radioactive disintegration of isotopes of these elements gives off heat. Thus heat flow in a radiogenic pluton is higher than that in the adjacent country rock into which it was intruded. If the granitic rocks are blanketed by sediments of low thermal conductivity, then relatively high temperatures can occur at the base of the sedimentary section over the radiogenic source (Figure 6.) The areal extent of the geothermal anomaly depends on the shape and thickness of the radiogenic source, the concentration of uranium and thorium in the radiogenic source, and the thermal conductivity and thickness of the overlying sediments.

FIGURE 6. Schematic model of a geothermal reservoir in sedimentary rocks of low thermal conductivity overlying basement plutonic rocks enriched in uranium and thorium.

GEOLOGIC ENVIRONMENTS OF GEOTHERMAL SYSTEMS

Volcanic belts

Volcanic belts of the United States are the loci of major geothermal anomalies and contain substantial geothermal energy (Smith and Shaw, 1979). This energy exists in magma, in low-

permeability igneous and country rock, and in associated hydrothermal convection systems. In general, volcanoes less than one million years old have the best chance of being sites of economic geothermal systems. Older volcanic areas are less favorable, but it should be kept in mind that the volcanic rocks at the Earth's surface do not necessarily indicate the age of rocks that may be cooling beneath the surface. That is, younger intrusions that have no surface expression may occur at depth and may support hidden (or "blind") geothermal systems.

Young volcanic belts are concentrated in the western United States (Smith and Shaw, 1979; Maps 1 and 2). Most voluminous are the volcanic rocks and associated intrusions of the Aleutian Volcanic Chain and of the Cascade Range (Figure 1), both related to converging margins of major plates. The Imperial Valley of Southern California is along the major spreading zone that extends northward from the Gulf of California, whereas Hawaii, the eastern Snake River Plain, and Yellowstone are related to intraplate melting anomalies. Other young volcanic belts occur along the east and west margins of the northern Basin and Range Province, along the Rio Grande Rift, and along the southwest margin of the Colorado Plateau.

Extensional environments

Environments where the crust of the Earth is under tensional stress are favorable geologic settings for the presence of hot water. These areas are commonly characterized by active faulting, relatively young mountain ranges, basins that have moderately thick unconsolidated to poorly consolidated sedimentary fill, and local sites of young volcanic activity.

In the United States, the Basin and Range province in Nevada and western Utah and the Rio Grande Rift of central New Mexico and southern Colorado are two areas of active extension that contain large amounts of geothermal water. Heat in extensional environments typically comes from elevated regional heat flow, which can be an important source of heat for a large region, or from young igneous intrusions, which can be locally important as sources of heat. Hot water in both these environments typically circulates through faults and fractures, but in areas where thick sequences of basin-fill sediments are present, the hot water may be encountered in the sediments themselves.

Northern Gulf of Mexico basin

From thousands of oil wells drilled in the northern Gulf of Mexico basin (Figure 1) it has been determined that extensive areas (both onshore and offshore) contain large geopressured geothermal reservoirs (Jones, 1970; Papadopoulos *et al.*, 1975; Wallace *et al.*, 1979). The geological circumstances which combined to produce these reservoirs are complex, but suffice it to say that heat coming into the lower portions of the thick deposits of sediments has been trapped by the rapidly depositing overlying sediments of low permeability and low thermal conductivity. This trapping occurs at depths generally about 10,000 ft (3050 m), and the geopressured reservoirs may extend to depths as great as 50,000 ft (15,250 m). There is some possibility that there are geopressured geothermal energy areas in other deep sedimentary basins of the United States (Wallace *et al.*, 1979; Fig. 26), but to date only the northern Gulf of Mexico basin has been clearly identified as containing this sort of reservoir.

Atlantic Coastal Plain

The Atlantic Coastal Plain is underlain by a wedge of sediments of Cretaceous and younger age that extends from New York to Florida. The sedimentary section is thickest (up to 10,000 ft—3050 m) along the coastline and consists of limestone, siltstone, sandstone, and conglomerate (Brown *et al.*, 1972). The several major aquifers that are present beneath the Coastal Plain include the Tuscaloosa Formation (a thick Cretaceous sandstone) and the sandstones of the Potomac Group. Wells producing up to 3500 gallons (13,250 liters) per minute (220 l/s) have been

reported (Siple, 1975).

Granitic rocks crop out over a large area of the central and southern Appalachian Piedmont and presumably extend eastward beneath the sedimentary cover of the Atlantic Coastal Plain.

Development of low-temperature geothermal energy in the eastern United States is most likely to occur in the Atlantic Coastal Plain where basement granitic rocks that contain moderate concentrations of radiogenic heat-producing elements are concealed beneath thick sedimentary sequences of low thermal conductivity. Geothermal gradients as high as 24°F per 1000 ft (44°C per km) have been observed in Coastal Plain sediments and are presumed to be associated with concealed granitic radiogenic rocks (Costain *et al.*, 1979).

GEOTHERMAL RESOURCE ASSESSMENT

Geothermal resource assessment is the process of estimating how much geothermal energy might become available for use at a specified time, under some set of generalized technologic and economic assumptions (Muffler and Cataldi, 1979). The process is analogous to the methods of estimating mineral and petroleum resources, except that the results are given in units of thermal energy rather than in tons of ore or barrels of oil. Also, geothermal energy figures must be given relative to a reference temperature, normally taken by convention to be mean annual temperature.

The terminology for geothermal resource assessment has been adapted from the petroleum and mineral industries (Muffler, 1973; Muffler and Cataldi, 1979). The term geothermal resource base is adapted from Schurr and Netschert (1960) to refer to all the thermal energy in the Earth's crust beneath a given area, referenced to mean annual temperature. The accessible resource base is defined by Muffler and Cataldi (1979) as that part of the resource base which is accessible to drilling; the depth limit of drilling must be specified in each situation. The accessible resource base is then divided into useful and residual components, with the useful component being that fraction of the accessible resource base that can be extracted and used at some future time under reasonable technologic and economic assumptions. The useful accessible resource base is termed the resource and is further divided into identified and undiscovered components. Still in a manner analogous to the mineral and petroleum industries, reserve is defined as that part of the resource which is identified and can be produced under present-day economics. These terms can be illustrated on a McKelvey diagram (Figure 7).

It must be emphasized that the geothermal resource constitutes only a fraction of the accessible resource base. For favorable hydrothermal convection systems, the ratio of resource to accessible resource base (i.e., the "recovery factor") may be as much as 25 percent (Nathenson, 1975; Nathenson and Muffler, 1975). For most geologic environments, however, the recovery factor is likely to be far less, perhaps only a fraction of 1 percent for large volumes of low-permeability rock in regional conductive environments.

The regional distribution of geothermal resources of the United States is discussed and depicted in U.S. Geological Survey Circular 790 (Muffler, 1979). This report is a refinement and update (to June, 1978) of U.S. Geological Survey Circular 726 (White and Williams, 1975). Both the 1975 and 1978 assessments estimate the accessible resource base to 30,000 ft (10 km) for regional conductive environments, approximately 22,500 ft (7 km) for geopressured-geothermal energy environments, and 10,000 ft (3 km) for hydrothermal convection systems. Geothermal resources are estimated only for geopressured-geothermal energy of the northern Gulf of Mexico basin and for hydrothermal convection systems $\geq 194^\circ\text{F}$ (90°C). No quantitative estimates are made of the thermal energy in geothermal waters at temperatures less than 194°F (90°C), but areas favorable for discovery and development of these low-temperature waters are depicted on

Map 1 and in the text figures of Circular 790.

FIGURE 7. McKelvey diagram for geothermal energy showing derivation of the terms resource and reserve (from Muffler and Cataldi, 1979). Vertical axis is degree of economic feasibility; horizontal axis is degree of geologic assurance.

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CHAPTER 2

EXPLORATION, CONFIRMATION AND EVALUATION OF THE RESOURCE

Work Group

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INTRODUCTION

The techniques of geothermal exploration originated in Italy during the first half of this century and were augmented by New Zealand and Iceland in the 1950's as part of their efforts to develop geothermal resources. No strong consideration was given to developing this discipline in the United States until the late 1960's and early 1970's.

The last ten years have witnessed a strong research effort in the U.S. and the development of a technical foundation is well under way. Great strides have been made in the development of concepts concerning geothermal reservoirs and their unique characteristics. New tools and techniques have resulted in defining an exploration strategy which is now beginning to provide positive results.

Geothermal pioneers in this country have had the marked advantage of a wealth of supporting material (tools, techniques and theory under development for over half a century by the petroleum and mining industries) and the availability of a team of trained and experienced scientists and technicians. In all probability, with this wealth of background data and ever-increasing effort, geothermal exploration will come of age far sooner than if it had developed on its own from the ground up.

GEOLOGIC CONSIDERATIONS

Three important questions at the beginning of any geothermal energy utilization project are: (1) where should a geothermal well be sited, (2) how deep must a well be drilled to obtain the required temperature for the specific need, and (3) how much heat (thermal energy) can be extracted per unit time after drilling a well to the required depth? At most places on the surface of the earth, heat is transferred from deep in the subsurface to the surface by conduction, with temperature increasing regularly along a geothermal gradient of about $14^{\circ}\text{F}/1000\text{ ft}$ ($25^{\circ}\text{C}/\text{Km}$; curve A in Figure 1). However, in some geological provinces, conductive geothermal gradients are as high as $36^{\circ}\text{F}/1000\text{ ft}$ ($65^{\circ}\text{C}/\text{Km}$; curve B in Figure 1).

Abnormally high temperatures at shallow depths are commonly the result of convective flow of hot water that picks up heat deep in the subsurface and transfers it to rock near the surface. Temperature-depth relations that could result from convective transfer of heat are depicted in curves C and D of Figure 1. The temperature reversal in the upper part of curve C indicates a component of horizontal flow of hot water. The maximum temperatures that are likely to be maintained for long periods of time in a hydrothermal convection system are shown by the boiling point curve in Figure 1 which separates the fields of steam and hot water. The relative position of the boiling point curve on a temperature-depth profile will vary according to the salinity of the subsurface fluids and the depth of the local water table.

Presently, thermal energy in the shallow crust of the earth is extracted by bringing to the surface the hot water and steam that occurs naturally in the open spaces in rock. Where rock permeability is very low, the rate of thermal energy extraction is low. Therefore, in addition to adequate temperature, a minimum permeability also is required to extract thermal energy economically. In order to extract the heat stored in the solid rock portion of the reservoir, there must be a slow recharge of water into the system as the initial water is extracted.

Research is under way to determine the feasibility (both practical and economic) of creating artificial permeability in hot, relatively impermeable rock (hot "dry" rock) and extracting heat by injecting cold water into the artificial reservoir through one well and removing heated water through a second well. It has been demonstrated that artificial permeability can be created and a water-circulation loop established. The economic feasibility of the system is still uncer-

FIGURE 1. Representative depth-temperature relations in the earth's crust. Curve A shows a normal conductive geothermal gradient. Curve B shows a high conductive gradient. Curves C and D show possible temperature-depth relations resulting from convective flow of fluids. Curve E is the boiling point of water vs. depth.

tain. In the remainder of this section, the geothermal exploration target will be assumed to be a conventional hot-water system, although many of the same exploration techniques would be used for any type of geothermal system.

In regions of normal geothermal gradient, it is necessary to drill deeper than four kilometers in order to obtain water above 212°F (100°C). The geological environment in which permeable rocks are most likely to be found at a depth of four kilometers or greater is a deep sedimentary basin such as the basins in Hungary and France that now provide hot water for direct-use geothermal applications. Highly faulted and folded rocks in regions of normal geothermal gradient may provide conduits for convective upflow of hot water and local shallow reservoirs of water suitable for direct utilization may be present in these types of terrain. Where conductive geothermal gradients are very high, economically useful geothermal reservoirs are likely to be found at relatively shallow depths, particularly where local convection systems are present. The types of geologic environments that have high conductive geothermal gradients and localized hydrothermal-convection systems have been discussed in Chapter 1.

BACKGROUND INFORMATION

Different applications of geothermal energy require different temperatures. Thus, the first step in exploring for the geothermal resource is to define the physical characteristics required for the application. The needed information may vary according to application, but generally include temperature, flow rate and water quality. Proximity of the resource to areas of probable use and the possible conflict with present land uses such as metropolitan areas, highways, industrial or agricultural centers, etc., must also be taken into account.

Once the temperature, quantity and location requirements of the resource are determined, a rational program of exploration can be developed. The first step is a library search to determine what is already known. The library search can be subdivided into two categories: land status and technical information. A good place to start an evaluation of land status is in the local office of the Bureau of Land Management (BLM) where detailed land-status maps are available. These maps show land ownership divided into federal (forest, Indian, military, recreational and BLM), state and private lands. More detailed information, such as leasing procedures, permits required, environmental regulations, etc. (see Chapter 6) can generally be obtained by contacting the agency controlling the lands or the state land office.

Technical information includes both specific geothermal data and general geological information that may bear indirectly on the nature and occurrence of geothermal resources. Specific geothermal information with references, such as locations of hot springs and hot wells, has been published by the U.S. Geological Survey in two circulars, 726 and 790 (White and Williams, 1975; Muffler, 1979). A nationwide geothermal gradient map has been published by the American Association of Petroleum Geologists (AAPG-USGS 1976 a, b) and several researchers have published national heat-flow maps (e.g., Sass, et al., 1976). In addition, the National Oceanographic and Atmospheric Administration has published a geothermal-resource map of the Western United States (See Muffler, 1979, Map No. 1). In addition, detailed state-by-state geothermal-resource maps have either been published or are in preparation (Wright, et al., 1978). A rather complete bibliography of geothermal publications has been published by the U.S. Energy Research and Development Administration, now the U.S. Department of Energy (ERDA, 1976), and is updated quarterly.

There may also be a wealth of site-specific geological information available which can be very important in designing an exploration program. This type of information is scattered throughout the geological literature and may, therefore, be difficult to locate. The most useful sources are reports of the U.S. Geological Survey, state geologic surveys and the major geological publications, such as those listed in the Bibliography of North American Geology. The types of

general geological information most useful in the early stages of geothermal exploration are the location and distribution of young volcanics and recent faults, chemical analyses of thermal and non-thermal waters upon which the standard techniques of chemical geothermometry can be applied, and the presence of deep sedimentary basins.

EXPLORATION TECHNIQUES

After a thorough review of the pertinent literature has been completed and access to the land has been established, a decision should be made as to whether or not a given prospect area shows sufficient potential to warrant detailed site-specific exploration. The various geological, geochemical and geophysical tools available to the geothermal explorationist are briefly described in the following sections. These methods are designed to produce specific information. Because each geothermal prospect is in many ways unique, there is no one method or series of methods which will work in all circumstances. The costs of various methods must be considered in terms of the benefits received and the value of the particular resource. Nevertheless, the final verification of a geothermal resource must be based on drilling.

GEOLOGICAL EXPLORATION

Geological exploration techniques are concerned with the identification and interpretation of the surface manifestations of geothermal activity and the identification of structures that channel the geothermal fluids in the shallow subsurface. The principal methods of data collection are geologic mapping and air-photo interpretation. Hot-spring deposits and associated hydrothermal alteration are often clearly shown on air photos. In addition, faults or intersections of faults which control hot springs commonly can be delineated on air photos. The documentation of the orientations of these structures allows prediction of the subsurface geometry of the structures which may control or communicate with the reservoir. From this information, coupled with other geochemical and geophysical data, drill sites can be located to intersect desired structures at depth.

Hot thermal waters alter the minerals of the rocks with which they come in contact (Browne, 1978). In addition, these waters commonly form hot-spring deposits consisting of calcium carbonate (travertine) or opaline silica (sinter). Extensive travertine deposits usually indicate that the temperature of the aquifer feeding the spring is less than 248-284°F (120-140°C). Sinter deposits are considered prime facie evidence of geothermal reservoir temperatures exceeding 356°F (180°C; Renner, et al., 1975). These higher temperature systems tend to self seal through the precipitation of silica and the alteration of wall rocks. This often results in the termination of hot-spring activity. Thus, even though activity has ceased at the surface, the geothermal resource may exist at depth.

Radiometric dating of rocks is a valuable tool for the identification of young volcanic rocks. The presence of rhyolites one million years old or less and basaltic activity within a few thousand years before present are both excellent evidence for the existence of anomalously high thermal gradients. Although the age dating of rocks is not a site-specific exploration technique, it does provide identification of regions of geothermal exploration interest.

Characterization of the geology either through existing geologic maps or new mapping provides a data base for the modeling and evaluation of many of the geophysical and geochemical techniques which will be discussed in subsequent sections. This is particularly true for the modeling of gravity and magnetic surveys as well as the interpretation of physical-parameter contrast identified using other geophysical techniques.

Previously obtained regional and site-specific geological information is available to a limited

extent from publications and personnel of state geological surveys, the Division of Geothermal Energy of the Department of Energy and the U.S. Geological Survey. Furthermore, ongoing geological and geothermal programs of the organizations continue to provide new as well as reinterpreted geological data. Professional geological services are available from consulting geologists who specialize in the evaluation of geothermal prospects. These consultants may be found through listings with state surveys, registration boards or advertisements in professional journals.

GEOCHEMICAL EXPLORATION

Geochemical investigations provide information about subsurface temperatures, locations of faults which act as conduits for upward movement of hot waters and gases, sources of potential scaling or corrosion during production and possible waste-disposal problems and environmental concerns. Summary information about geochemical-exploration methods pertaining to geothermal resources is contained in Ellis and Mahon (1977), Truesdell (1976), Fournier (1977; 1979) and Brook, et al. (1979).

The compositions of spring and well waters can be used to estimate geothermal reservoir temperatures provided that various implicit assumptions are valid. The most important of these assumptions are: (1) that chemical (or isotopic) equilibria have been established in the reservoir between wall rock and the geothermal fluid with respect to the specific indicator reaction, (2) that there is insignificant re-equilibration at lower temperature after the water leaves the reservoir and (3) that either there is no mixing with different waters during movement move to the surface or estimation of the results of the mixing is possible. At present, the most commonly used chemical and isotopic geothermometers are silica, Na/K, Na-K-Ca, Na-K-Ca-Mg, and $\Delta^{18}\text{O}$ ($\text{H}_2\text{O}-\text{HSO}_4^-$). Each of these geothermometers has its limitations and each requires considerable interpretation in its use. Application of chemical and isotopic geothermometers also requires proper collection, preservation and chemical analyses of the samples.

The following factors should be considered when using the silica geothermometer to explore for low-temperature resources. Most groundwaters which have not attained temperatures greater than 175-195°F (80-90°C) have silica concentrations greater than those predicted by the solubility of quartz. Many of these waters have equilibrated with chalcedony (sometimes up to 355°F, 180°C), but some silica concentrations result from non-equilibrium situations in which silica is released to solution during acid attack upon silicate minerals. The acid may come from decay of organic material, oxidation of sulfides or influx of H_2S or CO_2 from depth. High concentrations of dissolved silica in cold waters are particularly common where CO_2 reacts with serpentine at low temperatures. The pH of the spring water also must be considered. At 77°F (25°C) the solubilities of silica minerals are significantly increased at $\text{pH} > 9$. At temperatures above 212°F (100°C), significant increases occur at pH values as low as 7.5. However, in most geothermal reservoirs rockwater reactions buffer the pH of the water at values below 7.5. As those waters rise to the surface, dissolved CO_2 escapes from solution and the pH increases. Whether or not a correction should be applied to adjust the silica content of an alkaline hot-spring water for pH effects depends upon where and when the solution attained its aqueous silica. If a solution attained a high silica content because of high underground temperature and then became alkaline after cooling and loss of CO_2 , no pH correction should be applied.

The Na/K geothermometer has been used for several years, but has been found to be very unreliable at temperatures below 302-392°F (150-200°C). Therefore, the Na/K geothermometer should not be used in evaluating low-temperature resources. The Na-K-Ca method is reasonably good at low temperatures, but will give temperatures that are too high if CaCO_3 precipitated because of the loss of CO_2 after the water left the reservoir. The Na-K-Ca geothermometer may require correction for the Mg content of the water for certain types of waters.

The ^{18}O ($\text{H}_2\text{O}-\text{HSO}_4^-$) geothermometer has recently been investigated, but it cannot be used in cases where some of the sulfate in the water results from low-temperature, near surface oxidation of H_2S or sulfide minerals such as pyrite. Mixing of hot and cold waters also results in incorrect $\Delta^{18}\text{O}$ ($\text{H}_2\text{O}-\text{HSO}_4^-$) temperatures even if the low-temperature component of the mixture contains no sulfate.

When using chemical geothermometers to estimate reservoir temperatures in geothermal systems, the hydrologic complexities which are commonly present must be examined. Water may move relatively quickly and directly to the surface from a deep reservoir with little heat loss on the way, or it may flow through a series of intermediate reservoirs where new water-rock equilibria are attained at lower temperatures. In particular, geothermometers applied to water emerging at the surface give information about the temperature of the last water-rock equilibria. Hot water ascending to the surface from a geothermal reservoir may cool by conduction of heat to the surrounding rock, by boiling, by mixing with cooler shallow water or by a combination of these processes, depending on the depth of the aquifer, the geometric configuration and path of the channel way, the rate of mass flow, the coefficient of thermal diffusion through the surrounding rock, and the initial temperature of the water. The effects of these different cooling mechanisms should be considered when estimating reservoir temperatures from hot spring compositions. However, in those places where emerging thermal waters appear to be mixtures of hot water and cold, dilute, shallow groundwater, the composition and temperature of the high-temperature component may be calculated using mixing models, provided various favorable conditions are met.

Another use of geochemistry in a geothermal-exploration program involves determination of the isotopic composition of both the thermal and nonthermal groundwater in a given region. The isotopic information is useful for determining where the recharge water entered the system and the amount of water-rock reaction that occurred at high temperature as that water moved through the system. The tritium content of emerging hot-spring water gives an indication of how long that water has been underground. No tritium indicates that the water has been underground for many years and probably comes from a deep reservoir. Increasing amounts of tritium in hot-spring waters is a sure sign of near surface mixing with cold, meteoric water.

Analyses of soil gases for mercury, carbon dioxide and helium and groundwaters for volatile components in general (particularly boron and ammonia) have been found to be useful in some places for detecting where anomalously high temperatures exist at shallow levels. Larger than average amounts of helium, radon and mercury in soil gas also have been used to outline the presence of otherwise hidden faults. The above methods are most useful where boiling waters exist at depth. Unfortunately, they tend to outline areas of fossil geothermal activity and places where faults allow gases to escape from very deep in the crust. Soil geochemistry has also been shown to be useful in outlining geothermal resources on the basis of anomalous trace element zoning. Arsenic and mercury anomalies seem to be particularly successful in delineating the upper levels of hydrothermal systems. Analysis of drill cuttings for trace elements shows promise of being able to predict the approach to hot water entries in exploration holes (Bamford, 1978).

GEOPHYSICAL EXPLORATION

A geophysical survey consists of a set of measurements made over the surface of the earth, in the air above and parallel to the earth and in boreholes within the earth. The measurements are of the variations in the physical properties of the subsurface rocks including thermal conductivity, electrical resistivity, propagation velocity of elastic waves, density and magnetic susceptibility. Geothermal systems commonly give distinctive and fairly easily measured discontinuities in the above-mentioned physical properties, e.g., high heat flow, low electrical resistivity and attenuation of high-frequency elastic waves. Therefore, the existence of geothermal resources can be inferred from the indirect measurement of these various physical parameters at

depth. The most useful geophysical techniques for geothermal exploration are temperature or geothermal-gradient surveys, heat-flow determinations, electrical-resistivity surveys, and passive seismic surveys, such as microearthquake measurements. These geophysical methods can aid in the delineation of geothermal reservoirs and furnish data on subsurface thermal processes.

The accuracy with which geothermal systems can be detected by geophysical means depends on the degree of contrast in the physical properties between the rocks comprising the geothermal system and the surrounding subsurface. Geothermal reservoirs usually have irregular shapes and occur in rocks of complex structure and varying type, i.e., geothermal systems are three dimensional. The emphasis in geothermal exploration is therefore upon detection of geothermal systems and their lateral extents. Geophysical surveys are conducted in order to provide data for the location of geothermal systems and to aid in locating geothermal drillholes.

The direct applications of geothermal resources require lower temperature resources than do electrical applications; therefore, the extent of assessment may be significantly reduced in order to obtain a sufficient level of confidence for acquiring a suitable geothermal resource for direct applications. However, because a lower temperature subsurface environment is sought in most direct-use applications of geothermal resources, the discontinuities in the physical properties of the rocks are not as distinctive and therefore geophysical techniques that are quite useful for detecting high-temperature geothermal resources may not provide definitive data when exploring for low-temperature geothermal resources. Geophysical techniques or surveys can be grouped into four separate categories when considering their use for geothermal exploration. These four groups include structural methods, electrical and electromagnetic methods, passive seismic methods and thermal methods.

Structural methods

Active seismic methods (reflection and refraction), gravity surveys and magnetic surveys all fall under the category of structural methods as applied to geothermal exploration. In contrast to thermal and electrical methods, for example, these structural methods do not determine the physical properties of the warm and hot geothermal fluids sought, but instead investigate the attitude and nature of the host rocks. Structural methods may prove justifiable for geothermal exploration in refining a regional or local geological subsurface model, but they generally provide little useful information for defining geothermal reservoirs. However, these methods can be useful in defining faults or fault zones which may control the geothermal resource.

Active seismic methods (Dobrin, 1976) involve the use of man-made explosions or surface vibrations to generate elastic waves. The reflection method utilizes energy reflected back to the surface from subsurface interfaces between rocks of different physical properties. The refraction method utilizes seismic waves refracted horizontally along an interface and thence back to the surface. Both methods are used to determine subsurface structure and the configuration and depth to basement rocks.

Gravity surveys (Dobrin, 1976), which determine density contrasts of subsurface rocks, have been used both to outline major structural features and to delineate local positive and negative anomalies that may be related to geothermal systems. Local gravity anomalies may be caused by local structural highs, buried volcanic rocks, intrusive rocks, or hydrothermally altered rocks. However, because these gravity anomalies can be produced by factors other than active geothermal systems, gravity surveys in geothermal exploration are open to gross misinterpretation unless used in conjunction with other exploration techniques.

In general, magnetic surveys, which detect differences in magnetic susceptibility of subsurface rocks, are the geophysical method least useful in defining geothermal drilling targets. In some areas, negative magnetic anomalies appear to be caused by hydrothermal alteration, and in other

areas, positive magnetic anomalies can be related to very young intrusive and volcanic rocks associated with geothermal systems. In most areas, however, so many factors influence the character of a magnetic survey and the resulting magnetic map, that the results are difficult to interpret in terms of geothermal resources.

Electrical and electromagnetic methods

Electrical and electromagnetic methods (Keller and Frischknecht, 1966) in geothermal exploration measure the electrical resistivity of rocks at depth. Temperature, porosity, salinity of interstitial fluids and/or content of clays and zeolites tend to be higher within geothermal reservoirs than in the surrounding subsurface. Consequently, the electrical resistivity in geothermal reservoirs is relatively low compared to the host rocks.

Many different electrical and electromagnetic methods are used to measure electrical resistivity at depth. The telluric, audiofrequency magnetotelluric (AMT) and magnetotelluric (MT) techniques depend on measuring variations in the natural electrical and magnetic fields of the earth. Each of the several different electrical techniques utilized in geothermal exploration involve the use of man-made electrical generators putting current into the ground at two electrodes and measuring the resultant potential at two other electrodes. Electromagnetic methods involve the generation of a magnetic field that varies with time and the detection of either the electrical or the magnetic field arising from currents induced in the earth.

Published data on the application of electrical techniques in geothermal areas indicate that the most useful technique is DC-resistivity profiling or sounding using linear arrays, primarily the Wenner or Schlumberger array. DC-resistivity methods are preferred to AC methods because of skin effects present at large spacings with the AC methods. However, with linear arrays, the effective probing depth is controlled by electrode spacing so that in order to effectively evaluate deeper prospects, it may be necessary to lay cables over considerable distances and thus rugged topography may result in severe logistical problems. An electrical prospecting technique that has been increasingly utilized in geothermal exploration is the dipole-dipole array. Although the method is logistically simple and is essentially insensitive to rugged topography, effective dipole-dipole investigations require complicated data analysis and are subject to ambiguous interpretation.

Electromagnetic methods have been applied in geothermal exploration only during the past few years. Although instrumentation and interpretation are complex, electromagnetic (inductive) methods have two theoretical advantages over electrical methods: (1) with an inductive method, signal size increases with decreasing resistivity, making measurements easier and more accurate in geothermal areas; and (2) inductive methods are not adversely affected by near surface high-resistivity zones.

The major problem associated with all electrical and electromagnetic methods is the interpretation of the electrical-resistivity anomalies that are measured. Because the electrical resistivity of subsurface rocks is a complicated function of temperature, porosity, salinity and content of clays and zeolites, if and when a relatively low electrical-resistivity anomaly is observed, the causal relationship must be determined by utilizing some other type of data, e.g., direct temperature or geothermal-gradient measurements. More specifically, a low-temperature, highly saline, groundwater in the subsurface can provide the same low electrical resistivity anomaly that is exhibited over a high-temperature, moderate salinity, geothermal system.

Passive seismic methods

Geothermal areas are characterized by an enhanced level of microearthquake activity (Majer and McEvilly, 1979). The measurement or detection of these microearthquakes and determination of

their precise hypocentral locations provide the data necessary to locate active fault zones in a geothermal area which may be functioning as subsurface conduits for the geothermal fluids. In addition, the results of microearthquake surveys can be used to estimate the subsurface physical characteristics of geothermal systems because the temperature of the subsurface and the type and amount of interstitial fluids significantly affect the velocity and attenuation of elastic waves of both compressional (P) and shear (S) type. For example, the attenuation of shear waves may indicate high-temperature zones of low rigidity. Similarly, low values of Poisson's ratio found from the ratio of the velocity of compressional to shear waves may indicate rock voids that are not saturated with liquid and could therefore be steam-filled. However, passive seismic methods are just beginning to be used in geothermal exploration and are not completely understood. They may, however, provide many new and quite useful geothermal exploration techniques in the future.

Thermal methods

The temperature within the reservoir is the most important physical characteristic of a geothermal system. The physical and chemical processes within the geothermal reservoir depend critically on this quantity, and the techniques of heat and fluid extraction have to be selected with regard to these temperature conditions. Because the temperature constitutes the most important physical characteristic of a geothermal system, thermal exploration methods, such as geothermal-gradient measurements in boreholes and heat-flow determinations, are of primary importance. Thermal-exploration techniques provide the most direct method for making a first estimate of the size and potential of a geothermal system with surface geophysical exploration.

Temperature and gradient measurements at depths on the order of 3 ft (1 m) are fast and inexpensive, and can be used to detect anomalously hot areas. These shallow temperature measurements are strongly influenced, however, by near-surface effects, including insolation, topography, precipitation and movement of groundwater. The last of these effects is particularly important, for a relatively slow movement of groundwater across even a strong thermal anomaly can carry away the conductive heat flow, displacing surface-temperature patterns and grossly distorting gradient measurements.

Temperatures measured as a function of depth in boreholes 50-2000 ft (15-600 m) deep have been used as the primary thermal method in geothermal exploration. At these depths most near-surface thermal disturbances are avoided, and gradient measurements can be made with considerable precision and reliability. Nevertheless, the data must always be evaluated for the effects of lateral and vertical movement of ground water. Over most economically attractive geothermal areas, the gradients at shallow to intermediate depths are equal to or greater than 36°F per 1000 ft (65°C per km), compared to a normal geothermal gradient of about 14°F per 1000 ft (25°C per km).

Although gradient measurements do define the areal extent of geothermal anomalies, one must be very cautious in extrapolation of these gradients to depth. Two factors combine to ensure that a linear extrapolation will be in error on the high side. The first is the variation in thermal conductivity of the subsurface rock with depth. The second factor, thermal convection, will have an even greater effect in reducing gradients at depth (see Figure 1). In an area where thermal convection of water within the pore space of rocks is possible, the extrapolation of measured high, near-surface gradients is clearly unjustified and likely to suggest erroneously high temperatures at shallow depths.

When the mean thermal conductivity of the rocks is essentially constant throughout the subsurface through which boreholes are drilled, the geothermal gradients measured are obviously proportional to the heat-flow values, because heat flow is the product of geothermal gradient and thermal conductivity. Geothermal gradient must decrease with depth as the thermal conductivity

of the rocks increases. The advantage of heat-flow determinations, as opposed to purely geothermal-gradient measurements, is that heat flow is independent of the thermal conductivity of each rock type. Therefore, in nonhomogeneous terrains, only heat-flow measurements enable one to obtain accurate data on the potentially productive geothermal zones.

Remote sensing (infrared) techniques

Infrared techniques have been used for geothermal exploration with limited success. Under ideal conditions (flat homogeneous terrain), they can detect regions that are as little as 1°F (0.5°C) warmer than the ambient temperature and have duplicated results of shallow thermal gradient surveys measuring heat flows greater than 0.07 heat flow units ($3\text{W}/\text{m}^2$). However, emissivity effects due to natural terrain variances can obscure $1\text{--}10^{\circ}\text{F}$ ($0.5\text{--}5^{\circ}\text{C}$) temperature differences. Infrared scanners normally operate in the 3-5 or 8-14 micron ($3\text{--}5 \times 10^{-6}\text{m}$) or ($8\text{--}14 \times 10^{-6}\text{m}$) transmission ranges. To minimize solar heating effects, areas are usually flown between midnight and one hour before dawn.

Infrared methods are best suited for mapping surface manifestations, especially large areas of remote regions. For this reason, it has been used successfully by the United Nations in Ethiopia and Kenya (McNitt, U.N. proceedings, 1975). In general, this method has not been used as an exploration tool in the United States since most surface manifestations (hot springs, etc.) have already been mapped.

DRILLING

The exploration methods previously described are extremely important in the selection of a drilling site. However, drilling is the only way to confirm the presence of a geothermal resource. Exploration drilling can be very helpful in assessing the geological and hydrological controls of the geothermal system. Therefore, care and consideration should be taken in the planning of the drilling program so that one obtains all of the information that will be useful in the later development of the resource, in addition to the initial delineation and evaluation of the resource. Factors to consider in the drilling plan include basic well design (see Chapter 3), sample recovery (including collection of cutting and cores), geophysical logging and flow testing (including fluid sampling). The proper acquisition of this data will allow a reassessment of the previously acquired geological, geophysical and geochemical data. The result will be a better understanding of the nature and extent of the geothermal resource.

GEOPHYSICAL LOGGING

Geophysical logging is the application to the borehole environment of the physical principles used for surface geophysics. In the borehole environment, these techniques provide more resolution than is normally obtained from surface geophysics. Geophysical logging has been the primary tool used by the petroleum industry in assessing the properties of rocks in petroleum reservoirs. Much of this technology is directly transferable to the geothermal industry, and hence is useful in evaluating the properties of rocks in geothermal reservoirs. However, most of the rocks encountered in geothermal exploration are significantly different from the rocks commonly found in petroleum exploration. Hence, care must be taken not to run the basic petroleum logging suite blindly, attempting to interpret the data as if it were encountered in a petroleum reservoir.

Parameters extremely valuable in assessing the potential of a geothermal reservoir are temperature, flow rate, porosity (which can then empirically relate to permeability), elastic-wave velocity, electrical resistivity, density and natural radioactivity. Many of these parameters

are very useful in defining geological units and rock types for correlation with rocks in nearby boreholes. These help also to define potentially productive zones that dictate how to complete the well, and reinterpret exploration data for the siting of additional wells.

The nature and character of the logging suite will vary with the type of geothermal resource. The obvious parameters to be measured are temperature and flow rate, which are obtained with temperature logs and flow meters. However, for most direct applications of geothermal resources, the effective porosity (permeability) is a very important parameter. The effective porosity may be either intergranular or fracture-controlled (possible fault related). The porosity is best obtained via the gamma-gamma log (density), the neutron log or the sonic log. Lithology information can be gained from many logs, but the fundamental tools are SP (spontaneous potential) and natural gamma.

The acquisition of a complete suite of geophysical logs utilizing major petroleum logging firms is quite expensive. Some of these firms do, however, have equipment capable of logging very hot holes. However, there are other, less expensive firms that can run logs, especially in the relatively shallow and moderately hot holes drilled for direct-application uses. These firms include geothermal and mineral exploration firms. Some of this equipment is extremely portable. Thus, adequate logging services are available at a variety of costs, and hence the acquisition of this data is possible and essential to the orderly development of the resource.

EXPLORATION COSTS

The following table (Table I) shows many of the exploration methods discussed in the previous sections. Approximate times for completion of the surveys and order-of-magnitude costs for the methods are also indicated. It should be stressed that the costs shown are approximate and will vary as a function of many factors including survey detail, accessibility, terrain and weather. Geothermal-gradient/heat-flow borehole costs include cost of drilling and completing holes as well as logging. The geochemical procedures include sample collection as well as analytical costs. The methods are also characterized as being principally of use in regional and/or detailed evaluations.

TABLE I

Summary of costs, time frames and area covered with various geothermal exploration methods

Method	Time	Expense	Area
Consulting geologist	< month	\$200-\$400/day	Regional/detailed
Airphoto interpretation	< month	\$5/mi ² (\$2/km ²)	Regional/detailed
Water analyses	month	\$100-\$200/sample	Regional/detailed
Surface geochemistry	month	\$30/sample	Detailed
Volatile geochemistry	month	\$20/sample	Detailed
Temperature gradient/heat flow boreholes	> month	\$10-\$100/ft (\$30-\$300/m)	Regional/detailed
Electromagnetic methods	month	\$200-\$1500/line mi (\$125-\$930/line km)	Detailed
Resistivity	month	\$200-\$1500/line mi (\$125-\$930/line km)	Detailed
Magnetics - airborne	< month	\$25/line mi (\$15/km)	Regional
- ground	< month	\$200/line mi (\$125/km)	Detailed
Seismic - refraction	< month	\$5000/line mi (\$3000/km)	Detailed
- reflection	< month	\$5000-\$10,000/line mi (\$3000-\$6000/km)	Detailed
- microearthquakes	3-6 months	\$1200/day	Regional/detailed
Gravity	month	\$30-\$70 station	Regional/detailed
Magnetotellurics	month	\$1200-\$2000/line mi (\$750-\$1250/km)	
Geophysical logging	< week	\$2000-\$20,000/hole	Detailed

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CHAPTER 3

RESERVOIR DEVELOPMENT AND MANAGEMENT

Work Group

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INTRODUCTION

Reservoir development and management are well developed sciences in the petroleum, natural gas, and even groundwater irrigation industries. The principal experiences in the geothermal industry are at several fields (in four different countries) where electricity is being generated in minimum sized blocks of 75 MWe or nominally 350 MWt. These several fields are generally vapor dominated, two of them completely so: Lardarello and The Geysers. The liquid-dominated fields at Waiakel, New Zealand and Cerro Prieto, Mexico generate flash steam at the well heads. The techniques, considerations, and plans for direct-heat application reservoir development will differ substantially from the above examples. The projects generally will be in the 1 MWt to 50 MWt (3.4-170 million Btu/hr) range, an order of magnitude less than the minimum-sized modules for electric projects. Instead of 10 to 100 wells typically planned for a field, direct applications may require only one or two wells. Whereas the electric developments can call the first few production wells exploratory and hope to reduce costs significantly on future wells, the first few direct-application wells may be the only ones needed, and perhaps, the only ones ever to be drilled in the field.

Reservoirs in the large fields mentioned above can be evaluated with interference measurements between wells. A direct-heat application may only have one well, so interference testing is impossible without the expense (usually prohibitive) of drilling observation wells. Single-well tests, therefore, are extremely important, and may be the only means of technically evaluating the long-term performance of the reservoir for direct-heat applications.

Finally, the relative costs of electric vs. direct-applications projects must be recognized in planning the cost of the reservoir development and management program. A project that costs 1/10 as much as an electric project cannot afford (in fact does not need) the same sophistication in a reservoir management program as one for a planned 200 MW electric project. Cost savings can be significant for a direct-applications project. Consequently, the direct-application geothermal industry may develop a cadre of technicians oriented specifically to the needs of this industry--those who drill inexpensively and make the most out of evaluating sparse data.

PRODUCTION-WELL DRILLING

Drilling the wells probably represents the greatest expense and the greatest risk in geothermal-energy utilization. Once a geothermal-reservoir prospect is fairly certain, the next step is to confirm the size and usefulness of that resource, and confirm the economics of getting the energy out of the ground and using it for a period of time sufficient to amortize the investment that will need to be made.

Let us assume that we know where the first production or exploration-production well is to be drilled. We also have a depth estimate of the resource (with a contingency of 25 to 50% added to this depth estimate), and we also have geochemical or other data to indicate the temperatures to expect. We need to estimate the quantity of fluid we expect to produce from a single well. Recall that most direct-heat applications will bring the fluid to the surface in the liquid phase. Large flow rates--like 1000 or more gpm (gallons per minute; 63 l/s; 34,000 barrels a day)--are most desired. But what is the likelihood of this from a single well?

Typical well flow rates

1. Irrigation wells delivering 4000 gpm (250 l/s) are not uncommon, but 1000-2000 gpm (60-125 l/s) are more typical. Such flows conceivably could be expected from wells in shallow, low-temperature geothermal aquifers, using pumps.
2. Free-flowing (artesian) geothermal wells that produce 500 gpm (30 l/s) for sustained

periods are rare; however, 50-100 gpm free-flow rates are not uncommon.

3. Deep geothermal wells (greater than 3200 ft, 1000 m) that can be pumped to produce a sustained 1000 gpm (60 l/s) do exist, particularly in highly fractured, volcanic formations (Iceland, for instance), but these are exceptional. Flow rates in the range of 500 gpm (30 l/s) would be considered a good geothermal deep well.

Comparison of oil and geothermal costs and the relative risks

The geothermal well, if 60°F (33°C) of temperature difference can be stripped from the water and the flow rate is 1000 gpm (60 l/s), will produce \$1400 worth of heat each day, if heat is valued at \$2/million Btu (\$2/million kJ). But if the application is space heating, the well may only be used 25% to 50% of its full capacity yearly. On the other hand, a good oil well producing 500 barrels a day (1 l/s) will earn \$3000 to \$15,000 per day, every day (depending on whether it is sold at "old" or "new" oil prices). The oil well might only cost \$350,000, giving a very attractive return on investment even after expenses. The geothermal well cost must be close to this number, particularly since each producing well must, in general, be accompanied by one-half to one full disposal well. For instance, if the cost of the producing well, the pump, pipeline, and disposal facility for that well totals \$600,000, the return on investment would be about 25%, less any operating expenses. Qualitatively, the attractiveness of return on investment appears much better for an oil well than for a geothermal well. However, the ratio of success to attempts should be much higher with geothermal, thus the exploratory costs chargeable to the total operation should be less for geothermal. For example, oil-wildcat success ratio is less than 1 in 15. More deliberate exploration in previously proven areas succeeds about 1 in 4. Geothermal exploration needs to be significantly better if it is to compete economically. Since geothermal profit margins will generally be much less than for gas and oil, geothermal drilling and development cost must be kept as low as possible.

Because one of the keys to successful geothermal development is to drill wells less expensively than oil and gas wells, it is appropriate to emulate the water-well driller to whom well cost is very critical, rather than the oil and gas driller. Cost to the latter is secondary because he must drill as many holes as possible with a given rig to get as many producing wells as possible in a given time. Unlike the oil producer who is mobile, able to go where the oil can be found, the geothermal developer must have a user for the heat available at the location of the well.

These distinctions in philosophy and attitude of the drilling companies and drilling consultants are important. Although the equipment and safety precautions for geothermal drilling are more closely related to oil and gas drilling, the techniques needed to tap the resource and keep the cost minimal are more in empathy with water-well drilling.

Well-design considerations

Casing size, particularly at the bottom of the casing string, and the diameter of the hole in the producing section need to be established before the size of the well at the surface can be determined. In general, the production of the well will depend partially on each of the following:

1. Surface area of well bore in the producing zone (i.e., nominally proportional to diameter of well);
2. Pressure drop from bottom of well to the top (i.e., inversely proportional to the diameter to the 3.75 power).

Thus, for deep wells (greater than 2000 ft, 600 m), (2) is a major consideration. For

shallower wells, (1) is the major consideration. However, in the case of poor permeability ("tight" wells), or predominate fracture permeability, the production capability is quite insensitive to the diameter of the well bore.

As a guide to pressure drops within various sized casing, the following table gives a few examples:

<u>Casing Size</u>	<u>Pressure Drop In 1000 ft. (300m) for 1000 gallons/min flow (60 liters/second)</u>	
6 5/8 (5.75" ID) 16.8 cm (14.6 cm ID)	35	psi (240 kPa)
9 5/8 (8.91" ID) 24.4 cm (22.6 cm ID)	4.8	psi (33 kPa)
13 3/8 (12.6" ID) 34.0 cm (32.0 cm ID)	0.70	psi (4.8 kPa)

To scale to other flows, the pressure drop is proportional to the flow rate squared. Another factor in calculating well size is the installation of a pump. The inside casing size requirements for various capacity pumps are approximately as follows:

<u>Flow No Greater Than</u>	<u>Requires Casing Diameter of</u>
20 gpm (1.26 l/s)	4" (10.2 cm)
100 gpm (6.30 l/s)	6" (15.2 cm)
500 gpm (31.50 l/s)	9" (22.9 cm)
2000 gpm (126.00 l/s)	12" (30.5 cm)

Pump types are discussed in Chapter 5. For the purposes of this chapter, we need be concerned only with the fluid level in the well. The depth for setting the pumps should be sufficient to allow for long-term drawdown,¹ as determined from the well testing results discussed later in this chapter. Since those data are not available prior to the time the well is tested, other information must be used to estimate the pump-setting depth and hence the casing design for the well. It is not unusual to consider "drawing down" a well (i.e., reducing the water level in the well bore) by as much as 1000 ft (300 m). The pumping costs for lifting water from an additional 1000-ft (300-m) depth generally are much less when totaled over the lifetime of the well than is the cost of an additional well.

Types of drilling equipment

Basically, two types of drilling methods are commonly used:

1. The old-fashioned cable-tool drill (Figure 1). This is not a true drill since it doesn't rotate but employs a heavy hammer bit that pounds and crushes the rock. The rock mixes with a water slurry which is then bailed out of the hole. Often casing is driven directly behind the bit. This method is the least common used for drilling geothermal wells, but it is still common for water-well drilling. It does have advantages for low- to moderate-temperature geothermal wells.

One advantage of cable-tool drill rigs is that they are comparatively inexpensive to buy or rent, and can be operated by two men. Since they don't circulate water, they can operate in freezing climates and be shut down overnight. (Rotary rigs using water or mud must pre-

¹ Other considerations discussed in Chapter 5 are important. A minimum net positive suction head (NPSH) must be maintained over the pump. In determining drawdown amounts to maintain NPSH, steam-saturation pressure and pressure of dissolved gases must be considered.

BASIC ELEMENTS OF CABLE TOOL DRILLING RIG

GEOTHERMAL RESOURCES COUNCIL
JULY 1979

POWER IS GENERATED BY THE ENGINE AND IS TRANSFERRED TO THE SPUDDER BEAM VIA THE PITMAN ARM. ACTION OF THE PITMAN ARM CAUSES THE SPUDDER BEAM TO RISE AND FALL IN A RHYTHMIC MOTION, RAISING AND DROPPING THE BIT ON THE BOTTOM OF THE HOLE FROM A HEIGHT OF 1 TO 3 FT. (1.6 TO 1 M.).

NOTE THAT THE SURFACE CASING HAS BEEN CEMENTED INTO THE HOLE. THE DEPTH AT WHICH THE CASING IS PLACED IS GENERALLY SET BY A GOVERNMENTAL REGULATORY AGENCY.

THE DRILL STEM AND BIT WILL VARY IN LENGTH FROM 10 TO 30 FT. AND WILL WEIGH FROM 1000 TO 3000 LBS.

THE SHAPE OF THE DRILL BIT WILL VARY ACCORDING TO THE FORMATION BEING DRILLED.

THE ACTION OF THE BIT BREAKS ROCK CHIPS FROM THE BOTTOM OF THE WELL. FOLLOWING A PERIOD OF DRILLING, THE ACCUMULATED ROCK CHIPS MUST BE REMOVED. THIS IS ACCOMPLISHED BY BAILING THEM FROM THE WELL; GENERALLY A FLAT BOTTOM BAILER IS USED TO REMOVE CUTTINGS DURING THE DRILLING PHASE AND A DART BOTTOM BAILER IS USED FOR GENERAL WELL CLEANING SERVICE.

FLAT BOTTOM BAILER
DART BOTTOM BAILER

NOTE: CUTTINGS ARE TO BE TRANSPORTED AWAY FROM THE SITE. ONE HALF OF A STEEL DRUM IS USED FOR A BAILER DUMP BOX.

AFTER BEING PULLED FROM THE WELL, A FLAT BOTTOM BAILER IS DUMPED BY PLACING ITS LOWER END OVER THE PIN IN THE BAILER DUMP BOX. A DART BOTTOM BAILER IS DUMPED BY SIMPLY LOWERING THE BAILER ON ITS DART, THUS OPENING THE VALVE - NOTE BAILER VALVE AND DUMP BOX DETAILS.

DETAIL
FLAT
BOTTOM
BAILER

DETAIL DART
BOTTOM BAILER

NOT TO SCALE

FIGURE 1

vent freezing of the fluid if they shut down overnight, consequently they usually run around the clock.)

Another advantage is that casing can be driven directly behind the drill and eliminate caving of the hole and lost circulation, serious problems for those rotary drills that cannot drive the casing. However, casing drivers can be mounted on most rotary drilling rigs.

The main disadvantages are that blowout preventers are not readily adaptable (hence don't use this method on hot, free-flowing wells), the drilling rate is quite slow (compared to rotary drills), and the technique becomes time consuming for depths below 1500-2000 ft (450-600 m). Interestingly, in the first few decades of this century, practically all the oil wells were drilled by this type of rig, to depths of as much as one mile.

2. Rotary drilling. This technique is the more common and generally applicable for drilling geothermal wells (Figure 2). The bit more resembles a drill, even though its drilling action may be as much chipping and crushing as it is cutting. The cuttings are removed from the hole by fluid circulated down the drill pipe and up the annulus between the drill pipe and casing. (Reverse circulation is rarely considered appropriate.) Several types of fluids can be employed:

- a) Water or mud: The use of mud is preferred where caving of the sidewalls is a problem but should be avoided in geothermal production zones. The heavier density of mud helps to contain high pressures in gas wells, therefore, the operators of large rotary drilling rigs are accustomed to using it;
- b) Air mixed with water and a foaming agent: This technique further lightens the column of drilling fluid, making it easier for the geothermal water to enter the well bore;
- c) Air alone: Air is used where water or mud is being lost in the formation. If adequate makeup water is available, continuing to drill with water is advisable because it is superior to air in its lubricating and cooling qualities. Air is commonly used for water-well drilling, because air techniques enhance the ability to detect the water-bearing zones. Air drilling does require huge compressors and high pressures. Work around high-pressure pneumatic systems is hazardous, and, consequently, expensive. Air streams carrying the cuttings past the drill pipe create a very erosive environment for the pipe. Frequent replacement of drilling pipe is needed in air drilling operations.

Rotary drilling rigs are much larger, more expensive and require considerably more power than a cable-tool rig. Typically huge, 200- to 400-horsepower engines, one for rotating the drill, often two for lifting the pipe out of the hole, are needed. A mud pump (to circulate the drilling fluid) and a spare, may also be of about 200-horsepower capacity each. Thus, fuel to operate these rigs can cost \$500 to \$1000 and more per day.

Casing - types and installation

Well casing can be obtained with threaded joints, or it may be ordinary unthreaded pipe which has to be welded together. The latter can be tolerated for shallow wells, but threaded joints are a necessity for deep wells for two reasons: (1) the weight of the casing hangs from the top joint (doesn't apply if the casing is being driven into the ground as the hole is drilled); and (2) the casing may have to be removed if for some reason it won't fit into the hole. The latter may happen because the hole is not straight. There are tools to measure the inclination and direction of the hole, and these should be used periodically during drilling. A clever driller can partially compensate for a deviated hole; therefore, straightness of the well should be specified to the driller. Most drillers have their preferences of how to assemble and install casing. Also, there are service companies to assist drillers in installing long casing strings.

BASIC ELEMENTS OF A ROTARY DRILLING RIG

GEOHERMAL RESOURCES COUNCIL
JULY 1979

THE POWER TO TURN THE DRILL STRING AND THE DRILL BIT IS PROVIDED BY THE ENGINE AND IS TRANSFERRED TO THE ROTARY TABLE BY A CHAIN-DRIVEN GEAR. ENERGY IS TRANSFERRED FROM THE ROTARY TABLE TO THE DRILL STRING VIA THE KELLY BUSHING AND THE SQUARE KELLY.

FIGURE 2

A quality-control check is appropriate on the casing, if it is to be subject to conditions approaching its design limit. Many wells have been destroyed from collapse of casing and/or joints pulling apart. Consequently, quality drillers of deep wells reject many pieces of casing, and these rejected pieces are available as low-quality inexpensive casing that might serve adequately for the shallower, lower temperature geothermal wells.

Non-metallic casing has been used in some of the French geothermal wells at temperatures of 120-140°F (50-60°C). These plastic casings (Fiberglass-reinforced) do have temperature limitations and strength limitations (primarily on how much can be hung from the well head) so such casing cannot be used in the hotter and deeper wells. Unfortunately, to date its cost has not been significantly less than steel casing, but it is lighter and easier to handle with small drilling rigs.

1. Anchor casing at the top of the well (conductor pipe). This casing may be pipe 20-80 ft (6-24 m) long cemented into the ground to thoroughly anchor the well against high pressure inside and the punishment of the drilling operation. This casing usually is installed in a concrete-walled cellar (for the bigger and deeper wells) to allow room for the drilling equipment, valves, etc. between the conductor pipe and the drilling-rig platform. Large drilling rigs usually have two 20-ft (6.1-m) sections of pipe installed in the ground near the conductor pipe (the well) to store the next length of drilling pipe and the Kelly (a length of square or hexagonal pipe that mates with the Kelly bushing that fits into the rotary table; Figure 2) during the drilling operations. These are often referred to as the "rat" and "mouse" holes.
2. Surface casing. The next string of casing is usually required by regulation (law) to protect the drinking-water aquifer from contamination by geothermal water. This surface casing might eventually contain the pump turbine. A check with the appropriate regulatory body about the placement is advisable. The surface casing is cemented to the surface with a 2 to 4-inch (5 to 10-cm) annulus between it and the conductor pipe. The surface casing usually extends deeper than that of nearby domestic water wells, and the main valve and various safety valve equipment are attached to its head.
3. Production casing. This casing is the main casing string and protects the sidewalls of the well against collapse and conducts the fluid to the surface. It must also contain the down-hole pump, unless regulations allow the surface casing to be used for this purpose on the lower temperature wells. In that case, a "casing hanger" is used to hang the production casing near the bottom of the surface casing. Casing hangers cost \$1000-\$10,000 depending on the type and size.

Multiple strings of production casing may be used if trouble with sidewall retention is encountered during drilling. Casing hangers are used for these situations, thus making it unnecessary to run the new string back to the surface. The cost of buying and setting casing hangers, however, must be considered.

Figure 3 shows typical well construction.

Production zones

It is important to determine the production area because the solid casing should not extend into it. Because geothermal fluids are essentially indistinguishable from the drilling fluids, one can often drill right through the production zone and not know it. If flow is eventually produced in the well, temperature-logging techniques can identify this zone. However, by that time, the well may be free flowing, and there may be difficulty in stopping the flow so as to install and cement production casing. How can one determine possible producing zones before

FIGURE 3. Typical design for a low- to moderate-temperature geothermal well.

drilling well on past them? Again, temperature logging appears to be the most reliable method, using high-resolution temperature sensors, preferably on logging cables, that give a read-out at the surface. Examination of the drilling-chip returns can also give a clue as to when the drill enters a possible production stratum. Likewise, a continual monitoring of the quality of the return drilling fluids (such as measuring the fluid electrical conductivity), may also indicate if high-conductivity geothermal water is beginning to mix with the drilling fluids.

Cores. Obtaining cores during production or exploration-production drilling is generally not economically feasible in terms of identifying the production zones. Cores that are randomly taken and represent only a small fraction of the total hole will have limited practical value because they represent such a small fraction of the total hole depth.

Protecting the production zone. The producing zone in oil wells is often cased and cemented, then holes are shot through to allow the desired fluids to enter the well. This technique can be used in geothermal wells which are producing from homogeneous formations where the permeability is all due to intergranular porosity. This technique is unsuitable for formations which produce partially or completely from fractures in the rock. If the shot holes do not fortuitously penetrate the fractures, no production will be realized from these fractures. Therefore, the majority of geothermal wells, those depending on fracture permeability, need to keep all cement or types of materials that have cement-like properties, away from the production zone.

To finish the production zone, a screen or slotted liner (a liner is a piece of casing not cemented in place) can be hung from a casing hanger at the bottom of the production casing. If the production zone is in consolidated rock strata, a liner may not be necessary. In any case, it is desirable to drill a hole somewhat deeper than the known production zone so that any material that does cave away from the walls has a "wastebasket" section to fall into instead of accumulating in the production zone.

Cementing casing

The casing is usually cemented by pumping cement down the inside of the casing and up and around the casing, filling the annulus between casing and well bore, or between casing and existing outer casing. This requires that the end of the casing be fitted with a check valve made of soft material that can be easily drilled out later. The techniques for cementing casing have been well established and are common to the oil and gas and water-well industries. Geothermal wells present additional problems, however, for which the traditional cementing techniques are inadequate. The principal problem is created by temperature hardening the cement prematurely. This effect, however, can be retarded chemically. But if the retardation is too long, the cement may be diluted by naturally convecting waters in the formation; or if redrilling is begun, the casing may be jarred breaking the unhardened cement. Failures during or after the cementing process have been some of the more frustrating problems encountered in the hot-water geothermal wells.

It is important to have the cement bonded to the casing. This bond can be checked by a sonic technique. Such a check requires a logging service, and it is expensive. If the cement is found to be inadequately bonded or is known to have gaps, then remedial action may be needed (depending on the severity of the thermal stress that the casing will see and/or the requirements of state or federal regulatory agencies). Such remedial action may require shooting holes into the casing and squeezing cement into them. Again, this is an expensive operation, fraught with difficulties. It is obviously desirable to have a successful cement job on the first attempt.

Thermal losses can be significant in direct-heat application if the resource temperature is

marginal to begin with. Losses in heat traveling up the well can vary from a few degrees to 10-15°F (5-8°C). The problem is most severe for deep wells penetrating convecting cold water aquifers. To date, there are no examples of attempts to reduce the heat loss significantly. A possible method is to add material to the cement that will enhance its thermal resistance. Another possibility is to anchor the bottom of the surface casing with cement and fill the rest of its annulus with a rigid, expanding foam. This latter method offers tremendous potential for reducing heat loss. It must be approved by the state or federal regulatory agency, and the well head must be designed to handle the casing expansion. Expansion-compensating well-head equipment is commercially available. (Though the use of foam between the surface and production casing has been discussed by many organizations, the technique has yet to be tried in practice.)

Problems in geothermal drilling

Drilling of geothermal wells involves the same types of problems that plague water-well and oil-well drillers: broken bits, broken drill pipe and "lost" tools, stuck tools, etc. However, geothermal drilling has two concerns which essentially demand contradictory approaches to drilling technique. These must be assessed for any particular well-drilling situation, and the most critical concern at that point in the drilling operation is to allow one to take precedent over the other. The two concerns are as follows:

1. Avoiding the sticking of the drilling tools in the hole caused by sidewall sloughing away and collecting around the bit. Caving in of the hole is the bane of drillers and rig operators and is most likely to occur in the loosely consolidated formations in the first few thousand feet (300 m's). Generally, at greater depths, hundreds of years of high pressure and moderate temperature have cemented or consolidated the sediments. The common methods to avoid this problem are to use heavy drilling fluids (called mud) having 1-1/4 to 1-1/2 times the density of water and approaching the density of the formation and the lithologic pressure. Flow rates for these drilling fluids must not be so high as to erode the side walls. The use of heavy drilling fluids accomplishes the following:
 - a) Prevents caving;
 - b) Floats and removes the cuttings more effectively;
 - c) Seals the walls from loss of drilling fluid (very important when the mud is expensive);
 - d) Suspends cuttings for longer time when the circulation is stopped and the drilling bit is removed from hole;
 - e) Lubricates and cleans the cuttings from the bit.
2. Avoiding the use of heavy or unnatural fluids in the suspected production zone. This requirement clashes with (1) above. Yet some of the very reasons for using heavy drilling fluids, as in (1), are the same reasons that make it difficult to identify the geothermal-producing strata. For instance:
 - a) Heat in the geothermal zone may help solidify the drilling mud in the fractures, and the mud may actually develop the qualities of a cement;
 - b) Chemical reactions, especially at the higher temperatures, may contribute to the mud sealing the pores in the rock formation;
 - c) The weight of the mud can prevent the geothermal water from entering the hole, thus the driller has no clue that he has encountered the resource.

The latter concerns are extremely important in geothermal drilling, but of no concern in oil and gas drilling, where, as soon as the hydrocarbons come to the surface with the cuttings that contained them, the hydrocarbon "sniffer" will detect their presence. The oil and gas driller then knows he has hit a potential producing zone. The geothermal driller gets no such clue from his zone. The best detection technique is to conduct a high-resolution temperature log, from which

he might possibly deduce subtle temperature changes and a potential geothermal strata, but the chances are slim if drilling is done with mud. Hence, in the production zones (suspected or otherwise), the driller may just have to take his chances, drilling with water or with water made lighter with air, hoping that the sidewalls will not cave in on him and that geothermal water will leak into the well bore. Keeping the fluid circulating and getting the drill string out of the hole as quickly as possible (when circulation is stopped to remove the bit) are extremely important.

Safety considerations

1. Temperature. A temperature hot enough to scald (above 140°F, 60°C) requires having face shields, wet suits and insulated gloves available. Temperatures above boiling should be treated with the respect given to any steam system, with applicable codes (Section VIII of ASME, etc.), personnel protection, and operating procedures to prevent accidents.
2. Free-flowing (artesian) wells. Two conditions can create water flowing free at the surface. The geothermal reservoir could be fed from a higher elevation. At the location where the well is drilled, there could be a layer of cap-rock (see Figure 4). As soon as a drill breaks through this cap-rock stratum, the pressure will be that of the higher elevation, provided the well bore is not sealed and is not filled with heavy mud. If the well is fed from a higher elevation, no amount of cold water will kill the well once it starts flowing. These wells present special drilling problems during casing and cementing. It is thus desirable to complete these operations before drilling through the cap-rock and into the resource production zone. If such preparation is not possible, the use of heavy muds may be considered. Such practice is common in the oil and gas industry, but is generally ill-advised for geothermal wells (see Problems in Geothermal Drilling, above). Alternative methods are to back-fill with sand (and to drill the sand out later), or to kill the well with salt water with density up to 1.2 times the density of ordinary water if a suitable means of avoiding environmental contamination with salt is available.

The second condition leading to artesian well-head pressure is a density difference from a hot-water column in the well vs. a cold-water hydrostatic head above the geothermal reservoir. The following table lists the pressure difference with respect to 68°F (20°C) cold water, per 1000 ft (305 m) of vertical height.

102°F = 39°C	2.8 psi (19 kPa)
153°F = 67°C	8.7 psi (60 kPa)
193°F = 89°C	14.5 psi (100 kPa)
212°F = 100°C	17.8 psi (123 kPa)
240°F = 116°C	22.7 psi (156 kPa)
281°F = 138°C	31.0 psi (214 kPa)
302°F = 150°C	35.8 psi (247 kPa)

Since 1.0 psi (6.9 kPa) will elevate water 2.3-2.5 ft (0.70-0.76 m; depending on the temperature), the hot leg can stand substantially higher than the normal water table, perhaps enough to make the well free flowing at the surface. This type of well can be killed by pumping cold water into it. It can be restarted by air-lifting or by swabbing (pulling out a loosely fitting piston at a rapid rate).

3. Casing thermal expansion. The expansion differential between the casing and the material which it contacts (the cement, for instance) is a significant problem, as is the sole thermal expansion of the casing itself if it is allowed to expand freely. Steel casing, for instance, with a thermal expansion coefficient of

$$6.7 \times 10^{-6} \text{ per } ^\circ\text{F} \quad (3.7 \times 10^{-6} \text{ per } ^\circ\text{C})$$

FIGURE 4. The source of artesian pressure in wells.

will expand by 8 inches over every 1000-ft length for every 100°F of temperature change (20.5 cm/305 m/ 38°C). Its relative expansion, with respect to rock or cement, is about two-thirds of this amount.

If one tried to constrain a 1000-ft (305-m) length of casing 13-3/8" OD by 3/8" (34 cm x 0.95 cm) thick, the stress would be approximately 20,000 psi (1.38×10^5 kPa), and the force to constrain this expansion would be 318,000 lbf (1410 kN)--all this for just 100°F (38°C) change in temperature. The effects for longer strings of casing and for larger changes in temperature are proportionately greater. These effects are insignificant in ordinary water wells and usually of little concern in oil wells. But in geothermal wells, casing expansion, even during the casing installation operations, must be carefully considered to insure the inclusion of the appropriate allowances and clearances.

The most common practice today is to cement the entire surface and production casing thoroughly in place with a tight bonding cement. Afterwards, casing expansion can be ignored, unless the bond breaks. To minimize this possibility, operation of the well throughout its lifetime should be so planned as to limit the number of "ratcheting" thermal cycles---i.e., keeping the well hot even when it is not being used.

4. Containment of drilling fluids and well production. Most environmental regulations will not allow disposal of either drilling fluids or the produced geothermal fluids on the surface until it is proven that these do not affect the local environment. Therefore, all drilling operations must consider using hold-up ponds (reserve pits) and the necessary mechanisms to direct the fluids into these pits. Also, a reserve supply of cold water must be available for makeup water, if needed, and for cooling the well should an emergency arise.
5. Blowout preventers. This term is perhaps overused and is popular in the oil and gas industry and for steam geothermal wells. In general, blowout preventers are those mechanisms attached to the well head which can shut off the flow out of the well, even during drilling. These mechanisms are:
 - a) A set of blind rams (gate valves) used to shut off the well when not drilling;
 - b) A set of pipe rams that can close around the drill pipe;
 - c) A rotating head that forms a seal around the drill pipe but allows it to turn freely;
 - d) A check valve at the bottom of the drill pipe to prevent fluids from entering the pipe; and
 - e) An inflatable rubber sleeve that can close tightly around drill pipe or any other device hanging in the well.

Wells that are not free flowing or will flow only lukewarm fluids (say below 140°F, 60°C) may require no more than the standard gate valve. Figure 5 shows some typical well-head installations and blowout preventers.

Costs of drilling

The following approximate costs are presented for rough estimating purposes. All costs are drawn from 1979 quotations.

Drilling rigs.

1. Rotary rigs: These rigs vary in size, from truck-mounted units that can be quickly dismantled and transported, to large rigs capable of reaching depths of 20,000 ft (6 km) or more. The latter are seldom used in geothermal drilling. The following tab-

FIGURE 5. Containment equipment---blowout preventers. Typical for use on high-pressure wells.

ulation assumes a depth capability of at least a 6-inch diameter bit (15 cm) and 5-inch (13 cm) casing.

a) Truck-mounted rigs:

1) Depth capability of 1000-1500 ft (305-450 m)	
Day rate (24 hours)	\$800-\$1500
Move-in and move-out costs	\$2000 (approx)
2) Depth capability of 2000-4000 ft (610-1220 m)	
Day rate	\$2500-\$4000
Move-in and move-out costs	\$20,000 (approx)

b) Medium-sized rigs (capable of drilling to 10,000-15,000 ft, 3048-4572 m): Medium-sized rigs generally have hoist capability of 200,000-300,000 lbs (90,000-136,000 kg) and may take 30 or 40 truck loads to get all the equipment to the site. Their depth capability, using a 6-inch (15 cm) bit, significantly exceeds geothermal requirements (10,000 ft, 3 km). A 300,000-lb (136,000 kg) hook capability can handle 8000 ft (2.4 km) of 9 5/8-inch (25-cm) casing.

Day rate	\$4000-\$6500
Move-in and move-out costs	\$100,000 (approx)

c) Large rigs (capable of drilling to 30,000 ft, 9144 m): These rigs generally exceed geothermal requirements, with hook-load capabilities in the range of 1/2 million to 3/4 million pounds (0.23-0.34 million kg).

Day rate	\$10,000-\$15,000
Move-in and move-out costs	\$250,000 (approx)

2. Cable-tool rigs. These rigs generally cost \$500-\$1000 for a 10-hour day. However, many cable-tool operators will bid a footage rate, which will be approximately \$1.50 per inch diameter of hole per foot of depth (\$1.93/cm/m) to 500 ft (152 m, nominally), with higher rates for greater depths.

Casing. Approximate FOB prices for standard-sized well casing:

20" threaded (50.8 cm)	\$30/ft (\$82/m)
13 3/8" threaded (34.0 cm)	\$20/ft (\$59/m)
9 5/8" threaded (24.4 cm)	\$13/ft (\$43/m)
6 7/8" threaded (17.5 cm)	\$ 8/ft (\$26/m)
20" regular (50.8 cm)	\$20/ft (\$49/m)
12" regular (30.5 cm)	\$13/ft (\$33/m)
8" regular (20.3 cm)	\$ 9/ft (\$20/m)

Casing shoes typically cost several hundred dollars each.

Drilling bits and other expendable equipment. A rotary drilling bit from 6 inches to 12-1/4 inches (15-31 cm) may cost between \$500 and \$5000. The toothed bits are the least expensive. The tungsten carbide "button" bits with sealed journal bearings are the most expensive.

A bit will generally last for 100-1000 ft (30-305 m) of drilling, or from 12-30 hours, though some of the newer, advanced sealed, journal-bearing bits may be run for as much as 100 hours. The bit life depends on formation hardness, weight applied on the bit, and on the actual cutting rate. Manufacturers specify the nominal rotation speed and weight applied to the bit for best operations.

Services. Various services may be needed during a drilling operation. A few of these are listed below:

1. Geologists and a mud-logging truck to examine and record the drilling-chip rock type, and such other information as may be gleaned from drilling returns.
Cost: \$300-\$400/day
2. Casing crews - About \$2 per foot (\$6/m) of casing installed (\$2000 minimum).
3. Complete logging services - Minimum cost \$3000. However, temperature logging only costs \$500-\$1000 each time the well is logged with a rig and a crew already on site. Figure \$1 per mile (\$0.60/km) travel costs.
4. Fishing services - If tools are lost in a hole (typically \$2000/day).
5. Coring services - The diamond bit used for coring costs between \$7000 and \$10,000. In addition, a technician and a core barrel are rented.
6. Turbine drilling services for sidetracking or whipstocking - These services usually include an engineer on site.
Minimum costs: \$7000.

Time required to drill

1. A cable-tool rig will drill as much as 5 ft (1.5 m) per hour, to depths up to 500 ft (152 m). The rates become quite slow at greater depths or in hard formations.
2. A rotary rig can be expected to drill 500 ft (152 m)/day in soft formation. But in hard formations, the progress might be as little as 100 ft (30 m)/day (a 24-hour day).

As the well gets deeper, one must then figure the time lost in "trips" to bring the bit out of the hole, to replace the old bit, and to return to the bottom again. For instance, a round-trip from 4000 ft (1220 m) can occupy 3 to 7 hours, depending on the experience of the crew.

The contingency

Any cost estimate involving construction includes a contingency for inaccuracies of the estimate and the unexpected delays that necessitate changes in design or construction methods.

Although drilling, by its very nature, explores the unknown underground, many direct-heat applications projects need only one or several wells, not an entire field of wells. The contingency recognizes that you are dealing with the unknown and problems that do occur may be many thousands of feet away at the bottom of a drill hole. The contingency must adequately account for these conditions; it should not be merely a hedge for inaccuracies of the cost estimate. A minimum contingency of 25% is recommended.

Typical drilling costs for geothermal wells are plotted in Figure 6.² These figures are taken from those derived for wells that are low-to-moderate temperature (The Geysers field and Imperial Valley wells are not included). In general, these represent total costs, including unusual

² The authors wish to acknowledge the assistance of the U.S. Department of Energy, Idaho Falls Office (Robert Chappel) and the Earth Science Laboratory of the University of Utah Research Institute for portions of this data. Since some of the well costs were supported by federal funds, the costs may differ somewhat from wells drilled with private funding; however, the difference is not likely to be more than 40%.

FIGURE 6. Typical drilling costs for geothermal wells (corrected to 1979 dollars).

problems that developed and may be first-of-a-kind problems in some cases. Cost incurred by the owner or developer for his salaries or for consultants are generally not included in the well costs. It is apparent that there are two trend lines, one for very shallow, easy-to-drill wells, the other for the more conventional wells. These figures should serve as a useful guide for rough estimating, since all results have been escalated for inflation to equivalent 1979 dollars.

DRILLING REGULATIONS

Temperature

State regulations of geothermal production often begin at a given temperature. Temperature is an easy method of designating the point of demarcation for the more restrictive geothermal regulation. In the eastern states any depth or temperature allowing heat extraction would probably be covered by a state oil and gas commission or other regulatory body that reviews oil and gas exploration and production.

Conventional water rights and drilling regulations

In the more arid west, if temperature and depth limits set by state regulation are exceeded, geothermal-production permit or geothermal-injection permit may be required. Above that depth of demarcation, a water right is required since western states have developed a comprehensive system of water rights both judicially and administratively. This relation between water right and geothermal use varies somewhat from state to state.

Water rights protect the user but geothermal regulation protects the resource. Most western states have water rights based on a "first-in-time, first-in-right" principle. Geothermal regulation (permit) sets the standards for blowout prevention equipment (BOPE), casing requirements, logging, withdrawal quantity, data and other construction requirements and management tools. These regulations include geothermal exploration wells, production wells and injection wells. It is generally recommended that both water rights and geothermal permits be obtained.

Federal regulations on federal leased lands

Federal leased lands have many uses. Just a few such uses are: fish and wildlife habitat, silviculture, grazing of livestock, wild and scenic rivers, primitive areas, sports and recreation, and mining and related claims.

The Bureau of Land Management of the Department of Interior is the custodial agency of federal lands. Leasing requirements are established by Congress. The U. S. Geological Survey controls the geothermal rights and supervises the drilling and production operations. The regulations require an environmental assessment, construction criteria, on-site inspection and payment for heat used, usually for a 10% royalty. Leased land is obtained through competitive bidding for the obvious geothermal lands (Known Geothermal Resource Area, KGRA's). The procedures are stated precisely in the Geothermal Steam Act of 1970 and its implementing rules and regulations, Chapter II-Geological Survey, Department of Interior, Parts 270 and 271.

State regulations

State leasing requirements on state-owned land are similar but usually less stringent. Generally, the state land department awards the leases and governs such geothermal uses through the

oil and gas regulations of the state.

Driller licensing

The classification of well drillers depends on the type of well. The three classes are the licensed water-well drillers, the mineral (slim hole) test-well drillers, and the oil- and gas-well drillers. All three types have drilled geothermal wells.

Each state issues licenses to water-well drillers and the general public can review the driller files. State oil and gas regulatory agencies regulate oil- and gas-well drillers, review the drilling prospectus and inspect the sites. Mineral slim-hole drillers may not be required to have a license or be reviewed by either of the above.

Equipment and company resources become a ruling factor in geothermal well drilling. Oil and gas drillers have knowledge, equipment and company resources, but these drilling rigs are probably too expensive for shallow or even intermediate-depth (2000 ft, 610 m) geothermal wells. A licensed water-well driller can drill a shallow geothermal well if his rig is appropriate in size and quality and his company has the resources to complete the job in case of difficulty. As a rule of thumb, a large water-well drilling company may be considered even for wells expected to exceed 2000 ft (610 m). Below that depth, technical problems may dictate a larger type oil and gas rig and driller.

Geothermal-well drilling can be dangerous and expensive because of the depth of the well, the high pressure and temperature, leaks and possible contamination of groundwaters and surface waters. These problems generally increase dramatically as depth and temperature increase. Thus, the lower temperature, direct-heat application wells may have negligible problems when compared to those of the deep, high-temperature wells for electric steam power plants.

Liability

The owner, developer and driller are liable for infractions of the law and possible damage. More particularly, they must answer to conditions of permits, contracts, leases and to the judicial system if parties submit claims of damage.

Provisions for production testing

Production drilling must waste geothermal fluids temporarily. State agencies generally require some guarantee of protection of surface and groundwater from possible contamination by a waste product. They monitor the water quality if there is direct discharge to surface water sources or to lined containment ponds.

Water quality governs the methods of disposal. Water-quality standards may be lowered because of the temporary disposal of the geothermal product being tested. Sampling and consulting the regulatory agency before selecting the appropriate disposal method are important. Early sampling could save rig time in constructing lined ponds.

Geothermal fluids may be disposed during production testing by the following methods:

1. Waste directed to a known water course after being cooled if quality is acceptable;
2. Waste disposed on the surface, such as irrigation;

3. Waste disposed below the surface to shallow strata ponds. Quality water is injected through the pond bottom to a dry strata;
4. Waste held in a lined evaporation pond. This method requires a pond with a large surface;
5. Waste injected into a well to an authorized strata.

Suggested reading list.

1. State codes--specific sections applied to geothermal and water law,
2. Rules and regulations of state agencies,
3. Federal Geothermal Steam Act of 1970 and USGS rules and regulations (see Chapter II, Parts 270 and 271),
4. State leasing requirement (usually obtained from the state land department).
5. A survey of environmental regulations applying to geothermal exploration development and use--Environmental Protection Agency. These are currently being drafted by the agency.

DISPOSAL OF USED GEOTHERMAL FLUIDS

The direct use of geothermal waters for space heating or for industrial-process use requires large flows of water. For example, the Oregon Institute of Technology at Klamath Falls requires an average pass-through of 250 gpm (16 l/s) to heat 500,000 ft² (46,000 m²) of floor space in 8 buildings. Typical large industrial-process heating applications require flows of 500 to more than 1000 gpm (30-60 l/s). With multiple users in an area, demands for geothermal fluids could easily total 10,000 gpm (600 l/s). After the useful heat is extracted from these fluids, there must be an economically and environmentally acceptable method of disposing of them.

In the past, the most common practice has been to reject the fluid into the nearest water course. In most cases, this practice has not caused problems. However, with the anticipated increase in uses of geothermal energy, the ability of surface streams and lakes to absorb these waters will soon be passed, eventually causing noticeable environmental deterioration. State and federal laws now prohibit or severely restrict this practice of dumping, so other forms of disposal have to be used. Two alternatives exist: surface and subsurface disposal.

Surface disposal

Disposal by dumping is no longer legal except in rare cases where flows are minimal and will not damage the downstream environment. In some cases, beneficial downstream use of the geothermal fluid can be considered, depending on the tolerance of the use and the quality of the geothermal fluid. It may be possible to remove or to lower the amount of offending elements, thereby improving the quality of the geothermal fluid for a variety of downstream uses. However, for most projects, treatment of the geothermal discharges would not be economically feasible.

Ponding is the other surface-disposal alternative. Ponding is probably the best tool for short-term activities such as well testing. Long-term ponding has been used where level land is available. With ponding, the fluid is ultimately disposed of by evaporation or by leaching, or a combination of both. Leaching ponds are viable only if usable groundwaters are isolated from

the leachate and only in areas where there is a high rate of evaporation. The unique combination of circumstances to make ponding a practical long-term disposal technique may be unusual, so its application could be very limited.

Subsurface disposal

Waste can be disposed below the surface either by injecting the geothermal fluid away from the production reservoir or injecting it into the producing reservoir. In practice, it is difficult to find deep zones of sufficient permeability and porosity to absorb the large volumes of fluid from a geothermal operation, except for the producing geothermal zone. In areas of high permeability near the surface, this disposal method has been successfully applied. Returning the spent geothermal fluid to the production reservoir has proven to be a successful solution to several potential problems in addition to getting rid of the effluent. By injecting into the producing reservoir, the consumptive use is decreased or eliminated; the useful life of the field is extended by mining the heat from the rock, and the potential for subsidence is reduced.

The benefit of reduced consumption is obvious, as the same water can be reused many times to transfer the heat to the surface. This method can extend the useful life of the field through conservation of both the water and the thermal energy. Under nearly all reservoir conditions, there is more heat stored in the rocks in the reservoir than in the water, so recycling the water washes more heat from the rocks. The life of the reservoir can also be extended by returning the still energy-laden water to the reservoir rather than require its recharge from water outside of the system that is at ambient surface temperature. In practice, most geothermal installations utilize only 10-25% of the heat contained in the water and reject the rest. If this heat normally rejected were returned to the reservoir, less total heat would be required over the life of the field. Figure 7 illustrates a comparison of energy and water flows using the example of three schools in Klamath Falls that have return-water systems.

There is a serious concern that the returned geothermal fluid might cool the reservoir. In most cases, a change in temperature of a few degrees does not significantly affect a space- or process-heating use and the benefit of extending the life of the field makes injection a good trade-off. In practice, a history of fields that utilize injection shows there are no measurable changes in the fluid temperatures over time. In a field where any reduction in reservoir temperature would have detrimental consequences, the possibility of returning the water at a distance from the production wells, thereby allowing a long path to pick up heat, has been considered in several cases. Figure 8 shows an example of the effect of reinjection for an operation moving 1000 gal/min (60 l/s) of fluid from a production to a reinjection well. As can be observed, it will take many years for the first streamline of fluid to reach the production well 4,000 ft (1200 m) away. But that hydraulic front will not be cold when it reaches the production well, for the rock will have heated it to within a few degrees of the original reservoir temperature. Of course, the assumption of a homogeneous formation will rarely apply in regions where there is significant faulting. In those cases, reinjected fluid will travel along the faults and fractures. The connections, or lack of connections, between the production and reinjection wells can dramatically alter the time required for the "cold" hydraulic front to reach the production well, either decreasing or increasing that time depending upon the orientation of the fractures.

Disposal regulations

1. State regulations: Geothermal developers must comply with all regulations regarding disposal of waste waters. For new developments, this makes surface water discharge very difficult; in fact, it is usually unacceptable. Subsurface disposal is the preferred

FIGURE 7. A typical comparison study of two methods of disposal of geothermal fluids, showing one-year energy and water requirements for two schools in Klamath Falls, OR utilizing (1) an Injection system and (2) a surface-disposal system.

FIGURE 8. Migration of "cold" water from Injection well back to production well.

method, and at this time most states have not formulated any rules beyond treating geothermal effluent as groundwater. Oregon is presently considering regulations making injecting of geothermal effluent the preferred system; but if the developer shows damage will occur, other techniques would be considered.

2. Federal regulations: For geothermal in federal lands, return of the fluid to the producing reservoir is the approved method of disposal. Injection into other areas can be accepted if it is shown not to have harmful effects on domestic water resources. At present, geothermal injection regulations have not been issued by the EPA (as of December 1979).

Liability considerations

There is always a potential of damage to other resources by unanticipated contact with the geothermal return waters. Both state and federal regulations describe procedures and checks for subsurface disposal systems. It will be up to the operator to adhere to these regulations and to monitor the injection wells. By adhering to these practices, an operator will be protecting himself against claims for damages that might be instigated.

Cost considerations

Costs for injection wells are probably similar to costs for production wells of similar size and depth. In addition, pipelines and monitoring equipment will be necessary. In general, an injection well can accept more fluid than a production well can deliver. Thus, fewer injection wells

are needed. However, actual operating experiences with injection have been few, and chemical precipitation problems in the well bore are of concern. It is best to keep the geothermal fluid under pressure all the way from the production well head to the injection well head.

Unitization

In general, geothermal fluids will need to be reinjected because their chemical nature will not meet today's stringent environmental controls for surface disposal. But most direct-heat projects will involve relatively small amounts of energy and hence small amounts of fluids. The required number of wells, both production and reinjection, will be limited. Nevertheless, if the area is a good source for geothermal fluids, attempts will be made to develop adjacent properties for similar direct-heat applications. Even the initial developer may find it necessary or desirable to put the production wells on property of one owner and the injection wells on property of a different owner.

Under these varying circumstances of multiple land ownership and many small developments of direct application of geothermal, the choice of which properties have the production wells and which have the injection wells may be arbitrary. The questions are:

Which owner collects the royalties for the production wells?

Does the owner of the land on which the reinjection wells are located receive payment?

Will the production and reinjection wells affect, over the years, the thermal quality of the resources of adjacent property owners?

These questions can largely be avoided by unitizing the area to be affected by the development. Unless specific information to the contrary is available, one may assume that the reinjection fields are just as necessary and valuable as the production fields, and all the owners in the unitized area share proportionately in the royalties. Unitization should be accomplished early in the development program to avoid controversies.

ENVIRONMENTAL CONSIDERATIONS

Surface land use

1. Access road: To begin construction of any geothermal well, the driller and his rig must have access to the immediate site as well as access to the siting of the projected uses. The access road will require reasonably large radius curves with moderate grades and curves since the drill rig and other equipment will be long, heavy loads. Bridges and culverts for stream crossing should be adequate to support the rig, but need only be strong enough to support lowspeed infrequent usage by the heavier machines. Stream crossings may require a permit from the state water resources agency. Road widening and curve restructuring would require permits or leasing from the private land owner or a state or a federal agency such as the State Land Department, the U.S. Bureau of Land Management or the U.S. Forest Service.
2. Drill site. The drill site must be sufficiently level and cleared for the drilling rig and for a helper truck carrying drill pipe, casing, bits, etc., and the site also must have additional room for mud pits, holding ponds and vehicle parking. The required size of the area is a function of the size of the drilling rig. However, from 1/4-acre to 2 acres (0.1-0.8 ha) of land is a typical range. If the well is to be tested, a holding pond may be necessary, depending upon quality of the geothermal and local considerations. In areas of high relief, slope failure and landslide possibilities should be considered when the drill site is being prepared.

After drilling is completed and the well is brought into production, the site should be restored. A production well requires very little space. When the well is completed, there

is very little visual evidence, only the well casing above ground or in a concrete bunker (cellar). If it is necessary to pump the well, a small pumphouse may be constructed or a cellar can be excavated. In all cases, the restoration should leave sufficient room around the well to bring in a workover rig required for maintenance or repair work.

3. Drilling operations: The drilling operations can be offensive in populated areas as well as in unpopulated recreational areas. Careful use can reduce the noise, dirt, and dust. Roads may be watered; drilling operations can be scheduled to meet such local restrictions as no noise at night in residential neighborhoods. All trash should be kept in trash containers; oil waste from machines should be contained and appropriately disposed of in proper containers.
4. Pipelines: The pipeline and distribution system may be steel, requiring expansion loops, or an asbestos cement material with rubber gasket joints that allow for expansion. Steel lines are usually placed above ground. Asbestos cement pipeline will generally be buried. Surface pipelines may be used where they do not restrict other uses of the land and when below-freezing temperatures are not common. Pipelines are buried for very practical reasons: burying reduces the heat loss from the system and enables less expensive materials (such as asbestos cement) to be used; it also hides the pipeline from vandals and damage from machinery, etc. Control valves should be located in concrete boxes allowing room for operation and maintenance.

Subsurface influences on conventional water supplies

Withdrawal of geothermal waters could have a variety of effects on conventional water supplies. The effects entirely depend on the geologic formation and the inter-relationship of the ground-water system.

To predict the effects, we need to evaluate the interaction of the geothermal reservoir with the shallow cold-water reservoir or perhaps the converse. If the interaction is of major proportion, the geothermal development may have detrimental effects on the domestic water reservoirs.

Benefits of reinjection into shallow cold-water aquifer would include: (1) reducing injection costs due to shallow well depth; (2) possibly reducing the costs of pipeline because injection might be feasible at the point of waste, (3) providing water to conventional water supplies, (4) reducing the potential for subsidence.

However, the water quality of the effluent to be injected may not meet those standards that require the injected fluid to be the same or of better quality than that of the receiving reservoir.

Subsidence and seismic activity

This activity is generally not likely to be a problem, but, under some conditions, long-term production could trigger subsidence and attendant seismic activity. Subsidence becomes a potential problem when the reservoir is unconsolidated. In that case, the removal of fluid removes support for the overlying rocks and they will compact and thus cause subsidence. Where the reservoir is made up of competent rocks, the fluid does not provide support and its removal may not cause compaction. Injection of the used geothermal fluid back into the production reservoir usually minimizes any subsidence potential.

Seismic activity may be triggered by deep-seated subsidence caused by fluid removal. Such

activity could be possible where an unconsolidated reservoir was being produced and the fluid was not being reinjected. However, seismic activity could also be produced if reinjection were practiced into dry-fracture/faulted zones. The injected water could lubricate the fault and promote premature slippage.

Protection against liability from supposed damage of surface structures or to shallower water wells should be planned for any major geothermal production scheme. An elevation and well monitoring system would be good protection. In the event a major field is being exploited, a monitoring plan might best be implemented by an independent monitoring organization, which might be a tax-supported entity.

WELL TESTING

Well testing is the general name for all techniques used to determine whether a well will produce usable fluids economically and for how long. Testing begins during drilling and usually continues as a monitoring program for the life of the well or resource. Testing involves measuring the following quantities: 1) temperature, 2) pressure, 3) flow rates of both mass and heat, and 4) fluid composition. The measurements are taken at the production well, at nearby wells, springs, and at injection wells. The basic procedures for testing and analysis have been adapted from petroleum-reservoir engineering and groundwater hydrology. Many of the techniques can be used without modification, but some techniques have led to significant new methods, such as fracture-type curve analysis, to meet the special conditions of geothermal reservoirs.

Equipment

Table 1 is a chart showing type of equipment vs. cost for each quantity we want to measure.

1. Temperature: Temperature-measuring devices range from mercury in glass thermometers through thermocouples with digital read-outs to Kuster temperature bombs. Maximum reading thermometers and thermistors can be attached to a hand-operated winch lowered into a well at minimal cost. Good thermometers cost about \$50. Thermocouples with digital read-outs can be used only on the surface and cost about \$300. They are rugged, reliable, and easy to use. Kuster tools require a wireline rig and cost around \$8,000. They are used for temperature surveys of the entire hole and are justifiable only for fairly large products. They are effective but expensive. Temperatures should be taken downhole, at the well head, along the flowline and at the outflow end. All instruments should be calibrated before and after use. The type of winch or logging-cable drive depends on the needs. It may cost as little as a few hundred dollars for shallow-well capability or as much as tens of thousands for deep-well capability.
2. Pressure and water level (head) measurements: Pressure gauges vary in type and cost. Downhole gauges run high. The Hewlett-Packard quartz gauge is \$15,000. Wellhead pressure can be monitored with a small gauge screwed onto a valve (\$20) or a quartz gauge giving 6-figure accuracy (several thousand dollars). Gauges are easy to install along the flowline. Quartz gauges are most useful for multiwell interference tests where their extremely high sensitivity can give sufficient information to finish a test long before conventional gauges. Ordinary bourden-tube gauges are adequate for single-well tests. If the water level is below the surface, the most reliable method is the water-displacement technique using gas pressure in a small tube extending from the surface. Simple conductivity cells on the end of a line can serve for rough measurements, but they quickly foul from moisture, oil, etc.

A variety of methods can measure the flow rate of fluid. Downhole flow rates can be measured using spinners and thin film anemometers. Surface flow rates can be measured using a 55-gallon (208 l) drum and a stopwatch if the rates are low enough. Other methods include a home-built weir box and free discharge from a pipe with a manometer tube to measure differential pressure. The most precise, general-purpose method that can be used on wells of high pressure and high temperature is the orifice plate with differential-pressure meter recorder.

3. Composition. Numerous cheap, simple methods are available for determining composition. The pH can be measured with special paper for pennies or by a very rugged portable electric meter which costs about \$150, or the sample can be sent to a laboratory for about \$30-\$70/sample for determining the concentration of several elements as well as the pH. Total dissolved solids (TDS) can be determined with a small, rugged portable conductivity meter which costs about \$300 or sent to a laboratory. Hach kits and Draeger tubes are available at low cost for measuring specific chemicals. Non-condensable gas can be sampled in gas cylinders and analyzed in a laboratory, or it can be monitored on site using a gas chromatograph. This service is offered by mud loggers. If the expense is justifiable, portable gas chromatographs are available from \$1500-\$6000.

TABLE 1
Types and Costs of Measuring Equipment

<u>Measured Quantity</u>	<u>Least Expensive</u>				<u>Most Expensive</u>
	Increasing cost and complexity →				
Temperature	Maximum Reading thermometer \$20		Mercury in glass thermometer \$50		Digital thermometer \$300
Pressure	Simple mechanical gauges \$20		Pressure recorders \$900	Quartz gauges with recorders \$3000	Downhole quartz detectors \$15,000
Flow Rate	55 gal drum & stopwatch \$25	Weir box \$30	Free discharge manometer \$50	Spinners \$1000-\$2000	Differential pressure across orifice plates \$2000
Composition	pH paper \$5	Ioni-zation meters \$300	Hach kits Draeger tubes \$600	Other wet chemical \$1000+	Gas chroma-tograph \$6000
Water Level	Electric conduction probe				Pressure-tube water dis-placement device

Tests and analysis methods

1. Temperature: During drilling, temperature should be taken at every opportunity. For example, the in and out drilling-fluid temperature should routinely be measured. Downhole temperature can be periodically measured using maximum-reading thermometers or continuous-recording platinum resistance thermometers downhole on a wireline between bit runs. Continuous logging of temperature in the borehole for a period after drilling usually can indicate the strata in the borehole of the resource. More elaborate and expensive measurements include injecting cold water into the well and running temperature surveys regularly for several hours to several days to determine the hot-water entry zones. During drilling, temperature can be monitored by other indirect techniques (for example, Crosby's method as described in the 1977 Stanford Geothermal Reservoir Engineering Conference Proceedings). Temperature surveys can reveal temperature reversals, cold water entries, and rate of thermal recovery.
2. Pressure and drawdown testing: Pressure testing is extensively discussed in various petroleum-engineering and groundwater-hydrology books because it is the best method for determining formation and well permeability, transmissivity (sometimes called transmissibility), well-bore damage, presence and extent of boundaries, faults, and fractures, interwell interference and long-term reservoir projections. Pressure gauges or water-level indicators are required and the well must be flowed and shut in according to a specific schedule. Analysis methods include Horner plots, semi-log plots, log-log type curves, and free water-surface analysis. Initial tests (up to 24 hours) are run while the rig is still on location because the tests might indicate that the hole should be deepened or cased or cemented. Once the rig has left the site, short- and long-term tests are run. Duration depends on many factors, but a short-term test is roughly 1-3 hours, while a long-term test can be 6 weeks to 6 months or longer. See the section below on long-term well performance predictions for further discussion.
3. Flow rate: Mass and heat flow rates can be monitored and plotted vs. time on semi-log paper to form pressure- or "head"-decline curves. These curves can be extrapolated to future production rates by routine mathematical techniques.
4. Composition: The concentrations of individual components can be determined and plotted vs. time. Changes in individual concentrations or in ratios of concentrations can indicate changes in the reservoir which might forecast temperature and flow-rate changes. There is also concern about presence of chemicals which would be deleterious to the process using the water.
5. Reinjection: Siting is the key problem in reinjection because one doesn't want to kill producing wells with cold-water breakthrough. Pressure-interference tests can be used to determine inter-well connections. Injection wells should be flowed, if possible, to clean up the well bore. Then they should be tested like the producing wells in order to determine how readily they will accept fluids.

Long-term well performance predictions - theory and analysis

Well and reservoir performance is governed by the fundamental laws of fluid flow in porous media. This law essentially reduces to the time-dependent diffusion equation:

$$\nabla^2 h = \frac{S}{T} \frac{\partial h}{\partial t} \quad (1)$$

This equation has such other classic analogies as heat diffusion (conduction), neutron diffusion in a nuclear reactor, and diffusion of a solute in a solvent. The solutions to the equation (1) have many forms, depending on the particular geometry and the boundary conditions for the problem at hand.

In the case of a well, the typical approach is to assume a two-dimensional problem in radial geometry; i.e., the well is assumed to be a point source in a plane. Equation (1) then becomes

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r} \frac{\partial h}{\partial r} = \frac{S}{T} \frac{\partial h}{\partial t} \quad (2)$$

where r is the radial distance from the well

t is time

h is the level of water in the formation (if the well is artesian, this "level" will become a pressure)

S is the dimensionless storage coefficient. It is the volume of water an aquifer releases or takes into storage per unit surface area per unit change in head. For confined aquifers, S is between 10^{-3} and 10^{-5} , or about 10^{-6} per unit of thickness. For confined aquifers, it is about 0.1 to 0.3.

T is the transmissivity, the rate water is transmitted through the formation of unit width under a unit hydraulic gradient. Its units are gal/day-ft, ft²/day or m²/day ($L^2 T^{-1}$)

h is the water level or pressure head in the well

The typical boundary condition is one of an infinite medium. Reflection or recharge boundaries can then be simulated by a reflected well on the other side of the boundary. Positive reflections indicate nontransmitting boundaries, negative reflections indicate recharge boundaries.

The solution for a well at constant flow rate Q is:

$$h = \frac{Q}{4\pi T} \int_u^\infty \left(\frac{e^{-u}}{u} \right) du \quad u = \frac{r^2 S}{4 T t} \quad (3)$$

If the lower limit of integration, u , is less than 0.01, then an approximate solution is:

$$h = \frac{Q}{4\pi T} \left[-0.5772 - \log_e \frac{r^2 S}{4 T t} \right] \quad (4)$$

A plot of h vs. $\log T$ should give a straight line for times sufficient to make $u < 0.01$, with the slope of the line being $Q/(4\pi T)$. This is the common method of determining T . The drawdown to be expected for very long times can be obtained by continuing the slope on the semilog plot out to the desired time. Figure 9 shows a typical result of a well test. Good wells have value for T greater than 10,000 gal/day-ft (124 m²/day).

WELL DEVELOPMENT AND STIMULATION

Well development and/or stimulation is an attempt to increase or regain productivity (injectivity) with minimal additional cost. Table 2 lists some of the more common techniques. The cost effectiveness of any technique depends on resource type and knowledge of the resource. Some mechanical techniques used improperly or in the wrong environment can increase or cause formation or borehole damage or can be costly with no benefit. Many techniques have been used in sequence or combination, increasing the cost-benefit analysis of utilizing any development/stimulation technique.

FIGURE 9. Typical geothermal well drawdown result. In this case, the well was initially "artesian." When pumped at constant rate, it lost its artesian head 14 hours after start of the test.

TABLE 2

WELL DEVELOPMENT AND STIMULATION TECHNIQUES

Type	Method	Description	Use	Requirements
Passive Mechanical	Baller	Use sand line on drill rig to withdraw (add) water to well.	Clean well of cuttings or muds.	Can be accomplished with or without drill rig. No special equipment.
Passive Mechanical	Swabbing	Use a loose packer on drill pipe or sand line to swab/surge well.	Clean well of cuttings or muds. Develop gravel/natural pack.	Can be accomplished with or without drill rig. No special equipment.
Passive Mechanical	Rawhiding	Use a pump to produce (inject) fluid at rates higher than normal operation.	Clean well of cuttings or mud. Develop gravel/natural pack.	Pump and power supply. Dump (inject) large quantities of fluid.
Active Mechanical	Jetting	Use tubing with water ports at production face. Constant or pulsed flows.	Flush well of cuttings or mud.	Drill or pump rig to run tubing. Supply of fluid for jetting.
Active Mechanical	Explosives	Use explosives detonated at production (injection) face.	Promote or propagate secondary porosity. Correct drill damage or tight formation.	Experienced and licensed operator. Method to lower explosive.
Active Mechanical	Hydro-fracturing	Use high injection pressure to fracture rock. Can use proppant to hold fractures open.	Promote or propagate secondary porosity. Correct drill damage or tight formation.	Large quantities of fluid, pumper trucks, commercial services.
Active Mechanical	Sidetracking/whipstocking	Use directional drilling to reach (additional) resource.	Increase effective borehole radius. Reach additional fracturing. Minimize drill damage.	Drill rig, directional drill services.
Active Chemical	Emulsifiers	Attack drill muds or formation clays.	Increase rate or effectiveness of cleaning well.	Chemicals, depository for spent chemicals and fluids
Active Chemical	Acid	Attack drill muds or particular minerals on formation.	Increase rate or effectiveness of cleaning well. Correct drill damage. Reach additional fractures.	Chemicals, depository for spent acids and fluids.

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CHAPTER 4

UTILIZATION

Work Group

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INTRODUCTION

State of the art

Direct utilization of geothermal energy for space and process heating for the most part, utilizes known technology. Basically, hot water is hot water whether from a boiler or from the earth. The utilization of geothermal energy requires only straightforward engineering progress rather than revolutionary advances and major scientific discoveries. The technology, reliability, economics and environmental acceptability have been demonstrated throughout the world.

It must be remembered that each resource is different and the systems must be designed accordingly. Granted, there are problems with corrosion and scaling, generally confined to the higher temperature resources, but most of these problems can be surmounted by materials selection and proper engineering designs. For some resources, standard engineering materials can be used if particular attention is given to the exclusion and/or removal of atmospheric and geothermally generated gases. For others, economical designs are possible which limit geothermal water to a small portion of the overall system by utilizing highly efficient heat exchangers and corrosion resistant materials in the primary side of the system.

Summary of utilization

Direct utilization of geothermal energy was probably practiced by early man for cooking and heating. Recorded history shows uses by Romans, Chinese, Japanese, Turks, Icelanders, Central Europeans and the Māori of New Zealand for bathing, cooking and space heating. These uses have continued to today where, for example, over 1500 hot-spring resorts exist in Japan, visited by 100 million guests every year.

Early industrial applications include the use by the Etruscans of boric acid deposited by the steam and hot water at Lardarello, Italy. They used the deposits to make enamels to decorate their vases. Commercial extraction of the acid started in 1818, and by 1835, nine factories had been constructed in the region. Municipal district heating was first undertaken in Reykjavik, Iceland in 1928.

Today, over 7000 megawatts thermal (MWt) are utilized in the world for space heating and cooling (space conditioning), agriculture and aquaculture production and for industrial processes. Of this figure, over 1200 MWt are used for space heating and cooling; approximately 5500 MWt for agriculture, aquaculture, and animal husbandry; and over 200 MWt for industrial processes.

Typically, the agriculture-related uses utilize the lowest temperatures, with values from 80-180°F (27-82°C) being typical. Use of wastewater has wide applications here. The amount and types of chemicals and dissolved gases, such as boron, arsenic and hydrogen sulfide, are a major problem for this use. Heat exchangers and proper venting of gases may be necessary in some cases to solve this problem. Almost all of the agricultural-related energy utilization is in the Soviet Union where over 5000 MWt are reported being used.

Space heating generally utilizes temperatures in the range of 150-212°F (66-100°C), with 100°F (38°C) being used in some marginal cases and heat pumps extending this range down to 55°F (13°C). The leading user of geothermal energy for space heating is Iceland, where over 50 percent of the country is provided with geothermal heat. The only known cooling is in Rotorua, New Zealand, at the International Hotel; however, many other applications are presently being considered.

Industrial processing typically requires the highest temperatures, using both steam and superheated water. Temperatures up to 300°F (150°C) are normally desired; however, lower

temperatures can be used in some cases, especially for drying of various agricultural products. Though there are relatively few examples of industrial processing use of geothermal energy, they represent a wide range of applications, from drying of wool, fish, earth and lumber to pulp and paper processing and chemical extraction. The two largest industrial uses are the diatomaceous earth drying plant in Iceland and the paper and wood processing plant in New Zealand. A visual representation of the required temperature for various direct-thermal uses is shown in Figure 1 (Lienau/Lindal, 1974). Here both water and saturated steam are shown and cascading can be easily visualized.

FIGURE 1. The approximate temperature required for various geothermal uses.

Examples of current utilization

Traditionally, direct use of geothermal energy has been on a small scale by individuals. Surface hot springs were utilized and shallow wells could be justified with on-the-spot use or short transmission distances in uninsulated pipes or channels. However, at today's prices for development and hardware, the cost savings of these individual uses are often marginal. Large-scale use demands require more production and can thus justify deeper wells, longer transmission distances, more sophisticated utilization and lower temperatures.

Most of present-day developments involve large-scale projects, such as district heating (Iceland), greenhouse complexes (Hungary) or major industrial use (New Zealand). Heat exchangers are also becoming more efficient and better adapted to geothermal use, allowing the use of lower-temperature waters and highly saline fluids. Heat pumps are extending geothermal development into traditionally non-geothermal countries, such as France, Austria and Denmark, as well as the eastern U.S.

Space conditioning. The most famous space-heating project in the world is the Reykjavik municipal heating project, serving about 97 percent of the 113,000 people in the capital city of Iceland. At present, a total of 1.0×10^{10} gallons (3.8×10^{10} liters) of geothermal fluid are used annually to supply 16,000 homes with space heating. One field supplies water through two 14-inch and one 28-inch (35 and 70 cm) diameter pipeline over a 12-mile (19-km) distance. Insulated storage tanks (6.9×10^6 gallons; 2.6×10^7 liters) are used to meet peak flows and provide an emergency supply in the event of breakdown in the system. A fossil-fuel fired peaking station is used to boost the 176°F water to 230°F (80-110°C) during 15 to 20 of the coldest days of the year. The city is served by 9 pumping stations, distributing fluid through 200 miles (320 km) of pipelines. The entire system provides 1840 GWh per year or 420 MWt (including the peaking station; Lienau/Zoega, 1974).

An example of individual home space heating is in Klamath Falls, Oregon, where over 400 wells are used for space heating, using waters from 100-230°F (38-110°C). The principal heat-extraction system is the closed-loop downhole heat exchanger utilizing city water in the loop (Lund et al., 1974). Larger examples of space heating in Klamath Falls include the Oregon Institute of Technology campus, where three wells up to 1800 feet (550 m) deep produce up to 450 gpm (28 l/s) of 192°F (89°C) water and heat approximately 500,000 ft² (46,000 m²) of floor space. The geothermal water is pumped from the well using deep-well turbine pumps and, in most cases, is used directly in the heating system for each building. The annual operating cost of the campus system is approximately \$30,000, a savings of almost \$250,000 per year when compared with the cost of heating with conventional fuel. Other notable uses in the community include the 311-bed Merle West Medical Center hospital and nursing home, where the present worth of a 20-year savings due to a geothermal-retrofitted heating system is over one million dollars, and Maywood Industries, where 118°F (48°C) water is used for heating a large manufacturing building (Geo-Heat Utilization Center Bulletin, Lienau, 1977; Higbee, 1978).

Agriculture and aquaculture. In Hungary, greenhouse heating is second only to the USSR, with over 13 million ft² (1.2 million m²) being geothermally heated. Many of these greenhouses are built on rollers, so they can be pulled from their location by tractors, the ground cultivated with large equipment, and then the greenhouse returned to its location. In addition, to minimize cost, much of the building-structure pipe-supporting system also acts as the supply and radiation system for the geothermal fluid. About 60 wells are used for animal husbandry projects, mainly for heating and cleaning of animal shelters. Priority is given to agricultural use of geothermal energy in Hungary, as this increases the volume and variety of production.

Some experimental work is being performed with grain, hay, tobacco and paprika drying. In these cases, hot water supplies heat to forced-air heat exchangers and 120-140°F (49-60°C) air is blown over the product to be dried (Lienau/Boldizar, 1974).

In Japan, greenhouses cover about 157,000 ft² (14,600 m²), where a variety of vegetables and flowers are grown. Many large greenhouses are operated as tropical gardens for sightseeing purposes. Raising poultry through the use of geothermal energy has been a very successful enterprise. Here, under-the-floor heating is utilized in sheds where 40,000 chickens are raised annually. Another successful business is breeding and raising carp and eels. Eels are the most profitable and are raised in 10-in diameter by 20-ft long (25-cm by 6-m) earthenware pipes. Water in the pipes is held at 73°F (23°C) by mixing hot-spring water with river water. The adult eels weigh from 3-1/2 to 5-1/4 oz (100-150 g), with a total annual production of 8400 lbs (3800 kg). Alligators and crocodiles are also raised in geothermal water. These reptiles are being bred purely for sightseeing purposes. In combination with greenhouses offering tropical flora, alligator farms are offering increasingly large inducements to the local growth of the tourist industry (Japan Geothermal Energy Assoc., 1974).

Excellent examples of greenhouse operation exist in the U.S., the largest being the Honey Lake Hydroponic Farms complex near Susanville, California. Cucumbers and tomatoes are grown in a hydroponic system. Heat is provided to the greenhouses by geothermal fluid. At present, 30 greenhouses have been constructed, with expansion planned to over 200 units. Channel catfish are raised by Fish Breeders of Idaho near Buhl, using geothermal water. Using 6000 gpm (380 l/s) of 90°F (32°C) water, approximately 500,000 lbs (230,000 kg) of fish are raised annually (GRC Special Report No. 5, Ray, 1979).

Industrial processes. An example of industrial processing is the use of geothermal steam for the Tasman Pulp and Paper Company in New Zealand. Here, 100-125 MW (18 tons/hr steam) of thermal energy are used for the lumber drying, black liquor evaporation, and pulp and paper drying. The total investment cost for geothermal is \$6.8 million, the majority of which is for well development. This amounts to approximately \$70 per kWt and will reduce the price of energy to 70 percent that of conventional fuels for an annual savings of \$1.3 million. The annual maintenance costs are 2 percent of the capital cost (Lienau/Wilson, 1974).

In northern Iceland, a diatomaceous slurry is dredged from Lake Myvatn. This slurry is transported through a pipeline and held in storage ponds. The 80 percent moisture is then removed in large rotary-drum driers using high-temperature geothermal steam. The plant produces 27,000 tons (24,494 t) of diatomite filteraids per year, most of which are used in beer processing in Germany (Lienau, 1974).

Two industrial-processing uses of geothermal energy are of note in the U.S.: Medo-Bel Creamery in Klamath Falls, where low-temperature fluid is used for pasteurizing milk, and Geothermal Food Processors at Brady Hot Springs, Nevada, where high-temperature fluid is used for dehydration of onions and other vegetables (GRC Special Report No. 5, Belcastro, 1979; GRC Bulletin, vol. 7, no. 5, Nov/Dec 1978).

A major direct-thermal project in the U.S.A. in the development stage is the conversion of the Ore-Ida Foods, Inc., plant located in Ontario, Oregon. The Ore-Ida project involves drilling three production wells to a depth of 6000 feet (1.8 km) to obtain 800 gpm (50 l/s) at a temperature of 300°F (150°C). The geothermal energy would replace 55 percent of the energy now supplied by natural gas and fuel oil for potato processing (Lienau, 1978).

Summary: A summary of the present world-wide direct use of geothermal energy is as follows (GRC Special Report No. 5, Lund, 1979):

TABLE 1

Worldwide direct use of geothermal energy

Country	Space Heating/ Cooling (MWt)	Agriculture/ Aquaculture (MWt)	Industrial Processes (MWt)
Iceland	680	40	50
New Zealand	50	10	150
Japan	10	30	5
USSR	120	5100	---
Hungary	300	370	---
Italy	50	5	20
France	10	---	---
Others	10	10	5
USA	75	5	5
TOTAL	1245	5570	235

Benefits of direct applications

The main advantages of direct utilization of geothermal energy are:

1. High conversion efficiency (80-90 percent).
2. The use of low-temperature resources, which are numerous and readily available.
3. The use of many off-the-shelf items for exploitation (pumps, controls, pipe, etc.).
4. Short development time as compared to electrical energy development.
5. Lower-temperature resources require less expensive well development (and shallower in some cases), can be drilled with conventional drilling equipment in many cases and the water can be transported 20-40 miles (32-64 km).

All of these advantages give a favorable economic situation when compared to conventional fuel. At present-day prices, the geothermal application will cost about the same or less than the corresponding annual fossil-fuel cost. Due to the expected escalation of fossil-fuel prices, the costs of the geothermal system will decline. Most geothermal direct-use systems will pay for themselves in 5-10 years from savings in conventional fuel. Detailed economic evaluations are presented in Chapter 5, Economics.

The economics are greatly enhanced where cascading (multi-stage use) is considered. The Japanese optimize cascading where geothermal fluids are first used for electrical power production, then space heating, cooking and bathing (Otake). Here, an attempt is made to "squeeze" the "last drop of energy" from the fluid. Lower-temperature cascading could consider space heating, agriculture, bathing (swimming pools) and snow melting. Low- and intermediate-temperature geothermal resources can also be used to meet the base load of an energy demand. Heat pumps and fossil fuel can then be used to meet the peak demands, thus conserving the resource and minimizing capital investments (Ryback, 1979).

SPACE CONDITIONING

General background

In areas of the United States requiring significant heat for space conditioning, the most widely used residential space heating systems are forced air, circulating water and radiant electric resistance. Recently, restrictive actions initiated in several states limit new installations of electric resistance systems. In any event, forced-air and circulating-water residential heating systems will remain popular in the foreseeable future regardless of the energy being utilized. More recently, the use of heat pumps has become popular. Figure 2 illustrates these commonly used heating systems, all of which are adaptable to geothermal energy.

FIGURE 2. Space-heating systems suitable for geothermal applications
(source: EG&G Idaho, Inc.).

Forced-air heating systems transport heated air through distribution ductwork to outlet fixtures referred to as diffusers. The source of heat for such systems can be in many forms. Furnaces fueled with natural gas, propane or fuel oil are probably the most common in single residential

dwellings. In all of the furnace-type systems, the open flame provides heat to a multichambered heat exchanger device over which a fan circulates air to the space being heated.

Another device used extensively to provide heat to the forced-air system is the electric resistance duct heater. As the name implies, electric heating coils are installed directly in the ductwork through which the air is circulated.

In large, multiple-dwelling and commercial systems, a steam coil or hot-water coil is often used like the electric duct heater to provide heat to the moving air. The source of hot water or steam in a conventional system is a boiler utilizing various fuels or energy sources.

When considering new geothermal heating installations, or the ease of retrofit, the forced-air system is undoubtedly the most adaptable.

Finned-tube hot-water coils are manufactured in a variety of size and water-flow combinations that allow a maximum amount of heat to be extracted from the water. This, then, provides for satisfying a desired heat load while minimizing the size of accessory equipment, such as piping and controls.

The circulating hot-water or hydronic system, just as steam systems, uses a multiplicity of heat-distributing units. These units include radiators, convectors, baseboard, finned-tube and radiant-piping grids. The method of transferring heat to the conditioned space in all cases includes a radiant or convective heat transfer and usually a combination of both transfer mechanisms.

Any of the hydronic systems, properly designed and with automatic controls, can usually provide a more uniform space temperature than forced-air systems. When considering new installations of this type for geothermal, the design and component selections are straightforward once the geothermal resource temperature, flow and chemical characteristics are known. In retrofit situations, however, unless a match of combined temperature and flow can be obtained between the geothermal source and the original design parameters, a satisfactory and economically attractive conversion becomes difficult. For example, a system designed for 50 gpm (3 l/s) flow at 180°F (82°C) may require additional flow if the geothermal temperature is below the 180°F (82°C) original design.

In addition to the more popular heating systems just discussed, the water-to-air heat pump for residential and commercial applications has recently gained increased acceptance. This off-the-shelf device allows for the economic utilization of the marginal geothermal resource down to temperatures as low as 55-60°F (13-16°C). The heat-pump application adapts well to the forced-air system in retrofit situations and has the added benefit of providing cooling in summer months with no additional equipment cost. Off-the-shelf units are available to operate on water temperatures from 55-90°F (13-32°C), with custom-designed units for temperatures above 90°F (32°C).

Between 60°F and 90°F (16-32°C), standard heat pumps will have Coefficients of Performance (COP) of about 3 when used to provide space and low-temperature process heat. This means the heat output will be about 3 times the electrical input.

Large capacity custom-designed water-to-water heat pumps are also available that can boost the temperature of an inadequate or mismatched geothermal resource to an acceptable range for economic utilization. Where output temperatures of above 120°F (49°C) are required, COP of standard units drops off and the application may require special designs utilizing multi-stage compressors and special gases. Temperatures up to 230°F (110°C) are obtainable with COP's of about 2 and are readily adaptable to utilization of both geothermal waters and waste hot waters from

from other processes. A typical two-stage unit is shown in Figure 3.

FIGURE 3. Two-stage heat pump (source: GRC Special Report No. 5, 1979).

Geothermal application of heat pumps with COP of much less than about 3 should be investigated carefully from an economical standpoint when this is the only application of the water, since the cost of wells, pumps, etc., must be considered in the overall cost of obtaining the desired output. Where geothermal "waste" water is available from other space or process uses, heat pumps may make an additional use (cascading) very economical.

In considering geothermal for space heating in either new or retrofit installations, the supply of heat for domestic hot water should not be overlooked. With the simple addition of a water-to-water heat exchanger, typical single residential energy savings of 100 Kwhr/day can easily be realized.

Primarily as a result of emphasis in the solar-utilization area, a renewed interest in the absorption cycle for cooling applications is evident. Lithium bromide units are available in more-or-less off-the-shelf sizes that will utilize water temperatures of 180°F (82°C) and above. Custom-designed ammonia-adsorption units are available to utilize water temperatures above approximately 220°F (104°C). Both absorption cycles lend themselves more readily to the larger commercial installations than to the single residential dwelling.

A summary of the temperature ranges for various space heating and cooling devices is shown in Figure 4 (Lund, 1978).

Estimating heating and cooling loads (Rules of Thumb)

During initial phases of preliminary design, it is often necessary for the engineer or contractor to make estimates of building heating and cooling loads. Most experienced engineers have established their own methods or, if you will, "rules of thumb," from which they make these initial estimates.

FIGURE 4. Temperature ranges for heating and cooling methods.

All such rules of thumb must be used with caution and careful consideration of the criteria of the particular project and, more importantly, keep in mind that they provide estimates only.

We will attempt herein to give our version of some of these rules from which initial comparisons of systems can be evaluated.

Experience throughout much of the western U.S. indicates that in most cases for residential estimates, the maximum heat loss of normal sized buildings will vary between 15 and 60 Btu/hr/ft² (1.7×10^3 to 6.8×10^3 kJ/hr/m² or 47 to 189 w/m²) of floor area, depending upon the extent of insulation and design temperature difference.

Figure 5 illustrates this basic rule, where curve A relates to well insulated buildings, curve B is for a "normally" insulated building with R-19 ceilings, R-13 walls and double glazing, and curve C related to older homes with R-13 ceilings, single-glass and standard-frame construction with no wall insulation.

FIGURE 5. Design curves for heating and cooling loads.

Small commercial buildings will fall within the above parameters. For the larger and more complex commercial or industrial type of buildings, we recommend that a block load be calculated using the ASHRAE standards, even if it means estimating or "guesstimating" what the construction may be. This involves estimating the heat loss through outside walls and roof, but not considering the differences in heat requirements of different areas within the "block." Annual heat load may be estimated by numerous methods. ASHRAE Degree Day Method¹ usually produces a high figure, ASHRAE Bin Method¹ is far more accurate but is a lengthy process. Several computer programs that are quite accurate but expensive are available for more detailed estimating and comparison purposes.

The delivered heat to a project should allow for miscellaneous losses and start up from a cold start. Normally a factor of 25% is added to the heat loss calculations to obtain the total heat loss or heat load (HL).

Assuming this heat loss will be offset by either primary or secondary water flow, then the water flow (w) required will be equal to:

$$W \text{ (gpm)} = \frac{HL \text{ (Btu/hr)}}{500 \times \Delta T \text{ (°F)}} \text{ or } W \text{ (l/s)} = \frac{HL \text{ (kJ/hr)}}{15,200 \times \Delta T \text{ (°C)}} = \frac{HL \text{ (kw)}}{4.22 \Delta T \text{ (°C)}}$$

where T (temperature differential) is the amount of heat extracted from the fluid flow in °F.

For a quick method of determining annual heat load for comparison to other heating methods or systems, we recommend the formula:

$$\text{Annual Heat Load} = \frac{DD \times HL \times 24}{\Delta T} = \text{Btu/yr (or kJ/yr or watts)}$$

where DD = Annual degree days² (day-°F)

HL = Heat Loss¹ (Btu/hr), and

ΔT = Difference between inside and outside temperatures (°F).

For more detailed heat-loss calculations, the following basic formula is used:

$$HL = A \cdot U \cdot \Delta T$$

where HL = heat loss in Btu/hr (or kJ/hr or watts)

A = surface area in ft² of wall, window, ceiling, etc.

U = thermal transmittance³ in Btu/hr/ft²/°F, and

ΔT = design-temperature difference between inside and outside in °F

At the present "state of the art," residential-cooling applications utilizing geothermal energy are best left to professional engineers and no rules of thumb are applicable. Commercial cooling units are available which can utilize 180-210°F (82-99°C) water. In general, hot-water flow requirements are significantly higher for cooling than for heating and cooling water or cooling towers are required. Unless the hot and cold water are readily available, cooling systems may not be economical.

¹ Details of the Degree Day Method and the Bin Method may be found in the 1976 ASHRAE Systems Handbook, Chapter 43.

² Annual Degree Days--Obtainable from the local weather stations, ASHRAE 1976 System Handbook Chapter 43, or from National Oceanic and Atmosphere Administration, National Climatic Center, Asheville, NC 28801.

³ Thermal-transmittance values for various materials can be found in ASHRAE.

New Installations

As noted earlier, the design of a new geothermal space-heating system is quite similar to the design of a conventional hydronic space-heating system except that the designer often has no control over the temperature of the water available, and the temperature is often lower than conventional systems. Additional economic considerations must be made for the well, pumping equipment, in most cases heat-exchange equipment and, in cases where the well is some distance from the buildings, the transmission piping. These additional items will be covered in detail later, but in general their cost can be reduced by maximizing the temperature differential across the heat-emitting units. The problem reduces to one of utilizing the temperature available and balancing water-supply costs against the cost of obtaining high ΔT in the geothermal water. Considerations specific to different systems are below.

Radiant panels (floor, ceiling wall). This system can utilize water at lower temperatures than any other except heat pumps (see Figure 4). In order to obtain the required heat output at low inlet temperatures, the panels must have close coil spacing, shallow pipe depth, small pipe sizes and high flow rates. Plastic pipe 1/2-inch or less (13 mm) in diameter can be utilized to reduce coil costs and prevent corrosion and scaling where temperature limits of the pipe are not exceeded: 125°F (52°C) for ABS, 150°F (66°C) for PVC and 212°F (100°C) for CPVC.

Baseboard convectors. Baseboard convectors, due to their low initial cost, are in most cases the most economical heating system for residential and small commercial applications. They find little application in larger spaces since heat output and air circulation are limited and cooling is difficult. In order to attain a large ΔT and associated low flow rates, 3/4-inch (19 mm) and smaller tube sizes are required to maintain flow velocities in the desirable turbulent regime. Large, closely spaced fins with the width dimension greater than the height dimension provide greater heat transfer than square fins. Where multiple rows are required to obtain the desired output and space is available, horizontal placement of the rows will provide nearly one and one-half times the heat output of vertical stacking of the rows.

Since the heat output decreases rapidly with decreasing temperatures, the possibility of using geothermal water directly and eliminating the temperature loss in a heat exchanger should be investigated. In many low-temperature waters, iron pipe will provide better corrosion resistance than copper. The cost and availability of special tube materials to resist corrosion peculiar to the resource should be investigated and cost analysis run.

Average water temperatures below 140°F (60°C) are difficult to utilize and present special engineering and architectural problems.

Forced-air systems. Forced-air systems are by far the most popular for residential applications and are used almost exclusively for larger commercial applications either with or without supplemental perimeter heat convectors or baseboard units.

Although large temperature drops are desired, the designer should not necessarily set a ΔT to be attained in the design, but rather attempt to obtain as low an exit water temperature as possible. Although water temperature differential of 100°F (38°C) can be obtained when 200°F (93°C) water is available, under some conditions a 40°F (22°C) drop may be difficult when only 120°F (49°C) water is available. Conversely with high make-up air requirements in cold temperatures, water temperature drops in excess of 40°F (22°C) with 120°F (49°C) inlet water may be readily obtained with 6- or 8-row multiple-pass reverse-flow coils.

In many cases, the fan coil units will be of special design in order to obtain the high ΔT . Another approach is to use somewhat standard design units in series to obtain an overall high ΔT with the units on the low-temperature end of special design for the lower entering water temperatures.

Some examples of the special considerations and their consequences are:

<u>Desired parameter</u>	<u>Consequences</u>
High ΔT water	<ol style="list-style-type: none"> 1. Increased face area 2. Deep coils with high ΔP water 3. Serpentine paths with high ΔP water 4. Closer fin spacing with high ΔP air 5. "Stacked" coils with high ΔP air

where ΔP = change or drop in pressure

Low Inlet-Temperature Water	<ol style="list-style-type: none"> 1. Increased surface area 2. Closer approach temperatures 3. Higher water-flow rates
Low Temperature Air Out	<ol style="list-style-type: none"> 1. High air flow 2. Larger duct work 3. Higher ΔP air

High water- and air-pressure drops may require circulation pump and fan design differing from more conventional systems.

Figure 6 illustrates the approximate output rate for cast-iron radiators, finned tubes and fan coils.

FIGURE 6. Approximate heat output rate of radiators, finned tubes and fan coils vs. water temperature.

Retrofit

In general, hot-water systems of any type are not usually difficult to retrofit if geothermal water above 180°F (82°C) is available. Most conventionally fueled systems operate at 180-210°F (82-99°C) and many have sufficient capacity to carry the heating load if water temperature is reduced 20-30°F (11-17°C).

The ability to carry the heating load at reduced temperature is due either to original over-design or to selection of standard-sized components of the nearest size larger than actual requirements. The older the system, the better are the chances of having over-capacity, since modern design information was not available, component selections were not as large and larger safety factors were usually applied. Systems with capacities of 150-175% of actual requirement are often encountered. A few observations and simple calculations (heat requirements vs. capacity) will usually indicate if sufficient capacity may be available and warrant further investigation.

One of the simplest and most straightforward methods of checking system capacity is to gradually reduce system-input temperature during the peak heating season until the geothermal temperature available is reached or desired space temperatures are not maintained. The usual result is that system "on" time is increased and temperatures are maintained. Since geothermal-system operating costs are usually low, the conversion would prove economical.

Forced-air systems. Systems utilizing hot water in fan-coil units are generally the easiest and least costly to retrofit. Most conventionally fueled systems are designed with simple one- or two-pass coils with air flow perpendicular to the coils and inlet-water temperatures of 180-200°F (82-93°C). Where similar geothermal temperatures are available there are no problems.

Most geothermal systems will require heat exchangers to prevent corrosion of the fan-coil tube. Even considering the 10°F (6°C) or so loss across the heat exchanger, new coil units in series with existing coils or new multipass coils will provide the required output with surprisingly low geothermal temperatures.

Where the available resource temperature is considerably lower, such things as increasing the duty time as noted above may not suffice and deeper coils, increased coil-face area, reduced fin spacing and increased air volume may be required. Each of these will affect other system parameters. For instance, deeper coils, closer fin spacing and increased air volume will increase the air-pressure drop across the coil and may require increased fan speed and/or increased fan-motor power. Fan speed can often be increased by simply changing fan-belt pulley ratios, but significant changes require increased motor horsepower. Increasing the coil-face area will aid in maintaining low air-pressure drops and can be achieved by mounting the coil at an angle to the air flow or duct axis or installing transition duct work to obtain a larger mounting space, as shown in Figure 7.

Increased air volume affects the entire duct system with increased velocities and possible attendant pressure and noise problems. Most systems will accept some increase in volume with some cases requiring changes in diffuser size to eliminate noise. Additional duct work may be added to increase the air-handling capacity and new outlets may be strategically located in areas requiring more heat or where they can supply several areas.

Electrical resistance duct-heating systems can be retrofit utilizing the considerations above.

The retrofit designer should remember that forced-air systems are the most complicated of the common systems and as such have the greatest number of variables. In most cases, this allows

FIGURE 7. Simple methods to increase fan-coil face area.

more manipulation of the variables to attain the desired end results, but requires greater ingenuity and care in the design.

Hydronic systems. The common hydronic systems, baseboard or convector finned-tube units, radiators and radiant panels, have few variables one can change to accommodate lower inlet water temperatures, except to add radiation. Careful calculation of heat load and heating-unit output will ascertain the minimum permissible average temperature with existing radiation. (Better yet is the reduction of boiler outlet temperature as noted earlier.) Heat output of these units varies linearly though not directly with average water temperature as noted earlier in Figure 6. Lower inlet temperatures can be offset somewhat by increased flow rates, thereby reducing the temperature drop across the system. However, increased flows require increased pumping power, increase the possibility of water hammer, noise and, of course, require an adequate supply of water in direct-use applications. Proper control valves may alleviate the water-hammer problem, but noise can be eliminated only by maintaining flows below a critical velocity.

When retrofitting for lower temperatures, usually the most economical and desirable solution is to install new and/or increased radiation surface. Small tube sizes in new radiation will allow reduced water flow per radiation unit while maintaining nearly the same output allowing more radiation to be installed on existing piping systems.

Radiant panels (floor or ceiling) are the most difficult hydronic system in which to make large temperature changes since the expense of installing additional radiation of the same type is prohibitive. The retrofit designer must usually be satisfied with accepting the lower heat output of the panels and supplementing this with additional baseboard or other radiation or with supplemental forced air. In floor systems, the floor covering may be changed, i.e., from carpets to linoleum or tiles, but this is usually not acceptable.

Steam radiation. Steam systems utilizing convectors or radiators are probably the most difficult to retrofit. Water temperatures must be high to allow use of existing radiation (see Figure 6). Steam supply lines are usually adequate to supply hot water, but condensate lines (with steam traps removed) quite often are not. Inlet temperatures lower than 190°F (88°C) are usually impossible to utilize without extensive modifications unless the system was greatly over designed. The use of more efficient radiation devices in convection units with fans should be investigated to determine whether or not condensate lines will be adequate for required flows. Piping costs can sometimes be reduced by modification of the zoning arrangements allowing the use of some existing lines with additional new return piping to serve other zones. Accessibility of the piping system for modifications and additions often is an important consideration.

In all of the above types, the retrofit designer should not overlook the possibility of supplemental systems when available resource temperature will not permit the existing system to meet the demand. Often the supplemental units can be cascaded with the existing system thereby providing the required heat output with high temperature drops and efficient use of the resource.

Additional considerations

Importance of large temperature differential. In the early days of hydronic heating, it was commonplace to use a 20°F ΔT (11°C) for heat transfer from coils or radiation. This necessitated comparatively large pipe and pump sizes to circulate the amount of water required. In recent years, engineers have been using temperature differentials of 40°F, 60°F and 80°F (22°, 33° and 44°C), thus using considerably smaller pipes and pumps.

As an example, let us assume a system has a heating capacity of 500,000 Btu/hr (5×10^5 kJ/hr = 146 kw) capacity. At a ΔT of 20°F (11°C), this system would require 50 gpm (3 l/s). The same system on a ΔT of 60°F (33°C) would require a flow of only 16.6 gpm (1 l/s). Thus, in the case of the $\Delta T = 20^\circ\text{F}$ (11°C), a 3" (76 mm) pipe would be required, whereas at a $\Delta T = 60^\circ\text{F}$ (33°C), a 1-1/2 inch (38 mm) pipe would be required. This same reduction applies to pump sizing and all accessories. The economics of this are very evident in the piping system, but these savings are, of course, offset somewhat by higher costs of the heating units. Overall economics must be considered, but nearly always favor higher ΔT 's.

These same principles are multiplied in geothermal heating and piping systems, since another basic principle enters into the thinking, i.e., if you pump 500 gpm (30 l/s) of 180°F (82°C) water out of a geothermal well and only use a ΔT of 20°F (11°C), you have only 5,000,000 Btu/hr (1.47 MW) of usable heat extracted; however, if that same water is returned to the injection well at 100°F (38°C), or a $\Delta T = 80^\circ\text{F}$ (44°C), you have extracted a usable heat of 20,000,000 Btu/hr (5.86 MW). This represents a 400 percent increase in heat production with the same well, pumping and piping costs.

The increased ΔT may be obtained by several methods: increased coil size, multi-serpentine coils, cascading, or any other series-type flow.

Therefore, in any hot-water piping system, whether it is a primary geothermal water source, a secondary flow, or a system to a single coil, the larger the ΔT obtainable, the more significant will be the economic savings in the piping and pumping system.

Water quality considerations. In the design of a geothermal heating system, attention must be paid to the quality of the geothermal fluid. Many geothermal resources are high in total dissolved solids and most fluids contain hydrogen sulfide or other corrosive components.

Since the temperature of the geothermal fluid is decreased in a heating system, dissolved solids tend to precipitate out as scale. If the scale forms on a heat-transfer surface, such as the inside of a heater coil, the heater duty decreases due to increased resistance to heat transfer. As scale build-up continues, flow restriction becomes important, and pipes or tubes can plug.

One means of controlling scale is to use the geothermal resource to heat a secondary fluid which does not have a scaling problem. By heating the secondary fluid at the well area, scale buildup is localized. The heated secondary fluid is then circulated through the distribution systems, and reheated in a closed loop. Since the scale precipitates when the temperature decreases, most of the deposition from the geothermal fluid occurs inside the heat exchanger and chemical or mechanical cleaning of the exchanger is possible. In a system with a secondary heating loop such as this, it is possible to have a standby heat exchanger in parallel with the normal exchanger so that exchanger cleaning and maintenance does not force a system shutdown. Another advantage of a closed secondary heating loop is that anti-freeze and corrosion inhibitors can be added, thus protecting the distribution system and heaters.

In geothermal fluids that contain hydrogen sulfide or other corrosive components, it is important that the fluid does not contact susceptible materials. As an example, copper is readily attacked by sulfides, so the use of copper coils should be carefully studied if geothermal fluid is to be used directly. The use of a secondary heating loop can be beneficial because more expensive, corrosion-resistant materials can be limited to the well-area piping and heat exchangers.

There are many instances where geothermal fluids have been used directly in hydronic systems with little or no difficulty due to scaling or corrosion. To add a secondary heating loop or non-standard heating coil could be an unnecessary expense. Thus, the design of any system should be based on the particular quality of the geothermal source.

DISTRICT HEATING

District-heating systems are divided into three main components: the heat production unit, the distribution network and the consumer installations. The heating medium used in European systems is almost exclusively high-temperature (300°F, 149°C) to low-temperature (250-180°F, 121-82°C) hot-water systems. Swedish systems operate with high-temperature water requiring heat exchangers between the district and consumer. Denmark uses medium- to low-temperature hot water in the mains, providing the possibility of direct connection to the consumer installations, which simplifies system design. In the United States, steam is the most common medium used.

Why district heating?

A strong incentive for district heating is energy conservation and lower energy costs by using cheaper fuel and waste heat. Fuel economy is greater for district heating (for example, a home with an individual heating system operates at 50 to 70% efficiency compared to 80% in the case of district heating). Other incentives are improved air quality through improved discharges of fossil-fuel fired centralized plants; the concentration of the facility, allowing efficient use of fewer technical and supervisory specialists; and fewer oil-transporting vehicles for fossil-fuel plants. Using geothermal energy as the energy source, a more efficient use of the resource can be realized.

Obstacles to district heating are: cost of distribution, distribution heat loss, the high cost of supplying one-family houses on lots over 5000 ft² (460 m²), high initial capital investments and the many different types of heating systems in the United States. Natural gas is a severe competitor to district heating from an environmental and economic view; however, geothermal energy has proven competitive (Klamath Falls) where the resource is near the heating load.

Iceland has experienced great success in using geothermal energy for district heating with a savings of approximately 30% over using heating oil. Approximately 65% of the buildings in the

country and 97% in Reykjavik are on district heating systems. Other European countries, such as Sweden and Denmark, are expanding district heating systems because of fuel economy.

Heating density

A very important economic factor is the heat density, i.e., the possible connected heat demand for district heating divided by the ground area. High heat density is required since the distribution network which transports the hot water to the buildings is expensive. Studies which have been done in the U.S. and Sweden have categorized areas according to the economy prospects of district heating as shown in Table 2 (Swedish District Heating Manual, 1978).

TABLE 2

Economy prospects of heat density for district heating

Peak Heat Density MBtu/hr acre MW/ha	Area	Category
>0.97	Downtown - high rise	Very favorable
0.97 - 0.70	Downtown - Multi-storied buildings	Favorable
0.70 - 0.28	City core - commercial bldg & multi-family apartment buildings	Possible
0.28 - 0.17	Residential - multi-family houses	Questionable
<0.17	One-family houses	Not possible

The economy of a district heating system can be improved by adding an industrial base or cooling loads to the system. This is illustrated in Figures 8 and 9 by comparing duration curves for thermal loads only (Figure 8) and combined winter thermal and summer air-conditioning. The latter is based on the assumption that the summer cooling load does not affect the pipe size.

FIGURE 8. Thermal load duration curve.

FIGURE 9. Thermal and air-conditioning load duration curve.

The area below the curve expresses the total heat consumption in a year. This is improved for the combined curve, Figure 9.

Low- vs. high-temperature systems

District heating is a matter of heat transportation which is accomplished by using low-temperature (250°F, 121 °C), high-temperature (300°F, 149°C) hot water or steam as the medium.

Low-temperature hot water in the mains provides the possibility of direct connection to the consumers. Direct connection means better efficiency, an increase in the permissible temperature differential at a given temperature, and a smaller amount of circulating hot water with smaller pipes and lower heat loss. System design is simplified, and without recirculation there is usually no need to incorporate internal pumps in space-heating installations, which leads to lower installation and operating costs.

High-temperature hot-water systems usually require the addition of heat exchangers and recirculation pumps in the consumers' buildings. Higher heat losses also result in the distribution network. Steam systems generally have a lower efficiency and a limited transport distance when compared to hot-water systems.

Auxiliary boilers and heat pumps

Geothermal energy can be used as a preheater in the case of a low-temperature resource. The geothermal fluid can be boosted to a higher temperature by fossil fuel, such as in the Reykjavik system, or to preheat a secondary fluid which is in turn peaked by fossil fuel. Capital costs are generally reduced by introducing an auxiliary boiler into large district-heating systems. Designed to meet the peak heat load a few days out of the year by increasing fluid temperature, this results in smaller pipes, pumps, heat exchangers and fewer wells.

Another possibility in the case of a low-temperature (140-160°F, 60-71°C) geothermal resource is to include heat pumps in addition to the auxiliary boilers. A system of this type installed in the Paris basin supplies heat to 10,000 apartments and is claimed to be economical (Ryback, 1979). Annual heat consumption from the contributions of different sources for geothermal alone and geothermal plus heat pumps is illustrated by the areas under the curves in Figure 10.

Geothermal district heating

The main emphasis in using low-temperature geothermal energy will be in space heating in the future. Large-scale district-heating projects will be undertaken (such as being developed in Boise and Klamath Falls). District heating will become more and more economical with further escalation in conventional fuels resulting in the development of resources farther from the heating load. Transmission distances of 30-60 miles (50-100 km) are being considered and proven on paper (Akureyri, Iceland), with 13 miles (21 km) presently a reality (Reykjavik, Iceland). Transmission temperature losses in the below 212°F (100°C) range are around 0.3°F/mi (0.1°C/km) for insulated pipe.

A geothermal district-heating system will generally have the same basic components as a conventional system. The production field, which includes wells, pumps and collection mains, replaces the boiler in a conventional system. All other components, such as piping, valves, controls and metering, etc., would be similar to a conventional system.

District-heating metering systems for the purpose of billing consumers can be based on quantity of water used (volume metering), quantity of heat used (energy metering) or specified apportionment factors (non-meter billing).

Water-volume meters in use in the district-heating sector use mechanical principles to measure water flow through a counter which registers the passing volume of water. This type of meter

FIGURE 10. Meteorological conditions and corresponding contributions from different sources to total energy demand. (Ryback, 1979).

contributes toward making consumers economy-conscious in running their systems to achieve the greatest possible cooling of the district-heating water. Volume meters are relatively low cost for purchase and operation. The objection to volume metering is the variance in supply temperature to the consumer's installation.

There are two components in energy metering: quantity of flow and temperature differential across the system. Multiplication of these two values provides a measurement of the system's heat consumption. This method provides a favorable solution to heat measurement because consumers are billed on the basis of actual heat consumed. An objection to this type of metering has been the cost of purchase; however, Danish firms will be making available relatively low-cost energy meters.

Billing in proportion to the consumers installation, i.e., to the cubic volume or floor area, is a non-metering method used in some district-heating schemes. The advantage of this method is the savings in costs relating to the purchase, servicing and replacement of meters, as well as to meter reading, which is eliminated. This method is not suitable where there is a variation in insulation standards, mix of high- and low-density housing, or buildings of varying age.

A single-pipe (open-ended) distribution network with heat exchangers installed in each building and disposal of the geothermal fluid at the end of the consumer connections would be the most desirable type system. This makes the distribution network cheaper, as the cost of a single-pipe network is only about 70 percent of a two-pipe (closed-loop) system.

A two-pipe system involves a central heat exchanger, pumping and control facility. Depending on the location and characteristics of the resource, i.e., the necessity to recharge by means of injection wells, this may be the most desirable approach.

It is practical to divide the construction of the geothermal district-heating system into three main parts, which break down as follows:

Heat Production

1. Exploration and Assessment
2. Drilling and Well Completion
3. Collecting Mains

Transportation

1. Main Pumping Station
2. Supply Mains

Distribution System

1. Distribution Pumping Station
2. Street Mains
3. Service Branches
4. Consumer Connections

The cost of each part is variable. A specific example of geothermal costs is shown by two district-heating projects in Iceland (Reykjavik and Akureyri), where the proportions of costs are as follows:

Production	15 to 25 percent
Transportation	18 to 20 percent
Distribution System	58 to 66 percent

At present-day prices, the geothermal application will cost about the same or less than the corresponding annual fossil-fuel cost. Due to expected escalation of fossil-fuel prices, the costs

of the geothermal system will decline. Most geothermal direct-use systems will pay for themselves in 5-10 years from savings in conventional fuel.

An example of the economical aspects of a district-heating system is illustrated in Chapter 5, Economics.

AGRICULTURAL AND INDUSTRIAL APPLICATIONS

Geothermal energy can be used in a wide variety of applications in the agricultural and industrial sectors. This section has the main objectives of (1) indicating potential applications, (2) illustrating how geothermal energy can be used in several specific areas, and (3) providing guidelines on the "application-resource interaction factors" that must be considered in agricultural and industrial applications of geothermal energy.

The material in this section has been prepared by several individuals working on various aspects of geothermal energy utilization. The material presented here is heavily influenced by their experiences and works as well as the many recently completed works in this area. No attempt is made to refer extensively to previous works. However, the main references are indicated as a selected bibliography of works in the utilization of geothermal energy.

Since the maximum resource temperature considered in this work is 300°F (149°C), the processes are also necessarily restricted to those with an application temperature of less than 300°F (149°C). Appendix I lists most of the industrial processes, their application temperature range and the annual energy use for the process type in the U.S.

Figure 11 graphically depicts the application temperature range for many of the processes from Appendix I as well as the agricultural applications not included in the standard and industrial classifications (SIC) groups and Appendix I.

Agricultural growth applications

Agricultural applications are particularly attractive because they require heating at the lower end of the temperature spectrum where there is an abundance of geothermal resources. This section considers the agricultural growth applications; the other agribusiness applications are classified as processing and are considered in the Industrial Section which follows.

The following agricultural growth applications, all of which have been extensively documented, are considered here:

- greenhouseing
- animal husbandry
- aquaculture
- soil warming
- mushroom raising
- biogas generation

Greenhousing. Greenhousing is the raising of plants in a controlled environment to enhance yields. The greenhouse effect results from trapping of solar radiation and heat by using glass, plastic film or Fiberglas as environmental-control surfaces to enclose a growing area.

In addition to solar heating, other controllable heating and/or cooling must be applied to maintain temperatures for optimum plant growth. Environmental elements besides temperature that must be optimal or at least non-limiting in order to get the best yield of salable product dur-

FIGURE 11. Application temperature range for some industrial processes and agricultural applications.

ing the desired marketing period are: level of plant nutrients in the growing media; carbon dioxide content in the air; humidity; soil or nutrient media aeration; plant spacing; plant variety; disease control; sunlight or artificial light supplement; and cultural practices, such as pruning, plant training and pollination (Johnson, 1979).

All commonly marketed vegetables, flowers, house plants and many tree seedlings are suitable for greenhouseing. Greenhouse temperatures are a function of the crop; typical highest maintained temperatures range approximately from 65-80°F (18-27°C). Greenhouse heating can be accomplished by (1) circulation of air over finned-coil heat exchangers carrying hot water, (2) hot-water circulating pipes or ducts located in (or on) the floor, (3) finned units located along the walls and under benches, or (4) a combination of these methods. The heating fluid in these units can be as low as about 90°F (32°C). The air circulation method is more common and utilizes forced-air fincoil units similar to those discussed in the space-heating section. The heated air is often passed through perforated plastic tubes running the length of the greenhouse in order to maintain uniform heat distribution.

It should be noted that most crops require lower nighttime than daytime temperatures, with the consequent design benefit of having the lowest inside temperature when the coolest outside temperature occurs.

Animal husbandry. Environmentally controlled livestock raising provides significant advantages as compared to the typical practice of outdoor exposure to the elements. These advantages include: lower mortality (particularly during the critical first few weeks after birth), enhanced feed conversion (more weight gain per unit of feed), faster growth, better disease control, lower fat levels in the final meat product, improved quality byproducts (hides, for example), larger litter sizes for those species raised for multiple births, and relative ease of waste management. The level of thermal environmental control currently practiced ranges from floor heating for mostly open cattle finish-feed lots to totally enclosed raising of hogs and chickens. The totally enclosed systems utilize both space heating and floor-slab heating (at about 90°F, 32°C) to maintain about 70°F (21°C).

Aquaculture. Aquaculture is the cultivation and husbandry of freshwater and/or marine organisms under levels of control on the aquatic growth environment which are functions of the intensity of the aquacultural operation.

Fish farming is that portion of aquaculture which involves the rearing and harvesting of aquatic animals. Among farmable species are: common carp, Chinese carp, Indian carp, buffalo fish, paddle fish, catfish, pikes, perches, black bass, sunfish, tilapia, frogs, mullet, milkfish, eels, salmon, salmonids, smelt, sturgeon, shad, striped bass, shrimp, lobster, crayfish, crabs, oysters, clams, scallops, mussels and abalone (Bardack, 1972).

An emerging aquacultural industry is the cultivation of vegetable species adaptable for human and animal foods. Economics of harvesting and processing must be improved before such activity can become commercially viable. Crops adaptable to geothermally enhanced growth include: water hyacinth, duckweed, numerous algae species and kelp.

Heating can be accomplished using hot-water (90-110°F, 32-43°C) bearing pipes in the growth ponds or by direct addition of suitable quality hot water (70-90°F, 21-32°C) in order to maintain pond temperatures near 80°F (27°C).

Soil warming. Another agricultural application of geothermal water that shows some promise is that of increased production for certain crops through soil warming. From experimental work continuing at various sites throughout the world, it has been shown that certain root crops (vegetables typically thought of as "cool-weather" varieties) and certain rapid-growth tree

species (such as the poplar) show enhanced growth and larger crop yields if the soil is maintained at approximately 70°F (21°C). As another secondary use or the last step in a cascading energy loop, the geothermal water can be piped through an underground grid system made up of one of the more inexpensive plastic pipe selections. By maintaining a pipe-run spacing of approximately three feet and an installed depth of two to three feet, crops can be planted and harvested almost directly over the top of pipes without damage to the installation. Polyethylene tubing available in continuous 1000-ft (300-m) or greater length rolls has shown to be an economical pipe material selection for this application.

Mushroom raising. Mushroom culture is the production of edible fungi under controlled conditions.

The most edible fungus naturally found in the United States is the Agaricus campestris. A horticultural adaptation of this species, Agaricus bisporus, has been developed as the commercially cultivated mushroom of this country.

The United States produced over 142 million pounds (64 million kg) of mushrooms for the fresh sales market and almost 168 million additional pounds (76 million kg) for processing during the 1974-1976 reporting period. This production is projected by the mushroom industry to reach 544 million pounds (247 million kg) in 1982-1984.

Heating applications in mushroom culture are: compost preparation (130-140°F, 54-60°C), spawning (similar to seed propagation for chlorophyll-type vegetation, 72-75°F, 22-24°C) and production (60°F, 16°C; Lambert, 1963). Heating requirements are met by exposed hot-water piping along the mushroom-house walls; cooling may be geothermally driven if the resource temperature is adequate. Typically this may be accomplished using small electrically powered compressor units.

Biogas generation. The decomposition of organic matter in the absence of oxygen is called anaerobic fermentation and is the basis of biogas production. Anaerobic fermentation of organic products results in methane, carbon dioxide, hydrogen, traces of other gases and the production of some heat. The residue remaining is hygienic, rich in nutrients and high in nitrogen. Weed seeds and potentially damaging germs are killed by the absence of oxygen during the fermentation process rather than by the significantly higher heat generated by the aerobic (in the presence of oxygen) process.

The efficiency and rate of anaerobic fermentation are affected by temperature, relative concentration of carbon and nitrogen, pH and solids concentration.

The biogas-producing activities are optimal in temperatures ranging from 85-105°F (29-41°C), although digestion will occur from freezing to 156°F (69°C). Fermentation, however, is less stable in the higher of these two ranges and, consequently, biogas units are typically maintained in the lower optimal range (Singh, 1975).

The key equipment element in the biogas process is the enclosed biomass digestion tank. The temperature of such digesters is controlled by the addition of heat to maintain the desired 85-105°F (29-41°C) temperature range. This heating can be accomplished by circulating hot water through metal coils either inside the tank or in the tank walls; insulation is typically provided to minimize this heating requirement.

Temperature cascade considerations. Within the previously indicated temperature range suitable for agricultural-growth processes there is obvious potential for thermal cascading of the heat-bearing fluids. For example, an agricultural-growth complex might use the highest-temperature water (200°F, 93°C) for greenhouse-space heating, followed by mushroom-culture

applications from 110-140°F (43-60°C), biogas-generation process heating using 90-110°F (32-43°C) fluids, and, at the low end of the temperature scale, aquacultural activities could utilize water below 90°F (32°C). Such cascades can provide significant economic advantages as compared to single-purpose applications; cascaded applications have been discussed extensively elsewhere (Fageleman, 1978; Longyear, 1976; Reistad, 1978 and Swink, 1971).

Existing facilities. All of the above-described agricultural-growth facilities exist--no new technology is required, just proper design. Geothermally heated greenhouses are reported in at least three states; geothermal aquaculture activities are in practice in three states; and animal husbandry (although no geothermal facility yet exists) in both feedlots and totally confined buildings is commonly practiced throughout the United States, particularly in the Midwest and East. Much of the commercial-scale mushroom-growing operations are in the eastern U.S.; however, new western facilities are in the planning, with one such facility to be constructed at Vale, Oregon, which will use low-temperature (below 240°F, 116°C) geothermal fluids to power heating, cooling and humidity requirements (Geothermal Resources Council Bulletin, vol. 8 no. 6, June 1979). Biogas generation is common at sewage treatment plants; however, up to half of the methane generated is needed for heating of the generator in winter, making the value of the geothermal application obvious. Soil warming, practiced on a small scale in the U.S., is an increasingly common practice in Europe.

Industrial and agricultural processing

Lindal (1973), Reistad (1975) and Howard (1975) survey industrial applications and the potential for geothermal use in a number of the industries. Here we consider the basic processes and several of the more recently considered applications.

Basic processes. In industrial applications, thermal energy in the temperature range being considered here (up to 300°F, 149°C) is used in the basic processes of:

- Preheating
- Washing
- Cooking, blanching, peeling
- Evaporating
- Sterilizing
- Distilling and separating
- Drying
- Refrigeration

Preheating. Geothermal energy can be effectively used to preheat boiler and other process-feed water in a wide range of industries. Many manufacturing industries utilize boilers distributing steam throughout the plants. For a variety of reasons, much of the condensate is not returned. This imposes a considerable load on the boiler for feed-water heating of incoming water at typically 50-60°F (10-16°C) up to the temperature at which it is introduced into the boiler, typically 200-300°F (93-149°C), depending on the system. The geothermal resource can often be used to offload the boiler of some or all of this preheating load.

A wide variety of industries use, for various processes, large quantities of feed water which can be preheated or heated geothermally to the use temperature. Some of these applications also use heat-reclaim methods which must be analyzed when evaluating the potential for geothermal use.

Washing. Large amounts of low-temperature energy (95-200°F, 35-93°C) is consumed in several industries for washing and clean-up. One principal consumer is food processing, with major uses in meat packing for scalding, carcass wash and clean-up (140°F, 60°C); in soft-drink con-

tainer and returnable bottle washing (170°F, 77°C); in poultry dressing as well as canning and other food processes. Textile industry finishing plants are another large consumer of wash water at 200°F (93°C). Smaller amounts are used in plastics (190-200°F, 88-93°C) and leather (120°F, 49°C). Most of these are consumptive uses.

Sizable amounts of hot water and other hot fluids at temperatures under 200°F (93°C) are used in the several metal-fabricating industries (fabricated metal products, machinery and transportation equipment) for parts degreasing, bonderizing and washing processes. Most of these are non-consumptive uses with a 10-20°F (6-11°C) range in the fluid and reheating to the use temperature.

Peeling and blanching. Many food-processing operations require produce peeling. In the typical peeling operation, the produce is introduced into a hot bath (which may be caustic) and the skin or outer layer, after softening, is mechanically scrubbed or washed off. Peeling equipment is usually a continuous-flow type in which the steam or hot water is applied directly to the produce stream or indirectly by heating a produce bath. In most instances, produce contact time is short.

Blanching operations are similar to peeling. Produce is usually introduced into a blancher to inhibit enzyme action, provide produce coating, or for cooking. Blanching may be either a continuous or batch operation. Typical blanching fluids require closely controlled properties. Thus, it is unlikely that geothermal fluids could be used directly in blanchers and peelers because of the water quality. Geothermal fluids could, however, provide the energy through heat exchangers.

The temperature range for most of the peeling and blanching systems is 170-220°F (77-104°C). These heating requirements are readily adaptable to geothermal resources.

Evaporation and distillation. Evaporators and distillators are routinely found in many processing plants to aid in concentrating a product or separating products by distillation. Most frequently the evaporator will operate as a batch process in which a quantity of product is introduced and maintained at some given temperature for a period of time. The source temperature requirements vary with the product being evaporated. However, in a majority of agricultural processes, water is being driven off; and in these cases, operating temperatures of 180-250°F (82-121°C) are typical. In some circumstances, the evaporators operate at reduced pressures which decrease temperature needs and improve product quality. Evaporators are commonly found in sugar processing, mint distilling and organic liquor processes. Evaporators, depending upon temperature and flow-rate requirements, can be readily adapted to geothermal energy as the primary heat source. The energy can be transferred through secondary heat exchangers to the working fluids or, in some instances, used directly at the evaporator, depending upon existing plant designs or adaptations to new plant expansions (May, 1977).

Sterilizing. Sterilizers are used extensively in a wide range of industries and include applications such as equipment sterilization in the meat-packing and food-processing industries and sterilization for the canning and bottling industry. Most sterilizers operate at temperatures of 220-250°F (104-121°C) and would utilize geothermal energy with the use of heat exchangers to heat the potable sterilizer water. Many sterilizers operate in a continuous mode. Equipment washdown and sterilization, however, may occur periodically or at shift changes.

Drying. Many industries utilize heat at temperatures under 300°F (149°C) for evaporating water or to dry the product, material or part. The largest consumers are pulp and paper drying and textile product drying--mostly in the 200-300°F (93-149°C) range.

Other large consumers of energy for drying are in beet-pulp drying, malt-beverage and distilled-liquor grain drying and cement drying. Additional large energy consumers in the drying applica-

tion area (discussed later in this report) are grain, lumber kiln, plywood and veneer drying. Smaller consuming industries having drying applications include coal, sugar, furniture, rubber, leather, copper concentrate, potash, soybean meal, tobacco, pharmaceutical tablet and capsule, explosives and paving-aggregate drying.

Refrigeration. Cooling can be accomplished from geothermal energy through lithium-bromide and ammonia absorption refrigeration systems.⁴

The lithium-bromide system is the most common because it has water as the refrigerant; however, it is limited to cooling above the freezing point of water and has as its major application the delivery of chilled water for comfort or process cooling and dehumidification. These units may be either one- or two-stage. The two-stage units require higher temperatures (about 325°F, 163°C) but also have a higher COP (cooling output/source energy input), being about 1 to 1.1. The single-stage units are currently receiving substantial research emphasis in regard to use with solar energy and can be driven with hot water at temperatures somewhat below 190°F (88°C) and will typically have a COP of 0.65.

For geothermally driven refrigeration at temperatures below the freezing point of water, the ammonia absorption system must be considered. These can operate down to about -40°F (-40°C) evaporator temperature. However, these systems are normally only applied in very large tonnage capacities (100 tons and above) and have seen limited use. For the lower temperature refrigeration, the driving temperature must be at or above about 250°F (121°C) for a reasonable performance.

Specific applications

Food processing, crop drying and the forest-related industries have been extensively studied in regard to the use of geothermal energy. Examples of applications in these industries are presented below to show designs of using the geothermal energy and to indicate in an approximate manner how it might be used in other processes.

Food processing.

1. Vegetable and fruit dehydration (see Arnold, 1978; Lienau, 1978; Gordon, 1978 and Geothermal Resources Council Bulletin, vol. 7, no. 5, Nov.-Dec. 1978).

Vegetable and fruit dehydration involves the use of a continuous operation, belt conveyor or batch process using fairly low-temperature hot air from 100-220°F (38-104°C). The heat historically has been generated from steam coils and natural gas, but can be provided by geothermal energy. Typical continuous operation processing plants will handle 10,000 pounds (4500 kg) of raw product per hour (single line), reducing the moisture from around 83 percent to 4 percent, depending upon the product.

A crop currently being dehydrated with geothermal energy is onions. A similar dehydration process could be applied to fruits and other vegetables. Figure 12 illustrates a typical conveyor dryer for drying vegetables and which is the type presently being used for onions. High-powered blowers and exhaust fans move the air through water coils which contain either the geothermal fluid or a water in a secondary loop heated from geothermal energy and through the beds of onions on the dryer conveyor, to evaporate the necessary tons of water removed from the product each hour. Close air volume and pressure control must be maintained in all parts of this drying stage as the air moves up and down through the bed to obtain product drying uniformity. Automatic temperature controllers control the continuous operation.

⁴ Recent work has been devoted to developing other types of systems (Harris, 1977).

FIGURE 12. Schematic of conveyor dryer for vegetable drying.

At the proper point in the drying process, the onions are automatically transferred to the second stage of drying where, under reduced temperature conditions and deeper bed loadings (approximately 12 inches, 30 cm), the difficult-to-remove diffused water is slowly withdrawn.

Moderating temperatures and air flows are used to maintain close product temperature control as a steady evaporation of water is reduced from each onion slice and the evaporative cooling effect can no longer be counted on to maintain the low product temperature required for maximum product quality.

After drying, the onions are passed over a long stainless steel vibrating conveyor that gently carries them to the milling area. In the mill, skin is removed by aspirators from the onion pieces. The onions are then sliced, large chopped, chopped, ground, granulated and powdered.

2. Sugar-beet processing (see Vorum, 1978; Hornburg, 1975 and Pearson, 1977).

The first two stages of beet processing are preparation and slicing. Preparation is the stage between harvesting and slicing operations. It includes: receiving at the factory site; dirt and trash removal; short-term storage; beet-flow control; final trash removal and final cleaning; and elevating to the factory slicers. These stages do not use thermal energy.

Following the slicing operation (Figure 13), there are a number of processes that require thermal energy. The processes may be conveniently separated into five stages: a) diffusion; b) juice purification; c) evaporation; d) crystallization; and e) pulp-drying molasses (Lienau, 1978).

a) Diffusion

The diffusers separate the pulp and raw juice from the long thin strips (cosettes) of sliced beets. To start the process, makeup water enters and perco-

FIGURE 13. Processing stages for sugar production from sugar beets--composite flow sheet.

lates by gravity through the cossette mass, leaching out sugar as it proceeds counter-current to the cossettes. The temperature is raised to between 158-176°F (70-80°C) for better extraction. The rate of diffusion increases directly with temperature.

The sugar-depleted cossettes leaving the diffuser are known as pulp and are transferred to the pulp press and dryer. Sugar-enriched juice is next introduced to the juice-purification process. The diffusion juice contains between 10 and 15 percent sugar, which is about 98 percent of the sugar in the beets when sliced.

b) Juice purification

It is necessary to purify the juice since it contains nonsugar impurities. The nonsugar impurities in both true and colloidal solution make it very difficult to concentrate the diffusion juice or to crystallize pure sugar from it. Impurities are removed by introducing lime in the form of a slurry of calcium saccharates. Thermal energy is used preparatory to and during purification to heat juice from 148-194°F (64-90°C) and to provide the thermal energy used at lime kilns to produce CaO and CO₂.

The juice is heated to 240°F (116°C) and transported to the evaporators.

c) Evaporation

Heating is required to evaporate water from the beet juices. Water evaporated from the beet juices in the first-effect evaporator leaves a vapor which is subsequently used in succeeding evaporator stages and other processes in the plant. Thus, each evaporator effect acts as a condenser for the preceding effect. Each succeeding vapor pressure, and of course temperature, is proportionately lower with the lowest vapor pressure in the last effect under control of the barometric condenser.

One pound of steam admitted to the first-effect steam chest evaporates approximately one pound of water from the juice in the effect. One pound of the first vapor thus formed, when admitted to the second-effect steam chest, will evaporate one pound of water from the juice in the second effect. Consequently, one pound of steam admitted to the first-effect evaporator will evaporate approximately five pounds of water in a quintuple-effect evaporator. Evaporation comes from two sources: juice "flash" and condensation of steam or vapor in the chest.

In a conventional system, high-pressure steam from the boilers at 255 psia (1760 kPa) is expanded to exhaust steam pressure, either through turbines or reducing valves, and is used in the first-effect evaporator only. All other factory heating uses vapor from secondary evaporators.

By evaporation, the percentage of dissolved solids in the juice is raised from 10 to 15 percent to 50 to 65 percent and the outflow is called thick juice.

d) Crystallization

Sugar is crystallized by pan boiling in the vacuum pans. The boiling takes place at low pressure and thus low temperature in order to avoid caramelization.

When crystals are of the desired size and number, they are discharged from the vacuum pan into the mixer, which slowly agitates the mass. From the mixer, the mass of crystals is fed to the centrifuge. The liquid surrounding the crystals is centrifuged or spun off and leaves the basket through the perforations.

Following one or two brief washes with pure hot water, the wet white sugar crystals are discharged from the centrifugal basket and are sent to the dryer or granulator and the cooler. Hot, filtered air is passed through the granulator and cool, filtered air is passed through the cooler. The granulated sugar is then screened and either sacked immediately or stored in bulk bins.

e) Pulp drying

After the pulp leaves the diffusion process, it starts the pulp drying process. First, it enters the pulp press where much of the moisture is mechanically removed. It then enters the dryer where it is thermally dried and mixed with molasses, resulting in the dried molasses and beet-pulp product.

Presently, large quantities of low-pressure steam are used in the sugar processing industry. Many of the processes could be adapted to geothermal energy depending upon the resource temperature. The processes of diffusion and drying would utilize lower-temperature water, while 250°F (121°C) and above water could be used in the evaporation phases.

3. -Potato processing (see Lienau, 1978).

Many of the processing methods used by potato processors can utilize energy supplied by 300°F (149°C) or lower geothermal fluids. Typically, however, a few of the operations, notably the frying operation, will require higher temperatures than can be provided by a majority of the geothermal resources.

Usually in a potato-processing plant there are potato-product lines and several by-product lines. Figure 14 illustrates a french-fried potato-processing line. Potatoes for processing are conveyed to a battery of scrubbers and then moved into a preheater, which warms the potatoes and softens the peel, making it easier to remove the skin. The potatoes are then chemically peeled by a 15 percent lye solution maintained at a temperature of 140-175°F (60-79°C).

Upon leaving the chemical peeler, the potatoes are conveyed to a battery of scrubbers, where the peeling is removed. After the scrubbers, the peeled potatoes are subjected to another washing process and then conveyed to the trim tables by pumping. The peeling removed by the scrubbers is pumped to a holding tank and sold as cattle feed following neutralization of the lye residue.

After the potatoes are trimmed for defects, the product is conveyed to cutter areas. Shakers sort the product. The properly trimmed and sized product is then carried by gravity to the blanching system.

After blanching, the potatoes are dewatered and fed through a sugar drag, which adds a slight amount of dextrose to the surface of the potato, imparting a golden color when the potatoes are fried. They then pass through a dryer which removes the surface moisture prior to a two-stage frying process. The first stage cooks the product more completely, while the second stage gives it the golden color. The oil in the fryers is heated to 375°F (191°C) by heat exchangers receiving high-pressure steam at 275 psig (1895 kPa).

FIGURE 14. Potato-processing schematic.

For systems that would use geothermal energy, the energy would probably be supplied to the process via intermediate heat exchangers. To avoid any possible contamination of the product by the geothermal fluid, or the need for treatment of the fluid, the geothermal fluid passing through these exchangers will transfer energy to a secondary fluid, usually water, which delivers the energy to the process. The secondary fluid, circulating in a closed system, then returns to the intermediate heat exchanger to be reheated. For a geothermal fluid at 250-300°F (121-149°C), all of the thermal energy needs of the potato-processing plants could be met except for the heating of the fryers.

4. Slaughter operations.

Applications of hot water in slaughter operations are numerous and include: water at about 180°F (82°C) for required plant sanitation; heated water (140°F, 60°C) for washing of carcass shrouds and work clothing; heated soak tanks for hog dehairing; circulation of hot water through coils in waste tanks to prevent coagulation of fats, employee hot-water requirements and absorption refrigeration for many cooling requirements.

Crop drying.

1. Alfalfa dehydration (see Lienau, 1978 and Gordon, 1978).

Two different types of dehydration plants have been used for some time. The first, using conventional fuels, is a rotary-flame furnace and is common in the United States. It requires temperatures up to about 1800°F (1000°C). The other is used in New Zealand and operates on geothermal steam. It is a forced-air system using a multi-layer conveyor belt with temperatures up to about 275°F (135°C). In addition, a newer method has been used in the last few years. It involves field wilting to reduce the moisture content, with the remainder of the moisture to be removed in the dehydration plant. This process requires temperatures of about 180-250°F (82-121°C). Figures 15 and 16 show schematics of such an alfalfa-drying plant being geothermally driven. The chopped field-wilted material is fed to a dryer where air, heated by the geothermal fluid, contacts it and removes the moisture. The exact drying temperature depends upon the ambient conditions and moisture content of the alfalfa. The final pellets are checked for firmness, color, etc. and the plant adjusted accordingly. Dryer temperatures can be as low as 180°F (82°C).

2. Grain drying and barley malting (see Arnold, 1978; Lienau, 1978; Gordon, 1978 and Vorum, 1978.)

Significant amounts of energy are consumed annually for grain drying and barley malting. These processes can be easily adapted to geothermal energy in the temperature range of 100-180°F (38-82°C).

The kiln or grain dryer typically is a large vertical vessel with the grain entering at the top. Hot air is forced up through the grain, extracting the moisture before being exhausted.

The two important variables in the drying operation are the air-mass flow rate and the temperature at the inlet to the dryer. To maintain the fuel requirements at the lowest

FIGURE 15. Schematic of alfalfa-drying and pelletizing process.

FIGURE 16. Alfalfa-drying plant and well layout.

possible level, the air-flow rate should be minimized because the air is exhausted. However, two factors impose a practical lower limit on air flow: the rate must be high enough to provide uniform and sufficient contact between air and grain or malt across the entire bed, and the rate must also be high enough so that moist air leaving the bed is somewhat less than saturated with water. As a general rule, about 40-60 cubic feet (1.1 to 1.7 m³) of air per minute are required per bushel of green malt in the kiln. If the drying rate is too rapid, the grain will shrink and crack and suffer general physical damage.

Forest Industries.

1. Kiln drying of lumber (see Relstad, 1978 and VTN-CSL, 1977).

Most upper-grade lumber in the western United States is dried in batch kilns. In small saw mills where drying kilns are heated by steam from conventional oil-fired boilers, substitution of geothermal energy for the heating energy source can achieve substantial energy cost savings. In larger, well-integrated mills, all energy from operations can be provided by burning sawdust and other wood waste-products. If a market develops for the waste-products or if the energy can be more economically applied elsewhere, the

geothermal source may also become economical in integrated plants. It is evident that such a by-product market is developing.

The batch kiln is a box-shaped space with loading doors at the ends. The sawed lumber is spaced and stacked to allow for free air movement around the individual pieces and loaded into the kiln on specialized handling trucks. When the kiln is fully loaded, the doors are closed and the heating cycle started. The kiln has insulated walls and ceiling and has fans to circulate warm air over the lumber, exhaust moist air and draw in fresh air.

Drying is done for two main purposes: to set the sap and prevent warping. The sap sets at 135-140°F (57-60°C) and warping is prevented by establishing a uniform moisture content throughout the lumber piece, which can only be accomplished by carefully controlled drying schedules. The allowable drying rates vary from species to species and decrease with thicker pieces. Table 3 illustrates a typical drying schedule.

TABLE 3

Typical kiln drying schedules

<u>Ponderosa pine</u>	<u>Dry Bulb</u>		<u>Wet Bulb</u>		<u>Time</u>	<u>E.M.C.(%)</u>
	<u>°F</u>	<u>°C</u>	<u>°F</u>	<u>°C</u>		
4" x 4" (10 x 10 cm) All Heart Common Sort (fast on well sorted stock)	160	71	130	54	Approx 21 hrs	5.8
	No conditioning					
4" x 4" (10 x 10 cm) All Heart RW (Conser- vative) Common	150	66	130	54	Up to setting	8.0
	150	66	125	52	to 12 hrs	6.9
	160	71	130	54	12 hrs till dry (24-28 hrs)	5.8
	No conditioning					
4" x 4" (10 x 10 cm) Half & Half Common (mostly 8", 20 cm)	160	71	140	60	40-50 hrs	8.0
	No conditioning					
Shop & Select	115	46	108	42	First day	14.1
4" x 12" (10 x 30 cm)	120	49	110	43	Second day	12.1
	125	52	115	46	Third day	12.1
	130	54	120	49	Fourth day	12.1
	140	60	130	54	5th - 10th	11.9
	145	63	130	54	10th - 12th	9.5
	150	66	135	57	15th - 18th	9.5
	155	68	140	60	18th - 22nd	9.4
	160	71	140	60		7.9
	Cool					
	180	82	170	77	Approx 24 hrs	11.1
					Equalizing & Conditioning	

E.M.C. = Equilibrium Moisture Content

Originally from kiln-drying Western Softwoods, Moore Dry Kiln Company, Oregon; adapted here from VTN-CSL, 1977.

The difference in using geothermal hot water (180°F, 82°C) as an energy source as compared to a conventional steam-heated dry-kiln primarily would be in the selection of heat exchangers and fans, the absence of a boiler, and the presence of added piping and a circulation pump for the geothermal fluid. Evident from Table 3, geothermal fluids

at a temperature somewhat greater than 160-180°F (71-82°C) would be required to meet the entire drying schedule for Ponderosa pine. VTN-CSL (1977) reports that the geothermal fluid must be 20-40°F (11-22°C) above the operating temperature for economic operation, although where geothermal fluid of insufficient temperature is available, the heating can be supplemented by conventional fuels during the final high-temperature portions of the drying schedules.

Analyses comparing geothermal-heated lumber kilns with gas or oil-fired systems have been carried out for the Klamath Falls, Oregon, area (Reistad, 1978) and the Modoc County, California, area (VTN-CSL, 1977) which indicate substantial economic advantage of the geothermal systems in these two areas.

2. Material drying in plywood and particleboard mills.

In plywood mills, the main thermal-energy use is for the drying of veneer, while in particleboard mills, it is the drying of the particulate material used to make the particleboard. Because the wood in these instances is much smaller than the dimensional lumber mentioned above, it is typically dried at much higher temperatures, about 350-400°F (177-204°C) for veneer drying and 350°F (177°C) and higher for the particulate material. To be adapted for geothermal use, the drying operation would have to be redesigned to lower inlet air temperatures or else the geothermal energy could just be used for preheating the inlet air. The redesign presents no particular problem and could be readily accomplished for a particulate system.

3. Pulp and paper processing (Hornburg, 1975 and 1978).

The pulp and paper industry has good potential for use of geothermal energy at temperatures at and beyond the upper end of the range considered here. In New Zealand, the Tasman pulp and paper plant uses 120 psia (827 kPa, 341°F, 172°C) wet-saturated steam produced from a number of boreholes to provide much of the thermal energy requirements and some of the electricity requirements of a large pulp, paper and lumber operation.

Table 4 lists the process-heating needs of a conventional 1000-ton/day (907 t/d) pulp and paper mill based on the Kraft method.

TABLE 4

Process heat needed for a certain 1000-ton-per-day (907 t/d) pulp and paper mill (Kraft Process) of conventional energy system design.

Use	1000's of Btu/hr (907 t/d)	Steam - # Hr	
		25 psia (172 kPa)	135 psia (930 kPa)
Wash-Water Heating	248,100 (72.7 MW)	247,654	0
Evaporators	114,800 (33.6 MW)	114,594	0
Miscellaneous, L.P.	2,957 (0.9 MW)	2,952	0
Black Liquor Heating	5,372 (1.6 MW)		5,630
Digester	153,346 (44.9 MW)		160,734
Dryer	317,731 (93.1 MW)		333,016
Miscellaneous, H.P.	66,768 (19.6 MW)		69,980
Totals	909,074 (266.4 MW)	365,200 (165,600 kg)	569,360 (258,250 kg)

In addition to this process steam, 29.8 MW of electricity is needed for plant operation.

For geothermal resources at temperatures less than 300°F (149°C), the major impact comes in replacing the low-pressure steam use in the wash-water heating, evaporators and miscellaneous processing. Hornburg (1978) presents a design for the use of a 250°F (121°C) resource in the pulp and paper industry. That work indicates that the simplest and most efficient method of using geothermal energy is by direct exchange to a process fluid. Specifically, it was found that this was possible by heating the wash water and preheating the air for the paper dryers, amounting to 220 million Btu/hr (2.32×10^6 kJ = 64 MWt) for the 1000-ton/day plant (24% of total thermal requirements). Some potential for flashing of the geothermal resource and subsequent upgrading of the vapor phase to be used in some of the other processes in this industry is also shown.

Special considerations

In addition to the aspects discussed above, process-heating applications involve several additional factors that can seriously impact the design and feasibility of using the geothermal resource. This section considers a number of these factors.

Retrofit vs. new installations. In many of the large and complex industrial operations, most of the potential applications in the very near future will be of a retrofit type. For these, the geothermal system design will be largely the supply of the hot fluid to the system or building boundary, and extensive internal equipment modifications will be essentially absent for several reasons: expense, process disruption and the noted agribusiness practice of maintaining proprietary process secrecy.

New facilities offer the advantage of much greater potential geothermal heat applications: base loading levels can be established; equipment designs can be modified to accommodate the hot fluids (heat transfer surfaces, for example could be enlarged to provide the same amount of heat from hot liquids as compared to, say, high-pressure steam); and all suitable plant aspects can be designed in view of the rapidly deteriorating fossil-fuel situation.

Applicability of heat pump. In a number of instances, the situation may arise where the geothermal fluid temperature is lower than the required application temperature and/or the flow rate of geothermal fluid is not sufficient to directly meet the needs of the application. In such circumstances, the use of a heat pump to allow additional energy to be extracted from the geothermal fluid (lowering the disposal temperature) and raise the thermal-energy output temperature may be desirable. At the present time, units are commercially available with output temperatures up to about 230°F (110°C). A combination of heat pump and heat exchanger(s) may prove beneficial, in various situations, to obtain a greater energy extraction (larger temperature drop) from the geothermal resource. The economic feasibility of such installations varies with the specifics of the resource and the application. However, two major considerations are that (1) the temperature lift of the heat pump (for a COP $\leq$ about 3) should be less than about 80-90°F (44-50°C; the smaller the lift, the better the feasibility) and (2) auxiliary energy, usually in the form of electricity, is required.

Direct and indirect application of geothermal fluids in processing. Several factors should be considered by the designer in using a geothermal fluid directly in a process stream. In most instances, use of the geothermal fluid directly will result in the elimination of additional heat exchangers, pumping and piping. However, the economic savings may be overshadowed by consideration for peaking, product contamination and environmental concerns.

Direct use may not be practical in many cases. If the process has or is required to have a standby or peaking capability provided by an auxiliary boiler, it may not permit use of the geothermal fluid in the boiler as feedwater. In cases where the process loop has special water treatment requirements, introduction of geothermal water complicates such treatment and may prove uneconomical.

Product contamination and environmental factors must be considered in the cases where geothermal fluids come in contact with the product. Present EPA guidelines will not permit injection disposal of geothermal fluids which are chemically altered.

PRODUCTION AND INJECTION EQUIPMENT

Wellhead pumps

There are a variety of methods of providing geothermal fluid to an above-ground system. Artesian wells provide surface water naturally and some non-artesian wells can be induced to flow without pumping. However, wellhead pumps are necessary for non-flowing wells and can be desirable for wells that are self-flowing.

A mechanism by which a non-artesian well can be induced to flow is to reduce the density of the column of liquid in the well. For instance, if the liquid is mixed with a gas, the combined fluid density may be low enough that the downhole pressure is sufficient to force the fluid to the surface. If the geothermal source is hot enough and the downhole conditions allow the liquid to partially flash to steam, the reservoir maintains the low-density liquid-vapor mixture in the well. Under these circumstances, a well will continue flowing until the resource cools down or the well is capped.

When a reservoir flows by partial flashing to steam, the downhole fluid cools due to the latent heat of vaporization of the steam. If dissolved solids are at or near saturation in the reservoir, downhole depositions can form on casing walls and restrict well flow. In addition, these scale deposits can be harder material than the reservoir formation itself, so reaming out a plugged casing can be expensive.

An important advantage to pumping a self-flowing well is that pressure on the liquid is maintained, so downhole flashing and scaling are minimized. Also, by not allowing the fluid to flash, the pump discharge temperature can be much higher than the surface temperature of a self-flowing well. This is an important consideration when high-temperature geothermal applications are desired.

Vertical turbine pumps

Vertical turbine pumps have been used for many years in domestic and irrigation-water supply applications and have been successfully used in geothermal wells. Vertical turbine pumps increase fluid pressure by the centrifugal force imparted on a liquid by a shaft-driven impeller. In order to achieve the high pressure required in some geothermal service, these pumps frequently contain more than one stage arranged in series. Although the flow through each stage is the same, each stage of the pump successively increases the liquid pressure. An above-ground motor rotates a shaft that extends the length of the pump column to drive the impellers.

A sketch of a vertical turbine pump appears in Figure 17. As shown, the pump suction is at the bottom of the bowl assembly. The fluid progresses upward through each stage and exits in the annulus between the column pipe and the shaft-enclosing tube. At the top of the well, the fluid leaves the column pipe through the discharge head and enters the service piping.

The pump shown in Figure 18 is an enclosed lineshaft pump. Tubing bearings support the shaft at regular intervals (usually 5-7 feet, 1.5-2.1 m) and are lubricated by a fluid that is either pumped or gravity-fed through the tubing. Although oil has been successfully used for bearing lubrication in some geothermal applications, there has been little experience with oil lubrication for high-temperature (above 300°F, 149°C) geothermal pumps. In some high-temperature

FIGURE 17.
Vertical turbine pump.

FIGURE 18. Enclosed lineshaft pump (source: Worthington).

vertical turbine pumps, water has been pumped through the tubing to lubricate the bearings. This water can be a filtered slip-stream from the pump discharge or fresh water from a separate supply. Problems have arisen from solids depositing on the bearings, but these problems can be avoided (at least partially) by using softened water for lubrication.

An alternative to the enclosed-lineshaft and lubricating-fluid system is an open-lineshaft system. With an open lineshaft, the bearings are supported from the column pipe and there is no tube. The shaft bearings are lubricated by the production fluid moving up the column. Open-lineshaft pumps have found much use in domestic water-supply pumps (because there is no lubricating oil to contaminate the water) but have not found great success in geothermal applications.

Maintenance of a vertical turbine pump depends greatly on the fluid being pumped. In low-temperature, low-solids content applications, these pumps can provide years of service without maintenance. In corrosive service, or where solids readily deposit on the metal surfaces, the pumps may operate less than a year before cleaning and repair are required.

A problem associated with pumping a hot fluid is that metals in the pump expand. Since the lineshaft is frequently a different material from the column and tube, the expansion rate will also be different. This differential expansion rate is magnified by the length of the pump, so allowance must be made to adjust the shaft after the pump has equilibrated at the pumping temperature.

One common technique to solve the differential-expansion problem is to make the shaft adjustable from the surface. When the pump is installed, the shaft is adjusted to center the impellers in the bowls. After the pump has been producing hot fluid, the impellers will no longer be centered due to differential expansion, so the shaft must be readjusted. After adjusting the shaft when the entire pump, column and shaft have reached temperature equilibrium, no more adjustments are required.

The pump-power requirement can be found by the following formulae, where bhp is the brake horsepower:

$$\text{bhp} = \frac{\text{gpm} \times \text{total head in feet}}{3960 \times \text{efficiency}} \times \text{specific gravity} = \frac{\text{l/s} \times \text{total head in meters}}{206,000 \times \text{efficiency}}$$

or

$$\text{bhp} = \frac{\text{gpm} \times \text{pressure difference in psi}}{1714 \times \text{efficiency}} = \frac{\text{l/s} \times \text{kPa}}{3944 \times \text{efficiency}}$$

Typical efficiencies for vertical-turbine pumps are 50 to 80 percent and can be found from the pump curve for any specific pump and its operating conditions.

Downhole pumps

The electrical submersible pump has been utilized successfully in the oil industry for more than 50 years. Its adaptation to geothermal applications has only occurred during the last 6-8 years, but this adaptation, in many respects, has been a natural extension of technical knowledge gained over the 50 years of oil-pumping service.

A submersible pumping system consists of three major components: the drive motor, protector section and the pump (Figure 19). Surface components consist typically of an electrical junction box, switchbox and transformers, as required.

FIGURE 19. Conventional submersible pump (source: TRW REDA Pumps).

The motor section consists of a 3-phase, induction type which is oil filled for cooling and lubrication. A high-starting torque enables a full-load operating speed to be reached in a very short time period. Motor cooling is achieved through heat transfer to the well fluid moving by and such motors have been operated satisfactorily on well fluid temperatures in excess of 300°F (149°C). These motors are available in a wide range of diameters, horsepower and voltages to accommodate a variety of applications.

The protector section is located between the pump and motor. Its primary function is to isolate the motor from the well fluid. The protector design allows for pressure equalization between the pump-intake pressure and the motor's internal pressure, permitting expansion or contraction of the motor oil due to thermal gradients. Mechanical seals provide protection against fluid migration along the pump shaft and a marine-type thrust bearing is included to absorb axial forces induced by the pump.

The pump section consists of a multistage centrifugal arrangement quite similar to the surface-driven turbine pumps described earlier under Vertical Turbine Pumps. Capacity ranges up to approximately 2000 gpm (126 l/s) and lifts up to 15,000 feet (4500 m). Due to hydraulic limitations combined with diameter limitations, the lift per stage is relatively low; however, as many as 500 stages have been used in the past to meet high head requirements. Through the use of corrosion-resistant materials, pump wear and corrosion are minimized and long-term predictable performance in all normally encountered fluids can be assured.

Advantages of the submersible pumping system are many and include:

1. The system can efficiently deliver the largest amount of horsepower at the pump of any pumping system in the small-diameter casing sizes associated with wells of any depth.
2. Conventional designs can be utilized in crooked drill holes or deviated wells.
3. Conventional designs are now capable of operating at temperatures to 300°F (149°C).
4. Well-surface requirements are minimized.
5. No costly foundation pads or housing structures are required.
6. Pump and motor noise is confined to the well bore.

A recent development in submersible pumps allows for a well completion that permits easy and safe removal of the pump without removing the discharge pipe. Figure 20 is an illustration of how this pump is suspended inside the discharge pipe and retrieved with the attached cable. Removal (through a stripper valve) does not involve the use of well-kill fluids to hold back well flow, as is the case for more conventional pump-service operations.

Circulation pumps

In any geothermal utilization scheme, once the geothermal-well pump has been selected, auxiliary circulation pumps can become a requirement. These pumps can be used to boost the pressure in the geothermal loop or to provide the pressure and flow in a secondary closed-loop system. Many excellent selections are available in this regard. Centrifugal pumps, selected on the basis of pressure, flow, temperature and corrosive considerations of the fluid being handled, become a straightforward engineering task. Hot-water circulating pumps have been used for many years and the state-of-the-art can be applied directly to geothermal applications.

PIPING SYSTEMS

This section refers only to that portion of piping transporting geothermal water. Piping in a closed-loop system carrying city or potable water, which may have been heated by geothermal

FIGURE 20. Cable-supported submersible pump (source: TRW REDA Pumps).

water, becomes a standard heating system, is well documented in ASHRAE guidebooks and is no different from what has been in common use.

Types of pipe

Metallic pipe. The most commonly used pipe is black steel, schedule 40, for pressures under 125 P.S.I. (860 kPa). Jointing of this pipe may be threaded, welded or with use of gland-type couplers (Victaulic or equal). In using gland-type fittings, it is very necessary to research the chemical and temperature range of the elastomeric gaskets to make sure they are compatible with the water.

Generally, it is advisable to keep the velocity on the high side to provide scouring and reduce chemical build up. Free oxygen in these systems will produce Fe_3O_4 , therefore it is necessary to keep a tight system.

Other types of piping, such as copper, brass, stainless steel and the more exotic metals may be permissible under certain water conditions but should be used only as "last resort" due to their increased cost.

When buried in the ground, metallic piping should be well protected from exterior corrosion. Using magnesium anodes to offset the galvanic action of soils and ground water is often advisable, particularly in very moist soil or acid soils.

Nonmetallic pipe. Asbestos cement piping has been used for out-fall lines with good success; however, some waters will have a deteriorating reaction with the piping chemicals. On supply pipes or pressure pipes, there is the additional possibility of oxygen entering the water due to the porosity of the piping.

Polymer concrete pipes (mixtures of cement aggregate and various polymers) are presently under development. These pipes have been tested in various geothermal fluids and have been resistant to leaching, scaling and erosion. Testing is continuing and the pipes are commercially available, but at the present time there is no large commercial application experience.

There are many types of patented plastic pipes, such as PVC, CPVC, Fiberglass, polypropylene and other thermoplastic materials that have excellent chemical resistance, sealing, higher flow rates for a given size and a wide range of thermal expansion and temperature limitations. We advise a thorough study of their limitations⁵ before using any of these pipes and recommend providing the manufacturers with chemical analysis of the water and receiving from them a written guarantee for its usage. These materials have been used in only limited applications to this time and there is little experience on which to base design and operations and maintenance costs.

Some Fiberglass-reinforced plastic (FRP) pipes meet rigid military specifications (MIL-P-28584) of up to 115 psig (800 kPa) at 300°F (149°C) and have been used for steam-condensate lines with good results. Maintenance costs over a 12-year period have been nil and the pipe shows no sign of deterioration. FRP in general will not carry live steam as the steam breaks down the plastic; seeping and ultimate failure may result.

Determining pipe parameters

Pipe sizing. Pipe size is determined by the temperature difference (ΔT) between the water entering and leaving a system. For best economy of the overall design, it is most advantageous

⁵ For example, temperature limits for various pipes are 125°F (52°C) ABS, 150°F (66°C) PVC and 212°F (100°C) CPVC.

to use the largest ΔT possible. Flow rates are determined from the heat output required by the system divided by the temperature differential as follows:

$$\text{Mass Flow Rate (lb/hr)} = \frac{\text{Heat output (Btu)}}{\Delta T}$$

Expressed in the commonly used gallon per minute (GPM), this formula becomes

$$\text{Flow rate (GPM)} = \frac{\text{Heat output required}}{\Delta T \times 8.33 \text{ lb/gal} \times 60 \text{ min/hr}} \quad \text{or} \quad \text{l/s} = \frac{\text{kJ/hr}}{15,200 \times \Delta T(^{\circ}\text{C})} = \frac{\text{KW}}{4.22 \Delta T(^{\circ}\text{C})}$$

$$(\text{GPM}) = \frac{\text{Heat output required}}{\Delta T \times 500}$$

This would vary slightly due to the specific heat and density of the water at various temperatures. However, in the range of temperatures normally used, the above formulae are accepted.

Head loss. The second consideration is the head loss in a system. As the pipe size is decreased for a given water flow, the head loss will increase thus, increasing the pump motor size and the energy consumption. Head loss in a piping system is a function of the quantity (GPM), circulated and the friction loss in the pipe. Generally, a .75 ft/100 ft head loss to 2.5 ft/100 ft (0.75-2.5%) is desirable, the lower figure being used for smaller pipes. There are advantages to using the higher flow rates, such as scouring of the pipes and the ability to move entrained air through the systems.

In determining the total head loss in a piping system, one must know the total length of the system plus the equivalent length allowed for fittings and valves. The head loss in the piping system is equal to the total equivalent length times the friction loss per ft or per 100 ft. Tables for determining the friction-loss factors and resultant pipe sizes may be found in ASHRAE Handbook of Fundamentals, 1972 edition, Chapter 26. This reference also gives complete information for pipe sizing.

In addition to the water-friction loss in the piping system, one must also consider the head loss through the heat exchangers or coil system that the water passes through. These losses are usually quite significant and can be most easily obtained from manufacturers' catalogs or direct from the manufacturer of the equipment used.

Static losses in a system (that is, the loss to lift the water to the highest point of usage) must also be considered in determining the total head loss on a pump. Therefore, the total head loss is equal to H_f (Head Loss due to friction) plus H_e (Head Loss through equipment) plus H_s (Static Head Loss).

Static Head Loss is ignored in any closed-loop system since the total system is filled with water and the weight of the water rising in a system is offset by the weight of the water that is returning down in the system.

Design procedures. In any piping and utilization system, it is recommended that a preliminary layout be prepared and from this, preliminary pipe sizes, pressure drops, equipment sizing and pump selection be determined.

An overall examination of this preliminary design should then be affected and adjustments in pipe sizes and pump sizes may be made to determine the best first cost versus the operating cost of the system to obtain the optimum design.

Expansion allowances. Consideration must be given to the expansion and construction of piping due to temperature changes. This expansion must be taken up within the piping system either with offsets, pipe loops, expansion joints, special mechanical couplings, by utilizing the inherent flexibility of the piping in bending or by preheating. The method or devices selected will depend upon force limitations, available space, installed cost, serviceability, maintenance cost, length of life, etc. The amount of expansion within a given piping system depends on the temperature differential and the type of piping. The relation between these two for any given pipe material is available from most engineering handbooks or from manufacturers.

Where possible, we recommend utilizing the flexibility of the piping itself either by unrestricted movement of the pipe where it makes bends or by using offsets or pipe-loops. However, these methods are usually not satisfactory for a buried system.

Mechanical expansion joints are commonly used where space is a limiting factor; however, they must be accessible for maintenance.

Some piping systems use an elastomeric-gasketed type coupling, such as tapered joints with O-rings or those applied to grooved-end pipe to take up the expansion. However, these must be selected carefully to insure adequate expansion and to be able to operate within the pressure and temperature limitations of the elastomer selected.

Preheating of direct-bury piping for large central heating districts has been used in several countries in Europe. Insulated pipe is laid in trenches, preheated to a fixing temperature between the middle of the normal operating range and the middle of the total temperature difference (cold to high-operating) and back-filled at that fixing temperature. The system eliminates guides, anchors and expansion loops or compensators since they have already been "prestressed." A good bond between pipe, insulation and outer jacket (PVC, PEH, etc.) is required. The system is said to reduce installation cost by up to 20% and reduces system failures.

For a complete discussion on expansion in piping, we refer you to Chapter 14 of the 1976 ASHRAE Systems Handbook.

All expansion devices must be used in conjunction with anchors and guides to insure that the expansion occurs as designed and that the alignment of the piping is maintained in order to make the devices operate as designed.

Heat loss from piping system. The heat losses to be tolerated from a piping system will invariably be determined by the economic balance between first cost and operating cost. Also recent legislation and adoption of energy codes have dictated certain minimum insulation values for piping regardless of the type of heat source. Geothermal water is a natural resource, and although it may appear at this time that it is virtually an unlimited source of energy, it should not be wasted.

The thickness and type of insulation to be used on a system must be evaluated not only on cost but also on location of the piping and the temperatures involved. In an underground system, the resistance to moisture absorptivity and resistance to superimposed loads must be considered. Above-ground insulations must be evaluated for fire and smoke protection, from damage by personnel and from damage to thermal efficiencies.

Most of the criteria for proper installation of insulation can be obtained from the insulation manufacturers. ASHRAE, 1976 Systems Handbook, Chapter 14, gives a good comparison chart for evaluating the various types of insulation.

HEAT EXCHANGERS

The principal reason for having heat exchangers in geothermal systems is to confine the geothermal waters with their inherent impurities to locations where corrosion and/or scaling can either be controlled by materials selection or where cleaning or replacement will be relatively easy and economical. Thus, large and sometimes complicated piping and heat-emitter systems are protected from the harsher environment of the geothermal fluid. In some areas of relatively benign geothermal fluid, direct use in the system may be practical. Chemistry of the water and its effect on materials should be carefully checked.

It must be remembered that there will be a temperature differential between the primary and secondary fluids any time a heat exchanger is used. The smaller the differential (closer approach temperature), the more expensive the heat exchanger will be. Approach temperatures of less than 10°F (6°C) are often uneconomical but depend on the heat-exchanger type and particular application. In some cases, where well and piping costs are low, approach temperatures of 4-5°F (2-3°C) have proven economical.

The principal types of heat exchangers used in geothermal systems are the downhole heat exchanger; the shell-and-tube heat exchanger; the plate heat exchanger; the fluidized-bed heat exchanger; the direct-contact heat exchanger; and the plastic-tube heat exchanger.

Downhole heat exchanger

The downhole heat exchanger (DHE) eliminates the problem of disposal of geothermal fluid, since only heat is taken from the well. The exchanger consists of a system of pipes or tubes suspended in the well through which "clean" secondary water is pumped or allowed to circulate by natural convection. These systems offer substantial economic savings over surface heat exchangers where a single-well system is adequate (typically less than 0.8 MWe, with well depths up to about 500 ft (150 m) and may be economical under certain conditions at well depths to 1500 ft (450 m; Figure 21).

Several designs have proven successful, but the most popular are a simple hairpin loop or multiple loops of iron pipe (similar to the tubes in a U-tube and shell exchanger) extending near the well bottom (Figure 22) and a spiral coil of copper tube suspended near the well bottom. An experimental design consisting of multiple small tubes with "headers" at each end suspended just below the water surface appears to offer economic and heating capacity advantages.

In order to obtain maximum output, the well must be designed to have an open annulus between the well bore and the casing and perforations above and below the heat-exchange surface. Natural convection circulates the water down inside the casing, through the lower perforations, up in the annulus and back inside the casing, through the upper perforations. If the design parameters of bore diameter, casing diameter, heat-exchanger length, tube diameter, number of loops, flow rate and inlet temperature are carefully selected, the velocity and mass flow of the natural convection cell in the well may approach those of a conventional shell-and-tube heat exchanger.

The interaction between the fluid in the aquifer and that in the well is not fully understood, but it appears that outputs are higher where there is a high degree of mixing indicating that somewhat permeable formations are preferred (Figure 23).

Considering life and replacement costs, materials should be selected to provide economical protection from corrosion. Attention must be given to the anodic-cathodic relationship between the exchanger and the casing since it is relatively expensive to replace the well casing. Experi-

FIGURE 21. Unit energy costs for geothermal energy from downhole (DHE) and surface heat-exchange (SHE) systems for a well depth of 70 meters (230 ft). Points A, B and C indicate the limiting energy-extraction rates for the SHE and SHE_r (with reinjection) systems with well flows of 32 l/s (250 gpm) and 47 l/s (750 gpm) respectively at the temperature drop shown. (Note: 1¢/KW h = \$2.93/million BTU = \$2.78/GJ.), (GWh = Giga Watt hour)

FIGURE 22. Typical downhole heat-exchanger installation.

FIGURE 23. Typical hot-water distribution system using a downhole heat exchanger (Culver, 1978).

ence in the approximately 600 downhole exchangers in use indicates that corrosion is most severe at the air-water interface at static water level and that stray electrical currents can accelerate corrosion. Insulating unions should be used to isolate the exchanger from stray currents in building and city water lines.

Shell-and-tube heat exchangers

Conventional shell-and-tube heat exchangers may be utilized for geothermal applications with certain design considerations. Their application is well known and little will be said here. The shell-and-tube heat exchangers are placed above ground and can be either adjacent to the well head or at any place along the distribution system in the case of a large district-heating system.

This type of heat exchanger is readily available or may be custom-designed to meet the specific need. The shell-and-tube heat exchanger is just what the name implies, i.e., a series of tubes, normally carrying the geothermal water, surrounded by an enclosing shell, confining the secondary-system water around the tubes. The tubes in this type exchanger can be a "U"-tube configuration or a straight tube with removable heads at both ends to facilitate cleaning of the tubes. We recommend the straight-tube configuration strictly for ease of cleaning. Exchangers may be used in series to obtain higher ΔT , or for heating different secondary fluids.

Impurities in the well-water systems will determine the types of materials to be used in the heat exchangers. Less expensive exchangers are normally manufactured using mild steel for the shell and heads, with copper tubes. Stainless-steel shells and certain copper, bronze, silicon bronze or stainless-steel tubes and heads may be used for greater corrosion resistance. Further information may be found in the corrosion section of this report. In some cases, scaling can be a serious problem in shell and tube exchangers. The water can be chemically analyzed and the Langlier Saturation Index applied to obtain information on the amount of scaling to be expected. Large fouling factors, up to 25% or more, may be required.

When mild steel shells and copper or silicon bronze tubes can be utilized, the shell-and-tube heat exchanger will generally be more economical than plate exchangers. However, for the same duty, the shell and tube exchangers will generally require more space.

Plate heat exchangers

Although relatively unknown, plate-type heat exchangers have been used predominantly in the food-processing industry, where corrosion resistance and cleanliness are necessary, and in certain other applications where very close approach temperatures are required (Figure 24).

The plate heat exchanger consists of a series of plates held in a frame by clamping rods. The primary and secondary fluids are usually passed through alternating passages between the plates in single-pass counter flow, although other flow paths can usually be arranged by simple external piping. Since the flow is pure counter-flow, Log Mean Temperature Difference (LMTD) correction factors approach unity and high turbulence is achieved, providing a very efficient exchange in a small volume. Stamping of the plates provides a variety of flow-path patterns and sizes.

The plate-type exchangers can be economically constructed of corrosion-resistant materials since the plate material is usually more economical than tube material. Materials readily available for geothermal use include stainless steels, titanium, brasses and hastelloy.

Specific advantages of plate heat exchangers over shell and tube exchangers for geothermal applications are:

1. More economical when materials other than mild steel are required.
2. Less floor space required.
3. Closer approach temperatures at reduced costs.
4. Easy disassembly for cleaning.
5. Easy to expand for increased heating loads by adding plates.
6. Series and/or parallel systems can be incorporated in one frame.

Disadvantages for some applications are:

1. Low-density fluids (vapors and gases) are difficult to handle economically.
2. Since gaskets between plates must be elastomeric, temperatures are limited to 500°F (260°C).

FIGURE 24. Plate heat exchanger (source: APV Co., Inc.).

We recommend investigating the use of plate-type exchangers for all applications unless the disadvantages noted above clearly eliminate their use. In the several instances where they are in use or use is proposed, plate exchangers have shown great economic advantages. The economy is particularly advantageous where low-temperature geothermal fluid requires close approach temperatures for economic sizing of other components. Systems presently in operation have economically achieved approach temperatures of 4°F (2°C) with geothermal fluid of about 130°F (54°C).

Direct-contact heat exchanger

This type of heat exchanger provides one of the most efficient and simplest means of transferring heat from hot geothermal water to another working fluid. Direct-contact exchangers have been used in petro-chemical applications for a number of years, usually in the exchange between a fluid and a gas (Figure 25).

The basic exchanger consists primarily of a pressure vessel with its longitudinal axis vertical and piped such that the hot fluid and the fluid to be heated are introduced countercurrent to each other. Each fluid is usually directed through a nozzle arrangement to provide for efficient mixing and maximum contact between the two fluids. Once mixing and heat exchange has taken place, the two fluids are allowed to separate as a result of state or density changes. The working fluid carryover to the hot fluid is almost inevitable. Selection of the proper working fluid to minimize carryover is based on chemical and thermal characteristics. As an

FIGURE 25. Schematic of various types of direct-contact counter-flow devices.

example, the flash point of the working fluid selected should be well below the temperature of the geothermal water to assure complete vaporization of the working fluid and thus good separation after being heated.

The advantages of this device for direct applications include simplicity of design and a small volume size required for rather large heat-transfer rates. Applications considered primarily to date have usually been in the electric-power generation areas, but the application should lend itself well to heat pumps or process use or perhaps a Rankine cycle engine.

Fluidized-bed heat exchanger

The fluidized-bed exchanger is similar to a shell-and-tube in design and overall appearance. The difference is that a medium (sand, ground walnut hulls or almost any granulated, uniformsize material) that can be made to behave like a fluid (with the introduction of pressurized air or any other fluid, for that matter) is maintained in the shell portion surrounding the tubes. This fluidized medium provides for a constant scrubbing action against the tubes, eliminating many fouling or scaling problems. It can also have a beneficial effect on the overall heat transfer through turbulent action around the individual tubes, increasing the contact time between hot and cold fluids (Figure 26).

For the geothermal water high in dissolved solids that have a potential for severe scaling, the fluidized bed exchanger becomes an excellent choice. Heat-transfer rates can be maximized without the maintenance concerns of fouled exchanger tubes. In the application described, geothermal water would be piped to the shell side of the exchanger through nozzles to fluidize a sand medium. The secondary water or fluid to be heated would circulate through the exchanger tubes.

Typical process applications for the fluidized bed exchanger may include many drying applications where the fluidized medium is actually the material being dried. The drying process can be accomplished in a batch-type arrangement or through a continuous flowing process where the medium is constantly carried over and expelled once it reaches a certain moisture content. In this application, geothermal water would be used in the tube side of the exchanger and the material to be dried, fluidized with pressurized air, would be introduced in the shell side.

Plastic-tube heat exchangers

Plastic-tube heat exchangers with an upper temperature limit of 122°F (50°C) are presently available from a Swedish manufacturer and higher temperature units are reportedly under investigation. The units are completely corrosion resistant to most geothermal waters and should not be susceptible to scaling. As might be expected, the units are larger than a comparable capacity typical U.S. fan-coil unit, but the corrosion- and scaling-resistance overcomes the disadvantage of size.

Current use of the plastic units has been in heat-recovery systems where heat from corrosive water is transferred to air and, conversely, where chemical-laden air is used to heat water. There are no metal components with bolts, manifolds, end plates and spacers made of plastic.

Use of highly cross-linked polyethylene tubes or other engineering plastics should permit construction of units able to withstand temperatures of above 200°F (93°C) and pressures of 150 psi (1030 kPa) with safety factors of 3, although no such units have been tested to date. There are no U.S. manufacturers producing either the highly cross-linked polyethylene or the plastic-tube exchangers.

A plastic-tube heat exchanger has been in use for several years in the Blue Baths in Rotorua, New Zealand. The exchanger consists of a loose bundle of 640 0.025-inch (0.64-mm) ID Teflon

FIGURE 26. Horizontal arrangement of a liquid fluidized-bed heat exchanger.

tubes of suspended in a circulating bath of 200°F (93°C) geothermal water. Similar units are manufactured by DuPont.

CORROSION, SCALING AND MATERIALS SELECTION

Properly managed boiler water, steam or hot-water heating systems are free of the typical geothermal fluid components. These fluids are substantially less aggressive than geothermal fluids and have little tendency to form scales by deposition of dissolved solids. The chemical species present in geothermal fluids are the primary factors that result in corrosion and scaling when these fluids are used as heat sources.

Geothermal-fluid chemistry

Geothermal-fluid temperature and chemistry are so closely related that there is a general increase in total dissolved solids (herein referred to as salinity) as temperature increases. The chemical species found in the fluids are a function of the local, in situ geology. Certain important species are found to a greater or lesser extent in all geothermal fluids and are tabulated in Table 5. Hydrogen concentration, as expressed by pH, is a function of other species, e.g., carbon dioxide. Oxygen is not present in most geothermal reservoirs since oxygen and hydrogen sulfide do not coexist in significant amounts at equilibrium. The presence of significant concentrations of oxygen (>10 ppb) in the presence of hydrogen sulfide is usually an indication of leakage of air into the piping system or the mixing of very near surface water with the fluid (DeBerry, 1978).

TABLE 5

Dissolved major corrosion and scaling species in most geothermal fluids

Corrosion	Scaling	Character
Oxygen (in leakage)		Gas
Hydrogen Sulfide		Gas
Carbon Dioxide		Gas
Ammonia		Gas
Hydrogen		Ions
Sulphates		Solid
Chlorides		Solid
	Silicates	Solid
	Carbonates	Solid
	Sulfides	Solid
	Oxides	Solids

Hydrogen sulfide. Probably the most severe effect of H_2S is its attack on certain copper and nickel alloys. Copper, cupronickel and nickel copper alloys have performed well in seawater but are practically unusable in geothermal fluids containing H_2S . The effect of H_2S on iron-based materials is less predictable. Accelerated attack occurs in some cases and inhibition in others. High-strength steels are often subject to sulfide-stress cracking. H_2S may

also cause hydrogen blistering of steels. Oxidation of H_2S to H_2SO_4 in aerated geothermal process streams increases the acidity of the stream.

Carbon dioxide. In the acidic region, CO_2 can accelerate the uniform corrosion of carbon steels. The pH of geothermal fluids and process streams is largely controlled by CO_2 . Carbonates and bicarbonates can display mild inhibitive effects.

Ammonia. Ammonia can cause stress-corrosion cracking of some copper alloys. It may also accelerate the uniform corrosion of mild steels.

Sulfate. Sulfate plays a minor role in most geothermal fluids. In some low-chloride streams, sulfate will be the main aggressive anion. Even in this case, it rarely causes the same severe localized attack as chloride.

Oxygen. The addition of small quantities of oxygen to a high-temperature geothermal system can greatly increase the chance of severe localized corrosion of normally resistant metals. The corrosion of carbon steels is sensitive to trace (in the low ppb range) amounts of oxygen.

Hydrogen ion (pH). The general corrosion rate of carbon steels increases rapidly with decreasing pH, especially below pH 7. Passivity of many alloys is pH-dependent. Breakdown of passivity at local areas can lead to serious forms of attack, e.g., pitting, crevice corrosion and stress-corrosion cracking.

Chloride. Chloride causes local breakdown of passive films which protect many metals from uniform attack. Local penetration of this film can cause pitting, crevice corrosion or stress-corrosion cracking. Uniform corrosion rates can also increase with increasing chloride concentration, but this action is generally less serious than local forms of attack.

Transition metal ions. "Heavy" or transition metal ions might also be included as key species. Their action on most construction materials at low concentrations is ill-defined. However, the poor performance of aluminum alloys in geothermal fluids may be due in part to low levels of copper or mercury in these fluids. Salton Sea geothermal fluids contain many transition metal ions at greater than "trace" concentrations. Some oxidized forms of transition metal ions (Fe^{+3} , Cu^{+2} , etc.) are corrosive, but these ions are present in the lowest oxidation state (most reduced form) in geothermal fluids. Oxygen can convert Fe^{+2} to Fe^{+3} , which is another reason to exclude oxygen from geothermal streams.

An important factor to be considered when evaluating a geothermal resource is the variability of the chemical characteristics of the fluids. The compositions of geothermal fluids vary considerably from field to field. There are significant differences between wells in a given reservoir resulting from localized variations in the geology. There are variations with time in a well due to changes in the flow patterns resulting from production of the reservoir.

Corrosion and scaling inhibitors

The volumes of fluid required for most geothermal-heating applications are typically too large for economical use of corrosion inhibitors. The EPA requirement for the removal of any chemical added to the fluid for corrosion control prior to disposal provides further incentive for alternate corrosion-control methods. These factors suggest that materials selection is the most economical means of corrosion control.

Unlike the requirement for removal of corrosion inhibitors, EPA regulations regarding scale-control chemicals are much more liberal. Scale-control chemicals fall into two general classes: those that modify surface characteristics and retard nucleation and those that change the chemical character of the deposited species.

These chemicals interfere with nucleation and growth mechanisms rather than altering the equilibrium solubility of the depositing mineral. Polysulfates, polyacrylates and other low-molecular weight polymers are frequently used for scale control. One point should be borne in mind: corrosion scales frequently provide nucleation sites for mineral scale deposits.

Corrosion and materials selection

This section describes the forms and mechanisms of corrosive attack that can occur in geothermal-process liquid streams. These generalizations are especially useful when materials must be specified for conditions at which tests have not been done. If the corrosion rate of a material has been tested at the stream conditions of interest, this information is still useful. It explains the effects of fabrication practices, equipment configuration and operating stresses. It also identifies some additional ways materials can deteriorate.

Table 6 contains information about the performance of specific metals in liquid streams.

General guidelines

By taking appropriate precautions, carbon steels can be used for thick-walled applications in contact with most geothermal fluids. Thin-walled applications will be limited by the susceptibility of these materials to localized attack, such as pitting and crevice corrosion. High-salinity geothermal fluids will cause high uniform corrosion as well as localized corrosion and will severely limit the use of carbon steels. The application of mild steels to geothermal environments requires that precautions be taken for aeration, flow rate, scaling, galvanic coupling, protection of exterior surfaces and steel specifications.

Aeration. Acceptable uniform corrosion rates of carbon steels in fluids containing <10,000 ppm chloride ion are due mainly to the reducing, oxygen-free nature of the fluids. The introduction of small quantities of oxygen can increase uniform corrosion by at least tenfold and initiate pitting and crevice corrosion.

The effect of oxygen on the corrosion of a mild steel is shown in Figure 27 for an otherwise nearly gas-free seawater stream. The same effect occurs in geothermal systems. The solubility of oxygen in saline fluids decreases with increasing temperature up to 212°F (100°C), at which point it increases again (Cramer, 1974). The electrochemical reaction rate increases with temperature.

Aeration damage during plant operation should be minimized by guarding against leaks in the lower-temperature vacuum sections of the plant. The highest potential for serious damage from aeration occurs due to inleakage during plant outages or layups. Stagnant conditions are conducive to crevice and pitting corrosion promoted by oxygen. Oxidation of ferrous ions and H_2S in the geothermal fluid can produce ferric ions and local acidity, which accelerate attack. Procedures for avoiding damage during shutdowns include draining and rinsing equipment and purging with an inert gas. Oxygen scavengers might be applicable, but possible side reactions with species in the specific fluid should be evaluated.

Flow rate. The best performance of carbon steels occurs when liquid flow rates are limited to 5-7 ft/sec (1.5-2.1 m/s). Localized, uncontrolled flashing in geothermal streams can cause high flow rates in the system. This action can produce bubbles of noncondensable gas which can cause impingement attack. Entrained solids in the stream can cause erosion-assisted corrosion. The relative hardness of particle and metal has little effect on this type of corrosion.

Failure of components, such as pipe elbows, has occurred in fluids as diverse as those at Salton Sea and Raft River. These failures are probably caused by the flow conditions noted above.

TABLE 6

Forms and causes of corrosion for metals in liquid geothermal streams and ways to prevent attack.

Material	Major Forms of Corrosion	Main Environmental Factors	Limits and Precautions	Other Comments
<u>Mild & Low Alloy Steels</u>	uniform	pH chloride	Rapid rate Increase below pH 6 Rapid rate Increase above 2% Cl^-	Air In-leakage is a major hazard; local flashing in pipes can cause very high flowrates and erosion/corrosion
	pitting, crevice	flow velocity	Limit flow to 5-7 fps (1.5-2.1 m/s)	Avoid direct impingement on steel
		temperature chloride	Susceptibility increases with increasing temperature and chloride concentration	Avoid mechanical crevices
		scale	Remove mill scale; avoid deposits	
	sulfide stress cracking	H_2S	Can occur at very low H_2S levels	Complex Interactions
		yield strength (hardness) temperature	Use low strength material wherever possible ($R_c < 22$ g YS $< 100,000$ psi) Hazard greater at lower temperatures	
	hydrogen blistering	H_2S	Use void-free materials	Possible at very low H_2S concentrations
	galvanic coupling	electrical contact with more noble metal	Avoid coupling close to large area of cathodic metal	More severe when material has porous coating or scale
<u>Stainless Steels</u> ferritic alloys	pitting, crevice	chloride	In general, susceptibility increases with increasing concentration and temperature	Lower alloys may also have high uniform rates in severe environments; O_2 is a hazard. Higher alloys are much more resistant; Cr and Mo most effective alloying agents
		scale	Avoid scale deposits	
		stagnant or low flow oxygen	Avoid stagnant or low flow conditions O_2 greatly increases susceptibility	

(continued)

TABLE 6 (continued)

Forms and causes of corrosion for metals in liquid geothermal streams and ways to prevent attack.

<u>Material</u>	<u>Major Forms of Corrosion</u>	<u>Main Environmental Factors</u>	<u>Limits and Precautions</u>	<u>Other Comments</u>
austenitic alloys	Intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures	
	stress corrosion cracking	chloride oxygen temperature	Complex interaction; depending on other factors, cracking can occur for $\text{Cl}^- > 5\text{ppm}$; O_2 100 ppb; $T > 140^\circ\text{F}$ (60°C)	Hazard increases with increase in Cl^- , O_2 , T; some alloys more resistant; protect exterior surfaces
	pitting, crevice	chloride temperature	See ferritics above	Resistance increases with Mo content; avoid mechanical crevices
		scale	Avoid scale deposits	
		stagnant or low flow	Avoid stagnation or low flow conditions	
martensitic alloys		oxygen	O_2 greatly increases susceptibility	
	Intergranular	chloride, temperature	Avoid by proper welding and heat treating procedures	
	as above	as above	As above	
cast alloys	sulfide stress cracking	H_2S , temperature, stress, hardness	More severe at lower temperatures; use low strength levels where possible	General corrosion resistance depends on composition
	as above			See comments for equivalent wrought alloy; good crevice corrosion resistance needed for pumps and valves
<u>Titanium Alloys</u>	crevice, pitting	chloride temperature pH	Maximum temperature for resistance depends on chloride and pH	Several alloys have much better resistance than pure Ti. Pre-cracked Ti may undergo stress corrosion cracking

(continued)

TABLE 6 (continued)

Forms and causes of corrosion for metals in liquid geothermal streams and ways to prevent attack.

<u>Material</u>	<u>Major Forms of Corrosion</u>	<u>Main Environmental Factors</u>	<u>Limits and Precautions</u>	<u>Other Comments</u>
	galvanic coupling	electrical contact with more active metal	Coupling to large area of more active metal may cause hydrogen embrittlement of Ti	
<u>Nickel Alloys</u>	crevice, pitting	chloride, temperature	Similar to stainless steels except higher alloys more resistant to crevice corrosion; high flow rates	Resistance depends on alloy composition. May be susceptible to hydrogen embrittlement when coupled to steel
<u>Copper Alloys</u>	pitting, uniform, de-alloying	H ₂ S chloride, temperature, CO ₂	H ₂ S as low as 0.1 ppm can cause attack	Usefulness limited in H ₂ S environment
	stress corrosion cracking	ammonia, pH		
<u>Other Metals</u>				
cobalt alloys			Avoid galvanic coupling to steel or other active metal	Several alloys have good sulfide stress cracking resistance at high strength
zirconium & tantalum				Resistant to low pH, not chloride solution
aluminum	pitting, crevice	Hg and Cu ions, pH, chloride, temperature, lack of oxygen	Poor results obtained in geothermal tests	May be useful as exterior siding and construction material

FIGURE 27. Effect of oxygen on uniform-corrosion rate of 1010 mild steel in 250°F (121°C) seawater (based on data presented in George, 1975).

Designs to avoid direct impingement on carbon steels and localized flashing should alleviate these types of failures. Providing liquid buffer zones may help. Pump impellers, especially for downhole applications, may be subject to severe cavitation damage. The CO₂ content of many geothermal fluids can cause an apparent vapor pressure that exceeds steam-table values by tens to hundreds of psi (100's to 1000's kPa). Caution in design and material selection is required.

Effects of high velocities are illustrated in Figure 28 for seawater at 250°F (121°C).

Scaling. Some mechanical protection against uniform corrosion may result from scales formed on steel by precipitation from geothermal fluids, but localized corrosion can also occur under the scales. Scales in geothermal systems are porous and prone to cracking by differential thermal expansion. The exposure of the base metal to a geothermal fluid can lead to local acid-

FIGURE 28. Weight-loss corrosion rates of mild steel in high-velocity, high-temperature oxygen-free seawater (based on data presented in George, 1975).

ity and high chloride concentration similar to conditions during crevice corrosion. Accelerated attack by H_2S is increased in acidic environments such as this.

Attack at small exposed areas can become more serious if the steel is galvanically coupled to a more noble metal. In extreme cases, this concentration of the corrosion-steel dissolution current can cause perforation of thick-walled steel components in a very short time.

Chemical cleaning solutions used to remove scale should be evaluated carefully since some types (such as inhibited HCl) accelerate corrosion of mild steel. Severe attack can occur if aggressive cleaning solution is trapped in or under incompletely removed scale.

Stainless steels. The uniform-corrosion rate of most stainless steels is low in geothermal fluids, but many are subject to the more serious forms of corrosion: pitting, crevice corrosion, stress-corrosion cracking, sulfide-stress cracking, intergranular corrosion and corrosion fatigue. Stainless steels have been used successfully in geothermal environments, but care must be taken in their selection and application.

1. Aeration.

Many stainless steels that could perform well in oxygen-free geothermal environments can be subject to severe pitting and crevice corrosion in the presence of small quantities (low ppb concentrations) of oxygen. Stress-corrosion cracking of commonly used austenitic stainless steels in high-temperature chloride solutions can occur minutes after introducing oxygen in ppm quantities or less. This failure is often catastrophic. Other alloys are more resistant. Pits, crevice attack or cracks initiated during upset or plant-outage conditions can continue to grow once normal operation is resumed. Special care should be taken during plant commissioning due to the likelihood of unstable conditions.

2. Flow rate.

Stainless steels are more resistant to high velocities than plain and low-alloy steels. Continuous high-velocity flow is more desirable than low-flow rates or stagnant conditions. Under stagnant conditions, settling of entrained solids or spot deposition of loose scale can lead to crevice corrosion. Stagnant conditions should be avoided, and stainless components should be drained and rinsed during plant shutdown. Resistance to erosion-corrosion is more closely related to general corrosion resistance than hardness of the metal.

3. Scale.

Local concentration cells can develop under porous or cracked scale on stainless steel and lead to crevice corrosion to which many stainless steels are susceptible. After an attack is initiated, local increases in acidity and chloride concentration cause intense corrosion.

4. Welding.

Good welding procedures are important to the successful application of stainless steels. Physically poor welds may have crevices that are susceptible to crevice corrosion. Stress-corrosion cracking may initiate at pits close to poor welds. Sensitization of base metal during welding will cause rapid failure.

5. Exterior surfaces.

Measures should be taken to protect the exterior of stainless-steel components that are exposed to air. Leaks and splashes of hot chloride solutions combined with the high oxygen content of air can subject these components to stress-corrosion cracking conditions. Flange leaks leading to conditions in which geothermal fluid concentrates and dries under insulation can be dangerous. Non-porous gaskets are required to guard against cracking at flanges.

Titanium and titanium alloys. Titanium and its alloys have given good results in all but the most extreme environments when tested for geothermal applications. Titanium was used successfully for hydrogen and oil coolers exposed to aerated cooling water/condensate at the Cerro

Prieto geothermal facility (Geothermal Resources Council, 1976). Two other heat exchanger materials had failed in this environment.

Nickel-based alloys. High nickel alloys are frequently used to combat severe corrosion problems. The Ni-Cr-Mo alloys appear to be the most applicable to high-temperature geothermal fluids. Similar alloys containing iron in place of molybdenum face competition from the most resistant stainless steels, but may find application where their mechanical properties are desirable. Cupronickels will have limited usefulness in geothermal streams containing even trace (ppb) quantities of H_2S .

Aluminum alloys. Aluminum alloys have not shown good resistance in tests conducted in direct contact with geothermal fluids. Low levels of transition metal ions, especially copper and mercury, greatly increase localized attack of aluminum alloys. These ions are present in most liquid-dominated geothermal fluids. Aluminum alloys have also given poor results in geothermal-condensate cooling-water systems.

Copper-based alloys. The use of copper alloys in geothermal fluids is severely limited by the relatively high concentrations of sulfide found in most sources. The Raft River KGRA, with a low sulfide concentration of 0.1 ppm, appears to be an exceptional case. Even in this fluid, the performance of copper-nickel alloys (Monel 400, 70Cu/30Ni and 90Cu/10Ni) was very poor. De-alloying of some copper alloys was observed. However, some nickel-free brasses and bronzes gave acceptable performance (Miller, 1975).

Scaling

Scaling results from two sources: deposition of minerals from the fluid as a result of supersaturation and scales that result from accumulation of corrosion products. Either of these scales reduce the efficiency of the system by increasing the resistance to heat transfer and fluid flow. Such scales often promote localized corrosion.

Deposition of scales from solution. The minerals most frequently deposited from geothermal fluids are calcium carbonate (usually calcite) and silica. To a lesser extent, calcium sulfate (gypsum, anhydrite, selinite) may be deposited. Some geothermal wells carry high concentrations of heavy metals and sulfides; these fluids may yield sulfides of copper, lead, silver, etc., in addition to silica or carbonate scales.

Both calcium carbonate and calcium sulfate exhibit retrograde solubility (solubility is a strong function of pH and carbon dioxide concentration) and are related by several equilibria.

Because the solubility of calcium carbonate increases with decreasing temperatures and is pH-dependent, no deposition will occur if the partial pressure of CO_2 is maintained at a level equal to downhole level.

As pH is decreased, the solubility of the calcite increases; however, many materials are degraded as hydrogen-ion concentrations increase. The presence of calcite scales frequently

results in decreased corrosion by interfering with the diffusion of corrodants to the metallic surface. For this reason, calcite scales may be grown to controlled thickness as a general corrosion-control measure.

Calcium sulfate solubility is given by

The solubility product constant is

$$K_{sp} = [\text{Ca}^{2+}] [\text{SO}_4^{2-}]$$

When concentrations are expressed in mg/kg of fluid (ppm) the K_{sp} is reached at about 400,000. Geothermal fluids having a concentration product in this range or higher should be viewed as having a tendency towards calcium sulfate deposition.

The solubility of silica (SiO_2) is dependent on the form of the deposit. Amorphous silica has a much higher solubility than quartz, the familiar crystalline form. The usual assumption is that the geothermal fluid is in equilibrium with amorphous silica in above-ground environments and with quartz in the geological formation.

If the concentration of silica in the water is known, the temperature below which precipitation of amorphous silica can occur (from data in GRC, 1976) is given by

$$t = \frac{1531.98}{10.064 - \ln \text{SiO}_2} - 273.16$$

where

t = temperature °C

$\ln \text{SiO}_2$ = natural log of silica concentration in ppm.

If only the reservoir temperature is known, the amount of silica in the water assuming equilibrium with quartz is given by (Ellis and Mahon, 1977)

$$\ln \text{SiO}_2 = \frac{13.281 - 3531}{t + 273.16}$$

where

t and $\ln \text{SiO}_2$ are defined as above.

This value can also be substituted into the previous equation to find the temperature below which amorphous silica scaling is possible.

The rate of scale deposition is critically dependent upon the material being deposited. Silica deposition is very slow, often requiring several hours or days for equilibrium to be established. Calcite deposition is very rapid and its equilibria are achieved in short time periods, frequently milliseconds. Calcium sulfate deposition lies between these extremes.

Corrosion-product scales. Corrosion products may form a coherent scale on the substrate metal. In the case of plain carbon and low-alloy steels in geothermal fluids, the primary corrosion products are iron oxides, hydrous iron oxides, iron silicate and iron sulfides. The very

low solubility of these in the fluid results in solid corrosion products. These oxides, silicates and sulfides tend to form and grow on the substrate metal. Other corrosion products, such as metal chlorides that form in pits and crevices, are more likely to leave the reaction site. Copper and copper-base alloys, including combinations of copper and nickel, tend to react with the sulfides in the geothermal fluids to form copper sulfides, nickel sulfides and copper-nickel sulfides. These sulfides tend to form on the metal. Zinc and aluminum in brasses form relatively soluble corrosion products and are not, typically, found in association with the sulfides.

Corrosion-product scales usually exhibit lower heat-transfer properties than the metals from which they are formed. These scales also are rougher than the substrate metal. Both of these factors result in lower efficiencies that require, for example, larger heat exchangers and pumps. However, these scales do form a barrier between the fluid and the metal and may provide some general corrosion protection to the metal. In some cases, the corrosion-product scales contain cracks and/or small holes that permit localized corrosion in the form of crevice corrosion and pitting. The corrosion scales cannot be relied on for corrosion protection.

Control of corrosion-product scales is best achieved through materials selection because of the limited economic and environmental applicability of corrosion inhibitors. Care must be exercised in materials selection because some metals depend on a stable corrosion-product film for general corrosion resistance. Aluminum is one such material. The stable aluminum oxide protects the relatively reactive aluminum metal from the aggressive water. Geothermal fluids are reducing and this may retard repair of damaged film sites on the aluminum, resulting in rapid localized corrosion of the metal. Reduceable metal ions, such as copper and mercury, may also cause rapid corrosion of aluminum. Desalination environments, on the other hand, are oxidizing, and aluminum finds application in this type of service.

Many consider seawater experience to be directly transferrable to geothermal situations. However, seawater is usually free of sulfides and, in near surface sources, nearly saturated with air. Copper/nickel alloys are used extensively in seawater applications and are frequently the materials of choice. The hydrogen sulfide present in geothermal fluids, however, rapidly degrades copper and copper alloys containing nickel. These two examples suggest that care must be exercised when using data from either seawater or desalination service for materials selection for geothermal environments. Subtle differences in geothermal-fluid chemistry frequently result in the use of a heat exchanger and a "clean" secondary fluid for many heating applications.

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Appendix A

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr (10 ¹² KJ/Yr)	
<u>Group 10</u>				
1. Copper Concentrate - 1021 Drying	250*	(121)	1.7	(1.8)
<u>Group 12</u>				
2. Bituminous Coal - 1211 Drying (including lignite)	150-250*	(66-104)	18.0	(19.0)
<u>Group 14</u>				
3. Potash - 1474 Drying Filter Cake	250*	(121)	1.03	(1.09)
<u>Group 20 - Food & Kindred Products</u>				
4. Meat Packing - 2011 Sausages and Prepared Meats - 2013 Scalding, Carcass Wash and Cleanup	140	(60)	43.7	(46.1)
Edible Rendering	200	(93)	0.52	(0.55)
Smoking/Cooking	155	(68)	1.16	(1.22)
5. Poultry Dressing - 2016 Scalding	140	(60)	3.16	(3.33)
6. Natural Cheese - 2022 Pasteurization	170	(77)	1.28	(1.35)
Starter Vat	135	(57)	0.02	(0.02)
Make Vat	105	(41)	0.47	(0.50)
Finish Vat	100	(38)	0.02	(0.02)
Whey Condensing	160-200	(71-93)	10.2	(10.8)
Process Cheese Blending	165	(74)	0.07	(0.07)
7. Condensed and Evaporated Milk - 2023 Stabilization	200-212	(93-100)	2.93	(3.09)
Evaporation	160	(71)	5.20	(5.48)
Sterilization	250	(121)	0.54	(0.57)
8. Fluid Milk - 2026 Pasteurization	162-170	(72-77)	1.44	(1.52)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr (10 ¹² KJ/YR)	
9. Canned Specialties - 2032				
Beans				
Precook (Blanch)	180-212	(82-100)	0.40	(0.42)
Simmer Blend	170-212	(77-100)	0.24	(0.25)
Sauce Heating	190	(88)	0.20	(0.21)
Processing	250	(121)	0.38	(0.40)
10. Canned Fruits and Vegetables - 2033				
Blanching/Peeling	180-212	(82-100)	1.88	(1.98)
Pasteurization	200	(93)	0.15	(0.16)
Brine Syrup Heating	200	(93)	1.02	(1.08)
Commercial Sterilization	212-250	(100-121)	1.67	(1.76)
Sauce Concentration	212	(100)	0.44	(0.46)
11. Dehydrated Fruits and Vegetables - 2034				
Fruit & Vegetable Drying	165-185	(74-85)	5.84	(6.16)
Potatoes				
Peeling	212	(100)	0.33	(0.35)
Precook	160	(71)	0.47	(0.50)
Cook	212	(100)	0.47	(0.50)
12. Frozen Fruits and Vegetables - 2037				
Citrus Juice Concentration	190	(88)	1.33	(1.40)
Juice Pasteurization	200	(93)	0.27	(0.28)
Blanching	180-212	(82-100)	2.26	(2.38)
Cooking	170-212	(77-100)	1.41	(1.49)
13. Wet Corn Milling - 2046				
Starch Dryer	120*	(49)	3.03	(3.20)
Steepwater Heater	120	(49)	0.77	(0.81)
Sugar Hydrolysis	270	(132)	1.89	(1.99)
Sugar Evaporator	250	(121)	2.74	(2.89)
Sugar Dryer	120*	(49)	0.16	(0.17)
14. Prepared Feeds - 2048				
Pellet Conditioning	180-190	(82-88)	2.28	(2.40)
15. Bread and Baked Goods - 2051				
Proofing	100	(38)	0.84	(0.89)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr	(10 ¹² KJ/YR)
16. Cane Sugar - 2062				
Mingler	125-165	(52-74)	0.59	(0.62)
Melter	185-195	(85-91)	3.30	(3.48)
Defecation	160-185	(71-85)	0.44	(0.46)
Granulator	110-130	(43-54)	0.44	(0.46)
Evaporator	265	(129)	26.39	(27.84)
17. Beet Sugar - 2063				
Extraction	140-185	(60-85)	4.63	(4.88)
Thin Juice Heating	185	(85)	3.08	(3.25)
Thin Syrup Heating	212	(100)	6.68	(7.05)
Evaporation	270-280*	(132-138)	30.8	(32.5)
Granulator	150-200	(66-93)	0.15	(0.16)
Pulp Dryer	230-280*	(110-138)	16.5	(17.4)
18. Soybean Oil Mills - 2075				
Bean Drying	160	(71)	4.05	(4.27)
Toaster Desolventizer	215	(102)	6.08	(6.41)
Meal Dryer	300*	(149)	4.36	(4.60)
Evaporator	225	(107)	1.62	(1.71)
Stripper	212	(100)	0.30	(0.32)
19. Shortening & Cooking Oil - 2079				
Oil Heater	160-180	(71-82)	0.72	(0.76)
Wash Water	160-180	(71-82)	0.12	(0.13)
Dryer Preheat	200-270	(93-132)	0.60	(0.63)
Cooking Oil Reheat	200	(93)	0.32	(0.34)
Hydrogenation Preheat	300	(149)	0.37	(0.39)
20. Malt Beverages - 2082				
Cooker	212	(100)	1.53	(1.61)
Water Heater	180	(82)	0.53	(0.56)
Mash Tub	170	(77)	0.60	(0.63)
Grain Dryer	300*	(149)	9.18	(9.68)
Brew Kettle	212	(100)	3.98	(4.20)
21. Distilled Liquor - 2085				
Cooking (Whiskey)	212	(100)	3.16	(3.33)
Cooking (Spirits)	320	(160)	6.27	(6.61)
Evaporation	250-290*	(121-143)	2.32	(2.45)
Dryer (Grain)	300	(149)	1.94	(2.05)
Distillation	230-250	(110-121)	7.69	(8.11)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr	(10 ¹² KJ/YR)
22. Soft Drinks - 2086				
Bulk Container Washing	170	(77)	0.21	(0.22)
Returnable Bottle Washing	170	(77)	1.27	(1.34)
Nonreturnable Bottle Warming	75-85	(24-29)	0.43	(0.45)
Can Warming	75-85	(24-29)	0.52	(0.55)
Group 21 - Tobacco				
23. Cigarettes - 2111				
Drying	220*	(104)	0.43	(0.45)
Rehumidification	220*	(104)	0.43	(0.45)
24. Tobacco Stemming & Redrying - 2141				
Drying	220*	(104)	0.50	(0.26)
Group 22 - Textile Mill Products				
25. Finishing Plants, Cotton - 2261				
Washing	200	(100)	15.4	(16.2)
Dyeing	200	(100)	4.5	(4.7)
Drying	275	(135)	22.2	(23.4)
26. Finishing Plants, Synthetic - 2262				
Washing	200	(93)	35.9	(37.9)
Dyeing	212	(100)	15.2	
Drying & Heat Setting	<275	(135)	23.2	(24.5)
Group 24 - Lumber				
27. Sawmills & Planing Mills - 2421				
Kiln Drying of Lumber	200*	(100)	63.4	(66.9)
28. Plywood - 2435				
Plywood Drying	250	(121)	50.6	(53.4)
29. Veneer - 2436				
Veneer Drying	212	(100)	57.8	(61.0)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr	(10 ¹² KJ/YR)
<u>Group 25 - Furniture</u>				
30. Wooden Furniture - 2511				
Makeup Air & Ventilation	70	(21)	5.7	(6.0)
Kiln Dryer & Drying Oven	150	(66)	3.8	(4.0)
31. Upholstered Furniture - 2512				
Makeup Air & Ventilation	70	(21)	1.4	(1.5)
Kiln Dryer & Drying Oven	150	(66)	0.9	(0.9)
<u>Group 26 - Paper</u>				
32. Pulp Mills - 2611				
Paper Mills - 2621				
Paperboard Mills - 2631				
Building Paper - 2661				
Pulp Refining	150	(66)	175	(185)
Black Liquor Treatment	280	(138)	164	(173)
Pulp & Paper Drying	290	(143)	383	(404)
<u>Group 28 - Chemical</u>				
33. Cyclic Intermediates - 2865				
Styrene	250-300	(121-149)	35.0	(37.0)
Phenol	250	(121)	0.45	(0.47)
34. Alumina - 28195				
Digesting, Drying, Heating	280	(138)	113.2	(119.4)
35. Plastic Materials & Resins - 2821				
Polystyrene, suspension process				
Polymerizer Preheat	200-215	(93-102)	0.102	(0.107)
Heating Wash Water	190-200	(88-93)	0.067	(0.068)
36. Synthetic Rubber - 2822				
Cold SBR Latex Crumb				
Bulk Storage	80-100	(27-38)	0.179	(0.189)
Emulsification	80-100	(27-38)	0.086	(0.091)
Blowdown Vessels	130-145	(54-63)	0.865	(0.912)
Monomer Recovery by Flashing & Stripping	120-140	(49-60)	4.095	(4.319)

(continued on next page)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr (10 ¹² KJ/YR)	
36. Synthetic Rubber - 2822 (continued)				
Dryer Air Temperature	150-200	(66-93)	3.663	(3.864)
Cold SBR, Oil-Carbon Black Masterbatch				
Dryer Air Temperature	150-200	(66-93)	0.506	(0.534)
Oil Emulsion Holding Tank	80-100	(27-38)	0.090	(0.095)
Cold SBR, Oil Masterbatch				
Dryer Air Temperature	150-200	(66-93)	1.09	(1.15)
Oil Emulsion Holding Tank	80-100	(27-38)	0.090	(0.095)
37. Cellulosic Man-made Fibers - 2823				
Acrylic	<250	(<121)	23.5	(24.8)
38. Noncellulosic Fibers - 2824				
Rayon	<12	(<100)	37.8	(39.9)
Acetate	<12	(<100)	37.6	(39.7)
39. Pharmaceutical Preparations - 2834				
Autoclaving & Cleanup	250	(121)	18.85	(19.88)
Tablet & Dry-Capsule Drying	250	(121)	1.00	(1.05)
Wet Capsule Formation	150	(66)	0.05	(0.05)
40. Soaps & Detergents - 2841				
Soaps				
Various Processes in Soap Manufacture	180	(82)	0.50	(0.53)
Detergents				
Various Low-Temperature Processes	180	(82)	0.36	(0.38)
41. Organic Chemicals, N.E.C. - 2869				
Ethanol	200-250	(93-121)	6.0	(6.0)
Isopropanol	200-300	(93-149)	11.0	(12.0)
Cumene	250	(121)	1.0	(1.0)
Vinyl Chloride Monomer	250-300	(121-149)	9.0	(9.0)
42. Urea - 2873215				
Low-Pressure Steam-Heated Stripper	290	(143)	0.89	(0.94)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr (10 ¹² KJ/YR)	
43. Explosives - 2892				
Dope (Inert Ingredients)				
Drying	300	(149)	0.006	(0.006)
Wax Melting	200	(93)	0.118	(0.12)
Nitric Acid Concentrator	250	(121)	0.070	(0.07)
Sulfuric Acid Concentrator	200	(93)	0.027	(0.02)
Nitric Acid Plant	200	(93)	0.223	(0.23)
Blasting Cap Manufacture	200	(93)	0.016	(0.01)
Group 29 - Petroleum				
44. Petroleum Refining - 2911				
Alkylation	45-300	(7-149)	59	(62)
Butadiene	250-300	(121-149)	60	(63)
45. Paving Mixtures - 2951				
Aggregate Drying	275-300*	(135-149)	88.1	(92.9)
Group 30 - Rubber				
46. Tires & Inner Tubes - 3011				
Vulcanization	250-300	(121-149)	6.18	(6.52)
Group 31 - Leather				
47. Leather Tanning & Finishing - 3111				
Bating	90	(32)	0.094	(0.099)
Chrome Tanning	85-130	(29-54)	0.060	(0.063)
Retan, Dyeing, Fat Liquor	120-140	(49-60)	0.15	(0.16)
Wash	120	(49)	0.034	(0.036)
Drying	110*	(43)	2.05	(2.16)
Finish Drying	110*	(43)	0.13	(0.14)
Group 32 - Stone, Clay, Glass & Concrete Products				
48. Hydraulic Cement - 3241				
Drying	275-300*	(135-149)	8.0	(8.0)
49. Concrete Block - 3271				
Low-Pressure Curing	165*	(74)	12.29	(12.96)

Appendix A (continued)

Industrial Process Heat Requirements at Temperatures 300°F (149°C) and Below

Industry - SIC Group	Application Temperature Requirement		Process Heat Used for Application	
	°F	(°C)	10 ¹² BTU/Yr (10 ¹² KJ/YR)	
50. Ready-Mix Concrete - 3273				
Hot Water for Mixing Concrete	120-190	(49-88)	0.34	(0.36)
51. Gypsum - 3275				
Wallboard Drying	300	(149)	11.18	(11.79)
52. Treated Minerals - 3295				
Kaolin				
Drying	230*	(110)	12.7	(13.4)
Expanded Perlite				
Drying	160*	(71)	0.22	(0.23)
Barium				
Drying	230*	(110)	0.34	(0.36)
<u>Group 33 - Primary Metals</u>				
53. Ferrous Castings				
Gray Iron Foundries - 3321				
Malleable Iron Foundries - 3322				
Steel Foundries - 3323				
Pickling	100-212	(38-100)	151	(160)
<u>Group 34 - Fabricated Metal Products</u>				
54. Galvanizing - 3479				
Cleaning, Pickling	130-190	(54-88)	0.011	(0.012)
<u>Group 36 - Electrical Machinery</u>				
55. Motor & Generators - 3621				
Drying & Preheat	150	(66)	0.043	(0.045)
Baking	300	(149)	0.133	(0.140)
<u>Group 37 - Transportation Equipment</u>				
56. Motor Vehicles - 3711				
Baking-Prime & Paint Ovens	250-300	(121-149)	0.29	(0.31)

Note: SIC Groups 34, 35, 36, 37 utilize hot water for parts degreasing and washing in application temperatures of 80-180°F (27-82°C); total process heat used is not currently available.

*No special temperature required; requirement is simply to evaporate water or to dry the material.

CHAPTER 5
ECONOMICS OF DIRECT-USE DEVELOPMENT

Work Group

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INTRODUCTION

This chapter addresses itself to the economic evaluation of direct-use geothermal energy for space heating and for those businesses and industries that are known to be profitable and use conventional forms of energy. In this context, the economic feasibility of direct-use geothermal energy is a matter of determining the reduced costs of this alternative energy system as compared to the capital investment required for the system.

There are several elements which must be considered when determining the feasibility of direct-use geothermal energy:

1. The geologic parameters of the resource.
2. The engineering criteria or the technical viability of the project.
3. The economics of the venture, i.e., will the annual savings provide sufficient return to the investor to justify the capital expenditure?

Many knowledgeable entrepreneurs typically give careful attention to geologic and engineering detail, but fail to give proper consideration to the economic analysis of their project.

Economic evaluation or cost analysis comprises a myriad of variables but can be treated in a relatively simple manner. The analysis should constitute a carefully planned, dispassionate review of all available information to determine the probable value of the proposal. Primary consideration should be given to the cost of finding, developing and utilizing the geothermal resource. Often the preliminary estimates are unreliable due to a lack of historically accurate data. Nevertheless, this cost analysis should be made, since the objective is whether or not the project is worthy of consideration. At its very worst, such an evaluation is better than intuition.

Although there are many approaches to economic evaluation, a rather simple step-by-step procedure is as follows:¹

1. Collect historical cost of conventional fuel-use data. If there are no historical data available, estimate the heat load and current cost of conventional fuel.
2. Determine inflation rates for energy and operation and maintenance costs.
3. Estimate costs of geothermal equipment and installation.
4. Estimate annual operation and maintenance costs of both conventional and geothermal operation.
5. Consider effect of investment tax credit, depreciation and depletion allowance where applicable.

This chapter presents a hypothetical example of direct-use geothermal energy, modeled closely after an actual case. This example will serve to illustrate the parameters of a comprehensive economic evaluation. The discussion begins with a simple evaluation, progresses in complexity through extensive cost estimates and concludes with a more comprehensive, after-tax evaluation. The cost estimates used in this example are for Klamath Falls, Oregon, in terms of 1979 dollars.

¹ Assumes that the resource has been discovered.

COLLECTION OF HISTORICAL FUEL-USE DATA

For this hypothetical economic analysis, a city located near a known geothermal resource area (KGRA) wishes to develop a geothermal district-heating system for a ten-block business district. The first step would be to obtain a history of fuel consumption and costs over the previous three to five years. This data collection should include monthly fuel bills, type of fuel used, amount of consumption in Btu's, kilowatt-hours, therms or gallons, etc., and type of existing heating system in each building scheduled to use geothermal.

For this study, let us assume that the entire district uses natural gas at 85% efficiency with an annual heat load of 6.0×10^{10} Btu's (6.3×10^{10} kJ) and a current cost of \$0.35 per therm (1 therm = 10^5 Btu's; \$0.33 per 10^5 kJ). Therefore, at 85% efficiency, annual gas consumption for this district is approximately 7.06×10^5 therms. At the current rate of \$0.35 per therm (\$0.33 per 10^5 kJ) for natural gas, the annual cost of heating this district is \$247,100. The city plans to finance the geothermal project with an 8% municipal bond maturing in 20 years. Based on current costs, a 20-year life and an 8% cost of capital, we can now estimate the amount of capital the city can afford to invest in order to avoid these annual cash flows of \$247,100. For this estimate, we will use the same formula as that used to calculate the pay-off of a loan, given the amount and number of payments remaining: \$247,100 per year for 20 years.

$$\text{Formula: } PV = a \frac{(1 + i)^n - 1}{i(1 + i)^n}$$

Where PV = present value

a = annual payment

i = interest rate per year

n = number of years of payments

$$\text{Therefore: } PV = \$247,100 \frac{(1 + .08)^{20} - 1}{.08(1 + .08)^{20}}$$

$$PV = \$2,426,064$$

This figure represents the total amount of capital investment that could be made today to avoid a series of annual expenses of \$247,100 over a 20-year period. Of course, the annual operation and maintenance costs of the geothermal system have not yet been taken into account. Suppose that annual operation and maintenance costs were estimated to be \$10,000 per year. Then the annual savings would be \$247,100 - \$10,000 or \$237,100, resulting in $PV = \$2,327,883$, which is the maximum capital investment that could be spent today for the geothermal system.

This cursory analysis could very well indicate that the project is not economically feasible, and a more detailed study, using inflation rates of conventional energy, is required.

DETERMINATION OF INFLATION RATES

In order to reasonably project inflation rates, it is necessary to review the historical data regarding conventional fuel consumption and costs. Our data show that the city was paying \$0.175 per therm (\$0.166 per 10^5 kJ) for natural gas in 1976 and \$0.35 per therm (\$0.33 per 10^5 kJ) in 1979. Therefore, we need to consider this rapid escalation of natural gas prices. Using the single-payment compound-amount factor, we can identify \$0.175 as present value, \$0.35 as a future value and solve for the rate of inflation as follows:

Formula: $FV = PV (1 + i)^n$

Where FV = present rate

PV = past rate

i = inflation rate per year

n = number of years between rate change

Therefore: $.35 = 175 (1 + i)^3$

$$\frac{.35}{.175} = (1 + i)^3$$

$$2 = (1 + i)^3$$

$$\sqrt[3]{2} = 1 + i$$

$$1.2599 = 1 + i$$

$$i = 1.2599 - 1$$

$$i = .2599 \text{ or approx } 26\% \text{ Inflation/yr}$$

A word of caution: It would be dangerous to assume that this rate of inflation, based on a three-year study, would continue over the next 20 years. Exaggerated inflation rates will cause projects to appear economically feasible at one date, but the same project might be uneconomical if rates of inflation were lower. Therefore, it is better to use conservative inflation rates in determining the economic feasibility of a project. If actual fossil-fuel inflation rates prove to be higher than those forecast, the geothermal project will have an even larger advantage economically. The following conservative inflation rates for conventional fuels were obtained from the Oregon Department of Energy:

1. Natural gas - 5.2% above the economic inflation rate through 1986;
1.5% above the economic inflation rate thereafter.
2. Electric power - 2.5% above the economic inflation rate through 1986;
1.58% above the economic inflation rate thereafter.

The economic inflation rate chosen for this case study is 7% per annum. Therefore, inflation rates for natural gas would be 12.2%, changing to 8.5% in 1987. With this rate of inflation, the 20-year cash flow of natural gas costs would appear as follows in Table 1:

TABLE 1
20-YEAR CASH FLOW OF NATURAL GAS COSTS OF THE
KLAMATH FALLS PROJECT

Year	NATURAL GAS Annual Cost	PRESENT WORTH (For an 8% cost of capital)
	\$ 247,100.00	8%
1	277,246.20	256,709.44
2	311,070.24	266,692.59
3	349,020.81	277,063.97
4	391,601.34	287,838.68
5	439,376.71	299,032.40
6	492,980.67	310,661.44
7	553,124.31	322,742.72

(continued on next page)

(Table 1, continued)

Year	Annual Cost \$ 247,100.00	PRESENT WORTH (For an 8% cost of capital)
		8%
8	600,139.87	324,236.90
9	651,151.76	325,738.00
10	706,499.66	327,246.04
11	766,552.13	328,761.07
12	831,709.06	330,283.11
13	902,404.34	331,812.20
14	979,108.70	333,348.37
15	1,062,332.94	334,891.65
16	1,152,631.24	336,442.07
17	1,250,604.90	337,999.67
18	1,356,906.32	339,564.49
19	1,472,243.35	341,136.55
20	1,597,384.04	342,715.88
Total:	16,144,088.59	6,354,917.24

Accordingly, the city could spend \$6,354,917 as compared to the \$2,426,064 before considering inflation. Therefore, a project that may have appeared uneconomical initially may be feasible after considering the rapidly rising costs of conventional energy.

ESTIMATION OF COSTS OF GEOTHERMAL EQUIPMENT AND INSTALLATION

At this point, the costs of development of the geothermal resource and the distribution system should be considered. The design of the system and cost estimates should be obtained from a geothermal engineering-consulting firm. Such a firm obtained the following data and completed the feasibility study in the hypothetical model. The system design included: production wells, a primary (main-supply) pipeline, a centralized heat-exchanger system, a secondary (distribution system) pipeline, an injection well and a primary and secondary pumping system. A diagram of the system is shown in Figure 1.

To determine the size of transmission pipelines and the amount of flow required, i.e., the number of wells needed, the data for fuel consumption should be reviewed, paying particular attention to the coldest months of the year, to determine the peak load. This peak should be verified in the engineering design of the system by considering total volume (cubic feet or meters) to be heated, type of buildings, insulation, etc., the minimum outside-design temperature versus the desired inside temperature and the amount of energy that can be extracted from the geothermal resource. Heating systems are normally over-designed by 25 percent. The method of estimating peak load appears in Chapter 4.

Using this approach, the peak load for our ten-block model is estimated to be 27.8×10^6 Btu's per hour (29.3×10^6 kJ/hr = 8.14 MWt). With an assumed well temperature of 200°F (93°C) based on geologic forecasts and tests of existing wells in the area, the heating system will be designed to extract 40°F (22°C; ΔT) from the water pumped from the resource. This would require 1390 gallons per minute (87.7 l/s) flow, calculated as follows:

$$\frac{\text{peak load}}{500 (\Delta T)} = \text{flow rate}$$

where 500 is a constant

$$\text{therefore: } \frac{27.8 \times 10^6}{500 (40)} = 1390 \text{ gpm}$$

$$\frac{(\text{kJ/hr})}{15,200 (\Delta T \text{ } ^\circ\text{C})} = \text{l/s}$$

where 15,200 is a constant

$$\text{therefore: } \frac{29.3 \times 10^6}{15,200 \times 22^\circ\text{C}} = 87.7 \text{ l/s}$$

FIGURE 1. Diagram of the Klamath Falls hypothetical city heating system.

To satisfy the peak load, three production wells, each delivering up to 500 gallons per minute (31.5 l/s), would be required. Water would be delivered to the heat-exchange building by an 8-inch (20 cm) primary transmission line.

In many cases, it is not economical to design a system to satisfy the peak load if this peak load occurs infrequently. When retrofitting geothermal systems to existing conventional fuel systems, it is often more economical to design the geothermal system to handle the major portion of the heat load and supply the peak periods with a centralized conventional fuel-fired boiler. Consideration should be given to a conventional fuel that can be stored, such as coal or heating oil. These fuels would be used during the coldest periods of the year when conventional systems would also be demanding peak load and natural gas and electrical power would be in short supply.

For the heating-district model, three 1000-foot (305-m) production wells are to be drilled at a total cost of \$116,694. The decision to drill the third well was based on the fact that the peak load would require 80% production from the third well and because future plans for the system include expansion to a 54-block area.

Well-drilling costs (up to 3000 feet/depth, 914 m) in the Klamath Basin, using cable or rotary rigs are as follows:

\$1.00 per inch of diameter per foot (\$1.29/cm/m) of depth in "soft" rock;
 \$2.50 per inch of diameter per foot (\$3.23/cm/m) of depth in "hard" rock up to 500 feet (150 m) in depth;
 Every additional 100-foot (30-m) increment adds \$1.00 per foot of depth (\$3.28/m, incremental charges).

Casing costs can be estimated at \$1.05 per inch of diameter per foot of depth (\$1.36/cm/m). Full-depth casing is assumed for all wells. Example:

\$1.05 x 10-inch (25.64-cm) casing x 1 foot (.3 m) of depth = \$10.50/ft (.3 m).

Using the above costs, which include mobilization and demobilization and which consider drilling conditions in the Klamath Basin (i.e., one-third of drilling in "hard" rock), the following drilling costs were developed:

Average Well Costs²

Depth (feet)	100 (30 m)	500 (152 m)	1,000 (305 m)	2,000 (610 m)	3,000 (914 m)
Drilling costs (\$) ³	1,800	9,000	17,000	34,500	51,000
Casing cost (\$)	1,050	5,250	9,450	17,850	24,150
Total cost (\$)	2,850	14,250	26,450	52,350	75,150

Range of Costs²

All "soft" rock (\$)	2,200	11,000	20,500	41,000	59,500
All "hard" rock (\$)	4,000	20,000	37,000	72,500	103,000

² Based on current costs. Costs are expected to rise approximately 10% in the very near future.

³ Does not include costs for drilling mud, additional air compressors if required, foaming agents, etc.

Based on November 1978 costs and on the relative amounts of "hard" and "soft" drilling that are expected in the drilling area, cost of a 1000-foot (305-m) well would be:

0-350 ft	14-in drill	175' (35.6 cm/53 m)	@ \$ 1.00/ft ⁴	= \$2,450
(0-107 m)	14-in drill	175' (35.6 cm/53 m)	@ \$ 2.00/ft ⁴	= 6,125
	10-in I.D. casing	(25.4 cm)	@ \$10.50/ft	= 3,675
350-1000 ft.	12-in drill	238' (30.4 cm/73 m)	@ \$ 1.00/ft ⁴	= \$ 2,856
(107-305 m)	12-in drill	412' (30.4 cm/126 m)	@ \$ 2.50/ft ⁴	= 12,360
	8-in I.D. casing	(20.3 cm)	@ \$ 8.55/ft	= 5,557
Incremental depth charges				= 3,000
One 10-in (25.4 cm) and one 8-in (20.3 cm) casing shoe				= 225
100 sacks cement @ \$10.00/sack				= 1,000
Standby time @ \$350.00/day, 3 days				= 1,050 ⁵
Well completion by air @ \$125.00/hr				= 600
TOTAL				\$38,898

The production well pumps selected for our model are vertical turbine with variable speed fluid drive. These pumps have proven highly successful at Oregon Institute of Technology and Presbyterian Intercommunity Hospital in Klamath Falls. They are capable of maintaining a constant pressure in the supply lines while flow requirements vary from zero to full-flow. Maintenance costs are minimal. Specifications on the well head pumps and cost data are listed below.

Well head pumps

Vertical turbine with variable speed drive:

Rated flow at 1750 RPM	500 gpm	(31.5 l/s)
Column length	350 ft	(107 m)
Column diameter	8 in	(20.3 cm)
Bowl diameter	9-3/4 in	(24.8 cm)
Shaft diameter	1-1/2 in	(3.8 cm)
Number of bowls	11	
Discharge of pressure	20 psi	(138 kPa)
Motor (electric)	75 hp	
Drive - torque converter type 2% slip		
at full load. Rated Capacity	75 hp	
Wire to water efficiency	72%	
Current estimated cost	\$41,488	
Number required	2 ea	

Pump selection is site specific. In those areas where water quality of the resource is more corrosive, the pump costs and maintenance costs will greatly exceed the costs for the Klamath Falls model.

⁴ Per diameter inch (diameter centimeter).

⁵ Standby time accumulated while running logs, 48-hr pump test and miscellaneous delays for testing and logging.

The production well pumps supply fluid to two plate-type heat exchangers, the control system and two circulation pumps housed in a heat-exchanger building. Vertical turbine circulation pumps were chosen over centrifugal pumps due to higher efficiency and lower maintenance costs.

Circulation pumps

Two types of circulation pumps were investigated, vertical turbine and centrifugal. Although initial cost of the centrifugal pumps was lower, the vertical turbine pumps offer the following advantages: better packing life and much less likelihood of air entrainment in the closed-loop system with a resultant decrease in corrosion problems. It is nearly impossible for vertical turbines to allow air in the system since the packing is under positive internal pressure at all times while, under certain low-flow high-speed conditions, centrifugal pump-shaft packings may have negative internal pressure. Vertical turbine pumps also offer higher wire-to-water efficiencies, lower net positive suction-head requirements and flatter operating curves.

Circulation pump comparison:

<u>Vertical turbine</u>	<u>Centrifugal</u>
400 gpm @ 100 psi (25.2 l/s @ 689 kPa)	400 gpm @ 100 psi (25.2 l/s @ 689 kPa)
1750 rpm	3600 rpm
40 hp	40 hp
Wire-to-water efficiency 73%	Wire-to-water efficiency 62%
NPSH ⁶ 7.2 ft (2.2 m)	NPSH 10.2 ft (3.1 m)
Estimated maintenance cost: \$200/yr	Estimated maintenance cost: \$250/yr
Present cost: \$13,691	Present cost: \$12,033

The pumps selected have the following specifications:

Vertical turbine with variable speed drive

Rate flow at 1750 rpm, 100 and 400 gpm (6.3 and 25.2 l/s)

Column length and diameter	none required
Bowl diameter	6-5/8 in (16.8 cm)
Shaft diameter	1 in (2.5 cm)
Number of bowls	4
Discharge pressure	100 psi (689 kPa)
Motor (electric)	40 hp
Drive torque converter type, 2%	
slip at full load. Rated Capacity	50 hp
Wire-to-water efficiency	75%
Current estimated cost	\$13,691
Number required	2 ea

Two plate-type heat exchangers were selected for this application because of their high efficiency, small space requirements and ease of cleaning. The exchangers can operate at the minimum flows required for domestic water heating during summer months and also accept additional plates to handle increased loads while maintaining inlet and outlet temperature as the district is expanded.

The manufacturer based the design of the heat exchangers on engineering specifications for secondary water-flow rate, pressure drop, inlet temperature, outlet temperature, geothermal water-

⁶ Net Positive Suction Head

flow rate, pressure drop and inlet temperature. Geothermal water outlet temperature and exchanger cost are iterated to obtain the most economical exchanger with minimum flow rates. Data on the heat exchangers follow:

Plate heat exchanger general specifications:

Type - Single pass with 150 316 stainless steel plates EPDM gaskets
Size - 9'3" long x 1'7" wide x 5' high with maximum platage (2.82 x 0.48 x 1.52 m)

Geothermal side - 219°F (104°C) Inlet
176°F (80°C) outlet
4.3 psig (29.6 kPa) pressure drop
350 gpm (22.1 l/s) flow
(1000 gpm [63.1 l/s] maximum flow)

Secondary side - 200°F (93°C) outlet
160°F (71°C) Inlet
3.7 psig (25.5 kPa) pressure drop
378 gpm (23.8 l/s) flow
(1000 gpm [63.1 l/s] maximum flow)

Cost - \$14,000 ea

Number required - 2

Life of the 316 stainless steel plates is expected to be 30 years or more in the Klamath Falls geothermal water.

Additional plates for future expansion cost \$80 each, including gaskets.

The primary pipeline for the system is to be 8-inch (20 cm) steel, schedule 40, 4060 ft (1.24 km) in length, placed in a concrete tunnel. The cost of this line is estimated to be \$506,175. This figure includes cost of pipe, expansion joints, fittings, pipe guides, excavation, bedding placement and backfill, a highway undercrossing, a railroad undercrossing, a 42" x 30" (107 x 76 cm) concrete tunnel and six pre-cast expansion vaults.

The costs are based on estimates provided by various suppliers of equipment, City of Klamath Falls recent bid prices and estimates from Means Mechanical Cost Data Guide for 1978. It should be noted that there were large variations in estimates given by suppliers, as much as 2-300% variation. The costs presented below appear to be the most reasonable estimates, including allowance for profit and overhead.

8" (20 cm) Steel Pipe in a Concrete Tunnel

Primary line (8" (20 cm) steel pipe)

4060' (1237 m) @ 8" (20 cm) - Sch 40 @ \$10.323/LF ⁷	\$ 41,911
Install and weld @ 70%	29,338
Fittings	6,433
Install and weld @ 40%	2,573

(continued)

⁷ LF = linear foot (.3 m)

Expansion joints	\$ 5,303
Install @ 56%	2,970
Pipe guides (79 required)	3,804
Install @ 56%	2,130
Insulation @ \$4.59/LF	18,635
Labor @ 123%	22,921
Concrete tunnel 3860' (1177 m) of 42" (108 cm) x 30" (77 cm) @ \$46.50/LF (-200' [61 m] canal & highway crossing)	179,490
Excavation, bedding, placement and backfill @ \$35/LF	135,100
Highway undercrossing \$175 x 120' (37 m)	21,000
RR undercrossing \$100 x 250' (76 m)	25,000
6 pre-cast expansion vaults (Model 675 LA) @ \$1,063	6,378
Install @ 50%	3,189
Subtotal	\$506,175

The secondary distribution line totals an estimated \$631,060. A detailed cost summary of the secondary distribution system is as follows:

Secondary line (8" [20 cm], 6" [15 cm] and 3" [8 cm] steel pipe)

2170' (662 m) x 2 @ 8" (20 cm) - Sch 40 @ \$10.323/LF	\$ 44,801
2250' (686 m) x 2 @ 6" (15 cm) - Sch 40 @ \$6.865/LF	30,892
Install and weld @ 70%	52,985
1360' (415 m) x 2 @ 3" (8 cm) - Permapipe (installed, factory insulated) @ \$24.13/LF	65,634
Fittings	10,625
Install and weld @ 40%	4,250
Expansion joints	13,174
Install @ 56%	7,377
Pipe guides (368 required).	10,301
Install @ 56%	5,769
Insulation 8" (20 cm) @ \$4.59/LF, 6" (15 cm) @ \$3.89/LF	37,426
Labor @ 123%	46,034
Concrete tunnel	
2170' (662 m) of 42" (108 cm) x 30" (77 cm) @ \$46.50/LF	100,905
2250' (686 m) of 38" (94 cm) x 28" (72 cm) @ \$40.45/LF	91,013
Savings on concurrent construction of utilities	(49,265)

(continued)

Excavation, bedding, placement and backfill @ \$35/LF	154,700
8 Precast expansion vaults (Model 575 LA) @ \$737	5,896
1 Precast expansion vault (Model 675 LA) @ \$1063	1,063
Labor and equipment @ 50%	<u>3,480</u>
Subtotal	\$637,060
TOTAL	<u>\$1,143,235</u>

Four different designs for the pipe system were considered:

1. Steel pipe in a concrete tunnel
2. Steel pipe direct buried, insulated and sealed
3. Asbestos cement direct buried
4. Fiberglass reinforced plastic.

Although the steel pipe in a concrete tunnel has the highest initial cost, it was estimated to have nearly twice the life of the other piping systems and reduced annual maintenance costs. One of the vital factors in selecting this system was the fact that both primary and secondary lines will be run in congested areas. Pipelines laid in tunnels beneath sidewalks will provide easy access for maintenance and will melt snow during winter months.

Concrete tunnels for the primary line are oversized to allow for the planned future expansion. Although the oversizing raises the initial cost, it is much more economical than trenching, bedding, placement and backfill at a later date. Nearly all geothermal space-heating systems installed have provided for future expansion.

An 800-foot (244-m) injection well will be drilled at the end of the primary line for \$30,000. A total cost summary for the entire system appears below:

Total Cost Summary

<u>Item</u>	<u>Cost</u>
A. Wells and Well Head Equipment	
1. Production well (3) @ \$38,898	\$ 116,694
2. Production well pumps (3) @ \$41,988	125,964
3. Well head buildings (3) @ \$3,500	10,500
4. Power hook-up in buildings (3) @ \$500	<u>1,500</u>
Subtotal	\$ 254,658
B. Distribution Piping Network:	
5. Primary supply pipeline (8" [20 cm] steel in concrete tunnel)	506,175
6. Secondary supply pipeline (8" [20 cm] & 6" [15 cm] steel in concrete tunnel, 3" [8 cm] steel buried)	<u>637,060</u>
Subtotal	\$1,143,235

(continued)

C. Heat Exchanger Building:

7. Plate heat exchangers (2) @ \$14,000	\$ 28,000
8. Control System, wiring, etc. (basic)	44,537
9. Circulation pump (2) @ \$13,691	27,382
10. Expansion/surge tank	5,000
11. Building, including installation of equipment	90,000
12. Injection well (includes building)	33,500
13. Injection well pump	<u>2,587</u>

Subtotal \$231,006

Total Equipment and Installation Costs \$1,628,899

D. Overhead Costs:

Engineering @ 10%	162,890
Contingency (inflation @ 5% for 6 mos)	<u>81,445</u>

Total Cost \$1,873,234

ESTIMATING ANNUAL OPERATION AND MAINTENANCE COSTS

To complete the total cost for this project, it is necessary to project annual operation and maintenance costs of the geothermal system. Maintenance costs are limited to materials and labor. Operating costs involve electrical power costs for pumping and wages for personnel involved in operating the system. The maintenance costs of our hypothetical model are as follows:

A. Production-well pump maintenance costs are shown in detail. All pump maintenance costs were calculated in this manner.

1. Change packing and lubricate at 6-mo intervals

material per pump	\$ 6
labor per pump	<u>23</u>
Total	\$29

Annual cost $\$29 \times 2 =$ \$58

Total for 3 pumps: $\$58 \times 3 =$ \$174

2. Pull pump, inspect & replace bearings at 3-yr intervals

material per pump	\$ 700
labor per pump	<u>3,300</u>
Total	\$4,000

Annual cost $\$4,000 \div 3 =$ \$1,333

Total for 3 pumps $\$1,333 \times 3 =$ \$4,000

(continued)

3. Overhaul variable speed drive at 5-yr intervals

material per pump	\$180
labor per pump	<u>400</u>
Total	\$580

Annual cost $\$580 \div 5 =$ \$116

Total for 3 pumps $\$116 \times 3 =$ \$348

Total annual production-pump maintenance costs	\$4,522
B. Total annual circulation-pump maintenance costs	568
C. Total annual Injection-pump maintenance costs	79
D. Total annual primary pipeline maintenance costs	400
E. Total annual secondary pipeline maintenance costs	510
F. Total annual heat-exchanger maintenance costs	1,268
G. Total annual maintenance on 3 well-house buildings and heat-exchanger building	<u>1,200</u>
Total annual maintenance costs	\$8,547

Electrical operation costs

To determine the annual operating cost of the system, it is necessary to calculate the total electrical power requirements for pumping and the annual load for the system.

The load factor for our hypothetical system is 25%. The load factor is computed by dividing the estimated annual hours of operation by the total hours per year. Estimated annual demand for the system is 2190 hours divided by 24 hrs/day times 365 days/year = 25% load factor.

Three 75 hp production-well pumps operating at 60% of rated load with 72% efficiency:

$$225 \text{ hp} \times .6 = 135 \text{ hp} \div 72\% \text{ eff} = 187.5 \text{ hp Input}$$

One 20 hp Injection pump operating at 60% of rated load with 71% efficiency:

$$20 \text{ hp} \times .6 = 12 \text{ hp} \div 71\% \text{ eff} = 17 \text{ hp Input}$$

Two 40 hp circulating pumps operating at 60% of rated load with 73% efficiency:

$$80 \text{ hp} \times .6 = 48 \text{ hp} \div 73\% \text{ eff} = 66 \text{ hp Input}$$

$$\text{TOTAL} = 270.5 \text{ hp Input}$$

$$270.5 \text{ hp} \times 2190 \text{ hrs} = 592,395 \text{ hp hours/yr}$$

$$592,395 \text{ hp hrs/yr} \times .7457 \text{ kilowatt hrs/hp hr} = 441,749 \text{ KW hr/yr}$$

$$441,749 \text{ KW hr/yr at } \$0.025/\text{KW hr} = \$11,044/\text{yr electrical power cost}$$

Annual maintenance costs

The maintenance costs are estimated to inflate at 7% annually and the electrical costs are inflated at 9.5% through 1986 and 8.58% thereafter. Table 2 is a 20-year projection of electrical costs and operation and maintenance costs.

TABLE 2

20-YEAR PROJECTION OF ELECTRICAL, OPERATION AND MAINTENANCE COSTS
FOR THE KLAMATH FALLS PROJECT

Year	Geothermal Electrical Annual Cost	Geothermal Operation & Maintenance Annual Cost	Total Cost/Yr.
	<u>11,044.00</u>	<u>8,547.00</u>	
1	12,093.18	9,145.29	21,238.47
2	13,242.03	9,785.46	23,027.49
3	14,500.03	10,470.44	24,970.47
4	15,877.53	11,203.37	27,080.90
5	17,385.89	11,987.61	29,373.50
6	19,037.55	12,826.74	31,864.29
7	20,846.12	13,724.61	34,570.73
8	22,634.72	14,685.34	37,320.05
9	24,576.78	15,713.31	40,290.09
10	26,685.46	16,813.24	43,498.71
11	28,975.08	17,990.17	46,965.25
12	31,461.14	19,249.48	50,710.62
13	34,160.50	20,596.95	54,757.45
14	37,091.47	22,038.73	59,130.21
15	40,273.92	23,581.44	63,855.37
16	43,729.43	25,232.14	68,961.57
17	47,481.41	26,998.39	74,479.80
18	51,555.31	28,888.28	80,443.60
19	55,978.76	30,910.46	86,889.22
20	60,781.74	33,074.19	93,855.93
Total			993,283.71

Wages for operation in our hypothetical case were excluded due to the fact that personnel who operate and maintain the existing system will be identical for the geothermal system.

Now we are ready to construct a 20-year cash flow of the costs and savings resulting from converting the district to geothermal energy (Table 3).

The total cost of the proposed geothermal system (from page 14) is \$1,873,234. The present worth of the 20-year cash flows at an 8% cost of capital indicates that the city could afford to spend \$5,953,737 today to avoid the projected cost of natural gas over the next 20 years.

This completes the economic analysis for a non-profit organization. This example provides the reasons for giving careful attention to the costs of the proposed and existing systems. A precise cost analysis will aid the decision to drill or not to drill.

TABLE 3

20-YEAR CASH FLOW OF THE KLAMATH FALLS PROJECT

Year	Natural Gas Annual Cost	Geothermal Electrical Annual Cost	Geothermal Operation & Maintenance Annual Cost	Annual Savings	Present Worth 8%
	247,100	11,044	8,547		
1	277,246	12,093	9,145	256,008	237,044
2	311,070	13,242	9,785	288,043	246,950
3	349,021	14,500	10,470	324,050	257,242
4	391,601	15,878	11,203	364,520	267,933
5	439,377	17,386	11,988	410,003	279,041
6	492,981	19,038	12,827	461,116	290,582
7	553,124	20,846	13,725	518,554	302,571
8	600,140	22,635	14,685	562,820	304,074
9	651,152	24,577	15,713	610,862	305,583
10	706,500	26,685	16,813	663,001	307,098
11	766,552	28,975	17,990	719,587	308,618
12	831,709	31,461	19,249	780,998	310,145
13	902,404	34,161	20,597	847,647	311,678
14	979,109	37,091	22,039	919,978	313,217
15	1,062,333	40,274	23,581	998,478	314,762
16	1,152,631	43,729	25,232	1,083,670	316,313
17	1,250,605	47,481	26,998	1,176,125	317,870
18	1,356,906	51,555	28,888	1,276,463	319,434
19	1,472,243	55,979	30,910	1,385,354	321,003
20	1,597,384	60,782	33,074	1,503,528	322,579
			Total	15,150,805	5,953,737

CONSIDERATION OF INVESTMENT TAX CREDIT, DEPRECIATION AND PERCENTAGE
DEPLETION ALLOWANCE FOR A TAXABLE CORPORATION

In order to understand thoroughly the economic analysis for a taxable corporation, the reader should be familiar with the National Energy Act (NEA) of 1978, which is discussed beginning on page 22 of this chapter.

To illustrate the economic effect of the NEA, we can modify our hypothetical model with the assumption that the geothermal resource and distribution system are to be developed by a taxable corporation that intends to sell energy to the heating district. With this assumption, we can maintain identical capital investment and annual operating costs to exemplify taxable versus nontaxable cost analysis.

Obviously, there should be an economic incentive for the district to convert from natural gas to geothermal energy. It is doubtful that the corporation could charge the district the price of natural gas, allow this price to increase annually at natural-gas inflation rates and persuade the users within the distribution system to convert to geothermal energy. On the other hand, the corporation must charge some price that will cover its operating costs and provide an acceptable after-tax return on investment. In an attempt to surmount this stumbling block, we can hypothesize that the corporation agrees to sell geothermal energy at the same price as natural gas, inflating this price at the economic inflation rate. This rate would allow the corpo-

ration to recover the increasing costs of operation and maintenance and would provide the users with a cheaper source of energy due to the greatly reduced inflation rates. Figure 2 compares geothermal versus natural gas for a 20-year period using this hypothesis.

FIGURE 2. Geothermal and natural gas comparison under an inflation rate formula.

Hypothetically, the gross sales for the corporation will start at \$264,397 for 1980 and increase at 7% per year over the 20-year period. For simplicity, we will assume that the corporation elects to capitalize its intangible costs and use a ten-year life and straight-line depreciation with a ten percent salvage value.

As indicated in the later discussion on taxes, there are many methods of depreciation and treatments of intangible costs. However, the reader should bear in mind the limits placed on these various methods. The biggest factor is that the corporation must make a profit and owe taxes in order to reap tax benefits.

For example, in the year 1980, the corporation will be eligible for \$374,647 investment tax credit, a \$58,167 depletion allowance based on 22% of sales and \$168,591 depreciation expense which could reduce its total taxes by \$601,405. But its gross sales are only \$264,397. Therefore, the corporation cannot take full advantage of all the tax credits in the first year but will need to carry these credits forward. A large corporation with other alternative energy income could apply these tax credits against its total tax liability.

Since the depletion allowance cannot exceed 50% of net income before taxes, the depletion allowance will be \$37,284 for 1980 and \$45,643 for 1981 as indicated in Column B of the pro forma income statement.

The corporation will need to carry the 20% investment tax credit forward through 1988 in order to recover its total investment tax credit. However, the tax law provides only a three-year carry-back and a seven-year carry-forward for investment tax credits. Therefore, 1986 is the last year that the tax credit will be available. The corporation will be able to avoid \$268,544 of tax payments in this seven-year period.

A second economic analysis was done using straight-line depreciation with a 15-year life in an effort to recapture the full depletion allowance and a higher amount of investment tax credit. The end result was a slightly lower return on investment after taxes. No accelerated depreciation method was attempted since gross sales in the early years of the project are low and an accelerated depreciation would be of no advantage.

Table 4 presents a pro forma income statement as follows:

Column A (gross sales) is the rate charged to the heating district based on the current cost of natural gas and a 7% inflation rate.

Column B represents the depletion allowance with the first and second years adjusted to be not more than 50% of net income before taxes.

Column C represents a straight-line depreciation based on the amortization of all tangible and intangible costs, a ten-year life and a ten percent salvage value.

Column D represents the electrical power costs required to run the geothermal system inflating at the projected electrical rates.

Column E represents the operating and maintenance costs of the geothermal system inflating at the economic inflation rate.

Column F is net income before taxes.

Column G is the tax liability assuming an effective tax rate of 48%. Actual tax liability would be slightly less if the corporation had no other sources of income. No taxes are paid in the first seven years while the corporation is using up its investment tax credit.

Column H is net income after taxes.

Column I adds the calculated depreciation and depletion allowances to the net income after taxes since these items do not represent out-of-pocket expenses but rather methods used to reduce the tax liability.

Column J shows the after-tax cash inflow to the corporation.

Column K indicates the present worth of these cash flows at 15.49522%, which yields a total net present value of \$1,873,234, the cost of the original investment.

The data from our last analysis indicate that the project would be feasible for a corporation that requires an after-tax return on investment of less than 15.5%. The foregoing analysis, which may have seemed exhaustive, supports the advice that a careful study of the economics is as vital as a careful study of the engineering and the geology. The decision to use geothermal energy should be made only after all factors have been examined.

Note: All systems design and costs data were extracted from the Klamath Falls Geothermal District Heating the Commercial District Design, Interim Report for the City of Klamath Falls, PON EG-77-N-03-1553, Feb. 1979.

TABLE 4

PRO FORMA INCOME STATEMENT

	A	B	C	D	E	F	G	H	I	J	K
	Gross	Percentage	Deprecia-	Electrical	Operation &	Net	Federal	Net	Plus	After	Net
Year	Sales	Depletion	tion	Costs for	Maintenance	Income	Income	Income	Depreciation	Tax	Present
				Geothermal	Costs for	Before	Tax	After	& Depletion	Cash	Value
				System	Geothermal	Taxes		Taxes		Flow	
				11,044	8,547						15.49522%
1	264,397	37,284	168,591	12,093	9,145	37,203	0	37,283	205,875	243,159	210,536
2	282,905	45,643	168,591	13,242	9,785	45,643	0	45,643	214,234	259,877	194,823
3	302,708	54,487	168,591	14,500	10,470	54,659	0	54,659	223,079	277,738	180,278
4	323,898	51,824	168,591	15,878	11,203	76,402	0	76,402	220,415	296,817	166,814
5	346,571	51,986	168,591	17,386	11,988	96,620	0	96,620	220,577	317,197	154,351
6	370,830	55,625	168,591	19,038	12,827	114,751	0	114,751	224,216	338,966	142,814
7	396,789	59,518	168,591	20,846	13,725	134,109	0	134,109	228,109	362,218	132,136
8	424,564	63,685	168,591	22,635	14,685	154,968	74,385	80,583	232,276	312,859	98,818
9	454,283	68,142	168,591	24,577	15,713	177,260	85,085	92,175	236,734	328,909	89,950
10	486,083	72,912	168,591	26,685	16,813	201,081	96,519	104,562	241,504	346,066	81,944
11	520,109	78,016		28,975	17,990	395,127	189,661	205,466	78,016	283,483	58,120
12	556,517	83,477		31,461	19,249	422,328	202,718	219,611	83,477	303,088	53,802
13	595,473	89,321		34,161	20,597	451,394	216,669	234,725	89,321	324,046	49,805
14	637,156	95,573		37,091	22,039	482,452	231,577	250,875	95,573	346,449	46,104
15	681,757	102,264		40,274	23,581	515,638	247,506	268,132	102,264	370,395	42,678
16	729,480	109,422		43,729	25,232	551,096	264,526	286,570	109,422	395,992	39,506
17	780,543	117,081		47,481	26,998	588,982	282,711	306,271	117,081	423,352	36,569
18	835,181	125,277		51,555	28,888	629,460	302,141	327,319	125,277	452,597	33,850
19	893,644	134,047		55,979	30,910	672,708	322,900	349,808	134,047	483,855	31,333
20	956,199	143,430		60,782	33,074	718,913	345,078	373,835	143,430	517,265	29,002
TOTAL -											1,873,233

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APPENDIX A

OVERVIEW OF STATE AND FEDERAL TAXATION

INTRODUCTION

Whenever the issues of taxes, tax credits, tax incentives, depletion allowances and/or intangible deductions are raised, it must be remembered that there are 51 tax systems in this country: one federal and 50 state. State corporate and personal income-tax structures may or may not parallel the federal corporate and personal income-tax structure. Generally, the states have followed the federal government's lead in constructing their own tax systems. However, in the post-Proposition 13 mood of the electorate, it is not clear that states will adopt tax incentives for geothermal resources. Moreover, since the geothermal tax incentives adopted as part of the 1978 Energy Tax Act are so new, there will be some uncertainty as to their application until the IRS promulgates its Treasury Regulations for these new Internal Revenue Code (IRC) sections. Until that time, it is safe to assume that the IRS will follow (with certain exceptions) the Treasury Regulations and court cases that are applied to the oil and gas industry. All the Treasury Regulations cited in the footnotes in the text below were written for the oil and gas industry, but they are generally applicable to geothermal.

THE FEDERAL TAX SYSTEM

Prior to the passage of the Energy Tax Act of 1978,¹ the federal tax treatment of geothermal resources was based mainly on judicial decisions, not statutory authority. In 1969, the 9th Circuit Court of Appeals² held that the federal intangible drilling deduction³ and the percentage depletion allowance⁴ applied to the geothermal drilling at The Geysers. To reach this result, the Court held that geothermal steam was "gas" within the meaning of §263(c) and §613(b)(1) of the IRC.

In 1975, the Code was revised to provide a 22% percentage depletion allowance for any geothermal deposit in the U.S. or a U.S. possession that was determined to be a gas.⁵ But the IRS refused to follow either the Court decisions or the new Code provision and contested both the intangible drilling deduction and depletion allowance on activities and income from The Geysers. Furthermore, because of the IRS intransigence, the tax treatment of drilling a geothermal deposit that was hot water instead of steam was even less clear.⁶

The Energy Tax Act of 1978 has eliminated most of the uncertainties of tax treatment of geothermal exploration and development. The new provisions can be used to promote capital investment and to generate for the investor certain tax savings which reduce the risk of investment. Furthermore, the definition of geothermal deposits⁷ is broad enough to include all the various

¹P.L. 95-618, §403(b), amending IRC §613A(b).

²Arthur E. Reich, 52 T.C. 700 (1969), aff'd, 454 F.2d 1157 (9th Cir. 1972) and George D. Rowan, 28 T.C.M. 797 (1969).

³IRC §263(c).

⁴IRC §613.

⁵P.L. 94-455.

⁶In Miller v. United States, 78-1 U.S.T.C. P9127 (D.C.C.D. Cal. 1977) the federal district court denied the intangible drilling deduction to investors who drilled geothermal wells in Nevada in an area of hot water, not steam, reservoirs.

⁷"A geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure)."

forms of geothermal energy including dry steam, hot water or dry hot rocks. The Act covers three basic subjects: intangible drilling costs, depletion allowance and tax credits.

Intangible drilling costs

Option to deduct intangible drilling costs. §402 of the Energy Tax Act amends §263(c) of the IRC to allow a taxpayer the option to deduct as expenses intangible drilling costs (called "intangibles" or IDCs).⁸ The costs of drilling and completing a geothermal well are divided for tax purposes into two classes: intangible drilling costs and equipment costs. The equipment costs must be capitalized and "recovered" through depreciation or depletion. Intangible drilling costs may be treated in two ways.⁹ They may be deducted as expenses (in tax terminology they may be expensed) in the year in which they were incurred or they may be capitalized and deducted over a certain period of time as depreciation or depletion.¹⁰ Allowing a taxpayer to expense (deduct) all the intangibles in the year in which they were incurred gives the taxpayer a kind of "accelerated depreciation."

The taxpayer must make his election to expense or to capitalize intangibles in the first taxable year in which he incurs such costs.¹¹ Once having done so, the taxpayer must treat such expenditures on all geothermal properties in the same manner for all future years.¹² However, if the taxpayer elects to capitalize his intangibles, he is granted a second election to capitalize or to expense the portion of intangibles attributable to dry or nonproductive wells.¹³

⁸Intangible drilling costs are defined by U.S. Treasury Regulation §1.612-4(a) as any cost incurred which in itself has no salvage value and which is "incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas." Such expenditures expressly include "wages, fuel, repairs, hauling, supplies, etc." that are used (1) in the drilling, shooting and cleaning of wells; (2) in such clearing of ground, draining, road making, surveying and geological works as are necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. The IRS will probably follow this regulation for geothermal deposits, making adjustments for the differences between drilling in the oil and gas industry and the geothermal industry.

⁹Since the geothermal provision for the option to expense intangibles is separate from oil and gas activities, a taxpayer may make one kind of election for his geothermal deposits and a different one for his oil and gas wells. For example, he could decide to expense intangibles for both geothermal and oil and gas properties or he could capitalize oil and gas and expense geothermal intangibles.

¹⁰U.S. Treasury Regulations §§1.612-4(b)(1), (b)(2) & (b)(3) state that intangibles, if capitalized, are to be separated and recovered as depreciation or depletion. Intangibles not represented by physical property (clearing ground, draining, road making, surveying geological work, excavating, grading and the drilling, shooting and cleaning of wells) are to be recovered through depletion. Intangible expenditures represented by physical properties (wages, fuel, repairs, hauling, supplies, etc.) are to be recovered through depreciation.

¹¹A taxpayer must make a clear election either to expense or to capitalize. If he does not, the IRS will hold that he elected to capitalize intangibles. It is best that if a taxpayer desires to expense intangibles, he include with his income-tax return an express statement of election to expense in accordance with the option granted by U.S. Treasury Regulation §1.612-4(a).

¹²U.S. Treasury Regulation §1.611-4(e).

¹³But this second election need not be exercised until the first year in which a dry hole is drilled.

For example, if Taxpayer (T)¹⁴ has spent \$50,000 in intangibles in 1978, T may claim as a deduction on his income-tax return the \$50,000 of intangible costs. But if T decides to capitalize intangible drilling costs, T will not take a \$50,000 deduction for 1978 but instead will deduct this amount over a given period of time as depreciation or depletion.

But a noncorporate taxpayer, a Subchapter S corporation or a personal holding company that decides to expense intangibles instead of capitalizing them, may be subject to one of the following: the minimum tax (see "B"); a limitation on deductions to the amount "at risk" (see "C"); or recapture of intangible deductions if the property is sold at a profit (see "D").

Preference Income--minimum tax. Some types of income are given preferential treatment by special provisions of the tax law. A minimum tax applies to a number of items that are considered to be of a tax-preference nature. These types of income include capital gains, stock options and income offset by depletion, amortization and intangible drilling costs. The tax is computed by totaling all the items of tax preference, then reducing this amount by the greater of \$10,000 or one-half a taxpayer's regular income tax after reduction by credits. A flat 15% rate is then applied against the balance.¹⁵

If a taxpayer has "excess intangible drilling costs" that exceed net geothermal income, he will have preference income subject to the minimum tax. Intangible drilling costs are considered to be excessive when the intangible drilling and development costs of a geothermal well allowable for the tax year is greater than the sum of (1) the amount allowable if the costs had been capitalized and straight-line recovery of intangibles had been used and (2) the net income for the tax year from the geothermal property.

Straight-line recovery means the ratable amortization of such intangibles over the 120-month period beginning with the month in which production from the well begins (or, if elected, any method which would be permitted for purposes of determining cost depletion). Net income from geothermal properties means the gross income from all such property reduced by any deductions allocable to the properties, except intangible drilling and development costs in excess of straight-line recovery.

This preference does not apply to taxpayers who elect to capitalize by straight-line recovery their intangibles. Nor does it apply to nonproductive wells.¹⁶

Special rules apply to corporations in computing their minimum tax.¹⁷ And the IRS will publish rules under which items of tax preference of both individuals and corporations are to be properly adjusted where the tax treatment that gave rise to the preference does not result in a reduction of the taxpayer's income tax for any tax year.

¹⁴The owner of the operating rights in a property who has the responsibility to develop the property is granted the option of expensing intangibles. But each taxpayer, regardless of his relationship to another taxpayer, is entitled to a separate election. Thus each partner in a partnership is entitled to a separate election. Trusts as separate taxpayers are entitled to an election regardless of the kind of election made by the beneficiaries.

¹⁵A taxpayer may be able to claim the unused part of certain credits against his minimum tax. Also if a taxpayer has a net operating loss that remains to be carried forward to a succeeding tax year, the minimum tax otherwise due may be deferred in an amount of up to 15% of the net operating loss to be carried forward to subsequent tax years when the loss is absorbed. In the years when the loss is absorbed, the taxpayer will be liable for the minimum tax deferred in an amount equal to 15% of the net operating loss absorbed in each year. See IRC §57(a)(11).

¹⁶Nonproductive wells are those which are plugged and abandoned without having produced steam or hot water in commercial quantities for any substantial period of time.

¹⁷See IRS Publication 542, Corporations and the Federal Income Tax.

In effect, what this provision does is to lessen the benefit of the option to expense intangible drilling costs. Few taxpayers now have geothermal income and if they choose to expense intangibles, they will have preference income (that is, the amount they deduct by expensing intangibles will definitely be greater than the sum of intangibles capitalized and net geothermal income).

Losses limited to amount at risk.¹⁸ The 1976 Tax Reform Act limited the tax benefits available to persons engaging in oil and gas operations. These same limitations with some changes were extended to geothermal operations by the 1978 Energy Tax Act.

Before passage of the 1976 Act, a taxpayer could take deductions up to the amount of his cost (or "basis") in a business or investment venture. But the basis of a taxpayer often included expenditures financed by nonrecourse loans for which the taxpayer had no personal liability (i.e., he had nothing "at risk" because of the way the loan was made to him or to an investment group). Such leveraged nonrecourse loans were often employed by investors to finance drilling and development costs of oil and gas activities. Since a taxpayer could elect to expense intangible drilling costs, he could take deductions far in excess of his own actual investment. This kind of investment was desirable for a high-bracket taxpayer because the large deductions for intangibles could be used to offset income earned from other sources.

The 1976 law added §465 to the IRC and limited the amount of losses¹⁹ deductible by a taxpayer engaged in exploring for and exploiting oil and gas. The taxpayer's deduction cannot exceed the total amount the taxpayer has at risk in the venture. Deductions taken for intangibles are considered losses for purposes of this section.

The Revenue Act of 1978 changed the "at risk" rules for years beginning after December 31, 1978. The most significant change is that previously allowed losses must be recaptured when the taxpayer's "at risk" amount is reduced below zero. But only the excess of the losses previously allowed in a particular "at risk" activity over any amounts previously recaptured will be recaptured under this provision. However, such recaptured losses may be deductible in a later year if the "at risk" is later increased.

The practical effect of these "at risk" provisions is to eliminate the use of nonrecourse financing to increase available deductions.

Recapture of intangible costs expenses as ordinary income on disposition of geothermal property. Probably the most far-reaching change of the 1976 Tax Reform Act affecting corporate and noncorporate taxpayers is the requirement that upon the disposition of oil and gas property, taxpayers are required to recapture all or some part of the intangible costs incurred as ordinary income if the property is disposed of at a gain (a profit). These recapture provisions were extended by the Energy Tax Act of 1978 to intangible drilling costs incurred in connection with geothermal deposits.²⁰

This recapture provision applies only to intangibles which the taxpayer elects to expense in the year in which they were incurred and does not apply to intangibles which were capitalized. The amount of intangibles recaptured as ordinary income (instead of capital gains) is the lesser of (1) the intangible costs incurred (reduced by an amount which would have been allowed as cost depletion had such intangibles been capitalized) or (2) the gain realized on the disposition. Or, in other words, the amount recaptured and taxed as ordinary income is the amount that the intangibles deducted exceed that which would have been allowed had the intangibles been capital-

¹⁸See IRC §465(c).

¹⁹A loss is the excess of allowable deductions allocable to a particular activity over the income derived from the activity during a taxable year.

²⁰P.L. 95-618, §402(c), amending IRC §1254(a).

ized and amortized on a straight-line basis (120) months from time the property went into production.²¹

Percentage depletion

The IRC provides two methods of computing a depletion allowance: cost depletion and percentage depletion. Cost depletion provides for a deduction for the taxpayer's basis (cost) in the property in relation to the production and sale of minerals from the property. On the other hand, percentage depletion is a statutory concept that provides for a deduction of specified percentages of the gross income from the property. The deduction, however, cannot exceed 50% of the net income from the property. A taxpayer is required to compute depletion both ways and to claim the larger of the two amounts.

A depletion allowance reduces the taxpayer's basis in a property but the total amount taken as a depletion allowance is not restricted to the taxpayer's basis. Even though cost depletion will be zero after the taxpayer's initial basis has been recovered (for example, T deducts \$5000 per year for five years for a total of \$25,000 - the amount of his original investment), the taxpayer may continue to claim percentage depletion based on income from the property.²²

§403 of the 1978 Energy Tax Act grants percentage depletion on income from geothermal deposits. The rate through 1980 is 22%. It decreases by 2% yearly until 1983 and thereafter the rate is 15%.

This percentage depletion allowance is much more favorable than the one allowed oil and gas. It is not limited in any way to a specified amount of production. It has no 65% of taxable income limitation nor is it restricted to independent producers. However, the percentage depletion cannot exceed 50% of the taxable income from the property and is subject to the minimum tax-preference income rules.²³

There is some question about the availability of depletion on minerals which are consumed by the producer of such minerals. Many manufacturers are now exploring and developing their own sources of energy supplies, particularly natural gas reserves and in some areas geothermal. But the depletion allowance is dependent upon the sale of a mineral. Some courts have held that no depletion is allowable for minerals consumed in the operation of the producing energy property. It is not clear, however, if a depletion allowance is precluded with respect to gas used in manufacturing operations. For example, the IRS ruled in 1968 that the value of dry gas manufactured from wet gas and used as fuel for a gasoline absorption plant is includable in determining "gross income from the property" for percentage depletion purposes, but the value of dry gas reinjected into the geological formation is not includable. One way for the corporate taxpayer to avoid the problem is to conduct its exploration and development activities through a wholly owned subsidiary. The subsidiary could sell the gas to the parent at an arm's length price and create depletable gross income.

²¹ It should be noted that there are questions as to the proper method of calculating the reduction of recapturable intangibles under this section.

²² A depletion allowance on the income derived from production and sale of the minerals from a property is available only to the owner of an economic interest in that property. An owner of an economic interest can be an owner of mineral interests, royalties, working interests, overriding royalties, net profits interests or certain kinds of production payments.

²³ The excess of the depletion deduction over the adjusted basis of the property at the end of the year (determined without regard to the depletion deduction for the year) is what would be preference income.

Tax credits

Residential energy credit. §101 of the 1978 Energy Tax Act provides for a non-refundable tax credit for certain expenditures incurred for equipment which uses geothermal energy in a taxpayer's principal residence in the United States. The equipment must be new and must meet certain performance and quality standards; it must reasonably be expected to remain in production for five years. The credit is as follows: (a) 30% of the expenditure up to \$2000, (b) 20% of the expenditure from \$2000 to \$10,000. The maximum credit is \$2200. The credit may be carried over to future years for equipment purchased after April 20, 1977 and before January 1, 1986.

Additional investment tax credit for alternative energy property. A 10% investment-tax credit in addition to the existing investment-tax credit is available for geothermal equipment which qualifies as either "alternative energy property" or "specially defined energy property." Public utilities cannot benefit to the extent of "alternative energy property" but can use the credit for "specially defined energy property."

The business-energy credit is limited to 100% of tax liability, except for solar- or wind-energy property on which the credit is refundable. Until the IRS issues its regulations on this new section, it will not be completely clear what kind of equipment qualifies.

STATE TAX SYSTEMS²⁴

Of the fifteen states with known geothermal resources, Nevada, Texas, Washington and Wyoming have no state personal or corporate income tax. Alaska, Colorado, Hawaii, Idaho, Montana and New Mexico apply their income-tax levies to adjusted gross income as calculated for federal income tax. But five states have an independently determined income tax: Arizona, California, Louisiana, Oregon and Utah. Their differences from the federal law are largely due to the state provisions concerning percentage depletion for resources extraction industries.

Two states, California and Arizona, provide two examples of how complex the state tax picture can be. California has a Franchise Tax and a Corporate Income Tax. The franchise tax is for the privilege of exercising a corporate franchise within the state. The tax rate is 9% of net income attributable to California. Insofar as the franchise tax overlaps the corporate income tax, the amount due under the franchise tax is offset against the amount due under the income tax. The computation of income for both the franchise tax and the income tax follows generally the pattern of the federal income tax and interpretations of the federal law by the Treasury Department, with the exception of depletion provisions. The tax rate for the income tax is also 9%.

Prior to 1975, California provisions for depletion allowance for oil and gas and other minerals conformed basically to federal law. However, California did not follow the federal Tax Reduction Act of 1975 which eliminated percentage depletion for oil and gas wells (with a few exceptions). California merely placed a limit on the total amount deductible by each individual taxpayer. These limitations apply only after the total accumulated depletion allowed or allowable exceeds the adjusted cost of the property.

A deduction of 22% of gross income (less rentals and royalties) for the taxable year is allowed for oil and gas properties. This deduction may not exceed 50% of taxable income computed with-

²⁴For an extensive analysis of state tax systems, see State Taxation of Geothermal Resources Compared with State Taxation of Other Energy Minerals, Sharon C. Wagner, published by the Geothermal Resources Council, Davis, CA.

out allowance for depletion. In addition, where the deduction exceeds \$1.5 million and is greater than the adjusted cost of the taxpayer's interest in the property, the deduction is reduced. The reduction equals 125% of the amount in excess of \$1.5 million.²⁵

For example, suppose that the 22% depletion is \$3.5 million and that this amount exceeds the cost of the taxpayer's interest in the property. The deduction in this case is reduced by 125% of \$2 million (\$3.5 million minus \$1.5 million), which equals \$2.5 million. The allowed deduction in this case is \$3.5 million minus \$2.5 million which equals \$1 million. If, instead, the 22% depletion amounts to \$7.5 million, then the reduction is 125% of \$6 million, which is equivalent to the depletion allowance itself, and no deduction is allowed.²⁶

For oil and gas, California follows federal provisions for intangible drilling costs.²⁷ Exploration expenditures may not be deducted for oil and gas but they may for other minerals. Geothermal exploration, development or percentage-depletion deductions are not specifically allowed, but, in practice, companies at The Geysers have been allowed percentage depletion and deductions for intangible drilling costs.

In 1977, Arizona raised its corporate tax rates and then raised them again in 1978. But Arizona does specifically provide for a depletion allowance and depreciation in computing new income. The depletion allowance is 27-1/2% of gross income, excluding an amount equal to any rents or royalties paid in respect to the property. The allowance cannot exceed 50% of the taxpayer's net income computed without allowance for depletion from the property, except that in no case will the depletion allowance be less than it would be if computed without reference to this provision. Also expenditures paid or incurred during the income-tax year for the development of a geothermal resource well, if paid or incurred after 12/31/53, may be deducted from gross income or charged to the capital account. Amounts up to \$75,000 paid or incurred for the purpose of ascertaining the existence, location, extent or quality of any deposit of geothermal resources are allowed as a deduction.

²⁵CAL. REV. & TAX CODE §17686.

²⁶Bock, 1978 Guidebook to California Taxes, p. 123.

²⁷CAL. REV. & TAX CODE §24423. CAL. ADMIN. REG. 24831(d).

APPENDIX B

PRICING DIRECT-USE GEOTHERMAL ENERGY
(A Pricing Guide)

INTRODUCTION

Geothermal energy is not new. It has been used successfully for centuries. Now, when conventional energy supplied by non-renewable resources is in short supply, and when costs of this energy rapidly escalate, renewed attention is being focused on geothermal and the economics of its use.

This appendix will not provide a magic formula for pricing direct-use geothermal energy; it will introduce the reader to the parameters that ultimately dictate the cost of this energy to the end user.

The price of geothermal energy must relate to the cost of developing and delivering the resource. As in all enterprises, the final analysis reduces to dollars and cents. If the project will make no dollars of profit, then it makes no sense!

Many direct-use geothermal systems supply energy at a fraction of the cost of conventional fuels. Experience indicates, however, that the following major factors significantly influence the cost of geothermal energy:

1. Efficiency
2. Annual load factor
3. Capital investment
 - a) Transmission distance
 - b) Drilling costs versus confidence level
4. Cost of capital or required return on investment.

Other factors which influence cost to a lesser degree are water quality, site location and pumping depth. As technologies develop to reduce drilling costs and to handle water with corrosive properties, the influence of these factors will change. To simplify the analysis, we will assume pumping depths in the neighborhood of 300 feet (90 meters) and water quality from good to excellent.

EFFICIENCY

Most present-day space-heating systems use hot (200°F, 93°C) water that is piped either to heat exchangers placed in rooms throughout the building or to fan-coil units installed in a duct-work system supplying heated air to individual rooms. Both these systems are typically closed loops and they remove 20°F (11°C) of heat between the supply and the return lines. In other words, the supply water at 200°F (93°C) circulates through the system, then it returns to the boiler at 180°F (82°C), is reheated to 200°F (93°C) and recirculated. The efficiency of these systems is, basically, the efficiency of the heat source. Typical efficiencies are: heating oil - 85%; natural gas - 90%; and electricity - 100%.

With geothermal energy, water is pumped from a production well to a heat exchanger (where energy is withdrawn) and then to an injection well. The total annual operating costs of such a system

comprise the pumping, the maintenance and amortization of the capital invested in the system. These costs are unrelated to the efficiency with which heat is removed from the thermal waters supplied by a well.

Suppose System A extracts 10°F (5°C) from a 200°F (93°C) supply and injects the water at 190°F (88°C); System B extracts 100°F (56°C) and injects the water at 100°F (38°C). The cost per MBtu (GJ) for System A would be ten times that of System B. Assume the cost of drilling one production well and one injection well to be \$100,000. With an annual cost of capital of 15% and a 20-year well life, the total annual equivalent cost of developing and operating either system would be \$26,000. If both systems were operating 100% of the time, System A, extracting 10°F (5°C) of heat could deliver 2.19×10^4 MBtu (2.31×10^4 GJ) annually at a cost of \$1.19/MBtu (\$1.13/GJ). However, System B extracting 100°F (56°C) could deliver 2.19×10^5 MBtu (2.31×10^5 GJ) annually at a cost of \$0.12/MBtu (\$0.11/GJ). Systems designed to extract greater amounts of heat from the geothermal reservoir (increased efficiency) will usually increase the capital investment greatly. Normally, however, the annual savings resulting from this increased efficiency will more than repay the capital investment.

Geothermal systems are capital intensive and the fixed costs (capital recovery) often comprise more than 90% of the total annual cost. Thus drilling one production and one injection well and extracting 100°F (56°C) is more economically feasible than drilling ten production and three injection wells and extracting 10°F (5°C) from each of the producers to satisfy the same heat load. There are space-heating systems which have been successfully designed to extract 75°F (24°C) from a 140°F (60°C) supply. Some systems in use which were direct conversions from fossil fuel extract 80°F (44°C) because the original heating system was so over-designed.

Graph 1 shows the hypothetical Klamath Falls heating-district model described in the economics section of this text. The cost of capital is 15% and the project life is 20 years. The inflation rates are the same as those assumed in the economics section in this chapter. For the remainder of this section, this district-heating model will be referred to as the KF Model. The graph depicts costs of the KF Model when comparing the extraction of 20°F (11°C) versus the extraction of 40°F (22°C) of heat. Retrofit costs for the 20°F (11°C) ΔT (ΔT = amount of heat removed) system were assumed to be minimal or zero, and retrofit costs for the 40°F (22°C) ΔT system were assumed to be \$250,000. The yearly costs per MBtu of each of these systems are also compared to the forecast yearly costs of the present system, operating on natural gas.

It should be noted that the capital investment required for the 20°F (11°C) ΔT system is double the capital investment required for the 40°F (22°C) ΔT system, but that the retrofit costs are not required for the 20°F (11°C) ΔT system since the existing heating system is designed for a 20°F (11°C) ΔT . (This graph provides only an approximation since the cost of the secondary distribution line, concrete vaults and the primary supply line would increase by less than 200%.)

Graph 2 shows the KF Model with an annual load factor of 25%. Capital investment, operating and maintenance costs remain the same. It compares the 20-year annual equivalent cost per MBtu (GJ) resulting from heat extraction that ranges from 5°-100°F (3°-56°C), and the 20-year annual equivalent cost for natural gas. It can be seen that the systems break even at about 25°F (14°C) ΔT . A higher load factor would decrease the break-even ΔT .

ANNUAL LOAD FACTOR

The annual load factor depends upon the annual hours of operation of the system. For an industrial process application operating 24 hours per day, 365 days per year, the annual load factor is 100%. An industry operating 5 days per week would have an annual load factor of 23% per 8-hour shift. The KF Model has an annual load factor of 25% that is based on climatic conditions in Klamath Falls (6300 F degree days or 3500 C degree days).

GRAPH 1. KF Model cost per MBtu (GJ) as ΔT changes from 20°F (11°C) to 40°F (22°C) as compared to the forecast cost for natural gas inflating @ 12.2% through 1986 and at 8.5% thereafter.

GRAPH 2. KF Model with a 25% annual heat load factor showing 20-year annual equivalent costs per MBtu at 15% as the heat extracted varies from 5-100°F (3-56°C).

The annual load factor can be almost as influential on the cost of energy as the efficiency of the system. In the KF heating district, the geothermal system has been designed to supply the peak-load requirements, but the system is used only 25% of the time, based on that peak load. This 25% use reduces annual operation and maintenance costs, but does not make full use of the capital investment. The annual equivalent cost with a 15% cost of capital over a 20-year life for the KF Model is \$5.58/MBtu (\$5.29/GJ). If additional uses could be found for the available energy to increase the annual load to 100%, these uses would reduce the cost to \$1.84/MBtu (\$1.74/GJ). Therefore, as the annual load approaches 100%, the cost per MBtu (GJ) is significantly reduced.

Many heating districts have load factors in the range of 20-30%. If additional heat loads can be found to utilize the geothermal heat source during times other than peak heating periods, such uses would measurably improve the economic viability of the projects. One use for heating districts could be the provision of inexpensive air conditioning during the summer months. Absorption-type refrigeration units which can utilize heat from the geothermal system are readily available, but their addition would increase the capital investment required. It is expected, however, that the increased load factor will greatly offset incremental costs and thereby reduce the energy production costs. An industrial load coupled with space heating could also improve the load factor.

Graph 3 shows cost/MBtu (GJ) of the KF Model, holding capital investment constant and varying the annual load factor from 5% to 100%. The electrical pumping costs and the maintenance costs per MBtu vary directly with the annual load factor. On the other hand, the capital investment for the geothermal system is fixed and independent of the annual load factor. Therefore, these costs vary inversely with the annual load factor so that as the annual load factor increases, the annual equivalent cost of the capital investment per MBtu (GJ) decreases.

The graph indicates that there is a marked cost reduction as the load factor increases from 5% to 50%. This cost reduction tapers off and provides a savings of only \$0.50/MBtu (\$0.47/GJ) as the annual load factor increases from 70% to 100%.

In a plant using the heat for an industrial process, one should note the significant reduction in cost per million Btu's by operating two 8-hour shifts rather than one shift. Vertical lines indicate the annual load factors for an industrial process load operating one, two or three shifts five days per week.

CAPITAL INVESTMENT

Transmission distance

Geothermal pipelines are one of the largest capital investments in a geothermal system. Ideally, the well field and the user should be located close together. It is important that transmission lines be properly installed and insulated to reduce both heat loss and maintenance costs.

In the KF Model, an 8-inch (20-cm) supply line provided a maximum of 1390 gpm (88 l/s) of 200°F (93°C) water to a heat-exchanger building 4060 ft (1.24 km) from the resource. Based on the 25% load factor, the 20-year annual equivalent cost of the primary transmission line, at 15% cost of capital, is \$1.55/MBtu (\$1.47/GJ) or \$0.38/MBtu/1000 ft (\$1.18/GJ/km). Note that if the highway and railroad undercrossings were not required, the cost of the primary transmission line would be \$0.31/MBtu/1000 ft (\$0.96/GJ/km).

Graph 4 shows the cost/MBtu (GJ) of the KF Model extracting 40°F (22°C) from the geothermal fluid with a 25% annual load factor while varying the length of the primary transmission from 0

GRAPH 3. KF Model 20-year annual equivalent cost at 15% cost of capital as the annual load factor varies from 5% to 100%.

GRAPH 4. KF Model 20-year annual equivalent cost per MBtu (GJ) at 15¢ per thousand feet (km) of 8-inch (20 cm) transmission line in a concrete vault.

to 20,000 ft (0 to 6.1 km). It can be seen that transmission in excess of about 15,000 ft (4.6 km) may well be economically impractical.

Annual maintenance and pumping costs were not included in this graph. The annual maintenance costs for steel pipe in a concrete tunnel, properly installed, are extremely low. Pumping costs for the KF Model are negligible, since there is a slight down grade from the well head to the secondary pipeline. Nevertheless, it is worth considering that maintenance costs and pumping costs, along with temperature loss, would normally increase the costs per MBtu (GJ) slightly more than the graph indicates.

Drilling costs versus confidence level

The cost of drilling into a productive geothermal resource is site specific and highly variable. Drilling costs are directly affected by the geologic conditions, resource depth, site accessibility and the temperature of the resource.

One extreme example is Lava Hot Springs, Idaho, where 140°F (60°C) water is commonly encountered at depths of 6-10 ft (2-3 m). Thus, wells are dug with a back hoe. In contrast, geothermal wells elsewhere have been drilled into high-temperature resources at depths of over 10,000 ft (3 km) requiring expensive oil-well drilling and blowout-protection equipment. It is obvious, therefore, that drilling costs are a major component of the capital investment required for a geothermal heating system.

Drilling for geothermal resources can be risky. Some dry holes have been drilled even in areas known to contain geothermal resources and in areas delineated by state-of-the-art geologic, geophysical and geochemical studies. For example, Klamath Falls, Oregon, has over 500 geothermal wells; the resource is well defined; however, in spite of this, several drilling attempts near "good" wells have been unsuccessful, resulting either in "dry holes" or cold water.

The probability of completing a geothermal well that has the desired temperature and flow rate is referred to as the confidence level. In a known geothermal resource area where geologic studies indicate a 90% confidence level of reaching 200°F (93°C) temperature at 1000 ft (305 m) with a 60% confidence level of striking an aquifer at this depth, then the confidence level is $0.9 \times 0.6 = 0.54$ or 54%. This means that approximately two wells would have to be drilled in order to obtain one successful well. As one can readily see, drilling costs combined with the confidence level play a major role in determining the feasibility of a project or the value of the resource.

Though the costs of drilling an unsuccessful well are lower than for a successful one, because an unsuccessful well probably requires only surface casing while a successful one requires full casing, etc., even a dry hole can cost up to \$75/ft (\$80/m)—a very significant sum for a 1000-ft (305-m) well.

The KF Model requires three production wells drilled to 1000 ft (305 m) with drilling costs of \$17,000 each. As the confidence level drops from 100% to 80%, the increase in cost is \$0.03/MBtu (\$0.03/GJ). A confidence level of 50% increases the cost to \$0.14/MBtu (\$0.13/GJ). By comparison, suppose the anticipated depth of a production well was 5000 ft (1524 m) and the cost of drilling an unsuccessful well increased from \$17,000-\$200,000. As the confidence level decreases from 100% to 50%, the annual equivalent cost increases by \$1.60/MBtu (\$1.52/GJ). The above figures are based on a 20-year life and a 15% cost of capital and are calculated as follows:

$$I = \frac{\left(\frac{P}{C} - P\right) d_u \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right]}{L}$$

- Where P = The number of production wells required
 C = Confidence level (as a decimal number)
 d_u = Drilling cost of an unsuccessful well
 I = Interest rate (cost of capital or return on investment)
 n = Life of the project in years
 L = Annual heat load in MBtu (GJ)
 I = Incremental annual equivalent cost per MBtu (GJ)

Graph 5 pertains to the KF Model which has an annual heat load of 6.0×10^4 MBtu (5.7×10^4 GJ), a 20-year life and a 15% cost of capital. The graph plots the change in annual equivalent cost per MBtu (GJ) for a \$17,000 well and a \$200,000 well as the confidence level changes from 100% to 10%. These annual equivalent costs are compared with the 20-year annual equivalent cost of natural gas. The confidence level has little effect on the \$17,000 well, but if drilling costs were \$200,000 per well, the project would break even with the cost of natural gas at a confidence level of 50%.

COST OF CAPITAL

Graph 6 compares the 20-year annual equivalent cost of geothermal energy to the cost of natural gas for the KF Model as the cost of capital or return on investment (I) varies from 5% to 60%. Three different annual load factors are plotted. The 25% load factor breaks even with natural gas at about I = 28%. The 50% load factor breaks even with natural gas at about I = 38%, and the 75% load factor breaks even with natural gas at about I = 57%.

The Klamath Falls Model is a typical heating district developed by a municipality. The entire system was financed with city, county, state and federal funds. The production wells, transmission and distribution pipelines and injection well were all located on land owned by the city.

In a discussion of pricing of direct-use geothermal energy, it is necessary to consider that the owner of a resource may wish to develop that resource and sell the energy to a user, in this case, a heating district. The price charged by the developer would have to provide an advantage over conventional energies in order to persuade the user to abandon his present heating system and purchase geothermal energy.

Table 1 presents a pro forma income statement projected over a 20-year period, with the following assumptions:

1. The geothermal developer owns the resource.
2. The developer will bear the cost of the entire geothermal system including \$500,000 retrofit costs for the existing buildings.
3. The developer can borrow money at the prime interest rate of 15% (this would probably be higher).
4. The developer agrees to sell energy to the heating district at a rate that is 10% lower than the cost of natural gas.
5. The developer will maintain the system. This cost is estimated to be \$8547/year plus \$30,000 for salaries.
6. Insurance for the system, excluding reservoir insurance, will cost 0.6%/year of the total capital investment.

GRAPH 5. Confidence level vs. drilling costs.

GRAPH 6. Natural gas vs. cost of capital vs. annual load factors.

TABLE 1

PRO FORMA INCOME STATEMENT
PROJECTED FOR 20 YEARS

(ALL COSTS AND REVENUES ARE STATED IN TERMS OF PER MBtu [APPROXIMATE GJ] PER YEAR)

Year	Gross Sales	Geothermal System Electrical Costs	Geothermal System Maintenance	Geothermal Maintenance Salaries	Geothermal System Insurance	Total Variable Geothermal Costs	Annual Loan Payment	Total Cost	Net Income Before Taxes	Present Worth At 7%
Present Cost	3.71	0.18	0.14	0.50	0.24					
1	4.159	0.202	0.152	0.535	0.242	1.131	6.319	7.450	-3.292	-3.076
2	4.666	0.221	0.163	0.572	0.247	1.203	6.319	7.522	-2.856	-2.495
3	5.235	0.242	0.175	0.613	0.252	1.281	6.319	7.600	-2.364	-1.930
4	5.874	0.265	0.187	0.655	0.257	1.364	6.319	7.683	-1.809	-1.380
5	6.591	0.290	0.200	0.701	0.262	1.453	6.319	7.772	-1.181	-0.842
6	7.395	0.317	0.214	0.750	0.267	1.549	6.319	7.868	-0.473	-0.315
7	8.297	0.347	0.229	0.803	0.273	1.652	6.319	7.971	0.326	0.203
8	9.002	0.377	0.245	0.859	0.278	1.759	6.319	8.078	0.924	0.538
9	9.767	0.410	0.262	0.919	0.284	1.874	6.319	8.194	1.574	0.856
10	10.597	0.445	0.280	0.984	0.289	1.998	6.319	8.317	2.280	1.159
11	11.498	0.483	0.300	1.052	0.295	2.130	6.319	8.449	3.049	1.448
12	12.476	0.524	0.321	1.126	0.301	2.272	6.319	8.591	3.884	1.725
13	13.536	0.569	0.343	1.205	0.307	2.425	6.319	8.744	4.792	1.989
14	14.687	0.618	0.367	1.289	0.313	2.588	6.319	8.907	5.780	2.241
15	15.935	0.671	0.393	1.380	0.319	2.763	6.319	9.082	6.853	2.484
16	17.289	0.729	0.421	1.476	0.326	2.951	6.319	9.270	8.019	2.716
17	18.759	0.791	0.450	1.579	0.332	3.153	6.319	9.472	9.287	2.940
18	20.354	0.859	0.481	1.690	0.339	3.370	6.319	9.689	10.665	3.155
19	22.084	0.933	0.515	1.808	0.346	3.602	6.319	9.921	12.162	3.363
20	23.961	1.013	0.551	1.935	0.353	3.852	6.319	10.171	13.790	3.564
TOTAL PRESENT WORTH									18.34	

The pro forma income statement shows projected cash flows per MBtu (GJ) using the same inflation rates as those in the economics section of this chapter. Salaries were assumed to increase at the economic inflation rate of 7% and insurance costs were projected to increase 2%/year. It should be noted that because of the high capital investment required, the system operates at a loss for the first six years and requires the next six years to recover these losses. With a 7%/year inflation rate, the present worth of the 20-year cash flows to the developer is \$18.34/MBtu (\$17.38/GJ) before taxes. If a developer were in a 50% effective tax bracket, the present worth would be reduced to \$9.17/MBtu (\$8.69/GJ).

Table 2 uses the data from Table 1 with the assumption that the developer does not own the resource. The developer pays a royalty of 10% of gross sales to the owner of the resource. Notice that such an arrangement causes the project to operate in the red for the first seven years and requires the next seven and a half years to recover these losses. The present worth of the 20-year cash flow to the developer is \$7.78/MBtu (\$7.37/GJ) before taxes or \$3.89/MBtu (\$3.69/GJ) after taxes.

TABLE 2

EXTENSION OF 20-YEAR PRO FORMA INCOME STATEMENT
PAYING 10% OF GROSS SALES ROYALTIES TO THE LANDOWNER

(ALL FIGURES ARE IN TERMS OF PER MBtu [APPROXIMATE GJ])

Year	Less 10% Royalty	Net Income After Royalties	Present Worth At 7%	% of Increase In Variable Costs Due to 10% Royalties
1	0.416	-3.707	-3.465	36.7
2	0.467	-3.323	-2.902	38.8
3	0.524	-2.888	-2.357	40.9
4	0.587	-2.396	-1.828	43.0
5	0.659	-1.840	-1.312	45.3
6	0.739	-1.213	-0.808	47.7
7	0.830	-0.504	-0.314	50.2
8	0.900	0.024	0.014	51.1
9	0.977	0.597	0.325	52.1
10	1.060	1.221	0.621	53.0
11	1.150	1.899	0.902	53.9
12	1.248	2.637	1.171	54.9
13	1.354	3.439	1.427	55.8
14	1.469	4.311	1.672	56.8
15	1.593	5.259	1.906	57.7
16	1.729	6.290	2.131	58.6
17	1.876	7.411	2.346	59.5
18	2.035	8.629	2.553	60.4
19	2.208	9.954	2.752	61.3
20	2.396	11.394	2.944	62.2
TOTAL PRESENT WORTH			7.78	

Table 3 presents a 20-year cash flow for the resource owner and shows a present worth of \$10.57/MBtu (\$10.02/GJ) before taxes of \$5.29/MBtu (\$5.01/GJ) after taxes.

TABLE 3
20-YEAR CASH FLOW OF ROYALTY PAYMENTS
PER MBtu (GJ) TO THE RESOURCE OWNER

<u>Year</u>	<u>Royalty Revenue</u>	<u>Present Worth at 7%</u>
1	0.416	0.389
2	0.467	0.408
3	0.524	0.427
4	0.587	0.448
5	0.659	0.470
6	0.739	0.493
7	0.830	0.517
8	0.900	0.524
9	0.977	0.531
10	1.060	0.539
11	1.150	0.546
12	1.248	0.554
13	1.354	0.562
14	1.469	0.570
15	1.593	0.578
16	1.729	0.586
17	1.876	0.594
18	2.035	0.602
19	2.208	0.611
20	2.396	0.619
TOTAL PRESENT WORTH		10.57

To summarize these data over the 20-year project life in terms of present worth at 7% per annum:

Developer A develops the resource on his own land and earns \$9.17/MBtu (\$8.69/GJ) after taxes (Table 1).

Developer B leases the resource, paying a royalty of 10% of gross sales to the resource owner and earns \$3.89/MBtu (\$3.69/GJ) after taxes (Table 1 modified by Table 2).

The landowner earns royalties of \$5.29/MBtu (\$5.01/GJ) after taxes.

The assumption of a 10%-of-gross-sales royalty was based on the fact that the federal government currently charges a royalty of 10% of gross energy sales for geothermal energy developed on federal lands. Since the federal government is exempt from taxes, the present worth of the 20-year cash flows of royalty payments would be \$10.57/MBtu (\$10.02/GJ). If the KF Model is a typical example, the federal government would receive a higher present worth per MBtu (GJ) than any other participant. Surface lease costs were not considered in this analysis. Such costs would increase the benefit to the resource owner considerably more than is indicated. The KF Model is not a good investment unless the production wells can be drilled on the city's own property with a cost of capital considerably less than 15%. Table 4 shows the capital investment costs of the KF Model.

In order to provide further perspective on the major factors which influence the value of a geothermal resource, we can examine two actual applications. These will be referred to as Case A and Case B. Both cases occur in well established geothermal resource areas with an established history of production.

TABLE 4

KF MODEL
BREAKDOWN OF SYSTEM COSTS PER MBtu
ASSUMES A 20-YEAR LIFE AND 15% COST OF CAPITAL

TOTAL COST SUMMARY

<u>Item</u>	<u>Cost</u>	<u>Including 10% Contingency Plus 5% Inflation</u>	<u>20-Yr. Annual Equivalent Cost @ 15%</u>	<u>Cost/MBtu (Approx GJ)</u>	<u>% of Total</u>
WELL AND WELL HEAD EQUIPMENT					
Production well	\$ 38,898	\$ 44,733	\$ 7,147	\$.119	
Well pump	41,988	48,286	7,714	.12857	
Well head bldg	3,500	4,025	643	.0107	
Power hook-up	<u>500</u>	<u>575</u>	<u>92</u>	<u>.00153</u>	
Total/1 Well	84,886	97,619	15,596	.2598	
SUBTOTAL/3 WELLS	\$254,658	\$292,857	\$46,788	\$.7794	16%
DISTRIBUTION PIPING NETWORK					
Primary supply	\$ 506,175	\$ 582,101	\$ 92,997	\$1.5499	
Secondary supply	<u>637,060</u>	<u>732,619</u>	<u>117,044</u>	<u>1.9507</u>	
SUBTOTAL	\$1,143,235	\$1,314,720	\$210,041	\$3.5	70%
HEAT EXCHANGER BUILDING					
Plate H.E.	\$ 28,000	\$ 32,200	\$ 5,144	\$.0857	
Control system	44,537	51,218	8,183	.13638	
Circulation pump	27,382	31,489	5,031	.0838	
Expansion/surge tank	5,000	5,750	919	.0153	
Building and Installation	90,000	103,500	16,535	.2756	
Injection well	30,000	34,500	5,512	.0919	
Building and hook-up	3,500	4,025	643	.0107	
Injection pump	<u>2,587</u>	<u>2,975</u>	<u>475</u>	<u>.0079</u>	
SUBTOTAL	\$ 231,006	\$ 265,657	\$ 42,442	\$.7074	14%
TOTAL	<u>\$1,628,899</u>	<u>\$1,873,234</u>	<u>\$299,271</u>	<u>\$4.99</u>	

Case A is a 200-bed hospital with an annual heat load of 1.89×10^4 MBtu (1.79×10^4 GJ). The hospital drilled an on-site geothermal well to a depth of 1582 ft (482 m). The well cost \$32,915.00. It produced 400 gpm (25 l/s) of 191°F (88°C) water with a static level of 332 ft (101 m) and a drawdown of 15 ft (4.6 m). A 100-horsepower, 500 gpm (31.5 l/s) deep-well turbine pump was set at 550 ft (168 m). The pump cost \$29,100. Total cost to the hospital for pipelines, shell-and-tube heat exchangers and installation was \$250,250. These costs were financed by an 8% bond maturing in 20 years. The system reduced the annual heating costs of natural gas and diesel fuel by \$31,200 in the first year of operation. The projected 20-year annual equivalent cost using natural gas and diesel fuel is \$6.60/MBtu (\$6.26/GJ). Actual fuel costs over the past three years indicate that this estimate is ultra conservative. The 20-year annual equivalent cost of the geothermal system is \$2.34/MBtu (\$2.22/GJ). This includes the interest and the payoff of the bonds issued. The average annual equivalent savings are \$80,301 over the 20-year period. Based on the quality of the resource, the actual life of the system is anticipated to be 40 years, an unexpected benefit. Because of the over-design of the hospital heating system and the temperature of the resource, the hospital was able to extract 80°F (44°C) from the geothermal resource.

Case B is a much smaller hospital with an annual heat load of 5.556×10^3 MBtu (5.27×10^3 GJ). A 1500-ft (457-m) well had been developed 1700 ft (518 m) from the hospital. This well produced 170°F (77°C) water at 240 gpm (15 l/s) with water quality less than that of Case A. Because the resource was known to exist at 1500 ft (457 m), Case B presents an excellent example for a comparison to Case A. The cost to develop a geothermal system was estimated to be identical to Case A (\$250,250). With less than 30% of the heat load required for Case A, the need for 400 gpm (25 l/s) did not exist. The existing heating system in this hospital required 180°F (82°C) supply temperature with 160°F (71°C) return fluid (20°F [11°C] ΔT). The water quality of the resource dictated a plate heat exchanger to isolate the geothermal fluid from the hospital heating system. Because a 10°F (5°C) temperature drop would occur from the primary to the secondary fluid, the supply temperature would be only 160°F (71°C), the same temperature as the return fluid in the existing system. Therefore, this hospital heating system would require \$25,000 for retrofit in order to extract a 20°F (11°C) ΔT from 160°F (71°C) supply water. At an 8% cost of capital, the 20-year annual equivalent would be \$5.04/MBtu (\$4.78 GJ). The cost of pumping and \$2500 per year maintenance, due to poorer water quality, totals \$4.19/MBtu (\$3.97/GJ) annually. The total annual equivalent cost for the whole project is \$9.23/MBtu (\$8.75/GJ) for the geothermal system as compared to a 20-year annual equivalent cost of \$6.35/MBtu (\$6.02/GJ) for natural gas.

As an alternative, the hospital considered buying 170°F (77°C) water delivered at the site by a geothermal developer at a price of \$0.45/100 ft³ (\$0.16/m³), thus eliminating all but the retrofit costs. The consequences of buying energy at \$0.45/100 ft³ (\$0.16/m³) and extracting only 20°F (11°C) ΔT would result in a 20-year annual equivalent cost of \$6.67/MBtu (\$6.32/GJ), assuming a 7% per year price escalation rate by the supplier of the geothermal fluid. In the year following this study, the geothermal supplier increased his price by 24%, making the marginal project totally unfeasible. This hospital continues to operate on natural gas.

SUMMARY

When direct-use geothermal applications for space or process heating are evaluated, experience has shown that each study must be site-specific.

A recipe for maximizing the benefit of direct-use geothermal energy is:

1. Develop resources at shallow depths with flow rates and temperatures that are compatible to the user. Good to excellent water quality is important.

2. Keep distances between the production well and the user to an absolute minimum, i.e., short pipelines.
3. Seek or develop uses that will require an annual load factor of at least 25%; 50% or greater is preferred.
4. Obtain low interest loans and be willing to reduce the rate of return on investment in order to reap the long-run benefits.

If prices or royalties are to be charged in situations where the developer and the user are different organizations, then values must be assessed against the annual savings or cost benefit resulting from the geothermal system. This price or royalty must be evaluated for each and every application. Each direct-use geothermal application is unique with supply and demand dedicated to each other.

Consider the two actual applications, Cases A and B, in this chapter. Case A describes a very valuable resource with substantial savings to the user over a 40-year period, while Case B, with a resource only 20°F (11°C) lower in temperature, is of no value to the user.

To establish a price for direct-use geothermal energy, one must study the structures and characteristics of the costs presented in this chapter. One should also keep in mind the aspects and lessons of Case A and Case B. Our case rests.

CHAPTER 6

FINANCING DIRECT-USE PROJECTS

Work Group

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INTRODUCTION

The successful operation of any direct-use geothermal project will rely on the organization and implementation of a complete financing program. A major cause of failure of start-up business ventures is poor financial planning and inadequate capitalization. The developer must carefully determine and evaluate his geothermal project from several standpoints. Particular attention must be given to identifiable risk factors since the project's financial requirements will be defined not only by the characteristics of the resource, but also by the intended utilization and development program. The financing will be structured in such a manner as to allocate project risks and rewards appropriately to the different kinds of participating capital. Typically, the types of capital involved in a project will range from the highest-risk equity portion to the lowest-risk, fully secured or guaranteed loan.

To qualify for financing the developer must demonstrate to the prospective lenders and investors that the project in question is economically viable and well managed, as well as technically sound. Financial institutions and other potential investors must be informed fully so that they can ascertain the project's capability to sustain itself through time. A special consideration to be highlighted is whether the project is totally dependent on the continued use of geothermal, or if retrofitting to conventional energy sources is possible and economical should the resource fail.

The development of a financing program also depends on making satisfactory provision for a number of other aspects of the project such as construction budget (bonded contractors, cost overrun protection, etc.), well production rates, fluid quality, equipment life and product marketability. Although not themselves financial in nature, each of these aspects will affect the project's profitability and financial viability.

Financial personnel or consultants should participate fully in the earliest project planning and evaluation stages in order to assure a broad coordination of the financing aspects along with the plan's overall development. Such integration will accelerate the financing of the project by building in the information necessary to facilitate the project's evaluation from an investment point of view. In addition, tax and corporate attorneys are essential members of a project analysis and presentation team because of their expertise in tax benefit analysis and legal structuring. If the developer is retaining such consultants (especially finders and agents) from outside his own organization, their credentials and capacity to perform should be thoroughly verified before they become involved in the project. Money should be paid only for services rendered.

The following is a detailed outline of the various aspects involved in developing a financing program. Initially, potential projects are categorized by type. Risk considerations associated with the financing are identified and discussed. The sections first describe the range of available funding sources, both public and private, then define the different types of financing available from these sources. An overview of financial considerations precedes a practical guide on how to prepare a project presentation.

PROJECT DEFINITION

In approaching the financing of a project, we must first define the underlying business characteristics of the industry in question. Suitable understanding of one's starting point will avoid the "square peg/round hole" routine in trying to finance one kind of business on the format of another type.

Generic classifications

The capital structuring of an industrial, agricultural or utility business differs. Generally, agricultural businesses are the least capital intensive, utilities the most, with industrial projects falling somewhere in between. The capitalization and balance sheet characteristics of different types of businesses are compiled by a number of financial service companies such as Robert Morris Associates or Dunn and Bradstreet on their "Annual Statement Studies." Direct use of geothermal resources represents a new twist for agribusiness projects because more capital equipment is utilized thereby resulting in a corresponding reduction of non-depreciable land required. Whatever the business differences between traditional and intensive agriculture, it is important to know what institutions expect from a financial structuring point of view.

Start-up businesses

These ventures represent a more difficult financing challenge, especially if the total investment of the project is such that outside investors have to be brought in. Basically, many more unknowns and variables exist for a start-up company, no matter how established the industry itself is. For a start-up company, investors will want to find out whether the industry will continue to grow and prosper overall for as long as it takes them to earn a satisfactory return on their investment. They will want assurances as to the experience of the proposed management team. Technological, resource, environmental, marketing and regulatory risks will have to be defined from the viewpoint of a new business. Factors which may delay start-up or inhibit the commencement of cash flow will have to be analyzed as well. As a result, equity requirements as established by lenders to the project may have to be higher than for ongoing projects. The rate of return requirements expected by the equity investors will be higher as well.

Ongoing businesses

Established businesses fall into two categories.

Expansion projects. The expansion of a conventional facility by means of a geothermally powered addition may be an economically attractive investment for a company dependent on high-priced energy alternatives. The financing of such an addition may depend solely on the parent company's credit rating and proven track record. If the existing facilities are competitive based on conventional fuels, there would always be the possibility of retrofitting from geothermal should the resource fail. For these kinds of projects, financial participants will depend on the company's track record, financial strength, and the fall-back position.

Retrofits to geothermal. A conversion of the existing facilities to geothermal may be desirable for the cost-saving aspects thereof or because of an energy pinch where alternate energy supplies are becoming unavailable. The voluntary retrofit would most likely be financed on a similar basis to the expansion described above. The involuntary conversion may result in some disruptive financial pressures on the business and may require evaluating whether the business will discontinue its operations at the site or write off the existing facilities and install geothermal ones. Additional factors in evaluation are the company's ability to fund a significant part of the project internally, its present credit rating, and its prospects for future growth.

DEFINITION AND ASSESSMENT OF FINANCING RISKS

Having outlined the basic kinds of project scenarios, let us address the assessment of risk factors in such financings. The project developer should be aware that many viable projects have been denied financing due to a lack of information or a poorly conceived risk management

program. The goal is to educate the prospective financial participant in every phase of the project's business, leaving no questions unanswered. The fact that a project is based on a geothermal energy supply does not alter that project. Fundamentally, including geothermal only adds one more dimension of risk to be quantified. Some questions may arise concerning the following aspects of geothermal energy.

The geothermal resource

The geothermal resource, as the proposed energy source of a business, is of particular concern regarding its availability, the feasibility of its use, and its reliability as well as its economic competitiveness with alternate fuels. It will be easier to raise capital for a project which is dependent on a proven or operational fuel source rather than a new source. Even if the proposed application differs from the current utilization of that resource, the geothermal reservoir will benefit from the credibility which results from knowing its historic performance (flow and drawdown rates) and temperatures. Potential problems such as scaling, corrosion, and pumping requirements should be outlined as well as the methods necessary to overcome them. If operating history for the site in question is not available, it would be useful to note examples of resources possessing comparable temperature, pressure and salinity which have been successfully utilized elsewhere as well as furnishing all reservoir test and evaluation data available to date. In summation, the resource description should include its extent, its physical properties, longevity, problems encountered and solutions applied.

Process and technological risks

Process and technological risks should also be fully identified. The proposed technology should be clearly and concisely explained. The developer should specify whether the technology has a long history of commercial use or whether it is basically an unproven approach. Risks associated with the functioning of the plant are as important as those associated with the performance of the resource.

The overall economic viability

The overall economic viability of the project must be demonstrated to the potential financial participants. This phase will include market assessment for the production output of the project, and analysis of operating costs as well as incorporation of the cost benefits of the geothermal energy source. The economics of the geothermal energy source should be compared with the most appropriate alternate fuel available to the project. It should also be specified whether the project is economical solely as a result of geothermal resource use, or whether a backup system of electric, gas, fuel oil, etc. could be economically installed in the case of reservoir failure. In the latter case, geothermal would simply offer added internal profitability incentives to proceed with the project by reducing fuel costs and increasing the tax benefits available to the business with resource risk being a lesser consideration.

Management capability

The management capability of a project dictates the success of any business endeavor as much as technology, energy source, and product. A prospective investor will want to know about the key principals in the business, their background and qualifications, and, especially, their related business experience. The level of management commitment is most clearly exhibited by factors such as their own investment in the business, employment contracts they may have, or their status as simply talented "free agents." The concerns with management include not only technical experience but also managerial and financial expertise.

The business structure

The business structure can also make a difference in various financial options. The choice of structure (partnership, limited partnership, corporation, sole proprietorship, etc.) will depend, to a great extent, on the financial requirements of the major equity investor(s). It should be determined whether the assets need the protection of a corporate structure or if the investors prefer the greater tax flexibility of some types of partnership. This question, in particular, requires the advice of tax and legal experts.

SOURCES OF FINANCING

Because geothermal development proposals represent the utilization of an alternate energy source, financing is available not only from the usual source of capital, the private sector, but also from the public sector. In the private sector, financing is generally obtained from various debt and equity sources. Funds from the public sector may be in the form of debt, guarantees, or outright grants. This section outlines the different kinds of financial sources potentially available to the developer of a geothermal project. Some of the financing sources described can handle geothermal risk, but others can not. Since the actual portion of any direct-use project actually involving geothermal risk may be quite small, conventional financing sources might be utilizable for the remainder of the project. It is quite probable, however, that lending sources will view the geothermal risk as affecting and, in effect, classifying the entire project.

Private sector

Commercial banks. These banks typically finance automobiles, houses, working capital requirements of ongoing businesses, capital equipment, some project financings, etc. and are, generally, the most conservative lending institutions in the group of available sources. Loans are generally made over the short and medium term, i.e., under eight years. Interest rates will generally be charged at a fixed or variable spread over the bank's prime rate, i.e., the rate offered to the most credit-worthy clients. Fixed-rate lending was more common during periods of stable money market conditions and is, therefore, presently difficult to obtain. Currently, with prime in the double digits, money is both tight and expensive. Banks also have lending limits which means that they cannot lend more than 10% (generally) of their total capital to any single customer. Depending on the relative size of the proposed project and the bank's capital, a bank could be limited in the size of the loan it is able to fund by itself. This constraint does not limit the bank's ability to handle the project inasmuch as a bank can syndicate (offer participations in the loan to other banks) the project so that several banks would become involved. This approach also spreads the risks associated with the project. Banks are also the usual source for unsecured short term working capital lines of credit. However, an operating track record is necessary in order to demonstrate the ability of the business to pay back the entire loan at least once a year. Commercial banks vary in size and function. Some are full service banks in that they can arrange in-house private placements or leveraged leases and provide a variety of other financial services. Other banks simply engage in direct-loan and deposit transactions. For any type of business transaction, it is generally advisable to approach a full service bank in order to have a wider range of financing choices. The lending officer of the commercial bank will explain any financial requirements.

Savings banks. These banks invest primarily in local residential mortgages of modest size. Although their rates are competitive with those of other mortgage lenders, their terms (down-payments and loan periods) tend to be slightly more conservative than those of savings and loan associations, and about equal to those of insurance companies and a bit more liberal than those of commercial banks. They are generally smaller in size and more local in nature than savings

and loan associations.

Savings and Loan associations (S&L). These S&L associations lend primarily on residential and commercial property in the form of real estate loans secured by land and buildings. An S&L might be approached for the mortgage financing of new geothermal construction as well as retrofit to geothermal space heating or air conditioning of existing structures. This type of project fits well in the S&L portfolio since they will lend for periods up to thirty years. The down payments and loan periods on conventional mortgages granted by S&L's are typically more liberal than those granted by either commercial banks or life insurance companies on similar mortgage loans. On the other hand, mortgage rates charged by S&L's are usually higher than rates charged by other institutions. This is partly a function of accepting riskier mortgages, but it is also linked to the fact that the associations pay higher interest rates on savings accounts. The advantage of fixed-rate financing is that the cost of money is known for the life of the loan. A disadvantage is that taking on such financing at periods of high interest rates will result in high fixed interest costs over the life of the project. In that case, the loan should be structured so that it could be paid off and refinanced at a lower rate at a more favorable moment in the money market. S&L's always take a secured position in the real property or a first trust deed. Financing inquiries are handled by the local S&L lending officer.

Insurance companies. Insurance companies make both mortgage loans and business loans. Most investment is long term, ranging from ten to twenty-five years, since the insurance companies' long-term cash requirements are fairly predictable. The fixed rates offered by insurance companies are higher than mortgage-type rates since the level of risk accepted is somewhat higher. An insurance company can be approached through a commercial or investment bank, mortgage banker or investment broker. Local offices of the insurance companies may also be staffed to handle inquiries.

Trusts and pension funds. Trusts and pension funds are similar to the insurance companies in that they will make loans up to thirty years, because they do not have to disburse their funds for quite a number of years after the premiums are paid. Funds have been known to take greater risks than any of the lenders previously discussed. They lend at relatively high fixed rates of interest. However, recent rulings on the liability of fiduciaries have made all money managers more cautious. Although some trusts and pension funds answer direct inquiries, many are not staffed to handle requests for financing except for those referred from other financial institutions.

Commercial finance companies. Commercial finance companies specialize in lending to high-risk commercial customers through a wide range of short- and long-term debt arrangements. The interest rates charged by commercial finance companies are higher than most other lenders and are as varied as those of commercial banks, but their overall lending capability is much smaller. A commercial finance company can be expected to monitor the borrowing company's performance very carefully during the term of the indebtedness.

Personal finance companies. Personal finance companies are the most flexible of all lending institutions but they also charge the highest rates of interest. In addition, the size of the loans does not usually exceed \$25,000. The loan is made personally to the entrepreneur for the use in his business and depends on his credit rating. For a small business without an established credit rating, this may be the only means of obtaining a loan.

Mortgage bankers. Mortgage bankers usually act as brokers, packaging a deal and selling it to a large investor for a fee or sometimes making the investment themselves. Occasionally, they refinance first mortgages on projects with an existing equity investment and where the security is a subordinated interest in the asset. This type of financing is more readily available once the project has an operating history. Refinancing the first mortgage may be a source of operat-

ing funds if the debt restructuring takes place at a time when interest rates have decreased since the original loan was granted.

Investment banks. Investment banks, while not a source of funds in themselves, are a vehicle for obtaining funds. In general, investment bankers perform three basic functions: (a) financial counseling, (b) underwriting and (c) marketing and distribution of corporate securities. It is the first and third functions that are pertinent to the entrepreneur of a geothermal business. We have already identified the importance of qualified financial counsel. With regard to the marketing of corporate securities, investment bankers come into contact daily with investors and have first-hand information on the availability of funds. These services are provided for a fee.

Equity investors. Equity investors provide "at-risk" capital, usually through the purchase of common stock in the company or, alternatively, through making a loan or purchasing preferred stock, either of which may, at some time during the company's life, be converted to common stock. Equity investors generally prefer to control the operation since they bear the greatest risk.

There is no set rate of return or interest rate on common stock. Equity investors anticipate that the stock acquired will increase in value in addition to earning dividends.

One of the requirements an equity investor may have in investing in a start-up project is the utilization of available tax benefits. Tax considerations assist greatly in attracting equity capital, especially since the National Energy Act of 1978 has enhanced the tax benefits for investors in geothermal projects. Most investors are in high income-tax brackets and the available benefits such as immediate deductibility of intangible drilling costs, a 20% investment tax credit on "geothermal" equipment and a depletion allowance of 15%-22% are very attractive incentives. Depending on the structures of the investment, an investor could recover a significant portion of his investment through tax benefits alone. It is critical that tax counsel be requested for advice on these matters.

Traditionally, the primary method of identifying equity investors has been to work through a reputable investment banking house. To date, however, there is only one specializing exclusively in geothermal activities. Your financial advisor should be able to give guidance on the reputations and capabilities of these firms.

Small business investment companies (SBIC). Small business investment companies represent a special class of equity investors and lenders. SBIC's are generally privately owned investment companies which provide financing to small businesses that meet the specific criteria of the government's Small Business Administration (SBA). They are licensed by the SBA and given incentives to specialize in this type of investment, such as low-cost loans to supplement their capitalization. Most financing from an SBIC is supplied through the purchase of stock or "convertible debentures" (loans which can be converted into stock at a later date). Although this type of equity participation is preferred, SBIC's do make some loans at moderate rates of interest. The first step in approaching this source of funds is to contact the Small Business Administration's local office to determine if the business meets the criteria for eligibility and, if so, to obtain from them the published directory of licensed SBIC's. It is then necessary to contact the SBIC directly.

Leasing companies. Leasing companies represent another form of financing, specifically for the acquisition of capital assets. It is an alternative to purchasing the asset, making a down-payment or initial equity investment, and financing the remainder of the purchase price with debt. In lease financing, another party acquires, finances and then leases the assets to the users. A financial lease is a non-cancellable contractual commitment by the lessee to make a

series of payments to a lessor for the use of an asset. The lease period of a lease generally corresponds to 80% of the economic life of the asset. The total payments the lessee agrees to will exceed the purchase price of the asset. Assets eligible for lease property are generally limited to equipment and buildings.

Leasing offers the advantage of flexibility and essentially 100% financing of the assets as well as tax deductibility of the lease payment. One disadvantage is that the residual or terminal value at the end of the basic lease period goes to the lessor. However, it may be possible for the lessee to obtain an option to renew the lease or purchase the asset at the end of the basic lease period. Another disadvantage is that the interest cost is usually higher than the interest cost of debt when the amortization of the cost of the asset and the tax benefits is taken into consideration.

There are leasing companies which may be contacted directly and leasing services offered by most large financial institutions.

Public sector financing

Federal, state and local government agencies offer a variety of financing programs to private individuals and developers for energy projects. A project which can visibly benefit society, such as one which replaces scarce fossil fuels or attracts new business to an area, is a good candidate for government financing. By supporting these projects, government agencies can not only attain their chartered goals, but can also maximize the benefits which accrue to society in general.

Persons or entities seeking partial or complete funding for geothermal projects will have to apply to the appropriate government agency. Of all the federal, state, and local agencies, only one, the Department of Energy (DOE), has programs designed specifically for geothermal use. These include the Geothermal Loan Guaranty Program (GLGP) and other programs that are periodic in nature. Unequivocally, these programs will have the most bearing and relevance to one's project needs. Other public agencies, also described here, are tailored more to conventional business and agricultural operations. Their applicability and availability to geothermal projects will vary on a case-to-case basis. In all other cases, no geothermally related financing precedents appear to exist so that an approach to such an agency will be breaking new ground.

In some cases, two or more public programs might be combined to finance different portions of a geothermal project. The GLGP could fund the resource side and the Farmers Home Administration could fund the land and buildings, for instance. It is strongly recommended to check first with the Department of Energy to determine the fit between its financing programs and one's project needs. Contrary to any other assertion, it is best to contact GLGP personnel in the Oakland office directly with questions. Inquiry can also be made through the state or local Department or Chamber of Commerce for agency programs which might be available. Local agencies will often provide funding for small projects but will have neither the capability nor the funds to assist in larger projects.

Several important characteristics of public financing and government agencies must be borne in mind, particularly since these factors can result in delays before one's project gets off the ground:

1. Some of the public agencies only give assistance after all private lending sources have been approached. Valuable time is required to keep returning to private lenders, one after another as the agency dictates.
2. Public lending agencies may take from six months to a year or more to make their decision

If all the necessary paper work initially submitted is correct. Corrections require even more time.

3. Related public agencies (environmental agencies, local government planning agencies, county governments, law enforcement, councils of government, etc.) may be required to review and approve the project. This review may require additional time to satisfy the specific concerns of these outside agencies.
4. Budgets to the government lending agencies can be interrupted without notice, especially direct loan funds. Their programs are, in most cases, funded by quarterly committed money amounts.
5. Public agencies tend to require very tight fiscal control and audit procedures and almost every management decision regarding expenditures can be questioned. If government agency cost analysts don't agree with management approaches to problems, they interrupt or delay the funding.
6. Almost all agencies require formal equal opportunity employment practices to be instituted in the business.
7. Consistency in interpreting loan criteria may vary from one office to another or from person to person within the agency.

GOVERNMENT FUNDING DEPARTMENTS

Some of the departments with financing programs are listed below.

Department of Energy

The Geothermal Loan Guaranty Program. This program will guarantee up to 75% of total allowable project costs to the lender against loss of principal or interest in loans made to the borrower. Eligible projects may vary in nature, ranging from resource development to the construction and operation of facilities. Applications take between four months to one year to process depending on the type of project and the extent of environmental impact statements to be prepared. Terms and conditions for loan guarantees are specified by DOE. A fee of no more than 1% annually on the average outstanding loan balance will be charged to the lender and will be passed on to the borrower. Reasonable and prevailing loan rates are allowed on a basis as determined by the Secretary of the DOE in consultation with the Secretary of the Treasury. Loans are guaranteed for up to thirty years depending on the project. Contact the Loan Guaranty Program, Department of Energy, 1333 Broadway, Oakland, California 94612, (415) 273-7151, for program information.

The Small Business Administration (SBA, Department of Commerce)

This agency is set up to assist small businesses with counseling, management and/or funding. To qualify for funding assistance, a business must meet SBA requirements and demonstrate that funds were not available through normal channels. There are two funding approaches offered by the SBA:

Loan Guarantee Program. Up to 90% of a bank loan not exceeding \$500,000 will be guaranteed by the SBA. Interest rates on loans are determined by the participating bank and will generally be at the prevailing rates for similar types of federal guarantees plus a servicing charge. Should the applicant's bank have denied the project funding, it might be willing to reconsider

financing with an SBA guarantee, if asked.

Direct Loan Program. On low-risk projects, up to \$50,000 will be loaned directly. However, the amount tends to vary from region to region. Interest rates are lower on the SBA direct loans than on those secured from private sources.

The local state SBA representative should be contacted with regard to the geothermal project in question. Since the SBA is not chartered to fund geothermal risk, per se, funding availability will depend on the overall applicability of the project to SBA guidelines.

The Farm Credit System (FCS)

This system is divided into three major banking units. Individually, each is designed to meet specific borrowing needs as their names suggest: farm mortgage loans from the Federal Land Banks; production and intermediate term working-capital loans through the Federal Intermediate Credit Banks; and credit for cooperatives from the Banks for Cooperatives. Loans from these farm credit banks are made for periods ranging from a few days on commodities to forty years on land. They are secured by solid collateral, including land, buildings, equipment, livestock, and other agricultural assets. Details and eligibility requirements are provided by the Fiscal Agency Farm Credit Banks, 90 William Street, New York, N. Y. 10038.

The Farmers Home Administration (FmHA, Department of Agriculture)

This agency aids small operators needing assistance for a great variety of projects. Each state usually has at least one office which can determine if one's project is eligible for FmHA financing. Unlike the Small Business Administration which has lending limitations, FmHA has no limit. Among its financing programs are the following: (a) Farmer Program (Farm Operating Loans and Farm Ownership Loans); (b) Business and Industrial Loan Program; and (c) Loan Guarantee Program. Washington or the state FmHA office has needed details. Neither the FCS nor the FmHA are designed specifically for financing geothermal development per se but could be utilized for the financing of land and structures in agribusiness projects. Several hurdles exist, however, in both qualifying the project under USDA guidelines and in structuring the terms of the financing.

The Economic Development Administration (EDA)

This agency, like the FmHA, has a variety of funding programs depending on the specific need and nature of one's project. Most projects, however, must show the promise of increasing employment opportunities in the community. The EDA will assist in planning and give technical advice to public sector and non-profit organizations. Specific financing programs for these entities and for the private sector are by means of direct loans and loan guarantees. Specific eligibility requirements and detailed information, are available from the agency in Washington or from the state EDA representative.

Other public agencies

There are numerous smaller and larger agencies and programs on all levels which can provide loans, grants or guarantees. The appropriate state Department of Commerce should be contacted for the most up-dated list of these agencies and contacts should also be initiated at the local, municipal level as well as with Washington. In addition, one's financial advisor may be able to furnish advice and reference to some of the lesser-known but applicable programs.

FINANCING STRUCTURES

Each source of financing described thus far may be active in providing funds in a number of dif-

ferent formats. A structure that is appropriate to the specific needs of the project may be selected from some of the following:

Private sector debt financing

Secured lending. Secured lending may be available to firms that have little or no business experience track record or whose ability to service debt is not regarded as adequate by bankers. In this case a lender will require a security interest in the collateral of the borrower. Sufficiently marketable collateral may include buildings, accounts receivable, inventory, equipment or other assets of the borrower.

Project financing. Project financing makes funds available to a project based on a commitment of a credit-worthy customer to purchase the output of the project once it is operational. This arrangement, in effect, transfers most of the credit risk to that of the established entity.

Lease financing. Lease financing is a contractual arrangement under which the lessee agrees to pay the owner of certain equipment a fixed fee for its use. This agreement usually extends for approximately 80% of the life of the equipment and is non-cancellable.

Mortgage lending. Mortgage lending is a form of secured lending. In this case, the loan is usually secured by fixed assets, such as buildings and land, of the borrower. The property securing the loan is described in the mortgage or first trust deed, a legal document giving the lender first claim to the property in the event of a default by the borrower.

Term lending. Term lending provides funds in return for a loan agreement obligating the borrower to repay the amount of the loan plus interest over a specified period of time. The loan is made based on the credit of the borrower:

- (a) Long-term loans are repaid over a period of time longer than seven years.
- (b) Intermediate or medium-term loans are repaid over a one- to seven-year period.
- (c) Short-term loans are repaid in less than a year.

Working capital lending. Working capital lending provides cash for current operating needs and is usually both short-term and unsecured. These loans are typically regarded as "self-liquidating" in that the funds are utilized during periods of time that the company is "cash-short" and repaid when the company is "cash-rich", generally on a cycle of less than one year.

Private sector equity sources

All equity is known as "risk capital" because it does not warrant a specific return but it shares in the earnings of the business.

Venture capital. Venture capital is equity provided by investors, either singly or in groups for direct private investment in smaller start-up or development companies judged to have high growth potential. In most cases, the risks are judged to be high and the rewards, or share of the hoped-for profits demanded, are high as well. Venture capitalists are sure to become very involved in the business. In spite of these constraints on the project, the demand for venture capital far exceeds the supply. Only the "most-likely-to-succeed" projects are able to attract this type of funding.

Tax-shelter money. Tax-shelter money is capital made available by individuals in high

Income tax brackets with significant tax exposure. They are able to invest in projects that, by means of tax benefits such as investment tax credit, depletion allowance, and depreciation, will result in a decrease of their tax liability. However, the project has to be economically sound and yield a positive cash flow.

Stock placement. Stock placement involves the sale of a specified amount of ownership in a business--usually one having a history of earnings. It may be accomplished either privately with selected investors making substantial purchases or publicly to any number of investors. Typically, stock owners are more passive than venture capital investors. The stocks placed may be either common or preferred, depending on the requirements of the investors. Preferred stock receives a fixed dividend each year but does not normally have voting rights. Common stock has voting rights and receives a dividend as declared by the elected board of directors.

Convertible securities. Convertible securities are either bonds or preferred stock which receive a specified return but can be converted, at the option of the holder, into common stock. Usually the interest rate on convertibles is somewhat less than the same securities without the convertible feature. Convertible securities give the holder the advantage of receiving interest in the present and having the opportunity to participate in the earnings potential of the company in the future.

Public sector programs¹

Because of the great variety of public-sector financing options as yet largely untried in the geothermal context, we have restricted ourselves to outlining in this section the three basic types of programs available.

Direct loans. Numerous government programs extend loans to private and/or public sector entities for the financing of agricultural, industrial or residential facilities, although not specifically for use with geothermal resources. Each agency has differing interest rates and conditions attached to their loans. In general, direct loans from public sources will have longer terms and lower interest rates than those from commercial sources. If the proposed geothermal project qualifies, the federal, state and local agencies listed in the preceding section should be contacted.

Loan guarantees. On government-guaranteed loans, a government agency will guarantee up to 90% of a secured bank loan. The Geothermal Loan Guaranty Program, designed specifically for the commercialization of geothermal development, will guarantee up to 75% of total allowable project costs at a charge of no more than 1% per annum on the guaranteed loan balance outstanding. Other agency programs offering loan guarantees will generally have the capability to guarantee loans up to thirty years in length, will charge a guarantee fee, and will require the securing of the bank loan by the assets of the project.

Grants. Grants may be available for studies as well as demonstration projects. Cost-sharing is generally required. In this case, funds are advanced by the government agency but need not be repaid.

The Intermediary Risk Assuming Company (IRAC)

The Intermediary Risk Assuming Company is the first financing vehicle designed specifically to handle reservoir and utilization prove-out risks both for electric and non-electric geothermal developments, including industrial, space-heating and agribusiness projects. The IRAC structure

¹ For more information on agencies, refer to SOURCES OF FINANCING, Public sector financing or REFERENCES CITED.

is used when a developer has indentified a potential resource for utilization, but cannot afford the financial risks involved in building a plant on a previously unutilized reservoir. In this situation, the IRAC financing would supply the risk capital to develop required production levels from the reservoir, would finance the utilization facilities, and would maintain ownership of the development. The developer could contract with the IRAC to operate and manage the plant or maintain a fully arm's length posture. In any event, the developer would agree to purchase the product output of the facility. After reservoir prove-out, the developer could exercise a pre-arranged option to buy out the entire project. Developers interested in this financing arrangement should first contact risk financing groups or venture capital sources. A feature of major importance in the IRAC financing structure is that it can combine, with great flexibility, both public and private sector financing options.

FINANCING CONSIDERATIONS

In addition to the basic business plan, there are various other considerations of interest to prospective investors/lenders. Some points that may be relevant are the following:

Debt/equity ratios

The ratio of equity to debt financing varies among various industries depending on capital investment required per dollar of sales, established industry-wide pattern, classification of assets, etc. An industry comparison should be the guide for evaluation. A further consideration is whether the project under consideration is a start-up venture or not. For a financing where there is no prior experience or history, it is unlikely that financial institutions will lend to the project unless the debt to equity ratio approximates 1:1. For established businesses, where equity is commonly more highly leveraged, banks may be willing to lend on as much as a 2:1 basis. Higher leverages are possible if project financing structures or IRACs are utilized; thus, equity as low as 10% of the total project may be acceptable. This kind of structuring is dependent, however, on the shifting of the credit risk away from the borrower to the contracted customer(s) for the production resulting from the project.

Regional vs. money center funding

Local banking relationships are of major importance to a project in terms of short-term borrowings, receivables financing, credit lines, etc. A company should first attempt to secure any of its financing requirements from local sources. In some cases, however, local financial institutions may not be in a position to finance an otherwise desirable project because of local tight money conditions; therefore, contact should be made with financial institutions in major money centers, such as New York, Chicago or Los Angeles. Generally, a local bank would be able to take up the matter with its correspondent banks. In addition, a money center bank may provide funding to the local bank (a loan to the local bank for a loan by the local bank--at its risk--to the borrower).

Contingency planning

In predicting project performance, the likelihood of obtaining desired performance and profitability objectives under actual operating conditions is not very high. Contingency planning should be approached in two distinctive ways. In the first, a sensitivity analysis should be performed to identify the key performance and profitability variables. Performance projections should be prepared, evaluating both downside and topside outlook. The second approach should involve the identification of major potentially problematic areas and the development of specific management responses to resolve these problems.

Economic outlook

An overview of the economic setting, for the region as well as for the industry of which the project is a part, will help determine the willingness of financial institutions to lend to that economic sector. Loans and equity investments are traditionally harder to raise for declining industries than for growth sectors.

Multi-purpose facilities/retrofit applicability

Although these topics could also fall under the aspect of contingency planning, their importance to the basic structuring of a geothermal financing is such that they deserve separate mention. For a lender seeking security in real property as opposed to the indicated cash flow potential of a project, the multi-purpose nature of a given facility should be clearly demonstrated. For example, if the project originally conceived fails because the food processing market disappears, then the building itself will still be an excellent investment (no added expense necessary) for grain-sprout production. The greater the perceived security for a lender, the greater the likelihood of obtaining higher levels of more favorable financing. Likewise, if it can be demonstrated that economic use of the facilities can still take place even after the retrofitting of the facilities to a conventional fuel source should the geothermal resource fail, the attractiveness of the project to potential lenders is also enhanced.

Scale of project

Economic production levels vary from industry to industry with the scale of a project. Greenhousing and prawn farming can be conducted economically on an investment threshold of as little as \$100,000 to \$250,000. It is hard to imagine the establishment of a financially sound dehydration facility or an environmentally controlled meat production facility of less than \$3-\$5 million. A large-scale heating system may require minimum investments in excess of \$10 million for it to be economic. The scale of the project in question should incorporate consideration of viable economic units of scale. The project should not be too small, thereby limiting reasonable profitability, or too large, thereby taking too much risk at the front end or development stages. Tailoring a project to a viable economic unit size is an important consideration in the arranging of a financing program.

Availability of tax-oriented incentives

In attracting equity capital and maximizing project profitability, it is necessary to ascertain the extent and availability of enacted tax legislation to a given project. Included in these are the basic tax credit, the alternative energy tax credit, accelerated depreciation, depletion, intangible drilling cost deduction, new job credit, etc. Legal opinions or rulings may be necessary to confirm the availability of such. They should be obtained at the appropriate time.

Payout

Risk or equity capital have to determine an acceptable time frame and extent of payout resulting from their investment. The range includes returns on capital from 100 to 400%, with and without inflation adjustment, or some combination thereof, and will vary from project to project. Competition for venture capital from other sources (such as the stock market which is depressed at present) and high interest rates will determine the pricing in each specific instance.

Regulatory considerations

The amount of present or proposed government regulation, standards, environmental, reporting

requirements and other interfaces will, to some extent, affect the amount of capital available to certain projects. This situation may arise from local as well as federal regulations.

Completion guarantees

One of the major cost components in any project is the construction of the facility and equipment installation. It is essential that the maximum protection be obtained with regard to the control of such costs and the warranty of the equipment to be installed. This protection can be accomplished by: fixed price construction contracts, overrun cost sharing, force majeure insurance, use of bonded contractors, construction audit routines, etc.

Operating experience

The best-known method to date for the assessment of the reliability of resource/reservoir performance is the accumulation of operating experience. It appears that some combination of resource testing, commercial utilization, and initial size of development will permit the early accumulation of operating experience under revenue-producing circumstances. Expansion and refinancing under more favorable terms and conditions can thus be accelerated once the commercial production characteristics of the resource are known.

Growth potential

Opportunities for future development of the project site for expanded or related utilization technologies will enhance its overall attractiveness.

Over-engineering

The technical aspects of the project should incorporate as simple and direct operating systems as possible until performance capabilities can be established. To the maximum extent possible, innovations and refinements should be added after a suitable debugging period or upon plant expansion, thereby reducing technological risk at start-up.

FINANCIAL PROGRAM STRUCTURING AND PRESENTATION GUIDE

Because capital markets function under the theory that an investor/lender should be adequately compensated with respect to the degree of risk taken, a developer/entrepreneur must make every effort to quantify and analyze the risks associated with the project. Such a detailed evaluation of a business venture is usually drawn up in a business plan or placement memorandum which will present all of the information necessary for a critical assessment of the investment proposal. It will then be possible to approach financial institutions, government agencies or private investors since any credible source of financing will insist on reviewing the proposal in depth before considering any investment seriously. Therefore, a business plan must be concrete, comprehensive and clear in setting forth the potential of the business.

The package should develop (1) the business objective of the project, (2) its overall economic viability including an analysis of the proposed market, (3) the technological process and facilities, (4) the business structure, (5) management capability and (6) all of the perceived business risks and available counter measures associated with the project, dealing especially with the reliability of the geothermal resource. Financial information will be required and will include the investment contributed by key principals; detailed pro-forma income statements and balance sheets; a summary of financial assumptions utilized; and the proposed sources and uses of the fund requested.

As with any utilization of numbers in finance or in statistics, accuracy is of primary concern.

This concern is particularly acute in a start-up business situation where the numbers are based on a given set of assumptions rather than on historical performance. If the assumptions are not defensible, the pro-forma projection will be a useless exercise. A sensitivity analysis may be helpful in identifying key variables of the proposed business. Accountants and bankers or other financial advisors might be helpful in determining the extent of information required and the best possible format for presentation of the business concept. A list of references for use in the preparation of such material is attached in Exhibit A.

Above all, investors/lenders must be convinced that the entrepreneurs have developed a plan carefully and that the management is skilled and experienced enough in the chosen business area to manage effectively, seize opportunities, solve problems, and make profits.

GLOSSARY OF GENERAL BUSINESS TERMS

Balance sheet - a list of the measurable assets owned or controlled by the firm on a specific date equal to the liabilities and owners' equities listed in the firm at that time.

Capital equipment - physical equipment, the acquisition and installation of which represent major outlays of funds.

Capital structure - combination of debt and equity that make up the firm's total funding.

Cash flow - cash receipts and disbursements over a certain period of time.

Credit rating - evaluation of the credit risk or credit standing based on previous payment history.

Equity - amount of cash or assets that owners have invested in the firm at risk.

Guaranty - contract making a party responsible for repayment of a debt to a lender or some other performance.

Leverage lease - the process by which the leasing company (owner-lessor) purchases equipment by providing only a percentage of the purchase price and pledges the equipment to the supplier of the additional funding (e.g., bank) on a non-recourse basis.

Liability - legal requirement to make payment or provide services in the future in return for assets or services acquired.

Operating statement - see profit and loss statement.

Profit and loss statement - accounting statement summarizing the income for a particular period, including revenues and expenses.

Retrofit - Process of adapting one form of resource technology to apply and fit on another resource.

Subordination of debt - agreement that requires a borrower to repay some lender before other lenders.

Working capital - money which is used for the firm's immediate operations. Working capital is computed by subtracting current liabilities from current assets.

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Atlantic Office: William Greene, 600 Arch St., Suite 10424, Philadelphia, PA 19106.
Midwestern: 32 West Randolph St., 1025 Civic Tower Building, Chicago, IL 60601.
West: Lake Union Building, 1700 Westlake Avenue, North Seattle, WA 98109.
Rocky Mountain: Title Building, 909 17th Street, Suite 505, Denver, CO 80202.
Southwestern: American Bank Tower, 221 W. Sixth St., Suite 600, Austin, TX 78701.
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CHAPTER 7

LEGAL, INSTITUTIONAL AND ENVIRONMENTAL ASPECTS

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LEGAL, INSTITUTIONAL AND ENVIRONMENTAL ASPECTS

INTRODUCTION

To develop direct uses of geothermal energy, a few more factors must be considered than the presence of the resource, the ability of the resource to supply the energy needed for the intended use, financing and marketing. Early planning for compliance with federal, state and local environmental laws, regulations and ordinances, and for obtaining necessary permits is a "must."

A developer who learns the rules and is aware of the steps for obtaining the required approvals and permits at the very beginning of a project will be able to make realistic estimates for the time, money and personnel necessary to proceed. This chapter is designed to provide the potential developer or user with a general guide for negotiating and obtaining the necessary regulatory approvals associated with geothermal development--from obtaining access to the resource to exploration, development, distribution and use of the resource.

Fortunately, direct uses of geothermal energy usually have much less potential for severe negative environmental impact than electric power applications because direct-heat projects are smaller and do not need extensive transmission lines, power-generation equipment or cooling facilities. Direct uses generally require fewer wells per development, shallower depths, lower temperatures, and lead to less surface-disturbing activities.

Relationships with existing utilities are discussed, as well as sources for public assistance in negotiating the way through the appropriate regulatory framework. The basic thrust of this chapter is to help developers negotiate the regulatory maze without the expenditure of excessive time and expense.

The key to operating successfully within the institutional, environmental, and regulatory framework is to identify the required permits and potential environmental problems as early as possible.

It is assumed that the developer is convinced of the presence of a geothermal resource capable of supplying economical geothermal energy and that he has a use or market for the geothermal energy, such as space heating or cooling, or industrial process heat.

OBTAINING ACCESS TO THE RESOURCE

Determining the nature of surface ownership

Once the specific site or geographic area to be developed has been located and identified on appropriate maps, the would-be developer deals next with the problem of gaining access to the land, which requires a determination of ownership. This may not be as simple as it sounds. Although ownership of the surface and geothermal or mineral estates generally is the same, in some instances, the surface ownership is severed from the geothermal resource, which may require the developer to deal with the owners of both estates. In these situations, the owner of the mineral estate frequently has the implied right to enter the land and to use as much of the surface as may be reasonably required to develop the subsurface resource; but in each instance a close examination of title and a determination of the details of ownership will be required for each jurisdiction. For the developer who is experienced in the acquisition of petroleum and other mineral interests, there will be much in this process that is familiar. The problem has been complicated in some jurisdictions because the geothermal resource has not been adequately

defined, and as a result, its ownership may be uncertain (see National Conference of State Legislatures, July 1978).

In all instances, ownership is a title problem which should be handled with competent legal assistance by persons familiar with title company practices and local land records.

Determining the nature of subsurface ownership

The geothermal developer often must obtain rights in addition to surface entry and use. Water rights may need to be secured, and these, too, often are not part of the surface estate. Oil, gas, geothermal resources or, in more general language, "minerals" may be severed or separated from the surface rights. Under the Stock Raising Homestead Act of 1916, for instance, approximately 67 million acres (27 million hectares) of federal land was patented with coal and other minerals reserved to the federal government. Dry steam resources at The Geysers in California have been found to be part of this reservation, although the surface land is in private ownership.

The geothermal developer should identify and obtain all resource rights required for the planned direct heat application. This task is complicated by the complex nature of geothermal resources. Legally, the resource has both water and mineral aspects, and the inclusion of geothermal resources in a particular resource category or reservation often is uncertain. Definitions of geothermal resources in federal and state statutes should be examined. Any specific statutory assignments of geothermal resources should be evaluated. As examples, geothermal resources have been classified as mineral by Hawaii and as underground water by Wyoming. Colorado presumes that mineral reservations do not include geothermal resources, while Oregon places all geothermal resources in the surface estate. Confusion about the nature of geothermal resources is evident, and for security, the developer may wish to secure all resource rights that might possibly form the basis of a claim to geothermal resources (see Sacarto, State Policies for Geothermal Development, 1976, p. 43-46).

Entry and development rights

Private lands. Access to private land is usually gained by dealing directly with the owner of the surface and geothermal estates. In some instances, title to the land and resources may be obtained by outright purchase. In those instances, the usual caution should be exercised to ensure that clear legal title is obtained. However, access to the resource will more often be obtained through a geothermal lease. Sometimes an option to acquire a geothermal lease may be obtained, which will establish the terms of the lease and which will permit exploration during the option period in accordance with the option agreement. The owner of the land may permit access in advance of an option to purchase or lease. The developer may then conduct passive exploration including geological mapping, slim temperature gradient holes, or heat-flow studies if they are needed, or any other assessment activity allowed by the surface owner.

Although geothermal energy has been directly employed in the United States for space heating where hot springs and shallow hot-water wells occur, other commercial applications have not been common. Consequently, standard leases for direct geothermal applications have not been developed. From the developer's point of view, it would seem that lease forms for the typical commercial geothermal areas (such as The Geysers and the Imperial Valley) could be modified to fit the needs of the developer interested in direct uses. However, some consideration must be given to the royalty provision in these more standard lease forms, since the pricing model is likely to be different from that developed for the generation of electric power.

Whether access is obtained by purchase, lease, option, permit or any other arrangement, it is imperative that the developer accurately determine ownership to ensure that all the requisite

parties have joined in the transaction. In some instances, a developer may find that the property in which he is interested is already under lease for agricultural, grazing or other purposes. If so, the developer should also obtain the requisite consent from the lessee in possession, to avoid possible charges of trespass or other conflict. Substantially the same legal and title considerations are involved whether the developer is proceeding by way of purchase, lease, option or other agreement, and competent title assistance must therefore be obtained.

State lands. Rights to explore and develop geothermal resources on state lands are governed by statutes and regulations (see Appendix A). Geothermal exploration involving negligible surface disturbance may or may not require a permit or lease from the state. Check with the state lands office. In some cases, the developer may be allowed to proceed at will or after notifying the state lands officer. Intensive exploration and development operations will, however, require permits and leases.

The manner in which exploration permits and development leases are issued and the requirements they impose on the developer vary from state to state (Tables 1, 2 and 3). Diligent work requirements, lease-conversion provisions for exploration permits, rentals, royalties, acreage limitations, lease terms and renegotiation provisions for leases are important concerns for the geothermal developer.

In some states, a pre-lease environmental evaluation is required in which the potential effects of proposed exploration, development and production activities for the lease are examined for their environmental and socioeconomic acceptability. Where an environmental evaluation is necessary, delays will occur between filing for and issuance of a lease. The developer may be required to pay the costs of the evaluation. Therefore, it is important for the geothermal developer to file for the lease as early as possible to avoid delaying consideration of the potential environmental problems associated with geothermal exploration, development and production. Alternatively, developers should institute environmental baseline studies prior to lease filing, to minimize post-filing delays. Generally, baseline studies are financed by the developer.

TABLE 1

State geothermal exploration permits with conversion privileges
(from Sacarto, 1976, revised 1979)

<u>State</u>	<u>Manner Awarded</u>	<u>Term</u>	<u>Conversion Privilege</u>	<u>Annual Rental</u>
Alaska	By application	3 years Possible 2-yr extension	Yes	Variable; \$1/ acre minimum
California	By application	2 years Possible 2-yr extension	Yes; 90-day period	\$1/acre
Wyoming	a) Public drawing ¹ b) By application	3 years Possible 2-yr extension	Yes; 90-day period	\$1/acre

¹ When lands are newly offered for exploration, a period is set of at least 30 days and applications received during that period are awarded permits by public drawing.

TABLE 2
Leasing of state lands
(from Sacarto, 1976, revised 1979)

State	Non-KGRA Lands		KGRA Lands (Competitive Leasing)	
	Newly Offered	Application Overlap	Bidding Factor	Designation Criteria
Alaska			(A)	(A)
Arizona	By application	Qualifications or Cash bonus bidding	Cash bonus	Geology and/or competitive interest
California	(A)	(A)	Cash bonus or other (H)	Geology and/or competitive interest (H)
Colorado	(A)	(A)	(A)	(A)
Hawaii			(A)	All land awarded competitively (G)
Idaho	Public drawing (30-day filing)	By application		Producing well
Louisiana	(B)	(B)	(B)	(B)
Montana	Competitive	Competitive	Cash bonus	All lands awarded competitively
Nevada	(C)	(C)	(C)	(C)
New Mexico	Competitive (30-day filing)	By application	Cash bonus	Determined by Commissioner of Lands
Oregon	Public drawing (30-day filing)	By application	Cash bonus (D)	Geology and/or producing well
Texas	(B)	(B)	(B)	(B)
Utah	Cash bonus (E) (15-day filing)	By application	(E)	(E)
Washington	Competitive	Competitive	Cash bonus (F)	All lands awarded competitively
Wyoming			(A)	(A)

(A) Specified by state land commissioners.

(B) Regulations not finalized.

(C) Moratorium on leasing of state lands.

(D) If no bids received, Division of State Lands may reclassify for non-competitive leasing.

(E) Lands are offered non-competitively by order of application, except when they are newly offered. Newly offered lands are leased by cash bonus bidding.

(F) Unlike Montana, if a tract receives no bid, it is withdrawn.

(G) Board of Land and Natural Resources by a two-thirds vote may award a non-competitive lease to occupier of mineral reserve lands.

(H) Single biddable factor only, plus negotiable royalty rate up to 16-2/3%.

TABLE 3
State geothermal lease provisions
(from Sacarto, 1976, revised 1979)

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties	Annual Rental	Royalties	Acreage Limits
Alaska	10 years	One 5-year term if drilling; for duration of commercial pro- duction, up to 40 years	20-year intervals beginning 35 years after commercial produc- tion; and at end of first 40- year lease period	Variable; \$1/acre minimum	Primary: 10-15% Byproduct: 2-10% Minimum: \$2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres (5,750 for submerged lands) Maximum state holdings: 25,600 ac
Arizona	10 years	2 years if drilling; for dura- tion of commercial production		Not less than \$1/acre	Primary: at least 12.5% Byproduct: at least 12.5% Shut-in: 4 times annual rental per year	Maximum lease: 2,560 acres (4 sections) (confined to 6 miles square)
California	10 years	So long as geothermal resources are produced or capable of being produced in commercial quantities, up to 99 years	10-year intervals, beginning no sooner than 20 years and no later than 30 years after com- mercial production	\$1/acre	Primary: 10% Byproduct: between 2% & 10% Minimum: \$2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres Maximum state holdings: 25,600 ac (includes acreage under exploration permit)
Colorado	10 years	For duration of commercial pro- duction; lacking production, at discretion of state land board	Minimum royalty: 5-year inter- vals	\$1/acre	Primary: 10% Byproduct: 5%	
Hawaii	10 years	So long as geothermal resources or byproducts are produced in commercial quantities, up to 65 years; 5 years with diligent drilling without production, or with shut-in well without market	15-year intervals, beginning 35 years after the lease date	State: as bld or set in lease Surface occupant: as agreed or set by Board of Land and Natural Resources	Primary: 10-20% Byproduct: 5-10%	Minimum lease: 100 acres Maximum lease: 5,000 acres, or 2,560 acres if length of tract is more than 6 times the width Maximum state holdings: 80,000 undeveloped acres
Idaho	10 years	For duration of commercial pro- duction or drilling operations to at least 1000 feet, up to 40 years beyond primary term		First 5 years: \$1/acre Second 5 years: \$2/acre Thereafter: \$3/acre	Primary: 10% Byproduct: 5%	Minimum lease: all state lands within a section must be leased Maximum lease: 640 acres Maximum state holdings: interest in 50 township-and-ranges
Louisiana	At most 10 years	For duration of commercial production or development operations		At least \$1/acre or 1/2 cash bonus, whichever is greater	Primary: at least 10% Byproduct: at least 5%	Maximum lease: 5,000 acres
Montana	10 years	For duration of commercial pro- duction or drilling	10-year intervals, beginning 20 years after lease date	At least \$1/acre	Primary: at least 10% Byproduct: between 2% & 5% Shut-in: set in lease Minimum: \$2/acre/year	Maximum lease: 640 acres
Nevada				\$1/acre	Primary: 12.5% Byproduct: 5.0%	

TABLE 3 (continued)
State geothermal lease provisions
(from Sacarto, 1976, revised 1979)

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties	Annual Rental	Royalties	Acreage Limits
New Mexico	5 years	So long as geothermal resources are produced or capable of being produced in commercial quantities if production is maintained. Secondary 5-year lease available if production is not maintained, if production is lost, Commission may extend lease in one-year increments up to three years	10-year intervals, beginning 20 years after lease date	\$1/acre \$5/acre for leases extended for second 5-year term without production	Primary: 10-15% (KGRA lands) Byproduct: between 2% & 10% Recreation or Therapeutic: between 2% & 10% Powerplant: 8% (net revenue) Minimum: \$2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres Maximum state holdings: 51,200 acres
Oregon	10 years	10 years, if royalties in any year of preceding term equalled or exceeded annual rental due under lease; 5 years, if no production but discovery has been made or is deemed imminent; maximum of 50 years from lease date		Years 1-3: \$1/acre Year 4: \$3/acre Years 5-10: \$5/acre Years renewed: \$5/acre	Primary: 10% Byproduct: 1% demineralized water 5% other (rentals paid each year deducted from royalties due)	Minimum lease: 40 acres
Texas	(No lease terms established)			(No lease terms established)		
Utah	10 years	For duration of commercial production; or one-year terms, in absence of production, upon payment of \$5/acre advance royalty	3-year intervals	\$1/acre	Primary: 10% Byproduct: 10% (net proceeds)	Minimum lease: 40 acres Maximum lease: 640 to 2,560 acres, at discretion of director of state lands
Washington	5 years	So long as drilling with diligence; or upon commercial discovery, up to 20 years		At least \$1/acre At least \$5/acre upon commercial production	Primary: 10% Byproduct: at least 4% (net proceeds) Minimum: \$5/acre/year	Minimum lease: 40 acres Maximum lease: 640 acres
Wyoming	10 years	So long as geothermal resources produced or capable of being produced in commercial quantities	10-year intervals	\$2/acre	Primary: 10% Byproduct: 5%	Minimum lease: 640 acres Maximum lease: 2,560 acres

Federal lands. Surface access and the right to explore, develop and use geothermal resources on federal lands are joined and are controlled by the U.S. Bureau of Land Management (BLM) under the provision of the Geothermal Steam Act of 1970, except for Department of Defense and Indian Lands. In areas designated as Known Geothermal Resources Areas (KGRA's), all leases are by competitive bidding according to schedules developed by the Bureau of Land Management. Outside a designated KGRA, potential developers may submit applications to the surface-land manager on a non-competitive basis. Information about procedures and forms may be obtained from the nearest BLM or U.S. Forest Service (USFS) office.

Procedures for exploration and development of geothermal resources on federal lands provide for phased operations beginning with activities that do not disturb the surface, such as geologic mapping, geophysical measurement or shallow-temperature gradient holes (<1000 ft or <300 m) and ending with full field development and utilization.

Limited operations designed to provide a preliminary evaluation of resource potential may be carried out before leasing, under the supervision of the surface management agency (BLM, USFS, etc.). These are done under the provisions of a Notice of Intent or other appropriate form (sample form shown in Appendix B). Generally, the environmental impacts of such a preliminary resource assessment are minimal and can be covered by a negative declaration prepared by the issuing agency.

Water laws

State water laws generally will govern the production and use of geothermal fluids for process heat, space heating and cooling, but it is important to check with the state, to confirm that this is the case. State water-use regulations, existing water uses and the characteristics of the groundwater-geothermal interface are critical factors in geothermal development. They determine the availability of groundwater for geothermal development, the reliability of those geothermal groundwater supplies and the developer's legal authority to transfer geothermal fluids to a particular place of use. Geothermal fluids may grade into standard groundwater, so it is important to carry out geothermal operations so as not to damage or degrade the area's groundwater resources (Sacarto, 1976, p. 46).

Water rights for development on state and private lands generally will be governed by one of two regulatory systems. Groundwater may be considered a public resource or trust, in which case a right to appropriate water must be obtained from the state. In other states, groundwater is considered appurtenant to the surface, and the developer's right to produce water will be secured along with surface development rights. The developer may encounter some constraints on fluid production depending on the standards set for "reasonable use."

Appropriative rights for water are quantified and have priority dates. Under that system, the geothermal developer's first concern is the availability of a water right of sufficient quantity. If a groundwater basin is fully appropriated, the geothermal developer may be unable to produce the requisite geothermal fluids. This concern is moderated somewhat by the developer's ability to obtain water rights by purchasing them or by providing existing users with replacement water supplies. Also, if the geothermal fluids are determined to be separate from existing groundwater sources, the developer, by discovering and producing this new supply, may in some states have rights to the fluid as a "developed" water.

Reliability also may be a concern under an appropriative system, since earlier water rights take precedence over later appropriations.

Diversion of water to a selected place of use generally is provided for under appropriative rights systems. This is not the case in "reasonable-use" or riparian systems, in which the

water right is attached to the surface. Development requiring transportation of geothermal fluids away from the producing property to some distant load center will be constrained where the "reasonable-use" system exists.

For federal and Indian lands, development leases probably will encompass fluid production. The developer of such lands has two concerns. In states where water is deemed a public resource, the state may challenge the inclusion of water rights in federal or Indian leases. The developer should be sensitive to these conflicting jurisdictional claims and should conform with state requirements, if possible, to avoid litigation. Reliability of the water right also should be examined. Under a federal geothermal lease, for instance, the developer is allowed to produce geothermal fluids, but is not guaranteed a reliable supply since the "rule of capture" applies. A competing producer may drain the same geothermal system.

DEVELOPMENT REGULATIONS

Exploration and field development

Once land access and development rights to the geothermal resource have been secured through purchase or lease, the preparation for exploration/development activities may begin. The initiation of an exploration/development project usually requires permits from various regulatory bodies (local, state, federal) with jurisdiction over the project. Acquisition of required permits is usually preceded by different levels of review depending on the scope of the activities proposed. A project of limited scope or one that does not require surface occupancy can be reviewed in a relatively short period of time. A project that calls for the drilling of many wells or one that includes siting of an end-use facility may require several months to a year to obtain the necessary permits. Processing times also may vary among regulatory bodies due to complexities of procedure and responsibility and/or staff workload. In some cases, it may be necessary to obtain sequential permits for large-scale projects, to assess the phases of development individually.

Private and state lands. Permit issuance authority over geothermal exploration/development projects is usually vested in several regulatory bodies with separate or overlapping jurisdictions:

1. Conditional land-use permits may be required from local regulatory bodies such as city councils, county planning departments, or county boards with local zoning guidelines, and other applicable laws and regulations;
2. Drilling permits that may specify drilling and casing requirements, spacing, bonding requirements, sump construction standards and blowout prevention equipment will be required from the state agency that administers drilling of geothermal wells;
3. Solid-waste discharge permits may be required from local or state agencies. Solid-waste discharges include used drilling mud as well as any additives which must be disposed of;
4. Permits setting limits on air emissions and water discharges may need to be obtained from state or regional air- and water-regulatory agencies in order to assure compliance with state, federal and local environmental protection laws (Clean Air Act, Safe Drinking Water Act, etc.). Disposal of geothermal fluids may be a particularly difficult problem because surface and subsurface water resources must be protected and the resource conserved. In the absence of regional or state agencies to administer the processing of such permits, the U.S. Environmental Protection Agency may do so.

Some states require an environmental analysis of the proposed project and the preparation of an

environmental document such as required by the California Environmental Quality Act (CEQA) or similar environmental legislation. The intent of such analyses and documents is to provide regulatory bodies with a detailed description of the project, full disclosure of all potentially positive as well as negative impacts and a list of recommended mitigation strategies before a decision is made on the issuance of the permit. The time required to perform such analyses and to prepare and review environmental documents (usually with public participation) varies with the scope of the project, environmental baseline collection requirements, and any legal challenges to the scope and adequacy of the environmental review. If an environmental impact report is required, several months to a year or more might be needed to complete its preparation and review.

Federal lands. Exploration (except for non-disturbing preliminary assessments), development and utilization of geothermal resources on most federal lands are carried out under lease according to the provisions of the Geothermal Steam Act of 1970 and resulting regulations.² Issuing leases and licensing plants are the responsibility of the Bureau of Land Management and in some cases (small research or pilot plants), the U.S. Geological Survey (USGS). Operations on federal leased lands are supervised by the USGS Conservation Division Area Geothermal Supervisor, within the framework of Geothermal Resources Operational Orders.³

In general, once a lease is issued, all necessary permits are issued by the USGS Area Geothermal Supervisor. Exceptions are the permits required for emissions to the atmosphere, which are usually issued by the local air-pollution control district, and liquid emissions, which are issued by the state water resources agency or the Environmental Protection Agency, if a state has no regulatory body for water resources. The standards required on federal lands are usually the same as those imposed by the relevant state and local agencies, but enforcement of these standards on federal lands is entirely by federal agencies. In practice, federal lessees may wish to comply with local or county permitting requirements, particularly if operations are extensive or affect lands other than federal lands.

All activities on leased federal lands are carried out under a Plan of Operation submitted to the office of the Area Geothermal Supervisor. To provide for the typical phases of activity, separate Plans of Operation for exploration (one or more wells), development, utilization (plant construction), injection of spent fluid and production may be submitted sequentially or in combination, as the developer's data and commitments require.

On federal lands, most of the environmental documents to fulfill the requirements of the National Environmental Policy Act (NEPA) and state or local environmental laws during the exploration and development phases will be prepared by the federal government. An exception may be archaeological clearances for roads, drill sites or other areas to be disturbed. These are generally done by an approved professional archaeologist at the developer's expense. The developer may be asked to provide other environmental data and may need to revise and add detail to Plans of Operation in consultation with the USGS.

Most small-scale projects involving on-site uses (as is typical of direct heat applications) can be handled by a negative declaration (an analysis showing that net environmental impacts are adequately offset by the mitigating measures proposed). Public hearings and public comment are usually only necessary for more complicated projects. Formal Environmental Impact Statement (EIS) procedures may be necessary for large-scale operations, particularly those involving off-site facilities or transportation of geothermal fluids off federal lands.

² Public Law 91-581, 91st Congress, S.368, Dec. 24, 1970.

³ U.S. Dept. of Interior, Geological Survey, Conservation Div., Geothermal Resources Operational Orders, Issued under the Steam Act of 1970 (Menlo Park, CA, Jan. 1976), 30 p.

If extensive facilities are to be constructed (centralized heat exchangers, distribution lines, etc.), environmental analyses will be required. These usually are prepared by the federal permitting agency (BLM and/or USGS) at little or no expense to the permittee. They may, however, depend heavily on information provided by the lessee, so time for preparation, discussion and review of the documents should be allocated by the developer.

Production of the resource is carried out under a Plan of Production approved by the USGS and BLM or USFS. Before the plan of production can be approved, federal regulations (30 CFR 273.34 (k)) require the applicant to acquire environmental baseline data describing existing environmental parameters (air, water, noise, etc.), covering a period of one year. However, the Area Geothermal Supervisor may waive the baseline data requirement for direct-use applications and issue a negative declaration if the project will have minimal environmental impact. This waiver is done on a case-by-case basis, so the applicant/developer should consult with the USGS Area Geothermal Supervisor at the earliest possible time to determine whether a year of environmental baseline data collection will be required. Collection of environmental baseline information requires careful planning and timing, and is done at the applicant's expense. The intensity of the observations required is scaled to the scope and nature of the operations; but to avoid unnecessary delays and frustrations, plans to fulfill this requirement should be developed in consultation with the USGS Area Geothermal Supervisor as soon as possible.⁴

A permit to construct small-scale direct use facilities (one producing well and its attachments) can be issued by the USGS Area Geothermal Supervisor. Larger facilities will be licensed by the BLM, with technical advice from USGS. Many direct users of geothermal energy will not require centralized facilities, but those who do should plan sufficient lead time to obtain the necessary permits and complete environmental documents. On federal lands, only one basic permit is required for facility siting, but any off-lease facilities involve separate land-acquisition and permitting processes.

Distribution and use of the resource

The previous section examined the geothermal exploration and development processes. One of the final steps in the geothermal energy development process is to provide for utilization of the resource, either at the well site or off-site.

Private lands. To transport the geothermal fluid produced, the developer may face additional permitting requirements and problems associated with zoning compliance and right-of-way acquisition. Two scenarios are presented here, with suggestions for resolving potential problems. Scenario 1: A landowner owns property overlying a geothermal resource capable of providing his house on that property with space heating/cooling and/or hot-water heating. Scenario 2: A municipality or private investor wishes to utilize a nearby geothermal resource for a city-wide district heating and cooling and hot-water heating system.

In the first scenario, if the transportation system between the well and the house is to be located on the same parcel of property, legal problems will arise primarily in the context of zoning compliance and conditional-use permitting. Regulations and ordinances of local governments, typically cities or counties, will mandate permissible land uses and conditions under which an exception to accepted uses will be allowed. In this way, the local entity carries out its responsibility of protecting the public from potential "nuisances" created by individual citizens.

Once the geothermal system is enlarged to supply city-wide needs (Scenario 2), it becomes necessary to provide an extensive pipeline-distribution system which will cross over or run along

⁴See U.S. Dept. of Interior, The Geothermal Environmental Advisory Panel, Guidelines for Acquiring Environmental Baseline Data on Federal Geothermal Leases (Menlo Park, CA, Jan. 1977), 26 p.

many parcels of property, some of which may not be owned by the municipality. Therefore, before constructing the pipeline distribution system, the user must select an appropriate right-of-way. Selection of the right-of-way will depend upon the ability of the user to secure the right to enter and use properties which he does not own. If the property is privately owned, the developer may make an outright purchase of each strip of land the pipeline will cross. However, purchasing a portion of each needed parcel is normally too costly for private or public investors. Nevertheless, for the public user (e.g., a municipality), purchase may be possible through the power of eminent domain. This statutorily authorized power permits the public entity/user to take private property for a public purpose or use (In Scenario 2, the municipal distribution system). Just compensation, typically the market value of the land fairly determined, is paid to the private property owner whose land is taken under eminent-domain authority.

Often a more feasible alternative for both private and public users is to obtain an easement, the limited right to use each parcel crossed, from the owner of the surface estate. Different terms may be used to express this right, e.g., right-of-way permit, encroachment permit or right-of-way easement. If a user wishes to use an already-established right-of-way, such as one along the side of a public road, he must generally obtain a permit from the appropriate governmental agency. This permit will not allow the user to interfere with those existing uses properly being exercised by others. Should the user decide that his pipeline must occupy a specific area already being utilized by another, it may be possible to relocate the other party's system within the same right-of-way. In these instances, the user will typically bear the cost of relocation. Finally, where the established right-of-way is owned by private interest (a good example being property owned by a railroad for its rail network), the user should obtain its express permission.

Federal lands. Rights to transmit power, fluids or other materials from a federal lease across other federal lands are permitted or licensed by the BLM under provisions of its "Organic Act" (Federal Land Policy and Management Act 1976). On BLM lands, no additional federal approvals are required once the BLM environmental documents are completed. On USFS lands, permits are issued by the USFS after completion of its regional planning and site-specific environmental documents. On Department of Defense (DOD) lands, permits for transmission of geothermal fluids are issued by the USGS Area Geothermal Supervisor, with DOD concurrence.

Disposal of fluids

Requirements for disposal of fluids vary widely depending on prior history of the area, fluid temperature and chemical composition. For example, in cases where effluent from an existing spring is merely diverted and the spring effluent is of high quality, return to the riparian system may be required by water laws. In other cases where geothermal fluids are of poorer quality, subsurface injection may be necessary to avoid contamination of surface water.

Relationship with existing utility systems

For most direct geothermal applications, the need of the user for both electrical and natural-gas service is reduced but not completely eliminated. Residential/commercial heating or cooling applications typically reduce electrical consumption, while industrial-process applications of geothermal energy reduce natural gas or fuel-oil demand. Therefore, some backup system or standby service is needed.

The user of geothermal energy should familiarize himself with the statutes and regulations governing a particular type of utility service. Statutes dealing with electric utilities typically require them to provide service, including standby service, to those customers within the utility's service area. However, the costs and conditions for such service may differ among various classes of customers. Outside the utility's service area, standby service for a particular user

may not always be available, e.g., where such service would require the utility to enlarge its generating facilities.

A different situation potentially exists with respect to natural gas service. Shortages of this conventional fuel supply in recent years have frequently caused existing gas supplies to be allocated among users according to a set of priorities established by the government. For example, residential and commercial uses are accorded high-priority status. Supplies in these end-use categories are curtailed only after those uses having lower priority rights to supplies are curtailed.

In examining the available options for standby service, the user should determine the cost of such service. For electrical or natural gas standby service, the cost or rate charged to the customer will vary, depending upon the regulatory framework within which the utility operates. The following example may be useful: one natural gas company divides its rates or charges to customers into two components--a demand charge and a commodity charge. The commodity in the user's bill primarily reflects the actual amount of gas consumed. The demand charge represents the annual cost of pipeline and related facilities, including the storage requirements for natural gas held in reserve for standby needs. While the proposed use of the geothermal system should reduce natural-gas consumption and, therefore, the commodity charge, it may not greatly affect the fixed demand charge. The utility would likely wish to continue recovering these fixed-costs through higher rates charged to standby users.

In summary, the user should recognize that he will likely require some standby service where geothermal energy is used directly. In the early stages of planning for direct utilization, the user should secure assurances of new or continued standby service and learn of any differences in costs for this service. Where the user desires natural gas or electrical backup service, the appropriate local utility should be able to provide him with information on the above and to answer any other questions raised by the need for supplemental energy.

ENVIRONMENTAL ISSUES

The development of direct-heat applications of geothermal energy share many of the same potential environmental problems as electricity applications, although they are likely to be far less serious. Careful planning to avoid environmental problems, coupled with appropriate mitigation measures for the problems which cannot be avoided, can bring impacts to acceptable levels, at costs well below those required for electricity applications. Environmental issues to be considered in project planning and implementation include:

1. Land use. Any geothermal project, by virtue of the fact that the land use is changed, may be in conflict with previous uses of the land for recreation, agriculture, housing, etc. However, the conflicts are usually far less serious for direct-heat applications than for electricity production and may be minimized by careful siting in non-conflict areas.
2. Fish, wildlife, and natural vegetation; endangered species of plants and animals. Whenever natural areas are disturbed or changed to accommodate another use, natural habitats for wildlife and plants are either destroyed or altered. This kind of impact cannot be prevented, but with careful project planning, direct-heat facilities (wells, distribution systems, access roads and end-use facilities) may be sited to avoid unusual or unique habitats and critical habitats for endangered species. Negative impacts to fish and other aquatic organisms can be avoided by simply preventing geothermal discharges to aquatic bodies or by maintaining those discharges below harmful levels.

To obtain information and planning assistance regarding potential problems with fish, wildlife and natural vegetation, contact the appropriate state or federal agency in the project

area, e.g., local U.S. Fish and Wildlife Service office or equivalent state office.

3. Air quality. Natural geothermal fluids typically contain various noncondensable gases (e.g., hydrogen sulfide) and other components (e.g., mercury, arsenic, boron) that have presented rather serious environmental problems for geothermal electricity production; however, these problems can be virtually eliminated for direct-heat applications by simply using closed-loop systems that prevent gaseous emissions. Of course, certain emissions are inevitable during well drilling and flow testing, but such activities are of short duration and usually do not result in serious long-term environmental degradation.
4. Water quality. One of the most serious water-quality concerns is that geothermal fluids released to natural aquatic bodies will degrade water quality and result in negative impacts to fish and other aquatic organisms. The disposal of toxic fluids is closely regulated in most states, with no discharges permitted. Direct-heat projects should be designed to avoid or minimize equipment failure resulting in accidental releases of fluids to aquatic bodies. In areas where the geothermal fluids are potable or of irrigation quality, it may be possible to obtain permits for surface discharge or cascaded uses of the geothermal fluid (e.g., irrigation) after some of the heat is extracted.
5. Hot springs. One of the most serious concerns associated with the withdrawal of geothermal fluid is its possible affect on hot spring activity. Geologic and hydrologic data are often insufficient to predict potential impact. As a result, the drilling of geothermal wells and the utilization of geothermal fluids in areas adjacent to hot springs is usually controversial and may be prohibited within a certain radius. The California State Legislature has already considered, but not yet passed, such a legislative proposal.

In states where geothermal activities are regulated under water-rights laws, additional problems may be encountered with regard to obtaining rights to the geothermal resource (see elsewhere in this chapter for more discussion on water rights).

6. Geology. Normal site and soil-stability studies should be completed prior to any substantial exploration activity to avoid or minimize such geologic hazards as landslides, liquefaction and earthquakes. In particular, two geological hazards are usually mentioned in association with geothermal development--subsidence and induced seismicity.
 - (a) Subsidence. Subsidence may be a problem in any area if net fluid withdrawals exceed natural recharge or injection. The actual incidence of subsidence depends on the nature of the reservoir and the surrounding geologic formations--in fracture-permeability reservoirs, subsidence should be negligible, whereas in sedimentary reservoirs, subsidence could be a substantial problem. In this latter case, subsidence may be reduced through a well-planned program of injection of the geothermal fluids. Moreover, such injection also conserves the geothermal resource and extends the reservoir's producing life.
 - (b) Induced seismicity. Induced seismicity is generally associated with deep high-pressure fluid injection. Since such injection is unlikely to be associated with activities related to the direct-heat utilization of geothermal resources, induced seismicity is not an important concern.
7. Noise. Noise is usually a problem only during well-drilling/testing activities adjacent to residential areas, recreational areas and critical breeding areas for certain wildlife (1-1/2 miles or approximately 1 km). Noise problems can be minimized by siting geothermal facilities to avoid such areas and by applying well-known noise abatement strategies that can attenuate the majority of sound within short distances of the source.

8. Socioeconomics. Even with large-scale geothermal developments for electric power production, negative socioeconomic impacts have been quite small. Therefore, negative socioeconomic impacts from even large-scale direct-heat applications are likely to be small or negligible.
9. Archaeological/cultural resources. Archaeological resources may be disturbed during geothermal development activities. The simplest way to avoid such disturbances is to conduct thorough archaeological surveys of prospective development areas and to locate facilities in non-problem areas. Hot-spring areas, especially, were often favored Indian or pioneer sites of occupation--another reason to avoid areas immediately adjacent to hot springs for geothermal development.

PUBLIC ASSISTANCE AND INFORMATION

Government

State and federal government agencies responsible for alternative energy promotion, development and regulation are good sources of information regarding technical, legal and institutional aspects of geothermal utilization as well as sources of financial support. Staff are usually anxious to share information and to recommend procedures for the development of direct-heat geothermal projects. First contacts should be made with the state energy office (if one exists) and the U.S. Department of Energy. The Department of Energy administers geothermal programs from its headquarters in Washington, D.C. and through field offices such as the San Francisco, Nevada, and Idaho Operations offices, and the offices of the regional representatives. Most federal direct-heat geothermal programs are administered from either the San Francisco or Idaho Operations offices. Federal laboratories, especially Lawrence Berkeley, Jet Propulsion, Battelle and the Idaho National Engineering Laboratories, can also be of use when the developer has questions regarding legal, institutional and environmental aspects of direct-heat utilization. Universities, Energy Extension Service and Agricultural Extension Service offices may be helpful, as well as local Chambers of Commerce and local Economic Development Departments. The U.S. Economic Development Administration, Housing and Urban Development Agency, Farmers Home Administration, Community Services Administration and Geological Survey all have programs that may be useful to geothermal developers, from technical assistance, grants, loans and resource assessment to referrals for permit assistance.

Public

Two organizations are especially active in public assistance programs--Oregon Institute of Technology's Geo-Heat Utilization Center and the Geothermal Resources Council. The Geo-Heat Utilization Center is attached to the Oregon Institute of Technology in Klamath Falls, Oregon. The staff at the Geo-Heat Center have valuable "hands on" experience in direct-heat projects, from planning, permitting and construction to economics and evaluation.

The Geothermal Resources Council (GRC) is a non-profit organization dedicated to the dissemination of geothermal information and support of educational symposia, technical training courses, short courses and an annual meeting. The GRC publishes a directory, special reports and a monthly bulletin. Staff at the Council headquarters in Davis, California, are always willing to refer telephone inquiries to the appropriate entity. Refer to Appendix C for names, addresses and phone numbers of key direct-heat contacts for legal, institutional and environmental matters.

The National Conference of State Legislatures in Denver has published several informative docu-

ments including State Policies for Geothermal Development, Issues in Geothermal Legislation and State Policies for Geoheating. These reports provide excellent summaries of issues and problems and make suggestions for facilitating increased levels of direct-heat usage.

The American Bar Association's Geothermal Subcommittee (a subcommittee of the Natural Resources Committee) may also be a useful organization to contact.

Finally, private consultants can provide valuable assistance, ranging from identification of institutional processes and preparation of environmental impact reports to engineering and economic feasibility studies. Consult the GRC Registry or inquire within the "geothermal community" for consultants recommended for the particular need at hand.

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APPENDIX A
(from Sacarto, 1979)

State Laws and Regulations Regarding Geothermal Resources

ALASKA

- Statutes: Geothermal Resources Act (1971) AK.Stat. 38.05.181
 Leasing: Div. of Lands - Regulations & Statutes Pertaining to Coal and Other Leasable Minerals (1974) - 11 A.A.C. 84.700...
 Drilling: Div. of Oil & Gas - 11 A.A.C. 94.730... (1974)

ARIZONA

- Statutes: Geothermal Resources (1972); amend. HB 2257 (1977) A.R.S. 27-651...
 Leasing: Land Dept. - Geothermal Resources (1972) T.12C.5.A.22 (under revision)
 Drilling: Oil & Gas Conservation Comm. - General Rules & Regulations Governing the Conservation of Geothermal Resources (1972) T.27C.4.A.4

CALIFORNIA

- Statutes: Leasing - Geothermal Resources Act (1967) Pub. Res. Code 6902...
 Production - Laws for the Conservation of Geothermal Resources (1967, as amend.) Pub. Res. Code 3700...
 Siting - Energy Resources Development; Conservation Act (1974) Pub. Res. Code 25000...
 Leasing: State Lands Comm. - Leases & Prospecting Permits for Geothermal Resources (1970) C.A.C. 2250...
 Drilling: Div. of Oil & Gas - Statewide Geothermal Regulations (1976) C.A.C. 1900...
 Siting: Energy Comm. - Provisions Applicable to Geothermal Notices & Applications (1978) DRAFT

COLORADO

- Statutes: Geothermal Resources Act (1974) C.R.S. 34-70-101...
 Leasing: Board of Land Commissioner - Special Rules & Regulations Relating to Geothermal Resources Leases (1972) SLB #248-1
 Drilling: Oil & Gas Conservation Comm. - Rules & Regulations for the Development & Production of Geothermal Resources (1976) G101...

HAWAII

- Statutes: Government Mineral Rights (1974); amend. HB 3033 (1978) H.R.S. 182.1...
 Leasing: Dept. of Land & Natural Resources - Regulations on Leasing & Drilling Geothermal Resources (1978) Reg. No. 8
 Drilling: Reg. No. 8

IDAHO

- Statutes: Leasing - Geothermal Resources Leasing Act (1975) ID Code 47-1601...
 Production - Geothermal Resources Act (1974, as amend.) ID Code 42-4001...
 Leasing: Board of Land Commissioner - Rules & Regulations Governing the Issuance of Geothermal Resources leases (1974; under revision)
 Drilling: Water Resource Board - Drilling for Geothermal Resources (1978)

LOUISIANA

Statutes: Geothermal Energy Resources (1976) L.R.S. 30:800...; Geothermal & Geopressure Energy Research & Development Act (1975) L.R.S. 30:681
 Leasing: Mineral Board - none (oil & gas model likely)
 Drilling: Office of Conservation - Statewide Order 29-P (1978)

MARYLAND

Statutes: Geothermal Resources Act (1978) A.C.M. 8-8A-01...
 Leasing: Not available
 Drilling: Not available

MONTANA

Statutes: Leasing - Lease of Geothermal Resources (1974) R.C.M. 81-2601...
 Siting - Major Facilities Siting Act (1975, as amend) R.C.M. 70-801...
 Filling bottom-hole temperatures - Act to Facilitate the Discovery of Geothermal Energy Sources (1975) R.C.M. 60-127, 144, 148
 Leasing: Dept. of State Lands - Geothermal Rules & Regulations (1975) M.A.C. 26-2.6(2)
 Drilling: Dept. of Natural Resources & Conservation - Geothermal Investigation Reports (1975) M.A.C. 36-2.8(14)

NEVADA

Statutes: Leasing - An Act Relating to State Lands (1975) N.R.S. 322.030...
 Production - An Act Relating to Geothermal Resources (1975) N.R.S. 534A.010...
 Leasing: Div. of Lands - pending
 Drilling: Div. of Water Resources - Regulations Pertaining to Exploration Drilling (1978)

NEW MEXICO

Statutes: Geothermal Resources Act (1967) N.M.S.A. 7-15-1...
 Geothermal Resources Conservation Act (1975; Chap. 272)
 Leasing: State Land Office - Rules & Regulations Relating to Geothermal Resources Leases (1971)
 Drilling: Oil Conservation Div. - Rules & Regulations for Geothermal Resources (1974)

OREGON

Statutes: Geothermal Resources (1975) O.R.S. 522.005...
 Geothermal Heating Districts (1975) O.R.S. 523.010...
 Leasing: Div. of State Lands - Geothermal Lease Regulations (1975) 75-010...
 Drilling: Dept. of Geology & Mineral Industries - Rules, Regulations & Laws Relating to Exploration & Development of Geothermal Resources (1977) 632-20-005...

TEXAS

Statutes: Geothermal Resources Act (1975) V.A.C.S. Art. 5421s
 Leasing: Railroad Comm./Div. of Oil & Gas - none (oil & gas model likely)
 Drilling: Railroad Comm./Div. of Oil & Gas - Rules Having General Application to Oil, Gas & Geothermal Resource Operation (1976) 051.02.02.000
 School Land Board - Rules & Regulations Governing Drilling & Producing on Permanent Free School Lands (1974; general)

UTAH

Statutes: Water & Irrigation Laws (1973) U.C.A. 73-1-120
 Leasing: Div. of Lands - Rules & Regulations Governing Issuance of Mineral Leases (1973); Geothermal Steam Lease Agreement (1973)
 Drilling: Div. of Water Rights - Rules & Regulations for Wells Used for the Discovery & Production of Geothermal Energy (1978)

WASHINGTON

Statutes: Geothermal Resources Act (1974) T.79 R.C.W.
Leasing: Dept. of Natural Resources - Geothermal Leasing Policy (1978) DRAFT
Drilling: Dept. of Natural Resources - none

WYOMING

Statutes: Underground Water (1973) WY Stat. 41-121
Leasing: Board of Land Commissioner - Rules & Regulations Governing the Issuance of
Geothermal Resource Permits & Leases (1975)
Drilling: Oil & Gas Conservation Comm. - Rules & Regulations (1975; general)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Notice Number

NOTICE OF INTENT TO CONDUCT GEOTHERMAL RESOURCE
EXPLORATION OPERATIONS

Applicant(s)	Address (include zip code)
Operator	Address (include zip code)
Contractor(s)	Address (include zip code)

hereby apply for authorization to conduct exploration operations pursuant to the provisions of 43 CFR 3209 now or hereafter in force across and upon the following-described lands (*give description of lands by township, attach map or maps showing lands to be entered or affected*)

Type of operations to be conducted (*give brief description*)

Exploration operations will be conducted during the period (*date*) from

to

Attached ☐ \$ Surety bond ☐ Rider to Nationwide bond ☐ Rider to Statewide bond ☐ Bond to be furnished

Upon completion of exploration operations the undersigned agrees to notify the Authorized Officer that authorized exploration operations have been completed in conformance with the general and special terms and stipulations of the notice.

The undersigned hereby agrees (1) that he will not enter upon the described land until he has been informed in writing whether there are special stipulations applicable to his Notice of Intent, as to either time or method of operation or otherwise, and, if there are such stipulations, what those stipulations are, (2) that he will comply with those special stipulations, if any; and (3) that he will not enter upon the described lands until his entry has been approved by the Authorized Officer.

The undersigned agrees to be bound by the terms and conditions of this notice to conduct exploration operations when approved by the Authorized Officer.

The undersigned agrees that the filing of this Notice under the regulations (43 CFR Subpart 3209) does not vest or confer any preference right to a geothermal resources lease.

The undersigned agrees further that all exploration operations shall be conducted pursuant to the following terms and conditions:

1. Exploration operations shall be conducted in compliance with all Federal, State, and local laws, ordinances, or regulations which are applicable to the area of operations including, but not limited to, those pertaining to fire, sanitation, conservation, water pollution, fish, and game. All operations hereunder shall be conducted in a prudent manner.
2. Due care shall be exercised in protecting the described lands from damage. All necessary precautions shall be taken to avoid any damage other than normal wear and tear to improvements on the land including, but not limited to, gates, bridges, roads, culverts, cattle guards, fences, dams, dikes, vegetative cover, improvements, stock watering, and other facilities.
3. All drill holes shall be capped when not in use and appropriate procedures shall be taken to protect against

hazards in order to protect the lives, safety, or property of other persons or of wildlife and livestock.

4. All vehicles shall be operated at a reasonable rate of speed and, in the operation of vehicles, due care shall be taken to safeguard livestock and wildlife in the vicinity of operations. Existing roads and trails shall be used wherever possible. If new roads and trails are to be constructed, the Authorized Officer must be consulted prior to construction as to location and specifications. Reclamation and/or reseeding of new roads and trails shall be made as requested by the Authorized Officer.
5. Upon expiration, conclusion, or abandonment of operations conducted pursuant to this Notice, all equipment shall be removed from the land, and the land shall be restored as nearly as practicable to its original condition by such measures as the Authorized Officer may specify. All geophysical holes shall be safely plugged. The Authorized Officer shall be furnished a Notice of Completion of Geothermal Resource Exploration Operations (Form 3200-3) immediately upon cessation of all such operations and shall be further informed of the completion of reclamation work as soon as possible.
6. Location and depth of water sands encountered shall be disclosed to the Authorized Officer.

7. Operator shall contact the Authorized Officer, prior to actual entry upon the land in order to be appraised of practices which shall be followed or avoided in the conduct of exploration operations pursuant to the terms of this *Notice* and applicable regulations. Operator will conduct no operations on the land unless the attached bond is in good standing.
8. Due care shall be exercised to avoid scarring or removal of ground vegetative cover.
9. All operations shall be conducted in such a manner to avoid (a) blockage of any drainage systems; (b) changing the character, or causing the pollution or siltation of rivers, streams, lakes, ponds, waterholes, seeps, and marshes; and (c) damaging fish and wildlife resources or habitat. Cuts or fills causing any of the above-mentioned problems will be repaired immediately in accordance with specifications of the Authorized Officer.
10. Vegetation shall not be disturbed within 300 feet of waters designated by the Authorized Officer, except at approved stream crossings.
11. Surface damage which induces soil movement and/or water pollution shall be subject to corrective action as required by the Authorized Officer.
12. Trails and campsites shall be kept clean. All garbage and foreign debris shall be eliminated as required by the Authorized Officer.
13. Operator shall protect all survey monuments, witness corners, reference monuments, and bearing trees against destruction, obliteration, or damage. He shall, at his expense reestablish damaged, destroyed, or obliterated monuments and corners, using a licensed surveyor, in accordance with Federal survey procedures. A record of the reestablishment shall be submitted to the Authorized Officer.
14. Operator shall make every reasonable effort to prevent, control, or suppress any fires started by the operator, and to report, as soon as possible, to the Authorized Officer location and size of fires, and assistance needed to suppress such fires. Operator shall inform the Authorized Officer as soon as possible of all fires, regardless of location, noted, or suppressed by independent action.
15. No work shall be done within one-half mile of a developed recreation site without specific written authority from the Authorized Officer. Any travel within one-half mile of a recreation site shall be over existing roads or trails.
16. Use of explosives within one-half mile of designated waters is prohibited unless approved, in writing, by the Authorized Officer.
17. If operations conducted under the provisions of this *Notice* causes any damage to the surface of the national resource lands, such as, but not limited to, soil erosion, pollution of water, injury or destruction of livestock or wildlife, or littering, operator shall, within 48 hours, file with the Authorized Officer a map showing exact location of such damage and a written report containing operator's plans for correcting or minimizing damage, if possible.
18. Violation of, or failure to comply with any of these terms and conditions shall result in immediate shutdown of field operations until deficiency is corrected. Failure to correct deficiency within the time period allowed by the Authorized Officer shall result in forfeiture of bond.
19. The Bureau of Land Management reserves the right to close any area to operators in periods of fire danger or when irreparable damage to natural resources is imminent.
20. Contractor shall be liable for assuring compliance with all terms and conditions of this *Notice* and all actions of his designated operator, agents, and employees.
21. Where continuation of the operation will result in irreparable damage to the land and other natural resources this *Notice* will be immediately cancelled by the Authorized Officer.

22. Special Stipulations:

 (Signature of Applicant)

 (Date)

 (Signature of Operator)

 (Date)

 We hereby agree to the special stipulations added and made a part of this *Notice* to conduct exploration operations.

 (Signature of Holder of Notice)

 (Date)

 (Signature of Operator)

 (Date)

 I hereby approve this *Notice* to conduct exploration operations.

 (Signature of Authorized Officer)

 (Title)

 (Date)

APPENDIX C

Key direct-heat geothermal contacts for legal, institutional and environmental mattersGeneral Information

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General Information/ East Coast

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General Information/Institutional Aspects

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Technical Information

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