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contents

editor's introduction

This volume is the English edition of "La Géothermie," which was originally published in Paris by Doin Editeurs. Most of the book is devoted to a discussion, beginning with first principles, of the thermal regime near the surface of the earth, with particular reference to the interaction between the temperature field and circulating groundwater. The results are applied to the problem of extracting usable heat and power from geothermal sources. The operation of generating plants using both wet and dry steam are extensively described, and methods developed by the author to estimate the power output and useful lifetime to be expected from a given geothermal area are also discussed. One chapter is devoted to the economic and political constraints that must be satisfied if geothermal energy is to become a reality.

The final two chapters are devoted to topics of interest to students of earth science. One deals with the relation between geothermics and certain selected geological phenomena. These include the thermal effects of igneous intrusions and extrusions, heat produced by deformation and faulting, thermal stresses in rocks, and the problem of the source of the heat producing metamorphism. The final chapter addresses itself to the thermal state of the earth as a whole, discussing the cooling of the earth, the radioactivity of earth materials (including the important thermal effects of radioactive decay), the thermal energy budget of the earth, and the author's views on convective circulation in the mantle.

The author is presently Ingénieur général des Mines and Vice-President, Bureau des Recherches Géologiques et Minières in Paris. Throughout his career he has been attached to the Service de la Carte géologique, and is a former director of the Service. He has done research and consultation on the e[illegible]ploitati[illegible] of g[illegible] thermal p[illegible] 1952,

when he served as a consultant to Electricité et Gaz d'Algérie on the possibility of exploiting the hot springs at Hamman Meskoutine in Algeria.

SYDNEY P. CLARK, JR.

ture to vary. This energy can be in the form of heat; the degradation of all other forms of energy (mechanical, electrical, electromagnetic, chemical, etc.) also produces heat. However, the first law of thermodynamics, the equivalence principle, indicates that there is a total conservation of energy with the equivalence relation that 1 cal = 4.18 J. Thus, it would seem logical to measure heat quantities in joules like all other forms of energy. Nevertheless we will not do this due to convenience and present usage in the field. Recall that 1 cal is the quantity of heat necessary to raise 1 g of water 1°C at around 15°C. The kilocalorie, kcal, is also used and is a thousand times larger than the calorie.

For a substance, the specific heat is the quantity of heat necessary to raise 1 g (or 1 kg) of the substance 1°C in temperature. This specific heat is easy to measure by first raising a body to a known temperature and then placing it in a water calorimeter. The specific heat depends on the temperature; in general, for rocks, the specific heat increases with temperature and can double its room-temperature value at 500 or 700°C. The values indicated by tables[1] vary only slightly for different rocks; granite is 0.155, limestone 0.16 to 0.23, and sandstone 0.19 to 0.22. This number must be multiplied by the density to obtain the heat capacity per cubic centimeter (C), which is thus of the order of 0.4 to 0.5.

1-2 Heat transfer

Heat transfer can take place essentially through three processes: *conduction*, in which the transfer occurs gradually through a body that may be solid; *convection*, in which a fluid moves in a closed circuit and carries heat. This movement may be caused by differences in fluid density which result from differences in temperature, and thus convection transports heat upward and not downward. The final type of heat transfer is by *electromagnetic radiation*.

[1]The best source is in Sydney P. Clark (ed.), "Handbook of Physical Constants," Mem. 97, Soc. Geol. Am., 1966.

1-3 Conductive transfer

In a standing body which may be solid, if the temperature is not uniform there will be a heat transfer which we can characterize as a flux. Flux, in this case, is the quantity of heat which passes through an imaginary surface per unit area per unit time. It can be shown that this flux is a vector, which means that our definition corresponds to the flux of a vector, whatever the orientation of the surface element. The flux would be zero if the temperature were uniform. If the temperature is not, then the flux is linearly related to the temperature gradient and we may write $q = K\,\overrightarrow{\mathrm{grad}}\,\theta$, where $\overrightarrow{\mathrm{grad}}\,\theta$ is the vector with components $\partial\theta/\partial x$, $\partial\theta/\partial y$, $\partial\theta/\partial z$.

In a crystal, and in general for all anisotropic bodies, the thermal conductivity K is a tensor. Thus, usually the flux and temperature gradient vectors do not have the same direction (except along the three principal axes, which are mutually orthogonal). The anisotropy of this tensor can be considerable: in mica, the conductivity can be as much as five times larger parallel to the cleavage plane than at right angles to it. For schists, this difference can be a factor of 2.

Even for an isotropic rock for which the conductivity K is a scalar, the measurement of the conductivity coefficient requires care, and the result will only be precise within a few percent. The most accurate method appears to be that called the *divided-bar* method, the apparatus for which is made up of two metallic supports with the same cross-sectional area and a rock cut in the form of a disk (see Fig. 1-1). The upper part of this device is heated while the base is cooled, and thus a steady-state temperature distribution is established. Then the temperature measurements are taken at several points along the metallic bars, thus giving the thermal profile. The experiment is performed again with two different thicknesses of the same rock to eliminate the effect of the temperature discontinuity which could exist at the contacts. The results are compared with quartz disks cut

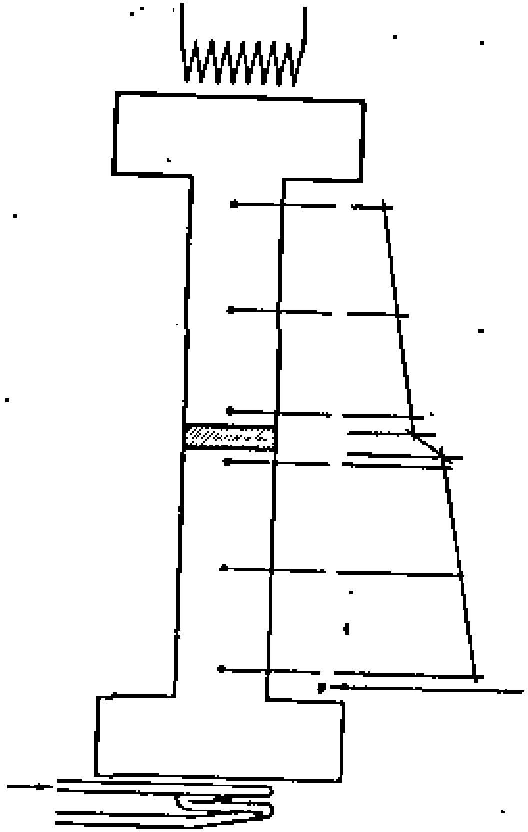


FIGURE 1-1 Principle of the divided-bar method for the measurement of thermal conductivity. The sample is cut in the form of a disk having the same cross section as the metallic rods. The rods are cooled at their bases and heated at their tops and steady-state temperatures are established. The temperatures are measured at three points by thermistors in each of the rods. The graph indicates the schematic form of the thermal profile which serves to compare the thermal gradients in the sample and the metallic rods for the same flux.

perpendicularly to the optic axis, whose conductivity is known and is conventionally taken as a reference.

The following values are cited: granite 5.7×10^{-3} cal/cm · s · °C, dunite 12×10^{-3}, limestone 5 to 7×10^{-3}, chalk

2.2×10^{-3}, marble 7.5×10^{-3}, dolomite 10×10^{-3}, quartzite 13×10^{-3}, schist 2 to 4×10^{-3}, and rock salt 27×10^{-3}. These orders of magnitude are all quite similar and much smaller than the conduction for metals (iron 0.15, brass 0.93, silver 1.001). Other less precise methods use variable temperatures. One of these will be described later.

The values for the heat capacity and thermal conductivity for rocks vary so little that, in the absence of more precise data, we can make calculations which will give an indication of the behavior of observed phenomena by taking average values. In the examples, unless otherwise indicated, $C = 0.5$, $K = 0.005$, and thus $\alpha = K/C = 0.01$.

1-4 The heat equation

In the absence of a heat source, it is easy to establish the thermal balance of an elementary volume. This balance will consist of the heat absorbed by the warming of the body and the excess of heat gained over the heat lost by conduction, $C\ \partial\theta/\partial t = -\mathrm{div} \cdot \mathbf{q}$; for an isotropic body, $q = K$ grad θ which yields the equation

$$C\frac{\partial\theta}{\partial t} = K\,\overrightarrow{\mathrm{div}} \cdot \overrightarrow{\mathrm{grad}}\,\theta = K\left(\frac{\partial^2\theta}{\partial x^2} + \frac{\partial^2\theta}{\partial y^2} + \frac{\partial^2\theta}{\partial z^2}\right) = K\nabla^2\theta \qquad (1\text{-}1)$$

The ratio $\alpha = K/C$ is often called the diffusivity. If heat is released in the rock because of the radioactivity of some of its constituent elements, then we would need to add this heat per unit volume per unit time to the right-hand side of Eq. (1-1).

To solve a conduction problem for a solid body, we need to find θ as a function of x, y, z, and t, knowing its value at $t = 0$ and the boundary conditions, which can be either a temperature or an imposed flux.

1-5 An example of a solution of the heat equation

The principle of measuring the thermal conductivity by a needle probe demonstrates an application of the heat equation. In an indefinite, isotropic, homogenous mass initially ($t = 0$) at a constant temperature (that we may take as zero), a quantity of heat is produced at a constant rate of m cal/cm · s along a straight line.

The measured temperature depends only on the radial distance r, and the flux is radial because of symmetry. In cylindrical coordinates, the heat equation becomes

$$C\ \frac{\partial\theta}{\partial t} = K\left(\frac{1}{r}\ \frac{\partial\theta}{\partial r} + \frac{\partial^2\theta}{\partial r^2}\right) \tag{1-2}$$

and $\theta = e^{-r^2/4\alpha t}/4\alpha t$ is a solution to Eq. (1-2).

The value of this solution for $t = 0$ is zero everywhere except at the origin where it becomes infinite. But, since its integral extended over an infinite surface is $\int_0^\infty \theta \cdot 2\pi r\, dr = \pi$, a constant, we can consider that the solution corresponds to the appearance at $t = 0$ of a quantity of heat πC per unit length of axis. If there has been a continuous production of heat between $-t$ and $t = 0$, the temperature distribution resulting from the heat diffusion at successive moments is given by

$$\theta = \frac{m}{\pi C}\int_0^t \frac{e^{-r^2/4\alpha t}}{4\alpha t}\, dt \tag{1-3}$$

This formula gives us the temperature evolution of a point situated at a distance r from the axis. If we make a change of variable such that $y = r^2/4\alpha t$, we obtain from Eq. (1-3)

$$\theta = \frac{m}{4\pi K}\int_y^\infty \frac{e^{-y}}{y}\, dy \tag{1-4}$$

This is a classical transcendental function called the *exponential integral* for which tables exist. It suffices for us to know that as soon as t is sufficiently large, its value becomes very close to $\ln \gamma y$, where $\gamma = 1.781$.

If the temperature has been measured at a distance r from the axis, a graph of θ versus $\ln t$ can be constructed. The curve rises progressively until it approaches an asymptote whose slope is given by $d\theta/d \ln t = m/4\pi K$. Or if we convert to log (to the base 10) this is $0.183\ m/K$. Thus we obtain the value of K by measuring the slope of the asymptote.

Conduction measurements following this principle have been chiefly done in marine sediments. A hollow needle, like a hypodermic, is equipped with an electric resistance wire passing through its axis giving off a known power dissipation of m cal/cm · s (see Fig. 1-2). The temperature is measured with a thermistor placed in a small cavity on the surface of the needle. The needle probe is then pushed into the sediment, and an electric current flows which gives off a constant thermal power; temperature is registered by the thermistor. A few minutes suffice for the measurement. If the dimensions of the apparatus are increased, the measurement time grows as the square of the diameter and the total power dissipation grows at least as the cube of the diameter, which in practice excludes the use of drilled holes with diameters of a few centimeters.

1-6 Convective transfer

Convection generally means the transport of heat by means of a free movement of fluid between two surfaces at different temperatures. Convective power is supplied by density differences between warm and cold fluid, and since the former tends to rise, convection only transports heat from the bottom to the top of the thermal system. In addition, it is not sufficient that the temperature be only slightly higher at the base of the fluid than at the top in order that convection may take place. The fluid, especially if it is a gas, cools by expansion as it rises, and thus it is necessary that the thermal gradient be at least equal to the adiabatic gradient. The adiabatic gradient corresponds to the temperature variation experienced by a mass of fluid being vertically displaced without any heat exchange. In the atmo-

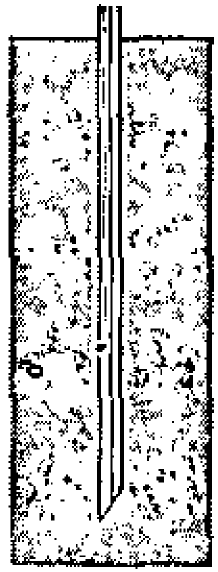


FIGURE 1-2 Principle of the measurement of thermal conduction by radial heat diffusion from one axis. A hollow needle (like a hypodermic) is used. An axial resistance dissipates a known constant thermal power. The temperature is measured at the surface of the needle probe, which is sunk in the sediment to be studied, by means of a thermistor lodged in a small cavity. The slope of the plot of temperature versus ln t permits the calculation of a, which gives K if C is known.

sphere, convection is the primary heat-transport mechanism, and it tends to produce a thermal adiabatic gradient such that the atmosphere is said to be in *adiabatic equilibrium*. Two cases can be distinguished according to whether or not the atmosphere is saturated with water.

Convection implies the individualization of ascending currents on one side and descending currents on the other, which can constitute more or less stable cells.

We shall frequently be concerned with a special form of convection in which water circulates in a porous rock and is so intimately associated with the rock that we can assume that the water is at the same temperature as the rock at all points. However, if there is a temperature gradient in the direction of the current lines, there is a heat transfer by water in addition to the transfer by conduction.

This transfer is in the direction of displacement of the water, which, strictly speaking, does not correspond to the direction of its velocity because the water molecules follow sinuous paths around the grains of the rock. Nonetheless, we can characterize this flow by a *unitary-flow* vector, u, which is such that its flux through a surface element is equal to the mass of water which crosses the surface element per unit time. This heat transport by water is proportional to the temperature gradient in the direction of the water displacement and the heat capacity C_w of the water. Thus, the water movement results in a heat loss per unit volume of $-C_w(\mathbf{u} \cdot \overrightarrow{\mathrm{grad}}\, \theta)$, which is proportional to the scalar product of the unitary flow of the water times the thermal gradient. In practice, C_w may be taken as unity. The above term figures in the left-hand side of the heat equation in the same manner as radioactive heat production r, and so the complete heat equation becomes

$$K\nabla^2\theta + r - C_w(\mathbf{u} \cdot \overrightarrow{\mathrm{grad}}\, \theta) = C\frac{\partial\theta}{\partial t} \qquad (1\text{-}5)$$

Whatever the motive power for water circulation in a permeable region, this type of heat transfer can play a role. Strictly speaking, however, we can only call a heat transfer *convection* if the motive power is furnished by density variations in the water as a function of temperature. These variations vanish at 4°C, and then, of course, convection is impossible.

1-7 Radiative transfer

The only method of heat transfer in a vacuum is through radiative transfer. All bodies emit electromagnetic radiation, which carries energy, and absorb all or part of the radiation received from other bodies.

The blackbody (or the radiation which escapes from the interior of a cavity) emits radiation which depends only on the body's temperature. The energy emitted per square centimeter per second is distributed in all directions and is given by Stephan's law:

$$W = \sigma T^4 \tag{1-6}$$

where $\sigma = 5.673 \times 10^{-12}$ W/cm² · °K⁴ and T is measured in degrees Kelvin.

To be more precise, the distribution of energy in the spectrum as a function of the wavelength λ, where λ is in micrometers, is given by

$$dw = d\lambda \times K_\lambda T^5 \tag{1-7}$$

with $K_\lambda = C_1/[(\lambda T)^5(e^{C_2/\lambda T} - 1)]$, where $C_1 = 1.2184 \times 10^8$ and $C_2 = 14{,}385$ when the flux is expressed in ergs per second per square centimeter. Observe that K_λ is a maximum when $\lambda T = 2897$ μ°K. The blackbody which radiates according to this law absorbs all incident radiation.

If a body is not black, it possesses for each wavelength a *color factor* which is less than 1. Its emission for each wavelength is multiplied by this factor. The energy which is received at this same wavelength is only partly absorbed, also depending on this same factor, and the rest is reflected. The color factor can vary greatly with the wavelength.

For the surface temperature of the sun (about 6000°K) the maximum for K_λ is in the visible part of the spectrum. For ambient temperatures (about 300°K), K_λ has a maximum in the far infrared at about 10 μm. Radio astronomers have established that there is also radiation from deep space which has a maximum at $\lambda = 0.7$ mm, which corresponds to a temperature of 4°K.

In a transparent substance, radiation emitted by a point source can cross a certain distance before being absorbed, and if there is a temperature gradient, the radiation emitted in opposite directions does not balance. Thus, there is a net transfer of heat by radiation. It is difficult to estimate its importance, which depends on the proportion of radiation absorbed per unit distance (which itself varies with wavelength). It appears that for certain silicates at 2000 to 3000°K, radiative transfer can be as important as conduction. At ambient temperatures, however, radiative transport is completely negligible.

In the stars, where temperatures reach tens or hundreds of millions of degrees, the radiative term is preponderant and we say that the stars may be in a radiative equilibrium. However, convection may play a part in the stellar interior.

1-8 Dilatation

Recall that all bodies expand when the temperature is raised. For a crystal or an anisotropic rock, expansion can be different depending on the direction. For calcite it is negative in the direction of the optic axis.

1-9 Brief explanation of the thermal regime outside the earth's surface

Outside the atmosphere, the earth receives 2 cal/cm² · min in radiative energy from the sun. Part of this energy is reflected and part is absorbed at different heights in the atmosphere or at the ground. On the other hand, the earth radiates during the day and night following a law which differs from that of a blackbody.

We will outline a calculation which should be instructive. A spherical blackbody at a uniform temperature T is under the influence of solar radiation at the same distance as the earth. It will absorb $\pi r^2/30$ cal/s which is equivalent to $(4.18/30)\pi r^2$ W. The sphere will radiate over its entire surface $(4\pi r^2 \sigma T^4)$, and on equating these two expressions we obtain the result that $T = 280$°K, which is 7°C. Such would be the temperature of a blackbody in equilibrium with the solar radiation. This example could be that of a satellite, the color of which must be carefully chosen to bring the temperature to the desired value. The similarity between this calculated temperature and the average surface temperature of the earth cannot be the effect of chance.

But things on the earth are much more complicated than the previous example: the surface te   ature at a

point is neither constant nor uniform because different parts of the radiation and the absorption take place at different levels in the atmosphere (for example, in the clouds). In particular, the far ultraviolet is strongly absorbed by the upper atmosphere, which is thereby raised to a high temperature. In addition, the solar radiation varies at each point because of the rotation of the earth. Finally, the atmosphere is not static but is in a constant state of mixing which dissipates an appreciable amount of energy. Overall, these movements tend to reduce temperature variations. This means that the atmosphere functions like a thermal engine and creates mechanical energy (wind, waves, and water-power).

1-10 Review of the second law of thermodynamics—*Carnot's principle*

This principle holds that perpetual motion is impossible. Now, if heat borrowed from a source at a constant temperature could be transformed into mechanical energy (inversion of the equivalence principle), perpetual motion could be achieved (that is, mechanical power could be produced from an engine borrowing heat at the ambient temperature). The second law forbids such a transformation.

Thus, mechanical energy can be produced from heat with a thermal engine only if sources at different temperatures are available. The machine will take heat from the warmer source and give it up to the cooler, but a certain proportion of heat will have been transformed into mechanical energy. The upper limit of this proportion, or *thermodynamic efficiency,* is given by a formula which also constitutes the definition of thermodynamic temperatures. If a thermal engine takes the heat Q_2 at a temperature T_2 and gives up Q_1 at T_1 while transforming $Q_2 - Q_1$, into mechanical energy, then we have

$$\frac{Q_2 - Q_1}{Q_2} < \frac{T_2 - T_1}{T_2} \quad \text{or} \quad \frac{Q_1}{T_1} > \frac{Q_2}{T_2} \tag{1-8}$$

The entropy is often defined by the relation $S = Q/T$ and we can see that the entropy gained by the cold source (Q_1/T_1) exceeds the entropy lost by the warm source. Thus, the entropy of the system can only increase. The entropy would remain constant for a system (called *reversible*) which remained infinitely close to its equilibrium point and could thereby function in either direction. Unfortunately, this is a practical impossibility. The inverse of a thermal engine would be a heat pump which absorbs heat at a low temperature and supplies heat at a higher temperature by means of consumption of mechanical power. But this time, if the efficiency is less than the thermodynamic efficiency of a reversible engine, this would mean that $Q_1/T_1 < Q_2/T_2$ and the consumed mechanical energy would be $Q_2 - Q_1$, which is larger than its ideal value.

1-11 Periodic and secular variations of the temperature

We will not deal with atmospheric and oceanic phenomena in detail but will simply recall that they influence the temperature at the earth's surface and give rise to periodic variations of which the periods of the day and the year play an important role. These variations are not sinusoidal, but we know that a periodic function (which is not exactly the case here) which is nonsinusoidal can be represented by a Fourier series, that is, a sum of sinusoidal functions with the fundamental period and the harmonics of that period.

Fluctuations with a period longer than a year are confirmed by the studies of paleoclimatology as well as the evidence of ancient glaciations. To explain these variations, should we consider the variations in the solar radiation which the earth receives? From solar studies, we are well aware of the solar cycle of 11 yr, but it does not seem to appreciably alter the radiation reaching the earth.

As a consequence of planetary perturbations, celestial mechanics allows calculation of some variations in the inclination and other elements of the terrestrial orbit. Milankovich studied the influence of these effects on the solar radiation and demonstrated that they would only lead to an average temperature change of at most 0.5 to 1.0°C, depending on the latitude.

It is also necessary to consider the possibility of instabilities (stochastic processes) in the differences of climate from year to year. The climate of one year can be influenced by the preceding year, which can lead to successive years with a warmer or colder climate than the average.

Consider a model of a globe in equilibrium with the sun's radiation. We will give an example of a thermal instability. Surfaces covered with snow or ice reflect a considerable portion of the solar radiation centered in the visible part of the spectrum. On the other hand, in the far infrared (10 μm), ice and snow are very absorbent and radiate like a blackbody. This is the wavelength of maximum thermal emission at about 0°C. Thus, if the snow- and ice-covered regions increased, the proportions of solar energy received would diminish but not the energy radiated by the earth. Therefore, the average temperature would decrease, leading to more surface area being covered with ice and snow, etc. This effect, of course, is much more complex, and such a rudimentary analysis cannot predict the rate at which the temperature would vary and the amount of surface which would be covered with ice and snow. It is also possible that opposing phenomena exist, caused, *for example*, by atmospheric movements, which could limit such instabilities. The complexity of phenomena such as those listed defies, even today, a precise analysis.

We can mention other examples of instabilities. Suppose that the accumulation of ice raises the land surface, until it reaches an altitude where the temperature is so low that an ice cap is preserved. (Compare Greenland, with an ice cap of about 3,000 m in elevation, with Baffin Island or other islands of the northern Canadian Archipelago.) Furthermore, such a large ice cap tends to create anticyclones which further lower the temperature. We will not enter into detail on such questions since they are poorly understood. Simply remember, we should not treat the average annual temperature as a constant since it can easily undergo short-

or long-term fluctuations. In addition, there are effects of man-made thermal pollution, which raise winter temperatures several degrees in cities, cause the heating of rivers, and lead to the formation of smog which perturbs solar radiation.

In the geologically recent past, such fluctuations resulted in glacial periods; for the last glacial period, the Würm, (or in North America, Wisconsin) enormous glaciers covered Scandinavia, parts of Northern Europe, the Alps, the larger part of Canada, and the northern part of the United States and did not disappear for tens of thousands of years. The temperature perturbations of the ground must have been stronger in the periglacial zones than in those areas protected by glaciers. The Quaternary glaciations seem to have begun 1 or 2 million yr ago.

Insofar as we know, there were no prior glaciations of major importance before the one just listed. However, there have been traces of some glaciations for certain geological periods: the upper Precambrian, the Ordovician (Sahara), and the Permo-Carboniferous (South America, South Africa, Australia).

1-12 Temperature of the ground

Up to this point, we have mentioned the temperature determined by atmospheric phenomena and solar radiation at the earth's surface. These influences produce temperature fluctuations of short periods around an average value which also fluctuates. If the temperature of the ground is measured at only a few centimeters depth, one finds that even in a limited area the temperature is strongly dependent on local conditions: Bare ground warms up more in the sun than land which is protected with even herbaceous vegetation. Such vegetation can evaporate water from the soil, which has a cooling effect, and, depending on the nature of the vegetation, will, or will not, affect the ground. The ground can be either favorable or not to dew deposits or [illegible]r frost accumulations. These p[illegible]s defy analysis,

and we are obliged to consider the temperature of the ground at a few centimeters in depth as empirical data.

1-13 Propagation of periodic temperature variations into the ground

Let us imagine a homogenous earth with an infinite plane surface. By reason of symmetry, the temperature depends only on the depth, and thus the heat flux is vertical. It is sufficient to write the heat equation for the vertical coordinate only:

$$\alpha \frac{\partial^2 \theta}{\partial z^2} = \frac{\partial \theta}{\partial t} \tag{1-9}$$

The boundary condition will be the temperature at the earth's surface for $z = 0$. If this temperature is expressed by a sum of periodic terms, we suppose that the expression of temperature will be of the same form at some depth in the ground after a sufficient time. This condition replaces the specification of an initial temperature.

It is immediately seen that all solutions of the form $\theta = A \exp(-z\sqrt{\omega/2\alpha}) \sin(\omega t - z\sqrt{\omega/2\alpha})$ satisfy Eq. (1-9). There would also be a solution with terms of the form $\exp(+z\sqrt{\omega/2\alpha}) \sin(\omega t + z\sqrt{\omega/2\alpha})$, but it would be absurd to find temperature variations increasing in amplitude with depth. If the surface temperature is represented by a sum of periodic terms, each of these terms will correspond to a term in the solution.

It is seen that temperature variations of a sinusoidal nature propagate downward while decreasing in amplitude. For $\alpha = 0.01$, an average value for rocks, the amplitude is reduced in the ratio by $e^{-\pi} = \frac{1}{23}$ at a depth $\sqrt{\alpha\pi T}$, T being the period in seconds. For $T = 1$ day, a depth of 52 cm is found, and for 1 yr, the depth is $\sqrt{365}$ times larger, or 10 m. At the same depth, the wave lags by π, i.e., is in opposition to the surface variation, since the propagation entails a delay of a half period. At twice the stated depth, the amplitude would be reduced in the ratio $(\frac{1}{23})^2 = \frac{1}{[illegible]}$. This is completely negligible (see Fig. 1-3).

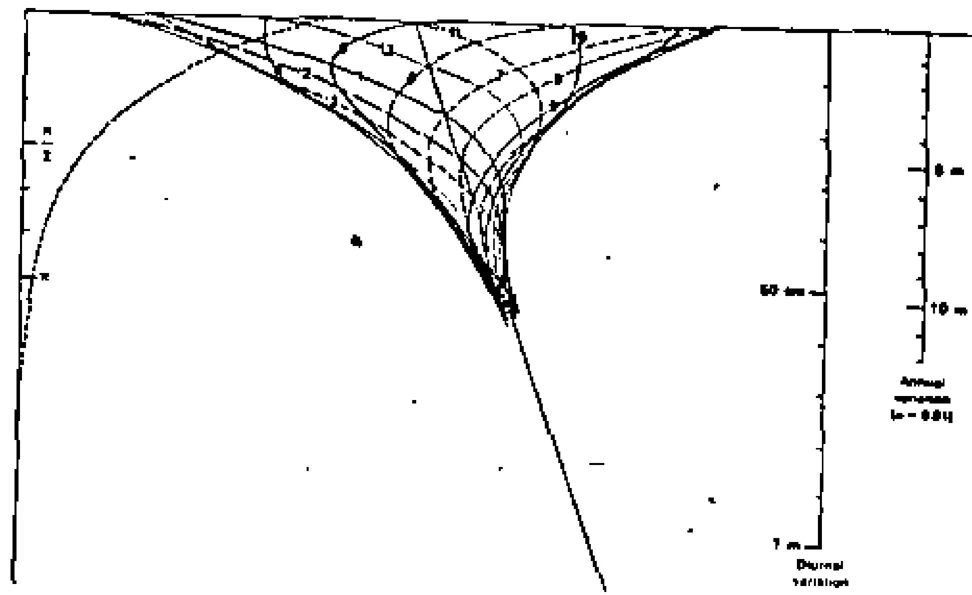


FIGURE 1-8 Temperature profile in a homogenous soil for a sinusoidal variation of the surface temperature, including the subterranean heat flux. The 12 curves can represent the monthly profiles for the annual variation, or every 2 hours for the diurnal variation. The vertical scales are marked for $\alpha = 0.01$ cm^2/s.

These conclusions are amply confirmed by experiment. We may add that if the surface variations are not sinusoidal, the higher harmonics decrease more rapidly and the temperature variation underground tends to become sinusoidal.

1-14 Stratified ground

If the ground were composed of horizontal layers with different thermal properties, there would be no difficulty in calculating the propagation of periodic temperature variations. For each layer, solutions of the form indicated for Eq. (1-9) would be valid, without excluding the solutions $\exp(+z\sqrt{\omega/2\alpha}) \sin(\omega t + z\sqrt{\omega/2\alpha})$. These solutions can be considered as reflected waves at the interfaces which propagate upward. For each interface, the te perature and flux equalities can be written for the two separate layers; each equality includes the phase and the amplitude for a sinusoidal term with a given period. The phase and amplitude for the two types of solution can be successively determined at each interface. The results of these calculations can be expressed by saying that at the interface crossing, waves traveling in the same direction have their amplitude multiplied in passing from layer 1 to layer 2 by $\frac{1}{2}(1+\sqrt{K_1C_1/K_2C_2})$ and that at the same time, a wave is reflected in the opposite direction with an amplitude multiplied by $\frac{1}{2}(1-\sqrt{K_1C_1/K_2C_2})$. Begin with an arbitrary phase and amplitude from the deepest, indefinite layer in which there exists only one type of solution. Afterward, determine the solution in each layer until the surface is reached, where the phase and amplitude are adjusted to meet the imposed boundary conditions. The general behavior of the solution stays the same as for a homogenous region.

Secular variations in temperature, the details of which are poorly understood, could in principle be described by a Fourier series, each term of which would easily allow us to calculate the underground effects. The depth penetration, that is, the depth at which the amplitude is reduced in a specified ratio, is proportional to the square root of the period. Considering the distance $l=\sqrt{2a/\omega}$, which is of the order of $3\text{ m}\times\sqrt{\text{period in years}}$ and for which the amplitude is reduced by the ratio $e = 2.7$, it is interesting to observe that the local gradient, which naturally decreases with depth as the temperature variation, has as a surface maximum one-half the amplitude of the total variation divided by $0.7l$.

As an example, for a period of 100,000 yr, $l = 1{,}000$ m. If the amplitude of temperature variation was 10°C, the maximum surface gradient would be 0.007°C/m and at 1,000 m, 0.003°C/m. The total amplitude of the temperature variation at the latter depth would still be 3.7°C. In a geothermal flux measurement down to 1,000 m, the error introduced could be of the order of 10 percent.

The variations can be more rapid and irregular, thus introducing terms with shorter periods. This effect will

eliminated if the lower parts of a drill hole are used, which is also recommended for other reasons.

1-15 Stresses caused by temperature variations

If a solid body was free from mechanical stresses, it would dilate as the temperature changed. When external conditions impose a certain temperature distribution on a body (we shall see how to calculate this), the geometric and mechanical solidarity of different parts of the body do not allow it to dilate freely. A distribution of mechanical stresses can result from this, which it is interesting to calculate. Of course, these stresses will be added to the preexisting stresses which we will not take into account here.

These internal stresses of the body are such as to be in equilibrium with the zero external forces. They produce on each volume element an elastic deformation, given by the classical equations, which adds to the thermal dilatation. It is the sum of these two deformations which make up the real deformation, subject to the geometric conditions, that they derive from a displacement. If we know the temperature distribution, the mathematical theory of elasticity will allow us to calculate the distribution of the thermal stresses and the deformation.

Actually, this procedure is not rigorous. Elastic compression releases heat, and if it takes place quickly, the temperature will rise. It would be necessary in the case of a rapid deformation (in particular, in the study of sound waves and especially shock waves) to write the mechanical and heat equations together.

Nonetheless, we will be content to take the approximation corresponding to slow changes, where we can by some means independently determine first the temperature distribution and then the resulting mechanical stresses.

As a case in point, let us consider the following problem. A blackbody (such as a satellite) is in thermal equilibrium with the solar radiation. An eclipse cuts off this radiation. How will the temperature change near the satellite surface which is turned toward the sun? (We suppose it is not rotating.) What mechanical stresses will result?

We will take $C = 0.5$, $K = 0.005$, and thus $\alpha = 0.01$, the average value for rocks. Now, as a first approximation, we will consider that the radiative flux loss is constant and equal to $\frac{1}{30}$ cal/cm$^2 \cdot$ s. We will let the temperature T (°K) be represented by $T_0 - \theta$; thus, $\partial\theta/\partial t = \alpha\, \partial^2\theta/\partial x^2$, with $\theta = 0$; at $t = 0$ and at $x = 0$ an imposed flux $K\, \partial\theta/\partial x = \frac{1}{30}$.

Considerations of homogeneity lead us to try a solution of the type $\theta = A\sqrt{\alpha t}\,\Phi(z)$, with $z = x/\sqrt{\alpha t}$. The equation then becomes $2\Phi'' + z\Phi' - \Phi = 0$. Let $\Phi = fz$ and we obtain $f''/f' = -(4 + z^2)/2z$ and thus $\ln f' = -\ln z^2 - z^2$. Integrating, we obtain $f = e^{-z^2}/z - \sqrt{\pi}[1 - \mathrm{erf}\,(z)]$, where $\mathrm{erf}\,(z) = (2/\sqrt{\pi}) \int_0^z e^{-y^2}\, dy$ is a function which often appears and which is tabulated in the appendix. Thus, $\Phi = fz = e^{-z^2} - z\sqrt{\pi}\,[1 - \mathrm{erf}(z)]$ and $\Phi' = -\sqrt{\pi}[1 - \mathrm{erf}\,(z)]$. For $x = 0$, $\partial\theta/\partial x = -A\sqrt{\pi}$, from which we obtain $A = 3.78$.

The surface temperature is given by $\theta = 3.78\sqrt{\alpha t}$, which is 3.78°C after 100 s, 37.8°C at 2 h 46 min, etc. However, after several hours we must take the slowing down of the cooling rate by radiation into account.

In the calculation of mechanical stresses, the pressure on the free surface is, and remains, zero. But a tension parallel to the surface appears which corresponds to an elastic elongation, equal and opposite to the free thermal dilatation.

We shall take for the expansion coefficient the mean value for quartz, that is, $\delta = 0.13 \times 10^{-4}$, and elastic coefficients $\lambda = \mu = 25 \times 10^{10}$ dyn/cm^2. Now we need to write an equation containing the three elasticity equations: $\sigma_{ii} = \lambda(\epsilon_{11} + \epsilon_{22} + \epsilon_{33}) + 2\mu\epsilon_{ii}$. Letting $\sigma_{ii} = 0$, $\sigma_{22} = \sigma_{33}$, and $\epsilon_{22} = \epsilon_{33} = -\delta\theta$, we solve the equations and obtain the result $\sigma_{22} = \sigma_{33} = (4 - \frac{2}{3})\lambda\delta\theta$, which is a stress of 11.44 bars at the end of 100 s, 114.4 bars at 2 h 46 min, etc. It remains to be seen whether these tensions, which can be repeated a number of times, can cause a surface fragmentation of the body.

CHAPTER TWO

heat flow

All the considerations of Chap. 1 could apply to an earth with a thermally inert interior. Such is not the case, although the perturbation of surface temperature by subterranean heat is negligible. This is easily demonstrated by considering the schematic model of a spherical blackbody which is in thermal equilibrium with the sun's radiation. We found, in Sec. 1-9, that such a body reaches a temperature of 280°K. If we modify this model by supposing an internal heat flux equal to the average geothermal flux (i.e., 1.2 μcal/cm$^2 \cdot$ s), Stephan's law immediately yields $\Delta W/W = 4\Delta T/T$; the mean power dissipation for the whole surface of the earth being $\frac{1}{4} \times \frac{1}{30}$ cal/cm$^2 \cdot$ s, it is increased by heat flow by 1.44×10^{-4}, which gives a temperature variation $\Delta T = 280°\text{K} \times (1.44 \times 10^{-4}/4) = 0.01°\text{K}$.

Even though this blackbody model is crude in comparison to the complexity of the external thermal system, we should remember that internal thermal activity cannot raise the surface temperature of the earth more than about a hundredth of a degree. This, of course, disregards unusual points such as next to volcanoes or active thermal sources.

This comparison emphasizes the fact that surface energy exchanges, where mobile fluids interact, are infinitely more intense than those in the earth's interior.

2-1 The measurement of heat flow

It has long been realized that once a depth of 10 m is exceeded (the effective limit of annual temperature perturbations), there is a steady increase in temperature on the order of 1°C for each 30 or 40 m. Sometimes, to designate this distance, the improper expression "geothermal degree" or "geothermal step" is used. This temperature increase with depth had been observed in mines in the seventeenth century and was attested to by Boyle in 1671 and Gensanne in 1740, although the temperature measurements were difficult to perform then. Arago was interested in this phenomenon in 1852, but it was not until 1868, under the influence of Lord Kelvin (then William Thomson), that a committee of the British Association systematically collected data on the thermal gradient and the thermal conductivity values for various rocks. Although these two types of measurements were not carried out in the same places, it was deduced that the average heat flux transmitted by conduction to the earth's surface was 1.3 μcal/cm$^2 \cdot$ s, an order of magnitude which has subsequently been confirmed.

In 1935, a new committee under the same association had Benfield and Bullard perform the measurements. Thermal profiles were measured in boreholes, and samples from the holes were used to determine the thermal conductivity. From that time on, it has been usual to present a graph with the measured temperature as the abscissa and the *thermal resistance*, $\int dz/K$, as the ordinate. Such a plot usually produces a straight line. It thus appears that the heat flow is approximately constant in a mine shaft or boring, even if the shaft crosses quite different rock layers. The geothermal degree (or gradient) is much more variable.

It was also demonstrated that for the first 1,000 m (in which most of the measurements were performed), a correction factor to take account of the earth's cooling during glacial periods would be on the order of 10 percent. This number is impossible to calculate accurately though, because we would need to know the detailed thermal history of the earth's surface. This effect tends to make us underestimate the heat flow.

Around 1949, Bullard made the first geothermal flux measurements in the ocean. It was expected that the heat flow there would be much lower than that existing on the

continents, but this was not the case and a complete new view of models explaining the relationship between the oceans and the continents had to be taken. Taking advantage of the fact that the bottom of the ocean is generally at a constant temperature near 0°C, probes were dropped into the ocean bed. These probes were 2 or 3 m in length and had electrical devices at three points to measure the temperature. In the head of the probe was a recorder, and the measurements were delayed for the longest time possible (at a minimum, ½ hour). During the recording of the temperature by the three thermometers, first the temperature of the seawater was seen (which allowed the thermometers' mutual calibration to be checked), then a warming due to friction as the probe penetrated the sea floor, and finally a restoration period during which thermal equilibrium was approached at an exponential rate. It was necessary to allow for a long enough time to elapse to extrapolate the rate of this curve and determine the equilibrium temperature of the oceanic sediment. If a sample of the ocean bed was obtained, then the thermal conductivity could be determined with a needle probe or deduced from the water content of the sediment by an empirical formula.

Ewing improved Bullard's apparatus by placing the temperature sensors on lateral fins fixed to the probe, which greatly accelerated the return to thermal equilibrium.

Admittedly, it is difficult to know if the probe is planted vertically in the sediment if the probe is not equipped with an inclinometer, and this can lead to an underestimate of the flux if the probe is inclined.

Thousands of measurements have been taken in the ocean with a precision which does not exceed 10 percent. These measurements have provided the same average heat-flow value as for the continents (1.2 μcal/cm$^2 \cdot$ s), but with significant regional variations to which we will later return.

Further continental heat-flow measurements were performed later; under the auspices of the International Union of Geodesy and Geophysics in 1963, measurements were made in many countries, including France. Drill holes which originally had served other purposes were used. Obtaining rock samples of the rock strata traversed was not too difficult to achieve, but drilling operations dissipated energy and heated up the surrounding area. In addition, the circulation of mud completely modified temperature distributions. This allows use of thermal measurement to abstract some information for various conditions. For instance, the depth of permeable layers from which water can penetrate into the shaft will be clearly indicated on a profile measured some time after the temperature has been equalized by cooling mud in the drill hole. Another application is to determine the height of a cement collar which is being placed around the casing by observing the heat released in the cement's solidification.

To obtain the thermal profile of the surrounding ground, it is necessary to leave the hole alone for a sufficient amount of time. The ideal situation would be to wait for a time equal to the actual drilling operation. Otherwise, measurements of the thermal profile can be taken at intervals of a few days, and from this the temperature evolution can be extrapolated.

The first measurements were made by lowering a maximum thermometer or, even better, a nongraduated thermometer whose shaft was cut obliquely. The mercury flowed out, and by heating the thermometer in the laboratory again, the maximum temperature could be calculated. These thermometers were placed in containers to protect them from the pressure.

Today, we prefer to do electrical measurements with a thermistor the resistance of which varies greatly with the temperature, but which must be specially calibrated. An elegant technique consists of regulating the frequency of an oscillating circuit by means of a thermistor, where the entire circuit is at the bottom of the drill hole, protected from the pressure. It is this oscillator which is standardized and the connecting cable has no influence on the measured frequency. With such a system, a precision of 0.01°C can be realized. However, this precision is perhaps illusory because it represents the temperature of the cooling mud, not the surrounding rock.

In New Zealand, for drilling operations which were at too high a temperature to allow reliable electrical measurement, an instrument was used which was inspired by the bathythermograph of oceanographers. This is a thin bimetallic strip which bends with temperature and which moves a needle which leaves a trace on a smoked-glass plate. The plate is connected to a ratchet device which advances the plate with each shock given to the cable which lowered the apparatus. The bimetallic strip and associated elements are standardized in the laboratory at the same pressure as in the drill hole.

The most notable cause of error is certainly due to aquifers that the drill hole penetrates. These layers are generally not in equilibrium with one another and give rise to a circulation along the hole. If there is a casing, such flows can circulate around it. To detect such errors, it is indispensable to measure a continuous profile or at least to take a large number of measurements. However, if such circulations are present, it is doubtful that their effect can be eliminated solely by calculation. The ideal situation would be to take the measurements in an impermeable homogenous layer. Too often though, we only have borings in sedimentary areas or near mineral deposits where there are frequently complex structures. Few authors have the courage to reject, as doubtful, measurements which required much time, money, and effort to obtain. Published heat-flow values undoubtedly include many doubtful measurements which are difficult to recognize.[1]

Nevertheless, large areas still lack any measurements and it would be completely illusory to seek overall patterns of heat-flow distribution on a worldwide scale. We will simply note that the heat flow appears low on ancient shields (approximately 1 μcal/cm^2 · s) and a little higher in recent

[1]See William H. K. Lee (ed.), "Terrestrial Heat Flow," 276 pages, no. 8, Geophysical Monograph Series, American Geophysics Union, 1965; also Geothermal Problems, Tectonophysics, vol. 10, nos. 1-3, September 1970.

tectonic zones. In the ocean, there are good indications of higher values along and near rifts on the midoceanic ridges (up to 8 or 10 $\mu cal/cm^2 \cdot s$). On the volcanic island arcs of the Pacific, low values (about 1) are found at the outside of the arcs and high values (about 2) on the inside. Any structural model of island arcs will have to take these variations in heat flow into account.

Of course, in the regions near active volcanoes, and to a lesser degree near thermal sources, all kinds of values for the heat flow can be found, even very high ones. However, it is clear that these active volcanic regions contribute only a negligible amount to heat flow on a global scale. The heat radiated and transferred by convection over the lava lake which occupies the crater of Nyiragongo is estimated at about 1 million kW. It is easy to calculate that this power is equal to the average heat flow (1.2 $\mu cal/cm^2 \cdot s$) over the surface of a circle with a diameter of 160 km, which is $\frac{1}{25,000}$ the surface of the earth. It is likely there are no more than one or two volcanoes having such permanent activity of this type at this time; out of about 500 known volcanoes, the majority have only intermittent activity and are much less intense than the lava lake at Nyiragongo. For Japan, the energy dissipated annually for all volcanoes has been estimated as an average of 7.3×10^{23} ergs/yr which is 2.3×10^6 kW, twice the value for Nyiragongo. That is one-tenth the normal heat flow for all Japan, and hot ground and thermal sources bring a surface flux of about the same magnitude.[1] But, by all evidence, Japan is not a representative case. Thus, it is clear that the major portion of the heat which escapes from the earth's interior is due to the normal heat flow. The additional heat supplied by volcanic zones is much smaller, on the order of $\frac{1}{1,000}$ or $\frac{1}{10,000}$. A precise figure is very difficult to give. What was the flux like during the time of formation of large basaltic plateaus (Deccan, Siberia, South America, Ethiopia, etc.), where the surface covered with lavas may have approached millions of square kilometers? We do not know the durations of such outpourings and thus an estimate of the heat loss is difficult. Observe that the cooling of 1 million km³ of basalt from 1000°C represents a heat loss on the order of 0.5×10^{24} cal. This corresponds to the normal heat flow for the whole world for a period of 2,600 yr. If the release of the basalt had lasted for a much longer time, the heat loss would still be small in comparison with the total normal heat flow.

[1] Koso Yuhara, Heat Transfer Measurements in a Geothermal Area, *Tectonophysics*, vol. 10, pp. 19–30, 1970.

It is easy to calculate that the total power dissipated by the normal heat flow is equivalent to 2.55×10^{10} kW. Of course this is much less than the energy brought to the earth by solar radiation (1.7×10^{14} kW), but most of the solar energy is either reflected or immediately reemitted.

We will see in Chap. 8 that the heat flow represents much more power than is dissipated by other manifestations of internal activity such as tectonic deformations or earthquakes. Also, note that the energy dissipated by tidal actions, which is taken from the kinetic energy of rotation of the earth and moon, is roughly estimated at 3×10^9 kW, which is approximately one-tenth of the geothermal flux.

2-2 Structural influences on the heat-flow distribution

We have implicitly assumed that the surroundings are homogeneous in our descriptions of measurement methods, and that heat can be considered to flow vertically. This is not necessarily so, and the lack of knowledge about local conditions can lead to errors. If different thermally conducting layers are joined vertically, it is the thermal gradients which are equal while the local fluxes are different. The regional flux, significant in subterranean regions, is a weighted average of the local fluxes. On the other hand, for horizontal layers with different thermal conductivities, the flux is the same and the thermal gradients are different. For other more complicated arrangements, neither the flux nor the gradient is uniform, or even vertical. It is perhaps

the method of the electrical analogs which would most easily permit us to determine the temperature distribution (analog of the potential) of a complex structure.

Assuming a homogenous, horizontal, transgressive terrain covering a complex structure with different rock units joined along vertical surfaces, the value of the gradient and the flux in the covering material furnishes an indication of the underlying rock distribution, since both thermal quantities are greater above highly conducting rocks. Theoretically, this would provide a prospecting method were it not so difficult to make precise measurements of the thermal gradient.

For a vertical flux, it is also necessary that the surface temperature be uniform. A borehole that was sunk at Resolute Bay, in the northern Canadian Archipelago, was measured for its thermal profile (in this case, the freezing of water around the measurement cable avoided the risk of perturbations caused by water circulation), and it appeared that there was an abnormally high flux. But in fact the site was next to the ocean, and if the average land-surface temperature was of the order of -20°C, and the temperature at the bottom of the ocean stayed constant at about 0°C, then in this case, the flux was certainly not vertical.

To study this case's behavior, we will schematize the situation by supposing that at the surface there were two temperatures differing by $\Delta\theta$ on either side of a linear boundary. Assuming that at great depths the flux has a given constant value, determine the temperature distribution.

We will take advantage of the fact that, since the heat equation is linear, a sum of individual solutions to the equation will also solve the equation. We will first consider the situation where the temperature at the surface ($z = 0$) is $\Delta\theta/2$ for $x > 0$ and $-\Delta\theta/2$ for $x < 0$, the thermal flux canceling at great distances. It is immediately seen that the solution for which the isotherms are planes passing through the axis $x = 0$, making an angle A with the vertical such that $\theta_1/\Delta\theta = A/\pi$, satisfies the given conditions. The unit

flux, perpendicular to the isothermal planes, has a value $K\,\Delta\theta/\pi r$, where r is the distance from the axis $x = 0$.

We will also take into account another part of the solution corresponding to a uniform flux whose value F is determined with the condition that the surface temperature equals zero ($\theta_2 = 0$); isotherms are then given by $z = K\theta_2/F$.

In adding these two solutions, we will find for $\theta = \theta_1 + \theta_2$ a distribution which satisfies the equation $\theta = \Delta\theta A/\pi + Fz/K$ (see Fig. 2-1 indicating the shape of the isotherms). It is seen that up to a distance $l = K\,\Delta\theta/F\pi$, the ocean gives up heat to the bottom, the flux being locally inverted. It is only further from the shoreline that the flux has its normal direction, the value being $F(1 - l/x)$. On land, the flux $F(1 + l/x)$ locally (for small values of x) takes values which can be quite high.

From the preceding solution, we can immediately draw the solution for a large limited area such as a lake, where there is a temperature difference $\Delta\theta$ between the area in question and the rest of the surface (in France, the bottom of a lake can be at 4°C while the surface is at 11°C). It is sufficient to add the solutions above for the two limits; in the absence of a subterranean flux, the isotherms would be circles; in its presence, the isotherms have shapes such as those indicated in Fig. 2-2.

2-3 Temperature in a tunnel

A problem frequently studied because of the interest in estimating the initial temperatures of rock strata which are cut by a tunnel concerns a mountain with average ground temperatures decreasing at a rate in the neighborhood of 1°C/100 m. As usual the flux has its normal value at large distances; the temperature distribution is wanted. Only approximate solutions can be found, taking the shape of the mountain more or less exactly into account and painfully estimating the rock distributions, with different conductivities, often anisotropic. (The high temperatures encountered

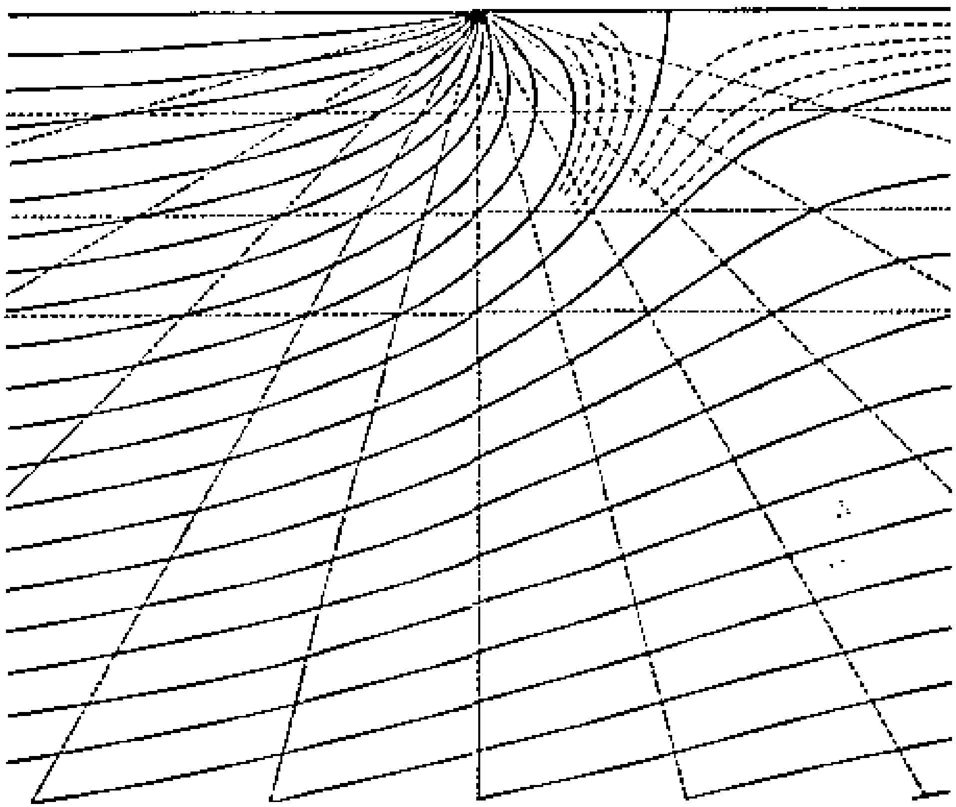


FIGURE 2-1 Temperature distribution under a rectilinear bank along which the average surface temperature suffers a discontinuity. The graph is applicable by a scale choice to all values of the discontinuity and the geothermal flux. (The scale can be fixed by means of the point where the flux is zero, corresponding to an isotherm, the abscissa of which is given in the text, which reaches the surface perpendicularly.)

in the Simplon tunnel were interpreted in retrospect as being due to the fact that the schistosity of the gneiss was horizontal while the Gothard tunnel's schistosity was vertical.) It can be useful to consider the desired solution as composed of the superposition of the normal thermal gradient, such as would be the case if the earth were horizontal, with indefinite upward extension and a correction term which must satisfy the heat equation and the imposed sur-

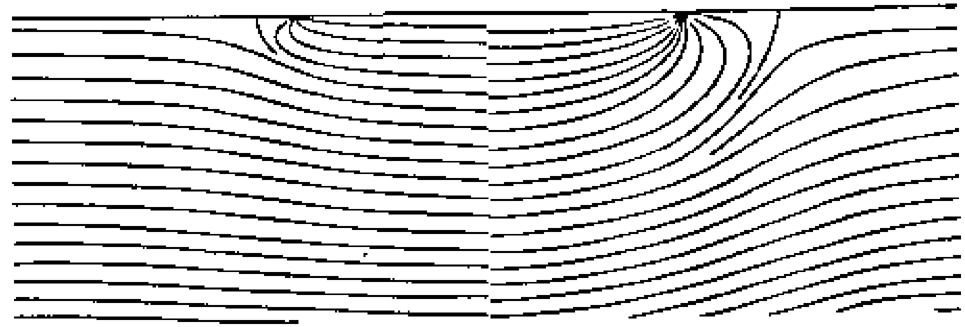


FIGURE 2-2 Temperature distribution under a lake compared to a parallel band where the average temperature is less than that of the surrounding surface. To the left: case where the average superficial temperature difference corresponds to the value of the thermal gradient for a depth of 0.2 times the breadth of the lake. To the right: for a case where the depth is equal to 0.8 times the breadth of the lake.

face temperatures, corresponding to a zero flux at infinity. Also, the solution must be zero on a plane surface outside the mountain and equal to the difference between the imposed surface temperature and the temperature resulting from the extrapolation of the thermal gradient to the mountain's surface.

Among the methods which we can consider, let us pay particular attention to electrical analogs. If we have a mold in the form of a mountain filled with a conducting fluid and if we establish voltage potentials along curves of equal level, we can determine the form of the volume equipotentials (or along the projected tunnel route) and thereby deduce the correction for surrounding topography.

2-4 Effects of erosion or sedimentation

Another perturbation can result if the surface temperature remains constant but there is erosion or deposition of sediment, which we will suppose to be of the same material as the substratum. To study this type of problem, a moving coordinate system is sometimes used whose origin remains at the surface while the surface moves with a velocity u. This requires that we replace $\partial\theta/\partial t$ by $(\partial\theta/\partial t - u\ \partial\theta/\partial x)$, $u\ \partial\theta/\partial x$ being the apparent temperature increase at a depth x, caused by the movement of the origin, and not corresponding to any actual heating. The heat equation then becomes

$$C\left(\frac{\partial\theta}{\partial t} - u\ \frac{\partial\theta}{\partial x}\right) = K\ \frac{\partial^2\theta}{\partial x^2} \quad \text{or} \quad \frac{\partial\theta}{\partial t} = \alpha\ \frac{\partial^2\theta}{\partial x^2} + u\ \frac{\partial\theta}{\partial x} \tag{2-1}$$

where u is positive in the case of erosion and negative for sedimentation, the axis being directed downward.

This equation allows us to solve the following problem: if erosion continues at a constant speed in a steady-state system, what would the temperature, which is assumed uniform, be at great depths underground in order that we observe the given surface gradient? The desired solution, which is assumed constant in a moving coordinate frame, is immediately found:

$$\theta = A(1 - e^{-ux/\alpha}) \quad \text{and} \quad \left(\frac{\partial\theta}{\partial x}\right)_0 = Au/\alpha$$

If we imagine an erosion of 1 mm/yr with $\alpha = 0.01$, the superficial gradient is 1°C/30 m which would correspond to a temperature at great depths of 950°C. However, the equivalent case for a uniform sedimentation cannot be visualized. The preceding problem is not realistic because we know that the temperature is not uniform underground and the erosion could not have followed its course indefinitely in the past (the solution of this problem would be drastically changed if the erosion had not been uniform at least for 50 or 100 million yr). At least, it gives us an idea of the degree to which erosion of long duration can disturb the thermal system. This reasoning cannot be applied if we look for a steady-state solution (in a moving coordinate system) given a condition satisfied at a great distance such as a nonzero flux or gradient, because the temperature variation of the entire half space would absorb an unlimited amount of heat flux.

A realistic way of treating the problem would be, given the steady-state solution corresponding to a given flux at a great depth, to consider erosion or sedimentation proceeding at a given rate during a limited time span and to look for the resulting perturbation of the thermal profile.

There are no analytically simple solutions in general, but if we consider erosion which goes as the square root of the time, $z_e = p\sqrt{t}$ (p would be negative in the case of sedimentation), the solution

$$\theta = mx - A\sqrt{t}\,\Phi\left(\frac{x}{\sqrt{4\alpha t}}\right) \tag{2-2}$$

with $\Phi(z) = e^{-z^2} - z\sqrt{\pi}\ \mathrm{erfc}\ (z)$, satisfies the heat equation for fixed axes and satisfies the condition $\theta = 0$ for $x = p\sqrt{t}$ if $A = mp/\Phi(z_0)$ with $z_0 = p/\sqrt{4\alpha}$.

From these conditions, we get the value for the gradient:

$$\frac{\partial\theta}{\partial x} = m\left[1 + \sqrt{\pi}z_0\ \mathrm{erfc}\left(\frac{x}{\sqrt{4\alpha t}}\right)/\Phi(z_0)\right] \tag{2-3}$$

Observe that at the surface, the gradient is a constant. If $z_0 = p/\sqrt{4\alpha}$ is small, which will generally be the case (for an erosion of 1,000 m in 1 million yr, which is 1 m in the first year, $z_0 = 0.089$), we can use the approximation $(\partial\theta/\partial x)z_0 = m(1 + \sqrt{\pi}z_0 - z_0^2)$.

From these results, we immediately deduce that in the case where erosion progresses uniformly, the gradient will constantly increase. Also, this gradient will be greater than the gradient for the same erosion in the same time following a law going as the $\sqrt{t}$ and less than one for the same erosion in half the time following a law going as the $\sqrt{t}$ (which will finally lead to the same instantaneous velocity). This suffices to furnish an order of magnitude.

We could also do an approximate calculation by supposing that the erosion occurs instantaneously. It is easy to see that the temperature profile corresponding to a progressive erosion falls between the results of an instantaneous erosion at the beginning and at the end.

If the initial gradient is given by $\theta = mx$ and if at $t = 0$ a thickness l of ground is removed and the new surface is brought to the initial temperature, taken as 0°C, the temperature is then given by

$$\theta = mx + ml \operatorname{erf}\left(\frac{x}{\sqrt{4\alpha t}}\right) \tag{2-4}$$

The surface gradient is $m(1 + l/\sqrt{\pi\alpha t})$. This formula shows that 1 yr after the removal of 1 mm of ground the gradient is only raised by 1 part in 10,000. But 1 million yr after the erosion of 1 km, the gradient is increased by 10 percent (these values are lower but in approximately the same ratio as would be produced by continuous erosion in the same time span).

Sometimes in place of these erosion or sedimentation problems, a more complicated problem is considered, in which we are given the temperature distribution as a function of depth (for example, $\theta = ax + T_0\,(1 - e^{-bx})$, and the grounds' contents of radioactive elements decreasing exponentially as a function of depth, and we must find a steady-state solution as a function of the rate of erosion.[1] But it becomes very difficult to distinguish between the desired physical phenomena and the consequences of particular choices of the parameters T_0, a, and b, which characterize the given temperature profile.

2-5 Effect of radioactivity

Until now, we have ignored the influence of the radioactivity of rocks, which results in a heat production which can reach 20×10^{-6} cal/g · yr for certain granites (see Chap. 8). Generally it is much smaller for sedimentary rocks, of the order of 2×10^{-6} cal/g · yr.

Considering the complete heat equation,

$$C\,\frac{\partial\theta}{\partial t} = K\left(\frac{\partial^2\theta}{\partial x^2} + \frac{\partial^2\theta}{\partial y^2} + \frac{\partial^2\theta}{\partial z^2}\right) + r \tag{2-5}$$

[1] H.S. Carslaw and J.C. Jaeger, "Conduction of Heat in Solids," p. 388, Oxford University Press, 1959.

we can look for solutions of the form $\theta = \theta_1 + \theta_2$, where θ_1 is the solution to Eq. (2-5) without the term r, and θ_2 is a solution to the equation $0 = K\nabla^2\theta + r$ with the boundary conditions $\theta_2 = 0$ and $\overrightarrow{\text{grad}}\,\theta_2 = 0$, at the surface. If θ_2 is only a function of z and r is constant, then we have $0 = K(\partial^2\theta_2/\partial z^2) + r$, which leads to $\theta_2 = -rz^2/2K$. If $r = 1.6 \times 10^{-12}$ or 1.6×10^{-13} cal/cm³ · s and if z is expressed in kilometers, we determine for the coefficient $r/2K$ the values of 1.7 and 0.17°C/km².

It would be easy, if this were the case, to apply this correction to the subterranean temperatures calculated from surface observations and, in particular, from the measured values of the gradient at the surface. It is clear that for sedimentary rocks, as well as for the metamorphic rocks which are derived from them, we can neglect the effect of radioactivity over the several kilometers where we will study the behavior of subterranean waters. The same is true for intermediate or basic eruptive rocks, which have radioactivities of the same order as above or less.

It is only for granites which are particularly radioactive that the correction term becomes more important and cannot be ignored in the temperature study of a deep tunnel. There are reasons, however, to believe that only the most external parts of certain intrusive bodies have significant radioactivity. We have shown that the correction factor is negative when the surface gradient is known, since the temperature is no longer simply proportional to the depth. But this does not alter the fact that if the average heat flux at various depths is given, a massive, very radioactive granitic rock will be warmer than its surroundings and will produce a larger superficial gradient.

CHAPTER THREE

influences of groundwater

As long as the water which soaks all rocks remains immobile, the water's only effect is modifying the values of the heat capacity and thermal conductivity. It can only be hoped that the measurements of these values has been done with samples saturated with water in the same conditions as would occur in nature. For the thermal conductivity, this is not always the case.

If water moves in the ground, we can characterize its displacement by the *unitary-flow* vector. This vector is represented by u, the flux of which across any surface element is equal to the mass of water that crosses the surface per unit time. We assume that this water immediately reaches thermal equilibrium with the rock that it penetrates. The rock gives up to the water a quantity of heat which is equal to the product of u times the specific heat of water C_w times the component of the thermal gradient in the direction of u. In practice, C_w can often be set equal to unity. The heat equation thus becomes

$$C\,\frac{\partial\theta}{\partial t} = K\Delta^2\theta - C_w(\mathbf{u}\cdot\overrightarrow{\mathrm{grad}}\;\theta) \tag{3-1}$$

It is also known that the unitary-flow vector of the fluid is connected with its pressure by Darcy's equation:

$$\mathbf{u} = \frac{\sigma}{\eta}\,\overrightarrow{\mathrm{grad}}\,(P + \varpi_g z) \tag{3-2}$$

where P is the fluid pressure and ϖ_g its specific gravity at the point under consideration, σ is normally, i.e., in an anisotropic body, a tensor but can degenerate into a scalar coeffi-

cient of permeability if the rock is isotropic. η is the coefficient of the viscosity of water; it varies drastically with the temperature.

It is sometimes necessary to take into account the variations of the specific gravity of water with temperature; these variations are essential factors in water displacements by convective currents. We could try to write a system of unitary equations to describe what have been called hydrothermal phenomena. The difficulty stems from the fact that there is no simple law to describe the variations of the viscosity of water with temperature.

The heat equation written in Eq. (3-1) can be applied without any great modifications to the case of water circulating in a permeable layer of negligible width (such as a fissure) or in a linear channel. The circulation manifests itself by the appearance of heat sources, superficial or linear, whose value is given by the scalar product of the thermal gradient times the flow (but this will not be the unitary flow, but rather the flow per unit width in a linear surface circulation).

As a case in point, and to fix the orders of magnitude, we shall examine the influence on the thermal gradient which would be produced by the absorption of rainwater by the ground. We suppose that rainwater filters in freely from the surface to a phreatic level situated at a depth h beneath which the ground is saturated with water. If we allow a rainwater collection of 31 cm/yr, which is not at all excessive, we find that $u = 10^{-6}$ g/s. Supposing a uniform gradient of 3°C/100 m, it is found that $\partial\theta/\partial t = -6 \times 10^{-10}$°C/s, which is about 0.02°C/yr.

Under the same conditions, let us suppose the phreatic surface is at a depth $h = 100$ m, and suppose that at this depth the temperature is constant (this could be because the sheet of water circulates horizontally and the region where rainwater is absorbed is of a limited area). It is easy to find the steady-state profile for this model, which will be of the form

$$\theta = A(e^{az/h} - 1) \tag{3-3}$$

which in this case gives $\theta = 1.75(e^{10^{-4}z} - 1)$. The change from the initial linear temperature profile is 0.37°C at middepth, and the gradients are 1°C/57 m at the surface and 1°C/21 m at the base of the perturbed layer. Comparison with the preceding result suggests that a steady state would essentially be attained in several tens of years.

The importance of this rainwater perturbation would completely invalidate all flux measurements conducted at a depth susceptible to the water's infiltration. There would also be other reasons for avoiding this particular range of depths, which could be the site of air circulation and of the condensation or evaporation of vapor. Subterranean seepage from lakes or rivers could have an even more pronounced thermal effect. Measurements of thermal gradient could be designed to show these effects.

In areas of karst topography, where underground caves can have substantial heights, it is impossible to measure the thermal gradient. The temperature there is essentially uniform, and this can be interpreted as the effect of weak air currents which guarantee an efficient transport of heat by convection.

A number of heat-flow measurements have been performed in mines. These mines always constitute water drains and strongly perturb subterranean water systems. We can only hope that gradients measured in mines have not been too strongly perturbed by such influences.

3-1 Convective movements

In a purely conductive system, the steady-state temperature distribution is stable. This means that if such a system is locally perturbed, the perturbation will diffuse, spread, attenuate, and finally disappear on a time scale which is simple to calculate. The steady-state distribution satisfies the heat equation, and the same equation must be satisfied by the perturbation. It is easily verified that the

expression

$$\theta = (4\pi\alpha t)^{-3/2}\, e^{-(x^2+y^2+z^2)/4\alpha t} \tag{3-4}$$

is a solution to the heat equation and that its integral extended over all space is equal to unity. For $t = 0$, the expression is zero everywhere except at the origin. Thus, this represents the manner in which a heat contribution released instantaneously at the origin diffuses. Equation (3-4) can also be used to estimate the rate at which the maximum temperature of an extensive perturbation decreases. This process can be characterized by the radius at which the maximum temperature is one-half its initial value, and leads us to represent this maximum temperature in Eq. (3-4) by taking t_0 such that $\rho^2/4\alpha t_0 = \ln(2.0) = 0.67$, which gives $t_0 = \rho^2/2.68\alpha$. Thus, the relative rate of decrease of temperature at the center of the system by conduction is

$$\frac{\partial\theta/\partial t}{\theta} = -\frac{3}{2t_0} = \frac{-4\alpha}{\rho^2} \tag{3-5}$$

On the other hand, if we take into account the presence of water in a porous soil, things can evolve in a different way. We shall study the conditions under which convection currents can develop; they can cause irregularities in the temperature distribution to increase.

Let us first consider the effect of groundwater movement on the transport of heat. The permeability of soil can be expressed either in practical units, grams per square centimeters for a gradient of 1 cm of water per cm, or in darcys σ, the practical unit being $10/\eta$ darcys, where η is the viscosity.

A temperature perturbation θ of the system with respect to the unperturbed system having a thermal gradient m produces a variation of the specific gravity of water given by $\lambda\bar{\omega}g\theta$, where λ is the coefficient of expansion and $\bar{\omega}g$ the specific gravity. This results in an equal variation of the pressure gradient with respect to the unperturbed system. As a result, a certain amount of water is raised and lightened because of its heating (or the inverse), with a flow $q = 10\sigma\lambda\bar{\omega}g\theta/\eta$. The upward motion of the water produces a heating of the surrounding rock at a rate given by $C\ \partial\theta/\partial t = mq = 10m\sigma\lambda\bar{\omega}g\theta/\eta$, which leads to a relative rate of change of

$$\frac{1}{\theta}\frac{\partial\theta}{\partial t} = 10m\sigma\lambda\bar{\omega}g/C\eta \tag{3-6}$$

It suffices to compare this rate of change caused by the displacement of water by convection with the rate of change calculated earlier [Eq. (3-5)] for the attenuation by conductive diffusion and to see if the perturbations attenuate and disappear, indicating stability of the thermal system, or, in contrast, grow (and if they grow at what rate). The latter case would suggest the possibility of establishing convection currents. We will look for an order of magnitude only, and it would be useless to attempt to describe the convective cells completely. We suppose that other opposing perturbations exist next to the phenomena which we are studying so that the circulation can occur in closed loops.

The value which we found for the relative rate of change of the perturbation by convection can be applied to the maximum temperature. To take account of the fact that within the radius ρ the temperature difference can vary between the maximum value and one-half that maximum, we will reduce the rate of change found for Eq. (3-6) by a factor of $\frac{3}{4}$. We can thus estimate the relative rate of change:

$$\frac{1}{\theta}\frac{\partial\theta}{\partial t} = 7.5m\sigma\lambda\bar{\omega}g/C\eta - 4\alpha/\rho^2 > 0 \tag{3-7}$$

This expression must be positive if convection is to be possible.

It is immediately seen that convection will occur much more readily as the thermal perturbation is enlarged. It will be found for each dimension that there is a limiting value of the permeability σ. Convection is aided by a high gradient m. Convection depends especially on the coefficient of expansion λ and the kinematic viscosity $\eta/\bar{\omega}$, both of which vary strongly with temperature. λ, which is 0 at 4°C, increases continuously with the temperature until the critical point is reached and has little variation with pressure. The viscosity

decreases greatly as the temperature increases, varying in the ratio of 10:1 between 0 and 100°C, and continues to decrease up to the critical point. The conjugate variation of these two factors makes convection much stronger when the temperature increases.

Table 3-1 indicates the limiting values of the permeability σ (for a gradient $m = 1$°C/30 m), in darcys, above which convection is possible according to Eq. (3-7). For a steeper gradient, these values would be reduced in the ratio $\frac{1}{30}$ m.

To provide an idea of the sizes of the above permeability values, for sand of uniform grain size of 0.1 mm, which would constitute an exceptionally permeable rock, we have $\sigma = 1.3 \times 10^{-6}$. However, it is rare that such a permeability is found over a substantial thickness, and we are often concerned with much smaller values. On the other hand, the aforementioned criterion corresponds to a limit for which the rate of development of convection cells would be infinitely small.

Even if in Eq. (3-7), which gives the rate of increase of the thermal perturbation, the first term greatly exceeded the second and, for instance, had twice its value, the temperature perturbation will only double in 53 yr for $\rho = 100$ m, 210 yr for $\rho = 200$ m, 1,320 yr for $\rho = 500$ m, and 5,300 yr for $\rho = 1{,}000$ m. Unless the permeability is much greater than the limits previously indicated, this increase in thermal perturbation is extremely slow.

The conclusion which we can draw seems to be that at the temperatures which occur at moderate depths there is practically no chance for convection to play a role in a

Table 3-1
Limiting values of the permeability in darcys (for $m = 1$°C/30 m)

θ	50°C	100°C	150°C	200°C
$\rho = 100$ m	1.2×10^{-4}	3.75×10^{-5}	1.66×10^{-5}	9.3×10^{-6}
$\rho = 200$ m	3×10^{-5}	9.4×10^{-6}	4.15×10^{-6}	2.42×10^{-6}
$\rho = 500$ m	4.8×10^{-6}	1.5×10^{-6}	6.65×10^{-7}	3.7×10^{-7}
$\rho = 1{,}000$ m	1.2×10^{-6}	3.75×10^{-7}	1.66×10^{-7}	9.3×10^{-8}

homogenous permeable region. On the contrary, at the high temperatures often reached in regions with a high thermal gradient, it becomes much more likely that the permeability may be high enough in a sufficiently extended volume to permit convection to become established. In the immediate vicinity of the critical point, convection becomes much easier, and we can consider that it has a good chance of being established when the surrounding rock is permeable over a certain area.

We will see in the following chapter that as soon as the vapor phase intervenes, convection is practically certain.

3-2 A case of intensive circulation

Numerous thermal sources (i.e., sources at a significantly higher temperature than the local average) are known. They may rise with considerable flows through conduits, and it is only in superficial loose soil that they disperse in multiple water filaments. This is proven when one attempts to collect the water. There are many reasons to believe that these are waters which rose from underground as a concentrated current by a direct route or by means of a fissure, fault, karstic duct, etc. We will show, with some schematic models, that in such cases the internal walls warm up quickly, over a certain distance, and that afterward the heat loss experienced by the water in its upward motion becomes negligible.

Descending circulations of colder waters occur under

250°C	300°C	350°C
$4.3 \times 10^{\text{[illegible]}}$	$1.86 \times 10^{\text{[illegible]}}$	$5.6 \times 10^{\text{[illegible]}}$
$1.07 \times 10^{\text{[illegible]}}$	$4.65 \times 10^{\text{[illegible]}}$	$1.4 \times 10^{\text{[illegible]}}$
$1.72 \times 10^{\text{[illegible]}}$	$7.5 \times 10^{\text{[illegible]}}$	$2.24 \times 10^{\text{[illegible]}}$
$4.3 \times 10^{\text{[illegible]}}$	$1.86 \times 10^{\text{[illegible]}}$	$6.6 \times 10^{\text{[illegible]}}$

exactly the same conditions, but they are far less likely to be observed. Certain observations made in tunnels can be noted, however. For example, at Mont Blanc (Italian side), the rock temperature, initially near 30°C, progressively decreased as the tunnel advanced, for some tens of meters, until a fissure in which cold water was circulating was reached. The water naturally flowed into the gallery, but there is obviously no relationship between the amount of water which emptied into the gallery and the flow which initially circulated in the fissure and whose amount remains unknown.

We can imagine the components of a convective circuit as being an intensive descending circulation, a certain amount of horizontal diffusion (in a reservoir where the water can assume the normal temperature of the surroundings at that depth) and then an intensive upward circulation. The difference in density between the water in the ascending and descending paths provides an adequate thermal engine. We could thus have, for example, on the banks of a lake, a thermal source being fed by the lake's water. We could also imagine a circuit composed of a diffuse divided descending water path, with only the upward circulation being intensive.

In some cases we can consider that the temperature distribution, and as a consequence the differences in pressure which make up the circulation, is practically independent of the flow. The amount of water flow will be determined by the head losses of the water, which depend in turn on the shape of the conduit.

In many cases, unless a pure closed convective circuit

Table 3-2

t	1 s	1 h	1 day	1 yr
$(K)/\sqrt{\pi at}$	0.0282	$4.7 \times 10^{\text{[illegible]}}$	$0.96 \times 10^{\text{[illegible]}}$	$0.503 \times 10^{\text{[illegible]}}$
x, $\theta = \theta_s/2$	1.25 mm	8 cm	39.5 cm	7.65 m

exists, the differences in pressure gradient caused by the temperature interfere with a normal hydrogeological cycle (i.e., precipitation in going from upper regions to springs at lower elevations) in such a way as to modify the cycle's circulation, and in particular to intensify the thermal currents in conduits.

To make the above statements more precise, we shall calculate, knowing the thermal properties of the appropriate rocks, the way in which conduit walls warm up when in contact with water and thereby diminish the thermal flux that they will absorb. For purposes of calculation, we will assume that the water circulation is established abruptly at an initial time, the rock being at the normal temperature for its depth. This initial phase is not too realistic, but it will give us an idea of the rate at which the conduit walls heat up.

When a large flow circulates in a compact channel, it can be asked if the walls are effectively at the average temperature of the water. We will see that the temperature difference would not be appreciable except for a very short period of time. Thus, it will not be necessary to take account of this difference between the temperature of the walls and of the water.

We shall take as a model of intensive circulation a plane fissure extending for a considerable vertical distance from the surface at which the heating is produced. We can then consider the temperature as solely a function of the distance x from the wall. If the temperature of the wall, initially equal to the rock temperature and taken to be 0°C, is brought to a value θ_1 at $t = 0$, the temperature in the rock is

10 yr	100 yr	1,000 yr
0.159×10^{-5}	0.503×10^{-6}	0.159×10^{-6}
24 m	75.5 m	240 m

given by

$$\theta = \theta_1\left[1 - \operatorname{erf}\left(\frac{x}{2\sqrt{\alpha t}}\right)\right] \tag{3-8}$$

and the flux at the surface is $K\theta_1/\sqrt{\pi\alpha t}$. The factor $K/\sqrt{\pi\alpha t}$ and the distance x at which $\theta = \theta_1/2$ are given as a function of time (for $\alpha = 0.01$ and $K = 0.005$) in Table 3-2.

Consider a fissure rising 100 m to the surface with a temperature difference of 3°C and a flow of $2q$ g/cm of conduit width. The water will reach the surface after a temperature drop of only 1 percent at the end of $(3.7/q^2)$ days. If $q = 1$, which is a flow of 1 liter/s for 5 m of width, this delay would be 3.7 days. For a seepage of 2 g/s · m, which would be difficult to notice, this delay would be 100 yr, which is still inappreciable on a geologic time scale. *A fortiori*, for a flow of several liters per meter, the delay would be on the order of 1 hour and the heat loss would continue to decrease as the square root of the time. This means the heat loss would be reduced to 1 part in 10,000 at the end of a year.

We could do the analogous calculations for a cylindrical conduit. The wall heating and the reduction of the heat losses at first would be the same as for a fissure with the same surface area and afterwards a little slower. It is not necessary to make these calculations, which are a bit more difficult than for a plane fissure.

It should be remembered that whatever the form of the conduit in which an intensive circulation takes place, several hours or several days are sufficient for the walls to come into thermal equilibrium with the water so that conduction losses become negligible.

Conversely, if we knew the shape of the fissure and the law with which the rock temperature varied with distance, we could try to calculate the time when the circulation became established (like the case earlier cited for the Mont Blanc tunnel).

When the search for hot water is made by driving adits, as has been done many times in the Pyrenees, the apparent rock temperature is often a guide. But we cannot exclude, a priori, the possibility that the temperature distribution may correspond to a steady-state system between the thermal water filaments and the surface (or possibly cold-water circulations).

3-3 Illustration of Hammam Meskoutine

This Algerian locality, well known for its thermal sources and the concretions which these sources have produced, will furnish us with a remarkable illustration of the stabilization of a conduit by convection.

A small plain is found there (see Fig. 3-1) having hundreds of limestone formations of about the same height (around 3 m). Each of these formations corresponds to a thermal conduit from which water once emerged at a temperature near 100°C and has produced abundant concretions, raising the conduit up to a height of 3 m above ground level. When the conduit reaches this height, it ceases to function and another conduit develops next to it. When the conduit is functioning, its walls are heated and the entire water column is at 100°C for which the specific volume of water is 1.0434.

On the other hand, in a fissure without water circulation the temperature should vary progressively between 100°C at the level of the subterranean aquifer and an average 20°C found at the surface. The average specific volume in this temperature range is 1.0193, and thus the pressure difference at the base of the source is $0.024h$ (in meters of water). If this difference is capable of overcoming the additional height of 3 m due to the concretions, then $0.024h \geq 3$ which means $h \geq 125$ m.

We can thus estimate the depth of the aquifer where water at 100°C is found and estimate the local gradient at 1°C/1.6 m. It would take us too far afield to discuss the underground thermal system at length, and besides it is still poorly understood.

For a number of hot springs, there is the same effect of stabilization of the acting spring, as compared with incipient ones, with no discharge, which remain cold. This prevents loss of thermal water toward other springs and facilitates their exploitation.

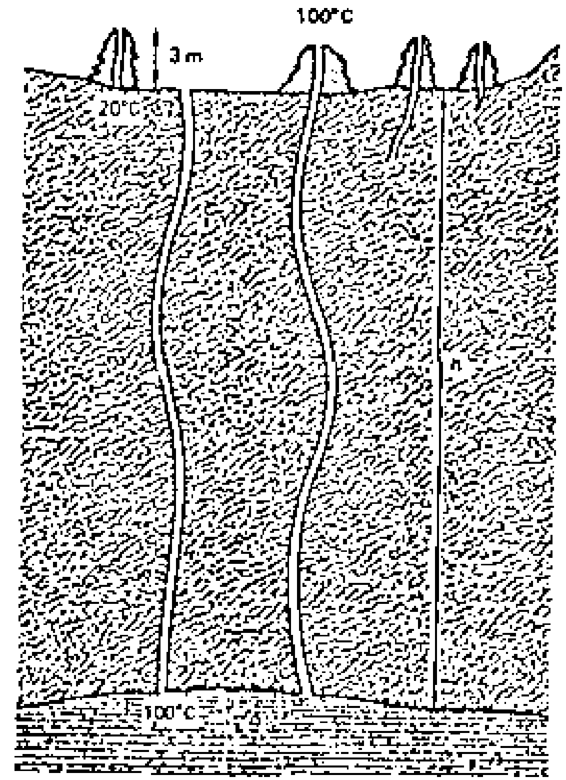


FIGURE 3-1 Diagram of the convection at Hammam Meskoutine (Algeria). The height of the concretions on successive conduits reaches 3 m and the height h for which there is an equilibrium between the conduit entirely at a temperature of 100°C and a potential conduit where the temperature of the immobile water varies progressively from 100°C to 20°C can be calculated.

3-4 Thermal effects in a drill hole

A drill hole consists of a cylindrical space filled with water (or mud) whose boring has given rise to strong thermal perturbations. It is necessary to understand these effects if we wish to use drill holes for underground temperature measurements.

In this section, we can distinguish between three phenomena: the perturbations resulting from drilling operations, the manipulations which can be performed to modify the drill hole's thermal regime, and the regime attained at the end of a waiting period.

In the course of drilling, the drill bit absorbs a significant amount of mechanical energy which is mainly transformed into heat. Water (or mud) is pumped into the drill stem which cools the bit and then rises between the stem and the surrounding rock. It is stored in mud tanks, where it generally does not have time to cool completely before being reused. It is normally cooler than the rock in the deeper parts of the drill hole, which it cools. One could propose to measure the temperature at the farthest point reached by the drill after letting a waiting period expire, such as rest on Sunday. This temperature would be representative of the temperature of the surrounding rock if the thermal perturbation at the bottom of the hole, during the brief and finite drilling time, had time to dissipate during the waiting period. Unfortunately, it is not generally possible to lower a thermometer suspended on a cable to the bottom of the hole, which is blocked by caved-in debris or sedimented mud. To reach the bottom of the hole, it would be necessary to reestablish circulation in the stem, and that would perturb the temperature distribution.

In the course of the boring, the surrounding rock will be cooled in the lower regions and heated in the upper regions. A given part of the drill hole will thus be successively cooled and then heated while the drilling progresses.

When a geothermal bed is drilled, it is customary practice to cool the mud at the surface by means of an aerated tower. Even if this cooling is small, 10°C for example, it prevents a progressive heating of the mud which would be bothersome if its temperature approached 100°C. In such a case, the walls are only heated by the drilling operation very near the surface, and over most of the height the walls are cooled, sometimes very strongly.

The rhythm of work in a drilling operation is too irregular to practically permit the calculation of the penetration of the thermal perturbation into the walls and the evolution of the thermal flux at a particular depth, as would be theoretically possible. We can only make a rough estimate of the order of magnitude of this penetration as a function of the drilling period.

Once the drilling is finished, it is possible to obtain certain hydrogeological data from the thermal profile measurement. For example, if an aquifer is cut by a drill hole, we can produce a uniform temperature along the hole by circulating the mud through pipes lowered to the bottom of the hole. After a waiting period, a thermal profile will indicate the entry level of the water at the temperature of the surrounding rock. It will appear warmer in the lower part of the hole and cooler in the upper part.

If there are indications of gas, they can be located (they give rise to endothermic expansions) by lowering the water level by pumping and determining the depth of the characteristic temperature drop on a thermal profile due to gas.

Finally, if we are trying to cement a collar in a drill hole, the best way to determine the height reached by the cement is to observe on a thermal profile the heat produced by the setting of the cement.

In these operations, the thermal measurements have well-determined objectives and give us poor information at best about the temperature of the surrounding rock. Given the above objectives, thermometers are sometimes not standardized precisely. In general, these measurements are of very short duration, and the supplemental perturbation which they bring to the wall temperature is small compared to the perturbation caused by the drilling.

Once the drill hole is left undisturbed, it frequently happens, especially when sedimentary formations are traversed by the drill, that permeable layers are encountered which are not in pressure equilibrium with one another. In these circumstances a mixing circulation can be established

in the drill hole and eventually outside the tubing, if it is not cemented, running, for example, from the deepest permeable layer toward the shallower permeable levels. It was found in the previous case considered that, in the section of the drill hole where the mixing circulation occurs, the walls of the hole are reheated after a sufficient time to the temperature of the deepest aquifer. The opposite process can also occur: in the southern part of France a drill hole registered a temperature essentially the same as at the surface in penetrating a sedimentary layer. It then encountered a discontinuity and a normal thermal profile in the crystalline basement. From such a thermal profile it is quite easy to recognize the sections of the drill hole in which the water circulates. It can also happen that the undisturbed portions of the thermal profile are aligned and give the impression of furnishing a true thermal profile of the ground; however, it must always be considered that smaller circulations of water could still exist.

Implicitly, it has been assumed that thermal profiles are measured long enough after the end of drilling operations so that spontaneous circulation of water has been fully developed. At the same time, the thermal perturbations arising from the drilling operations must have had time to dissipate from the walls of the hole. When the purpose of the drill hole is to measure a completely representative thermal profile, it is often necessary to make at least an approximate calculation of the time necessary for such perturbations to have disappeared.

In Chap. 1 it was seen that in cylindrical coordinates the solution $\theta = (1/4\alpha t)e^{-r^2/4\alpha t}$ represents the diffusion of a thermal perturbation produced along the z axis at the time $t = 0$. Such is not the case for a drill hole when it is left at rest. The thermal perturbation, whatever its sign, has penetrated into the walls of the hole to a depth which ought to increase as the square or cube root of the duration of the drilling operation. For example, we might take the values indicated earlier for the depth of penetration of half the

maximum temperature drop as a function of time. Taking the radius of the hole into account as well, we can estimate the radius at which the thermal perturbation coming from an axial source would reach the same distance. For example, at the end of a drilling period of several weeks, say, we estimate that the halfway point of the perturbation should be found at a radius of 2 m, from which we get $\ln 2 = x^2/4\alpha t = 200^2/0.04t$, and thus $t = 1.4 \times 10^6$ s $= 16$ days. We deduce that 16 days later the perturbation will be reduced by half, 32 days later it will be a fourth and that it would be necessary to wait 144 days in order that the perturbation be reduced to less than 10 percent of its initial value.

Of course, it is difficult to estimate the thermal perturbation distance in the walls of a drill hole. We can hope that different perturbations will partly compensate for one another, but that is not a reason to underestimate the waiting time necessary so that the measured thermal profile will be perfectly representative.

For the geothermal drill holes in New Zealand, where the shaft walls are strongly refrigerated during the drilling, it is current practice to wait 3 months before measuring the thermal profile. What has just been described shows that this delay is not at all excessive. Unfortunately, it is to be feared that a number of the published values of heat flow are based on thermal profiles measured without a sufficient waiting period.

There is one last consideration that we should mention, although it is rarely taken into account. In the water column inside the drill hole there exists a certain thermal gradient. Does this produce convection currents which would agitate the water and tend to regularize its temperature? This is a problem in hydrodynamics which is outside the scope of this book, but it has been indicated that for the thermal gradients normally encountered, convection will only occur for large diameters (50 cm and more). This is one reason (others are chiefly economic) to make exploratory geothermal drill holes of small diameters, even if commercial holes must be of a larger diameter.

3-5 Example of a sheet circulation

We have successively seen the convection which can result from a movement of water in a permeable volume and the effect of an intensive circulation in a limited channel. The following problem, which is encountered in the study of certain geothermal regions, will furnish an example of the effect of water circulation along a given layer. We suppose that at a certain depth there is a sheet circulation of water in a layer whose thickness we will neglect. The given flow is q per unit width. Now, suppose that there is a localized underground thermal anomaly such as would be produced by a heat source. The water flows will cool the ground and heat it downstream. Thus, the thermal anomaly will appear displaced with respect to where it would be in the absence of circulation. We wish to calculate the distribution of the surface gradient or any other aspect of the temperature distribution once the steady state is reached.

If the surface of the ground is horizontal, we can satisfy the condition $\theta = 0$ (taken for a constant value) by adding fictitious heat sources, symmetrical and with opposite sign, to those sources which exist underground. In the absence of a circulation of water, the combination of these heat sources (including a source at infinity to take the gradient into account) determines a temperature distribution θ'.

In the presence of the water circulation, the temperature distribution becomes θ. Along the water's path, there is a new source of heat $q\, d\theta/ds$ at each point which determines a temperature distribution

$$\Delta\theta = \frac{q}{2\pi K}\frac{d\theta}{ds}\ln(r)\, ds$$

and the temperature change is due to the sum of these perturbations,

$$\theta - \theta' = \frac{q}{2\pi K}\int \frac{d\theta}{ds}\ln(r)\, ds$$

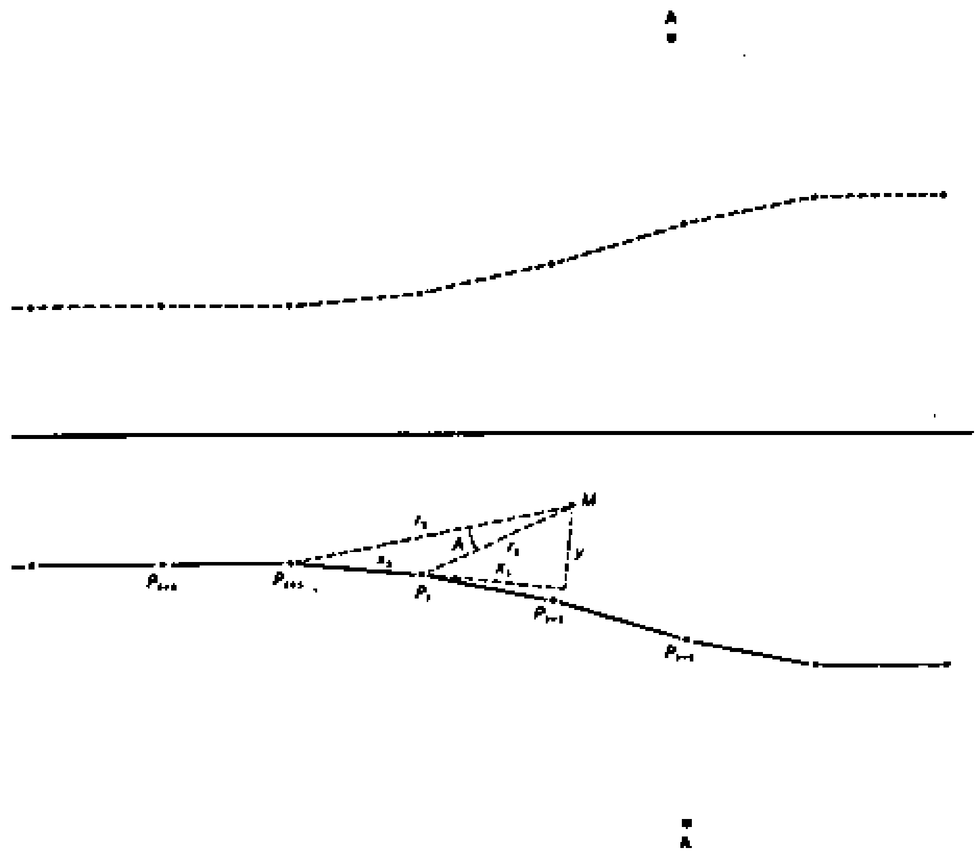


FIGURE 3-2 Principle of the calculation of the effect of a circulating sheet of water following the path P_i, P_{i+1}, ... on the temperature distribution defined by a gradient, localized heat sources A, and the condition of a constant temperature on a horizontal surface.

where r is the distance from the point where we are calculating the temperature to the point along the water's trajectory where we perform the integration (do not forget to also carry the integration over the fictitious symmetrical path). To lead to a solution by a numerical method of approximation, we will take the final temperature at a limited number of points P_i along the water's path as unknowns. In addition, we will assume that from one point to another the temperature variation is linear (see Fig. 3-2). This

allows us to write, between two of these points, $d\theta/ds = (\theta_{i+1} - \theta_i)/s$ and to write this constant outside of the integral sign. As for $\int_{P_i}^{P_{i+1}} \ln(r)\, ds$, this is a simple calculation. If x_1 and x_2 are the projections of P_iM and $P_{i+1}M$ on the line P_iP_{i+1}, and y is the distance from M to this line, A the angle P_iMP_{i+1}, and r_1 and r_2 the distances P_iM and $P_{i+1}M$ respectively, then

$$\int \ln(r)\, ds = x_2 \ln(r_2) - x_1 \ln(r_1) - (x_2 - x_1) + yA$$

It can be verified that this expression remains finite at P_i and P_{i+1} and that, if $y = 0$, this reduces to $x \ln(x) - x$. Of course only a computer allows us to solve this system of linear equations by equating each of the unknown temperatures to the sum of the initial temperature values at the considered point and the perturbations brought in at that point by the successive segments along the water's path.

The calculation is possible for any form of the water path resembling a polygon. The formulas are simplified if the water path is horizontal.

CHAPTER FOUR

changes of state of groundwater

4-1 Freezing

Water is transformed into ice at a temperature of 0°C; this transformation temperature changes very little with pressure. The freezing of 1 g of water liberates a latent heat of about 80 cal. The temperature at which a saline solution deposits crystals—in general, pure ice—can be appreciably lowered depending on the solution's concentration. The specific heat of ice is about half that of water, and the thermal conductivity of a loose soil saturated with water that has frozen is multiplied by a factor of 2 or 3. In addition remember that the density of ice is 0.9, and hence freezing is accompanied by an increase in volume. Actually, we will see that this phenomenon plays only a minor role.

To a first approximation, which would be valid if the groundwater content was infinitely small, what we have seen in Chaps. 1 and 2 shows how and where a temperature of 0°C can be reached: on the one hand, in the winter in a surface zone where the annual temperature variations penetrate, and on the other hand, if the mean annual temperature is less than 0°C. In the latter case there may be an underground frozen region, with an overlying layer that may thaw during the summer. This is what is called *permafrost*, and it covers vast areas in the north of Siberia and Canada. Permafrost can be found to depths of several hundred meters, which implies that its origins are very old (beginning of the Quaternary).

Observation confirms these general indications, which can be completed by saying that in consequence of climatic fluctuations from one year to the next, it can happen that the surface which thaws above the permafrost during the summer may not completely refreeze the following winter, or that the frozen winter surface does not completely thaw the following summer. Thus, alternate frozen and thawed layers can exist above the permafrost. Naturally, these layers are not continuous.

To go a bit farther, we should remember that the water content of the surface areas affected by these phenomena is in general considerable. Their freezing therefore absorbs appreciable heat. From this, what has been called a *conduction barrier* results. All incident heat flux, whatever its direction, is absorbed by fusion or freezing across the zero isotherm and is not propagated further down. Its only effect is to displace the freezing boundary, and while this surface is being shifted, the flux and gradient values on either side of the barrier are very different. If $\bar{\omega}$ is the porosity, u the displacement velocity of the freezing boundary, L the latent heat (80 cal), and K_W and K_I the conduction coefficients for thawed and frozen ground, respectively, the difference between the thermal gradients is given by

$$K_W\left(\frac{\partial\theta}{\partial x}\right)_W - K_I\left(\frac{\partial\theta}{\partial x}\right)_I = L\bar{\omega}u \qquad (4\text{-}1)$$

It immediately becomes apparent that the calculations of Chap. 1 concerning the propagation of periodic temperature variations into the earth's surface are no longer valid. Nonetheless, the general behavior of the phenomenon stays the same with at most a decreased depth to which the temperature variations propagate.

A more important perturbation results from the fact that water inside fine capillaries does not freeze until temperatures are well below 0°C. This fact is easily observable in the freezing of a surface layer of mud. The mud does not freeze altogether in a body, but thin sheets of pure ice appear between which the mud desiccates and becomes powdery. At a few degrees below 0°C, there is a thermodynamic disequilibrium between the water which is still in liquid form in the capillaries and the thin lenses of ice which have

formed near by. The water tends to move from the pores toward the ice crystals, which enlarge and are capable of compressing the surrounding ground.

This phenomenon has been especially studied for roads which can swell if ice crystals forming in inevitable cracks are fed by capillarity from below; they may grow to large sizes, resulting in a swelling which can become quite large (several centimeters or tens of centimeters). At the beginning of the thaw, ice melts on the spot, and the pavement becomes flooded with an excess of water. A small load can severely degrade roads and from this comes the institution of the "thaw barrier"—temporarily forbidding certain roads to heavy trucks. However, the real solution lies in preventing the ascension of water by capillarity to roadways which are likely to freeze. This can be achieved by interposing a barrier layer under the road consisting of cobbles without any fine filler.

Another consequence of the way in which ice can form in the ground is "cryoturbation." This involves special types of ground deformations caused by repetitive alternations of freezing and thawing. Ice lenses can form under stones (which conduct heat better than the surrounding soil), and this can lift the stones up. Doubtless this is the way that the *soil polygons* in arctic zones are produced. These polygons are also sometimes observed in mountains such as the Alps, whenever loose soil forms a horizontal surface above 2,700 m.

For permafrost, this unusual type of ice formation can also play an important role. It explains the underground formation of lenses of pure ice either horizontally, forming hydrolaccoliths, pingos, etc., or vertically, forming wedges in cracks and crevices whose traces (after thawing, they are filled by the fall of surface gravel) are frequently visible in ancient alluvial deposits. These cracks appear to form large polygons with dimensions of 10 to 20 m.

Let us add that the circulation of subterranean waters, either in the unfrozen surface layer (permafrost is totally impermeable) or through gaps in the permafrost, plays an essential role. Lakes and watercourses also introduce per-

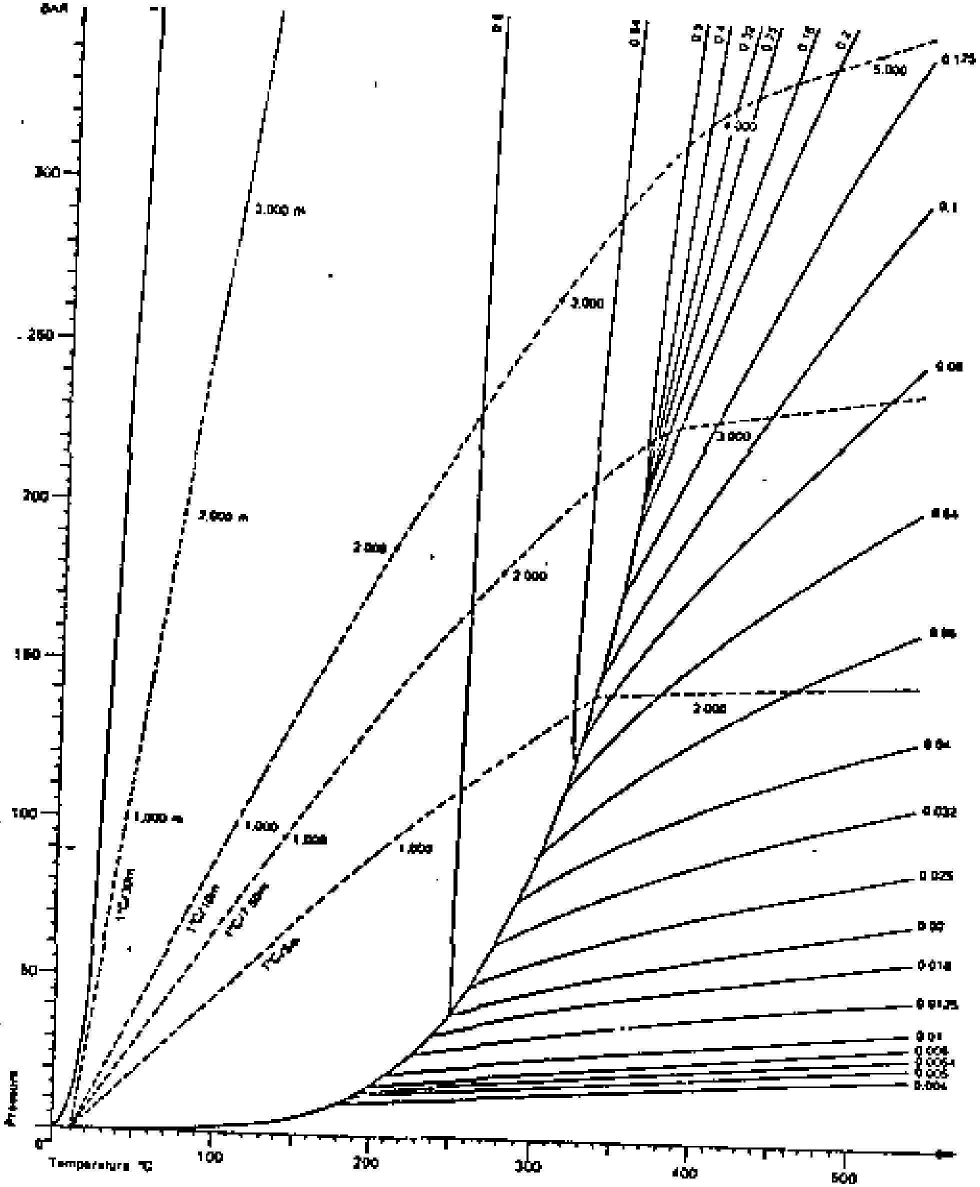


FIGURE 4-1 Graph of water density as a function of temperature and pressure. The dashed lines indicate the states as a function of the depth for a fluid phase in static equilibrium with a temperature of 11°C at the phreatic level and the different values of the thermal gradient, supposed uniform, taking account of the water density. Note that the critical state of water is reached for a gradient of about 1°C/7.5 m at a depth of 2,700 m. For a higher gradient, the hypothesis of a uniform thermal gradient becomes incompatible with the hypothesis of a static fluid equilibrium, this equilibrium being unstable.

turbations which can break up the continuity of the permafrost.

The existence of permafrost presents particular engineering problems for highways, homes, and pipelines which will not be discussed here.[1]

4-2 Vaporization

The transition of water to a gaseous form (steam) occurs at a temperature which is a function of pressure (Fig. 4-1). This transition absorbs a considerable latent heat, which appreciably diminishes when the temperature increases. The density of steam, like all gases, diminishes slightly when the temperature increases and increases greatly with pressure. At the critical point ($T = 375$°C, pressure $= 221.06$ bars), the specific volume of steam becomes equal to that of liquid water (3.1975), the latent heat falls to zero, and there are no longer any differences between the two phases. For temperatures and pressures with higher values than the critical point (supracritical domain), there exists only a single fluid phase whose density varies in a continuous manner. There are tables which furnish for water as well as for steam all the pertinent characteristics as functions of temperature and pressure, in particular the specific heat. The viscosity values appear to be the least well known in the supracritical domain (see Fig. 4-1)

If the water contains dissolved gas, it will accumulate in the vapor phase, where the total pressure will be the sum of the partial pressures of the gases and the water vapor. The vapor will exchange matter with the liquid until the pressure of the latter is in equilibrium with the total pressure of the gaseous phase.

On the other hand, dissolved salts are distributed very unequally between the two phases, nearly all being found in

[1] A. Cailleux and G. Taylor, Cryopédologie, étude des sols gelés, no. 1203, Act. Sc. and Industrielle, Hermann, Paris, 1954; S. W. Muller, "Permafrost, or Permanently Frozen Ground and Related Engineering Problems," 231 pages, Edwards, Ann Arbor, Mich., 1947.

the liquid. The presence of salt can have the effect of increasing the critical point. This means that above the critical temperature of pure water there can be two phases, one with a high salt content and thus more dense, and the other phase low in salt content (the water content in relation to the volume being about the same). Depending on the salts and provided that both solutions are saturated (presence of an excess of solid salt), the distinction between the two phases can continue whatever the temperature and pressure (such as with NaCl), or it can end at a critical point beyond which there is only one unique phase (such as the case of SiO_2). For less concentrated solutions, there is only a slight rise in the critical point.

Having recalled these properties, under what conditions can we find water in the ground in the form of steam?

First, of course, it is necessary to consider the neighborhood of the earth's surface. In the atmosphere, the partial pressure of water varies from place to place. It particularly varies with the temperature, the atmospheric pressure changing very little. In general, there exists, above the phreatic level, a certain fringe region in whose pores air can circulate. Depending on the temperature changes, the water vapor can condense or, on the contrary, the region can desiccate. These transfers, and the heat exchanges which they imply, must be considered as part of the complex surface phenomena which contribute to the determination of the average ground temperature. We shall not study these surface phenomena further.

4-3 Geysers

A given hydrogeologic situation can involve the ascending of waters from the depths through faults or karstic conduits. We have already seen that such springs can reach the surface with hardly any heat loss if their flows are large enough.

A priori, nothing prevents subterranean waters having temperatures exceeding 100°C from reaching the surface.

The adiabatic transport (i.e., a transport without heat exchanges, which will be the case once a steady-state system is achieved) of such waters up to atmospheric pressure necessarily entails a partial vaporization in a proportion x, which is easy to calculate. If $\theta > 100°C$ was the water source's initial temperature, then $x = (\theta - 100)/540$, 540 cal being the heat of vaporization at 100°C. But, although this can happen, we will not necessarily have two regular flows, one of water at 100°C and the other of steam at the same temperature. Especially if the flow is large and the conduit by which the water reaches the surface has a suitable form, boiling can have a discontinuous nature and produce periodic expulsions of water and steam, which are characteristics of geysers.

When a geyser is inactive, the conduit is filled with water which, at each depth, is at less than the boiling point for the local pressure (100°C at the surface, 120°C at 10 m, 135°C at 20 m, etc.). But with the arrival of warmer underground waters, this water column will progressively heat up. Finally, a moment will arrive when boiling will start somewhere and that will lighten the column thus diminishing the pressure sufficiently so that boiling will become generalized and lead to an expulsion of some water to the outside. The steam will escape, and, to finish the account, the water which has not been expelled and which has been cooled by a partial vaporization will constitute a new water column in thermal equilibrium in the conduit. Numerous complications can be imagined, for example, lateral pockets in which either hot water or pressurized steam can accumulate. The heat capacity of the walls can play a role in the regularization. However, we are still a long way from explaining all the singularities of geysers. For example, why does a geyser's eruption come a few minutes after soap is thrown in the conduit? Nevertheless, it can be considered as an established fact that a geyser is a manifestation of the emergence of subterranean waters which are in a liquid state above 100°C underground and which circulate in concentrated enough conduits to have heated the walls in such a way that the water's heat losses are reduced.

4-4 Vaporization at depth

Leaving aside the case of intensive circulation, we now imagine the situation resulting from a uniform geothermal gradient in a somewhat permeable region. Below the phreatic level, the pressure due to the hydrostatic head of water rapidly increases. There can exist complex hydrogeological situations in which the head, relative to the different water layers separated by impermeable layers of rock, increases as we go to deeper and deeper pools of water. Sometimes the subterranean fluid pressure tends to approach what is called the *lithostatic pressure*. This is the pressure caused by the weight of overburden, and this limit cannot be exceeded by the fluid pressure, since the ground would then tend to rise and produce fissures, which would allow the water to escape. The critical pressure of water is reached, that is, is equal to the lithostatic pressure, at a depth of 800 or 900 m. However, at these depths, the temperature will almost always be less than the critical temperature (375°C, that is, a gradient less than 1°C/2.5 m), and so the water remains liquid. In a region where the fluid pressure tends to equal the lithostatic pressure, however, unusual local fissuring can allow a transport of water to the surface and cause a drop in fluid pressure which, if the temperature is sufficient, can lead to vaporization. Such is the situation at the Geysers (California), which is a geothermal field, situated in the middle of the Franciscan formation in which the fluid pressure nearly equals the lithostatic pressure.[1] On the other hand, the Geysers correspond to a zone with a high thermal gradient which could be in contact with a hypothetical underground batholith; it is also a zone with a low fluid pressure. We cannot tell if this vapor occurrence is a consequence of local heating or of fissuring which would have reduced the pressure, or both.

Leaving these complications aside, let us concentrate for the moment on the simple case where, the ground being somewhat permeable, the impregnating water is at a hydrostatic pressure in equilibrium with the water at the surface or at the phreatic level, which is equal to the hydraulic pressure produced by a continuous column of water, the summit of which coincides with the phreatic level.

[1] K. A. Frederix and F. Berry, High Fluid Potentials in California Coast Ranges and their Tectonic Significance, *AAPG Bull.*, vol. 57, no. 7, pp. 1219-1249, July 1973.

Assuming that the thermal gradient, which we will take as a constant to simplify matters, is known, it is easy to calculate, as a function of depth, the hydraulic pressure and temperature at the same time. We can calculate the hydraulic pressure by taking for each depth the actual density as a function of the temperature and the pressure (see Fig. 4-1). For usual values of the gradient, the values obtained exceed the critical pressure for water at a much lower temperature than the critical temperature (i.e., there cannot be any vaporization).

In order for this not to be the case, the gradient, supposed uniform, must reach 1°C/7.5 m. The critical point is then reached at a depth of 2,700 m (supposing the phreatic level has a temperature of 11°C). For a higher gradient, we would expect to find a layer of liquid water on top of vapor. It is clear that this is an unstable situation. Even if the rock is only slightly permeable, it is inevitable that water will descend in some places and steam will rise in others. Where the water descends, it encounters hotter rocks and cools them while being partially vaporized. Where the steam ascends, it meets cooler rocks and partially condenses while heating the rocks, and the pressure drop brings forth more steam from underground. Our implicit assumption of a regular thermal stratification fails. In fact, there will be warmer zones in which steam rises, and cooler zones where water descends.

Such a convective system can be established for a mean gradient such that the critical point and the vaporization level are not reached. In the supracritical domain, but near the critical point, the density varies greatly with the temperature and the onset of convection, even if the rock has low permeability, is very likely. Such a convective action must progressively increase. The cooler descending branch will remain in the supracritical domain, but the ascending branch can reach and exceed the critical point. Convection will then be composed of a vapor phase, with a finite density difference with respect to water and a certain latent heat. This vapor phase rises easily, and on condensing heats the rock which permits the continuation of the cycle.

We can thus expect that the convection currents, the onset of which are inevitable if the gradient is such that the critical conditions are fulfilled, will take two forms, one cooler descending water currents which remain supracritical (i.e., in a dense form), and the other of ascending steam currents which progressively attain a higher and higher elevation. The low density of the vapor with respect to water determines the pressure differences which constitute the driving force for such a circulation.

It is hardly possible to tell what the transverse dimensions of the convection cells were initially, but, if they were small and numerous, it is to be expected that certain ones among them would develop more rapidly than others, and for these the convective action risks being interrupted by a pressure drop underground caused by larger cells. We can predict an evolution toward a small number of important ascending cells, each of which must produce a substantial flow of vapor.

The possibility that a supracritical domain still reigns far underground is not excluded. This means that the relatively cold descending water, which comes into contact with rocks progressively heated by the high local geothermal flux, passes in a continuous manner, without change of state, into ascending currents which are brought about by a pressure drop, and which are individualized as vapor currents making their way above the level where the critical pressure is found.

In the region where the water descends, there can easily be temperature fluctuations, depending on whether the circulation is more or less rapid, but the density variations resulting from such fluctuations are small. Thus it is unlikely that these fluctuations in the rate of circulation tend to be amplified. Rather, we must expect an almost uniform descent over a certain area.

These considerations lead us to predict that if locally

the geothermal flux exceeds 4 or 5 $\mu cal/cm^2 \cdot s$ (we consider only the surfaces of the continents, because in the ocean depths the pressure already exceeds the critical pressure and the conductive flux can reach greater values) and if the rocks have a certain permeability, even though it may be small and irregular, heat transfer by conduction, which implies a regularization of the thermal gradient, will not act alone. Eventually a relatively restricted number of zones of rising steam must appear in which the pressure gradients corresponding to the density are low enough so that the flows reach high values, possibly with considerable head losses. As the rising steam reaches cooler layers, it condenses while heating these layers, and the heated zone thus tends to rise higher and higher. The condensed water and the cooler groundwater tend to descend along the margins of the steam currents because it is there that the pressure gradient is smallest. These cooler waters tend to give the sides of the steam plume an abrupt nature with strong horizontal temperature gradients. The entire water balance can be put in equilibrium by a steady descent of groundwater outside the ascending steam plumes, but direct evidence for such a descent is lacking.

In the process which has just been described, an essential part—the steady passage of descending supracritical water to ascending currents which individualize themselves higher in the steam plume—has escaped observation till now because boreholes have never been drilled to such a great depth (it would be necessary to go to 3,000 m) in abnormally warm regions. Hence, the origin of this abnormal heating remains largely hypothetical. We can imagine the injection of eruptive rocks, for example, a granitic batholith, the cooling of which could supply a large heat flux for a considerable time.

But under these circumstances, petrology leads us to suppose that crystallization of the granite would liberate a certain quantity of volatile substances which could have been dissolved in the molten magma. Water is the most abundant of these substances, but there can be many others (CO_2, Cl, sulfur in different forms, B, etc.). A portion of these volatile substances could be found in the ascending vapor phase. But, on the other hand, the vapor, especially in the supracritical domain, can, while circulating in contact with rocks, produce diverse alterations in them and leach certain elements (in particular, steam will dissolve silica, which is always present).

The "juvenile" or *phreatic* origins of the steam found in geothermal pools has been the subject of much discussion. There is nothing to exclude the possibility that part of the steam, and especially the volatile impurities, are of a juvenile origin (i.e., they originated directly from a magma in the course of its consolidation and cooling). But that can only represent a small amount of the steam. The cooling of each gram of granite will supply 25 to 40 cal from the latent heat of crystallization and, for a cooling of 200°C, about another 40 cal; but the magma could scarcely contain as much as 10 percent in volatile substances even if the magma had been entirely molten; if the fusion was only partial, which would be very likely, the total content of volatile substances would be much less. From these numbers, which are only orders of magnitude, the fact emerges that the volatile products given off by a granite would not be able by themselves to transport the amount of heat liberated by the granite's cooling. This makes it very probable that the granite will produce a high thermal gradient leading to, besides an enhanced heat transport by conduction, the establishment of a substantial convective movement of phreatic waters.

4-5 Evolution of a convective system near the earth's surface

The behavior of the ascending vapor plumes which transport heat in excess of that carried by conduction (about four times the normal flux) can take quite different forms depending on the structures encountered.

Even if the paths along which the steam reaches the surface are convoluted, it is to be expected that its ascent is very rapid, since its low density entails a nearly negligible pressure gradient near the surface. Thus the removal of the

excess subterranean heat will be rapid. On the other hand, neighboring waters tend to invade the geothermal site, especially at its base, and steam condenses in rocks which are cooled in this way. We can imagine that a final situation is thus established in which the terrain is entirely invaded by water, but which at each level is at the boiling temperature under the local pressures. When that happens, pressure equilibrium is substantially realized and the waters can remain practically immobile. However, as long as a vapor "bubble" exists, it must tend to rise because of its low density, even through regions of low permeability.

Research done in New Zealand has shown that in geothermal sites, this temperature distribution is essentially the one that is found with the rocks containing water in the liquid state. Many measured temperature profiles are typical in this respect. The geothermal zones where these conditions take place are of a limited area and are separated by very sharp boundaries from surrounding regions in which the thermal gradients are high but regular.

In geothermal sites below an underground depth of about 500 m, the temperature ceases to increase, due to the invasion of neighboring cooler waters. Such a temperature distribution is established even when the terrain (as is the case in New Zealand) consists of an alternation of layers with very different porosities and permeabilities. The permeable strata (it may be chiefly fracture permeability) constitute reservoirs from which hot water can be extracted.

4-6 Underground steam accumulation

A very different case exists when there is an impermeable cover, in any form which will assure closure (i.e., a reservoir with its higher rim at a lower level than the summit). The reservoir can be of any geometry, and, for example, at Larderello (Italy), it consists of an assemblage of karstic voids in the Triassic and Liassic limestones overlying a series of horsts in a crystalline basement, covered by an impermeable layer of exotic Oligocene "argile scagliose."

The result of such a covering is that steam accumulates in the reservoir. When there is a local cooling and condensation, water flows to the bottom of the system and is replaced by steam of subterranean origins. This steam remains in a saturated condition (at Larderello, 240°C at 35 bars), and its density is much lower than that of water. The pressure and temperature vary only slowly with the depth. The walls of fissures or steam-filled spaces are at the same temperature as the steam, but this temperature is quite different from the temperature of the rocks included between the fissures. A sounding at Larderello has shown an approximately regular thermal profile with a gradient of the order of 1°C/8 m, disturbed only by a few temperature anomalies in the Trias, probably caused by neighboring steam-filled fissures with which communication has not been established. We should keep this evidence in mind when we examine the age of a geothermal site.

4-7 The age and the origin of geothermal beds

The interpretation which we have given to the genesis of thermal layers implies that these generating processes may no longer be active today. This is evident for those processes where a rock saturated with water is found at the boiling point as determined by the local pressure. The accumulation of steam under an impermeable cover, which provides a proper closure, should persist for a certain time after the end of the arrival of the subterranean steam which gave rise to the accumulation.

Certain prospectors, in New Zealand for example, hoped to sink holes that would reach the subterranean source that was supposed to supply heat to the geothermal sites. Unfortunately, this hope was not realized. How should we react to this?

What is the cause of the subterranean heat which produces exploitable geothermal sites as a superficial manifestation? We could immediately think of volcanic phenomena, but how would they act? We could invoke the formation of a laccolith or a batholith which could have gradually cooled over a very long time. But we should also consider the possibility of a network of dikes which are individually very thin and thus susceptible to rapid cooling, or even to the release of steam. In any case, we know by numerous observations of volcanic eruptions that eruptions are essentially irregular in time. Active periods can last for several days or weeks and be separated by years of apparent calm. It is for this reason, rather than because of technological difficulties, that the direct utilization of volcanic energy has not been envisioned. Volcanic activity could perfectly well be the primal cause of exploitable geothermal sites. The heat flow is regularized by the enormous thermal capacity of the underground rock mass. However, we cannot determine whether this regularization occurred as deep as the high-temperature rocks. Such would be the case if the deep source were a batholith or a large laccolith. If the heat flux at high temperatures, which is expressed by the formation of subterranean vapor plumes, participated in the irregularity of volcanic phenomena, the regularization resulting from accumulation of heat by the rock mass may occur only at the level of the geothermal sites themselves.

In any case, we can easily determine the age of a geothermal site. In effect, if a geothermal site is not supplied with heat, simple conduction must lead to a progressive temperature decline and thus to the site's degradation. This is true even without taking account of possible convection or losses through surface manifestations such as geysers, steam discharges, mud pots, etc. It is easy to calculate the conductive cooling for a realistic model, and the study of this cooling will allow us to estimate an order of magnitude for the maximum age (i.e., since the period in the course of which the geothermal site must, however formed, at least have experienced a rejuvenation by a new supply of heat).

To start the calculation, we will consider a geothermal site indefinite in the horizontal plane and characterized by a thermal profile as a function of depth. In this profile, we must distinguish between the normal permanent geother-

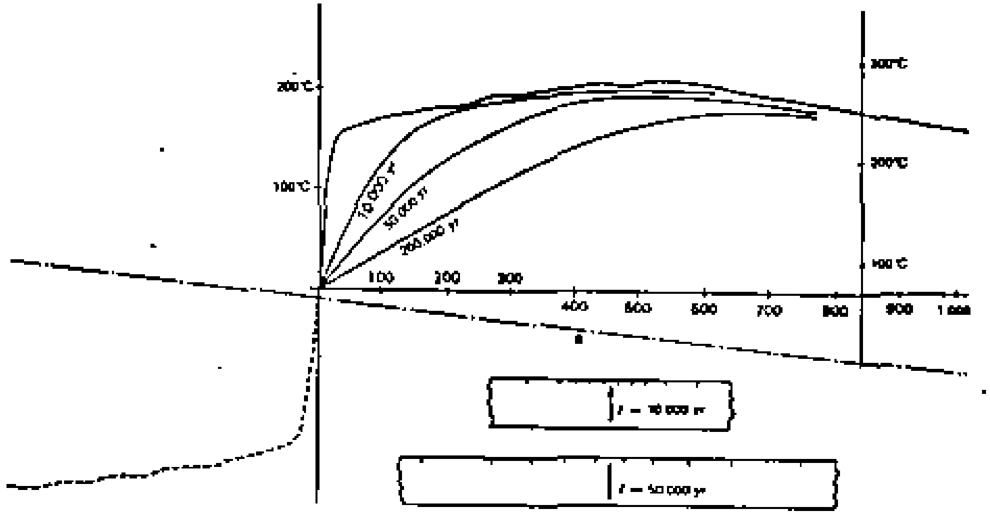


FIGURE 4-2 Calculation of the evolution of the thermal profile of a geothermal site with heat diffusion. The thermal profile example is taken from well 48 at Wairakei; account is taken of the normal geothermal gradient and the surface temperature. The profile was completed symmetrically. To calculate the temperature at the end of a given time, the average of 10 values is taken on both sides of the position studied, at distances which increase as the square root of the time. Representation of two of the rules for this calculation. Observe that at the end of 10,000 yr the useful heat which could be extracted, (i.e., below 200 m), will be practically unchanged.

mal gradient maintained by conduction as a consequence of the subterranean geothermal flux, and we must subtract it from the actual thermal profile so as to define the thermal anomaly associated with the geothermal site, which will gradually disappear through conduction.

We must impose the condition that the temperature at the ground surface remains constant and equal to our conventional 0°. To meet this condition, it suffices to extend the thermal profile symmetrically, but with opposite sign, above the earth's surface, thus assuring the constancy of the temperature at the surface.

Now, we apply the formula which describes heat diffusion in a region, initially at a temperature $T(z)$, and which

gives the temperature after a time t as a function of z_0:

$$\theta = \frac{1}{\sqrt{4\alpha\pi t}} \int_{-\infty}^{+\infty} T(z) e^{-(z-z_0)^2/4\alpha t}\, dz \tag{4-1}$$

From this formula we can calculate the value of the gradient at any point or at the surface:

$$\left(\frac{\partial\theta}{\partial z}\right)_0 = \frac{1}{\sqrt{4\alpha\pi t}} \int_{-\infty}^{+\infty} \frac{T(z) e^{-(z-z_0)^2/4\alpha t}}{4\alpha t}\, 2(z - z_0)\, dz \tag{4-2}$$

The calculation of an actual thermal profile, $\theta = T(z)$, must be done numerically, which means that we must replace the integral by a sum over a limited number of terms. Let us therefore take $(z - z_0)/\sqrt{4\alpha t} = s$; $I_1(s) = 1/\sqrt{\pi} \int_{-\infty}^{s} e^{-s^2}\, ds$; $I_2(s) = \int_{-\infty}^{s} e^{-s^2} s\, ds$ where $I_1(\infty) = 1$ and $I_2(\infty) = 0$. Then, formulas (4-1) and (4-2) can be written

$$\theta = \int T(z)\, dI_1 \qquad \text{and} \qquad \frac{\partial\theta}{\partial z} = \frac{1}{\sqrt{4\alpha\pi t}} \int T(z)\, dI_2$$

We will replace dI by a finite segment equal to 0.1 and will take 10 values of s at the interior of the corresponding intervals, $S_1, S_2, \ldots, S_{10}$. It will suffice to take the average of the 10 values of T, for the values of Z corresponding to $S_1, S_2, \ldots, S_{10}$, z_0 and t being chosen. For the gradient, the same average will be divided by $\sqrt{4\alpha\pi t}$.

For $N = 10$, we will take $S_n = \pm 0.088$, 0.273, 0.476, 0.732, and 1.163. For the gradient, $S_n = \pm 0.324$, 0.597, 0.832, 1.097, and 1.52.

In practice, we would graphically trace the thermal profile at the initial time (subtracting the temperature corresponding to the normal gradient) and complete this profile by its symmetry beyond the earth's surface. To determine what the profile would be at the time t, we would carry on a rule the values of $z - z_0$ corresponding to the S_n, and by centering the rule on a value of z_0, we would read the 10 values of T, whose average would give the temperature of z_0 at t.

If it is especially sought to calculate the evolution of the temperature at a point and the gradient at the surface, we can trace the thermal profile as a function of ln (z), and in

the same manner the rule with the values of ln (z) corresponding to S_m such that it would suffice to move the rule along a scale of $\frac{1}{2}$ ln t.

Figure 4-2 indicates the results of a temperature evolution calculation for the profile of shaft 48 at Wairakei, New Zealand. The evolution of the gradient at the surface has been directly calculated with the results in Table 4-1.

Table 4-1
Evolution of temperature gradient at the surface

Present	100	200	500	1,000	2,000	4,000	10,000 yr
5	1.5	1.09	0.727	0.54	0.379	0.228	0.148°C/m

From these results, we can infer that part of the rising steam has heated the surface until a very recent date—in fact, this heating is still going on—but part of the energy of the geothermal bed will hardly decrease from the value that exists today in 10,000 or 50,000 yr. The heated rock can conserve its temperature for a very long time at a certain depth, even when the surface gradient has decreased to a point where all surface manifestations have seemingly disappeared.

For a geothermal steam bed, like at Larderello, things are a bit more complicated. We can assume that under the impermeable cover the steam is at an apparently uniform temperature and pressure (for Larderello, 250°C at 40.5 bars). The surrounding groundwater can thus be in pressure equilibrium with the steam at a certain depth. For example, if the geothermal bed cools by 1°C, the saturated vapor pressure decreases by 0.685 bar, then the equilibrium level between the water and the vapor will rise about 6.85 m. The mass of vapor which is present diminished partly because of the reduction of occupied volume and partly because of the pressure drop. The latent heat corresponding to the condensation of the difference will thus be liberated. However, a more complete calculation shows that this effect is very small in comparison to the cooling of the rocky mass in which the geothermal site is included. Because of vapor convection, all the geothermal site which is occupied by steam

will cool in a nearly uniform manner. The temperature of the entire geothermal site will follow the cooling of its roof, and that can lead to an appreciably more rapid cooling that in the preceding case.

This reasoning would apply to a geothermal steam site embedded in permeable rock which has a sensibly uniform temperature. The case of Larderello is different, since the steam there occupies fissures and karstic spaces and only heats the walls to a limited distance which is still not well known. The results indicated in Chap. 3 lead us to deduce a recent age for the geothermal steam site. Otherwise all the rock between the fissures would be at an approximately uniform temperature.

4-6 Rock alterations and water geochemistry

It is well known that hot water reacts with the rocks it traverses and acquires by this means chemical compositions that are different from cooler waters of the same region (to which is attributed the therapeutic properties of thermal mineral waters).

A fortiori, very hot water reacts strongly with rocks that it traverses. It is striking to see outcrops of rock in New Zealand which have been leached by thermal water and have become porous and profoundly altered to a silica-aluminous and ferric skeleton while being leached of all soluble elements such as the alkalis. Such altered rocks should draw attention, and it is surprising that they have not been pointed out more often.

On the other hand, at the time of the extraction of mineralized hot waters, especially if this operation involves vaporization, it is bothersome that drill holes sometimes become rapidly obstructed by deposits. It has been supposed that analogous deposits could have been formed in the natural terrain and could have obstructed fissures by which steam escapes to the surface. This would create an impermeable cover which would assure the conservation of the geothermal site. This process, called *self-sealing*, ought to occur at the time of vaporization of mineralized water to make the roof watertight; its reality has never been clearly established.

The chemical composition of water can furnish valuable indications of its origin, and compositional studies are indispensable in prospecting for a geothermal field. The handiest indication of the maximum temperature reached by water is furnished by its silica content, since silica does not immediately precipitate on cooling.[1] The solubility of quartz and amorphous silica increase rapidly with temperature up to around 300°C if the pressure is that of the vapor phase (much more rapidly at higher temperatures under higher pressures). We suppose that at great depths and at such temperatures, quartz is present everywhere and that the water is in equilibrium with quartz as a solid phase. At the time of its ascent to the surface, decompression of the water results in its partial vaporization which increases the silica concentration by an easily calculated amount (it matters very little whether the steam produced remains constantly in equilibrium with the water, which corresponds to an expansion at constant entropy, or is involved in a throttling process, which is a cooling at constant enthalpy). Near the surface, the water will be in contact with amorphous silica, but precipitation is sufficiently delayed so that the total silica in the water furnishes a precise indication of the initial temperature. If the initial temperature was less than 210°C, however, the silica content in the water after expansion remains less than the saturation limit for amorphous silica, and so the water can dissolve the silica in the conduit, leading to an overestimate of the temperature. Figure 4-3 shows the result of such a calculation.

Other proposed indicators which are sometimes used have a much less general application. The ratio K/Na has been proposed; it increases with the final temperature reached by the water, but it depends strongly on the local

[1] R. O. Fournier and J. J. Rowe, Estimation of Underground Temperature from the Silica Content of Water from Test Springs and Steam Wells," *Am. J. Sci.*, vol. 264, pp. 685–697, November 1966.

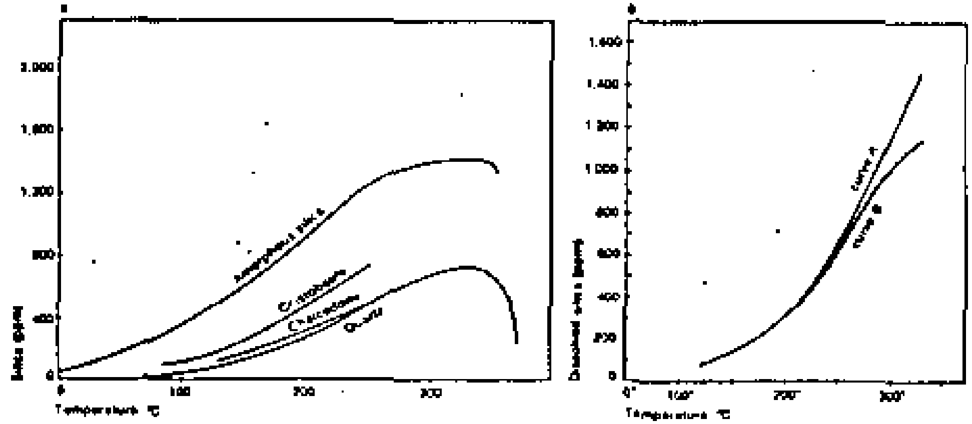


FIGURE 4-3 Relationship between the maximum temperature achieved and the silica content. (*a*) Solubility of different silica varieties as a function of the temperature; (*b*) temperature of water at the time it was in equilibrium with quartz as a function of the measured silica concentration (B, adiabatic cooling, i.e., a steady-state system; A, cooling with irreversible steam expansion). (*From Fournier and Rowe, Estimation of Underground Temperature from the Silica Content of Water from Test Springs and Steam Wells, Am. J. Sci., vol. 264, pp. 685–697, November 1966.*)

petrography. It is an index the significance of which must be established in each region.

When there is vaporization of water containing both dissolved salts and gas, they are unequally distributed between the two phases. Thus it ought to be possible to recognize water coming from condensation of steam, and also, depending on the gases present, it should be possible to tell if a vapor is of a very deep origin or results from evaporation relatively near the surface.

The geochemical indicators require very careful interpretation which cannot be put into general rules. Only careful comparison of the chemical composition of different waters in a region, taking into account the petrographic nature of the rocks present, can lead to valid conclusions.

CHAPTER FIVE

utilization of geothermal energy

The Romans used hot springs to heat their baths, and such uses are found everywhere (aside from possible therapeutic applications which have considerable economic importance). Certain Parisian swimming pools are heated directly by wells driven into aquifers of Albian greensands with a temperature of 35°C. Since the Middle Ages, localities like Chaudes Aygues, Dax, and Ax-les-Thermes in France have distributed water at 80°C for domestic and heating purposes.

Many such direct applications have developed. The entire domestic heating in Reykjavik (which is likely to be used a large part of the year) and the heating of greenhouses use geothermal waters. In New Zealand, a paper factory as well as many domestic applications (hotels, breeding farms, etc.) can also be cited.

All these applications depend on local needs. The problem of the utilization of geothermal energy does not take on all its significance until it is placed in the framework of an energy market made possible by means of electrical energy transport. Thus, we will examine the use of geothermal energy primarily to produce electrical power. We must also mention that when there exist needs for heat at a low temperature, it is more economical to omit the electrical intermediary.

All electrical or mechanical energy production from heat rests on the first two laws of thermodynamics. On the one hand, there is an equivalence between the total heat absorbed and the energy according to the relationship 4.18 J = 1 cal. On the other hand, it is not possible to produce

energy by the consumption of heat at a uniform temperature (this heat could be obtained in practically unlimited amounts from a source such as a river, the ocean, the atmosphere, etc.). The engine which produces mechanical energy must take heat from a warm source and give back a lesser quantity of heat to a cold source in order to transform the difference between these two quantities of heat into energy. The absolute temperatures T_1 and T_2 of these sources (in practice $273 + \theta°C$) are defined in such a way that $Q_2/T_2 \geq Q_1/T_1$, Q_1 being the quantity of heat taken from the hot source T_1. In other words, the entropy, $dS = Q/T$, can only increase. The energy produced is equivalent to the difference $Q_1 - Q_2$. In general, it is the hot source which limits the production of energy and is taken as a reference for the overall efficiency. However, the cold source does not play any less important role in the economics of energy extraction, and it is useful to have next to the power plant, as at Wairakei, New Zealand, a large river (Waikato) with permanently cold water. Otherwise one may have to use the atmosphere to cool water at the base of towers where upward movement of heated air assures a natural draft. Apart from the cost of such an installation, in some climates it does not produce a very low temperature.

Related to the heat taken from the hot source, the efficiency is

$$\frac{Q_1 - Q_2}{Q_1} < \frac{T_1 - T_2}{T_1}$$

The ratio on the right-hand side of the inequality is the thermodynamic efficiency, which constitutes an upper limit. In fact, the practical efficiency is much lower than that theoretical limit, but the discrepancy depends on technological considerations, and we can always try to reduce the difference.

What are the theoretical possibilities for geothermal energy production? Let us consider a surface of 1 km² where the regional geothermal flux is greater than the average world flux in a ratio m. This flux, $m \times 1.2\,\mu cal/cm^2 \cdot s$, is equivalent to $1.2\,m \times 10^4 \times 4.18$ W, which is $50\,m$ kW/km².

But in order that this flux be partly transformed into energy, we must tap the heat in subterranean regions which is at higher temperatures than at the surface, the heat of which represents the cold source. If the thermal gradient is m°C/30 m, the temperature difference at the surface will be $(m \times h)/30$ and the resulting thermodynamic efficiency is $(mh/30)/(283 + mh/30)$.

A hot spring represents a natural device which brings to the surface, with little temperature loss, part of the subterranean flux. There have been several developments based on the energy utilization of heat transported by a hot spring. At Kiabukwa in Katanga, there is a spring of 40 liters/s at 91°C which has been equipped to produce 140 kW.[1] But such an extraction, which could continue indefinitely, is highly unusual. As a general rule, a close inspection of different developments shows that the heat contained in a certain volume of rock is used up. This heat is transported to the surface by water circulation in either the liquid or the vapor state. Such a geothermal site is thus likely to deplete itself, the more quickly the larger the flow, unless the subterranean phenomena which gave rise to the geothermal site renew themselves. But the way in which these original phenomena are distributed in time remains obscure.

It is easy to calculate that a cubic kilometer of rock cooling from 250 to 200°C, liberates 25×10^{15} cal, which is equivalent to 10^{17} J. By taking an average efficiency of (225°C − 30°C)/(273°C + 225°C) = 38 percent, we could theoretically produce 12,000 kW for 100 yr.

Although this is very theoretical, we can undertake a more precise calculation. Let us take 27°C, which is 300°K, for the surface temperature and suppose a gradient of $30m$°C/km, which gives T = 300°C + $30\,mh$°C. If we remove some of the heat contained in 1 km³ thus decreasing the temperature from T to $T - dT$, it will provide $0.5 \times 10^{15}\, dT$ cal, with a theoretical efficiency $(T - T_0)/T$, which can produce a total energy of $2.1 \times 10^{15} \int_{T_0}^{T} [(T - T_0)/T]\, dT = 2.1 \times 10^{15}$

[1] A. Rollet, "La Centrale Géothermique de Kiabukwa," Report of the Congrès Scientifique, fiftieth anniversary of the Special Committee for Katanga, communication 96, Elisabethville, 1950.

$[T - T_0 - T_0 \ln (T/T_0)]$, or approximately $2.1 \times 10^{15} (T - T_0)^2/2T_0 = 1.05 \times 10^{15} (30mh)^2/300 = 10^5\, m^2h^2$ kW · yr.

If we extracted all the ground heat to a depth of H km, we could theoretically produce $(10^5/3)m^2H^3$ kW · yr/km². Presently only thermal sites with high thermal gradients are used; m can attain a value of 10, but only over small areas and to a shallow depth H. However, if this formula is extended to all the land area above sea level, which is 142 million km², we would find a total of $4.8 \times 10^{12}\, H^3$ kW · yr. Although in extracting this heat one would encounter considerable technological problems, we should remember this figure because it sets practically no theoretical limit to the possibilities of geothermal energy production. Now it remains to discover how to produce this energy and at what cost.

Practically, we are able to distinguish three cases in the operations technology: first, the geothermal site which only furnishes steam; second, the site which supplies very hot water which can be partially vaporized by a pressure drop, and this subsidiary steam used for energy production; and finally, the site in which the heat directly contained in the water is used without vaporization. We will examine these cases in succession.

5-1 Operating techniques for a steam site

The classic example of this case is the steam site at Larderello[1] in Tuscany, where the first energy was produced at the start of the century and where the production of energy has now reached 200,000 kW. The geothermal site at the Geysers, in California, also uses a steam field which extends over 25 km². This site reached 396,000 kW (October 1973) and has continued to increase. It is expected to reach

[1] A. Mazzoni, "I Soffioni boraciferi Toscani e gli Impianti della Larderello," Bologna, 1951. Also see the reports given at the United Nations on new energy sources, Rome, 1961, and at the Symposium of the United Nations on the Development and Utilization of Geothermal Resources, Pisa, 1970.

600,000 kW. There is also a steam field which is utilized at Matsukawa, Japan.

The sinking of commercial wells involves precautions which we will find in all the cases. Before reaching the roof of the bed, it is necessary to have cemented in a casing that can withstand the pressure exerted when the main valve is closed without the risk of vapor infiltrating into the ground. After the hole has been drilled using refrigerated mud, with normal precautions to control possible eruptions (fast-acting valves called *blowout preventers*), a protective column can be installed with a casing or the productive zone can be left open. At Larderello, a drill hole was generally stopped as soon as a steam-producing fissure was reached. In principle though, with a sufficiently cold mud, drilling could continue to obtain higher production capacity.

Once the hole is opened and emptied, the steam escapes into the atmosphere. Then, once the walls of the shaft are at temperature equilibrium, the steam expansion becomes adiabatic. It is known that a saturated vapor in an adiabatic expansion to atmospheric pressure becomes humid. That is, the steam contains about 25 percent (by mass) of water in suspension. The steam will appear as a white plume; at the end of several very spectacular days of this free release into the air, the plume becomes transparent and only condenses higher up by mixing with the colder air. Under atmospheric pressure, the steam drys up. We can interpret this change by supposing that the expansion from the geothermal pool no longer takes place in the drill holes but a little bit upstream, and the steam cooled by expansion is reheated on contact with hot rock remaining at 250°C (in the case of Larderello). Of course the propagation of the pressure drop due to the release of steam in a fissure network whose form we do not know cannot be described accurately. We only know that the steam with a lowered pressure takes heat from the surrounding terrain. At that time, the drill hole is connected to the central power station by insulated piping of a large diameter (massive flows can be hundreds of tons an hour,

and a ton of steam occupies 279 m³ at a pressure of 7 bars). The pipes are arranged so that they can freely dilate, but there is no worry about water condensation since the steam is superheated.

Formerly, to avoid corrosion of the turbine, an exchanger was used to vaporize pure water while the natural steam condensed. Naturally, there was a loss of temperature and pressure in this operation. There was then no problem in using a condenser where the final condensation of the steam occurred at a low temperature and pressure.

Then, it was decided to construct turbine vanes out of steel resistant to the corrosion of the natural steam. But the gas contained in natural steam (5 percent at Larderello, 1 to 2 percent at the Geysers, where this proportion is dropping in the course of the operation to 0.5 percent) accumulates in the condenser increasing the pressure, which has to be lowered by pumps. In spite of that, the pressure in the condenser is never as low as with a boiler using recycled water.

A third solution, more primitive and permitting only a marginal efficiency (that comes from taking 100°C as the temperature of the cold source), consists in letting the turbine exhaust go directly into the atmosphere. This method is sometimes used for a short while by a field unit to utilize the production of a drill hole until it is connected with the power station.

5-2 Directives for geothermal operations

A number of drill holes are connected by pipelines to the entrance of the turbine. There can be two or more separate networks connected to different turbines which can work at different pressures or a joint collection allowing several turbines to be fed. But in any case, the turbines are calibrated for a certain entrance pressure, which means a slightly higher pressure at the wellheads. Regulation of flow, as a function of the electrical power to be provided, is controlled by regulators at the turbine entrance which maintain the steam flow at a certain pressure. Sometimes, in the course of the operation, that entrance pressure is appreciably different from the design pressure. In the power station's operations, it is necessary to choose between maximum energy production, which corresponds to a strong flow with a relatively low upstream pressure, or a high efficiency in kilowatts per kilogram of steam per hour, which requires a high upstream pressure with a lesser flow.

Even if it was demonstrated that the total quantity of heat which can be extracted from the ground, and thus the total steam tonnage which the site would be able to produce, is limited, producers will rarely sacrifice the possibilities of a high production capacity in the immediate future for the benefits of prolonging the site's reserves, since its limitation will not appear until after a very long waiting period. In the establishment of the power-station plan, the upstream pressure at the turbines should be fixed (or possibly the pressures if there are two groups of wells, stronger and weaker producers, feeding different turbines). This is a delicate choice which requires a thorough knowledge of the production capacities of the wells, at a time when development wells are hardly completed or are still to be drilled. In practice though, it is often found that the power plant is working at a pressure lower than designed. Should we thus conclude that the production pressure was chosen too high or the plant overequipped? The constant concern of the producer is to increase the production capacity by sinking new wells extending the surface area of the exploited field.

These new wells are especially necessary as experience has shown that well production decreases with time (for example, to one-half in 2 or 3 yr in Larderello, although exact information has not been published). One of the explanations of this decline holds that the ground heat used to superheat the steam is depleted further and further upstream from the fissures by which the steam reaches the drill holes.

5-3 Geothermal exploitation involving water vaporization

An example of this type of exploitation is that at Wairakei, New Zealand.[1] This site is equipped to produce 175,000 kW. The proximity of the Waikato River, which originates from Lake Taupo with a large flow, was used to advantage by installing the power plant on its banks, permitting very efficient operation of the condensers. However, this extends the piping a bit and inhibits the development of the extension of the geothermal field that was discovered on the opposite side of the site.

A well penetrating into a bed where the water temperature is at the boiling point under the appropriate pressure does not risk eruption whenever the mud is cooled. Yet, it may be necessary to maintain the cooling mud circulation while the drilling operations are halted. In New Zealand, they did not limit themselves to cementing only the first casing in the ground, but immediately set a truly massive mooring, which is perhaps dispensable. A casing is set slotted at a suitable level even for exploratory drill holes.

After 3 months of waiting, during which the main valve is closed, the well comes into equilibrium with the surrounding ground. The water at the bottom of the well is in equilibrium with the ground, but gas can accumulate and mix with the steam; this gas occupies a certain height in the column so that the valve pressure has no particular significance.

After the temperature profile is measured, production tests can proceed. If steam accumulates, it suffices to open the main valve; the pressure falls in the well, and the entire column of water begins boiling, the steam jet driving out the water (and possibly all the rocky debris which has accumulated in the well). If the eruption does not begin spontaneously, it is necessary to raise part of the well's water

[1] G. W. Grindley, The Geology, Structure, and Exploitation of the Wairakei Geothermal Field, Taupo, New Zealand. *N. Z. Geol. Surv.*, Bull. No. 75, p. 131 (geological map and cross-sections), 1965. See also the numerous publications of the Department of Scientific and Industrial Research of New Zealand in the form of internal reports, or the *New Zealand Journal of Geology and Geophysics*.

column to initiate the eruption. This can be done by a process called *air lift*. Essentially, this involves injecting compressed air at a certain depth in the well.

In the course of the eruption, water flows from the ground toward the well, and either in the fissures or later when passing the slotted casing, part of this water is vaporized because of the pressure drop; the temperature then decreases. We can easily calculate the proportion, by weight, of water transformed into steam. Let θ_1 be the initial temperature, θ_2 the boiling point of water at the pressure in the well, and L the latent heat of vaporization at that temperature. The vapor proportion x is such that $x \cdot L = \theta_1 - \theta_2$. Although x is much less than unity (25 percent at most), the vapor volume is large with respect to the water volume, and the water is reduced to a suspension in the steam jet which can reach a high velocity. This suspension could be formed in a well open to the atmosphere as well as in a hole with a back pressure maintained at the well's main valve.

When a well furnishes superheated steam, as at Larderello, the flow can be measured by one of the methods applicable to gases, such as the pressure difference on the two sides of a calibrated orifice, or the pressure measured upstream from a conical fitting which leads into free air and which functions like a venturi. However, these methods are not applicable to a humid vapor. In New Zealand the production is measured while a back pressure is maintained by a calibrated orifice, or *duse*. The pressure is measured upstream from this orifice. The steam content and the flow of the mixture are measured downstream after a new expansion which increases the amount of steam. To determine this amount (see Fig. 5-1), part of the steam jet is collected and is condensed in a receptacle containing cold water. The increase of mass and of temperature give the proportions of water and steam. The total flow is estimated by the ratio of the total cross section of the jet to the sampled cross section. Care must be taken to move the sampling device over the entire area of the jet during testing. With different orifices,

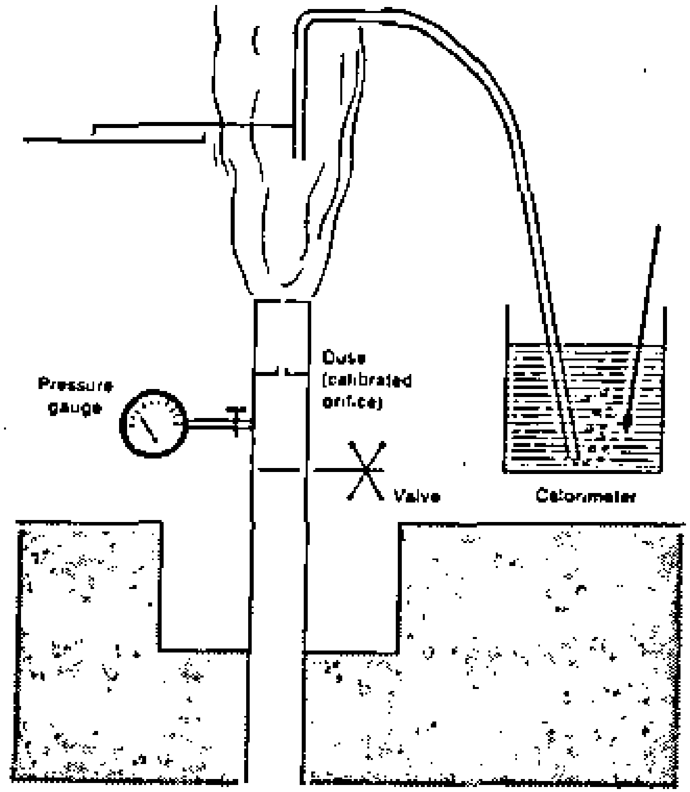


FIGURE 5-1 Principle of the production measurement of a geothermal well. Different outputs, characterized by their pressures at the wellhead, are obtained with different *duse* (calibrated orifices). After expansion, a fraction of the flow is removed from the steam jet (a calibrated cross section being displaced for a systematic sampling), and the product is then condensed in a calorimeter and the heating and mass increase are measured.

one can determine the well's production as a function of the pressure at the main valve, and thus is able to choose the range of turbine operation. It is necessary to repeat these measurements periodically.

To utilize the well, we must first separate the water and the steam. This is done in a large vertical tank (Fig. 5-2) which the steam jet enters tangentially. The steam is extracted from the upper part of the tank and the water ac-

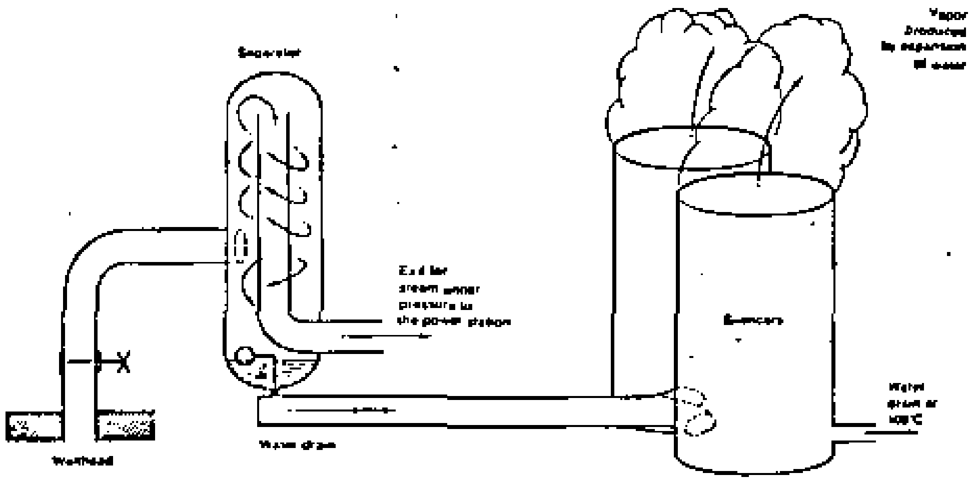


FIGURE 5-2 Diagram of the wellhead equipment used at Wairakei. A separator and a muffler are found in which water is successively separated under pressure and expanded with partial vaporization up to atmospheric pressure.

cumulates at the base. The temperature of the steam is a function of the pressure at which the vapor is used, but in any case it is much higher than 100°C. On further expansion, the water that has been collected partially vaporizes and the steam thus produced could be used by a second collection network at a lower pressure. As there are two collecting networks, one at high pressure and one at low, this seems easy. If this is not done, it is simply because it appears more economical to increase production by sinking new wells. It is evident that in this comparison no consideration has been given to the total energy which will be produced during the life of the geothermal field. The heat contained in the geothermal site will dissipate at a higher rate in the course of the operation than if thermal recovery had been allowed.

It is even theoretically possible to use the steam produced by the expansion of water to atmospheric pressure (and even use the heat of water below 100°C), if the condensers can be arranged downstream from the turbines. This will be seen later.

But this recovery is not done at Wairakei, where the water is flashed at a temperature greater than 100°C (up to 160°C, at which temperature steam production by expansion reaches 15 percent). It is the noise produced by this expansion which is the most irritating aspect of a geothermal energy operation, and to reduce it water is expanded in *silencers* formed by two vertical cylinders coupled at the base where water enters. The escaping steam condenses in the cold air producing white steam plumes (actually, mist).

5-4 The evolution of a geothermal site

We have assumed that at the beginning of the exploitation, the geothermal water is vaporized on reaching the well or while traversing the slots in the casing. An evolution of producing conditions is observed at Wairakei that suggests that this is not always the case. It seems that, in the long run, a pressure drop propagates upstream and leads to a partial vaporization of the groundwater. It is clear that at each point the vapor will tend to occupy the upper regions of the permeable reservoir, near the impermeable cover. But this cover cannot be totally impermeable, and the steam must infiltrate it. As a result the superficial manifestations (i.e., geysers, mud pots, etc.), which made Wairakei a tourist area long before geothermal operations began, tend to increase instead of being reduced as was anticipated. The steam proportion in the well production has increased, which implies a vaporization not only by expansion but by contact with rock having sufficient thermal inertia to supply the necessary heat for vaporization, due to a pressure drop in the bed. It is evident that this forms a very favorable opportunity for exploitation.

But it is not easy to tell to what distance from the wells this vaporization could propagate in the surrounding ground. If we imagine the case of a permeable matrix in which vaporization takes place, we realize that (taking account of the volume flows of the water and steam, for similar mass flows and actual viscosities) the pressure gradients must be much stronger in the region of the steam than in the region occupied by the water. Hence we might expect the matrix (at Wairakei, it is tuffs and volcanic cinders that are rather friable) to burst in the area of vaporization. It is likely that this occurs in uncased wells, where the jet of steam and water is often loaded with rocky debris.

It is thus likely, especially taking into account the large production differences between neighboring drill holes, that fissure permeability plays a larger part than matrix permeability. We can conceive that, in a fissure with easy access to a well, water is ejected by vaporization and this process results in the creation of a system of communicating fissures in the well walls filled by steam until ultimately water is replaced by steam in the matrix itself.

Ideal operating conditions would be realized if, in the layer which constitutes the geothermal reservoir and whose upper regions are perhaps filled with steam, at least near the well, only the upper region of the layer interacted with the drill hole. Then vaporization would be produced in the layer itself, and at the limit, we could extract only the steam with all the advantages which have been previously indicated. This could resolve the problem of what to do with the residual hot water. Also, this would limit a great deal the problem of resupplying water to the geothermal site. The vaporization of the water contained in a rock having a porosity of 10 percent effectively lowers its temperature 80 or 90°C, which closely corresponds to all the heat which can be usefully extracted.

If we recall the technological progress which has been achieved in the development of oil wells, we can hope that the same will develop in the future exploitation of geothermal sites and that we will thus succeed in extracting only the steam contained in a bed initially occupied by water. This is definitely in the future, however, and it will be indispensable to understand, much better than today, how vaporization propagates in the matrix as well as in the fissure network.

5-5 The utilization of steam

The steam gathered in separators is sent to turbines by a system of pipes. But, as this is a saturated vapor, it constantly condenses and the water flows to the bottom of the pipeline, which must be automatically purged at all low points. The simultaneous flow of both water and steam in the same pipe can be unstable and should be avoided. The use of steam at the power station equipped with turbines and condensers presents no new insights.

Observe that in both the modes of operation which have been described, a certain number of wells are linked in parallel to the same collector network. It should be understood that there can be several different supply networks utilized at different pressures, pressures which are defined downstream by the functioning of the turbines. Thus, we do not know which wells supply the steam utilized, which in the long run could be very inconvenient (a well could effectively stop producing, without notice). This makes it necessary to take periodic measurements, in practice monthly, of the conditions under which each well is producing steam.

In the design of a commercial energy project, we have pointed out that the first problem is the choice of the operating pressure. Another problem concerns the number and position of the power stations. On the one hand, it would be useful to reduce the length of the steam pipeline, which is costly and the site of heat losses. But also, it is desirable not to disperse the power installations too much in order to use large steam engines, which are more economical than small ones. These conditions lead to a compromise, with some dispersal of the power stations. At the Geysers (California), where the first power station reached 14 and then 28 MW, they plan to reach 600 MW at the end of 1975 (without this being an upper limit), with power stations including two groups of 55 MW each. However, local conditions, particularly the availability of cooling water for the condensers, make a detailed study necessary for each case, since general rules cannot be formulated.

5-6 Energy utilization without steam production

There is no fixed limit between the application of this method and the preceding method. Theoretically, we can vaporize water at less than 100°C in a partial vacuum created by an efficiently cooled condenser downstream from the turbine. This is how the small installation at Kiabukwa worked. As is done in Reykjavik, water can also be used at 140°C for urban heating without allowing it to vaporize, by maintaining the water in a pipeline system which is under pressure. However, for this, pumps must be immersed deeply in the drill hole so that the pressure of the extracted water is always at least of the order of 3 bars on the surface. In Reykjavik, this pressurized hot water is used in exchangers for domestic water heating and for heating greenhouses.

If it is necessary to produce energy, steam turbines operating at very low pressures should be avoided because dissolved gases accumulate in the condenser, increasing the pressure, which then must be lowered with pumps. Instead, closed-circuit thermal engines operating between two exchangers which respectively constitute the boiler and the condenser could be used, with a turbine in the steam path and an injection pump to supply the condensed liquid to the boiler.

This circuit can just as well be used with a liquid more volatile than water, and thus the vapor pressure will be higher at operating temperatures, and turbines and pipes can be smaller. In China (near Peking), ethyl chloride is used. Butane, propane, or even Freon or ammonia could also be used. It can be observed that the technology necessary to make such circuits pressure-tight, while extracting the mechanical or electrical energy produced, is the same as for refrigerators, and everyone knows that leaks are no longer a problem there.

However, the theoretical efficiency remains limited by the second law of thermodynamics, whatever the fluid employed. The cost of an exchanger, overall, should be pro-

portional to its exchange capacity, and it becomes much more costly as we try to reduce the difference between the secondary fluid exit temperature and the primary fluid entrance temperature. The establishment of a project necessitates an optimum choice between the installation cost and the efficiency. There do not yet seem to be any rules which allow a calculation of the cost of an installation as a function of its output power, but undoubtedly such installations are possible (witness the Chinese experience).

Anytime there exists a need for heat at a low temperature, whether for domestic heating or for certain industries such as the desalination of water or brine (whether or not this is the water in the geothermal bed), there is great interest in utilizing the heat of the water extracted from the ground directly without the intermediary of electrical energy. For heating, electrical energy is generally employed through the joule effect, which means the transformation of electrical energy to heat through a resistance. Thus, we do not retrieve all the energy spent to produce the electrical energy, which lowers the effective efficiency to less than the theoretical limit of the thermodynamic efficiency, which is very marginal for waters at relatively low temperatures.

It would not make any difference if we used a heat pump for the electrical heating, which is equivalent to a refrigerating engine and which utilizes the heat which a refrigerator dissipates in the ambient air. It would be forced to cool some external source (the atmosphere, for example). We pay little attention to the cost of cooling by our refrigerator since it is the only way this cooling can be done. But for the calories produced by a heat pump, the comparison of cost with the cost for producing heat by the joule effect is striking. Equipment for heating by the joule effect, largely composed of resistances, is remarkably simple and economical. The equipment cost for a heat pump is much higher and even though the practical efficiency is higher than for the resistance heater, the savings in running costs (consumption of electricity) are insufficient to justify the initial cost of the equipment. In fact, no heat-pump design has ever gained undisputed advantage in this economic comparison.

Thus, the problem of the use of a heat pump has no relationship to the utilization of geothermal energy, especially at low temperatures. It only concerns the best way to utilize electrical energy.

We will not enter into the details of the utilization of geothermal waters for heating at low temperatures except to point out that the degree of water mineralization often requires the use of a heat exchanger, and that disposal of the pollution by mineralized water can be difficult.

The utilization of water from natural thermal sources or from artificial drill holes poses no particular problems. It is applicable on a large scale in a country like Hungary, where there is no hesitation in exploiting deep aquifers with wells 1,500 or 2,000 m in depth.

5-7 Water injection

In many other cases than those just mentioned, the supply conditions for subterranean water layers, which are often captive, are not such that we can expect steady large flows for profitable geothermal energy extraction. This stimulates the idea of artificially supplying subterranean water layers by injecting, in suitably placed wells, cooled mineral water, which we have already seen is a nuisance after the heat has been extracted.

This artificial supply can take very different forms. The project undertaken in the Imperial Valley, in the southern part of California (which is partially associated with the hypermineralized site of the Salton Sea), will utilize an apparently massively permeable basin. It has been proposed to inject water in the cooler marginal areas of the basin. This injection would simply add to the actual water supply outside the convection cells.

But if we consider an aquifer at a relatively uniform temperature, it could be advantageous to inject cooler waters directly into the hot aquifer. The model of such an injection was done at Melun (near Paris) and assures a supply of hot water and heating to nearly all of a large set of

apartment buildings (a supplementary use of heating fuel is necessary a few weeks each year). From petroleum prospecting, it is known that in the Bajocian, at a depth of 1,800 m, there is a very permeable aquifer at a temperature of 70°C. This bed has been reached by two separate wells drilled in approximately the same spot with deviations in opposite directions. One of these serves to extract hot water, and the other well injects this same water after cooling through heat exchangers. The thermal-siphon effect, which may be expected, is insufficient during the winter to assure the necessary flows, and pumps are used to inject the cold water.

5-8 The future of an operation with reinjection of water

If we imagine the long-range future of such an operation—and all operations which could be achieved under the same conditions, since the geothermal site at Melun is known to extend over thousands of square kilometers—we must be concerned about the risk of the injected cold water cooling a progressively increasing area of the geothermal bed until finally the temperature of the extracted water is lowered. The calculation of the predicted temperature evolution of such waters can be accomplished in the following manner.

We will neglect the dependence of the viscosity on temperature and thus will consider it as a constant. This will lead us to overestimate the cooling of the extracted water since the viscosity variations tend to slow down the movement of cooler waters and thus increase the proportion of warmer waters in the supply networks of the wells. The hydraulic system will thus be steady, and it is easy to determine the system (see Fig. 5-3) in the case of any number of extraction wells P_i and injection wells Q_k each employed at a constant flow (the sum of the flows not necessarily being equal). We can take into account a steady circulation in the aquifer, which is equivalent to placing two wells, P and Q, at plus and minus infinity. Observe that for a single well, the

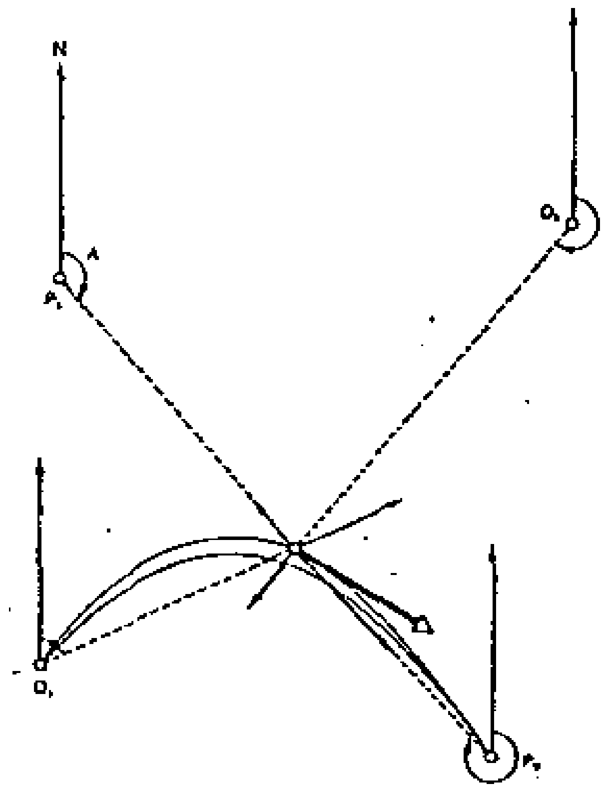


FIGURE 5-3 Principle of the calculation of current filaments circulating in a permeable layer between injection and extraction wells: geometrical definition (in consequence of the weighted sum of the azimuths being a constant), and calculation of the instantaneous flow.

unitary-flow vector is radial and inversely proportional to the distance to the other wells. In addition, the flow passing between two points is proportional to the angle of the radius vectors. For any number of wells, we obtain the unitary flow at a point by adding the unitary-flow vectors for all the wells. For a flow line, a weighted sum proportional to the flows of the wells, the azimuths of the radius vectors are constant. In the case of two wells P and Q, with equal flows, this last rule shows that the flow lines are circles passing through wells P and Q. But we could also consider

two wells with unequal flows and an aquifer with a steady inflow.

We will suppose that we have effectively traced the flow lines bordering on a well P and determined the width of a current filament of known flow along this line. The width will be inversely proportional to the unitary-flow vector.

We will study[1] separately the thermal evolution along each current filament as they are defined at the end of the calculation by the principle just indicated. The current filament includes, upon leaving the well Q, between the directions Φ and $\Phi + \Delta\Phi$, a flow $\Delta Q = Q\ \Delta\Phi/2\pi$. At a distance l from the origin, its width is $r\ \Delta\Phi$, and we will have to consider its surface $s\ \Delta\Phi$, s being defined by $s = \int r\ dl$. When reaching the extraction well P, s has the value S.

Before injection, a certain temperature distribution holds, constant and in equilibrium with the geothermal flux and the surface conditions. Let θ_0 be this steady-state temperature of the aquifer, which we will consider as uniform, neglecting the variation over the thickness of the layer. When the system is perturbed by the injection of cold water, the perturbation to the temperature will satisfy, outside the aquifer, the heat equations without taking into account the geothermal flux. Moreover, the perturbation must be zero at the surface, a condition which can be satisfied by the method of images, but that we will neglect here because the aquifer is at a relatively great depth.

If θ_0 is the initial uniform temperature in the layer and θ_1 the temperature of the injected water, we will let $\theta = \theta_0 + \tau(\theta_1 - \theta_0)$. Outside of the aquifer, $\tau(\theta_1 - \theta_0)$ will be the thermal perturbation calculated with respect to the initial local temperature.

In the first phase of the calculation, let us treat the walls surrounding the aquifer as insulating. Let h be the thickness of the aquifer and C its heat capacity per unit volume. The unitary flow is then given by $q = \Delta Q/\Delta\Phi\, eh =$

[1]This calculation is due to M. Alain Gringarten (oral communication), whom I wish to thank for allowing me to present it here.

$\Delta Q/2\pi eh$. We will assume that the temperature stays uniform in a cross-sectional area of the filament considered, and we will neglect the heat transfer by conduction in comparison with the transfer resulting from water circulation. Then the heat equation reduces to

$$C\frac{\partial\theta}{\partial t} = -q\frac{\partial\theta}{\partial l} \tag{5-1}$$

On introducing τ and replacing $\partial\theta/\partial l = e\,\partial\theta/\partial s$, Eq. (5-1) becomes

$$\frac{\partial\tau}{\partial t} = -\frac{Q}{2\pi hC}\frac{\partial\tau}{\partial s} \tag{5-2}$$

All solutions of the form $\tau = F(t - s \cdot 2\pi hC/Q)$ satisfy Eq. (5-2). In other words, the profile of the thermal variation caused by the injection propagates in the layer, with respect to the variable s, without change. If the injection of cold water begins at a time $t = 0$ with a uniform flow, the thermal wave will initially have an abrupt front, and theoretically it would continue to propagate with this abrupt wave front and a velocity $\partial s/\partial t = Q/2\pi hC$, or a true velocity $\partial l/\partial t = Q/2\pi hCe$.

It is very evident that with a constant width e, the thermal wave cannot progress without its profile being attenuated, especially if it was abrupt at the origin. A primary cause is the horizontal thermal conductivity of the layer, which, if the initial wave front is abrupt, will give a smoothing to the profile with time that could be calculated by means of the diffusion equation. But this diffusion occurs with respect to the length l of the filament, whatever its width, and it would not be convenient to introduce it into the equations. Perhaps a more important factor that smooths the thermal profile is the fact that the permeable water layer is actually composed of beds having very different permeabilities, where the water, and in consequence the thermal perturbation, progresses at very different velocities. We can infer that a certain amount of diffusion reestablishes the uniformity of temperature between different layers by

water exchanges between fast- and slow-moving filaments, but this process only occurs over a distance which is not negligible. These two processes have the character of a diffusion. They will smooth the thermal profile while retaining its median position, and their effect will be greatly lessened as the profile becomes smoother. We can expect that the diffusion progresses as the square root of the time. But perhaps we should analyze the diffusion with the true length of the filament l and not s.

In spite of these restrictions, when we calculate the thermal perturbations at the extraction wells P_0, the approximation of an abrupt thermal wave front is useful. We will consider for each instant the proportion of supply filaments whose temperature has been perturbed, which will permit us to calculate the resulting temperature of the assemblage of filaments. The modification which needs to be added to this perturbation curve to take account of the fact that along each filament the thermal wave has a smoothed profile, and is not abrupt, will only slightly change the initial part of the curve.

As a case in point (see Fig. 5-4), we will perform this calculation for two wells, extraction and injection, with equal flows. Then the lines of flow are circles, and if $2E$ is the distance between the shafts, a simple geometric calculation gives $S = 2E^2(\sin\ \Phi - \Phi\ \cos\ \Phi)/\sin^3\ \Phi$ (this trignometric

Table 5-1

Φ, degrees	0	10	20	30	40	50
$t(Q/4\pi E^2Ch)$	$\frac{1}{3}$	0.3463	0.3526	0.3728	0.409	0.456
τ	0	0.055	0.11	0.16	0.22	0.27

	90	100	110	120	130	140	150
	1	1.46	1.924	2.94	4.96	10.75	22.9
	0.5	0.55	0.61	0.66	0.72	0.77	0.83

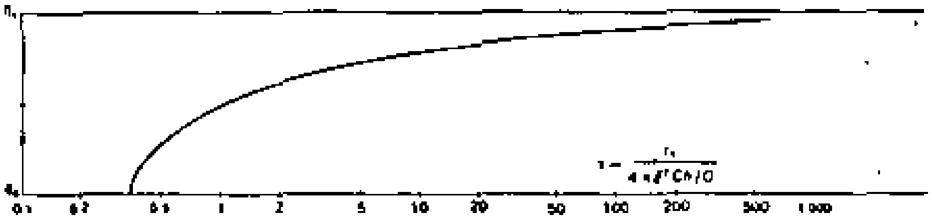


FIGURE 5-4 Calculation of the temperature at the extraction well for a pair of drill holes, supposing a permeable layer of thickness h, heat capacity C cal/cm³, and a flow Q g/cm·s. The walls are assumed insulating; the time is expressed in a reduced form as a function of the distance between the shafts, $2E$, and h, C, and Q.

expression is equal to $\frac{1}{3}$ for $\Phi = 0$). Thus, the arrival time of the thermal wave at the extraction well is

$$t = \frac{(4\pi E^2 Ch/Q)(\sin\Phi - \Phi\cos\Phi)}{\sin^3\Phi} \tag{5-3}$$

The trignometric expression takes, as a function Φ, the following values. The corresponding values of τ have also been indicated in Table 5-1.

Let us perform again the previous calculation, but this time taking into consideration the conduction of the layers surrounding the aquifer. Hereafter, z will be the distance to the edge of the aquifer on either side. In the walls, we will ne-

60	70	80
0.483	0.639	0.882
0.23	0.38	0.44

160	170	180
74	591	∞
0.89	0.94	1

glect the horizontal conduction in order to only consider the vertical heat flux. Thus we will only have to consider the equation

$$\frac{\partial\theta}{\partial t} = a\frac{\partial^2\theta}{\partial z^2}$$

which leads to

$$\frac{\partial\tau}{\partial t} = a\frac{\partial^2\tau}{\partial z^2} \tag{5-4}$$

In the aquifer, it is necessary to take into a thermal balance the loss of heat toward the walls, $2K\,\partial\theta/\partial z$ per unit surface, which gives the equation

$$hc\frac{\partial\tau}{\partial t} + \frac{Q}{2\pi}\frac{\partial\tau}{\partial s} - 2K\frac{\partial\tau}{\partial z} = 0$$

Letting $t' = t - (2\pi hC/Q)\cdot s$, this equation becomes

$$\frac{Q}{2\pi}\frac{\partial\tau}{\partial s} = 2K\frac{\partial\tau}{\partial z} \tag{5-5}$$

Eq. (5-4) not changing form. Equation (5-5) is satisfied by a function of $z + (4\pi K/Q)\cdot s$, and $\tau = \operatorname{erfc}[(z + (4\pi K/Q)\cdot s)/\sqrt{4at'}]$ follows. Returning to real time t, we find

$$\tau = \operatorname{erfc}\left\{\frac{[z + (4\pi K/Q\cdot s]}{[4at - (8\pi Kh/Q)\cdot s]^{1/2}}\right\} \tag{5-6}$$

We obtain the temperature value of the current filament upon its arrival at the well P by letting $z = 0$ and replacing s by its corresponding value S.

A statistical calculation for all the current filaments feeding the well P, which arrived from diverse injection wells, possibly at different temperatures or from infinity where the temperature always equals its initial value, would furnish, as a function of time, the temperature of the extracted water.

But the integration for the different filaments of that expression, where S is given by the geometry as a function of Φ, is not very convenient. The calculation is simplified if

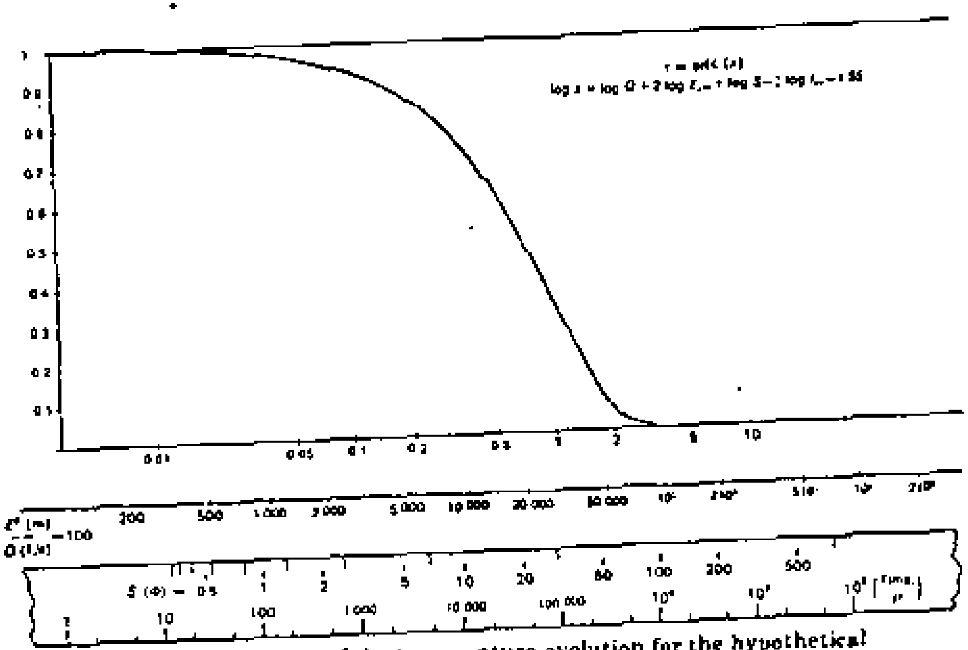


FIGURE 5-5 Calculation of the temperature evolution for the hypothetical case of a thin permeable layer with conducting walls. On the graph with abscissa of ln (E^2/Q) (m·liters/s), the form of the sliding rule having a gradation in time (years) has been calculated, the value utilized being put opposite the value of E^2/Q. For each filament characterized by $s(\Phi)$, the proportion of the temperature drop will be read on the other scale, from which a weighted average of the diferent filaments will be taken. The values of S for 10 filaments with equal flows have been indicated for a pair of wells.

the aquifer is thin (in the limit, it could reduce to a simple fissure) and if we can neglect h. By attributing all the heat capacity to the wall rocks rather than the aquifer, assuming the cross-sectional area to be uniform, we will not commit a very great error. Then from Eq. (5-6), we have $\tau = \text{erfc}\,(2\pi KS/Q\sqrt{\alpha t})$.

To do the numerical integration in $\Delta\Phi$, it will be convenient to let $\tau = \text{erfc}\ (x)$ and $\ln x = \ln\,(2\pi K/Q\sqrt{\alpha}) + \ln S(\Phi) - \frac{1}{2}\ln t$ (see Fig. 5-5). In the preceding hypothetical case of two wells with equal flows, $\ln x = \ln\,(2\pi K/\sqrt{\alpha}) + \ln\,(2E^2/Q) + \ln\,[(\sin\Phi - \Phi\cos\Phi)/\sin^3\Phi] - \frac{1}{2}\ln t$. We will con-

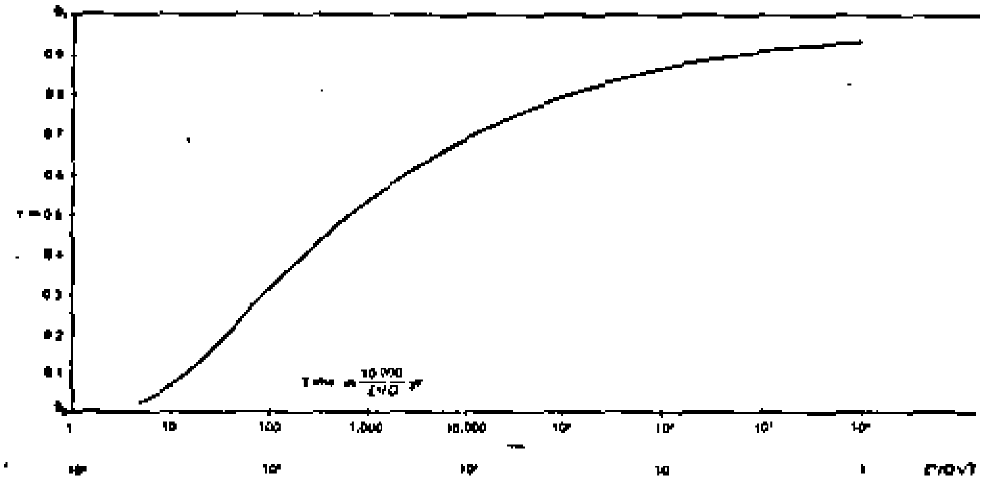


FIGURE 5-6 Curve giving the cooling behavior for a pair of wells with the hypothesis of a thin aquifer and conducting walls. E is in meters, Q in liters per second, and T is in years.

struct the curve giving τ as a function of $\ln x$ (see Fig. 5-6), and on a rule we will have the values $\ln X$ for regularly spaced values of Φ. By moving the rule according to the values t, we read diverse values of τ, from which it will suffice to take the average.

Figure 5-5 shows the rule for the case of two wells of equal flow just studied. The flux of one of the wells has been divided into 20 equal filaments, each characterized by the median behavior of the current line. For $\Phi = 9, 27, 45, 63, 81, 99, 117, 135, 153$, and $171°$, the result of the calculation is given in Fig. 5-6 as a function of time in years for $E^2/Q = 10{,}000$, or directly as a function of $E^2/Q\sqrt{T}$. It would not be too much more difficult to calculate the temperature distribution for any arrangement of wells. Observe that the thermal evolution is much slower than for the first hypothetical model (nonconducting walls). This corresponds to the fact that in the long run, taking account of the conductivity of the rock, we can utilize the heat in an increasing height of the ground. However, a precise study for a particular case should take the thickness of the aquifer into account.

Thus, in a relatively fair manner, we can predict the long-term evolution of a well's temperature and thus the commercial conditions for operation. If a uniform movement, even if it is very slow, exists in the subterranean water, it can serve to assure the permanence of the heat supply. It is consequently very important to document such movement by careful measurements of the static pressure, so as to best choose the locations of injection and extraction wells. It has earlier been seen that viscosity variations, which were neglected, tend to benefit the circulation of warmer waters, which will be favorable for extraction of heat.

But the permeability of the ground is not necessarily uniform; far from it. This nonuniformity can lead to a deformation of the current filaments, but more important, a large proportion of the extracted flow will originate from a small number of filaments. The cooling in those places will be rapid and will have a great influence on the temperature of the extracted water. When it is a question, as we supposed previously, of a sedimentary layer, we can expect that the fluctuations in permeability will be small. But if we imagine a fissure, essentially plane and extended, to which we try to apply the previous reasoning, it must be remembered that the fissure's width is not uniform but leads to the establishment of preferential circulation routes. These routes cool much more quickly than the rest of the fissure and have an important effect on the temperature of the extracted water.

5-9 Geothermal energy prospects at low temperatures

The utilization of thermal energy at low temperatures (i.e., outside the limited zones of abnormal heating) opens up large possibilities. Although this is a favorable circumstance, high values of the heat flow or the gradient are not a necessity. But it appears that deep aquifers which are sufficiently permeable are absolutely necessary. Certain of these aquifers (for example, in the Hungarian basin or the artesian basin of Australia), are supplied with a sufficient

amount of water to allow a simple exploitation. In other cases, injections of water will be necessary either to maintain the pressure or to avoid pollution. But the existence of a sufficiently permeable layer seems to be the essential condition of such an operation.

It has been proposed by NASA (National Aeronautics and Space Administration) to attempt heat extraction from a massive impermeable rock, such as a granite, found at a sufficient depth by producing fissures in this rock by the technique of *hydraulic fracturing*, extensively practiced in the petroleum industry. A fracture produced in a first well would be intercepted by a second well, and a forced circulation would be established with the hope that the thermal shock would lead to secondary fissuring, which would enable the rock to liberate an appreciable amount of heat to the water circulating between the two shafts. Such a project involves a number of unresolved problems. Will the fissuring really reach an appreciable proportion of the rock? Will it not establish a group of preferential routes where the major portion of the flow will pass and whose walls will consequently cool rapidly? It would be premature to think that these difficulties can be resolved.

It has also been proposed that subterranean fissures be created by means of nuclear explosions. In fact, even now little is known about how fissures could be created by such a method, and it is almost certain that they would be very irregular with major portions of the circulating water passing along preferential routes which would be rapidly cooled.

5-10 Prospecting

Before being able to exploit a geological site, whether it is geothermal or mineral, it is necessary to establish its existence. First, a favorable zone is identified and places are specified where the existence of an economically feasible geological site seems probable. Then, its existence is proved by sinking drill holes, and the size of the site is established.

This prospecting is actually the most delicate phase of development. There are too few known examples to allow rules to be formulated, and it would undoubtedly be an error to define a routine procedure to direct such prospecting. In addition, we have seen that geothermal sites are of relatively recent genesis. This means that we cannot count on erosion having exposed parts of the site or its characteristic alterations.

The use of geothermal energy began with already known geothermal sites. At Larderello, wells were sunk to obtain steam in order to increase the natural steam supply of the field and consequently its supply of borax. In Iceland, geyser activity was well known and this knowledge was sufficient to tap these sources at depth.

The case of New Zealand is particularly interesting. Certain thermal zones displayed very spectacular activity, and the Maoris were already utilizing this activity at certain vents to cook their food. Domestic uses were developed in the neighborhood of these zones. When the government of New Zealand attempted an industrial production of geothermal energy, extremely extensive studies were carried out and the results of these studies were published. At first, interest was in surface zones of activity, and measurements of the superficial thermal flux that they represented were performed. But in retrospect, it is apparent that the heat flow which could be obtained underground had no correlation with surface manifestations. The fact that at Wairakei the western extension of the site, which seems the most productive, gave rise to no surface indications and that, of all the fields which were prospected with wells, Broadlands, which seems the most promising field, gave surface indications which were much less spectacular than other fields having less promise, led to a great reduction in the importance attached to surface manifestations. At the same time, in Italy the site of Mount Amiata was discovered, which showed surface thermal sources at very low temperatures only. The California sites (the Geysers, where there were no geysers but only a few fumaroles, and the Salton Sea, where there were almost no indications) confirmed the conclusion that there is no strict correlation between

the value of the geothermal site and the superficial indices. Should we, inspired by the ideas of petroleum geologists, go so far as to say that superficial indices show only that the geothermal site is being degraded by losses? This would undoubtedly be going too far, but it is certain that these indices (i.e., mud pots, fumaroles, etc.) must be studied in a regional and not strictly local perspective.

Of course, all the methods of geology will be applied to try to specify the local structure. But these methods are often foiled if it is necessary, for example, to determine the structure at depth of a recent sedimentary basin and the positions of permeable levels and impermeable layers capable of forming covers. Geophysics can furnish some complementary information. Without furnishing a foundation for direct prospecting, it should be observed that the electrical resistivity of a soil which is saturated with water diminishes as the temperature increases. But all these methods only provide an outline. Hydrogeologic knowledge of the area is essential, as much to predict if there exist isolated aquifers which could be locally heated as to analyze surface perturbations, particularly the infiltration of cold water which can lead to disturbances of thermal-gradient measurements. The study of this system implies the listing of all pertinent sources and the examination of water flows (which can infiltrate into the ground or be reinforced by subfluvial sources). The flows will be determined as precisely as possible and obviously all the temperatures will be measured. Of course a systematic geochemical study is required. As we have seen, the silica content directly indicates the maximum temperature reached by the water, and variations of other constituents can draw attention to the relationships between waters of different origins and give some information about these waters.

If a geothermal site exists, it necessarily gives rise to a thermal flux by conduction which should be revealed as an elevated thermal gradient. An essential part of prospecting is trying to determine the gradient.

Unfortunately, when permeable soils which can be infiltrated by water exist at the surface, the aforementioned thermal gradients can be totally perturbed and their measurement will only be valid at a sufficient depth. The prospector should place a high value on the study of the near-surface materials from which one attempts to determine where, and at what depths, it will be possible to measure a representative thermal gradient in a drill hole. In uniform soil, impermeable and saturated with water, wells should be sunk for thermal-gradient measurements to a depth of 30 to 50 m in a grid pattern, established a priori, which will allow the places with the highest values of the gradient to be found. However, with permeable, aerated, upper layers, and where cold surface water seeps in, the results are not necessarily significant; and it is necessary that deeper borings be undertaken to measure the gradient below the perturbed zone.

In such a campaign to measure the temperatures, should we sink several tens of costly drill holes to depths of around 50 m, or should we plan temperature measurements in holes of about 2 m, which can be dug by a laborer in soft soil in less than an hour and lined with plastic tubing? It is certain that for many fields the gradient is such that a significant variation can be seen at the shallower depth. But we should only compare measurements corresponding to the same surface conditions and observe the long-term (annual) temperature variations in several test holes. Obviously these measurements must not be done until a certain waiting period has elapsed. As a precaution and in the absence of unduly marked superficial perturbations, such a campaign, called a preliminary reconnaissance, can be justified. This does not mean that we can dispense with the prospecting phase where temperature gradients are measured at a depth of around 50 m.

When these gradient measurements indicate a hot subterranean region, it is still necessary to consider if the geologic formations allow us to hope to find a permeable layer, suitably supplied with water and possibly protected by a relatively impermeable cover. But these data and what they imply about the existence of a geothermal site can be further specified only after one or several wells have been sunk with the same precautions as for commercial wells (possibly with smaller diameters) and lined with a casing before making any measurements. A reliable thermal profile can only be obtained after a sufficient waiting time, but more hasty measurements can be useful to direct the course of the preliminary reconnaissance.

To what depth should we sink the wells? Field production experience shows that a depth of 500 m is considered normal. At lesser depths, we have only weak geothermal sites. There should be no hesitation to sink deeper drill holes if there is some indication that the temperature is continuing to increase. At the Geysers, deeper wells discovered a more extensive site than one that was exploited earlier at 300 to 400 m. Thus, it seems reasonable to consider the possibility of sinking reconnaissance wells to 1,000 or even 1,500 m. Obviously, there is no set rule.

Once the thermal profile is measured and after a sufficient waiting period, if high temperatures have been found, it is necessary to try to make the well erupt. If this does not occur spontaneously, then it is necessary to cause an eruption by reducing the head of water in the well with a pump, or, even better, with an air lift. As it is not very well known to what extent the cold mud used for drilling has penetrated into the ground, we should wait until the eruption has reached a steady flow before taking production measurements (their purpose was indicated earlier). It would be imprudent to undertake a commercial project before having the results from several wells, of which some will be of the same diameter as the commercial ones, and having let these drill holes flow for a long enough time to assure the permanence of the flow.

Finally, the decision to exploit a geothermal site is not only a technical problem. It also involves economic aspects which we will briefly examine in the next chapter.

CHAPTER SIX

general remarks on the economic management of geothermal energy

6-1 General view

If, in comparison with the operation of a conventional thermal power station, the savings realized by not buying fuel are considered and if we add the savings resulting from the absence of a boiler against the drilling costs and equipping of wells for steam extraction, it appears that geothermal power should be more economical.

But on the other hand, it is necessary to consider the fact that geothermal generator groups are small units with turbines operating at low pressures often dispersed over a rugged terrain, these groups are often distant from rivers which would permit efficient cooling of the condensers, and the construction of cooling towers may be required. Also, prospecting is not guaranteed to succeed, and if an exploitable site is not discovered, the money spent will be lost. These are the unfavorable circumstances which interfere with profitability.

A return price per kilowatt-hour could be calculated[1] for a geothermal plant and for conventional plants taking account of capital investments, amortization at a rate which must be established, and operating costs. But if these items are examined a little closer, it is realized that such a calculation does not have a great deal of significance because of the uncertainty of the various factors and also because the circumstances depend on the economic situation in which the new power station is placed.

[1]For example, see G. Facca and A. Ten Dam, "Geothermal Power Economics," Geothermal Exploration Company, Los Angeles, 1964.

The ideal case would be where the power plant only has to supply a limited number of consumers, such as was the case at Kiabukwa. In such a monopoly situation, it suffices to fix the sales price for the energy in order to amortize the expenditures, cover the operating costs, and realize a certain profit.

6-2 The marginal economic situation

However, the situation is rarely so simple. When a new producer of energy appears, in general there already exists a distribution network which satisfies the requirements of the consumers and it is through this network that the energy supply must pass from the new power station. What should be the price of the energy sold to this distribution network?

In the case of a classical liberal economy which considers separately the costs affected by the decision to buy this new energy, envisaged as marginal, the answer may well not be at all the same as if the problem of energy production in the long run is considered. The distributor will fix the buying price for the geothermal energy which is offered to him by calculating it not with respect to the total cost of the energy produced by the existing power stations, but with reference to the marginal cost (i.e., the savings realized by not producing that power). In the cost of a produced kilowatt-hour, expenditures of different natures occur; certain are proportional to the energy produced (fuel costs) and others are constant in time (security, maintenance). Finally, on the one hand the capital invested in the construction of the power plant must be paid back, while, conversely, capital must be put aside for the day when the power station, becoming antiquated, can no longer operate. But this amortization does not occur only for the power stations which produce the energy for which we seek the price. The demand—daily, weekly, annually—varies strongly from the peak hours when demand is maximum and to base hours when consumption is much lower (the base hours refer to the power which is constantly utilized). Due to existence of peak hours of consumption additional plants must exist to supplement, if only for a few hours per day, the normal energy production. Nonetheless these extra plants must be amortized. Finally, the distributor guarantees the power supply required in spite of possible problems which might occur either due to the consumers or to production problems (breakdowns, repairs); this obliges the distributor to have a certain production capacity in reserve, which is never used except in emergency (or which is operated in rotation) and whose amortization and fixed costs must also be charged to the cost of the energy sold.

For the producer, the difference in value of the energy at peak or base hours may be large enough to justify the construction of regulating works which store energy during base hours (by pumping water into an elevated basin) for use later during peak hours, in spite of the cost of such installations and the inevitable energy losses.

When a geothermal power station offers its produced energy, it appears obvious that no savings are made by not producing energy during base hours. Or more exactly, the saving realized in leaving the nonextracted heat in the ground will only materialize at the end of the operating period by prolonging its duration. This is a nebulous term which is too uncertain for economists to be disposed to take it into account. Thus, the production of the geothermal power station will be utilized to assure the base energy supply, energy to which the producer gives the lowest possible value (the same problem occurs for nuclear power plants).

The distributor will perhaps try to offer only the marginal cost of the base energy on the pretext that his equipment allows him to guarantee the power required. But the geothermal station should figure in the power reserve which is necessary if the distributor is to guarantee service, and the price of the energy which the station produces should reflect this. A large network, facing a constantly increasing demand, must always have supplementary power in reserve so that it has the margin which will permit it to give its guarantee. Thus the existence of a geothermal power station permits the distributor to dispense with the construction of an equivalent power station, and the buying price of the energy should reflect this situation and cover the corresponding amortization over and above the marginal cost savings. But this is less evident for a small network which can estimate that it already has the power necessary to guarantee its supplies. The distributor may not be disposed to consider the time when it will be necessary to add to its present equipment; such a project is delayed, and the distributor can thus avoid, for a time, gathering the financial reserves which will be necessary for these additions.

We are often placed in the situation—very frequent in actual practice—where the producer of geothermal energy is distinct from the distributor through whom the energy must pass. The latter has a quasimonopoly which he may be tempted to abuse. This situation would not be changed if, instead of selling the electrical energy produced by the plant, the geothermal plant operator sold the steam instead. This was the case at the inception of the Geysers' fields. However, since the steam flow is difficult to measure, it was finally agreed to calculate the price according to the electrical energy consumed.

It can also happen that the distributor, anxious to diversify his production sources, will undertake a geothermal energy operation of his own, which would permit a more equitable valuation of the distribution of the return price.

Implicitly, we have assumed a situation such as in Western Europe or the United States, where all the large industrial states have an extensive interconnection and where the energy consumed is very large with respect to the increase of energy made possible by the use of geothermal power. Because of this fact, there is no need to consider the effect of geothermal energy production on the amount of energy consumed.

It is not the same situation in an isolated region, and it is in such conditions that we may hope the production of geothermal energy will have a marked influence on the development of a country. The volume of energy consumption will then strongly depend on the price at which the energy is sold. There are certain needs (domestic lighting, air-conditioning, refrigerators) for which consumers will accept any price that is demanded of them. A second category of consumers will compare this price to the cost of another solution such as producing their own energy with a diesel. Again, it would be necessary to calculate the value of the guarantee resulting from connection to the network, even without a normal call for energy.

Schematically, a third consumer category can be imagined—those industries which have installed their plants to take advantage of the price at which energy is offered to them. This only applies to industries which are large consumers of electricity, such as those that prepare aluminum from the electrolysis of alumina. The localities of certain plants—in Norway or British Columbia—are only justified by the availability of hydroelectric energy at very low prices and in large quantities. It can be said that the long-distance transport of alumina and aluminum is the most economical method of transporting electrical energy beyond the relatively limited distances permitted by interconnecting power networks.

When considering the development of geothermal energy networks in underdeveloped regions with a low consumption rate, it is naturally thought that the presence of the power will attract new industries. But there can be a considerable difference between the power which can be produced on the spot and the energy which must not only be produced but must also be guaranteed for a sufficient time to attract new industries, which require, besides low-cost energy, other resources such as water, a qualified labor force, transportation facilities, etc.

6-3 General remarks

Can the attitude of a traditional liberal economy which considers a decision such as the construction of a geothermal power plant in terms of immediate financial objectives be justified when formulating longer range goals?

The economic basis of our civilization is supplied by nature in the form of energy resources which have been developed by us and distributed in the form of fuel for mobile engines or electrical energy. It is scarcely necessary to recall the successive stages in this energy evolution: domestication of animals; development of windmills, sailing vessels, and water wheels; development of steam engines fueled with coal first for local power production and later integrated into electrical power systems; transformation of water wheels into hydroelectric plants and, at the same time, regulation of energy production for peak-energy demands through the use of dam reservoirs; partial substitution of hydrocarbons for coal first in mobile vehicles (where they have gained a monopoly) and then in fixed power-plant locations; and use of easily distributed natural gas. Most recently, nuclear energy has appeared, which at present—and perhaps for a long time in the future—is confined to large fixed installations which, for technical reasons, have to be used for assuring base-power requirements. Even in the realm of nuclear energy it is necessary to distinguish between "classical" fission-power stations, which have been technologically developed to the point where almost identical installations can be constructed, and the experimental prototypes, such as the breeder reactors, which will use the natural resources of uranium more economically in the long run (this does not mean to say financially more economical in the short run). This says nothing of the hope, perhaps distant and illusory, of a domestication of fusion energy.

Even such a brief survey makes it clear that there is a constant increase in global energy consumption and that the means of producing it must also be in constant evolution. This evolution would be even more striking if we were to enter into the details of production techniques and analyze, for example, the evolution of steam engines from the first piston engines up to high-pressure turbines, constituting more and more powerful units, or those evolutions which led from the internal combustion engine to the jet engine and the gas turbine.

If one of the factors in this technical evolution is the constant problem of increasing the efficiency of production, another factor results from the availability of natural resources to exploit. Coal mines fed the essentials of the industrial revolution of the nineteenth century, but in a country like France, their future seems very limited for two reasons which perhaps have not been sufficiently distinguished: their price is higher than that of imported hydrocarbons and the reserves are depleted. The two factors are interdependent because the reserves can only be estimated if the maximum price that one is prepared to pay for their extraction is fixed.

The problem of reserves and the depletion of resources is particularly acute for hydrocarbons because of the ease and thus rapidity of exploitation once they are discovered. With a doubling every 20 yr in consumption and with reserves which scarcely can last more than 20 yr, prospecting ought to be constantly increasing, although the virgin regions where exploration can be carried out are rapidly decreasing. Prospecting has occurred recently in shallow marine waters. Undoubtedly this exploration will be extended to deeper water, but the time when all these possibilities of extending the areas of exploration are used up is inexorably approaching.

It can be added that oscillation between two extreme political positions can be seen. One of these positions considers that a market economy for a worldwide production of energy will furnish the most economical solution, and the other viewpoint stresses the advantage of dependence on national resources whose availability is not subject to international tensions.

Finally, another consideration appears, the importance of which some people have tended to exaggerate. Certain mineral operations degrade the countryside in which they are carried out. An example is strip mining. In addition, the utilization of sulfur-bearing fuels introduces a gas into the atmosphere which normal respiration can tolerate only in infinitesimal doses, and which now risks reaching excessive concentrations around some industrial centers. Nuclear reactors leave waste products consisting of highly radioactive fission products the existence of which constitutes a permanent menace. It appears necessary to take these pollution factors into account, and that could seriously limit the development of certain energy sources.

In this picture of constant evolution and sometimes somber perspectives, what place can be envisaged for geothermal energy? Its present influence is extremely small, practically limited to a few particular cases. The operation at Larderello (Italy) happened to facilitate the electrification of the railroads, but the percentage of energy which it gives to the Italian energy pool is only 3 or 4 percent. It is the same situation to a much greater degree for the production of the Geysers, which is fed into the Western United States energy grid. In New Zealand, the development of geothermal energy could technically go much farther, but the increase in consumption is not large enough to justify it. New Zealand has abundant hydroelectric resources, chiefly on the South Island. The laying of an underwater cable (600,000-V direct current) in Cook Strait has retarded the development of the next geothermal field (Broadlands) for several years. However, I believe it is necessary to emphasize that this delay has no relation to the economic success of the operations at Wairakei but arose essentially from the structure of the energy market in an isolated region.

Outside of the case of New Zealand, where the geothermal potential is a part of the energy reserves which will be developed as the need arises and will guarantee consumer satisfaction in the future, and perhaps Iceland, where the availability of heat at low temperatures at a cheap price for domestic heating and greenhouses has a significant importance for the country's development, what is the future of geothermal energy?

It is necessary to emphasize one of the reasons why it is difficult to answer this question; we are only at the beginning of geothermal energy production. At first, this development occurred at a few exceptional sites which we are sure exist only in a very few countries, and it is only more recently that geothermal fields having real economic value and which displayed few superficial indications were discovered. It is these latter discoveries (which now exceed 10, although most of them are not yet in full commercial operation) that we should consider as a basis for estimating the future of geothermal energy, and not the first generation of plants constructed on exceptional sites which were evident, such as Larderello and Wairakei.

In addition, the understanding of the phenomena which act in geothermal beds, to which we have devoted Chaps. 4 and 5, is still very imperfect. There remains much to be learned about the way in which a pressure drop can cause vaporization underground and in the way in which the steam can escape, either by means of the permeability of the rock or through a network of fissures. Also the technology utilized for geothermal exploitation seems extremely rudimentary; numerous improvements could be considered, from the enlargement or even the creation, of fissures through which the ground can be drained to the selective exploitation of steam by drill holes. Consideration of the evolution of oil-field technology in one century leads us to imagine what a comparable development could bring to geothermal operations.

If this technological progress is achieved, if an inventory of geothermal resources is actively encouraged and methods of prospecting are developed and perfected, I think that a prudent appraisal of the future of geothermal energy would permit us to say that at least in certain countries (the imprecision of this phrase reflects the prudence which must be imposed) the utilization of geothermal energy will be able to attenuate the energy crisis that the depletion of hydrocarbon reserves could make acute in 20 or 30 yr.

Attenuate, but not mitigate, because different forms of energy cannot be casually substituted for one another. Geothermal energy will be exploited by fixed stations at sites determined by the availability of hot water or steam for the basic purpose of assuring base-power consumption (although a daily regularization by accumulation of steam in subterranean reservoirs is not inconceivable). The role of

these power stations will thus be analogous to atomic power stations, which appear to represent the ultimate response to the energy crisis in the long run. But, it is still probable that the crisis will be especially intense for mobile vehicles, which are almost exclusively dependent on hydrocarbons.

Yet, it seems to me that it would be imprudent to count on nuclear power stations entirely and to renounce the possibilities that geothermal energy offers in certain regions and in particular for isolated regions which cannot claim a priority for the construction of nuclear power plants. But in order to obtain the geothermal energy which ought to be expected, at the moment of need and in economic conditions which could be quite different from those of today, it is necessary between now and then that research be continued, tending on one hand to identify geothermal sites (even if their exploitation must be postponed) and on the other hand to improve the operational technology which will be required.

It is necessary, it seems to me, to specify the aim in this development of technology with care. We can decide to undertake an experimental operation to test the capacity of a geothermal site, and the permanency of its production and to try to bring technological improvements to the methods of exploitation. Energy production in what could be called a pilot plant will result from these efforts. Of course, attempts will be made to sell this energy under the best possible conditions, and that will help defray the total costs of the operation of the pilot plant. Indeed it may entirely support these expenses, even if the amortization of installations and exploration cannot be assured.

If we leave aside the future of the power stations of New Zealand and the Geysers, for which the profitability under present conditions seems already assured, it would seem to me that this perspective of the development of pilot plants, which are technically indispensable if the long-term ability to construct economically profitable power stations is desired, must be kept in mind while making all decisions to undertake the exploitation of a geothermal field.

The first power station at the site of the Geysers, with 14,000 and then 27,000 kW, was in fact nothing more than a pilot plant and would undoubtedly never have allowed the amortization of operations performed prior to its installation. But this represented a necessary experimentation stage before a larger production capacity could be considered.

By definition, the profitability of a pilot plant is not assured in itself. To estimate the economic viability of future developments which it makes possible, even in the long run, it would be necessary to take into account the evolution of the site on which the plant is installed, as well as the value of technological improvements that can be hoped for and that may find applications elsewhere. It is with this perspective, and not that of marginal profitability on the actual energy market, such as was analyzed in this chapter, that all decisions concerning the development of geothermal energy should be made.

6-4 The legal regulation of geothermal energy

Perhaps we should mention here a necessary condition for the development of geothermal energy, although it is certainly not enough in itself. A convenient legal system, inspired by mining law, must be established to assure the explorer the benefits of his discoveries, without making him liable to unreasonable demands from the land owner, and to protect him from competition from other groups who would like to take advantage of his discoveries to operate on the same site. A simple extension of the mining law, differing from one country to another, could in general protect prospectors in these situations. In France, this extension was made for the Antilles and the French territory of the Afars and the Issas, precedents on which an extension of the same concept to the metropolitan territory shall rely—an extension which must occur in the very near future. In fact, such an extension will simplify the legal system while assur-

ing the protection of miners' exploration rights in low-temperature fields (low-temperature fields means less than 100°C). The New Zealand system could provide a model for Anglo-Saxon mining law. In the United States, a law went into effect on December 29, 1970, which defined the conditions under which exploration and exploitation rights could be given for public lands (i.e., the quasi totality of the land surface in the Western United States, where the federal government reserved the mining rights for itself when other land rights were (if they were) given to others). Although the interest in geothermal energy operations that arose following the success of the Geysers fields could not be manifested until this law, geothermal energy enterprises, some with shaky foundations, arose and suddenly flourished and much interest was manifested on the part of private industry and by diverse public organizations in geothermal energy operations.

The legal system instituted for the Western United States has three variations, subject to more and more rigorous conditions of competition, depending on whether the regions considered correspond to zones where the presence of geothermal sites is considered as "possible" or "probable." However, the U.S. Geological Survey had to make this classification in a very brief time for a considerable area of land, over 2 million km². No prospecting was possible in the limited time available, and the classifications which were given rest on some very tenuous presumptions. Possible serious misunderstandings can occur if the word "probable," which only designates a certain procedure of distributing licenses, is confused with the sense of that word when referring to mineral reserves.

6-5 The role of the public sector

The case of a new source of energy, which appears likely to become economically competitive at the end of a more or less prolonged period of development, is not new, and it is interesting to analyze some examples of how such developments were financed. From Denis Papin to Fulton, the development of the steam engine and its applications was in the main left to isolated inventors who tried to convince capitalists with a sense of the future to help them. With multiple episodes, sometimes with heartbreaking checks and delays, this system functioned better than worse, although it is evident today that it is outmoded. We could also point out the birth of the internal combustion engine, whose inventor was not financially rewarded, as his actual success would have justified. (In fact, he was not rewarded at all.) A majority of other developments, for example, the steam engine and the appearance of the turbine, were done progressively and were financed as work continued by constructors, thanks to immediately realizable increases in efficiency.

The jet engine of aviation required enormous expenditures on research, experimentation, and development; it was entirely supported by the military, i.e., by the public sector, and it matters little to us whether the justifications for these expenses were economic or strategic.

Since its beginning, nuclear energy also benefited from military-oriented financing. It was clear in 1945 both that there was a possibility of nuclear energy production and that it would only become economically competitive at the end of a long development process. This development was supported by the public sector, but not without the intervention of strictly military considerations at different stages. Recall the progress of this development from low-power pilot plants to powerful reactors which were not economically competitive until the present time. Today the extrapolation of economic conditions over a period of 20 yr for different possible energy sources amply justifies the construction of nuclear power plants.

One also knows of the efforts devoted to the breeder reactor, which no military considerations now justify. It is not even certain in the immediate future that these devices will be economically competitive with the slow neutron reactors already in use. But its best justification is in the long-range savings of uranium, the known supplies of which today are minimal with respect to future needs. The interest in the breeder reactor in one of the rare examples of a case in which an actual decision is affected by considerations of foreseeable conditions 30 to 50 yr in the future.

This brief review was designed to show that the actual development of a new source of energy cannot be left to private financing alone. Funds to develop new ideas, or for improving installations which are already economically justified, are unlikely to be adequate. It is apparent that such development is a political problem.

In what countries will this development take place? Should the progress already realized in more advanced countries (which in our case includes New Zealand, Italy, and the U.S.A.) be utilized in other countries by acquiring licenses or employing foreigners who are experienced in geothermal energy equipment and production? For countries of moderate industrial importance such as France, such solutions were not considered for the jet engine or for nuclear energy. Obviously, military considerations influenced these decisions, but in retrospect it appears that independent development was a necessary condition for the ability to participate afterward in information exchanges and the international cooperation which results from such exchanges.

Even though absolutely no military considerations are relevant to the case of geothermal power, the influential countries whose territories offer some possibilities in this realm are undoubtedly interested in financially encouraging its technological development, from adaptations and improvements realized in other fields, to assure the best utilization of their natural resources.

6-6 The immediate effects of the increased price of energy

The large increase in fuel costs, which must be interpreted as the end of a transitory era of cheap imported fuel, led to a reexamination of the overall energy market. In Western industrialized nations this market is divided into three approximately equal divisions corresponding to transportation, industry, and heating.

For this last item, the fuel (oil, gas, coal, or even electric heating energy) produces calories that are utilized at a temperature only slightly exceeding the ambient. If geothermal heat were directly employed, it could easily substitute for these other resources calorie for calorie. Thus, for geothermal energy at low temperatures (which may be much more available than is currently contemplated) there is a very important future.

However, there still exists a technological problem: our habits in the matter of heating rest on the ease of heat transfer with large temperature differences. Without considering the use of fireplaces, central heating consists of a boiler, the surface area of which can be quite small thanks to the high temperature of a flame, and radiators at a temperature of perhaps 90°C to heat a room to 22°C.

The utilization of geothermal energy requires more efficient heat exchangers with only slight temperature differences. There is first the exchange between the extracted groundwater (which must generally be reinjected, if not to reduce pollution, to maintain pressure in the geothermal bed) and the water of the heating circuit, and afterward between the heating circuit and the area to be heated. Heating elements in the floor, which can be used at 30°C, are one possible solution, but there are certainly other ways to improve the heat exchange between radiators and the surrounding air.

From now on, in areas of known deep subterranean aquifers, new housing could and should be constructed to utilize geothermal energy as the heating source. The renovation of older housing poses a more delicate problem. It is probable that boilers will be retained for exceptionally cold periods. We could also imagine a combination of heat pumps with geothermal heat which may be justified by the fact that it is sometimes costly and difficult to find an adequate cold source for conventional heat pumps. Subterranean geothermal waters, even at only a slightly elevated temperature, constitute such a cold source and allow heat

pumps to supply conventional radiators at the necessary temperature.

Thus, the problem is to reconsider heating installations and to disseminate new innovations. Aquifers should also be sought, which means recognizing permeable areas in sedimentary basins. In France, we could cite the sands of Lussagnet in the south of Aquitaine, the sandstone of the Trias in the north of Rhine graben, and the base of the Oligocene strata in the north of the area around Limagne. Obviously, this list is not comprehensive. Undoubtedly, other countries offer similar opportunities.

By such efforts, even though we cannot solve the energy crisis, we can save several million tons of fuel per year in the next few years. This prospect amply justifies the necessary efforts.

CHAPTER SEVEN

thermal aspects of some geological phenomena

It will not be possible here, even in a quick review, to explain volcanic activity, tectonic deformations, which imply a dissipation of energy which is essentially transformed into heat, or metamorphism, the fundamental cause of which appears to be an elevation in temperature. But in the study of such problems, properly thermal questions are incidentally encountered, and it seems useful to indicate some solutions.

7-1 Volcanic eruption mechanisms

Volcanism implies, in the first place, openings in the rocks of the crust through which products at high temperature rise and flow out at the surface or sometimes infiltrate along fissures and joints in the ground. These products are essentially composed of a molten silicate magma which, upon solidification, yields a lava but can also contain an appreciable number of volatile substances in solution (water, CO_2, SO_2 or H_2S, etc.). These gases are sometimes released in abundance, but we cannot say whether they existed in a free state or only dissolved in a magma underground. One feature of volcanism is its extreme irregularity in time, whether on the scale of an hour, day, year, or century.

The first question to ask concerning volcanism concerns the piercing of the crust by molten lava, generally very viscous, which rises in a fissure or moves horizontally along a bedding plane to form a sill or laccolith. A hydrostatic interpretation, taking into account the differences in

density between molten lava which is lighter than the rocks of the lower crust and this same solid lava and the lighter sedimentary rocks, often permits us to clearly visualize the distribution of such injections. But this does not indicate the piercing mechanism, which requires a considerable excess of pressure to break the rocks in the vicinity of the injection. Now these molten lavas are very viscous, which means that when they advance there is a substantial pressure difference between the leading and rear portions, and it is difficult to understand how the increase of pressure, which is capable of breaking the surrounding rocks, is produced. The solution of this paradox is undoubtedly thermal. At a given stage of the injection, heating of the surrounding rocks vaporizes the water which these rocks contain. The steam reaches a pressure in excess of the pressure which is acting on the rocks and consequently shatters them. The steam then escapes through the fissures thus formed and condenses on contact with cooler rocks thereby reducing the pressure in the pocket which the steam has opened, and the viscous lava can progressively occupy this space. The same cycle then repeats itself. When a high vapor pressure persists at the leading edge, the lava cannot advance, but it is too viscous to be pushed back.

7-2 Cooling of a volcanic injection

Geologists often pose the questions of the time necessary for the cooling of such an injection (or flow) and the temperature attained by the surrounding rocks at some distance. These questions would be easy to answer if the thermal characteristics of the lava and the surrounding rock were exactly known. This is not the case because the thermal conductivity can change with the temperature, generally slightly decreasing while the heat capacity increases, often by 50 percent at 400°C. Since we do not know the details of these variations, we must be content to use average values which are more or less happily chosen. The results of these calculations, which we will indicate, will only have the precision of the given values, but in any case we will obtain valid orders of magnitude and a description of the general behavior of the phenomena.

The thermal perturbations are imposed on a prior thermal system composed of a steady thermal gradient in equilibrium with the geothermal flux. It is this prior temperature distribution which must be taken as zero. Thus, the temperature of the injected lava will be calculated as an addition to the initial temperature of the rocks, and the calculation of the heating of surrounding rocks will also be taken from this temperature. It is clear that the thermal perturbation must satisfy the heat equation.

The heat carried by a molten lava, which will diffuse in the surrounding rocks as the cooling occurs, is partly heat corresponding to the specific heat of the lava and partly the latent heat of crystallization which, for a pure material, is released at a constant temperature during solidification. But we do not know if the injected lava was already carrying crystals, and we are also not sure that the last phase of crystallization occurs at a constant temperature. We will indicate the principle of the rigorous calculation including the latent heat. However, this calculation sometimes raises certain difficulties, and it is often more convenient to neglect the latent heat. To compensate we may slightly increase the temperature attributed to the injection, and consider its cooling with a constant specific heat.

It remains to take account of the way in which the injection occurs. A dike can be emplaced in several distinct ways. It can be made all at once by the injection of basalt in a fissure which opens rapidly. Or it can be made progressively, with new basalt being injected between two older layers of basalt which are plastered against the fissure walls. The old basalt is cooled at its contacts with the country rock, while it is heated by the new basalt toward the axis of the dike. But it is rare that an examination of a dike allows us to choose between these two interpretations. Even if we accept the second, the total injection time remains unknown. It may have been brief with respect to the cooling period.

If we wish to take latent heat into account, we will consider the wall of a dike brought, at the moment $t = 0$, from an initial temperature θ_0 to the molten lava temperature θ_1 and remaining at this temperature until all the latent heat is dissipated. If the thickness of the lava dike is $2e$ cm, the latent heat L cal/g, and ϖ the specific gravity, the heat which must be dissipated before the lava is entirely consolidated is $e\varpi L$ cal/cm². We have seen that the temperature at distance x from the wall will be given by

$$\theta = \theta_0 + (\theta_1 - \theta_0)\,\mathrm{erfc}\left(\frac{x}{2\sqrt{\alpha t}}\right)$$

The heat flux at the wall is given by $K(\theta_1 - \theta_0)/\sqrt{\pi\alpha t}$, and its value integrated in time from the origin is $2K(\theta_1 - \theta_0)\sqrt{t/\pi\alpha}$. These equations lead to the total time for the solidification of a lava dike:

$$t = \frac{\pi\alpha e^2\varpi^2L^2}{K^2(\theta_1 - \theta_0)^2} \tag{7-1}$$

Observe that this time is proportional to the square of the thickness.

We have implicitly assumed that the temperature in the dike was uniform and that the heat exchanges took place easily enough so that the latent heat was dissipated from the dike surface. This would be reasonable if the lava remained liquid until solidification. But it cannot be the same case if the lava is almost solid, and thus the latent heat must be dissipated by conduction. In this case, there would be a progressive solidification from the walls with a thinning of the central fluid core, and the displacement of the solidification boundary x_L would be tied to the gradient in its neighboring solidified side by

$$\varpi L\,\frac{dx_L}{dt} = K\,\frac{\partial\theta}{\partial x} \tag{7-2}$$

Hence, it is evident that the progression of the solidification does not depend at all on the thickness of the dike and the central portion that remains fluid but only on the distance from the wall where the cooling occurs.

We can easily find the temperature law applicable to the surrounding rock and the solidified part of the dike, the temperature θ_1 remaining constant in the remaining liquid portion.

This temperature law is identical to the law which would result from the cooling of a dike, supposed initially at a higher fictive temperature θ_2, but without taking the latent heat into account. In fact, in this case, the temperature on the x axis is given by

$$\theta = \theta_0 + \tfrac{1}{2}(\theta_2 - \theta_0)\left[1 + \operatorname{erf}\left(\frac{x}{\sqrt{4at}}\right)\right] \tag{7-3}$$

Let λ be the value of $x_L/\sqrt{4at}$ for which $\theta = \theta_1$. We find for the corresponding value of x_L:

$$\frac{dx_L}{dt} = -\lambda\sqrt{a/t} \qquad \text{and} \qquad \frac{\partial\theta}{\partial x} = \frac{(\theta_2+\theta_0)e^{-\lambda^2}}{\sqrt{4\pi at}}$$

In order for these values to satisfy the boundary conditions, it suffices that

$$\frac{\varpi L}{C} = \frac{(\theta_1 - \theta_0)e^{-\lambda^2}}{\sqrt{\pi}\lambda[1 + \operatorname{erf}(\lambda)]} \tag{7-4}$$

From this equation we can obtain the value of λ, with the help of Fig. 7-1, and from that we obtain

$$\theta_2 - \theta_0 = \frac{\varpi L}{C}\sqrt{\pi}\lambda e^{-\lambda^2}[1 + \operatorname{erf}(\lambda)] \tag{7-5}$$

This expression can be shown to always be less than $\varpi L/C$.

These formulas describe the temperature evolution until the end of solidification of the fluid core, but not afterward since we must then take account of the cooling through both faces of the dike. The consolidation time of a lava dike of thickness $2e$ cm is given in seconds by

$$t = \frac{e^2}{4a\lambda^2} \tag{7-6}$$

For example, Fig. 7-2, with reasonable values $L = 75$, $\varpi L = 200$, $C = 0.5$, $\theta_1 - \theta_0 = 800$°C, we find that $\lambda = 0.551$, $\theta_2 - \theta_0 = 1027$°C, and $t = 82.7e^2$. For $2e = 2$ m, t is about 10

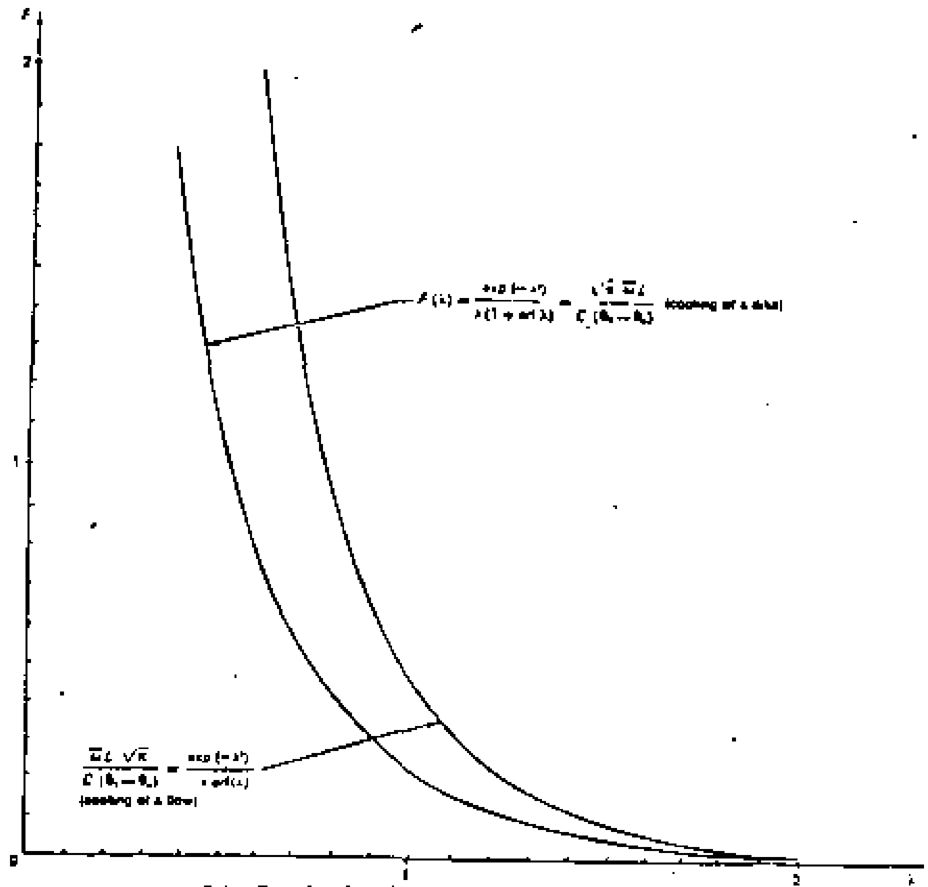


FIGURE 7-1 Graphs for the calculation of λ for studying the cooling of a lava dike or flow, including the latent heat of solidification.

days and until then, the temperature at the boundary of the dike stays at $\theta_0 + 513$°C.

Let us now imagine the case of a dike at an initial temperature θ_1 without any latent heat to be dissipated and with a thickness $2e$. We immediately find, x being the abscissa taken from the middle of the dike, that

$$\theta = \theta_0 + \tfrac{1}{2}(\theta_1 - \theta_0)\left[\operatorname{erf}\left(\frac{x+e}{\sqrt{4at}}\right) - \operatorname{erf}\left(\frac{x-e}{\sqrt{4at}}\right)\right] \tag{7-7}$$

This formula is general if we agree to the convention that $\operatorname{erf}(-\lambda) = -\operatorname{erf}(\lambda)$.

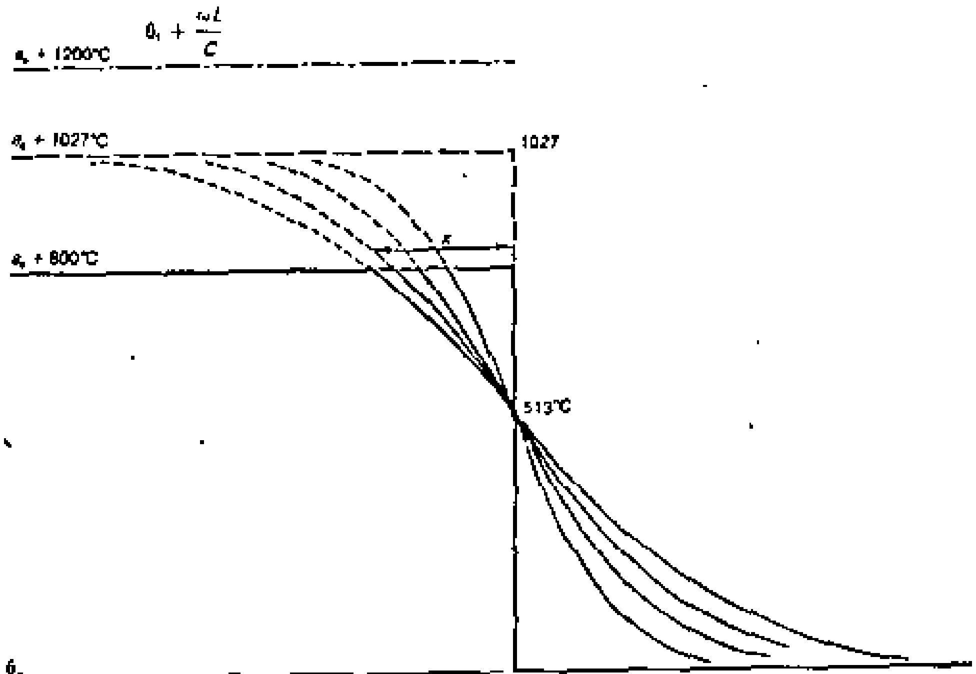


FIGURE 7-2 Successive thermal profiles for the cooling of a face of a lava dike, including the latent heat of crystallization for $\lambda = 0.551$ ($\theta_1 = \theta_0 + 800°C$, $L = 75$ cal/g, $\omega L = 200$, $C = 0.5$) for times proportional to 1, 2, 3, and 4.

We can also ask the question of when the maximum temperature is reached at a point on the abscissa $x > e$. We easily find that for this case it is necessary that

$$\frac{(x+e)^2}{4\alpha t}\, e^{-(x+e)^2/4\alpha t} = \frac{(x-e)^2}{4\alpha t}\, e^{-(x-e)^2/4\alpha t}$$

Letting $m = (x^2 - e^2)/4\alpha t$, $\beta = (x+e)/(x-e)$, this equation becomes $m = 2\beta \ln \beta/(\beta^2 - 1)$ which then gives $t = ex/\alpha \ln [(x+e)/(x-e)]$ and

$$\theta_m = \theta_0 + \tfrac{1}{2}(\theta_1 - \theta_0)\Big(\operatorname{erf}\left\{(x+e)^2\,\frac{\ln[(x+e)/(x-e)]}{2ex}\right\} - \operatorname{erf}\left\{(x-e)^2\,\frac{\ln[(x+e)/(x-e)]}{2ex}\right\}\Big) \qquad (7\text{-}8)$$

Observe that for a given value of λ, this time increases as the square of the thickness. Equation (7-8) gives us the maximum temperature attained as a function of distance.

If the consolidation of the dike brings the latent heat of crystallization into effect, as previously, we can try to take this into account by adding a fictive temperature to the lava's initial temperature. But in the study of the temperature behavior of the surrounding rocks what is important is the total liberated heat, and that leads us to take an additional fictive temperature such that $(\theta_1 - \theta_i)C = L\varpi$. This is always greater than the earlier fictive temperature which we found, but is of an order of magnitude which is not too different.

The difference between the results which follow from the two types of calculations at the exterior of the dike is undoubtedly less than the effects of surface irregularities of the structure which we did not consider. As a case in point, for the previous example, ($L\varpi/C = 400$, $\theta_1 - \theta_0 = 800°C$), the temperature at the end of consolidation gives a wall temperature of 530°C instead of 513°C, and at the center of the dike, a temperature of 665°C instead of 800°C. However, it is at the center of the dike that the discrepancy between the two calculations is maximal. These results are independent of the thickness. But at the center of the dike, we can actually expect that the molten matter remains in irregular pockets, and not in a band the thickness of which remains constant.

7-3 Cooling of a neck

The conditions for the cooling of a neck, an intrusive cylindrical formation, results immediately from Eq. (1-2). The temperature distribution $\theta = (1/4\pi\alpha t)e^{-(x^2+y^2)/4\alpha t}$ satisfies the heat equation in two dimensions and reduces, for $t = 0$, to a zero temperature everywhere except at the origin with

$$\iint \theta\, dx\, dy = 1$$

We will take a neck temperature θ_1 at the initial in-

stant, which can possibly take the latent heat of crystallization into account as previously.

At a point X, Y the temperature at a time t will be given by

$$\theta = (1/4\pi\alpha t)(\theta_1 - \theta_0) \iint_S \exp \frac{-[(X-x)^2 + (Y-y)^2]}{4\alpha t}\, dx\, dy \tag{7-9}$$

This integral is extended over the cross section S of the neck in the plane Oxy. This formula does not suppose that the neck has the shape of a cylinder of revolution. However, in this case the integration cannot be carried out in closed form and must be done numerically. It presents no particular problems.

7-4 Cooling of a lava flow

Observation shows that the surface of a lava flow sets very quickly, and since lava is a poor thermal conductor, the surface is approximately at ambient temperature, which we will take as 0°C.

As long as part of the lava remains fluid, with a latent heat of solidification L cal/g, the cooling of the base continues as we have calculated for a dike. For the surface, the formulas must be slightly modified to account for the condition $\theta = 0$ for $x = 0$. The equations then become

$$\theta = \theta_2 \operatorname{erf}\left(\frac{x}{\sqrt{4\alpha t}}\right) \qquad \theta_1 = \theta_2 \operatorname{erf}(\lambda)$$

and

$$\frac{\varpi L}{C} = \frac{\theta_1 e^{-\lambda^2}}{\sqrt{\pi}\lambda \operatorname{erf}(\lambda)} \tag{7-10}$$

(see Fig. 7-1). We will calculate λ by Eq. (7-10), then for θ as a function of x and t,

$$\theta_2 = (\varpi L/C)\sqrt{\pi}\lambda e^{\lambda^2} \tag{7-11}$$

When the solidification from the base and the top, which progresses at different speeds, meets at a point whose position as a function of θ_1 and L can be calculated, these formulas will no longer be applicable, and we will consider as previously for the dike, an initial fictive temperature $\theta_2 = \theta_1 + \varpi L/C$, to study further cooling. To satisfy the condition $\theta = 0$ for $x = 0$, we will introduce an antisymmetric initial fictive profile with a temperature $-\theta_2$ for $-e < x < 0$. Then the temperature is given by

$$\theta = \tfrac{1}{2}\theta_2\left[2 \operatorname{erf}\left(\frac{x}{\sqrt{4\alpha t}}\right) - \operatorname{erf}\left(\frac{x-e}{\sqrt{4\alpha t}}\right) - \operatorname{erf}\left(\frac{x+e}{\sqrt{4\alpha t}}\right)\right] \tag{7-12}$$

In the immediate vicinity of a lava flow, the temperatures attained will be practically the same as for a dike. But at a distance greater than its thickness, the temperatures are much lower. The calculation for the maximum temperature attained would be a little more complicated, but could be done according to the same principle.

7-5 Mechanical stresses of thermal origin

We have just seen how it is possible to calculate the temperature evolution at a point situated in the vicinity of a lava flow or dike. The unequal distribution of temperatures at a given moment leads to thermal dilatations which are not compatible with the preexisting mechanical stresses and which will consist of an increase in the pressure parallel to a dike or a flow or tangentially around a neck (but then, there would also be an increase in the radial pressure).

During a relatively long heating period, it can happen that there is a certain creep which reduces these stresses and tends to establish a hydrostatic distribution. During subsequent cooling, relative tensions will appear parallel to the walls of a dike or tangentially around a neck. It would also be necessary to account for stresses outside of the dike.

The results depend too much on the assumed hypotheses—as much on the initial stresses as on their relaxation during the heating phase. These hypotheses are necessarily gratuitous so that it does not seem useful to present an example of such a calculation here. Nevertheless, such stresses may play a part in the development of columnar jointing.

7-6 Cooling of a batholith

Until now, we have considered dikes or injected bodies, which are relatively thin with respect to their extension, a fact which allowed us to neglect the influence of the earth's surface. On the other hand, the resulting formulas show that the cooling time increases as the square of the thickness. This leads us to seek the cooling conditions for a granitic batholith, which can be very large, and which is emplaced underground under conditions which are still poorly understood. It is interesting to try to specify the order of magnitude of the cooling time, and, to that end, we will consider a schematic model with the top of the batholith at a depth h with an indefinite thickness. This batholith will be quickly brought up to a temperature θ_1, greater than the temperature which would normally occur at the depth h. We will not include any heat of crystallization. The condition $\theta = 0$ at the surface, for $x = 0$, is satisfied by considering a negative temperature profile, antisymmetric with respect to the surface. It is immediately found that

$$\theta = \tfrac{1}{2}\theta_1\left[\mathrm{erf}\left(\frac{h+x}{\sqrt{4\alpha t}}\right) - \mathrm{erf}\left(\frac{h-x}{\sqrt{4\alpha t}}\right)\right] \tag{7-13}$$

The gradient at the surface is given by

$$\left(\frac{\partial\theta}{\partial x}\right)_s = \frac{2\theta_1}{\sqrt{4\pi\alpha t}}\exp\frac{-h^2}{\sqrt{4\alpha t}}$$

It is easily verified that the gradient passes through a maximum for $t = h^2/4\alpha$. This maximum has a value $0.482\,\theta_1/h$, and if the time is expressed in years and h in kilometers, then Eq. (7-13) yields $t_{\text{years}} = 63{,}500h^2$ km. Thus, if the depth $h = 5$ km, $t = 1.6 \times 10^6$ yr (see Fig. 7-3).

Before the gradient reaches its maximum value at the

surface, it has higher values underground and it can happen that the temperature is high enough so that convection comes into play with rising steam (analyzed in Chap. 4). It is equally possible that water released by the crystallization of granite (which was formerly in solution in the silicate magma) is added to this steam. But the heat transport by water which escapes the magma is only a small portion of the heat which is liberated by the magma's crystallization and cooling. The major portion must escape by conduction or secondary convection.

The total heat dissipated at the surface can be calculated, per square centimeter, by integrating the flux $Q = K\int \partial\theta/\partial x\, dt$, and it is found to be

$$Q = Ch\theta_1\left[\frac{\sqrt{4\alpha t}}{h\sqrt{\pi}}e^{-h^2/4\alpha t} - \mathrm{erfc}\left(\frac{h}{\sqrt{4\alpha t}}\right)\right]$$

$$= Ch\theta_1\frac{\phi(z)}{z\sqrt{\pi}} \tag{7-14}$$

where $z = h/\sqrt{4\alpha t}$. At the time $t = h^2/4\alpha$ (maximum flux), the total heat released is $0.165Ch\theta_1$. This is the total heat contained in a slab of granite with a thickness one-sixth of its depth. Of course, the cooling will continue afterward, but it will come from lower and lower levels in the granite, and because of that will slow down.

Figure 7-3 indicates the temperature profiles at various times and can be used for any values of h and θ_1.

These results allow us to estimate under what conditions the emplacement of a granitic batholith (at a depth of several thousand meters) could perhaps give rise to a geothermal site, according to the hypothesis proposed for Larderello.

7-7 Phreatic explosions

Sometimes volcanic eruptions are confused with explosions in which the ejected materials are exclusively preex-

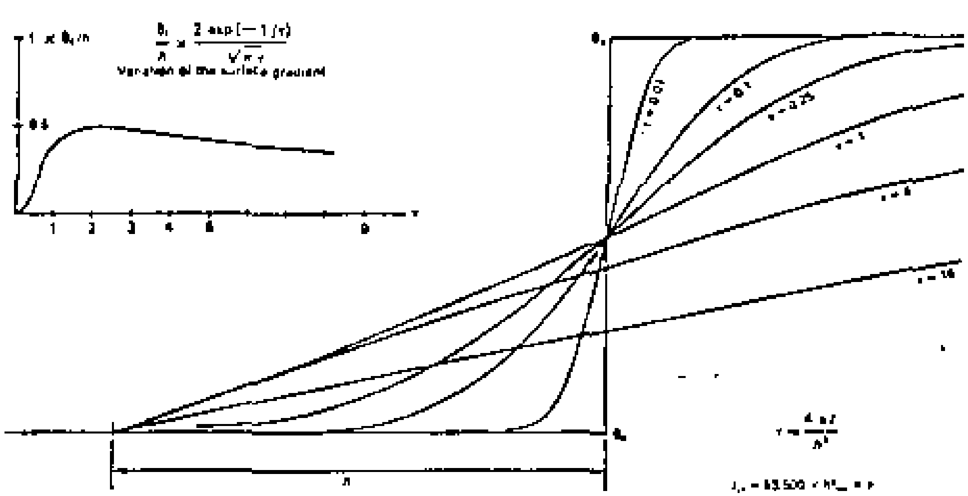


FIGURE 7-3 Thermal profiles for the cooling of a granitic batholith of infinite height; account is taken of the prior normal gradient and variations of the surface gradient.

isting rocks, without any lava, remaining at relatively low temperatures and sometimes damp. Such explosions, called phreatic, result from vaporization of water which impregnates porous rocks and becomes heated to a temperature greater than 100°C underground. In the expansion to atmospheric pressure, the water partly vaporizes while cooling, but the rocky matrix reheats this water, and if the water, steam, and rock remain intimately associated, which is plausible if it is a case of a massive pulverization, the ultimate result at atmospheric pressure can be either a suspension of rock in dry steam at a temperature greater than 100°C or a mixture of water and saturated steam in a proportion x, with the pulverized rock, at a temperature of 100°C. If ϖ is the porosity (water mass per unit volume), 2.7 the specific gravity of the rock, and C, the heat capacity, is 0.5 cal/°C · cm³, then the final state after expansion and the mechanical work available in that expansion can be calculated[1] as a function of the initial temperature θ and the porosity, the deduction being made from the amount of mechanical work which is absorbed by atmospheric pres-

[1]Jean Goguel, "Le régime thermique de l'eau souterraine," *Ann. Mines*, Paris, X, p. 24, 1953.

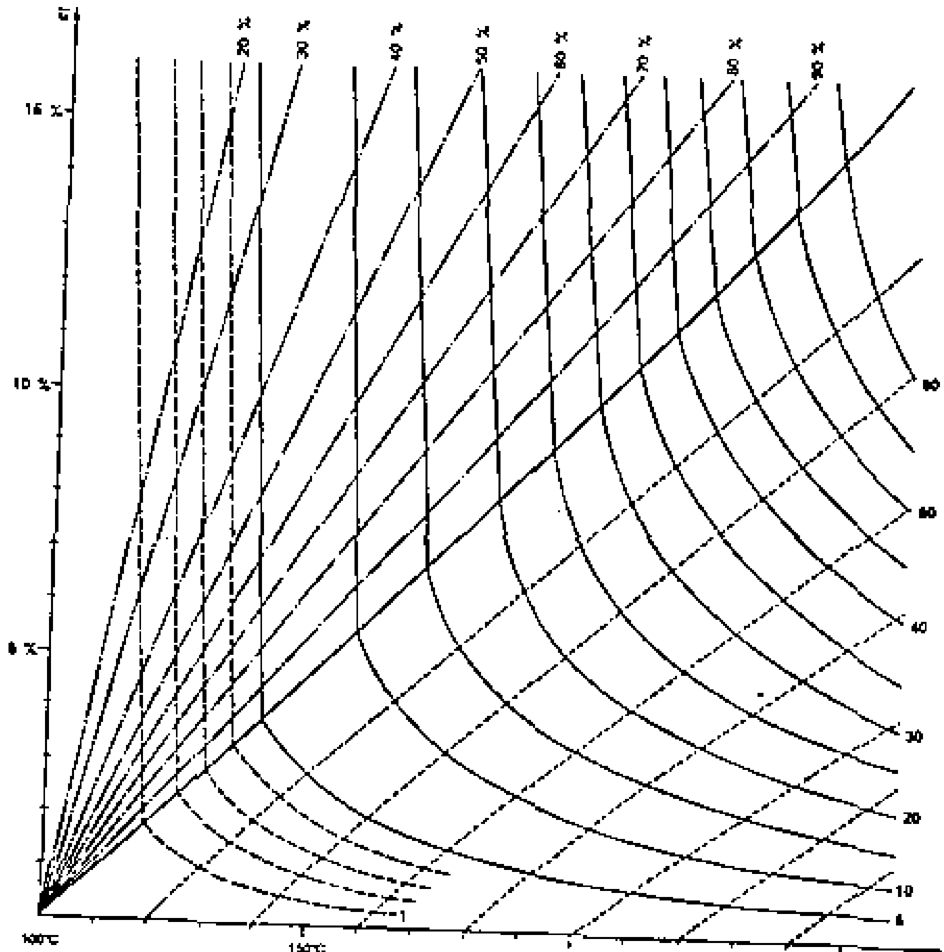


FIGURE 7-4 Graph giving the work available in an adiabatic expansion of a humid soil up to atmospheric pressures as a function of the porosity and the temperature (in joules per cubic centimeter).

sure. Figure 7-4 indicates the value of that energy in joules per cubic centimeter. It is easy to see that the temperature distributions whose origins we analyzed in Chap. 4 under the influence of phreatic pressure represent a considerable potential energy in such an expansion. The explosion could be initiated by the opening of a fissure (possibly by a drill hole) which would accidentally cause an eruption and thus empty the water column which maintained pressure on the fissure walls. The same energy release can be produced by a depression of the phreatic layer which allows water to descend to contact with hotter rocks or by a lowering of the water pressure at constant temperature, which can also cause its vaporization. It is hardly possible to predict how the conclusion of this explosion will occur, since it must propagate in the walls of a funnel-shaped region while material is being released by the expansion. In any event, this explosion is not instantaneous since it implies the transport of heat by conduction from the centers of the rock grains to their surfaces.

Some historical examples of phreatic explosions are known, such as the explosion at Bandai-San, Japan, on July 15, 1888, or Usu-San, on the island of Hokkaido, in July 1944, and of Taal in the Philippines. Numerous craters (some filled with lakes) are found in New Zealand, which have been established to have resulted from phreatic explosions only a few centuries ago.

7-8 Heat produced by tectonic deformations

Heat is not the only form of internal energy. Geology has established that rocks have sometimes been profoundly deformed and folded by forces originating internally. Although these deformations are often very gradual, earthquakes can be imagined as being of analogous origin. Part of the earthquake energy propagates through the earth's crust in the form of seismic waves. Internal energy also manifests itself in upheavals which create relief, which erosion then modifies and finally destroys. These upheavals sometimes appear to us as a simple reestablishment of isostatic equilibrium. But in order for this equilibrium to have been destroyed, it would be necessary for subterranean density variations to be produced which absorbed mechanical work which was ultimately expressed in the surface upheaval. We will examine in the next chapter the manner in which we can interpret the mechanical energy thus released. Here, we will limit ourselves to evaluating the heat production which can result from such mechanical phenomena.

When a solid body such as a rock suffers a permanent deformation under the action of a stress to which it is subjected, the mechanical energy expended per unit volume is given by $\Sigma\sigma_{ij}\epsilon_{ij}$, where σ_{ij} represents a component of the stress tensor and ϵ_{ij} a component of the strain tensor. The best approximation that can be given for the law through which the deformation is produced is to suppose that the deformation occurs at a constant volume ($\Sigma\epsilon_{ii} = 0$) and that it is produced at the moment when the second invariant of the stress deviator reaches a limit S (which can be a function of the average pressure $\frac{1}{3}\Sigma\epsilon_{ii}$, but which is often treated as a constant). Let $S = D$ and $6D^2 = 2\Sigma\sigma_{ii}^2 - 2\Sigma\sigma_{ii}\sigma_{jj} + \Sigma\sigma_{ij}^2$, and let the components of the deformation be proportional to the components of the stress deviator. Then, it can be demonstrated that the work absorbed is given by $2S\sqrt{\Sigma\epsilon_{ij}^2 - \Sigma\epsilon_{ii}\epsilon_{jj}}$. For the most part, this work is transformed into heat. Only a small portion is found in the forms of defects or crystal dislocations.

The expression under the radical only depends on the geometrical deformation and in many cases its value can be estimated for a finite deformation, knowing the initial and final states and supposing that the passage from one state to the other occurs in the simplest fashion. For example, for a homogenous crushing which changes the height from h_1 to h_2, the energy absorbed per unit volume at constant thickness is $2S \ln (h_1/h_2)$, and $S\sqrt{3} \ln (h_1/h_2)$ if the crushing obeys rotational symmetry.

The study of tectonic deformations permits us to directly estimate the amplitude of the geometric deformation, which in a folded mountain range, such as the Jura (France-Switzerland), is on the average much less than one and generally only a few percent at most. If we knew the values for the threshold of plasticity, we could thus calculate the energy absorbed and almost completely transformed into heat. But it seems that there exist very slow deformation processes, by dissolution and recrystallization of matter, which play an essential role in geological deformations and which cannot be reproduced in the laboratory where rapid deformations are produced by totally different processes. It is clear that the strengths measured in the laboratory correspond to higher threshold values S than occur with slow geological deformations; we do not know in what ratio, but we know that laboratory experiments for threshold values furnish an upper limit for energy dissipation. If we assume that the compressive strength measured in the laboratory for the Jura mountains reaches a value of 1,000 bars (which is an overestimate for many of them), then $C = 1/\sqrt{3} \times 1{,}000$ bars. For a deformation of 1 percent, the absorbed energy is equivalent to 0.225 cal/cm^3, which raises the temperature 0.45°C.

Sometimes it happens that certain geological beds are much more deformed than others, for example, contacts along which the competent strata slide in the course of the folding. But if the folds are produced in this manner, it is because it would absorb less energy than a homogenous crushing affecting all the strata equally. The calculation of absorbed energy taking into account the entire deformation will thus give us a value that is too high. As folding is certainly a slow deformation, the heat released along certain strata can diffuse, and we can conclude that the temperature rise resulting from a folding such as that of the Jura or sub-Alpine ranges is at most a few degrees and probably much less. There can be zones where the general average deformation is much higher, but the temperature rise, even if it reaches one or several tens of degrees in places, is certainly much too low to be able to explain the metamorphism which is often associated with strongly deformed zones. The inverse relation can also be suggested, and it may be said that when the temperature is raised sufficiently so that new minerals are formed, or older minerals recrystallize, this recrystallization allows a slow rock deformation, even under the action of quite weak differential stresses, which could allow a large-amplitude deformation with only a moderate expenditure of energy.

7-9 Heat produced by faults

This situation is different only in the case of faults whose displacement can have a finite amplitude in a very short time, particularly at the time of earthquakes. The heat dissipated by friction along the surface only diffuses over a small distance and the temperature can increase appreciably. This phenomenon is much more important than in the preceding section, as this temperature rise can modify the frictional conditions and allow a much easier movement. Of course, it is only necessary to take into account the effective pressure, which is transmitted by the solid and which is less than the total pressure by the amount of the pressure of the fluid which saturates the rock. In certain cases, the fact that this fluid pressure is high can reduce the friction and facilitate the movement. Let p be the normal component of the pressure, f the coefficient of friction during the movement, which we will consider as constant, and v the speed of the movement. The power dissipated by friction per unit surface is pfv, and its equivalent heat q is dissipated on the two sides of the fault. The temperature distribution at a time t after the beginning of the movement (x being the distance to the fault) is given by

$$\theta = \frac{q}{C}\int_0^t \frac{1}{\sqrt{4\pi a t}}\, e^{-x^2/4at}\, dt = \frac{qx}{2\sqrt{\pi a}C}\, \Phi\, \frac{x}{\sqrt{4at}} \qquad (7\text{-}15)$$

In the plane of the fault, this reduces to $\theta = (q/C)\sqrt{t/\pi a}$. It is easy to see how quickly this temperature increase occurs. Suppose that $p = 100$ bars (i.e., the hydrostatic pressure at 400 m), $f = \frac{1}{3}$, and the fault velocity is v cm/s. Then $q = 0.8v$ cal/cm^2 · s, which gives $\theta = 9v\sqrt{t_s}$. This temperature can also be expressed as a function of the displacement $h_m = vt$ and the duration of the movement $\theta = 9h_m/\sqrt{t}$.

When large earthquakes occur, fault displacements are of the order of one to several meters and the movement occurs in a fraction of a second. The formula above would indicate a temperature of several thousand degrees, but such a temperature would obviously modify the frictional conditions. This must have something to do with the formation of slickensides, which are sometimes observed in a displacement of only a few centimeters and which must lead to very low friction. But especially, this heating can increase the fluid pressure and this reduces the effective pressure transmitted by the solid, which alone produces the friction.

It can happen that hydrated minerals, such as gypsum, serpentine, and perhaps goethite (hydrated iron oxide) may exist along the fault. Once the dissociation temperature is reached (105°C for gypsum, 450 to 500°C for serpentine, and 150 to 170°C for goethite), the mineral decomposes and the water liberated contributes to the increase in the local fluid pressure. This effect can make that pressure equal to the total mechanical pressure and suppress all friction, allowing the displacement to continue without any resistance.

If the total pressure is less than the critical pressure of water, the heating in the plane of the fault may vaporize the groundwater and the pressure of the vapor may reach the value of the total mechanical pressure, which will also lead to a suppression of all frictional resistance.

But if such an event occurred, heat diffusion would immediately begin to lower the temperature, leading to a drop in fluid pressure, and thus the friction would reappear. Disregarding the fact that the system can be locally unstable, with accidental pressure drops succeeded by periods of nearly no friction, an ideal state can be conceived whereby there would exist only enough friction to maintain the temperature in the plane of the fault at a value for which the fluid pressure equaled the mechanical pressure. It does not matter if this is continuous friction or a series of shocks where friction occurs briefly between opposing rough areas in the fault surface. The heat flow in calories per square centimeter per second necessary for this case will vary as a function of time. It ought to be such that

$$\theta_s = \frac{q_0}{C}\int_0^{t_1} \frac{1}{\sqrt{4\pi\alpha(t-\tau)}}\, e^{-x^2/4\alpha(t-\tau)}\, d\tau + \int_{t_1}^{t} \frac{q(t)}{\sqrt{4\pi\alpha t}}\, e^{-x^2/4\alpha t}\, dt$$

knowing that

$$\theta_s = \frac{q_0}{C}\int_0^{t_1} \frac{1}{\sqrt{4\pi\alpha t}}\, e^{-x^2/4\alpha t}\, dt \tag{7-16}$$

The approximations which were made do not justify the effort necessary to solve this equation, and we can be satisfied with a limiting solution $q(t) = q_0\sqrt{t_1}/(\sqrt{t} + \sqrt{t-t_1})$. This expression shows that $q(t)$ will finally decrease as $1/2\sqrt{t}$.

Table 7-1

$t = t_1 \times 1.5$	2	5	10	100
$q = q_0 \times 0.565$	0.414	0.236	0.161	0.05

But it can equally well happen that the fluid released, the presence of which lessens the friction, can escape, and it would require a greater release of heat than can be provided by friction to compensate for its loss. In particular, this situation can occur when friction vaporizes groundwater. The steam can escape when the plane of slippage reaches the surface, which is necessarily the case for a landslide, and several examples are known in which this process has played a role.[1] But this leakage which occurs at the periphery of the fault will play a relatively less important role when the sliding surface is more extensive, and it appears that when this sliding surface exceeds 1 km², the steam leakage is unimportant.

But the steam can also infiltrate the surroundings of the fault plane, compressing water before it, if the rock is sufficiently permeable. To analyze this phenomenon, it is necessary to account for the apparent compressibility of water (taking into consideration the elasticity of the pores in the rock). If the mass of water per unit volume is written

[1] J. Goguel and A. Pachoud, "Géologie et dynamique de l'écroulement du Mont Granier, dans le Massif de Chartrouse en Novembre 1248," *Bull. BRGM* (2d série), Sec. III, no. 1, pp. 29–38, 1972.
J. Goguel, Why Are Large Landslides Different from Small Ones?, in Barry Voight (ed.), "Geology and Mechanics of Rockslides and Avalanches," Pennsylvania State University Press.

as $\bar{\omega}(1 + \lambda P)$, Darcy's law allows one to write

$$\mu \nabla^2 P = \bar{\omega}\lambda \frac{\partial P}{\partial t} \tag{7-17}$$

where μ is the permeability. Equation (7-17) is identical in form to the heat equation. The fluid pressure, which assumes large values in the plane of the fault, is thus propagated in the ground in the same manner as the temperature. If the propagation velocity of the fluid pressure is more rapid than that of the temperature in a permeable rock, the steam driving the water would make contact with cooler rocks where it would condense, and it would require a large increase in temperature along the plane of the fault to compensate for this condensation. Conversely, if the temperature diffuses more rapidly than the fluid pressure, the vaporization will progress evenly and the pressure can easily be maintained.

For an intermediate case, a more detailed description including the heat of vaporization can be undertaken to calculate the temperature—greater than that strictly necessary to guarantee vaporization under the existing pressure—which must be attained in the plane of the fault in order that the pressure is maintained in spite of steam penetration into the fault sides.[1] However, it will suffice to compare the equations for the propagation of the pressure and temperature in order to ascertain that if $(\mu/\bar{\omega}\lambda) < \alpha$ the pressure will be maintained, but not if $(\mu/\bar{\omega}\lambda) > \alpha$.

The apparent compressibility of water λ is of the order of $\lambda = 4$ to 7×10^{-5} bars^{-1} and $\mu/\bar{\omega} < 4$ to 7×10^{-7}, and depending on whether $\bar{\omega} = 1$ or 10 percent, this gives $\mu < 4$ to 7×10^{-5} to 10^{-4}. This permeability should be expressed in darcys if the water viscosity was 1 centipoise. At high temperatures, the water's viscosity decreases (it is four times less at 100°C and eight times less at 200°C) and the limiting

[1] Jean Goguel, Le rôle de l'eau et de la chaleur dans les phénomènes tectoniques. *Rev. Geogr. Phys. Geol. Dyn.*, vol. XI, no. 2, pp. 153-163, April-May 1969.

value of the permeability should be reduced in the same ratio.

The limit which has just been calculated should not be considered as a fixed limit. The processes described would certainly be able to act if the permeability was of an order of magnitude less than the limit considered above. In addition, it suffices that this value of the permeability be valid over a small thickness, since if the movement is rapid, the heat and pressure increase will only penetrate a small distance (several centimeters or several decimeters). An impermeable stratum in a lithologic series composed mostly of permeable strata can allow slippage according to the mechanism envisaged, if the slippage follows a stratigraphic contact. Near the limiting condition, it should be expected that even if the vapor pressure increases, it will only partially reduce the value of the effective pressure.

When the friction is reduced by such a process of vaporization, we have seen that, even though the velocity of motion is only several centimeters per second, the frictional resistance falls rapidly after a very small displacement. Thus, it is perfectly possible that the beginning of movement is not simultaneous along the entire plane of the fault. At the moment of rupture, the loss of the shear stress (which occurs because the moving friction is less than the stationary friction) leads to an elastic deformation of the two sides of the fault with the rupture propagating at a finite speed (but much greater than the relative velocity of the two sides). The beginning of the vaporization process can follow the propagation of the rupture with a slight lag, and so for the total resistance to gliding, which results from an average taken over the entire surface area, we will not have to consider successive phases as for the displacement of a specific surface element.

These phenomena can play an important role by allowing displacements of large dimensions and by facilitating overthrusting, which constitutes one of the structural characteristics of certain mountain ranges such as the Alps or Canadian Rockies. But their thermal role remains very limited. The ease of gliding greatly reduces the mechanical energy absorbed and thus the total heat produced. The temperature rise remains confined to the immediate neighborhood of the gliding surface, and as soon as the movement is terminated, this heat diffuses away and the temperature quickly returns to normal. The briefness of heating (the duration of which can be counted in minutes) explains why we generally do not observe metamorphism, which would allow us to estimate the maximum temperature attained by the presence of characteristic minerals.

7-10 Metamorphism

We have seen that the thermal equivalent of mechanical energy dissipated in tectonic deformations remains, on the average, very limited. The temperature rise demanded by metamorphism cannot be caused by these processes. On the contrary, we will see in the next chapter that the mechanical energy expended in these deformations must be considered as *derived* from the geothermal flux.

The essential cause of metamorphism must be considered to be elevated temperature (without excluding the possibility that this high temperature occurs only in rocks carried to great depths by tectonic deformations) at a given pressure, and the rock could include a fluid phase whose role can be important. Under these conditions, certain minerals are no longer stable and others can replace them. There is crystallization of new minerals or recrystallization of old ones.

This recrystallization, occurring in a solid body, is strongly influenced by the system of mechanical stresses which occur and which determine a preferred orientation for the crystals. This constitutes one of the most striking features of metamorphic rocks. At the same time, this recrystallization permits a relatively slow and easy deformation of the rock.

From a thermal point of view, we will not have to be concerned with the conditions that produced the temperature rise which is the origin of metamorphism and with the

physical state of the fluids which can play a role in these processes.

The schematic model of a batholith studied previously and the heating which results in the country rock can give an idea of the necessary delay period for an appreciable temperature rise in a large volume of rock. Even if such a model does not seem to satisfactorily explain the temperature rise in metamorphism, it is actually not clearly understood how we could represent this temperature rise.

Mineral transformations, characteristic of metamorphism, imply a certain heat of reaction. As a general rule, a temperature increase must promote endothermic reactions and the heats of reaction can be several tens of calories per gram of new mineral. This can appreciably slow the heating. Guitard and Fonteilles remarked that when a sedimentary cover lay on an older basement which had experienced a prior metamorphism and whose constituent minerals were thus in a high temperature equilibrium, the heating of the basement would be much faster than the heating of the cover where the formation of new minerals absorbs heat. Thus, we should count on, if not a discontinuity in the maximum temperature attained (attested to by the metamorphism), at least a discontinuity in the gradient at that temperature. This is what has been called the *basement effect*.

7-11 Possible fluid phases

Certain secondary aspects of metamorphism, and in particular vein deposits, are often attributed to fluids circulating along fissures. To describe these fluids, the words *hydrothermal* and *pneumatolitic* are often used. This last word implies the action of a gas or a vapor. It is useful to try to specify the different fluid phases which may be involved.

We have previously described the way in which two phases, water and steam, are no longer distinguishable for pure water beyond the critical point (221 bars, 374.11°C). But the same question should also be examined for mixtures or solutions.

Carbon dioxide (for which we do not have to distinguish between liquid and gas, the critical point being very low), although it has a mutual solubility with liquid water, can constitute a distinct phase from water, while, like all gases, it is totally miscible with steam. The limit of existence of these two phases extends beyond the critical point of pure water, up to a temperature which slowly decreases as the pressure increases (350°C at 365 bars, 300°C at 600 bars). However, it is doubtful that the "wet CO_2 phase" plays an appreciable geological role.

In the presence of an excess of soluble salt, the salt contents of water and vapor phases in equilibrium with each other are generally very different. They are not equal at the critical point (as opposed to the properties of pure water), and above the critical point of pure water there can coexist two distinct fluid phases with very different salt contents. For sodium chloride, the coexistence domain between the two phases extends up to the fusion point of anhydrous salt. The pressure at which the two phases are in equilibrium is less than the vapor pressure of pure water, but the pressure continues to rise beyond the critical temperature of water until reaching 389 bars at 600°C. Then the pressure decreases and is equal to atmospheric pressure at 804°C, the fusion point of pure salt. The dense phase then consists of a molten salt whose fusion point is lowered by the presence of water in solution, and there is also a gaseous phase, a mixture of water vapor and sodium chloride vapor (whose vapor pressure is small). At a sufficient temperature, there is thus a continuous passage from the aqueous salt solution to the molten salt.

For other less soluble substances—particularly for silica—there exists a critical point for saturated water in equilibrium with the solid phase. This critical point is slightly displaced with respect to the critical point of pure water. Nevertheless, the laws of gas mixtures (addition of partial pressures) are totally inapplicable and the solubility of silica in supercritical water is relatively high.

At the fusion temperature of silicate solutions, water can be dissolved in the melt with a percentage (on a weight basis) which increases much less quickly than the vapor pressure of water, and which can go to 3 percent at 500 bars and 9 percent at 4,000 bars. Conforming to the law of gas solubility, this percentage decreases slightly when the temperature increases. In addition, it is known that the presence of this water greatly lowers the solidification temperature of silicates (from 100 to 200°C). But if the silicates crystallize, it is in an anhydrous form and water must be released. Thus, again we are concerned with two phases, one of which is identified with the mixture of molten silicates and the other with supercritical water, saturated with respect to the silica and other oxides which are present. This aqueous phase is liberated at the time of silicate solidification, and if it escapes along a fissure, its temperature and pressure will vary and thus it can release the oxides which it held in solution. Such is the origin of hydrothermal veins. It is only near the surface, depending on the temperature distribution, that supercritical water will reach either the liquid water domain, where the solubility is high for many substances and where mineralization can occur to form an ore deposit, or the steam domain, in exceptionally hot region, making a fumarole. Well before reaching the surface this will have essentially no solids in solution and will contain practically no impurities except other gases.

Thus, it does not seem necessary to distinguish between pneumatolitic and hydrothermal deposits. There can be a difference between the deposits formed at the expense of the volatile phase in the vicinity of a magma in the course of crystallization (perhaps certain pegmatites) and those deposits left by thermal waters at moderate depth, perhaps with differences caused by the temperature and the pressure. But it does not seem that there can be a fixed distinction between the two discontinuous fluid phases.

It would theoretically be different in the case where the solid constituents were soluble enough to act like sodium chloride; the water vapor phase would be able, in the path by which it escaped to the surface, to meet the saturation curve and pass from the vapor state, with a very low concentration of dissolved salt, to the liquid state with a capacity for considerable dissolved salt. This passage is what has been called *regressive boiling* (i.e., in fact, a condensation). It would be marked by a very strong dissolution of previously deposited salts, appearing as corrosion. But it does not seem that this phenomenon, which has been theorized, plays a very important role.

The detailed study of the solubility and stability of different minerals and the conditions in which they can be deposited goes beyond the scope of this book and will not be further discussed.

CHAPTER EIGHT

geothermics on a global scale

As soon as the existence of a gradient and thus a geothermal flux was discovered, the question was asked about the origins of the heat so dissipated. In the eighteenth century, the answer seemed evident to Buffon: the earth was cooling off, and he tried to estimate the earth's age according to these cooling conditions. Not possessing any valid theory of heat, he measured the cooling times for musket balls and cannonballs of various diameters (from ½ to 6 in.), heated in his kilns at Montbard. These times being proportional to the diameters, he unhesitatingly extrapolated them to the dimensions of the earth and got an age of 63,000 yr (according to his manuscripts, Buffon hesitated between this figure and an age ten times greater). One of his errors was to consider a ball as cooled when it could be "held in the hand without the hand being burnt." This obviously corresponds to a thermal gradient much higher than that of the earth.

The calculation of Buffon was performed again several times during the nineteenth century. It inspired Fourier to construct his theory of heat and was finally brought up to date by Lord Kelvin.

In the meantime, Helmholtz's attention had been drawn to another source of energy, which is essential for the stars, particularly the sun but which is not negligible for the earth: in the contraction of a celestial body under its own gravitational attraction, from what may be taken to be a cloud of matter initially dispersed over large distances, gravitational potential energy is dissipated and the greater part of that energy is transformed into heat. This energy

suffices to explain how the stars were brought to very high temperatures, and it would have supplied enough solar radiation for 10 million yr, which led Lord Kelvin to give this as a limit to the age of the solar system, but not without incurring some objections from geologists.

It is well known that the discovery of radioactivity and then nuclear fusion completely changed the perspective of this problem. Even though the earth's rocks are low in radioactive elements, their radioactivity is such that the heat produced is of the same order of magnitude as the geothermal flux and thus constitutes an essential factor in the thermal history of the earth. On the other hand, nuclear fusion reactions, such as occur in the transformation of hydrogen to helium, have been able to supply the solar radiation for 4.6 billion yr, which is the age attributed to the solar system, and will continue to do so for an even greater length of time.

In a global thermal balance, it can be shown that possible chemical reactions do not play an appreciable role. On the contrary, tectonic activity, by which rocks are deformed, mountain ranges raised, and energy dissipated in earthquakes and perhaps in other forms in relative plate displacements, represents a mechanical energy which must be accounted for in a total energy balance. Again it can be shown that this term is very small compared to the geothermal flux; it can thus be imagined that this mechanical energy can be derived, by a mechanism to be specified, by conversion from thermal energy but not the inverse.

In the energy balance, the magnetic field, or rather the energy dissipated in the course of its modifications, represents a much less important term. But its great significance is to give us information about the regime existing in the earth's core, of which we possess little knowledge.

Thus, the ideas of the thermal history of the earth for two centuries have evolved in a quite radical manner. Even now, the temperature distribution in the internal regions of the earth is certainly the most poorly understood physical property of the earth, particularly because the study of that distribution is inseparable from hypotheses of the earth's

origin. It is hardly necessary to state how uncerta... these hypotheses are.

We are going to undertake in more detail the study of the different terms in an energy balance just sketched to show how their orders of magnitude can be estimated. Afterward, entering the domain of hypotheses, we will try to show how the thermal system of the earth as a whole can be imagined and connected to its origins.

8-1 Cooling of a solid sphere

Obviously it is not very satisfactory to compare, as did Buffon, the cooling of the earth to the cooling of a cannonball (i.e., treating the earth as a homogenous sphere in which the thermal parameters such as the specific heat and thermal conductivity are considered constant). Nonetheless, it will be useful to recall the results of this model.

The heat equation for a sphere, when the temperature distribution is a function of the radius only, reduces to

$$\frac{\partial(r\theta)}{\partial t} = \alpha \frac{\partial^2(r\theta)}{\partial r^2} \tag{8-1}$$

This equation permits solutions of the form

$$\theta = A[\sin \delta r/r]e^{-\alpha\delta^2 t}$$

The temperature distribution of a sphere with an initial uniform temperature θ_1 at $t = 0$, and whose surface $r = R$ is afterward maintained at zero, is obtained by letting $\delta = n\pi/R$ and representing the initial temperature by a sum of the type

$$\theta = \frac{-2R\theta_1}{\pi r} \Sigma \left[\frac{(-1)^n}{n}\right] \sin\left(\frac{n\pi r}{R}\right) e^{-\alpha n^2\pi^2 t/R^2}$$

(which is equal to θ_1 at $t = 0$). This equation gives a surface gradient of

$$\frac{\partial\theta}{\partial r} = \frac{-2\theta_1}{R} \Sigma e^{-\alpha n^2\pi^2 t/R^2}$$

An approximation to the right-hand side of this equation can be obtained by replacing the summation by an integration, and thus we find that approximately:

$$\Sigma e^{-\alpha n^2\pi^2 t/R^2} = \frac{R}{2\sqrt{\pi\alpha t}} - \frac{1}{2}$$

This allows us to calculate the value of the surface gradient:

$$\frac{\partial\theta}{\partial r} = \frac{\theta_1}{\sqrt{\pi\alpha t}} - \frac{\theta_1}{R} \tag{8-2}$$

The first term represents the gradient for a cooling of a half-space (infinite radius), and the second term takes the spherical shape into account.

On the whole, the successive terms in the series representing the temperature die out more and more rapidly, and at the end of enough time, only the first term remains appreciable. But for a sphere having the thermal properties of superficial rocks ($\alpha = 0.01$) and the earth's radius, this would be so only after a time on the order of hundreds of billions of years. For the age of the earth, 4.6 billion years, the initial temperature would barely have changed and the surface cooling would only have penetrated to a depth shallow compared to the earth's radius. A gradient of the order of 1°C/30 m would require an initial uniform temperature on the order of 25,000°C. Obviously, it would be absurd to suppose that at such temperatures a solid state exists with thermal properties analogous to those of superficial rocks.

This was essentially the model by which Buffon (in an incorrect manner because he misunderstood the significance of the gradient) and other physicists reasoned till Lord Kelvin. Lord Kelvin would still have found acceptable central temperatures for durations much greater than 10 million yr, which was the time to which he intended to limit the age of the earth (and for which $\theta_1 = 1000$°C) by his reasoning concerning the solar radiation.

For any other initial temperature distributions, an analogous conclusion would be reached. The simplest way to show this is to consider this temperature as the sum of a uniform temperature equal to the initial temperature at the surface and an initial temperature distribution canceling at the surface. A calculation similar to the preceding one would show that this second distribution generally brings only a negligible contribution to the gradient and would only have evolved slightly in a time equal to the age of the earth. The initial distribution of temperatures in the central regions of the earth has practically no influence on the surface gradient, which depends on the cooling conditions near the surface only. In the model of a solid sphere, the earth is much too young to allow the initial thermal conditions in the central regions to be manifested in any way at the surface. Of course it is extremely unlikely that this model corresponds to reality; it only constitutes a reference which it was necessary to recall.

8-2 The role of radioactivity

Since the discovery of radioactivity in 1896, the energy dissipation by radioactive elements has led to the reexamination of the whole problem of the thermal history of the earth. This is because the radioactive substances existing in the interior of the earth release heat at a rate which could be comparable in order of magnitude to the heat dissipated by conduction to the surface. To be more precise, it would be necessary to be able to estimate the amount of radioactivity found in the interior of the earth. First there is uranium and thorium. Natural uranium is composed of two isotopes; ^{238}U constitutes $\frac{139}{140}$ of the total uranium content. ^{235}U is less abundant but has a higher disintegration constant. This constant λ characterizes the disintegration probability in unit time such that the amount of radioactivity present varies as $e^{-\lambda t}$ and, in particular, is reduced to one-half its initial value in a time $t = 0.6932/\lambda$, often called the *half-life*.

Table 8-1 indicates, besides the values of λ, the heat release from 1 g of the substance supposed in equilibrium with all the products resulting from its disintegration.

Outside of uranium and thorium, we could also take into account potassium, whose isotope ^{40}K is scarce (0.011 percent) and which is radioactive through two different processes, producing argon and calcium, respectively. We need not distinguish between these processes in our study.

The effect of Rb, whose isotope ^{87}Rb makes up 27.8 percent of the total Rb content and which has a disintegration constant of 1.47×10^{-11} yr, is often neglected. Estimates of the abundance of ^{87}Rb give the same approximate figure as for the amount of ^{40}K. The extreme slowness of disintegration justified neglect of its heat production. The effect of rhenium, which is very scarce, can certainly be ignored.

Of course we do not have to include the radioactive element produced in the upper atmosphere by cosmic radiation (^{14}C, tritium, etc.). Their disintegration at the surface simply returns a portion of the incident radiant energy.

However, we will raise a very obscure point here: it is known that the neutrino is a particle whose existence has been established by theory to ensure the principles of conservation of mass and energy in certain reactions, but it has practically no interaction with matter and cannot be detected. It is sometimes asked if the neutrino flux received from the sun is such that the feeble absorption which would occur when it passes through the earth would lead to a heat release which should be taken into consideration. This would mean that we should admit the principle of energy conservation is faulty at a certain level, which is exactly the level in which we are interested. Some theoretical discussion, into which we will not enter, seems to show that even on this scale the effect would be completely negligible.

Table 8-1

	λ, yr^{-1}	cal/g · yr
^{235}U	9.72×10^{-10}	4.3
^{238}U	1.54×10^{-10}	0.71
U (ordinary)		0.73
Th	4.99×10^{-11}	0.20
^{40}K	5.3×10^{-10}	0.21
K (ordinary)		27×10^{-6}

Once in possession of these facts, which can be considered as well established, it remains to estimate the quantities of radioactive elements present, and this is extremely difficult and uncertain. It is certain that the rocks accessible at the surface are only representative of a thin layer (a few tens of kilometers) which makes up the crust, and again, in proportions which ought to be weighted.

Samples of rocks which we can consider to belong in the mantle have very weak radioactivities (at the limit of what is measurable), and even then we may wonder if the samples have not been contaminated during the processes which brought them to the surface.

Meteorites, in particular chondrites, which are habitually considered as being representative of the interior of planets analogous to the earth, also have very small percentages of U, Th, and potassium. Clearly, the percentages of radioactive elements in the crust are much higher; but, even the small percentages in the mantle and core may produce an amount of heat which may not be negligible.

In the crust, there exist accumulations of certain elements which constitute exploitable deposits. Clearly, for the three elements in which we are interested, they only represent an infinitesimal proportion of the total existing tonnage and it can be shown that their thermal effect can be neglected. An occurrence of 100,000 tons of uranium would be quite extraordinary; at a content of 1 percent, that would occupy a sphere with a 100-m radius; the heat liberation of 2300 cal/s, supposed uniformly distributed in the sphere, would lead to a steady-state thermal system with a temperature increase of 3.6°C at the surface and 5.7°C at the center. Thus, this would only be a very local perturbation.

For many rocks, a nice correlation is observed (which is poorly explained but is perhaps not a coincidence) between the percentages of uranium, thorium, and potassium. For basic and intermediate rocks, the percentages can vary between 0.1 and 3 ppm for uranium, with an average of 0.9 ppm, and between 0.3 and 10 ppm for thorium, with an average of 2.7 ppm. On the other hand, for granites (in the broad sense), U percentages are found from 1 to 20 ppm and more, with an average of 4.9 ppm, and for thorium, from 2 to 20 ppm, with an average of 9.3 ppm. For these rocks, the potassium contents are from 3 to 4 percent.

The misleading significance of averages should be pointed out: they represent a weighting between samples and not between the tonnages they represent. Samples are more often collected at the edges of massive granitic rocks than in the centers. Radioactive elements (other than potassium) are, in granite, almost exclusively contained in certain accessory minerals such as zircon.

If certain sedimentary rocks, such as biogenic limestones where the radioactive contents are small or evaporites where they are practically nonexistent, are set aside, the proportion of U in sedimentary rocks varies with the proportion of clay, quartz, or heavy minerals. It appears to oscillate around an average of 2 to 3 ppm; the Th percentages have a less strict correlation than for eruptive rocks.

Certainly the "granitic layer" of seismologists should not be identified with the intrusive granites observed on the surface and which result from refusion processes probably leading to a concentration of Th and U. Gneiss on the other hand should retain percentages of U and Th much the same as those in the rock from which it originates.

In summary, it is very difficult to give numbers which can be considered as representative values for the average radioactivity of the crust. The act of taking for the examples average concentrations of 2 ppm for U, 8 ppm for Th, and 2 percent for K should not make us forget that these numbers can be off by a factor of 2 in either direction. These values lead to a heat release of 3.6×10^{-6} cal/g · yr, or 9.6×10^{-6} cal/cm^3 · yr; a thin layer of 39 km could furnish the average geothermal flux of 1.2 μcal/cm^2 · s. This thickness would be a little greater than the depth which is normally assigned to the continental crust, but we should remember that the orders of magnitude are similar.

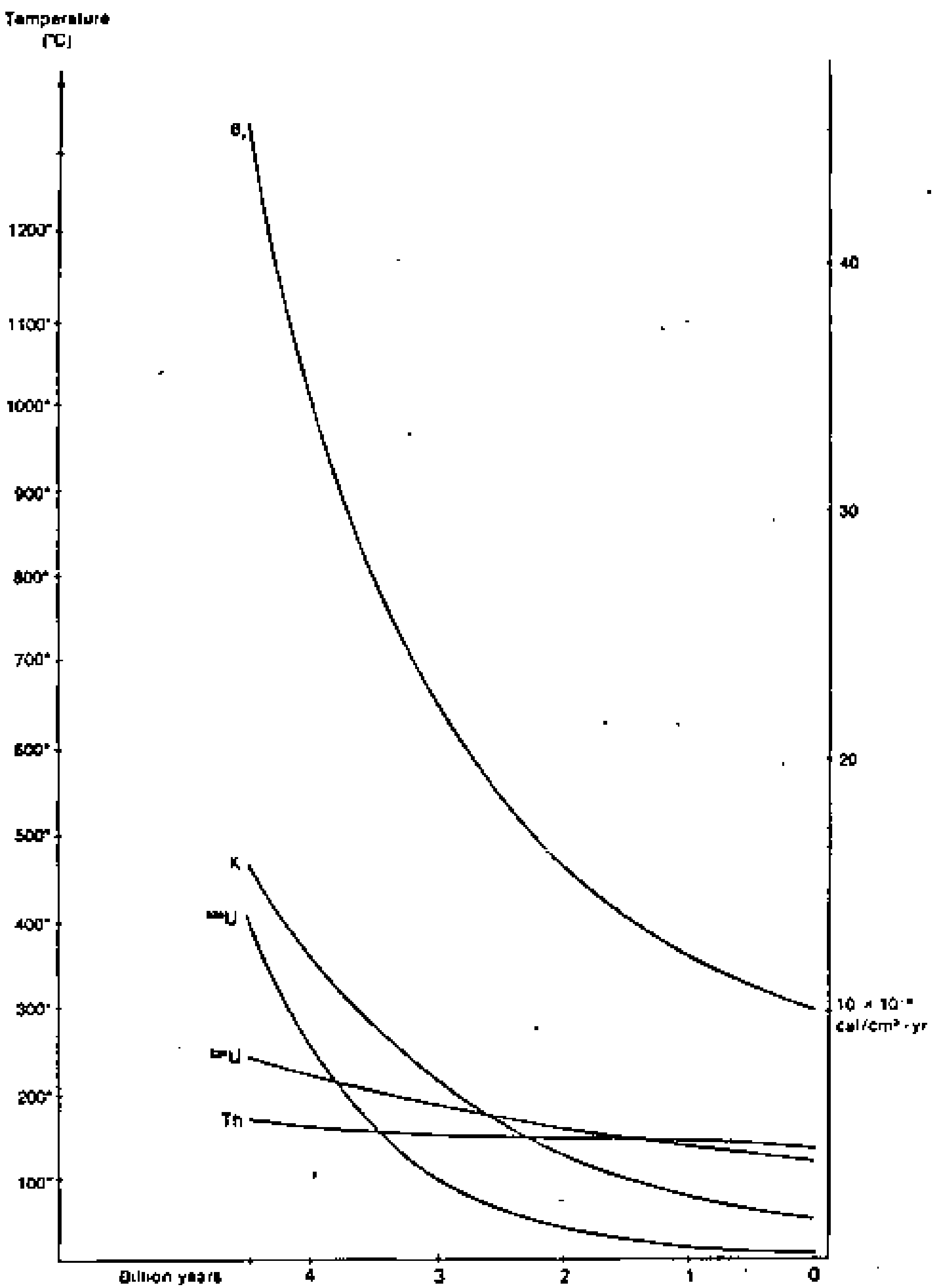
In oceanic regions, on the contrary, what is known of the crust's composition (thinner and nongranitic) seems to indicate a heat production much lower than the geothermal flux, the average of which is the same as for the continents.

To estimate the significance of these terms, we can calculate the temperature rise if the radioactive rock was isolated. It is easily found, taking into account the law of variation of the quantity present as a function of time, that the temperature of this rock would have been raised 5770°C in the last 1 billion yr and 47,575°C during the last 4.5 billion yr. It is quite evident that conductive cooling in the crust is very important on this time scale. But, if we supposed that in the central regions of the earth the percentages were a specified fraction of those taken for the crust, we would be able to deduce from these numbers the temperature rise which, if only solid conduction had occurred, would only have been slightly modified.

It is indispensable when the thermal evolution of the earth is considered to account for the decrease in radioactive elements with time, which results in heat liberation being more rapid in the past. Figure 8-1 indicates for past ages the heat released for a composition such as we have previously imagined; it is seen that 3 billion yr ago the role of potassium in the heat release was preponderant and 4.5 billion yr ago it was the heat release by ^{235}U which was important (at that time, the percentage of ^{235}U was 27 percent of the total uranium content).

Observe that if no other indications of the earth's age existed, the extrapolation of these figures would lead us to fix an upper limit for this age. From Fig. 8-1, we can also deduce the variations of the geothermal flux during past geological times caused by the radioactive elements then contained in the crust. But for the portion which would arise from cooling from an initial state at a high temperature, it could well be that this cooling rate was higher in the far distant past.

The comparison of the flux value 4 billion yr ago (3.5 times today's flux) with the limit which we have shown in Chap. 4 for the hypothesis of a thermal stratification as it results from heat transfer by conduction would not be compatible with the presence of liquid water in a permeable terrain. This leads us to think that the formation of steam plumes and heat transfers by convection must have been



much more frequent than today; generally, all the subterranean processes in the crust must have been much more active. This is a fact which must be considered in the study of the lower Precambrian.

8-3 The cooling of the earth including radioactive effects

If we suppose that all radioactive substances are contained in the crust, one way of studying their influence on the cooling of the earth is by considering the temperature as the sum of two terms. One term (θ_1) satisfies the heat equation without taking into consideration the heat released by radioactive substances, and the other (θ_2) is taken to be zero below the base of the crust and takes into account the radioactive heat release, which is of the form $\Sigma q(x)e^{-\lambda t}$. For each of the four terms of this sum, let $\theta_2 = F(x)e^{-\lambda t}$, where $F(x)$ satisfies the equation

$$-C\lambda F(x) = K\frac{\partial^2 F}{\partial x^2} + q(x) \tag{8-3}$$

If the first term is neglected, we have $F(x) = (-1/K)\int_x^h q(y)\,(y - x)\,dy$, and at the surface $F(0) = (-1/K)\int_0^h q(x)\,x\,dx$. Supposing that the radioactive elements are uniformly distributed over a thickness of 30 km, it is then found that $\Sigma F(0) = 290$°C.

It is easy to see that the left-hand side of the equation is of the order of a hundred times less than each of the two terms of the right-hand side, which allows us to limit our-

FIGURE 8-1 Graph giving the heat release per cubic centimeter in 10^{-6} cal/yr, for a typical rock of density 2.8 and composed of 2 ppm of U, 8 ppm of Th, and 2 percent of K. The graph is given as a function of geological time; the amount of heat resulting from each element or isotope is shown. The superficial fictive temperature θ_1 has also been indicated, and so its effect can be included in the study of deep subterranean cooling with the hypothesis of a uniform distribution of such a rock over a 30-km depth.

selves to the approximation furnished by the solution: $\theta_s = \Sigma\theta_i e^{-\lambda t}$, with $\Sigma\theta_i = 290°C$. In Fig. 8-1 the fictive temperature θ_s is indicated.

For θ_s, which satisfies the heat equation not taking the radioactivity of the crust into account, the condition $\theta = 0$ at the surface must be replaced by the condition $\theta = \theta_s$. Thus everything happens for θ_s, as if, instead of cooling through a surface kept at a constant temperature that is taken as 0°C and determined by equilibrium with the external radiation, this surface has been kept at a fictive temperature θ_s which progressively decreases from 1300 to 290°C.

In a manner analogous to what was just done, if an initial temperature distribution was given, it would be broken down into three parts: first, a uniform distribution equal to the difference between the initial surface temperature and 1300°C and which will evolve as we have seen above; next, an initial temperature distribution of 1300°C with a superficial fictive temperature progressively decreasing from 1300 to 290°C, according to the law indicated; and finally, an initial distribution zero at the surface and for which the surface temperature will remain 0°C. It has already been stated that this last portion would only bring a small contribution to the surface gradient.

Essentially we have to consider the second distribution to see what gradient results from a progressive lowering of the surface temperature. The calculation can be done for a sphere,[1] but it leads to a slowly converging series whose terms are exponentials and it does not seem useful to develop this calculation here. We will study the problem in the plane approximation.

It has been seen that if at the instant t the temperature at the surface of a half-space is lowered by $\Delta\theta$, the subsequent temperature will be given at time τ by

$$\theta = \Delta\theta \operatorname{erfc}\left(\frac{x}{\sqrt{4\alpha(\tau - t)}}\right) \tag{8-4}$$

[1] J. Goguel, Note sur le refroidissement du Globe, *Ann. Geophys.*, vol. IV, no. 3, pp. 253-258, 1948. At the time, we adopted slightly different thermal characteristics.

If the surface temperature, initially 0°C, is afterward given by $\theta_s = f(t)$, we will have

$$\theta(x,\tau) = \int_{-\infty}^{\tau} f'(t) \operatorname{erfc}\left(\frac{x}{\sqrt{4\alpha(\tau - t)}}\right) dt$$

and

$$\frac{\partial\theta}{\partial x} = -\int_{-\infty}^{\tau} f'(t) e^{-x^2/4\alpha(\tau-t)} \frac{1}{\sqrt{4\alpha(\tau - t)}}\, dt$$

where for $x = 0$ and $\tau = 0$, this expression becomes

$$\frac{\partial\theta}{\partial x} = -\int_{-\infty}^{0} \frac{2f'(t)}{\sqrt{-4\pi\alpha t}}\, dt \tag{8-5}$$

The integral has been numerically calculated, supposing concentrations of the type indicated earlier distributed uniformly over a 30-km thickness. With $f(t) = \Sigma q e^{-\lambda t}$, which gives $f'(t) = \Sigma q \lambda e^{-\lambda t}$, the gradient is found to be equal to 1°C/480 m.

This shows that, because of the temperature drop at the surface, a thermal flux issues from the earth's interior with corresponding cooling and is dissipated at the earth's surface at the rate of 0.1 μcal/cm² · s, which is approximately a tenth of the geothermal flux.

In fact, it is extremely doubtful if the interior of the earth can be assigned the thermal properties of superficial rocks, even if only the thermal properties of the upper part of the mantle were important, as would be the case in the schematic problem which has just been treated. In particular, it can happen that in the mantle, heat-transfer processes take place which are much more effective than conduction. We will see later that is is undoubtedly necessary to call upon convection. For the moment, we will limit ourselves to representing these processes by the choice of a higher value for the coefficient K, and thus also for α.

In the expression for the flux, K occurs in the numerator and the square root of α in the denominator under the summation sign. The effect of an increase in K is an increase in the thermal flux reaching the surface (or the base of the crust), as a consequence of the decline of the fictive temperature at the surface, which goes as the square root of the conductivity. Whenever convection plays an important role in thermal exchanges at the level of the upper mantle, it happens that in the geothermal flux, the portion resulting from the cooling imposed on the lower levels by the thermal evolution of the crust, represents a substantial proportion of the total thermal flow.

It is perhaps useful to emphasize that this effect does not depend on the total amount of radioactive substances present, but on an integral in which their depth occurs (as a moment of the radioactive substance's amount with respect to the surface). If it is supposed that in oceanic regions the processes which led to the concentration of uranium and thorium in the granitic rocks of the crust did not act in the same way as for the continents, it could be imagined that, even if the total radioactive concentration is lower than for the continents, this moment could be higher and thus play an appreciable role in the flux originating from underground caused by cooling, which could explain the equality of the average oceanic and continental fluxes.

Certain of our hypotheses are very arbitrary, in particular those which concern the amounts of radioactive materials and their distribution with depth in the crust. But we have the definite result that we do not have the right to imagine an earth whose geothermal flux would exactly be balanced by the heat released by radioactivity in the crust: from the sole fact of the decay of radioactive substances, there results a fictive temperature decline (and thus also for the temperature at the base of the crust), which leads to a flux caused by cooling, at least of the order of one-tenth the normal heat flow (and perhaps higher).

In the calculation of the integral which yielded this result, and in spite of the factor $1/\sqrt{T}$, the earliest geological periods play a preponderant role. In fact, this only holds for one of the initial temperature distributions, that part which corresponds to an initial uniform temperature equal to the fictive temperature due to the radioactivity of the crust, which therefore was not initially subjected to any tendency to cool. It would equally well be necessary to consider the other parts of the initial distribution, one nonuniform and the other presenting an initial discrepancy with the surface temperature. These two terms could easily give contributions of the same magnitude to the actual surface gradient.

As a case in point, although it does not seem at all probable, let us suppose an initial temperature of 0°C everywhere and a radioactivity concentrated only in the crust; we should add to the solution which has just been studied, and which corresponds to an initial temperature of 1300°C, a solution corresponding to an initial uniform temperature of −1300°C. The calculation in Eq. (8-2) furnishes us with a value for the corresponding gradient of 1°C/500 m, nearly equal and opposite to the gradient resulting from the decay of radioactive substances. This shows that, first, the radioactivity of the crust heats the underlying rocks and, then, the crust begins to cool and a small amount of the heat which was accumulated below returns to the crust. There is no interest in a detailed investigation of a model so far removed from reality, and we only mention it as an example of the way in which a temperature distribution can be obtained which is appropriate to any sort of hypothesis relating to the initial state.

If we knew the distribution of the radioactive elements, it would be easy to calculate its consequences for the temperature distribution; unfortunately we lack precise information on the distribution of radioactive materials in the mantle and especially the core. Comparison with meteorites, particularly chondrites, furnishes the only model which we can apply, but it is not known to what extent it is valid; it can only be remarked that it furnishes us a strong justification for the notion of mantle concentrations much lower than in the crust, but not zero. This confirms the conclusions of a purely thermal analysis which shows that the heat flow would be much higher for mantle concentrations of the order of those in the crust, which can thus be formally excluded. On the other hand, the necessity for an engine for the internal mechanical activity, the consequences of which are so visible on the surface, makes it likely that there is a nonzero concentration in the mantle and in the core. Our uncertainty is perhaps even greater for the distribution in the oceanic regions.

8-4 The dissipation of gravitational energy in condensation

Helmholtz's attention was drawn to the energy source which is liberated when a mass, initially dispersed at a great distance, condenses under the effect of the mutual gravitational attraction of its parts and whenever the radial mass distribution is altered (we will assume that the spherical symmetry is preserved, and we will neglect the effects due to rotation). Part of this energy will be found in the form of elastic energy in the compressed matter, but the rest must be dissipated in the form of heat.

To calculate the energy liberated between dispersion at a great distance and a condensed state, we can proceed in the following manner. Consider the mass $m(r)$ interior to the radius r, such that $m = 4\pi\int_0^r \rho r^2\, dr$. This mass exerts on a mass dm, between the radii r and $r + dr$, a gravitational attraction $\gamma = f(m \cdot dm)/r^2$, and if this mass was dispersed to infinity, the work done would be

$$dU = f\left(\frac{m \cdot dm}{r}\right) \tag{8-6}$$

For the entire sphere, the work done by dispersion to infinity would be equal to $U = f\int_0^M (m \cdot dm)/r$, if we consider r as a function of m, or if we consider m as a function of r, then $U = f\int_0^R m\, dm/dr\, (dr/r)$.

For a sphere with uniform density equal to 5.51, we have $m = \frac{4}{3}\pi r^3 \times 5.51$ and $dm/dr = 4\pi r^2 \times 5.51$, and it is immediately found that $U = f16\pi^2 \times (5.51)^2 \times R^5/15 = 0.6\ MgR$, which is $f \times 3.35 \times 10^{46}$ ergs $= 22.4 \times 10^{38}$ ergs.

For the actual earth, using the density distribution of Bullen's model A, a numerical integration gives the value 25.0×10^{38} ergs.

It is easy to calculate the elastic energy contained in the earth since we know as a function of the depth the pressure, the density, and the speeds of seismic waves, which are given by $\sqrt{(\lambda + 2\mu)/\rho}$ and $\sqrt{\mu/\rho}$. These yield the values of the elastic coefficients λ and μ. The elastic energy per unit volume is given by

$$\frac{3P^2}{2(3\lambda + 2\mu)} \tag{8-7}$$

The numerical integration (using the densities of Bullen's model A and the seismic velocities of Gutenberg and Richter) gives 7.88×10^{37} ergs (4.45 in the core and 3.43 in the mantle), which is 3.2 percent of the potential energy dissipated in the condensation of the earth and is thus not at all negligible.

To give an idea of the significance of these quantities, remember that the mass of the earth is 5.976×10^{27} g. If the average specific heat was of the same magnitude as that of rocks, which is 0.185, the energy dissipated in coming from infinity less the elastic energy, $(25 - 0.79) \times 10^{38}$, would correspond to a temperature rise of 54,000°C!

It is known that for a mass of the magnitude of the sun, condensation can release sufficient energy to raise the entire mass to a temperature of several tens of millions of degrees, which allows the beginnings of the nuclear reactions which furnish the energy radiated by the sun and the other stars.

To return to the earth, the transition from a state with a uniform density to the present state, having a dense core, would release 2.6×10^{38} ergs, which is 1040 cal/g and which is enough energy to raise the entire mass of the earth to 5000°C if the heat capacity was of the order of that of superficial rocks (this is without taking into account a possible increase of elastic energy made possible by the increase in pressure which took place as more dense material sank toward the center of the earth).

The genesis of the earth is often imagined as the condensation of a cloud of dispersed primitive matter. But it is not certain that this condensation happened all at once, which would have heated the entire mass of the earth as we have just seen. It is more plausible to imagine a successive

accretion in layers, slow enough to dissipate the kinetic energy of rotation (by bodily tides or the action of a magnetic field?). The heat caused by condensation would then be released principally on the surface, and it could be imagined that it would at least be partly dissipated by radiation as the process continued. It is thus difficult to estimate exactly what was the heating of the terrestrial sphere as a result of initial condensation. But it seems certain that there was an initial heating.

In any case, the transition from a homogenous density distribution to the present state with a highly differentiated core required internal displacements of matter. The energy so dissipated must have heated the interior of the earth.

It is not at all certain that this potential energy dissipation had to occur at the time of the earth's genesis. It is perfectly possible that a certain differentiation is still taking place. A tenth of the energy dissipated in the transition from a sphere with a uniform density to the present globe with a differentiated core would have sufficed to supply the present heat flow (1.95×10^{20} cal/yr) for 2.9 billion yr without taking radioactive decay into consideration. *A fortiori*, the energy dissipated in mechanical forms (earthquakes, plate tectonics) only represents a very small proportion (on the order of a few parts per thousand) of the mechanical energy furnished by the differentiation of the core.

8-5 What conclusions can be drawn from these data?

We have tried to present the facts relative to different times in a thermal balance of the earth, considered in its entirety, independently of the ideas and hypotheses concerning its internal constitution so as to specify certain orders of magnitude and eliminate uncertainties which prevent any conclusions. It is clear that the thermal balance and the temperature distribution that results from it, presently or in the past, can only be established in the outline of a model

incorporating information furnished by other disciplines such as seismology, gravimetry, magnetism, petrology, and geology in general, and coordinating this information in the framework of adequate hypotheses.[1]

A model could be constructed to describe the present state of the earth: what we have seen of the time scale of all the phenomena of conduction on an earth-scale basis and the variations of the heat released by radioactivity make it apparent that such a model will only furnish valid results in the thermal domain when it is completed to describe the evolution of the earth in the course of 4.6 billion yr (which we now know represents its age). The present thermal system is directly dependent on this prior evolution, and, in particular, it would not be possible to analyze it without making hypotheses about the genesis of the earth.[1]

Obviously the scope of this book does not permit us to analyze the geophysical data upon which the current hypotheses on the internal constitution of the earth rely.[2] Thus, we will suppose that they are known and will only call on them occasionally to justify a choice between different hypotheses.

8-6 Outline of an energy balance

The heat flow is not the only form in which energy of internal origin is manifested. Without mentioning volcanoes, which appear essentially as thermal phenomena, the most spectacular manifestation of internal energy is folding and, in a more general way, the deformation of

[1] As an example of such a historical synthesis, coherent and implying a certain number of hypotheses, see: E. A. Lubimova, Thermal History of the Earth, in P. J. Hart (ed.), "The Earth's Crust and Upper Mantle," geophysical monograph 13, pp. 63-77, American Geophysical Union, 1969; and E. A. Lubimova, Theory of the Thermal State of the Earth's Mantle, in T. F. Gaskell (ed.), "The Earth's Mantle," pp. 232-323, Academic, New York, 1967.

[2] J. Coulomb and G. Jobert, "The Physical Constitution of the Earth," Oliver & Boyd, London, 1963. Also see Geophysique in J. Goguel (ed.), "Encyclopedie de la Pleiade," 1971; J. Coulomb and G. Jobert (eds.), "Traite de géophysique interne," vol. 1, Masson, Paris, 1973, vol 2, 1976; J. Goguel, Terre (constitution interne), Encyclopaedia Universalis, Paris, vol. XV, 1974, pp. 967-973; B. Gutenberg (ed.), "Internal Constitution of the Earth," Dover, New York, 1951.

rocks and the upheavals which form mountains. It is now known that this is a manifestation restricted to the continents; in general the plates which make up the crust (or more exactly, the lithosphere) glide with different speeds which are expressed by specific structures at the junctions between plates.

Let us at least try to estimate the order of magnitude for the energy dissipated by these different phenomena. One of the manifestations of present tectonic activity is the existence of earthquakes. Thanks to seismographs we have today a complete listing of all earthquakes above a certain magnitude. The estimation of the energy they release is difficult. It requires as an intermediary an empirical definition of magnitude, and then energy estimates for some chosen earthquakes, which leaves room for considerable uncertainty. It is generally conceded that from one magnitude to the next, the energy changes in a ratio of about 63 and the frequency in a ratio of 10. It is clear that the larger earthquakes represent the most important contribution to the total energy released. The figure proposed, 10^{25} ergs/yr, is equivalent to 3×10^7 kW · yr/yr, noting that the major portion of this energy is dissipated in a few seconds.

Outside of seismic energy, for which we will suppose that the present rate can be taken as representative of past geological ages, tectonic energy is partially manifested in the creation of relief and partly by the deformation, sometimes very strong, of rocks that are mechanically resistant.

It is easy to calculate the potential energy of the visible relief using the statistics of surfaces classified by altitude, which is expressed by the hypsographic curve. The potential energy of continental relief is calculated separately with respect to sea level and gives 4.7×10^{21} kJ, and the potential energy of relief at a constant oceanic depth is 29×10^{21} kJ. But we must take isostatic compensation into account. To all visible relief there correspond density deficits situated at a certain depth that make us underestimate the previous figures in the ratio of the density of the crust to the variation of the density which determines the compensation, commonly taken as 0.6 g/cm³. This gives $2.67/0.6 = 4.5$ for the

continents and $1.67/0.6 = 2.7$ for the oceans, to account for the Archimedean pressure. In reality, these factors are quite poorly determined, the subterranean densities being hypothetical, and could be in error by from 10 to 20 percent.

Geology shows us that ancient relief was destroyed by erosion and that all the relief that we now observe resulted from relatively recent upheavals (i.e., post-Miocene), even when the material raised had been deformed at a much earlier time. We will suppose then that the rate of energy dissipation in the formation of relief corresponds to the creation in 10 million yr of the continental relief equivalent to that now existing. The oceanic relief is in totality much older, and its creation should be spread out over a duration of 200 million yr or perhaps more. For the continental relief, $4.7 \times 4.5 \times 10^{21}$ kJ/$(10^7 \times 3.15 \times 10^7) = 6.7 \times 10^7$ kW. The creation of oceanic relief in 200 million yr would absorb $(29 - 4.7) \times 2.7 \times 10^{21}/(2 \times 10^8 \times 3.15 \times 10^7) = 1.07 \times 10^7$ kW, which is in total about 8×10^7 kW.

It is very difficult to estimate the energy absorbed by rock deformations because we only know that the stresses under which they were produced (for very slow processes which essentially result from recrystallization) were certainly much less than that which we observe in the laboratory for rapid deformations by different processes. We know that the total energy absorbed is divided between deformation and creation of relief in such a way that the total energy absorbed, for a given deformation, is a minimum and must be reflected in comparable orders of magnitude for these two terms.

Plate theory implies that over the entire surface of the globe rigid plates formed by the lithosphere glide with respect to the internal regions of the earth by means of the viscosity of a region called the *asthenosphere*, with a speed of a few centimeters per year. The best indication that we have for the viscosity of the asthenosphere is furnished by postglacial readjustments in Scandinavia. For a surface area whose diameter is 2,000 km, half of the isostatic disequilibrium has vanished in 6,000 yr and this delay can hardly be attributed to anything else than a viscous action.

If the depth of the asthenosphere is great, a viscosity of the order of 10^{21} poise would be deduced. If the asthenosphere has only a limited depth, we would naturally find smaller values, inversely proportional overall to the cube of the thickness, which would be of the order of 10^{19} poise for a thickness of 100 km.

Let v be the speed of the plate in centimeters per year. We will set the thickness of the asthenosphere as $h \times 100$ km, which gives a value of the shear stress, produced by the coefficient of viscosity times the gradient of the speed, of $\eta \times (v/h) \times 3.15 \times 10^{-15}$ dyn/cm² and of the work in a year of $(\eta v^2/h) \times 3.15 \times 10^{-15}$ erg/cm². If v is the root-mean-square plate speed for the entire earth, the total power is $(\eta v^2/h) \times 5 \times 10^{-14}$ kW. For $h = 1$, $v = 3$ cm/yr, and $\eta = 10^{19}$, we find 4.5×10^6 kW, and for $h = 3$, $\eta = 10^{21}$, and $v = 2$ cm/yr, we find 6.6×10^7 kW. We would find a power of the same order or smaller if we supposed a thinner asthenosphere with a lower viscosity. It is very probable that this viscosity varies greatly with depth, but it would be of little use to introduce in the model a viscosity law of which we know nothing.

From the collection of these estimates, rough as they are, we can conclude that the mechanical energy spent in tectonic processes must be of the order of 1 or 2×10^8 kW, which is very small compared to the geothermal flux of 2.56×10^{10} kW. It is thus very likely that we should look for a mechanism by which this mechanical energy can be derived from thermal processes without, however, necessarily excluding a direct transformation of gravitational potential energy caused by differentiation of the core, or as a consequence of other density differentiations in the midst of the mantle, to mechanical energy.

It is easy to show that the hypothesis of a contraction caused by the cooling of the earth, which was suggested at the beginning of last century, would not be satisfactory. To show this, it suffices to calculate the mechanical energy accumulated in elastic form resulting from the stresses due to cooling. These stresses increase in proportion to the time, and thus the elastic energy increases as the time squared. The average power available is proportional to the time that

the stresses accumulated. But the calculation done[1] for the most rapid cooling imaginable, which is that of the model of Buffon, without considering radioactive effects, shows that these stresses would have had to accumulate for a time period greater than the age of the earth and would reach values of hundreds of kilobars, which no rock could withstand without rapidly deforming. Thus, we can formally eliminate this old hypothesis of contraction.

8-7 Convection

The only mechanism left which we can invoke is that of convection currents. But we should be ready to recognize convection in unusual forms. For example, the eruption of a volcano, in which the weight of the overburden, consisting principally of consolidated lava, exerts pressure on the lava reservoir which allows lighter molten lava to rise to the surface, can be considered as a form of convection (see Fig. 8-2). If the molten lava, before solidifying, released volatile substances which contributed to lightening the lava and causing it to rise, a process of gravitational differentiation would be added to the thermal convection.

Convection implies a uniform chemical composition (with the reservation that differentiations which could occur in the course of convection could contribute to activate the gravitational potential energy). The increase in density with depth between 400 and 900 km in the earth, which seems to be too great to result from compression of matter alone, is attributed to the appearance of high-pressure mineral phases. The best known is the spinel form to which olivine can invert above a pressure which increases with the magnesium concentration. But other transformations are also possible; silica can appear in the form of

[1] Jean Goguel. Une estimation de l'énergie mécanique disponible dans la contraction par refroidissement. *Tectonophysics*, vol. 2, no. 5, pp. 395-400, 1965.
Jean Goguel. La contraction thermique peut-elle expliquer les déformations tectoniques?. *Bull. Volcanologique*, vol. XXXIII, no. 1, pp. 89-100, Napoli, 1969.

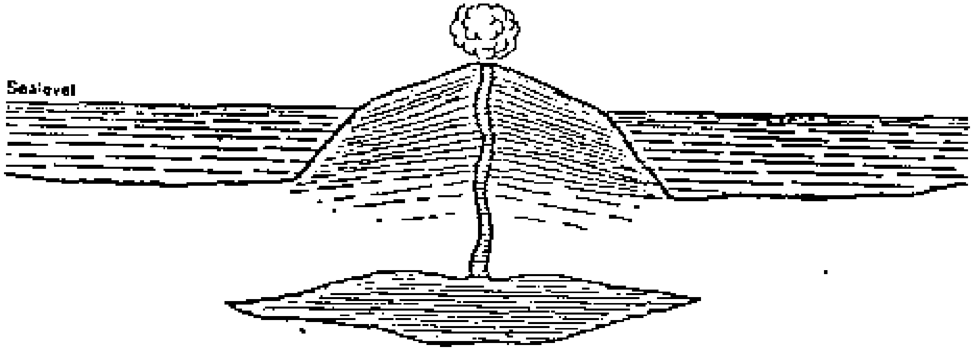


FIGURE 8.2 Sketch of a Hawaiian volcano showing how a lava eruption can be considered as a type of convection.

stishovite above 100 kbars, with a density at atmospheric pressure, greater than 4.

Convection also implies a certain fluidity, but we shall see that the viscosity can be very high; but it is necessary that weak stresses can cause a very slow deformation without it being necessary for the stress to exceed a threshold of plasticity.

Convection can only be produced if the thermal gradient is greater than or equal to the adiabatic gradient which corresponds to the temperature variation due to the change of pressure with depth. As best we can guess from mineral properties studied in the laboratory, this gradient may be of the order of 0.25 to 0.30°C/km.

From the moment that a thermal gradient exists, it gives rise to a heat flux by conduction which does not interfere with convection. The latter implies a heat transport by moving matter, and it is to this heat transport that Carnot's principle can be applied in order to calculate the maximum proportion of heat transformed into mechanical energy as a function of the temperatures at the base and top of the convective system. This proportion will be given by the ratio of the temperature difference between the base and the top and the absolute temperature of the base. If the height is limited, with a gradient nearly that of the adiabatic gradient, this efficiency must be very low.

But the viscosity in the midst of this region is certainly high, and part of the mechanical energy produced is dissipated by viscosity in the movements of the currents. It could even happen (which is what we observe in many convective movements which do not have an external effect) that the total mechanical energy produced is dissipated by viscosity; in general, this will be the case for a substantial amount of the energy.

As a first approximation, we can give a description of a system of convection currents relative to the average situation, which has a regular thermal gradient. For any sort of model of currents perturbing this regular gradient, we will consider a distribution of the thermal perturbation, through a factor $\Delta\theta$, and a distribution of velocities, also through a factor, that will be characterized by a typical velocity V. Let L be the characteristic dimension which defines the scale of the motion. The velocity gradients are proportional to V/L; the stresses which result from these gradients go as $\eta V/L$, the power dissipated per unit volume as $\eta V^2/L^2$, and the total dissipated power goes as $\eta V^2 L$. In addition, the fluctuations in density are proportional to $\lambda\,\Delta\theta$ if λ is the coefficient of thermal expansion and the pressure variations go as $\lambda L\,\Delta\theta$. The mechanical power furnished is equal to an integral extended over the product of the velocity times the fluctuation in the pressure gradient with respect to equilibrium, an expression which must vary as $L^3V\lambda\Delta\theta$.

In order that this system of currents can act under the conditions we are considering, it is necessary that $\lambda\Delta\theta VL^3/(\eta V^2L)$ exceed a certain numerical value which depends on the convection model and on the definition of the velocities, the dimensions, and the variations of the characteristic temperature. This ratio is equal to $\lambda L^2\,\Delta\theta/\eta V$, and it is always possible to take V small enough, whatever the viscosity, so that this condition is fulfilled. But the dissipated mechanical power is given by an expression proportional to $L^3\lambda V\,\Delta\theta$; $\Delta\theta$ will not take too large of a value and will not exceed the temperature difference between the base and the top of the system, which limits the mechanical power which can be produced. It is likely that this limitation acts and is lower than the limitation resulting from Carnot's principle.

The preceding considerations suppose nothing about the form of the convection currents or the model which represents these currents and which can—as we have indicated at the beginning of this section by an example—take the most diverse forms. It is not possible to undertake a calculation of such models because their particularities can result from quite complex phenomena such as viscosity variations with the temperature.

In fact, there exist no models of convection currents at present which can be put to an exact calculation even by simplifying the representation of physical properties (viscosity taken as uniform and independent of the temperature, etc.). There are models which lend themselves to calculations concerning the initial stage, for which, supposing a thermal perturbation, we can investigate whether the movements of the fluid will permit the perturbation to amplify or disappear by conduction more rapidly than the movements caused by density differences can augment it. This is a stability calculation analogous to the calculation we did in Chap. 3 to analyze the possibility of a convection of a very different nature (in a porous rock). We have no valid mathematical model prepared to account for convection in full development, assuring an effective heat transport, furnishing mechanical power, and absorption of part of that power by viscous friction.

Now, given the dimensions of the earth and the extremely high viscosity of the mantle, it is indispensable to give an idea of the orders of magnitudes of the currents which we are considering. We can derive them by approximate reasoning relying upon very rough models.

The simplest way to represent a linear convection cell of width $2a$, depth $2b$, and length c, is to write the speeds of the fluid:

$$U = v_0 \frac{a}{b} \cos \frac{\pi x}{2a} \sin \frac{\pi y}{2b}$$

$$V = -v_0 \sin \frac{\pi x}{2a} \cos \frac{\pi y}{2b}$$

The temperature in an ascending or descending current must be characterized by its difference from the adiabatic profile (it would be more correct to characterize the current by its entropy, which is conserved). If G is the superadiabatic gradient (excess of the actual gradient over the adiabatic gradient), the margin of possible variations in temperature is $2Gb$ and the difference between temperatures in the currents and the average is $Gb \sin (\pi x/2a)$. The variation of the density due to thermal expansion is $\rho g \lambda \, \Delta\theta$, and we will take $\rho = 3$, $g = 900$, $\lambda = 5$ to 8×10^{-6}, and for the viscosity, $\eta = 10^{21}$.

It is easily found that the power dissipated by viscosity from a cell is

$$W = \frac{2ac}{b} \eta v_0^2 \pi^2 \left(\frac{a^2 + b^2}{4ab}\right)^2 \tag{8-8}$$

The motive power results from the vertical displacement of the fluid occurring in a pressure gradient modified by the variation of density, and it is found to be

$$P = 2ac \left(\frac{2}{\pi}\right) g\rho\lambda G v_0 b^2 \tag{8-9}$$

To get orders of magnitude applicable to the earth from these formulas, we will express the vertical velocity V in centimeters per year ($V = v_0 \times 3.15 \times 10^{-8}$) and the height of the convective system, $2h$ in kilometers ($h = b \times 10^{-5}$), and we will extend the calculation over the entire earth's surface by taking an average radius for the system of 5,000 km, which gives a surface area of $\pi \times 10^{18}$ (which replaces $2ac$). We will express the superadiabatic gradient S in degrees Celsius per kilometer, which means $S = G \times 10^5$.

From these substitutions it is found that $P = 10^4 SVh^2$ kW and $W = 10^{10} V^2/h$ kW, and the heat flux transported by convection over and above the flux transported by conduction equals $2.7 \times 10^{10} hV$ cal/s or $10^8 hV$ kW, an expression which could take excessively large values for some models which have been proposed. Thus, it is the heat flux to be transmitted which will limit the temperature differences of the convective current to smaller values than we have allowed as the possible maximum (Gh); it may also happen that the velocities are smaller or that the currents instead of distributing themselves over the entire available surface, as our model supposed, are much more localized.

From the preceding formulas the condition can be given that

$$V < S\left(\frac{h}{100}\right)^3 \tag{8-10}$$

If $S = 1$ (it can scarcely be imagined that S will exceed a value of 2 or 3), this gives a velocity limit $V = 1$ cm/yr for a system 200 km high and $V = 1$ m/yr for a system 1,000 km high.

These formulas show us how the power furnished depends on the height of the system. Suppose that the velocity is half of the limit and also that $S = 2$. We will then have $V = (h/100)^3$ and the power furnished will be given by $P = 2 \times 10^{-2} h^5$ kW, of which half will be absorbed by the viscosity and the other half will be utilizable.

Note especially the exponent of h in Eq. (8-10); the mechanical power which can be produced by convection, appearing in the mantle where the thermal gradient is determined in another way (very likely this gradient is close to the melting-point gradient which is produced by pressure), increases enormously with the height of the convective system.

Our calculations are much too rough for us to obtain the value of the power furnished; Carnot's principle imposes a much surer limit. But it should be remembered that a convective system with a small height, of the order $2h = 200$ km, will furnish insufficient mechanical power and that a thicker system, of the order of 1,000 km, seems much more probable. The maximal velocities of the currents could then be of the order of a meter per year.

On the whole, it appears that we can retain the hypothesis of convection currents, originating from a thermal flux in the mantle and producing mechanical energy which is manifested in internal activity of the earth. But the model utilized for these calculations should absolutely not be considered as a description; actual convective currents can be quite different.

Remember that the viscosity very likely changes with depth, and the action of dissipating energy through viscous friction by currents locally raises the temperature and reduces the viscosity; it thus appears that the current forms are certainly very different from the forms discussed previously. In particular, ascending currents, hotter and less viscous, tend to be more rapid, thus occupying a small cross-sectional area, and are separated from larger descending currents by a slippage surface along which the temperature will increase sufficiently to greatly reduce the viscosity, rather than by a zone with a regular velocity gradient.

We must emphasize a difference between the convection currents that we have the opportunity to observe and those currents which can exist in the interior of the earth. In the first type, inertia plays an appreciable role, and, as a consequence, there is a tendency for the current system to maintain the same sort of motion. It is not the same for currents in the mantle, where the kinetic energy, with velocities of the order of magnitude prevously indicated, is totally negligible. For harmonic models which lend themselves to calculation, it can be shown that the kinetic energy corresponds to the energy absorbed by viscous friction in a time which is of the order of $\frac{1}{10}$ s. As a consequence, nothing excludes the possibility that the movement is very irregular in time with alternations of halts (when elastic energy is accumulated) and more rapid movements.

Finally, let us remember that all the considerations on the power furnished by any system of thermal convection currents can be false if there is at the same time a differentiation which is expressed by a density difference (at equal temperatures) between ascending and descending currents. A lighter residue then will accumulate at the top of the system and a heavier residue at the bottom. Such a progressive differentiation could have continued since the beginning of geological time and furnished a considerable part of the mechanical energy dissipated in tectonic events.

These theoretical considerations show that the hypothesis of convection currents does not run into any objections (at least if they exist over a sufficient height). But these considerations do not give us any valid indication of what their form or their depth could be.

What indications of these characteristics can we obtain by other methods? There is a decline in seismic velocities at a depth of around 150 km which has been interpreted as indicating the beginning of fusion and which marks the top of the asthenosphere. This interpretation is usually invoked to allow plate gliding and isostatic readjustments. It is natural to assume that the upper limit of convection currents also occurs there. What is their base? Models have been proposed by different authors attributing a quite small height for these currents. This seems unlikely given the difficulty that there would be in producing the energy dissipated in tectonic processes. It is poorly understood how heat transport by conduction alone could exist beneath convection currents without producing thermal gradients leading to other zones of incipient fusion. It seems that it is much more likely that these currents occur over a large depth in the mantle, and there are no peremptory arguments to dispute such a hypothesis.

The classical mechanism proposed for plate tectonics is in fact a form of convection, in particular the ascent of intrusive rocks, basic or ultrabasic, in fissures which mark the openings of rifts. It is known that the magnetization acquired in the earth's field in prior times by rocks in the course of their cooling is the origin of magnetic anomalies parallel to the rift on both sides. Actually, the geothermal flux is greater than normal (up to eight times) on the axis of the rift and up to 100 km on either side. The additional amount of flux by comparison with the normal value can be of the order of 3×10^5 cal/cm^2 · yr, which for a supplementary annual thickness of 2 cm of intrusive rock effectively represents the heat liberated by a cooling of 500°C over 60 km of depth. But it is quite evident that such an average balance would not completely describe the phenomenon, and all models proposed to describe plate action include a geothermal interpretation, destined to interpret the diffusion of heat away from the injections.

The descending convective branch in the lithosphere and even lower would be represented by the subduction of plates under a Pacific-type island arc (or under a continental plate like South America). But here, the geothermal flux distribution, with higher than average values of about 2 μcal/cm^2 · s behind the arc, is not so easily interpreted; the flux distribution makes it necessary to invoke secondary phenomena (refusion, secondary cells of convection, etc.) which remain very hypothetical. But there again, the geothermal interpretation is essential for all proposed models of plate action. However, the detailed analysis of such models takes us away from our subject, and they can be found in descriptions of plate theory.

The arrangement of convection currents in the asthenosphere is probably related to the behavior of these convective phenomena in the plates themselves, and this must be reflected in their general disposition, with ascending currents in the vicinity of mid-oceanic rifts and descending currents in subduction zones and along mountain ranges which resulted from compression. But it can well be thought that certain geometric constraints which appear in the case of plates as transform faults which offset the rifts do not act on the currents whose axes can take much more supple forms. Are there other areas of ascending and descending currents which should be held responsible for the evolution of certain regions in the midst of plates such as uplifts (followed by erosion) which would result from weak compression or depressions which permitted the accumulation of thick sedimentary basins and which could result from a small extension? I can only ask the question.

It has been pointed out recently that some volcanoes sequences appear more and more ancient as the distance from the region of presently active volcanoes increases (the best example is furnished by the Sandwich Islands). This may be taken as a consequence of the gliding of a plate above a fixed heat source which has been identified as a plume of hot material escaping from the lower mantle at points which have remained stationary for durations approaching hundreds of millions of years. Although the depth from which these plumes issue remains very poorly determined, it is a first indication of what could be the arrangement of currents in the lower mantle. But of course, there could not be any ejection of material by a certain number of quasi point sources unless it was compensated by the descent of cooler material, perhaps over a much greater surface area and with a very small velocity. It would be geometrically improbable that the descent was produced radially in every direction in a sphere. It can be imagined that the system of ascending currents has the form of a network but that the upward motion tends to reach greater and greater velocities and be concentrated at the intersections of the network. This arrangement is what would be expected of matter so completely solidified that the viscosity is very high except where the dissipation of energy by viscous friction raises the temperature.

The existence of convection currents in the lower mantle is made very probable by an interpretation which is given today to the origins of the internal magnetic field. It is thought to originate in the core by magnetohydrodynamic processes. These processes imply, as a source of energy, convection currents of thermal origin stirring the molten iron which constitutes the core with velocities much higher than in the mantle, of the order of 100 km/yr. It can be shown that for such speeds, the Coriolis force caused by terrestrial rotation is not negligible and tends to make circulations predominate in planes perpendicular to the axis of rotation. This yields the N-S component of the average magnetic field. The displacement of conductive iron in the magnetic field gives rise to electric currents which, in their turn, maintain the magnetic field.

One may wish to know the amount of energy spent in the creation and modifications of the terrestrial magnetic field, but this can only be estimated and that only by default. However, let us indicate the elements of the argument. If the portion of the magnetic field which represented the effect of a central dipole, and which constitutes the essential portion of the field observable at the surface, was caused by electric currents circulating on the surface of the core, it would correspond to an energy of 6.3×10^{23} ergs, which is 2×10^{6} kW · yr. But if the currents which produced the field circulated in a sphere of lesser radius, this energy would increase as the inverse of the radius cubed—and there are many reasons to think that the currents are in fact distributed in the volume of the core. Thus, we are led in the calculation of the energy of the magnetic field, to consider successive terms of its harmonic development, although this development is a purely mathematical artifice; these terms are simply added. Now, it is observed that the energy corresponding to each of the terms of order 4, 5, 6, 7, and 8 would be of the same order as the energy of the first term (central dipole) if the currents which caused them circulated in a sphere of radius 2,650 km, which is three-quarters (77 percent) of the radius of the core. Our observations, necessarily confined to the earth's surface, do not inform us about higher terms, but it is perfectly possible that they also correspond to energies of the same order and represent local irregularities of the field of the core. The total energy of the field, then, at a minimum is 10 to 20 times greater than the number previously cited, and could even be greater. Theoretically, the maintenance of a magnetic field does not absorb any energy, but its creation and modification does. At the surface we observe variations in the magnetic field with periods of about 1,000 yr. But before deducing an order of a magnitude for the energy absorbed from this period, it is necessary to remark that if the activity in the core implied more rapid variations in the magnetic field, they would not be observable at the surface because they would be compensated by induced currents in the conducting lower mantle. It is this filtering in time which limits the observable rate of change at the surface, and thus much more rapid variations of the field in the core are not at all excluded. In total, the facts in our possession risk leading us to a grave underestimate of the power absorbed in changes of the magnetic field, which would be at least 10^{7} to 10^{8} kW.

It would also be necessary to take into account, besides

the power dissipated by the joule effect, the power dissipated in electric currents in magnetohydrodynamic phenomena, and it is likely that the thermodynamic efficiency of the convection currents in the core, which allow these phenomena, must be very low. So much so that the heat flux generated in the core must be much higher than the above figures.

It is very unlikely that such flux can be transmitted by conduction through the base of the mantle without leading at least to partial fusion. It seems that the most likely solution is to admit that convection currents occur over the entire depth of the mantle.

6-8 A hypothetical model for the mantle

The extrapolation of properties measured at the surface lead us to think that the melting-point gradient of the ultrabasic silicates which must constitute the mantle (but what is the gradient for high-pressure mineralogic forms?) is distinctly higher than the adiabatic gradient. From this it can be concluded that if the convection currents maintain a gradient nearly that of the adiabatic, then the mantle must have begun to crystallize at its base. But in reality, near the fusion point the adiabatic thermal profile becomes entangled with the thermal profile of solidification. In an adiabatic transformation, it will be the proportion of solid and liquid phases which will vary, the solid phase increasing toward the bottom. This is not incompatible with what is known of the form of convection currents in the lower mantle.

From the preceding, we can imagine that in the mantle the temperature everywhere would be close to the temperature corresponding to the beginning of fusion, giving the mantle the ability to deform with perhaps a very high viscosity. The fusion conditions of ultrabasic rocks are not sufficiently well understood at high pressures, where minerals take their high-pressure forms, to permit us to calculate the temperatures; at least we can say that this

depends only on determinations which are in principle possible in the laboratory.

Such a distribution of temperatures is certainly not a simple coincidence. First, let us imagine an earth that at its beginnings was heated sufficiently so that all matter was molten. Differentiation of the core could then easily occur with a complementary production of heat. As soon as radiation had sufficiently cooled the surface so that a solid crust could form, the conductive transfer through the crust would become very slow, in spite of the relatively high thermal gradient existing there. On the other hand, convection would continue to occur in the mantle beneath and assure easy heat transfer to the base of the crust. The interior of the earth could then cool until the moment when the beginning of solidification rapidly increased the viscosity. But this solidification could not run to its ultimate end because the latent heat of solidification would not be removed by conduction through the solid rock, given the low value of the gradient inherited from the prior convective system.

If, on the contrary, the earth was formed cool, it would progressively heat up by radioactivity and compression and we would have to concede that this heating had reached, at least in some places, the fusion temperature. Then convection would start which would allow removal of heat much more easily than by conduction alone and would limit the temperature increase in the molten region and regularize the temperature distribution there. If the entire mantle had thus reached the fusion temperature, the analogy with the preceding imagined situation of an earth formed at a high temperature would be complete. If it is conceded that the mantle only reached the fusion temperature in a few places over a limited thickness, the fusion temperature would permit the establishment of a convective system and the differentiation of the core would remain to be explained. This raises enough difficulties so that it seems to us that this hypothesis must be discarded.

Recall that the model we imagined would not have to be stationary; the decrease of the percentage of radioactive substances in the crust would necessarily lead to a tempera-

ture decline at its base which is inevitably reflected by conditions at the top of the mantle. It is perhaps necessary to admit that in the lower Precambrian the convective system occurred over the entire depth of the mantle, thus assuring its homogeneity. In contrast the crust became chemically differentiated and lighter. We have already noted that the geothermal flux and the gradient ought to have been higher then, which would have important geological consequences. In conclusion (see Fig. 8-1), from the upper Precambrian, the top of the mantle must have cooled, solidified, escaped convective action, and made a mechanical connection with the crust to form the lithosphere. It can be asked in what way such an evolution would be translated into the tectonic, magmatogenic, and metamorphic characteristics of mountain ranges of different ages compared with those of the lower Precambrian.

appendix

Table A-1
Useful functions

x	e^{-x^2}	$\mathrm{erf}(x) = \frac{2}{\sqrt{\pi}}\int_0^x e^{-y^2}\,dy$	$\mathrm{erfc}(x) = 1 - \mathrm{erf}(x)$	$\Phi(x) = \sqrt{\pi}\int_x^\infty \mathrm{erfc}(y)\,dy = e^{-x^2} - \sqrt{\pi}\,x\,\mathrm{erfc}(x)$	
				$\Phi(x)$	$\Phi(-x)$
0	1	0	1	1	
0.1	0.99005	0.1125	0.8875	0.8317	1.1862
0.2	0.96079	0.2227	0.7773	0.7022	1.3032
0.3	0.91393	0.3286	0.6714	0.5569	1.6194
0.4	0.85214	0.4284	0.5716	0.4942	1.8639
0.5	0.77880	0.5205	0.4795	0.3521	2.1345
0.6	0.69768	0.6038	0.3962	0.2756	2.4025
0.7	0.61263	0.6778	0.3222	0.2122	2.6936
0.8	0.52729	0.7421	0.2579	0.1611	2.9370
0.9	0.44486	0.7969	0.2031	0.1204	3.3108
1	0.36788	0.8427	0.1573	0.08871	3.6336
1.2	0.23693	0.9103	0.0897	0.04591	4.2997
1.4	0.14086	0.9523	0.0477	0.02235	4.9351
1.6	0.07730	0.9763	0.0237	0.01002	5.6818
1.8	0.03916	0.9891	0.0109	0.004355	6.3852
2	0.01831	0.9953	0.004677	0.001735	7.0915
2.5	0.00193	0.9996	0.000407	0.0003278	8.8626
3	0.000123	0.9999779	0.0000221	0.000008063	10.6347

Table A-2
Properties of water and of saturated steam

Temperature, °C	Pressure, bars	Latent heat, cal/g	Specific volume, cm^3/g	
			Water	Steam
100	1.013	539.7	1.0434	1,673.
120	1.9854	526.6	1.0603	891.7
140	3.6136	512.5	1.0798	508.66
160	6.180	497.1	1.1021	306.85
180	10.027	480.2	1.1275	193.85
200	15.550	461.6	1.1565	127.19
220	23.202	441.25	1.1900	86.062
240	33.48	419.45	1.2291	53.674
260	46.941	397.2	1.2755	42.149
280	64.19	368.6	1.3321	30.133
300	85.92	336.6	1.4036	21.643
320	112.89	295.7	1.4992	15.451
340	146.08	245.5	1.639	10.779
360	186.74	172	1.894	6.943
374.15	221.20	0	3.1	

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GEOTHERMAL ENERGY

Recent Developments

Edited by M.J. Collie

NOYES DATA CORPORATION
Park Ridge, New Jersey, U.S.A.
1978

Foreword

The heat underneath the Earth's crust seems a highly desirable energy source; alternative to oil, gas, and coal. The Earth does not give up her energy readily, still geothermal energy activities are progressing on a broad front worldwide wherever possible.

Operational fields are increasing in numbers, and new and improved technologies, especially new turbine designs and deep-well pumps, coupled with heat exchangers at the surface, are leading to much greater operating efficiency.

Yet, as a rule, geothermal power stations, with a few exceptions, are inefficient in converting thermal energy to electric energy, because of the overall low temperatures. Also the highly mineral-laden waters in the geothermal reservoirs increase operating expenses through scale formation, thus complicating the process of extracting the heat.

Geothermal energy is not expected to play a large overall role in the United States. But it can have regional significance, especially in the west. For developing countries, however, geothermal energy, especially in volcanic regions, may be the only economic form. Electricity distribution systems there are too small to justify nuclear power stations, but the comparatively small size of geothermal power stations fits the scale of electricity supply systems in these countries.

This Energy Technology Review is based mostly on studies conducted under the auspices of various government agencies, and the last chapter describes proprietary processes gleaned from U.S. patents.

Because the information in this book is taken from many sources, it is possible that certain portions may disagree or conflict with other parts of the book. This is especially true of monetary values and opinions of future potential. We chose to include these different points of view, however, in order to make the book more valuable to the reader. Cost figures provided are those given in the report cited, the date of which is always given. When the dates of the cost figures themselves are given, we have included them.

Foreword

Adva composition and production methods developed by Noyes Data are employed to bring our new durably bound books to you in a minimum of time. Special techniques are used to close the gap between "manuscript" and "completed book." Industrial technology is progressing so rapidly that time-honored, conventional typesetting, binding and shipping methods are no longer suitable. We have bypassed the delays in the conventional book publishing cycle and provide the user with an effective and convenient means of reviewing up-to-date information in depth.

The Table of Contents is organized in such a way as to serve as a subject index and provides easy access to the information contained in this book. The primary sources on which this book is based are listed at the end of the volume, as are the patents (by company, inventors and numbers).

Some of the illustrations in this book may be less clear than could be desired; however, they are reproduced from the best material available to us.

Contents and Subject Index

Introduction

Although geothermal energy in the form of geysers and hot springs has been used for recreational and health purposes and as a source of minerals for hundreds of years, its use for heating and the production of electricity developed during the twentieth century. The first large scale geothermal power plant began operation at Larderello, Italy in 1904. New Zealand began developing its geothermal fields in the 1950s and has power plants in operation at Wairakei and Kawerau. Other geothermal power plants are in operation in Japan, Mexico, the USSR, Iceland and the United States. The 500 MWe plant at The Geysers, north of San Francisco, is the largest geothermal power plant in the world.

Iceland, with its abundant geothermal resources, has led in the use of geothermal energy for space heating, hot water supply and agricultural uses, such as the heating of greenhouses. More than half of Iceland's population lives in homes heated by geothermal energy. Hungary, the USSR and New Zealand also make extensive use of nonelectric applications of geothermal energy.

A significant portion of the energy now supplied by natural gas, coal and oil could be supplied by geothermal energy. In the United States its energy potential is hundreds of times greater than its present use. It has been estimated that from 5 to 10% of the U.S. electrical energy needs could be supplied from geothermal energy by the year 2000. The environmental problems encountered in the use of geothermal energy are minor compared to those of fossil fuels and nuclear energy.

The first two chapters of this book give an overview of geothermal energy—its origin, environmental effects and present stage of development. The next two chapters describe resources in California with special emphasis in one chapter on the Salton Trough which has been the focus of many recent studies. The fifth chapter is a feasibility study for a 25 to 50 MWe plant; the study compares three reservoirs of different temperatures and three power conversion options. Materials and scale management studies follow. Other chapters give description of work on development of the moderate temperature/low salinity resource at Raft River, Idaho and the Los Alamos Subterrene and dry hot rock projects. Studies of potential benefits of electrical and nonelectrical uses of geothermal energy with cost analyses are given. The final chapter is a survey of recent patent literature.

earth is an immense reservoir of heat, and for over 3,500 million years energy has steadily flowed from the interior to the planet's surface.

Most geothermal energy in fact does not derive from chemical processes. Like the other major energy options—solar, fusion and fission power—geothermal energy results from nuclear processes. (Some heat also is generated by compression and friction at crustal faults and plate junctures. Exothermic chemical reactions may contribute heat in some locations.) Radioactive thorium, potassium and uranium distributed more or less evenly in the earth's crust yield heat as they decay. These elements are very long-lived, with half-lives of several billions of years, and their heat will continue without fail for millenia.

While the earth's store of thermal energy is tremendous, the heat's practical value depends on the ability to effectively employ it. This becomes increasingly difficult as the heat grows diffuse; it is impossible when the heat lies behind rock shields tens of miles thick. Geothermal energy, like petroleum, is transferred to the surface through wells, and these cannot be drilled commercially beyond about 10 km (33,000 ft) because of high cost and technical limitations.

For most of the earth's surface, temperatures accessible by drilling are too low to be economically employed. Geothermal development therefore involves a search for heat reservoirs relatively near the earth's surface. Many valuable sites have been found in the United States and in other areas of the world. The pattern of such discoveries reflects the basic geologic structure of the planet.

Plate Tectonics

The earth's crust is composed of giant plates of solid rock. These are in motion relative to one another. Where they spread apart, molten rock underlying the crust flows upward and builds onto the receding plates. Where the plates impact, the crustal rock is forced downward and melts into the interior. At these junctures heat travels from the molten interior to the inhabited surface (Figure 1.1).

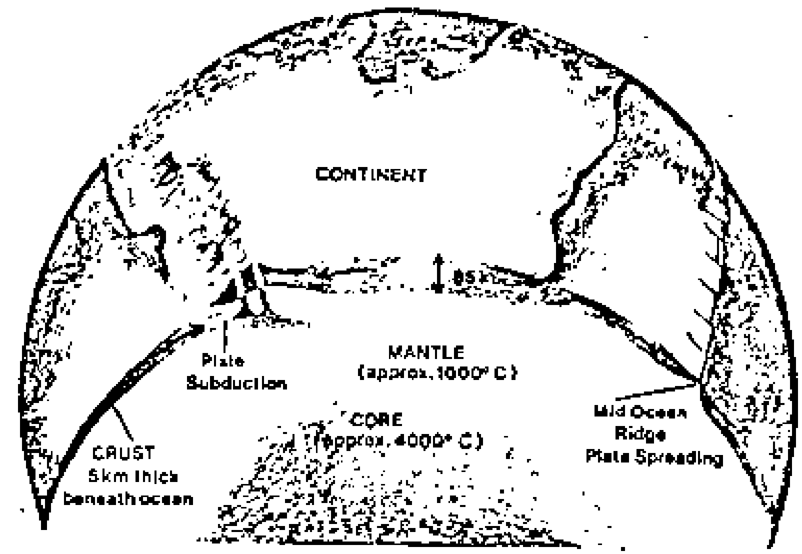
High volcanism along crustal faults reveals the upwelling of magma which brings internal heat near to the surface. Fissures at the plate junctures also allow cool surface waters to penetrate downwards to great depths: when heated, the water returns upward by convection, sometimes appearing at the surface as hot springs and geysers. The intrusion of magma near to the surface and deep circulation of surface waters make the earth's high interior temperatures potentially available for use. Along the plate junctures, therefore, lie the most promising high-temperature geothermal areas.

In the United States, a plate juncture runs from the Gulf of California northward, including the San Andreas fault, along the Cascade Mountains of Oregon and Washington to Alaska, where it parallels the southern coast through the Aleutian Islands.

Another high-temperature structure runs along the Rocky Mountains. Thermal springs and geysers at Yellowstone National Park are the most prominent geothermal evidence of the mid-continent structure. These two geologic features are part of a major geothermal area covering the western continental states and

portions of Alaska. The Hawaiian Islands are a discrete volcanic occurrence not closely associated with a major crustal structure. But certainly near-surface magma chambers are a rich geothermal base for the island state.

FIGURE 1.1: EARTH CROSS SECTION



Source: PB 261 744

HIGH-TEMPERATURE RESERVOIRS

Volcanic intrusion to or near the surface and deep circulation of surface waters along crustal faults form high-temperature geothermal regimes. Four types may usefully be distinguished. These are (1) magma, (2) hot dry rock, (3) water-dominated, and (4) vapor-dominated systems.

Magma and Hot Dry Rock

Where magma chambers lie sufficiently near the surface to be penetrated by drilling, they are themselves a potential resource. Their very high temperatures (700° to 1600°C) make them both attractive and problematic. The hazards of drilling at such extreme temperatures and associated pressures are great. One study of the present ability to directly tap magma is underway at Sandia Laboratories, with field tests anticipated for Hawaii (2).

Magma chambers rarely lie near the surface. More generally, magma intrudes just close enough to the surface to heat the overlying rock to high temperatures. To be utilized, the rock's heat must then be brought to the surface. Water naturally present may form a hydrothermal convection system. If water is not present—hot dry rock—it (or some other heat transfer medium) must be supplied.

Geothermal Energy—The Resource and Its Environmental Effects

The material in the following sections has been based upon a report by D.M. Sacarto of Renewable Energy Resources Project (PB 261 744).

THE VALUE OF GEOTHERMAL RESOURCES

Every point of the globe rests on an ocean of molten rock at 1000°C. Heat from this immense reservoir flows steadily to the earth's surface, where it appears most dramatically as volcanoes, hot springs and geysers. But valuable geothermal resources are more widespread than these special displays. Broad geothermal belts encircle the entire planet. In these areas, the earth's heat is accessible and forms a valuable, multifaceted resource.

Over the centuries numerous beneficial uses have been discovered for geothermal resources. Hot springs have traditionally been gathering places for recreation, and during the thirteenth century, the Larderello hot springs of Italy provided sulfur and other minerals for trade. Later, boric acid was commercially produced, and in 1904 electricity was first generated from the earth's heat, again at Larderello.

With improvements in exploration, well drilling and electric conversion technology, geothermal resources have become available during the past decades on a broad scale. The growing demand for secure energy supplies has also made their development especially desirable. As a source of electricity, geothermal resources globally supply approximately 1,500 MW of power from over a dozen geothermal areas. The Geysers dry-stream field north of San Francisco (the only commercial power development in the U.S.) generates about 500 MW, which is adequate to supply a city of one-half million.

Equally important globally are direct heat uses for geothermal resources in agriculture, industrial processing and for heating and cooling of buildings. The Soviet Union, Hungary, Iceland and New Zealand far exceed other countries in

direct application of geothermal energy; their use totals almost 6,000 MW. In the United States, geothermal energy is used directly for heating at Klamath Falls, Oregon; Boise, Idaho; and in other scattered locations (Table 1.1).

TABLE 1.1: APPROXIMATE ELECTRIC AND NONELECTRIC GEOTHERMAL ENERGY USE IN 1975

Country	Electric Power (MW)		Non-Electric (MW)
	Operating	Planned	
Hungary	....	....	380
Iceland	3	55	285
Italy	406	15	15
Japan	43	75	25
Mexico	79	75	....
New Zealand	170	210	120
United States	413	196	15
U.S.S.R.	6	20	5100
El Salvador	....	30	....
Guadaloupe	....	30	....
Turkey	....	10	....
TOTAL	1120	716	5940

Source: Reference (1)

Geothermal resources can help limit new electric power demands and reduce consumption of natural gas, oil and coal. These limited fuels could instead be conserved through direct use of the earth's heat.

Safe Energy: In addition to their energy potential, geothermal power projects are environmentally safe compared to coal combustion and nuclear fission. Geothermal resources can be produced and wastes disposed through wells with limited disturbance to the land, to ground and surface waters or to other natural resources. In contrast, surface mining of coal and uranium disrupts large land areas and wildlife habitats, and produces extensive water and air pollution.

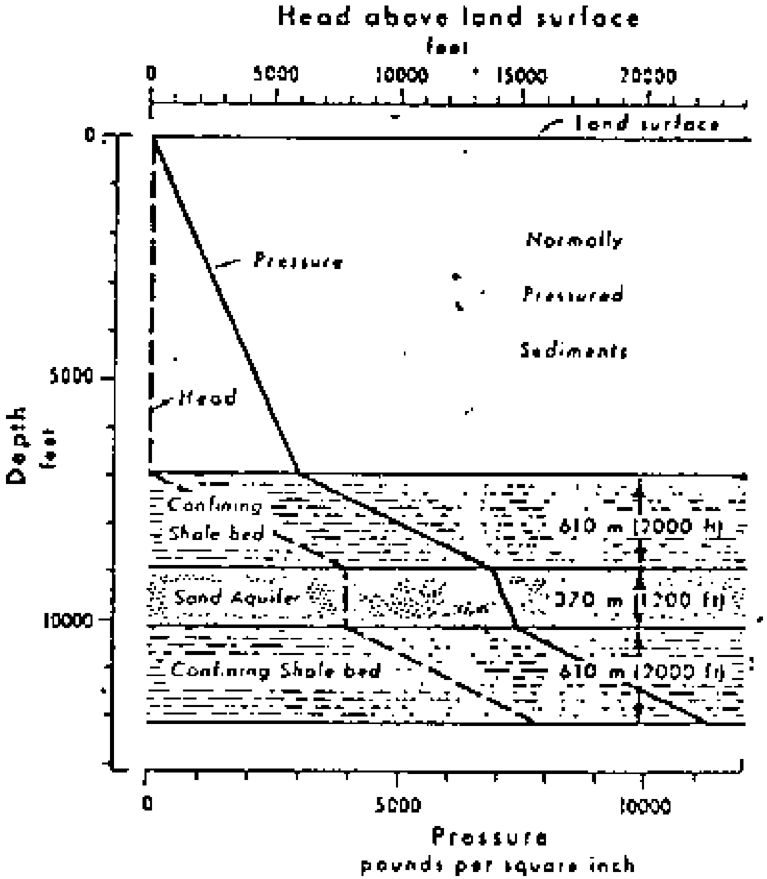
Geothermal power plants also are relatively clean. They create no major pollutants comparable in quantity or complexity to air pollution from coal-fired plants (SO_x, NO_x, particulates) or to radioactive wastes from fission reactors.

At all stages, therefore, geothermal development offers a secure domestic energy supply with comparatively minor environmental impact. And other land uses, such as farming, are not excluded by geothermal facilities. At The Geysers, cattle grazing and recreational hunting continue in the area of geothermal operations; and large-scale geothermal development has for several decades been compatible with vineyards, orchards and seed crop farming in the Larderello district of Italy.

RESOURCE ORIGIN AND POTENTIAL

In terms of its potential, the present use of geothermal energy is small. The

FIGURE 1.2: SECTION OF IDEALIZED GEOPRESSURED RESERVOIR



Source: Reference (11)

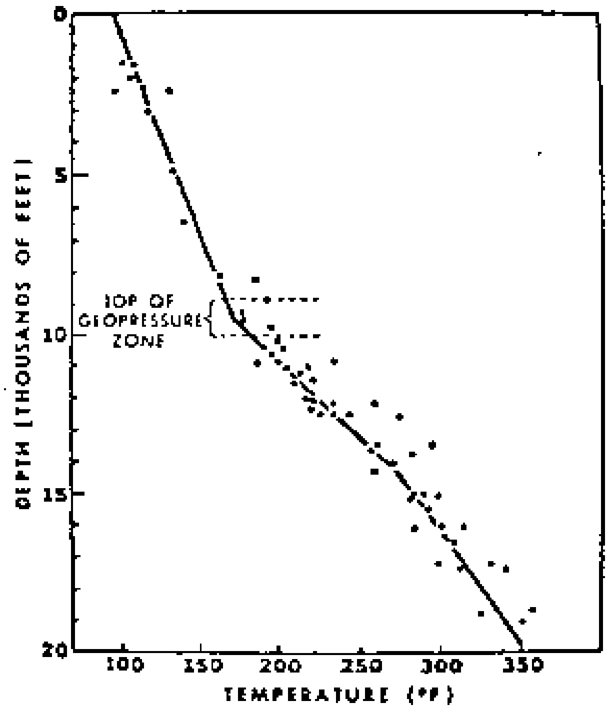
As a result of faulting, these aquifers are partitioned into large vaults, in some cases hundreds of square miles in extent (12).

Shale and water are poor conductors of heat, and water has a high heat storage capacity (about five times that of most rock). These layers of trapped fluid consequently have stored large quantities of heat energy. Temperatures of the fluids range from 90°C to over 200°C (200° to 400°F). See Figure 1.3.

The unusual temperatures are thought to result not only from the low conductivity of the confined formations, but also from unusually high heat flow. The solid crust along the Gulf Coast and underlying the continental shelf is believed to be comparatively thin, with high-temperature magma close to the surface (9).

Geothermal reservoirs along the Gulf Coast in addition have two valuable aspects not typical of geothermal formations in the other western states of the U.S.

FIGURE 1.3: MAXIMUM TEMPERATURES RECORDED IN BOREHOLES IN CAMERON COUNTY, TEXAS



Source: Reference (9)

The reservoirs have unusually high pressures, and the fluid is generally saturated with natural gas. Fluid in the reservoirs is at extraordinary pressure because it is bearing part of the weight of overlying rock, that is, it is geopressured.

Typical reservoir pressures may range, varying with depth, from 5,000 psi to 13,000 psi (10). See Figure 1.4.

This mechanical pressure can be converted to electricity with efficiency as high as 90%, and in some instances, it may account for half of the available electric energy for the geopressured reservoir (10).

The other resource constituent, methane, is expected to exist at saturation in most Gulf Coast geopressured reservoirs (11). Its solubility in the geothermal fluid varies with temperature and pressure, and therefore, the amount of methane produced in a barrel of fluid will depend on specific reservoir conditions (9). See Figure 1.4.

The rate of heat transfer to the surface is the critical factor, and this depends on the rock temperature and on the surface area in contact with the water. The water must circulate in the rock. If the rock is impermeable—the expected situation—it must be fractured to create a large surface area for heat exchange to the water. Explosives or pressurized water may be employed. Under pressure, water induces a vertical "pancake" fracture in the rock, and cool water will extend the fracture by thermal stress (3).

If the rock should happen to be naturally permeable, a reverse problem may result. Unless the permeable area is confined, injected fluid may simply be lost without achieving a circulating system.

As may be expected, hot dry rock areas are extensive compared with hydrothermal or magma systems. Hot rock at temperatures above 290°C (550°F) has been estimated to underlie 95,000 square miles (61 million acres) of the western United States at a depth of 5 km (16,400 ft) (4). Magma systems are a special case in which molten rock is accessible to drilling. Hydrothermal systems are hot rock formations where circulating fluid occurs naturally, transporting heat toward the surface.

Well costs will be critical to the economic feasibility of hot dry rock development. These relate directly to the depth at which suitable temperatures are reached. In addition, rock fracturing techniques to allow heat transfer still must be demonstrated.

Hydrothermal Convection Systems

Vapor-dominated and water-dominated reservoirs are two types of hydrothermal convection systems which differ basically only in the amount of fluid present. The geologic structures are the same. A deep water-bearing strata of permeable rock (aquifer) permits fluid circulation to basement high-temperature rock.

Two types of aquifers may be identified. One type, which includes sandstone, is rather like a fine-pored rigid sponge. Other aquifers result from fracturing of otherwise impermeable rock. Any permeable rock formation can serve as a good geothermal reservoir: The Geysers (impermeable graywacke with fissure permeability); Larderello, Italy (carbonate rock with karstick permeability, i.e., limestone region heavily structured and faulted); Wairakei, New Zealand (fissured ignimbrite); Otake, Japan (permeable deltaic sands) (5).

Above the aquifer in high-temperature formations, an impermeable cap rock prevents the rapid diffusion of the reservoir heat. Faulting is generally present and restricts the lateral loss of geothermal fluid. A fluid's natural tendency to circulate in columns also reduces dispersion of heat (6).

Fluid in most convection systems has originated at the surface from precipitation of rain or snow. The fluid has percolated downward through porous topsoil and then along cracks, faults and through permeable rock strata. This form of fluid is termed meteoric (6).

Not all geothermal fluid is meteoric. Some originates in the underlying magma. Water is also trapped during the formation of rock strata. These types of fluid are termed magmatic and connate. The geopressured geothermal reservoirs of

the Louisiana and Texas gulf coast are the most important occurrence in the United States of connate geothermal fluid.

Water-Dominated: As the volume of liquid increases in a reservoir, boiling at depth is prevented. This is due to the rapid increase with depth of hydrostatic pressure and the corresponding boiling temperature. Under these circumstances, a water-dominated reservoir is formed, with temperature and pressure equilibriums controlled by fluid circulation. Hydrostatic pressure will fall sufficiently to permit boiling if deep fluids which have retained their high temperature circulate to near the surface (6).

Vapor-Dominated: Dry-steam or vapor-dominated reservoirs may occur when a shallow table of water lies near a (usually deep) high heat source, with the inflow of water restricted to no more than reservoir losses. Hydrostatic pressure is thereby limited, and the fluid will boil at depth. Under an impermeable cap rock, a steam system rather like a pressure cooker forms. Some steam venting is usually present, and surface waters will be heated by the steam and steam condensate (6).

MEDIUM-TEMPERATURE RESERVOIRS

High-temperature reservoirs located along crustal faults are not the only exploitable geothermal formations. In those same locations, lower temperature reservoirs may exist where the source-heat is more remote, more diffused in reaching the surface, or less completely trapped (5). If reservoirs are similar except for temperature, the higher temperature formation is the more valuable. Higher temperatures inherently can do more work. Nevertheless, lower temperature fluids may warrant exploitation.

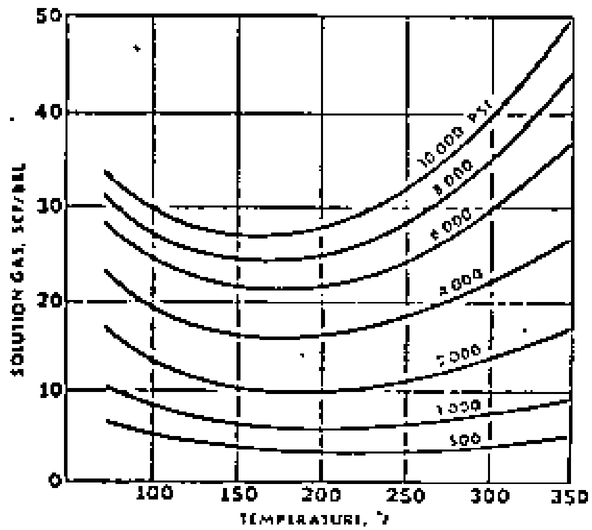
Another type of medium temperature reservoir may exist far from crustal faults. Rock strata in the crust which conduct heat poorly will accumulate regional heat flow and can form a medium-temperature regime. The temperature of a particular strata will depend both on its heat conductivity and on the heat flow at that location.

The sedimentary basin of southwestern Hungary is an important example of this type of formation. At depths of 1,800 to 2,000 meters, geothermal wells produce 85° to 130°C water (7). This is twice the temperature normally expected at 2,000 meters. The Hungarians make extensive use of this resource in space heating and for agriculture. Several hospitals and factories and 2,100 apartments are heated geothermally. In Budapest, 5,600 apartments are supplied with geothermal hot water. Farm uses are equivalent to over 400 MW of power. The costs of geothermal space heating in Hungary, even before the rise of oil prices, were less than half the alternative coal, oil and natural gas prices (1)(8).

Geopressured Reservoirs

The sedimentary basin along the Texas and Louisiana Gulf Coasts is another medium-temperature regime. At depths from 1,500 to 15,000 meters (5,000 to 50,000 ft), connate fluids in porous rock strata several hundreds to thousands of feet thick are sealed between impermeable layers of clay and shale (9)(10). See Figure 1.2.

FIGURE 1.4. TEMPERATURE, PRESSURE AND METHANE CONTENT EXPECTED FOR GULF COAST GEOPRESSURED RESERVOIRS



Pressures and Temperatures for Typical Geopressured Reservoirs

Depth (ft)	Pressure (psi)	Temperature (°F)
5,000-10,000	5,100	200
10,000-15,000	9,100	250
15,000-20,000	12,800	300

The solubility of methane in the geothermal fluid varies with temperature and pressure. Therefore the amount of methane produced in a barrel of fluid depends on specific reservoir conditions.

Source: References (9)(10)

GEOTHERMAL BY-PRODUCTS

Methane in geopressured reservoirs is a by-product of the geothermal system. It is produced by the action of heat and pressure on organic substances deposited in the sedimentary basin. In different formations other types of by-products occur. Minerals and gases dissolve in water, especially as its temperature increases. Metals and insoluble minerals intermixed with the soluble elements also become entrained in geothermal fluids. In the past, potash (KCl) and carbon dioxide have been commercially produced near Niland (7).

Water itself may in some cases be an important geothermal by-product. The fluid heat may be used through distillation or other processes to demineralize the water (13). Where water is scarce and valuable, as in the Imperial Valley, production of both water and minerals may be economical. A U.S. Bureau of Reclamation project is testing this possibility at East Mesa in the Imperial Valley (14).

EXPLORATION

Exploration must locate a field capable of supporting electrical generation at a feasible cost. The factors which determine the suitability of a given reservoir are its temperature, depth, fluid productivity, fluid quality and productive lifetime.

The first step in exploration is a review of existing literature to identify prospective areas. Features are sought in the geology, hydrology and surface characteristics indicative of geothermal potential. Attractive possibilities are pursued by examination of the site using various geophysical and geochemical survey techniques. Geothermal development rights should be secured for the most promising areas.

At this stage, prospects are surveyed further and temperature holes located. Temperature holes range in depth from several feet to a few hundred feet and are used to measure increases in temperature (thermal gradient). The normal thermal gradient between 15 meters and 150 meters is approximately 3°C per 100 meters. In general, geothermal exploration seeks thermal gradients at these depths in excess of 7°C per 100 meters (15).

Surface exploration methods are inferential and can be misleading in numerous ways. Nevertheless, they give fairly strong indications of a geothermal reservoir's depth, minimum temperature and fluid characteristics. On the other hand, they do not reveal the reservoir's ability to produce fluid (15).

Reservoir productivity is controlled by its fluid supply and permeability (the rate at which fluid can move through the aquifer). As a rule, these factors are determined only by drilling into the formation. Permeability, for example, may vary even within a reservoir. Local variation is characteristic of fracture permeability as found at The Geysers or Wairakei, New Zealand (16).

Remaining major unknowns after surface exploration require that geothermal exploration undertake deep drilling. Well location is dictated by results from the preceding exploration, as well as local topography and other environmental factors. If a strong producing zone is encountered, the well-bore is cased and prepared for testing. Additional step-out wells are used to prove the reservoir's production capacity (16).

Exploration Risk

It is important to remember that exploration does not necessarily provide a discovery. Almost certainly several tracts will be surveyed before finding one suitable for deep exploratory drilling. Neither will all tracts warrant equally thorough examination. Exploration expenditures will differ between them.

To estimate exploration expenditures required to discover a producible reservoir, one needs a schedule of probable successes. Table 1.2 is based on an estimate of statistical success developed by Robert Greider of Chevron Oil Company. On the average, according to his figures, 64 tracts of 7,500 acres will be explored before discovery of a field capable of supporting 200 MW in electrical generation (17).

TABLE 1.2: SCHEDULE OF PROBABLE SUCCESSES AND STATISTICAL COSTS IN EXPLORATION

Exploration Method	Cost/Tract	No. of Tracts	Risk-Weighted Cost
Geology & Geophysics	$ 40,000	64	$ 2,560,000
Land Acquisition ($7-acre)	$ 52,500	32	$ 1,680,000
Additional Geophysics	$ 15,000	32	$ 480,000
Temperature Holes	$ 40,000	24	$ 960,000
Test Well to 5000 ft			
a) bore	$ 365,000	16	$ 5,840,000
b) casing	$ 85,000	4	$ 340,000
Subtotal	$ 597,500		$11,860,000
Three Step-out wells	$1,095,000	1	$ 1,314,000
Testing Operations	$ 540,000	1	$ 648,000
Total	$2,232,500		$13,822,000

Source: Reference (17)

For the 200 MW field itself, investment in exploration up to step-out wells is $597,500. The statistical cost, however, is $11,860,000. To this stage, the overall success rate is one in twenty. Neglecting tax benefits, this figure gives the risk burden for investment to this point in the exploration venture.

Beyond the need for 20% return on expenditures, no special risk factors are applied to the step-out wells and testing. If greater uncertainty exists at this stage, expected statistical costs may be significantly greater. As calculated, total investment in the discovered field is $2,232,500. Overall costs leading to the discovery are $13,822,000. Therefore, the success rate for investment in exploration through step-out wells is just under one in six.

Leasing: The importance of land costs in the overall expenditure for exploration should be noted. Fairly early in the evaluation of lands, control of the geothermal interests is secured. Without such control, the property and, consequently, the investment in exploration may be lost to another party.

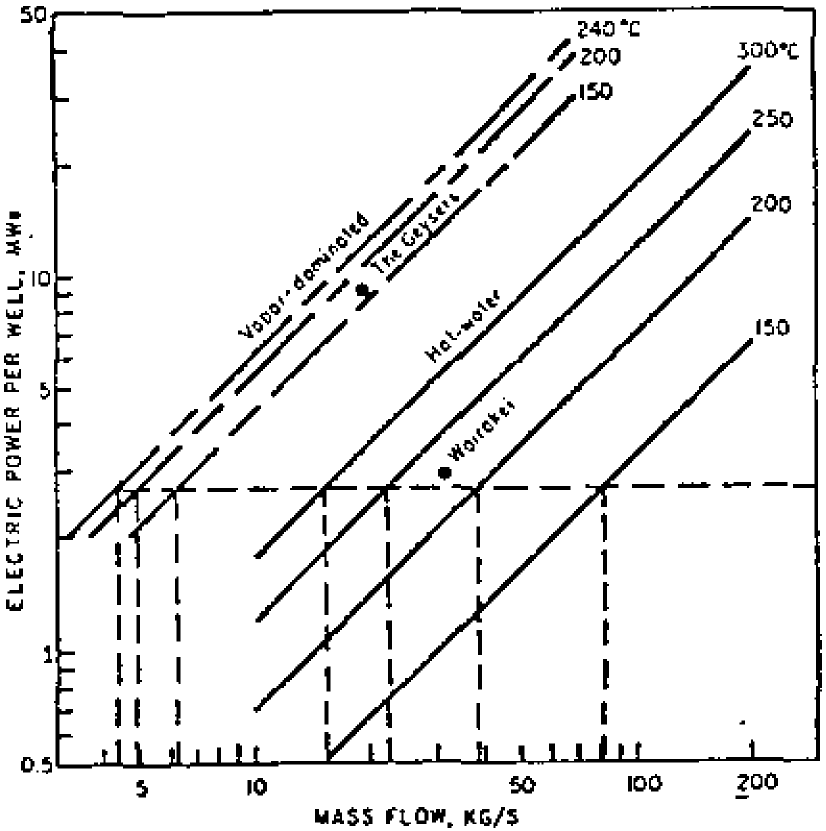
The cost of the geothermal property interests also increases as exploration progressively proves the land's potential. Early control of a promising area is therefore encouraged.

Property investments are strongly affected by risk. The table of probable successes (Table 1.2) shows one influence of uncertainty. It is estimated that of 32 tracts leased, on the average only one will be productive. At $7/acre, this investment is the third largest component of exploration costs, and its weight may force small exploration companies to forego all but the least costly (promising) lands.

Uncertainty in locating and sizing a prospective reservoir also influences property investment by forcing the explorer to lease large tracts. From Figure 1.5 it is seen that a well flow of 40 kg/s (480,000 lb/hr) from a 260°C reservoir will sup-

port 5 MW of power. At 40-acre spacing with back-up wells, a 200 MW field will occupy 2,000 acres.

FIGURE 1.5: ELECTRIC POWER AS A FUNCTION OF MASS FLOW



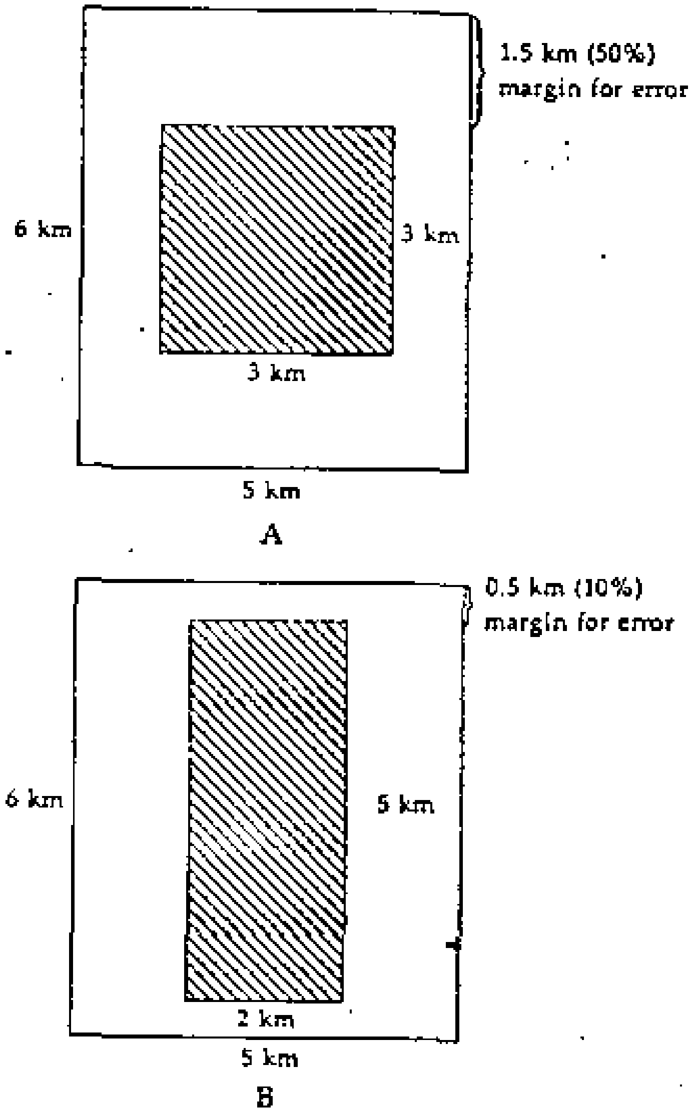
Source: Reference (18)

Temperature, well flow rates and well spacing determine the minimum area necessary to generate 1 MW of power. These factors vary considerably between reservoirs, but for purposes of discussion 10 to 15 acres/MW is taken as typical.

In Figure 1.6 a 200 MW field (9 to 10 km^2) is placed within a parcel of 7,500 acres (30 km^2). As seen, there is little room for error in locating the field center or estimating its total size. In the "best case" (A), no more than a 50% error in location (1.5 km) is permissible. Under less optimum conditions (B), an error of 50% (2.5 km) could place 40% of the resource outside the 7,500 tract.

Location of the reservoir may in fact be subject to great error. At Ahuachapan, Salvador, the thermal center of the reservoir is 7 km from the nearest surface discharge. At Kizildere, Turkey, the thermal center is 5 km from the up-flow center. Deflection of convecting water in these two systems results from lithologic barriers. In other instances, groundwater may mask and deflect thermal discharge many kilometers from the source (16).

FIGURE 1.6: LOCATING A 200 MW FIELD (9 TO 10 KM^2) WITHIN 7,500 ACRES (30 KM^2)



Source: PB 261 744

Estimation of reservoir size also is subject to wide error. This prob was encountered in the USGS assessment of geothermal resources. Order-of-magnitude differences were noted there.

To compensate for such uncertainty in placement and sizing of a prospective reservoir without extensive exploration, large areas of land must be leased. The effect on statistical investment is considerable. Tracts of 15,000 acres, rather than 7,500 acres, would require an overall exploration budget increase of 13%.

Geothermal exploration is a relatively new endeavor. Consequently, not all workers in the field concur with the risk estimates given above. Table 1.3 compares other estimates that have appeared in the literature; more than a factor of three separates the high and low estimates.

TABLE 1.3: ESTIMATES OF EXPLORATION SUCCESS RATES

Exploration Phase	Cost	Success Rate	Present Value
Geophysical	$ 95,000	18%	$ 531,000
		2%	$ 4,000,000
Exploratory Well	$ 450,000	40%	$ 1,125,000
		16%	$ 2,889,000
		7%	$ 6,183,000
Subtotal	$ 545,000	33%	$ 1,656,000
		16%	$ 3,420,000
		5%	$10,180,000
Three Step-out Wells	$1,350,000	80-85%	$ 1,590,000
			to $ 1,690,000
		66%	$ 2,025,000
Testing	$ 540,000	15% return	$ 621,000
Total	$2,435,000	61-63%	$3.9-$4.0 million
		40-42%	$6.1-$5.8 million
		19%	$12.5 million

Source: References (19)(20)(21)(22)

RESERVOIR DEVELOPMENT

Various combinations of temperature, depth, fluid quality, productivity and longevity may yield a commercially producible geothermal reservoir. A moderate-temperature, near-surface reservoir, for example, may be as attractive for development as a higher temperature reservoir that is more saline or lies at greater depth.

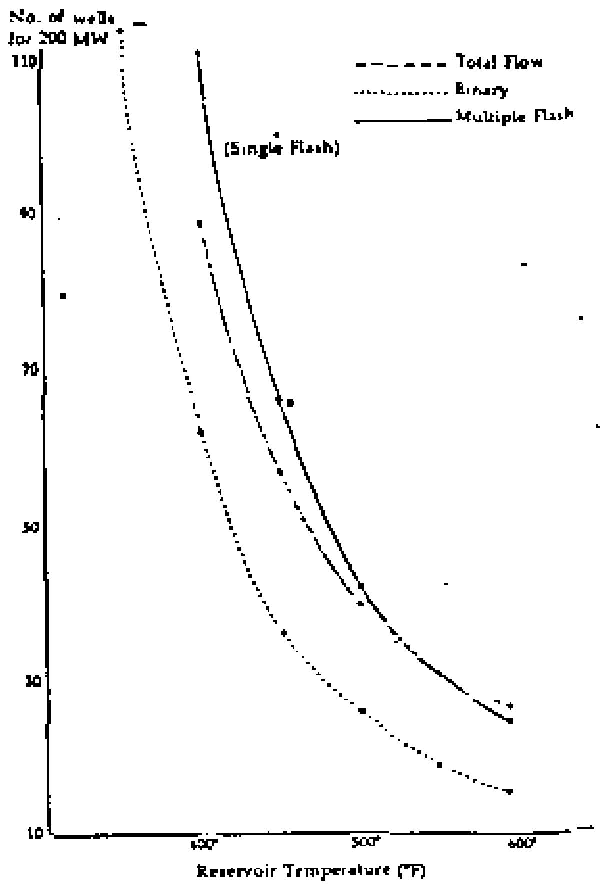
A reservoir is suitable for power production, though only if the developed fluid can be economically matched to an electric generation facility. Therefore, unlike petroleum and other mining operations, field engineering and power plant design are fused into a comprehensive reservoir development program.

Field Development Costs

Fluid Temperature: Other things equal, the cost of producing geothermal electric power declines with increasing fluid temperature. Both the heat value (enthalpy) of the fluid and the efficiency of electric conversion are greater at higher temperatures. In addition, high-temperature wells tend to produce fluid at a greater rate than low-temperature wells. Consequently, less fluid is required to generate the same amount of power, and fewer wells are needed to supply the fluid.

The importance of temperature can be seen in Figure 1.7, which graphs according to temperature the number of wells required to generate 200 MW of power (23). The cumulative effects of reduced fluid enthalpy, conversion efficiency and well production at lower temperatures result in an exponential increase in supply wells.

FIGURE 1.7: WELLS TO SUPPLY 200 MW AS A FUNCTION OF RESERVOIR TEMPERATURE

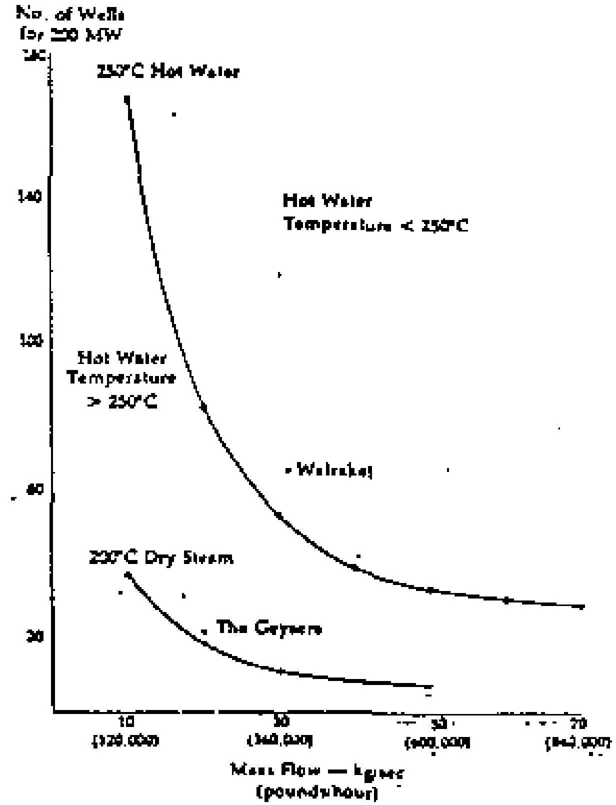


Source: Derived from Reference (23)

Plant costs also are lower for high-temperature reservoirs. Smaller flow rates involve smaller piping, turbines and heat exchangers, while increased plant efficiency permits smaller capacity cooling systems. These components constitute major capital expenses in geothermal plants (24).

Reservoir Permeability: The rate at which fluid can be produced from geothermal wells depends on aquifer permeability. The effect of permeability on power costs can be inferred from Figure 1.8, which plots required supply wells for a 200 MW plant as a function of well (mass) flow rate (18).

FIGURE 1.8: WELLS TO SUPPLY 200 MW AS A FUNCTION OF FLOW RATE



Source: Derived from Reference (18)

Well Depth: Drilling costs increase dramatically with depth. It is this fact which makes most of the earth's immense heat inaccessible. The exact amount spent to drill a well varies with site and formation character. Average costs are revealing, however, and several estimates appear in Table 1.4.

TA[illegible] .4: DRILLING COSTS FOR GEOTHERMAL WELLS

Depth (km)	Total Cost ($)	Average ... Cost/Meter ($) ...	Marginal	Reference
0.5	50,000	100	100	(19)
1.0	150,000	150	200	(19)
	150,000	150	–	(18)
2.0	420,000	210	270	(19)
	300,000	150	150	(18)
	300,000-520,000	166-216	–	(20)
3.0	810,000	270	390	(19)
	500,000	167	200	(18)
	425,000-770,000	170-260	250	(20)
5.0	1,000,000	200	250	(18)
	635,000-1,055,000	200-230	250	(20)
10	5,000,000	500	800	(18)
	2,750,000	300	340	(20)

Source: Derived from References (18)(19)(20)

While deeper holes are more expensive to drill, they generally produce higher temperature fluids. Savings associated with higher fluid temperatures must therefore be weighed against higher drilling costs.

Field Development Risk

Success in drilling development wells is not guaranteed even though a producible reservoir has been discovered. As previously noted, aquifer permeability is not uniform throughout a geothermal reservoir. Wells may fail to encounter a sufficiently permeable, productive region within a generally strong reservoir.

Different estimates of success ratios for development drilling have appeared in the literature, ranging from 66 to 90%. (See Table 1.3.) The rate of success will necessarily depend on the character of the producing formation, but using these figures, the statistical investment in development wells may be obtained.

If 50 production wells are needed, a 66% success ratio implies that a total of 75 wells will be drilled; with 90% success, 56 wells will be drilled.

Using $500,000 as the cost for completed wells and $400,000 for unsuccessful wells (no production casing, etc.), the following expenditures result:

TOTAL WELLS	TOTAL COST	DIFFERENCE
75	$35,000,000	
		$7,600,000
56	$27,400,000	

At a 20% return on investment, the difference in well costs would be $1,520,000 per year. This calculation assumes, however, that unsuccessful development wells have no value. Actually, this may not be true. A supply well failure may be a very useful disposal well. Power plant effluent generally must be eliminated by

returning it to subsurface strata. For water-dominated reservoirs, e[illegible] supply well needs an injection well for disposal. Drilling risk is therefore reduced by the fraction of unsuccessful wells which are valuable for other purposes. On the other hand, any estimate of field development costs should include expenditures for injection wells.

Reservoir and Well Lifetimes

Performance of geothermal wells and reservoirs over time is a major uncertainty in geothermal development. Geothermal well-life varies between 10 and 20 years according to the nature of the fluid and its rates of production and recharge (25); these same factors affect the lifetime of the reservoir (26)(27)(28).

Short lifetime or uncertainty about production longevity induces rapid amortization of capital. Any requirement for rapid amortization strongly affects the cost of power.

The annual returns on exploration investment in a 200 MW field calculated for amortization periods of 10 and 20 years appear in Table 1.5. The present value of return corresponds to the statistical investment in exploration previously calculated (Table 1.3). A 10% discount factor was used.

TABLE 1.5: AMORTIZATION OF EXPLORATION COSTS FOR 200 MW FIELD

Present Value	Annual Return (10 yr)	Annual Return (20 yr)
$4 million	$656,000 – 0.47 mills/kwh	$471,000 = 0.34 mills/kwh
$6 million	$984,000 – 0.7 mills/kwh	$706,000 = 0.5 mills/kwh
$12 million	$1,967,000 = 1.4 mills/kwh	$1,412,000 = 1.0 mills/kwh

Source: PB 261 744

The calculation reveals the strong impact of a short amortization period. Amortization of any investment over 10 years rather than 20 years with a 10% discount rate increases the required annual return by almost 40%.

POWER PLANT DEVELOPMENT

Plant design for a particular geothermal reservoir is selected according to the character of its fluid. Dry-steam reservoirs, like The Geysers, produce steam that may be used almost directly in relatively inexpensive turbines. For water-dominated reservoirs, plant design is dictated by fluid temperature, mineral content and the quantity of dissolved noncondensible gases (e.g., CO_2, H_2S).

Local water supply, meteorological conditions and environmental sensitivities also affect plant selection. Cooling and makeup water requirements differ between designs, and discharges to the environment vary between them.

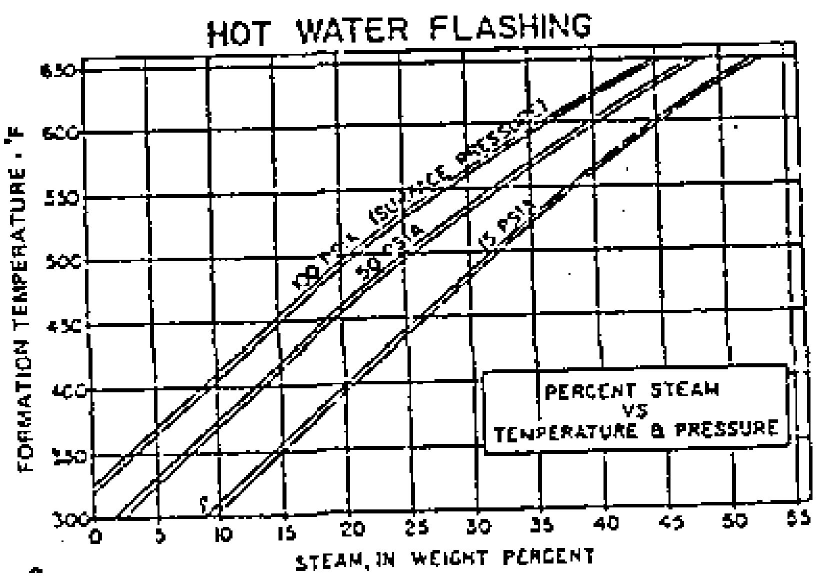
Three basic design options have been advanced for water-dominated reservoirs. These are the flashed steam, binary fluid and total flow systems.

Flashed Steam Plant

The boiling point of water increases with depth due to hydrostatic pressure. If fluid pressure is allowed to drop at that temperature, a portion of the fluid will flash to steam. The amount of steam produced depends on the original temperature and the pressure decrease.

When geothermal fluid is withdrawn without maintaining the reservoir pressure, some of the fluid flashes to steam. A flashed steam plant employs this steam, and the remaining fluid is discarded. As seen in Figure 1.9, a large percentage of fluid heat value is lost with the discharge.

FIGURE 1.9: PERCENTAGE OF HOT WATER FLASHING TO STEAM AS A FUNCTION OF TEMPERATURE AND PRESSURE



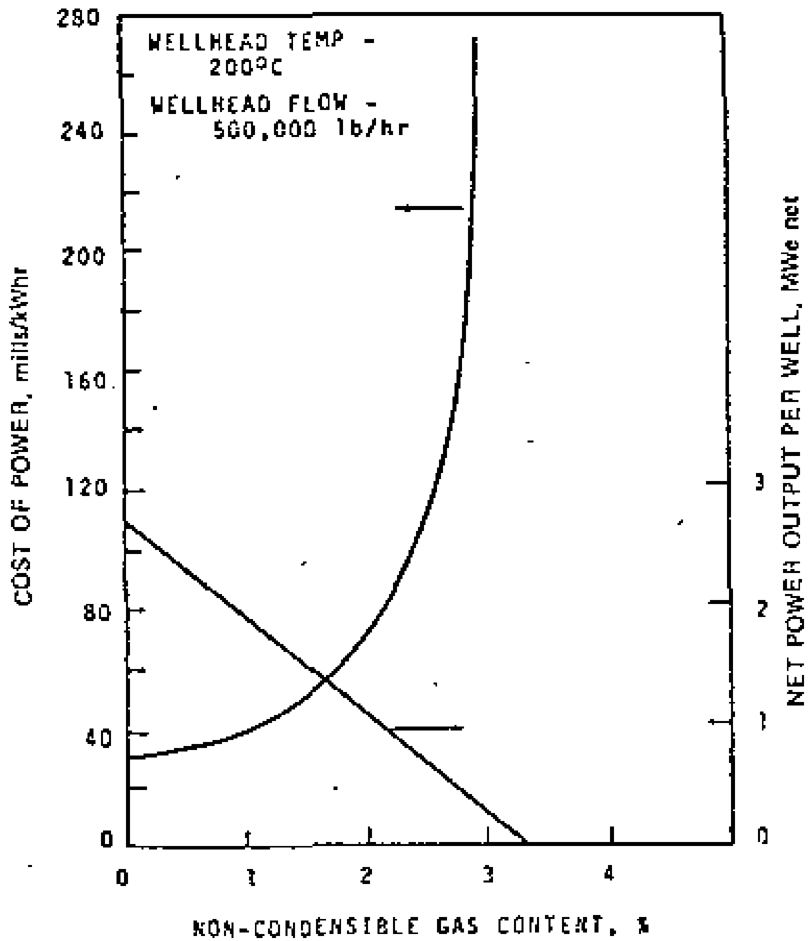
Source: Reference (17)

The flashed steam plant is attractive despite considerable waste of fluid heat value because it employs simple and relatively inexpensive steam turbines. Installed plant cost is approximately $200/kW (17). Improved recovery of fluid heat can also be achieved through multiple-flash stages. In general, multiple-flash design is preferred because of savings in supply wells and other field development costs, even though it significantly increases plant complexity and cost.

For fluids high in minerals or noncondensible gases, however, flashed steam plants may be impractical. Flashing results in deposition of the solids, and non-

condensible gases greatly reduce net power production from steam turbines (Figure 1.10) (64). Noncondensible gases may also create environmental problems. When released from the fluid stream through flashing, they are discharged to the atmosphere. Hydrogen sulfide is one such gas which in small quantities is both poisonous and extremely noxious in odor.

FIGURE 1.10: EFFECT OF NONCONDENSIBLE GASES ON NET POWER OUTPUT AND COST



Source: Reference (24)

A flashed steam plant may also be unattractive for moderate-temperature reservoirs. Steam yield from such fluids is very low, and the consequent increase in supply well costs becomes prohibitive. Under these conditions, alternative design options may be preferred.

Binary Fluid Plant

A binary fluid plant utilizes a heat exchanger to transfer heat from the produced geothermal fluid to a secondary fluid. The secondary fluid (e.g., Freon, isobutane) is chosen to have a boiling point significantly below the temperature of the produced fluid. In this way, the secondary fluid is vaporized and used to drive a turbine. Capital cost estimates for binary plants range from $300/kW to $500/kW (29)(17)(24).

The binary cycle has several attractive features compared to the flashed steam plant. In the first place, the system can be tailored to the temperature of the geothermal fluid to capture a larger percentage of the fluid's heat value. This advantage is especially marked at temperatures less than 200°C (30).

The binary cycle is able to utilize saline brines. This is an important strength. Two types of scaling occur in geothermal systems. Some deposition results when the temperature of the fluid is reduced. Silica scaling is of this type and is common to all geothermal plants for water-dominated reservoirs. Its severity depends on the solids content of the fluid.

The second type of scaling results when fluid pressure is reduced. Deposition of calcium carbonates, for example, results from pressure reduction. Pressure drop also causes silica deposition. With binary cycles, the geothermal fluid pressure can be maintained, using pumps to circulate the fluid from supply wells, to the heat exchangers and back into the reservoir through injection wells. Part of the plant's electrical output must be consumed to power the pumps, but in this way some serious scaling problems are avoided and others considerably reduced.

Unlike flashed steam plants, binary fluid plants are not affected by the noncondensible gas content of geothermal fluids. Electric conversion is not impaired, and noxious gases such as hydrogen sulfide are not allowed to degrade local air quality. The entire fluid stream is totally confined and returned to the reservoir.

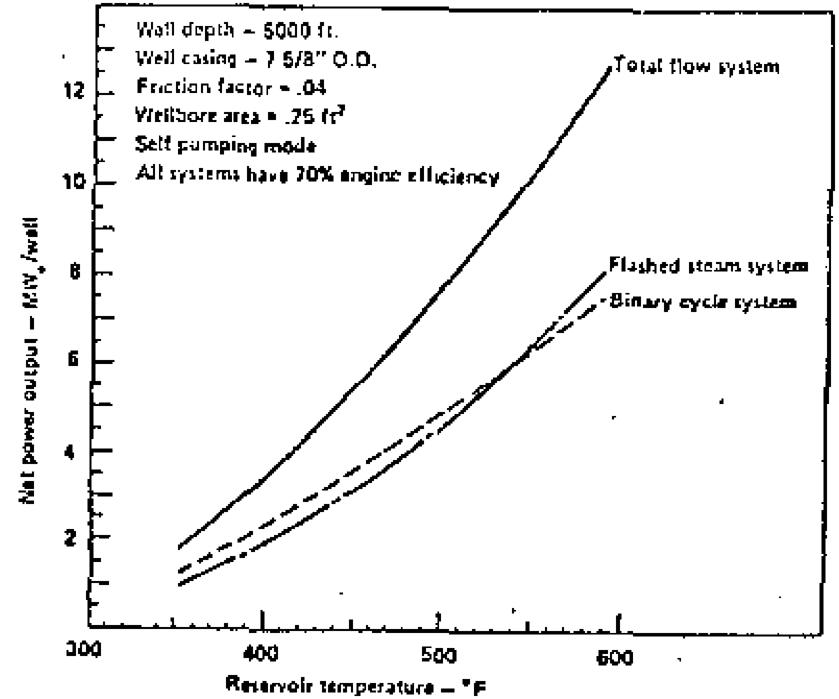
Total Flow Plant

Electric conversion in the total flow plant employs all of the produced fluid with a specially designed nozzle and turbine. One proposed design uses a helical screw which rotates as the fluid expands along its axis (23). Another type is designed somewhat like a waterwheel (31). Both types have design efficiencies greater than binary or multiple flashed steam cycles. Figure 1.11 compares the efficiencies of flashed steam and binary cycles to the Lawrence Livermore Laboratories helical screw expander.

While steam turbines and binary fluid heat converters are well known and tested technologies, the total flow systems are as yet unproven designs. Whether theoretical efficiencies can be attained in practice at reasonable costs is still to be demonstrated.

Scaling and the release of noncondensible gases are problems this design shares with flashed steam systems (32).

FIGURE 1.11: COMPARISON OF GEOTHERMAL POWER SYSTEMS



Source: Reference (23)

GEOTHERMAL ACREAGE AND RESERVES IN THE UNITED STATES

Acreage

Almost three million acres in 82 locations have been classified by the U.S. Geological Survey as known geothermal resource areas (KGRAs). These sites are currently the most promising in the country for geothermal development. An additional 100 million acres are considered prospectively valuable for geothermal development. Acreages within each state are given in Table 1.6 and indicated on the accompanying maps (Figures 1.12, 1.13, and 1.14) (33)(34).

The federal government owns little land in Texas, Louisiana and Hawaii, and no area designations have been made for these states. Nevertheless, all three contain valuable geothermal areas. In Texas and Louisiana, geopressured reservoirs underlie an extensive region totalling approximately 375,000 km² (93.6 million acres) (9)(11).

TABLE 1.6: CLASSIFIED GEOTHERMAL ACREAGE

State	KGRA (1967)	Prospectively Valuable (1967)	KGRA (1975)
Alaska	....	....	88,160
Arizona	....	1,694,000	3,240
California	838,000	16,324,000	1,399,709
Colorado	....	2,002,000	20,825
Hawaii*	....	....	....
Idaho	16,000	14,102,000	120,042
Louisiana*	....	....	....
Montana	18,000	6,226,000	58,655
Nevada	38,000	13,200,000	487,940
New Mexico	140,000	7,414,000	198,687
Oregon	....	14,432,000	367,652
Texas*	....	....	....
Utah	....	4,554,000	118,209
Washington	....	5,236,000	35,613
Wyoming	....	743,000	..........**

*Hawaii, Louisiana and Texas contain very little federally-owned land. The U.S. Geological Survey has not classified lands, although extensive geothermal resources occur in these states.

**Yellowstone National Park includes geothermal resources. These are not developable under current regulations and the acreage is not included here.

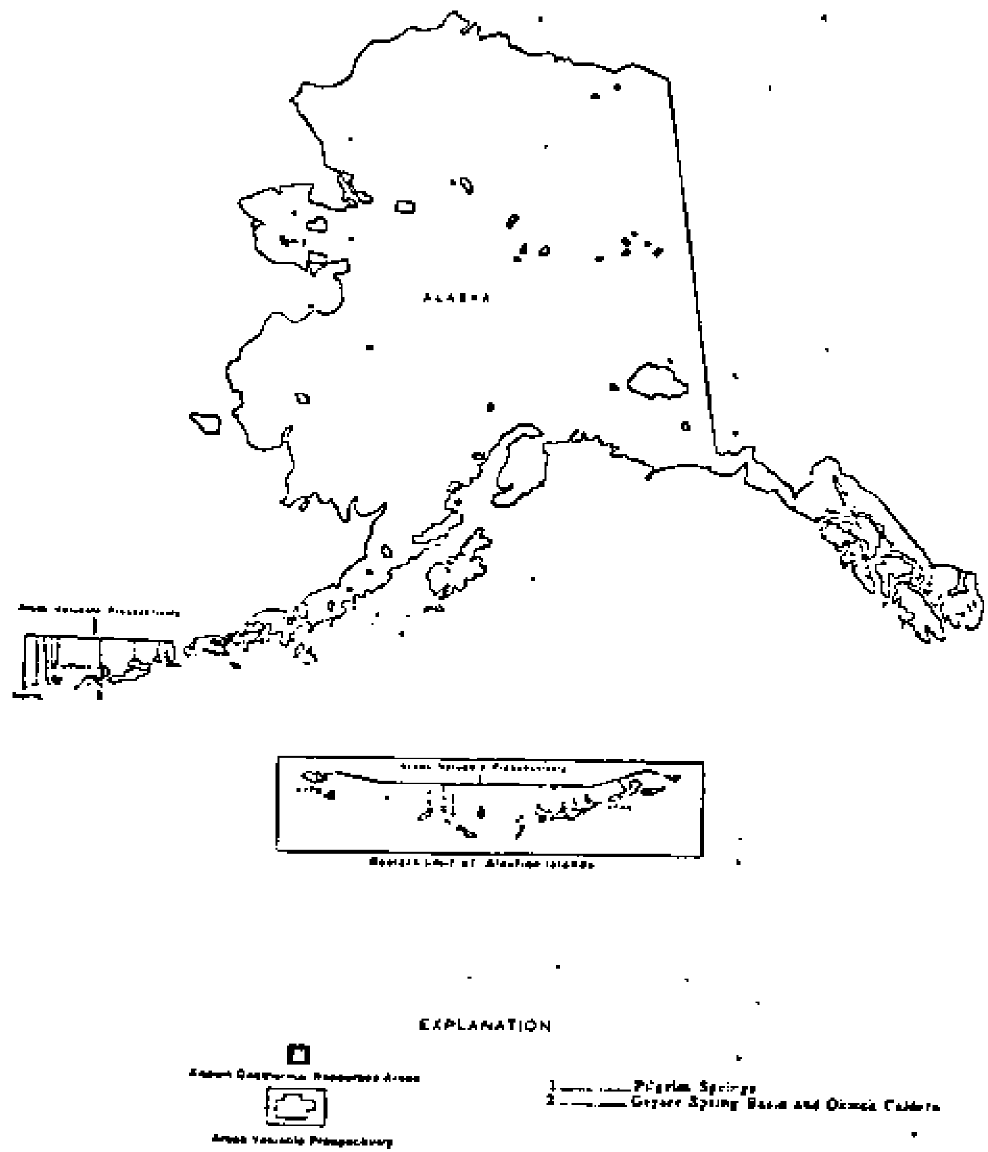
Source: References (33)(35)

Reserves

Heat is an ubiquitous form of energy. Beneath every point on the earth's surface lies an ocean of magma at 1000°C. But available technology and the costs of resource development limit geothermal "reserves" to a fraction of the earth's total heat.

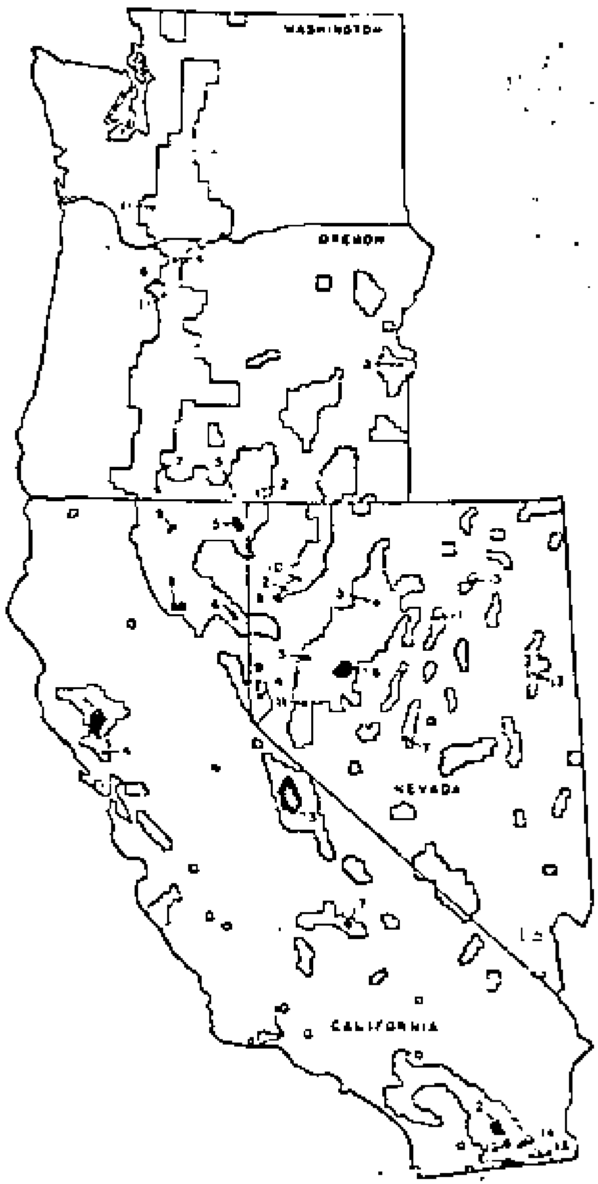
As mentioned above, in 1975 the U.S. Geological Survey completed an initial assessment of geothermal resources in the United States (36). The study calculated the amount of heat energy stored in geothermal formations hotter than 15°C to a depth of 10 km. (Hydrothermal systems were assessed only to a depth of 3 km.) The portion of this resource base available for development with existing technology was also estimated according to three separate cost assumptions. Geothermal resources recoverable at costs competitive with current energy resources were designated "reserves;" those recoverable at costs between one and two times current energy prices as "paramarginal resources." "Submarginal resources" were estimated to be recoverable at more than two times present energy costs.

FIGURE 1.12: MAP OF CLASSIFIED GEOTHERMAL ACREAGE IN ALASKA



Source: Reference (34)

FIGURE 1.13: MAP OF CLASSIFIED GEOTHERMAL ACREAGE IN CALIFORNIA, NEVADA, OREGON AND WASHINGTON



EXPLANATION

Known Geothermal Resources Areas

Areas Valuable Prospectively

California

1 .... The Geysers
2 .... Salton Sea
3 .... Mono-Long Valley
4 .... Calistoga
5 .... Lake City
6 .... Wendel-Amedee
7 .... Coso Hot Springs
8 .... Lassen
9 .... Glass Mountain
10 .... Seigler Hot Springs
11 .... Heber
12 .... Brawley
13 .... Dunes
14 .... Glamis

Nevada

1 .... Beowawe
2 .... Fly Ranch
3 .... Leach Hot Springs
4 .... Steamboat Springs
5 .... Brady Hot Springs
6 .... Stillwater-Soda Lake
7 .... Darrough Hot Springs
8 .... Gerlach
9 .... Moana Springs
10 .... Double Hot Springs
11 .... Wabuska
12 .... Monte Neva
13 .... Elko Hot Springs

Oregon

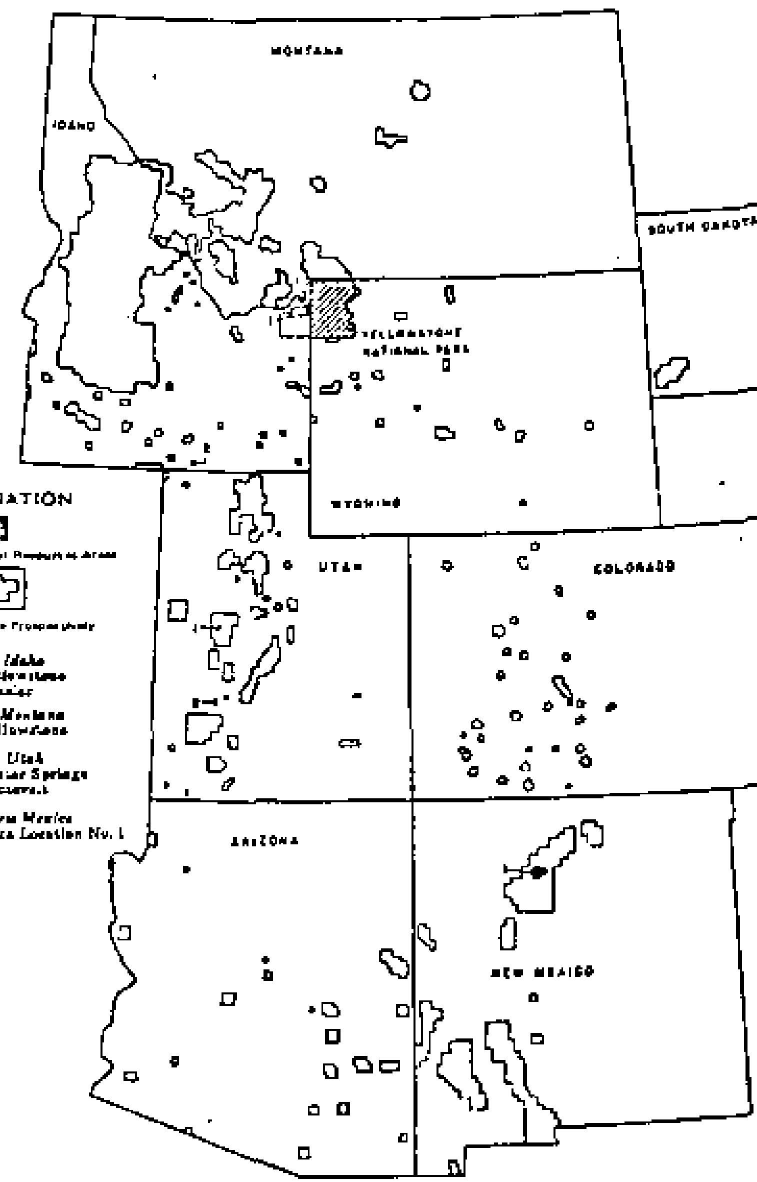
1 .... Breitenbush Hot Springs
2 .... Crump Geyser
3 .... Vale Hot Springs
4 .... Mount Hood
5 .... Lakeview
6 .... Carey Hot Springs
7 .... Klamath Falls

Washington

1 Mount St. Helens

Source: Reference (34)

FIGURE 1.14: MAP OF CLASSIFIED GEOTHERMAL ACREAGE IN ROCKY MOUNTAIN STATES



EXPLANATION

Known Geothermal Resources Areas

Areas Valuable Prospectively

Idaho

1 .... Yellowstone
2 .... Frazier

Montana

1 .... Yellowstone

Utah

1 .... Crater Springs
2 .... Roosevelt

New Mexico

1 .... Baca Location No. 1

Source: Reference (34)

Total stored heat as calculated in the USGS study is shown in Table 1.7. Estimates of recoverable electric power were made only for geopressured and high-temperature hydrothermal convection reservoirs. These appear in Tables 1.8 and 1.9. No estimates were made for the other geothermal formations as electric conversion technology was not considered adequately developed.

Their heat content, however, is very great. If heat in igneous systems were extracted and converted with the same efficiency as in high-temperature hydrothermal reservoirs, the power from $100{,}000 \times 10^{18}$ calories would be approximately 3.2 million megawatts for 100 years $[(100{,}000/1{,}200) \times 38{,}000 = 3.2 \times 10^6]$.

The USGS estimates show that geothermal resources have a large electric generation capacity. High-temperature hydrothermal convection systems are evaluated at approximately 30,000 MW for 100 years, or 100,000 MW for 30 years, at prices between one and two times current power costs. While only a portion of total geothermal potential, this represents a significant fraction of the country's present electrical capacity of some 500,000 MW.

Although large, these tentative heat and power estimates are in fact conservative. A paucity of facts concerning geothermal formations led to minimizing assumptions. The assessment of igneous systems, for example, included 48 out of 151 identified volcanic intrusions within 10 km of the surface, and assumed that no preheating or recharge of these chambers had ever occurred. Injection or convection of fresh magma dramatically increases the available heat of such formations, but minimum assumptions were adopted in the absence of other evidence. According to the USGS researchers, igneous heat content may be at least ten times greater than the assigned value (38).

The assessment of known hydrothermal convection systems similarly minimized calculated heat values. Temperatures for most reservoirs were estimated according to the chemical composition of geothermal fluids at the surface. These chemical "thermometers" provide rough approximations and in many instances may underestimate reservoir temperatures (37).

The USGS calculation accounts for heat stored in hydrothermal reservoirs only to a depth of 3 km; this is the depth of current geothermal drilling, but just half the depth commonly reached today by oil wells. It assumes no heat recharge by fluid convection from below 3 km, and unless other information is available, the top of the reservoir is set at 1.5 km. These assumptions yield a reservoir thickness of 1.5 km.

As pointed out in the USGS report, areas assigned to hydrothermal reservoirs also may be too small by as much as three orders of magnitude (x 1,000). In many instances, no information was available to establish areas, and they were set at 1.5 km².

As a consequence of these assumptions, many of the evaluated hydrothermal systems were assigned a volume of 2.25 km³. This figure may be compared to volumes determined for relatively well-explored reservoirs. See Table 1.10.

TABLE 1.7: HEAT CONTENT OF U.S. GEOTHERMAL RESOURCES ESTIMATED WITHOUT REGARD TO RECOVERABILITY

	Identified systems		Identified + estimate for undiscovered
	Number	Heat Content (10^{18} cal)*	Heat Content (10^{18} cal)*
1. *Hydrothermal convection systems* (to 3 km depth, ~10,000 ft, near the maximum depth drilled in geothermal areas)			
Vapor-dominated (steam) systems	3	26	~50
High-temperature hot-water systems (over 150°C)	63	370	~1,600
Intermediate-temperature hot-water systems (90° to 150°C)	224	345	~1,400
Total	290	~741	~3,050
2. *Hot igneous systems* (0 to 10 km)			
Molten parts of 48 best known, including Alaska and Hawaii		~13,000	
Crystallized parts and hot margins of same 48		~12,000	
Total		~25,000	~100,000
3. *Regional conductive environments* (0 to 10 km; all 50 states subdivided into 19 heat-flow provinces of 3 basic types, Eastern, Basin-and-Range, and Sierra Nevada)			
Total, all states		~8,000,000	~8,000,000
Overall total		8,025,741	8,103,050

*10^{18} calories equivalent to heat of combustion of ~690 million barrels of petroleum or ~154 million short tons of coal

Source: Reference (36)

TABLE 1.9: RECOVERABLE ENERGY FROM ONSHORE GEOPRESSURED RESERVOIRS OF TEXAS AND LOUISIANA
(Plan Maximizes Total Recovery Over 20-Year Period; No Pressure Decline Below 2,000 psi; 17,160 Wells; Subsidence of 5 to 7 Meters)

	Heat in pore fluids, (10^{18} cal)[1]	Percent recovery (heat only)	Heat equivalent at well-head (10^{18} cal)[2]	Conversion efficiency	Electrical energy, MW-cent[3]	MW for 30 years
Gulf Coast geopressured fluids in sediments of Tertiary age; assessed on-shore parts only, to depth ranging up to 7 km.	10,920					
Thermal energy		0.021	229.4	0.04	24,380	81,260
Methane (thermal equivalent)			124.2		[5]	[5]
Mechanical energy (thermal equivalent)			9.4	0.80	9,970	33,230
TOTAL			363.0		34,350[4]	114,490[4]
Other unassessed parts of Gulf Coast geopressured environment, on-shore and off-shore to 10 km[7]	22,000		>500		>50,000	>166,700
Other geopressured environments to 10 km[6,8]	11,000		>250		>25,000	> 83,300

[1]Thermal energy only. 10^{18} cal is equivalent to heat of combustion of 690 million barrels of oil
[2]All plans assume 0.15 m³/sec flow rate per well and saturation of water with methane, but reliable data lacking.
[3]Unit of electrical energy, 1 MW-cent is equivalent to 1000 kw produced continuously for 100 yrs
[4]Estimates made for 20 yr. production period, converted to 30 yrs. to be consistent with other estimates of this circular
[5]Methane assumed recovered but not used locally for electricity
[6]Perhaps in part reserves but mostly paramarginal, depending on environmental and other costs
[7]Thermal equivalent of methane included in heat at well-head but excluded from electrical energy, recoverable part highly speculative because of unknown porosities and permeabilities, but probably largely submarginal
[8]No detailed assessment but considered likely to exist in California and other states

Source: Reference (36)

TABLE 1.8: RECOVERABLE ENERGY FROM U.S. HYDROTHERMAL CONVECTION RESERVOIRS

	Heat in ground (10^{18} cal)[1]	Heat at well-head (10^{18} cal)[2]	Conversion efficiency	Beneficial heat (10^{18} cal)[3]	Electrical energy (MW-cent)[4]	MW for 30 years[5]
High-temperature systems (>150°C; for generation of electricity)						
Identified resources	257	64	0.08 to 0.2			
Reserves					3,500	11,700
Paramarginal resources					3,500	11,700
Submarginal resources					>1,000[6]	> 3,300[6]
Undiscovered resources	1,200	300	0.08 to 0.2		38,000[7]	126,700[7]
Intermediate-temperature systems (90° to 150°C; mainly non-electrical uses)						
Identified resources	345	86	0.24	20.7		
Undiscovered resources	1,035	260	0.24	62.1		
TOTAL	2,837	710		82.8	46,000	153,400

[1]10^{18} cal (a billion-billion calories) is equivalent to heat of combustion of 690 million barrels of oil or 154 million short tons of coal
[2]Assumed recovery factor 0.25 for all convective resources
[3]Thermal energy applied directly to its intended thermal (non-electrical) use. 10^{18} cal of beneficial heat, if supplied by electrical energy, would require at least 1,350 MW-cent (or 4,400 MW for 30 years); however, a user of this geothermal energy must be located or must relocate close to the potential supply. Insufficient data available to predict demand or to subdivide into reserves, paramarginal, and submarginal resources
[4]Unit of electrical energy: 1 MW-cent is equivalent to 1000 kw produced continuously for 100 years.
[5]Assumes that each MW-cent of electricity can be produced at rate of 3.33 MW for 30 years.
[6]Small because of exclusion of systems with temperatures below 150°C.
[7]Perhaps as much as 60 percent will be reserves and paramarginal resources, costs of discovery and development are more speculative than for identified resources

Source: Reference (36)

TABLE 1.10: VOLUME AND ELECTRICAL ENERGY POTENTIAL FOR 13 WELL-EXPLORED GEOTHERMAL SYSTEMS

System	Volume* (km^3)	Electrical Potential (MW for 30 years)
The Geysers, CA (Dry Steam)	140	1570
Surprise Valley, CA	250	1100
Long Valley, CA	450	6020
Salton Sea, CA (Imperial Valley)	108	2760
East Mesa, CA (Imperial Valley)	56	460
Heber, CA (Imperial Valley)	100	960
Brawley, CA (Imperial Valley)	27	330
Beowawe Hot Springs, Nev.	42	420
Brady Hot Springs, Nev.	30	390
Steamboat Springs, Nev.	16	210
Valles Caldera, N.M.	130	1970
Cove Fort - Sulphurdale, Utah	22.5	270
Yellowstone Nat'l Park, WY	940 (with 6.5 km^3 dry steam system)	> 10,000

*These volume estimates are themselves limited by the hypothetical exclusion of convection or reservoir depth below 3 km.

Source: Reference (18)

The volumes of explored fields suggests that identified but unexplored systems may often be larger than 2.25 km^3 by at least a factor of twenty. This is supported by evidence that extinct volcanic/hydrothermal systems typically have ranged from several tens to hundreds of cubic kilometers in volume (37).

For purposes of calculation, a depth limit of 3 km and minimum area assignments of 1.5 km^2 are useful since areas, recharge rates and depths are not known for most of the reservoirs. It is important to note, however, that these assumptions result in minimum values for hydrothermal reserves.

The identification of new hydrothermal systems will, of course, multiply geothermal reserves. The USGS report suggests that new discoveries will total about five times known reserves. One indication of the extent of undiscovered reserves is the amount of land classified known or prospectively valuable for geothermal development. These areas and the areas assigned in the USGS study to identified systems appear in Table 1.11.

TABLE 1.11: AREA COMPARISON FOR IDENTIFIED AND POTENTIAL HYDROTHERMAL CONVECTION SYSTEMS

Hydrothermal Convection Systems	Area (km^2)
Identified high-temperature	1,500

(continued)

TABLE 1.11: (continued)

Hydrothermal Convection Systems	Area (km^2)
Identified medium-temperature	3,000
Known geothermal resources areas	11,600
Prospectively valuable areas	400,000

Source: References (33)(37)

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The material for the following sections has been based upon a report by Resource Planning Associates (PB 271 561).

ENVIRONMENTAL EFFECTS–OVERVIEW

The widespread belief that geothermal resources represent a relatively "clean," nonpolluting energy source recently has played an important role in heightening public interest in geothermal development. Although knowledge of the related environmental impacts is still incomplete, geothermal resources do appear to offer several significant environmental advantages over alternative energy sources.

Since geothermal energy must be utilized or converted in the immediate vicinity of the resource to prevent excessive heat loss, the entire fuel cycle, from resource extraction to transmission, is located at one site. Unlike fossil fuel or nuclear power production, in which large land areas are required for processes such as mining, refining, transportation, fuel processing, and waste disposal, geothermal energy is not a technology that requires a massive infrastructure of facilities and equipment and large amounts of input energy.

Although geothermal development necessarily involves some disturbance of the earth's surface, the effects are not as severe as are those resulting from the surface mining of coal or uranium. Furthermore, the controversial safety issues that have been raised about underground coal mining and the consequences of a major accident during nuclear power production do not arise in connection with geothermal power production.

Another environmental benefit arises from the fact that those geothermal power plants that use steam as a working fluid to drive a turbine do not need an external source of water for cooling purposes, because the condensed steam is recycled for that purpose. Thus, they do not place additional demands on scarce water supplies.

In addition to these environmental benefits, the development and application of geothermal power would reduce the demand for alternative fuels currently in critically short supply (specifically, oil, natural gas, and uranium).

Unfortunately, however, not all the potential environmental effects of geothermal energy are positive. Among the most significant adverse impacts of the exploration, development, and production of geothermal energy (see Table 1.12) are possible land subsidence, seismic activity, air pollution resulting from the discharge of noncondensable gases such as hydrogen sulfide, high noise levels of drilling and power plant operation, and mineral or thermal pollution of surface and ground waters. Other concerns include increased erosion and sedimentation resulting from site disturbance; possible climatic changes resulting from the release of heat, water vapor, and carbon dioxide; and disturbance of soils, vegetation, and wildlife.

TABLE 1.12: POTENTIAL ENVIRONMENTAL IMPACTS OF GEOTHERMAL POWER PRODUCTION

Impact	Estimate of Probability	Technology/ Resource Type	Severity of Consequences
Land subsidence	moderate	hot-water	variable—can be high
Induced seismic activity (earthquakes)	low	all	high
Air pollution resulting from discharge of noncondensable gases (e.g., hydrogen sulfide, carbon dioxide)	high	all except hot water binary fluid and other "closed-cycle" use of geothermal fluids	variable—depends on emission controls
High noise levels of drilling and plant operation	high	all; worst for vapor-dominated	moderate
Chemical or thermal pollution of surface and groundwaters	moderate	all, greatest probability with hot-water	high
Well blowouts	low	hot-water; vapor-dominated	moderate
Increased erosion and sedimentation resulting from site disturbance	high	all	moderate
Consumption of water for cooling purposes	high	hot-water binary fluid, hot dry rock	high
Consumption of land for wells, power plants, transmission lines	high	all	moderate
Short-term climatic changes resulting from release of heated steam and carbon dioxide	high	hot-water, vapor-dominated	low
Disturbance of habitat, alteration of ecosystems	moderate to high	all	moderate to low

Source: PB 271 561

The actual impacts of geothermal development can vary widely, probably more widely than the impacts associated with fossil or nuclear energy sources. For example, the chemical constituents of geothermal steam or hot water can differ significantly from site to site, causing markedly different air and water pollution emissions from power plants having identical generating capacities. The potential severity of the environmental impacts associated with geothermal development depends on several factors: type of geothermal resource being developed; chemi-

ical constituents of the geothermal fluid (steam or hot water) and subsurface rock; overall characteristics (geology, hydrology, topography, vegetation) of the development site, both above and below the ground surface; and engineering design technologies used to produce energy and control pollution.

Depending on the site, geothermal power production could result in either equivalent or substantially lower pollution levels than those produced by a coal- or oil-fired plant of identical capacity. Thus, generalizations about the magnitude and significance of the likely environmental impacts resulting from geothermal development must be based on careful, site-specific analysis that takes each of these factors into account.

Both the likelihood and potential severity of the possible impacts of geothermal development warrant careful consideration in determining the significance of any impact. Even if the likelihood that a certain impact will occur is relatively small, it requires close attention if its consequences are potentially serious. For example, although at present it is considered unlikely that geothermal development would induce a major earthquake, the extensive damage that could result from such an event justifies its further investigation.

3ecause geothermal development has not been widely pursued, both the likeli-
iood and severity of many impacts are still relatively unknown. Extensive in-
formation is available for only a few sites, such as The Geysers and the Wairakei
lant in New Zealand. Projections of impacts at other locations where develop-
nent is planned are still preliminary and highly speculative. Since intensive re-
earch on environmental impacts is only just being initiated, it will be several
ears before a detailed understanding of actual impacts is developed.

his section describes the major impacts of geothermal resource development on
arious aspects of the environment. The anticipated impacts of developing the
vo most immediately promising types of hydrothermal convection systems,
por-dominated and hot-water, are discussed in detail. Because available infor-
ation on the other types of geothermal resources is limited, the probable im-
acts associated with their development are noted but not discussed extensively.

AND USE

lthough the extent and severity of land disturbance is relatively less than for
her resources, geothermal resource development does have several significant
nd-use impacts. These impacts relate to: (1) the total acreage requirements
r development of a geothermal field and the extent to which the land is dis-
pted, (2) the compatibility of geothermal development with adjacent land uses,
d (3) protection of sensitive land areas.

:reage Requirements

e development of a geothermal field requires the installation of drilling pads
supply and reinjection wells, sumps, by-product processing facilities, access
ads, pipelines, generating plants, cooling towers and transmission lines. Table
13 offers figures for the average amounts of land required for each of these
s. The total land area required to develop a geothermal reservoir is primarily
unction of the electrical capacity of the generating plants, the number and

density of supply wells (which are, in turn, dependent on the inherent characteristics of the reservoir), and the topography of the site. Impacts resulting from these requirements are inherent in the development procedure.

TABLE 1.13: LAND USE REQUIREMENTS FOR A TYPICAL GEOTHERMAL DEVELOPMENT SITE

Phase	Surface Area
Exploration and Testing Phase	
Road construction	3 to 4 miles, graded and compacted
Drill pads	1 acre each, cleared and compacted
Mud sump	Each one requires an area 100' x 125' x 10' deep to temporarily store up to 1,000,000 gallons of effluent and cuttings
Full Field Development	
Road construction	Acreage varies. Access roads may be built to drilling pads, mud sumps, buildings for housing equipment and storage. Estimate: 20 acres of land cleared for every 15 wells.
Pipelines	Each pipeline is 10" to 30" in diameter, raised on supports rising no more than 12 feet. The area cleared for the pipeline is from 10' to 300' wide, depending on whether access roads are constructed.
Power generation facilities	Roughly 5 acres are required, most of the land must be paved or otherwise made impervious
–turbine generators & condensors –cooling towers –transformer	Each is 150' x 65' x 60' high. Each is 360' x 65' x 60' high. Each is 100' x 100' x 55' high.
Transmission lines	Lines consist of towers or poles at a height of 50 to 120 feet, with concrete bases 40 feet apart.

Source: Reference (1)

Factors Affecting Acreage Requirements: The first factor, electrical capacity, is the easiest to comprehend: the larger the generating plant, the more steam is required to attain a given level of output, and the more wells must be drilled.

The second factor, well spacing, is influenced by several considerations: first, wells must be drilled into specific target areas–zones of subsurface fracture where the heat reservoir is located–without consideration to topography, surface condition, or watersheds. Second, the initial rates of steam flow and the constituents of the steam may influence how many wells must be drilled and whether auxiliary facilities, such as those required for the reclamation of chemicals or condensation of steam for water supplies, are built.

Third, whether the field development policy is rapid or slow has a marked effect on well spacing. Rapid development is achieved by drilling more wells per acre in a cluster arrangement, with relatively short pipelines feeding steam to generating units located at the center of the wells. With a slower rate of development, wells are more widely spaced, and relatively long main supply lines are fed by a more extensive network of feeder systems (2).

The third factor, topography, can also influence acreage requirements. As the slope of the land increases, the total surface area required for development increases, because slope support must be provided and cut-and-fill banks stabilized (2). Heavily sloped areas, as at The Geysers, often require double the acreage for a given activity.

The amount of surface land disturbed in a geothermal development area ranges from 10 to 50%, with 20% as the average (2). Scaling up from the acreage presently used at The Geysers, a 1,000 MWe facility consisting of ten 100 MWe units with a well spacing density of 1 well per 58 acres, would cover 2,025 to 3,645 hectares (5,000 to 9,000 acres) or 21 to 40 square kilometers (8 to 14 square miles) of land. Of this amount, an average of 20%, or 405 to 729 square kilometers (1,000 to 1,800 acres) of surface area would be disturbed physically through clearance of vegetation, grading, and paving. The current spacing at The Geysers is lower than will occur if additional wells are drilled to exploit marginal areas. In that case, acreage requirements probably will be greater.

Variability in Land Requirements: Figures on land requirements vary considerably from those recorded for the geothermal operations at Lardarello, Italy, and Wairakei, New Zealand. Based on 1970 figures at the dry-steam field of Lardarello, 13 generating units supplied a total capacity of 360 MWe from 467 wells distributed over 168 square kilometers (65 square miles), a ratio of 1 well to 36 hectares (89 acres).

In 1971, at the Wairakei hot-water field, 61 wells supplying a 160 MWe power plant were concentrated in a compact well field of less than 2.59 square kilometers (1 square mile), a ratio of 1 well to 4 hectares (10 acres). Thus, a complete 1,000 MWe facility based on the much more densely developed Wairakei site would require 16 square kilometers (6.25 square miles) for 381 wells.

Wherever possible, impacts have been compared on a quantitative basis. However, a quantitative comparison of the total land requirements of geothermal energy and alternative energy resources is difficult to make because of the complexity of the fuel cycle for the alternatives. The specific acreage requirements for the equipment common to all types (such as power plants, cooling towers, and electrical transmission lines) are roughly the same for any 1,000 MWe facility. Moreover, specific geothermal equipment, such as drilling pads, does not usually take up more space than oil or natural gas drilling equipment.

However, the difficulty in comparing alternatives arises in attempting to determine whether the total amount of land required for all other fuel types (fuel pipelines or transportation lines, processing facilities, storage and disposal facilities) can reasonably be attributed solely to providing 1,000 MWe of electrical power.

Compatibility with Adjacent Land Use

Another important land-use issue associated with geothermal development is the extent to which such development is compatible with surrounding land uses. Possible adverse effects to adjacent land could result from the changes in the use of the land at the site, human activity, and noise and pollutant emissions; furthermore, such impacts are likely to be long-term in relation to the life of a geothermal field.

To date, the use of geothermal resources for the generation of electricity has occurred primarily on undeveloped lands. Consequently, geothermal development has radically altered passive multipurpose land uses such as wildlife reserves, cattle grazing, and watersheds.

As a result, whatever value these uses once gave to the land is now diminished. To the extent that the scenic and aesthetic characteristics of undisturbed landscape are replaced by noise, odor, built forms, or defoliation, the changes are not especially pleasing. Human activity in the area must sometimes be restricted, especially during testing, when the dangers of well blowouts are greatest, restrictions that could lead to the overuse of adjacent areas.

The impact of geothermal development on the productivity of adjacent lands is not yet fully known, but appears to be minimal. One important exception is the adverse effect of land subsidence, which results from the withdrawal of geothermal fluids. Subsidence of adjacent land is a major adverse impact that could drastically reduce the value of the land affected if easily damaged facilities, such as irrigation canals or buildings, are present.

Subsidence is not rare. It has occurred at Wairakei, New Zealand, and Cerro Prieto, Mexico; but so far the economic effects have been limited by the relative remoteness of these areas. Both are hot-water fields, which are apparently more vulnerable to subsidence. If subsidence were to occur as extensively in the agricultural Imperial Valley, there would be major adverse economic impacts. To the extent that reinjection of geothermal fluids may prevent subsidence, the impacts would, of course, be less.

To date, the impacts of geothermal development on land fertility appear to be minimal. During most of the 60 years of field development at Lardarello, Italy, for example, the surrounding land has had varied agricultural uses. Today, pipelines traverse vineyards, orchards, and farmlands with no known detrimental effect. At The Geysers, wilderness surrounding the development area has remained largely unaffected. Extensive studies are presently being conducted to identify additional effects on the surrounding ecosystems.

Some concern has been expressed at The Geysers about the extent to which improved access to the wilderness area provided by new roads would increase residential and industrial growth, especially over the extended life of the field. To date, development of The Geysers has spurred neither residential nor industrial development.

Effective emission controls, noise muffling, proper plant and equipment design, and continual monitoring of adjacent areas, in other words, comprehensive planning and conscientious management, can contribute significantly to the prevention of adverse effects.

Protection of Sensitive Lands in the U.S.

The Geothermal Steam Act of 1970 precludes the geothermal development of

certain environmentally fragile land areas in order to protect their sp[illegible] land-use values or unique characteristics. The protected lands are generally public lands acquired with federal funds, and include lands reserved for Native American Indians, lands administered by the National Park Service (including Yellowstone National Park), lands within national recreation areas, lands used for fish hatcheries, wildlife refuges, wildlife or game range lands, wildlife management areas, waterfowl production areas, lands registered in the national wild and scenic rivers system, and lands reserved to protect and conserve species threatened with extinction.

The possibility that geothermal development will cause damage to certain types of sensitive or critical land areas—such as valuable farmland, mature or near-mature forest, or historical and archeological sites—has also resulted in various leasing restrictions. Certain lands administered by the Department of Agriculture and lands withdrawn under the Federal Power Act (16 USC 818), may be leased only with the consent of, and under the conditions prescribed by, the governing legislation (3).

Research Needs

An implicit issue facing geothermal developers is the trade-off between the use of land for geothermal energy versus its use for recreation, watersheds, or agriculture. In some areas, this trade-off may be a central barrier to the rapid development of geothermal resources. There is a need to determine more specifically, in terms of economic and natural resources, what productivity may be lost when lands are developed for their energy potential. Disruption of aquifers, emission of potentially toxic substances, erosion, and subsidence—each of these may pose a threat to the long-term productivity of adjacent lands. Learning to measure the potential for harm, and adequately considering this through the instrument of the environmental impact statement, is a primary research need.

The potential also exists for geothermal development to beneficially affect the productivity of adjacent lands. For example, geothermal development may facilitate water reclamation in semiarid and arid regions. This and other possibilities need to be identified.

GEOLOGY AND SOILS

The stability of surface soil and subsurface geologic formations can be affected in a number of ways by the activities related to developing geothermal resources. Among the most significant potential adverse effects are surface soil erosion, land surface subsidence, and inducement of seismic activity.

Erosion

The exploitation of any geothermal resource necessarily involves site clearing, which disturbs the land surface, particularly during the initial stages of development. On steeply sloping sites, extensive earth-moving, or "cut-and-fill," may also be required for the construction of access roads, drilling sites, steam pipelines, power plants, and electrical transmission lines. Such activities invariably remove protective vegetation and thereby accelerate erosion of exposed soil by storm water runoff if protective measures are not taken. The eroded soil is car-

Control of Subsidence: The primary technology available to prevent subsidence is the reinjection of geothermal fluids to deep wells following power production. While highly promising, the application of this technique may be limited by at least six unresolved problems.

(1) While some compaction is elastic and reversible, the withdrawal of fluids can cause the irreversible collapse of some of the air spaces or pores.
(2) Geothermal fluids sometimes contain a large amount of dissolved solids, such as silica or calcium. If the lower temperatures of the reinjected fluid cause these dissolved solids to solidify or precipitate, the reinjection pipes could become clogged; thus reducing the permeability of the aquifer. Concern about this problem has prevented the use of reinjection at the Wairakei power plant, where the geothermal water has a high content of dissolved silica. Such problems could be solved by placing chemical additives in the hot water to keep dissolved solids in solution; however, their use may create another problem: because additives increase the ability of the hot waters to dissolve solids, they dissolve more solids in the host rock once reinjected. Subsequent use of the geothermal hot water containing increased dissolved solids would, in turn, worsen pipe clogging. This type of problem represents a major uncertainty in the development of geothermal energy.
(3) Reinjection could lower the temperature and thus the energy potential of subsurface geothermal waters.
(4) Only part of the geothermal fluid may be available for reinjection because part of the fluid used in the electrical generating process may be discharged as water vapor from a cooling tower.
(5) While reinjection, particularly of the concentrated brines characteristic of the Imperial Valley, may not always be practical at the site where the fluids were withdrawn, reinjection at too great a distance may induce seismic activity and consequent earth movement at the surface.
(6) The cost of creating reinjection wells for hot-water systems can be quite high relative to other less environmentally desirable means of fluid disposal, thus increasing the cost of geothermal power.

Further research will be necessary to evaluate the likelihood of subsidence for varying resource types and under different geohydrologic conditions, as well as to resolve the potential problems of reinjection as a control technology.

Seismic Activity

Seismic activity induced by the withdrawal or reinjection of geothermal fluids is a potential hazard of geothermal development. A connection between subsurface fluid pressures and earthquakes has been suggested recently. A series of earthquakes recorded at the Rocky Mountain Arsenal near Denver, Colorado, for example, followed the injection of waste fluids to crystalline rocks at a depth of three miles (5,000 meters). At Rangely, Colorado, earthquakes have been associated with the injection of fluids to oil fields as a way to increase production. It is hypothesized that similar events could occur as a result of geothermal development.

Natural Relationship with Geothermal Resources: Geothermal resources and seismicity occur naturally at the same locations; the unstable conditions in the earth's crust that create geothermal resources are the same conditions that produce faults and earthquakes. In fact, the presence of seismic activity is commonly used as a propsecting tool in the search for geothermal resources. As noted previously, most of the geothermal resources currently being developed are located in zones of recent volcanic or tectonic activity, which are often located along the margins of major crustal "plates." Active faults in some geothermal areas appear to create zones of high permeability that permit conduction of heat to the surface and keep open the cavities in which geothermal steam forms.

Microearthquakes, that is, earthquakes with magnitudes of less than 4 on the Richter scale, have been observed near many major geothermal areas around the world, including The Geysers and the Imperial Valley. Available data suggest that geothermal zones experience more frequent microearthquakes than do immediately adjacent areas. However, earthquakes having magnitudes greater than 4.5 and the potential to cause significant surface damage have rarely been observed in geothermal areas, although they may occur nearby.

The apparent difference in seismic activity within geothermal areas and outside is exemplified by the Imperial Valley earthquake of 1940, one of the largest to occur near a geothermal area. With a magnitude of 7.1, it caused faulting, which extended most of the distance between the geothermal fields just south of the Salton Sea, California, and those near Cerro Prieto, Mexico; but never into the geothermal areas (8).

One possible explanation of this distinction is that the frequent microearthquakes in geothermal areas act to relieve regional tectonic stress, thus reducing the possibility of a major earthquake. In immediately adjacent areas, where no continual stress release occurs, major earthquakes appear to be more common (8).

To date, there is no evidence to indicate that geothermal activity has increased the seismicity of an area; both The Geysers and the Wairakei sites have been monitored and no effects reported. However, because data are insufficient to reach any reliable conclusions, detailed seismic monitoring is being conducted at The Geysers and the Imperial Valley.

Underground nuclear detonation, which is currently under consideration as a technology for fracturing hot dry rock formations, has been related tentatively to the inducement of seismic activity. Underground experiments with nuclear detonation at the Nevada test site of the Plowshare Program have created small aftershocks, which represent the release of natural strain energy. Even at substantial distances, damages have been reported to buildings as a direct result of the shocks caused by these underground nuclear detonations. Based on these reports, the use of nuclear fracturing near populated areas is probably impractical (9).

The rock formations of the Gulf Coast geopressured reservoir, the third type of geothermal resource, are highly porous and permeable. The faults in this area are not tectonic, but result from relatively minor ground settling due to continuing deposition of sediment. Under these geologic conditions, fluid withdrawal ried into streams and subsequently deposited, raising suspended solids levels and causing sediment buildup on stream bottoms. Both increased levels of suspended solids and sedimentation can be harmful to fish and other aquatic species. Although erosion is most severe when the soil is exposed during construction, significant erosion from cuts, fills, roadsides, and culverts continues throughout all development stages. Earth-moving activities may also disturb national drainageways and slopes.

While some increase in the rate of erosion and sedimentation can be expected with virtually all types of geothermal development, the extent of the increase varies widely, depending on particular site conditions and development practices. At The Geysers steam field in Northern California, for example, the combination of steep slopes, poor soil structure, and high seasonal rainfall and runoff rates renders the soils highly erodible.

Because a steep slope is also a site condition that requires substantial earth-moving, extensive erosion has occurred in the past. Frequently, fill material has slumped and soil and rock slipped above cuts into hillsides following the construction of drill pads and roads, particularly when built on active landslide areas. Degradation of nearby streams by siltation has also occurred.

In contrast, at the development sites having flatter terrain and less erodible soils, the impacts of geothermal development have been less severe. Moreover, since the land disturbance associated with geothermal development is not nearly as severe as that caused by the surface mining of coal or uranium, a smaller total amount of erosion is likely to occur.

The impacts of soil erosion and earth movement during geothermal development can be mitigated significantly by applying readily available erosion control techniques. Drains, mulch, and matting can be installed; revegetation measures can be taken; and the total land area disturbed can be minimized. Such techniques are currently being used on all U.S. federal lands, because federal leasing regulations require that disturbance to vegetation and natural drainage be minimal.

At The Geysers, the state of California has recently begun to carefully regulate earth-moving activities on the lands it owns, thus markedly reducing the severity of erosion-related impacts and highlighting the need for site planning prior to development.

Subsidence

Land subsidence resulting from the withdrawal of geothermal fluids from the earth is among the most serious of the potential impacts of geothermal development. Vertical subsidence and associated horizontal ground movement can occur whenever support is removed from beneath the ground; such movements have occurred throughout the United States as a result of the pumping of ground water in numerous locations, as well as during the development of mines and oil fields.

Whenever subsurface fluids, such as oil or water, are withdrawn, the cause of the resulting subsidence is the same: a reduction in the fluid pressure that supports the overlying rock causes a marked increase in effective stress and subsurface compaction, or the collapse of pores in the rock structure. In petroleum fields,

which are areas of unconsolidated or semiconsolidated sedimentary rock containing pore spaces, subsidence has occurred but has been successfully controlled by injecting water around the periphery of the field to maintain fluid pressures.

Likelihood of Subsidence: Land subsidence has not occurred during the development of the two existing vapor-dominated geothermal fields at The Geysers and in Larderello, Italy. The lack of subsidence has been attributed to the geologic conditions under which such systems form. One of the fundamental conditions considered necessary to formation of a vapor-dominated system is a competent host rock; that is, rock not subject to compaction and, therefore, not subject to subsidence (4).

In contrast, hot-water systems are expected to behave more like petroleum reservoirs and subsidence is more likely to occur unless subsurface pressures are maintained through fluid reinjection. In Wairakei, New Zealand, where geothermal water is discharged to a river rather than reinjected after being used to generate power, total vertical movement has exceeded 3.7 meters (12 feet) since 1956, affecting an area of over 65 square kilometers (25 square miles). Horizontal movement also has been recorded (5).

Significantly, the area of maximum subsidence occurs outside the production field, which means that subsidence could affect the property of adjacent landowners more than the immediate development area.

In Cerro Prieto, Mexico, a hot-water field located near the Imperial Valley in California, subsidence was recorded some seven miles outside the well field even before extensive production began (6). At this site, geothermal waters have been discharged to an evaporation and sedimentation pond rather than reinjected.

Land subsidence has serious implications for the future development of the Imperial Valley's geothermal resources. Potentially one of the most promising geothermal areas, the valley is tectonically active and may be subsiding naturally. Since most of the valley is a flat, fertile plain with extensive agricultural irrigation systems, subsidence induced by geothermal development could cause serious damage.

Concern about this issue has led to extensive studies by the U.S. Geological Survey and the state of California's Division of Oil and Gas. To monitor the extent of subsidence caused by both geothermal development and naturally occurring processes, surface benchmarks have been measured since 1971. Research to develop a reliable computer simulation model of the subsurface environmental effects of geothermal development has been funded by the National Science Foundation and is nearing completion.

Subsidence is also a concern in developing geopressured reservoirs such as those located along the Gulf Coast. However, two conditions are expected to reduce the likelihood of subsidence there: the deep location (frequently more than 10,000 feet or 3,000 meters) of the reservoir suggested by preliminary engineering proposals, and a seal of cap rock above the reservoir. Furthermore, the previous withdrawal of oil and gas from these zones has not yet resulted in detectable subsidence (7).

"Thermal 4" blew out in September 1957; as of 1975, it was discharging about 80,000 kg/hr (176,000 lb/hr) of steam and noncondensable gases to the atmosphere. Since the discharge is steam, air pollution is a greater concern than water pollution. However, the harmful substances being released to the atmosphere, such as mercury vapor, may contribute to local water pollution if removed from the atmosphere by rainfall.

Erosion and sedimentation associated with the construction of drilling pads, roads, transmission lines, and power plants can have a significant effect on the quality of nearby surface waters unless careful monitoring and preventive control measures are implemented. Recently, state and federal agencies have directed that increased attention be accorded to limiting erosion and sedimentation at The Geysers. These efforts have proven successful in reducing the pollution of nearby surface waters.

The most serious water pollution problems are likely to develop during power plant operation. The Geysers uses a production method in which relatively pure steam passes through turbines, is then condensed by contact with cooling water, and is finally evaporated in a cooling tower. However, the rate of evaporation from the cooling towers is slower than the rate at which the steam is fed into the turbines. Some of the steam condensate must consequently be removed in another fashion. On the average, 80% of the steam is evaporated through the cooling towers, leaving 20% as "blowdown" water (10).

From 1960 to 1971, the blowdown wastewater at The Geysers was discharged directly into a stream (10). There, the ammonia and boron contained in the condensate caused some surface water pollution and harm to aquatic life. Since 1971, the wastewater has been reinjected to the steam reservoir rocks.

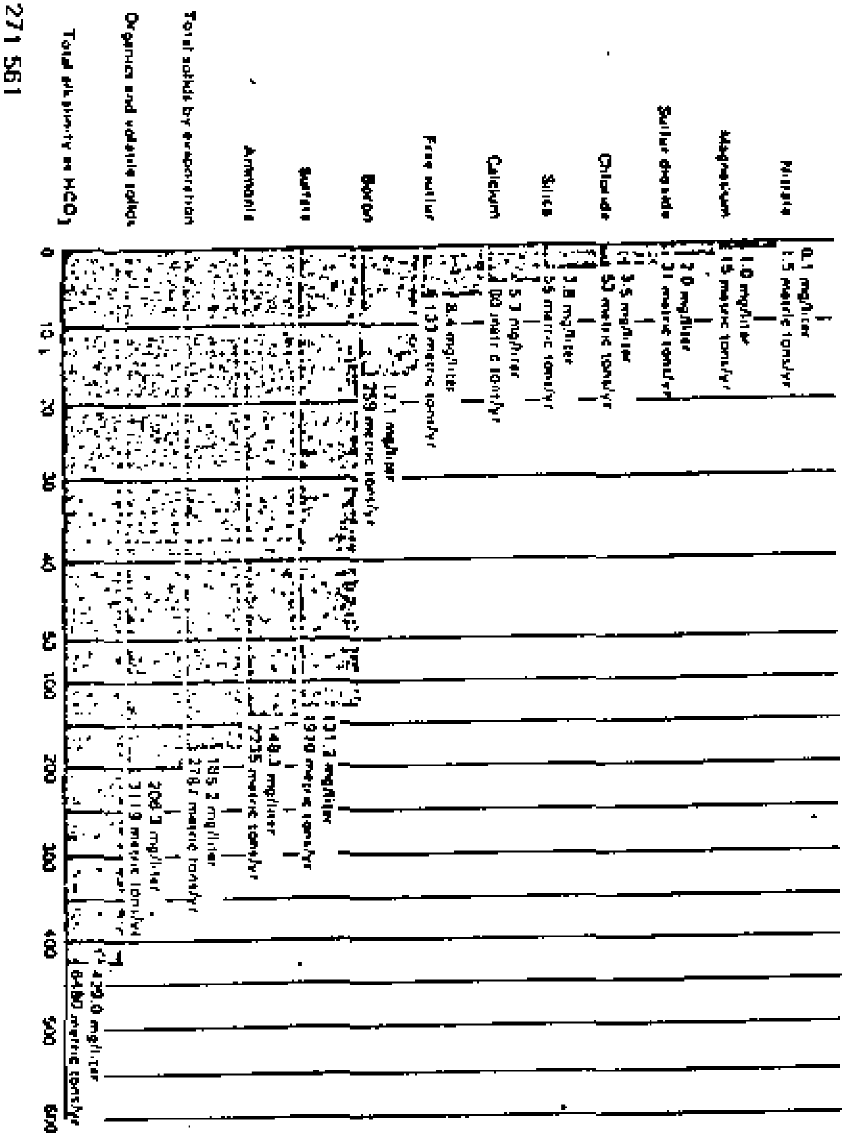
Of the various disposal methods, reinjection is considered to be the most advantageous because the pollutants in the wastewater do not come into contact with relatively pure surface waters and groundwaters. To ensure safety, reinjection wells must be carefully encased to prevent the leakage of geothermal brines to shallow aquifers.

Once introduced to the subsurface reservoir, the wastewater boils and produces steam, in effect artificially recharging the reservoir. Because it has proven to be effective in preventing both surface water and groundwater pollution, it will be used in future expansion at The Geysers.

Each 100 MWe of generating capacity at The Geysers produces a relatively small wastewater flow of over one million gallons (3,785 cubic meters) per day, volume that can be handled adequately by one large injection well. An expanded 1,000 MWe of generating capacity would produce over 10 million gallons (37,850 cubic meters) per day, requiring 8 to 10 large injection wells. Figure 1.15 shows the expected water pollutants contained in the condensate return water of 1,000 MWe of generating capacity at The Geysers.

Power plant operation at The Geysers produces wastewater containing a moderate amount of total solids. The quantity of total solids produced during power generation is higher than that produced by nuclear or fossil fuel plants. However, these technologies also generate large amounts of pollutants during mining and processing, which are not involved in geothermal energy production (see Table 1.14).

FIGURE 1.15: COMPOSITION AND YEARLY QUANTITIES OF MAJOR POLLUTANTS IN CONDENSATE RETURN WATER OF A 1,000 MWe PLANT (THE GEYSERS)



Source: PB 271 561

or reinjection at geopressured reservoirs is not expected to induce seismic activity. However, conclusive information for this assumption is not yet available.

Monitoring and Prevention: Operating procedures that would reduce or eliminate the possibility that geothermal development could induce seismic activity are not well known and will require careful investigation if further research indicates a probable seismic hazard. For the present, structures in geothermal areas, particularly those housing superheated steam and water, should be designed to withstand naturally occurring, local earthquakes. Since this type of design is often expensive, the likelihood and potential magnitude of an earthquake should be determined before design criteria are established. If additional research shows that earthquakes of magnitudes greater than 4 or 5 are highly unlikely to occur in a geothermal development area, only moderate attention would need to be directed to structural precautions, except where faulting may occur near the surface (8).

Research Needs

Although the erosion-related impacts of geothermal development can be significant, they are predictable for a proposed site and can be controlled with available technology. Consequently, little additional research needs to be undertaken. The possibility of land subsidence or induced seismicity at a particular site, however, is difficult to predict; and the adequacy of available control measures, such as reinjection of geothermal fluids, is uncertain. Extensive research is currently under way in the U.S. to develop adequate control measures, and actual effects are being monitored at development sites leased by the federal government to private operators.

Most programs to monitor subsidence have established local and regional networks of interconnected surveying (leveling) stations. Elevation is measured repeatedly at these stations to determine the degree of subsidence over time. The instruments used include tiltmeters, which measure surface deformation, and extensometers, which can be used to differentiate deep subsidence resulting from the withdrawal of geothermal fluids and shallow subsidence resulting from groundwater pumping.

The interagency Imperial Valley Subsidence Detection Committee is presently monitoring subsidence in the Imperial Valley. One monitoring technique not being employed that could provide useful data is a gravity reading. While not as accurate as detailed, "first-order" leveling, gravity measurements can be performed rapidly and inexpensively.

Moreover, when taken in conjunction with first-order leveling, gravity readings permit estimation of the net losses of geothermal fluids from a reservoir and the surrounding area. Both are important parameters in determining the ultimate life of the field and the optimum level of production.

A wide variety of techniques can also be used to investigate seismic effects. Prior to geothermal development, portable, high-frequency seismographs should be used to establish levels of background seismicity, locate areas unsuitable for reinjection, and help locate the geothermal resources. Remote sensing techniques, such as SLAR (side-looking radar), and false-color infrared and conventional aerial photographs, can also be employed to identify surface features that indicate active faulting. During the actual development of new geothermal fields, a network of permanent seismographs can be installed to identify any induced seismicity. Such a network is presently being installed in the Imperial Valley and should be installed in other prospective geothermal areas as well.

A variety of research is currently under way to evaluate the feasibility of reinjection at geothermal sites. While these studies appear to address most of the important questions, at least one additional problem should be investigated: how to prevent reinjection-well plugging. To understand the chemical reactions that occur between geothermal fluids and the geologic formations into which they are injected, basic research on the precipitation of silica, calcium carbonate, and other dissolved minerals is needed first.

Applied research should be conducted on the prevention of well-plugging and the related problem of mineral deposition on operating equipment. Based on this research, the potential for both stabilizing geothermal fluids against the precipitation of minerals and deliberately inducing precipitation before the fluids are reinjected should be assessed. Laboratory studies should be conducted based on actual samples from proposed development areas.

WATER RESOURCES

Geothermal development raises three primary concerns related to water resources: water pollution, effects on hydrology, and impacts on local water supplies. Water pollution may result from the disposal of fluids withdrawn from subsurface geologic reservoirs following their use for testing wells or generating power. Large-scale withdrawal and disposal of geothermal fluids may also alter both the surface and subsurface hydrology of an entire development area. Finally, geothermal development may affect local water supplies in the largely arid American West.

Water Pollution

The pollution problems associated with vapor-dominated systems are generally more manageable than those associated with hot-water systems, because the water from the geothermal steam is often relatively low in pollutants. However, water pollution can occur during any stage in geothermal development—well drilling, construction, or power plant operation.

Sources of Pollution: Muds used during the early stages of well drilling may contain various substances harmful to water quality. To prevent the contamination of surface waters, these substances, together with rock dust and the wastewater used in the drilling operation, must be isolated. At The Geysers, sumps with an impervious lining or steel tanks are currently used to store drill cuttings and waste fluid during drilling operations. Nontoxic wastes may be permanently disposed of in a sump if it is protected from erosion; however, toxic wastes must be transported to an approved waste disposal site.

Well blowouts could also create water pollution. The California Division of Oil and Gas requires that blowout prevention equipment be used during the drilling of all geothermal wells as a control if pressure conditions become unfavorable. Only one well has blown out during the drilling phase at The Geysers. Well

TABLE 1.14: EXPECTED WATER POLLUTION EMISSIONS FOR ALTERNATIVE ELECTRICAL GENERATING PROCESSES, 1,000 MWe PLANT

Process	Suspended Solids A	Suspended Solids B	Dissolved Solids A	Dissolved Solids B
	metric tons per year*			
Nuclear (light-water reactor)	0	0	0	0
Coal	500	4,000	500	2,800
Residual fuel oil	500	**	550	100,000***
Natural gas	500	**	550	0
Low Btu synthetic natural gas (from coal)	500	**	550	2,600
Geothermal (The Geysers)	**	**	2,600†	**

Note: Column A under each process includes total pollutants generated during power plant operations. Column B includes total pollutants during all other steps (mining, etc.).

Source: Reference (11).

*Rounded to the nearest fifty.

**Not available.

***Produced by a hypothetical 500,000 bbl/day refinery of which 34,000 bbl/day are residual fuel oil to supply a 1,000 MWe power plant.

†Total solids by evaporation.

Source: Reference (11)

Moreover, the technology of reinjection to the geothermal reservoir, now being applied at The Geysers and planned for hot-water development sites in the western U.S., would, if successful, almost eliminate the major cause of water pollution.

Hot-water systems pose far more difficult water pollution problems because wastewaters from testing and production are more abundant, more water pollutants are contained in the geothermal fluid, and large amounts of cooling water are used. At Wairakei (a 143 MWe plant), approximately 30 million gallons (113,600 cubic meters) of wastewater are disposed of each day from the condensed effluent and the excess water not flashed to steam. This is a far greater proportion than is produced at The Geysers. Such large amounts of wastewater must be disposed of in an environmentally safe manner.

Characteristics of Geothermal Fluids: The quality of geothermal hot water—its physical and chemical characteristics, including impurities such as total suspended solids—varies widely. While some geothermal hot waters contain relatively few pollutants, most contain a relatively large amount of dissolved solids and heavy metals because the high temperatures of the brines increase the dissolution rate of solids and heavy metals in the rock (4). Radioactive elements such as radium and radon also may be present.

The geothermal hot waters at Cerro Prieto, Mexico, contain 1.5 to 2% total dissolved solids (15,000 to 20,000 mg/l, compared to a value of about 35,000 mg/l for seawater). At the Imperial Valley in California, about 75 miles north, geothermal waters are substantially more saline at most locations; brines with dissolved solid concentrations (typically over 25,000 mg/l and sometimes reaching 260,000 mg/l, or 26% of the total) are found in many wells (6).

In sharp contrast, at certain other locations in the western U.S., geothermal hot waters are sufficiently pure to be used for agriculture and industry. For example,

geothermal waters are used for stock watering in Klamath Falls, Oregon, and for domestic hot water supplies in Boise, Idaho. In Iceland, geothermal waters are widely used for both municipal heating and domestic purposes (4).

The Special Problem of Waste Disposal: Based on the variability in the amount and type of dissolved solids in geothermal fluids, a number of different methods for disposing of wastewater from drilling and power plant operation have been tested and used. These include direct release to surface water bodies, evaporation, surface spreading to shallow aquifers, desalination with subsequent water reuse, and reinjection to the producing reservoir by use of deep wells. The selection of a disposal method has depended on local hydrologic conditions, the quality of the wastewater, and environmental regulations.

The only extensive commercial experience with hot-water system waste disposal has been outside the United States, and some of the methods used in other countries are not acceptable in the U.S. because of their harmful environmental effects. For instance, at Wairakei, New Zealand wastewaters are discharged into a river near the plant, substantially increasing the arsenic, sulfur, and mercury levels of the river. At Cerro Prieto, Mexico, production wastewaters are separated from the geothermal fluid and then stored in a large evaporation and sedimentation pond (8 km^2 or 3 square miles in size for the existing 74 MWe plant). As the waters in the evaporation pond become highly saline, developers plan to discharge them into nearby waterways having high natural salinity.

A major concern in the Imperial Valley of California is the salinity level of the Salton Sea and various shallow aquifers. Local water supplies are limited and in great demand for agriculture. Because water supplies already contain large amounts of dissolved solids, additional salinity must be prevented. The state of California has prohibited the discharge of waste fluids with high dissolved solids content into either surface waters or shallow aquifers.

In complying with this restriction, wastewaters produced during test drilling at the Imperial Valley are stored in plastic-lined holding ponds from which the water evaporates. This disposal method prevents infiltration to groundwater and has thus far proven effective. However, the very large volume of wastewater generated during actual power plant operation limits its use; the rate of evaporation is not fast enough for large volumes of wastewater.

As a rough indication of the magnitude of the problem, a 1,000 MWe plant in the Imperial Valley is estimated to require the disposal of approximately 50 billion gallons (18,900,000 m^3) of brine per year containing 50 million tons of solids (12). Thus, the most probable long term disposal method for wastewater from power plant operation seems to be reinjection to deep wells. Initial tests of reinjection have proven promising. In a year-long experiment, 2,727 liters (600 gallons) per minute were successfully injected into a single well without reducing the ability of the formation to receive water (3). However, a number of complex technical problems remain to be solved.

Desalination, which has the additional benefit of producing usable fresh water for a locality, is another alternative for wastewater disposal. However, because the expense of desalination increases with the salinity of the water, the technology is probably limited to waters with dissolved solids concentration below hydrologic systems and the characteristics of geothermal waters that would disclose their presence in surface and ground waters. Data would be particularly useful in water samples from surface waters, shallow groundwaters, and geothermal reservoirs. Detailed laboratory analysis of the chemistry of geothermal fluids, similar to that performed to determine potential reinjection problems, would also be helpful in determining potential water quality problems.

The liquid wastewater disposed of during geothermal operations often contains a variety of chemical compounds. Because wastewater is a potential source not only of water pollution, but also of water supply and commercially valuable chemical by-products, high priority should be assigned to developing economical methods of producing fresh water (desalination) and extracting valuable chemicals such as boric acid and sulfur compounds.

NOISE

Perhaps the most ubiquitous environmental disturbance associated with geothermal development is noise. Loud, continuous noise occurs during both the drilling and production testing of geothermal wells and the operation of the plant. Nevertheless, noise does not represent as immediate a concern as do some of the other environmental impacts of geothermal development because its effects are limited to the immediate area under development. And because the health and welfare effects of noise are well documented, this section reviews those effects only briefly and then focuses on the sources of noise at a site.

Effects of Noise

The harmful health and welfare effects of exposure to excessive noise levels or vibration over a prolonged period of time range from the relatively minor, such as temporary task interference and irritation, to the severe and permanent, such as sleep loss, physiological stress, speech impairment, and hearing loss. Since the extent of harm is related directly to the frequency and duration of exposure to high noise levels, workers at a geothermal site experience the highest risk.

Noise standards established by the U.S. Occupational Safety and Health Administration (OSHA) require that exposure of workers to unmuffled noise at levels above 95 dB(A) be limited (13). Several geothermal development activities produce noise at levels close to, or substantially higher than, this level. Persons in the vicinity of a geothermal site may be exposed to continuous noise at levels varying from 60 to 120 decibels, depending upon the ongoing development and distance from the noise source.

In addition to direct health and welfare effects, the noise generated by geothermal development may have other adverse impacts. In communities with little industrial development, residents may regard the continuous noise associated with geothermal development, even at a relatively low level, as an intrusion into their previously quiet environment.

Animal behavior also is affected by excessive noise, which has been shown to cause changes in the size, weight, reproductive activity, and behavior of farm animals. In some wildlife species, changes in mating behavior, predator-prey relationships, and territorial behavior have been observed.

Sources of Noise in Geothermal Development

High noise levels are produced during each of the major phases of geothermal development: well drilling and production testing, construction, and plant operation.

Well Drilling and Production Testing: The process of drilling and testing geothermal wells is comprised of a number of separate operations of varying duration in which steam under high pressure escapes to the atmosphere, generating high noise levels. Some of these operations can be effectively muffled, others emit essentially unavoidable noise.

At vapor-dominated sites, only the shallow portion of a well can be drilled by using mud as the circulating fluid. For much of the procedure, compressed air must be used as the circulating fluid when penetrating the probable steam zone to avoid clogging or damaging the steam-producing rock fractures. Air drilling is much louder [120 dB(A)] than mud drilling [75 to 80 dB(A)], primarily from the horizontal pipe ("blow line"). The engines operating the air compressor also produce a deep resonant sound that carries for considerable distances. Of the total drilling period of two to three months (during which drilling is conducted 24 hours a day), about one-third of the time is spent drilling with compressed air.

Drilling companies have experimented with a wide variety of methods for controlling air drilling noise at The Geysers and have tested several types of mufflers. Recently, significant reductions in noise have been achieved by directing the discharge of the blow line into a large "air sampler," a large chamber designed to capture loose rock cuttings. Injection of water into the air sampler, a method originally developed to increase the amount of rock captured, also reduced noise (10). These techniques have been employed extensively in well drilling at The Geysers.

Once drilling is completed, the noise levels associated with extraction do not drop significantly. A well must first be allowed to "blow" freely for three to six days until the accumulated dust and rocks are removed. Noise levels during the procedure approach 118 dB(A). It is generally considered infeasible to muffle this operation, because only large rocks blown up under pressure would damage currently available muffling equipment.

Following the clean-out, the well is tested to evaluate the steam reservoir and production rate by releasing steam from the well to the atmosphere. The accompanying noise level is high [approximately 118 dB(A)]. Several types of mufflers have been used in an attempt to control testing-related noise. One of the most effective, a "rock muffler," significantly reduced the noise level by 29 dB(A), from 118 to 89 dB(A), according to tests by Union Oil Company (10).

A completed test or production well is discharged or "bled" continuously into the atmosphere through a small diameter pipe (bleed line), which permits releases of 5 to 10% of the total potential steam flow. The noise associated with bleed line discharges is relatively low, about 86 dB(A), and can be lowered to 65 dB(A) by venting the line into a rock-filled ditch. While this discharge continues until the power plant is operational (possibly more than a year if delays are encountered), an attempt is usually made to limit this source of air and noise pollution

35,000 mg/l. The economic feasibility of desalination has also been questioned because if less heat is extracted from the brines, less electric power can be produced. Thus, at relatively low temperatures a tradeoff exists between the production of power and the availability of fresh water.

Hydrology

Geothermal development at The Geysers has not as yet altered the area's surface hydrology significantly. However, continued withdrawal of geothermal fluid could reduce the amount of water in the deep steam reservoir and in the rate of water flow and possibly change the temperature or chemical characteristics of nearby thermal springs.

Pressure decline tests indicate that The Geysers reservoir is almost a closed system; that is, it is not being recharged with water at a rate sufficient to prevent a decline in steam pressure as energy is produced. Although some of the fluid is restored through reinjection, geothermal steam at The Geysers should be viewed as a depletable, rather than a renewable, resource.

Large-scale extraction and reinjection of hot-water geothermal fluids in the Imperial Valley also may cause changes in the subsurface hydrologic system. The lack of comprehensive, reliable data on subsurface hydrology makes impossible the determination of whether long-term power production would ultimately deplete the geothermal resources of the Imperial Valley or other hot-water systems in the United States. Investigations at Wairakei, New Zealand, suggest that geothermal energy could be developed at a rate that permits production for an indefinite period of time (5).

Reinjection could also help to maintain the long-term productivity of the geothermal resource. Research involving computer simulation of resource behavior is under way to identify the most effective long-term production strategy (including the rate and method of withdrawal and reinjection) for both hot-water and geopressured reservoirs.

Water Supply

Geothermal power production may also require the use of water for cooling purposes. At The Geysers and other vapor-dominated systems, water can be supplied by the geothermal resource in the form of condensed steam, thereby eliminating the need for an external source of water. A similar cooling system can be used in a flash turbine hot-water plant. However, in a binary fluid system, because the geothermal hot water is reinjected directly to the geothermal reservoir once it has passed through a heat exchange device, it is not available for use in cooling the Freon or isobutane used to drive the turbine, and an external source of water is needed.

Current Alternatives for Cooling: The cooling water can be provided to a geothermal site in one of three ways: with a "once-through" cooling system, in which external water, frequently from a river or lake, is utilized once for cooling, and then discharged to its source; with an evaporative or "wet" cooling tower, in which the external water is evaporated to the atmosphere; or with a "dry" cooling tower, in which the fluid is cooled by air and continually circulated in a closed system.

The water requirements of these systems may vary widely. Once-through systems and wet cooling towers require substantial amounts of water; dry cooling towers very little. Their environmental impacts also vary substantially. A once-through cooling system is currently used at Wairakei, New Zealand; however, the potential for thermal pollution of surface water limits the applicability in the United States.

New Designs for Still-Undeveloped Resources: Preliminary designs prepared by Bechtel Corporation for a 10 MWe demonstration binary power plant with an evaporative or wet cooling tower indicate that 830 gallons per minute of makeup water is required, of which about 20% is blown down and reinjected to the reservoir. At this rate, for a 1,000 MWe plant, 83,000 gallons per minute (almost 134,000 acre-feet, or 165 million cubic meters per year) are required. This amount is substantially greater than that needed by alternative power generation systems because the thermal efficiency of a geothermal plant is low.

Alternatively, a dry (air-cooled) cooling tower could be used. Based on present prototype designs, dry cooling towers are expected to be 30 to 40% more costly than evaporative towers (11) and may reduce the already low thermal efficiency of the power plant.

A moderate quantity of makeup water is required to operate hot dry rock systems. Requirements are estimated to be about 26,500 gallons (100 m^3) per day for wells supplying 100 MWe of thermal energy; at this rate, 1,325,000 gallons (5,015 m^3) per day (1,484 acre-feet, or 4,830,000 m^3 per year) would be needed to supply a 1,000 MWe plant, assuming that a binary power plant with 20% efficiency is used (11). Additional cooling water would, however, be required to cool the isobutane or other working fluid.

Research Needs

In any geothermal development area, impacts on water quality, hydrology, and local water supply can be predicted only on the basis of comprehensive, site-specific data.

Geologic and hydrologic data are usually obtained from deep test wells drilled during exploration for geothermal fluids. Insufficient data are often obtained from such wells at shallow and intermediate depths. Data on the vertical variation of water level, depth, temperature, and pressure; and on rock permeability, porosity, and cementation, should be collected in each zone. To provide a thorough understanding of local hydrology and determine whether reinjection is likely to be successful, test wells should also be drilled on the periphery of geothermal areas, where temperatures decrease rapidly and rock cementation occurs.

In many geothermal areas, data on rock porosity and permeability are insufficient to assess the hydrologic nature of the reservoirs. Well-logging techniques using radioactivity (including gamma-gamma and neutron logs) provide the most reliable means of estimating porosity and permeability. Where appropriate, such techniques should be applied to new wells (both deep and shallow) in geothermal areas.

To assess impacts on water quality, data should be collected not only on the standard water quality parameters (e.g., dissolved solids) but also on the local by timing the completion of production testing to coincide with the completion of the power plant. Occasionally, wells are allowed to vent at full pressure for several hours to prevent the buildup of condensate. Because this operation is not usually muffled, it produces about the same noise levels [118 dB(A)] as do unmuffled test wells.

Well blowouts, or unanticipated venting, rarely occur during the drilling phase of geothermal development. The noise emitted when they do occur, however, is extremely loud, probably as loud as an unmuffled test well. If not controlled, blowouts can continue to be sources of air and noise pollution for extended periods of time. At The Geysers, "thermal" well No. 4 "blew out" in September 1957 and is still discharging some steam into the atmosphere; however, this blowout has been partially controlled and is no longer a significant noise source.

Drilling noise levels pose less of a problem in hot water than in vapor-dominated systems. Well drilling and production testing for hot-water systems is a far less noisy operation than for vapor-dominated systems because mud, rather than air, is used as the circulating fluid. Also, the period of time required for drilling in hot-water systems is somewhat shorter, 30 to 45 days rather than 2 to 3 months.

The most significant noise associated with hot-water wells is that emitted during production testing for power generation, when 20 to 25% of the hot water is flashed to steam. If unmuffled, the noise of the expanding steam could reach a level as high as 100 dB(A) at 50 feet. Well blowouts could also produce high noise levels. Following the testing period, the wells are completely capped and thus cease to be a source of noise.

Construction Activities: Full development of a geothermal field involves construction of access roads, steam pipelines, generating plants, and electrical transmission lines. Construction of generating plants requires the longest period of time. During this period, the operation of earth-moving and construction equipment (such as large trucks, bulldozers, tractors, cranes, and cement mixers) generates noise levels familiar to anyone who has experienced a city building construction site.

Noise associated with construction activities can often be controlled through the use of engine mufflers and other abatement techniques. However, construction equipment is generally operated at the same time that production wells are being drilled and tested; the simultaneous field development and plant construction phases cause high noise levels.

Plant Operation: Operation of a geothermal power plant also creates high noise levels. At The Geysers, the most significant continuous noise sources are the cooling towers and jet gas ejectors, which release noncondensable gases from the condenser. The noise created by the fans in the cooling towers is continuous, but is confined by the structure to the immediate vicinity of the plant. While the jet gas ejectors on older units at The Geysers emit considerable noise, newer units are acoustically insulated and are therefore considerably quieter.

Installation of improved air pollution control equipment designed to transfer gases from the jet gas ejectors to other locations in the plant for the removal of hydrogen sulfide may also reduce the noise emitted from the ejectors. The particle separators and the movement of steam through the steam lines also repre-

ent significant sources of noise. Another loud but intermittent noise source is the venting of steam lines during plant shut downs and accidental steam line breaks.

Research Needs

The noise levels produced by any type of geothermal development are largely determined by the actual equipment used and the operating procedures followed. While the geothermal industry has conducted extensive research and experimentation on noise control, much of this research has taken the form of "trouble-shooting" aimed at controlling individual operations such as well drilling at a specific site. A need clearly exists for comprehensive research on noise control and the development of appropriate equipment and operating procedures.

Ambient noise levels at new geothermal sites should be monitored to determine noise intensity, frequency, and duration before and during development. In addition to site-specific data collection, a more general, comprehensive engineering study should be undertaken to analyze in detail each geothermal operation that produces noise in the development of both vapor-dominated and hot-water fields. Existing equipment and procedures used to reduce noise levels during each operation should be compared in terms of effectiveness, reliability, cost, and environmental impact, and specific procedures and equipment recommended for use.

AIR QUALITY

Noncondensable gases and particulates accompany the geothermal steam released to the atmosphere during well drilling, production testing, and plant operation. At sufficiently high concentrations, several of these substances, particularly hydrogen sulfide, can have harmful effects on human health. The odor of hydrogen sulfide can also be regarded as aesthetically objectionable.

To date, no significant health effects resulting from emissions of hydrogen sulfide or other air pollutants during geothermal power production have been documented, either at The Geysers or at geothermal power plants in foreign countries. However, relatively high emission levels of various air pollutants have been recorded at geothermal power plants in other countries, and moderate emission levels of hydrogen sulfide have been documented at The Geysers.

Since data on health effects, air pollutant emission levels, and ambient air quality at geothermal development areas are still incomplete, the air quality impacts that will result from full-scale geothermal development at sites currently in the early stages of exploration and development cannot be predicted accurately. However, because the concentration of air pollutants in geothermal fluids (and, thus, of the steam released to the atmosphere) varies widely from site to site, the development of better methods to evaluate and control emissions is generally considered to be one of the most important environmental issues associated with geothermal development.

Types of Pollutants

The types of pollutants likely to result from geothermal development are primarily determined by the chemical composition of the geothermal fluid at a site. Both the total quantity of gases in the fluid and the relative concentration of their constituents depend on the geochemistry of the underground reservoir. The chemical composition of the geothermal fluid can vary substantially in different reservoirs, at different wells within the same reservoir, and even during the lifetime of a single well. Thus, the levels of pollutants emitted during geothermal operations can also vary widely overall. Table 1.15 compares the composition of geothermal steam at The Geysers and Wairakei.

TABLE 1.15: COMPARISON OF NONCONDENSABLE GASES IN STEAM FROM WELLS AT TWO GEOTHERMAL POWER PLANTS

	. . . Range of Concentrations Measured (ppm) . . .			
	. . . . Geysers			Wairakei
Gas	Low	High	Average	Average
Hydrogen sulfide	5	1,600	222	40
Carbon dioxide	290	30,600	3,260	600
Methane	13	1,447	194	5
Ethane	3	19	–	1
Ammonia	9	1,060	104	8
Nitrogen	6	638	52	3
Hydrogen	11	213	56	10

Source: References (5) and (10)

The gaseous emissions associated with the geothermal production of electricity differ considerably from those associated with nuclear and fossil-fueled production. Since geothermal processes operate without combustion, the resulting gaseous emissions are the reduced compounds (primarily hydrogen sulfide, ammonia, and hydrocarbons such as ethane and methane) of elements contained in the geothermal fluid. In the burning of fossil fuels, these elements are found in oxidized form as sulfur oxides, nitrogen oxides, and carbon dioxides.

In vapor-dominated systems and in the "flash" steam process used with hot-water systems, the geothermal steam contains an assortment of noncondensable gases. Carbon dioxide represents the main component (75 to 95%); ammonia, methane, hydrogen sulfide, and nitrogen typically are present in smaller quantities; and gases such as radon, mercury vapor, and argon are present in trace amounts (5).

Small quantities of minute particulate matter (including rock dust, heavy metals such as lead and silver, and boron) are also likely to be in suspension in the steam. Measurements at sites throughout the world indicate that because the chemistry of geothermal fluids in both vapor-dominated and hot-water systems can vary so widely, neither type of system inherently results in more air pollution than the other.

Potential Health Hazards

Several of the noncondensable gases emitted during geothermal power generation pose potential health hazards. To date, the emission levels associated with existing geothermal power plants have generally not been high enough to cause most

of the effects; however, because the nature of the geothermal fluid varies considerably from site to site, serious effects could occur at new development sites.

Hydrogen sulfide and ammonia present the greatest potential hazards; carbon dioxide, although usually present in higher concentrations, is somewhat less significant. Mercury and radon are of concern because they are toxic even at low concentrations.

Hydrogen Sulfide: Hydrogen sulfide is a highly toxic gas. Its direct effects on humans range from a noxious, "rotten-egg" odor and eye irritation at low concentrations to respiratory damage and even death at high concentrations (14). Although atmospheric dilution of geothermal steam generally prevents ambient hydrogen sulfide from reaching dangerously high levels in the immediate vicinity of steam releases, concentrations may be sufficient to create an occupational health hazard for workers. The potential hazard of this gas is increased by the fact that it cannot be detected by smell at the high concentrations which are most dangerous.

Hydrogen sulfide is chemically reactive, and readily converts to other compounds of sulfur, such as sulfur dioxide, sulfur trioxide, sulfuric acid, and particulates (metal sulfides and sulfates). Conversion is particularly likely to occur in urban areas where ambient oxidant levels are high (14). Recent research shows that this conversion frequently occurs within hours or at most several days following introduction of the gas to the atmosphere. The other sulfur compounds into which hydrogen sulfide is converted also have significant negative health effects on humans, including increases in irritation to the respiratory system.

Although the odor of these compounds does not constitute a nuisance as does hydrogen sulfide at similar concentrations, they are of greater national significance overall as air pollutants because they are emitted in large quantities by "stationary sources" such as fossil-fuel-burning power plants. Thus, geothermal emissions of hydrogen sulfide contribute to raising ambient levels of sulfur oxides regionally. This is particularly important because sulfur dioxide is one of the "criteria pollutants" for which EPA sets and enforces national ambient air quality standards under the authority of the Clean Air Act and its 1970 amendments. Geothermal emissions of hydrogen sulfide may also contribute to regional climatic problems, such as increases in the acidity of rainfall.

Ammonia: Most geothermal steam contains ammonia at levels too low to pose a direct health hazard. Moreover, as with hydrogen sulfide, atmospheric diffusion rapidly lowers ammonia levels to acceptable values. Inhalation of high concentrations (1,000 ppm) of ammonia, which can cause extensive irritation of the eyes and upper respiratory tract, coughing, and vomiting, is thus a rare occurrence. However, if ammonia reacts with other chemicals to form more toxic compounds (such as with hydrogen sulfide to form ammonium sulfate), harmful environmental impacts on human health and certain plant and animal species may result (14).

Carbon Dioxide: Carbon dioxide is present in undiluted geothermal steam in quantities more than twice its toxic level. Because it is a normal component of the atmosphere, it tends to diffuse rapidly and therefore does not usually pose a major danger. However, the accumulation of carbon dioxide in terrain depressions (which can occur as a result of its greater density than air), may result in high concentrations in the ambient air.

Mercury: Mercury, which can be toxic to living tissue, is a known constituent of some geothermal fluids in trace amounts. Because of its natural tendency to vaporize, mercury can be emitted to the atmosphere through natural releases of steam as well as those caused by geothermal development, and can be washed from the atmosphere by rainfall. Mercuric compounds are soluble in water and thus can be absorbed by living organisms directly from water or indirectly through the food chain.

Radon: Radon 222, the only radioactive gas, is found in trace amounts in the noncondensable gas portion of geothermal steam. It is produced by the decay of uranium in the rocks of the geothermal reservoir. Although only a minute amount of radon is present in geothermal effluents, its very presence has caused considerable concern. Once introduced to the atmosphere, radon acts as a source of highly toxic decay products. While radon itself does not accumulate in human beings, it has a relatively short half-life of 3.82 days, and breaks down into "daughter products" that readily attach to other particles in the atmosphere.

These particles can, in turn, attach to human tissue. Increases in lung cancer at industrial sites have been associated with exposure to radon and its daughter products. A concentration standard of three picocuries per liter has been set by the state of California for the radon-222 concentration in the air.

Sources of Air Pollutants

The major sources of air pollutants emitted during geothermal power production are (1) direct releases of geothermal steam during all stages of development and (2) releases of noncondensable gases during plant operation.

Vapor-Dominated Systems: In vapor dominated fields such as The Geysers, dry steam is released to the atmosphere when the steam-producing zone is penetrated, during subsequent well cleanout, and again during production testing. Results of extensive tests at The Geysers indicate that the average initial steam flow of a well is 68,000 kg/hr (150,000 lb/hr), although initial steam flow rates as high as 172,000 kg/hr (378,000 lb/hr) have been recorded.

An average well producing 68,000 kg/hr of steam with an average hydrogen sulfide content of 222 parts per million would result in the emission of 15 kg/hr (33 lb/hr) of hydrogen sulfide during well testing. A successful exploratory well at The Geysers will be cleaned and tested for approximately 20 days; during this time an average of 7,200 kg (15,800 lb) of hydrogen sulfide is emitted per well.

Following production testing, the well is discharged continuously through a bleed line until it is connected to the power plant. The average steam and hydrogen sulfide flows through a bleed line are small, 450 kg/hr (990 lb/hr) and 0.1 kg/hr (0.221 lb/hr), respectively; however, the time period of discharge is variable, and can be as long as several years. The total estimated quantities of air pollutants released to the atmosphere prior to power plant operation for 1,000 MWe of generating capacity located at The Geysers are shown in Table 1.16. These quantities represent combined total emissions from well drilling, clean-out and production testing, and not rates of emissions per unit of time.

TABLE 1.16: EXPECTED TOTAL AIR EMISSIONS AT THE GEYSERS PRIOR TO OPERATION OF GEOTHERMAL WELLS FOR 1,000 MW OF GENERATING CAPACITY

Constituent	Total Metric Tons*
Steam	12.09×10^4
Carbon dioxide	9.55×10^4
Ammonia	8.46×10^3
Methane	6.04×10^3
Hydrogen sulfide	6.04×10^2
Nitrogen and argon	3.63×10^3
Hydrogen	1.21×10^1

*Calculation assumes that well testing continues for approximately 2 months per well.

Source: Reference (11)

Uncontrolled blowouts, which have occurred infrequently during well drilling and production testing, also represent a source of air pollution. Power plant operation represents the most significant source of air pollution associated with geothermal power production. At The Geysers the solids and particulates are removed in a "centrifugal separator" built into each steam line. In existing units, the steam is cooled in direct contact with circulating cooling water. About one-third of the total hydrogen sulfide, and most of the other noncondensable gases in the steam, are continuously emitted to the atmosphere.

A portion of the gas, including about two-thirds of the total hydrogen sulfide, is dissolved in the condensed geothermal fluid, circulated to the cooling tower, and then released to the atmosphere, along with the evaporated water (10). A small amount of the hydrogen sulfide (less than 10% of the total) is naturally oxidized to elemental sulfur and sulfates in the cooling tower and is reinjected to the subsurface reservoir along with the excess condensed water (15).

Concentrations of hydrogen sulfide as high as 0.87 ppm have been recorded in the ambient air at a sampling station located close to a cooling tower near The Geysers; the average of 44 measurements taken was 0.126 ppm. Of 1,218 measurements taken at 37 sampling stations in the area, 84% recorded hydrogen sulfide levels lower than the California standard of 0.03 ppm (16).

Table 1.17 compares the total air pollution emissions that would be generated by a 1,000 MWe geothermal plant located at The Geysers with air pollution emissions from fossil-fuel and nuclear power plants. The relative significance of each of these sources can be assessed in terms of the total weight of polluting substances released. Calculations of this weight are based on the average steam flow for each source, size of the power plant, period of operation, and concentration of noncondensable gases in the steam.

The comparison shows that geothermal power plants are not necessarily "cleaner" than fossil-fuel plants. Furthermore, the odor of hydrogen sulfide emitted by geothermal power plants creates a nuisance that does not occur with the sulfur dioxides and sulfates emitted by fossil fuel plants. Experience at The Geysers indicates that it is technically feasible to reduce hydrogen sulfide emissions during power plant operation by as much as 90%.

TABLE 1.17: AIR EMISSIONS OF ALTERNATIVE ELECTRICAL GENERATING PROCESSES, 1,000 MWe PLANT

Process	SO_x	NO_x	CO_2	CO	Hydrocarbons	NH_3	H_2S	Particulates
	....	....	....	metric tons per year	....	....	....	....
Nuclear (light-water reactor)	50	42	0	–	–	8	–	–
Coal	54,000	38,000	*	2,000	600	–	–	23,000
Residual fuel oil	37,000	25,000	*	700	470	–	–	150
**	20,000	18,000	*	4,300	20,000	2,000	–	–
Natural gas	20	20,000	*	***	34	–	–	5
	900	267	*	20	11	–	–	–
Low Btu synthetic natural gas (from coal)	5,600	13,000	*	***	***	–	–	*
	1,600	–	*	550	5	–	12	5,000
Geothermal (The Geysers)	0	0	250,000	0	15,000	15,000	1,700†	0
††	0	0	–	0	–	–	–	0

Note: The first row under each process defines emissions during power plant operation; second rows define emissions during other steps (mining, transportation, etc.).

*Not available.

**Emissions from a hypothetical 500,000 bbl/day refinery which produces 34,000 bbl/day residual fuel oil to supply a 1,000 MW power plant.

***Negligible.

†Assuming 90% reduction of uncontrolled hydrogen sulfide emissions due to use of hydrogen sulfide abatement equipment (uncontrolled emissions are 17,000 metric tons/yr).

††See Table 1.16 for total pollutant emissions from wells prior to power plant operation.

Source: Reference (11)

Hot-Water Systems: As previously noted, geothermal steam derived from hot-water systems may contain either more or fewer air pollutants than does steam from vapor-dominated systems. The likely emissions resulting from development of a new hot-water system can only be estimated based on (1) detailed, site-specific analyses of the chemistry of its geothermal fluid, and (2) monitoring of emissions and ambient air quality.

During well drilling and production testing, steam flashed from geothermal hot waters may represent 20 to 25% of the total fluid, depending on its temperature. For comparable levels of electricity generated, the total quantity of steam released to the atmosphere during these phases is probably comparable to that emitted at The Geysers. The resulting air pollution is strictly a function of the amount of noncondensable gases in the steam. Since the hot-water wells can in some fields be "capped" or completely shut off after production testing, well "bleeding" prior to power plant operation may not represent a source of air pollution.

During operation of a flash-turbine power plant, the system currently used at both Cerro Prieto, Mexico, and Wairakei, New Zealand, noncondensable gases are vented to the atmosphere; thus, air pollution control techniques similar to

those at The Geysers should be applicable. In the binary-fluid type of generating unit, the geothermal hot waters would be reinjected directly to the production reservoir following use and no air pollution emissions would occur. However, binary-fluid systems are still experimental.

At Wairakei, New Zealand, geothermal steam is relatively "clean;" it contains only about one-fifth as much hydrogen sulfide as steam at The Geysers. This 145 MWe plant discharges about 14 kg/hr (30.8 lb/hr) of hydrogen sulfide to the atmosphere at concentrations of about 5,000 ppm in the stack gas. About five times this amount is transferred to the plant's cooling water and discharged into a nearby river (16). In contrast, geothermal steam at Cerro Prieto, Mexico, contains substantially more hydrogen sulfide; emissions of this gas from a 37.5 MWe unit have been measured at 355 kg/hr (780 lb/hr) (17).

Preliminary estimates indicate that steam from the geothermal fluids of the Imperial Valley will also contain large amounts of hydrogen sulfide (18). At the experimental 10 MWe generating unit at Niland, flashed steam will be "scrubbed" to remove the polluting gas. However, available data are insufficient to assess accurately the total quantities of hydrogen sulfide and other air pollutants that would be emitted from a geothermal power plant in this area.

Research Needs

The air pollution problems currently receiving the greatest attention are those related to hydrogen sulfide emissions. Most of these approaches focus on treating hydrogen sulfide after it reaches the turbine in the power plant and do not provide for pollution abatement during periods when the plant is shut down for maintenance or repairs. Increased emphasis should be placed on controlling hydrogen sulfide before it reaches the turbine; not only would this control pollution at all times, but it could improve the operating efficiency of the plant as rock, dust, and other foreign particles are removed from the geothermal steam.

While hydrogen sulfide is known to be harmful at high concentrations, little is known about the possible health effects of long-term exposure to low concentrations. As these effects could include irritation of the respiratory system and interference with the transport of oxygen in the human body, they should be thoroughly investigated. Research should also be conducted into the time required for hydrogen sulfide to oxidize to sulfates and sulfuric acid under varying topographic and climatic conditions.

The development of control technologies for other air pollutants, such as arsenic, ammonia, mercury, and radon, will be important if the modeling and monitoring efforts currently under way show that these compounds would be released in significant quantities at geothermal development sites. For example, researchers in New Zealand are currently experimenting with removing silica and arsenic from geothermal wastewaters by adding slaked lime to precipitate calcium silicate.

Increasingly precise and systematic techniques must be developed to monitor air pollution in geothermal development areas. Sophisticated chemical and radiochemical sampling methods must be developed, for example, to determine the concentrations of all harmful substances at a site and to distinguish between the effects of naturally-occurring and development-related pollutant discharges.

Removal of harmful air pollutants from the gases discharged at a geothermal facility may create solid waste disposal problems. The ideal solution is the development of an economically feasible technology to recover waste materials in usable form. To encourage this solution, high priority should be assigned to the development of hybrid geothermal facilities that combine chemical production and power generation.

THERMAL POLLUTION AND CLIMATE

Geothermal development can also have a variety of thermal and climatic effects. The most serious are caused by the release to the atmosphere of waste heat, water vapor, and carbon dioxide from geothermal wells, steam lines, and power plants.

Geothermal power plants emit larger amounts of waste heat than do fossil fuel or nuclear power plants because of their lower "thermal efficiency"; that is, less of the total heat energy contained in the geothermal fluid is converted to electrical energy. For example, a typical generating unit at The Geysers utilizes about 785 MWe of input energy to produce 110 MWe of electrical output, for a "primary efficiency" of 14%. At the Wairakei plant in New Zealand, the primary efficiency is approximately 8%. In comparison, fossil fuel and nuclear power plants have primary efficiencies ranging from 32 to 42%, thereby producing markedly less waste heat (see Table 1.18).

TABLE 1.18: EXPECTED WASTE HEAT EMISSIONS DURING POWER PLANT OPERATION FOR ALTERNATIVE ELECTRICAL GENERATING PROCESSES, 1,000 MWe PLANT (kilowatt-hours/year)

Process	Total Waste Heat ($\times 10^{10}$)
Nuclear (light-water reactor)	1.86
Coal	1.2
Residual fuel oil	1.2
Natural gas	1.2
Low Btu synthetic natural gas (from coal)	1.2
Geothermal: The Geysers	4.5*
Wairakei	9.7**

*Discharged to air.
**4.3×10^{10} is discharged to air, and 5.4×10^{10} is discharged to water.

Source: References (11)(15)

Waste heat and water can be discharged either to the atmosphere or to water. In terms of environmental impacts, an important tradeoff is involved: while the discharge of waste heat and water vapor to the atmosphere can have negative climatic effects, discharge to bodies of water can have harmful biological effects. Since water quality effects are commonly considered the more harmful, the trend in power plant construction has been toward atmospheric discharge with the use of cooling towers.

Cooling tower designs for any type of power plant, including a geothermal, are of two basic types: the conventional "wet" or evaporative cooling tower, and the dry cooling tower. In the former, the steam from the turbine enters a condenser, where it is reconverted to water. The steam heat is transferred to circulating water, and the warm water then transferred to the wet cooling tower, where it is brought into contact with a flow of air, which causes evaporation. Since the cooling water is lost through evaporation, the supply must be replenished continuously.

In a dry cooling tower, the water circulates in a closed system. It is cooled by a flow of air created by either mechanical or natural draft, as in an automobile radiator. Only the heat is transferred to the atmosphere. Since water is not lost through evaporation, a dry cooling tower does not require a continuous source of cooling water; consequently, it may be more desirable environmentally than a wet cooling tower in localities having limited water supplies.

Dry cooling towers are significantly more expensive than wet, and may reduce the operating efficiency of the power plant as well. This is why only wet cooling towers have been constructed for large power plants to date. Their effects at fossil-fueled power plants have included a slight heating of the atmosphere in the vicinity, increased humidity, and occasional fogging. These impacts are generally considered to be minor and local in scope.

At The Geysers, about 80% of the geothermal steam is discharged from wet cooling towers as water vapor containing waste heat; the remainder is reinjected to the steam reservoir. The result is a slight heating of the atmosphere in the vicinity, increased humidity, and occasional fogging. A greater incidence of plant disease resulting from higher humidity has been noted in some nearby areas. Some vegetation has also been "scalded" by direct releases of steam from wells and steam lines.

At Wairakei, a liquid-dominated field, the water of a nearby river is used for cooling the geothermal hot waters (a once-through cooling system). The wastewaters remaining after steam separation are also discharged to the river. About half of the total waste heat remains in the river; the other half enters the atmosphere along with the water vapor. This method has resulted in a heating of the river and extensive ground level fogging near the plant (19). It is thus unlikely that this system would be used at new geothermal power plants.

In general, the climatic effects associated with existing geothermal and conventional power plants using cooling towers are considered to be relatively insignificant in comparison with other environmental impacts. However, their significance will increase as larger plants are built. Moreover, if a geothermal resource is located in an area whose topography and local meteorological conditions limit adequate atmospheric dispersal of heat and moisture, the problem of local weather modification could be significant.

Preliminary analyses of the potential for weather modification resulting from geothermal development in Lake County, California (adjacent to The Geysers) indicate that ten 55-MWe generating units utilizing wet cooling towers could increase the moisture content in a small closed basin by almost 50%, probably leading to some increase in fog and icing (19).

Larger-scale climatic effects are also thought to be possible from geothermal development. The emission of large quantities of hydrogen sulfide might increase the acidity of rainfall in a region which would lead to corrosion and harmful effects on vegetation and wildlife; and the emission of carbon dioxide could trap heat in the lower atmosphere, thereby raising the earth's temperature (the so-called "greenhouse effect"). While the scale of geothermal development worldwide is unlikely to be large enough to cause such significant effects, the advantages of monitoring the climatic effects of geothermal development are clear.

Research Needs

Research into the thermal and climatic effects of geothermal development has to date been assigned relatively low priority because these effects appear to be less significant than other environmental effects. However, certain potential impacts are serious enough to warrant further investigation. In particular, changes in the acidity of rainfall should be carefully monitored throughout the regions surrounding geothermal development, and any resulting damage to aquatic species and terrestrial vegetation and wildlife assessed. The pH and sulfate levels of rainfall should be analyzed, not only near geothermal development areas but also in the surrounding region, both prior to and during geothermal development.

If extensive geothermal development is planned in areas where topography and local weather conditions limit atmospheric diffusion of the heat and moisture released from cooling towers, as it does in narrow, closed valleys, extensive local climatic data should be collected. A data base for predicting the likely extent of weather modification should include ambient wind speed and direction, rainfall frequency, humidity, and temperature. Similarly, if the development of a particular geothermal site involves significant thermal discharges to lakes or streams, monitoring data on ambient water temperatures, flow rate, and currents should be collected.

FISH, VEGETATION AND WILDLIFE

The development of geothermal resources inevitably causes some disturbance to natural biological systems in the vicinity of a development site; primarily, land disruptions, air and water polluting emissions during well testing and power plant operation, and increased levels of noise and human activity. The extent, severity, and long-term consequences of the disturbance vary considerably from site to site, depending upon the geochemistry of the geothermal resource and the development technology employed.

Conscientious application of sound management techniques and pollution controls can reduce, but not eliminate, the disturbance. Nonetheless, the disturbances to biological systems caused by geothermal development are less severe than is the development of alternative fuels that require large land areas for mining, transportation, and processing.

Types of Impact

Geothermal development may affect natural biological systems by reducing the diversity (the kinds of species in the ecosystem) or the total number of plants and animals in an area. These impacts may be of concern if the species endan-

gered are rare or if the disturbed habitat is important to a large popu...on. For example, extinction of the Devil's Hole Pupfish (a species believed to have existed in the western U.S. for several million years) would be regrettable because of its rarity, antiquity, and unique characteristics; but the loss would not affect any other species. On the other hand, destruction of an estuary would have far-reaching consequences for numerous species.

In addition, certain species may be valued for their beauty, for the recreational opportunity they provide, for their economic value, or for all these reasons. Snow geese, deer, and redwood trees are examples of species which may be valued for any or all of the reasons cited.

An extensive body of legislation protects certain categories of wildlife from disturbance. The most far-reaching, the Rare and Endangered Species Act of 1973, grants the Department of the Interior authority to prevent development in areas where threatened species of plants and animals will be adversely affected. Without adequate baseline information, maps of critical areas, and knowledge of the interrelationships of the plants and animals in the area, especially in a desert ecosystem, substantial harm can occur inadvertently.

Sources of Adverse Impacts

The causes of adverse biological impacts associated with geothermal development that could lead to a reduction in the diversity or population levels of species are: land disruption, erosion and sedimentation, water effluents, air pollutant emissions, noise, and human activity.

Land Disruption: The removal of earth and vegetation from an area to accommodate geothermal development can reduce habitat; kill small rodents, reptiles, or birds living on the land surface; and cause erosion. An average of 20% of the total land for geothermal activities is cleared (3) and is changed sufficiently in character to affect habitat. Of this 20%, approximately half is needed for permanent buildings and facilities, such as roads and power plants, which require original vegetation to be replaced with impervious surfaces. In addition, land along steam lines and immediately surrounding drilling pads, permanent buildings, and facilities may be temporarily cleared of vegetation (3).

The clearing of a site for geothermal development usually has the following adverse effects on an area's natural biological systems (1): (1) The nutritional support for the area is altered as the physical aspects of the habitat are altered. (2) Specific types of habitat (such as an "edge"), dependent upon complex interrelationships, are severely affected. (An "edge" effect occurs when two levels of vegetation adjoin one another, as when a shrub layer abuts a grassland. An "edge" makes the environment doubly valuable. For instance, many small game species can browse on grasses and find protection in the shrubs.) (3) Lower population levels may result until the site revegetates. (4) Surface soil temperature and moisture are altered. (5) Erosion may be accelerated.

The recoverability of vegetation varies by species, soils, climatic conditions, and severity of disturbance (3). In cool, moist, mountainous regions, areas dominated by grasses and shrubs recover relatively quickly; forested areas, however, require a much longer recovery time. In dry regions, where the ecosystems are fragile, the amount of time needed to restore a site is far longer. During the

The outlook for the improved control of sulfur emissions is promising. The recently developed "Stretford" process, which is to be installed at new generating units at The Geysers, is expected to remove 85 to 90% of the sulfur prior to release. This process is expected to work on the "flashed-steam" hot-water system as well. (The binary system involves no release of pollutants.) Research projects are ongoing to determine the threshold levels of various species of fish, wildlife, and vegetation to toxic gases, acid rain, heavy metals, and steam; and to gauge the effects of long-term exposure at sublethal levels.

Noise and Human Activity: The impacts of noise on natural biological systems have not yet been researched extensively. Some studies have uncovered no evidence of effects on animals in their natural habitats at a reasonably short distance from the site (20). However, other studies are being conducted to measure subtler changes including those of behavior and physiology (21). Of particular importance is the possibility that noise in frequency ranges inaudible to the human ear may affect animals adversely. Loud, continuous noise may also affect animals who depend on acute hearing for protection, hunting, or mating. Particularly sensitive species need to be identified. If animals were to permanently abandon their habitat as a result of noise, the ecosystem would probably be affected adversely as well.

The impacts of human activities on natural biological systems are even more difficult to measure. Intrusion may pose a severe threat to some species, but relatively little to others. Associated dangers such as fire, litter, and garbage may pose threats to foraging animals. Yet, at The Geysers, deer and other animals have been reported to graze near the drilling site and steam pipelines, where they find warmth and forage in the winter. Desert ecosystems may be threatened more severely by human intrusion than upland forests and grasslands.

Research Needs

To maintain the diversity, productivity, and stability of an ecosystem subject to intrusion from geothermal development, extensive, site-specific examinations of existing ecosystems must be conducted in potential geothermal areas prior to development. Such investigations are vital to the development of management plans for those activities that can reduce harmful effects to the biota. Among the baseline environmental information which must be collected are (1):

(1) Identification of plant and animals species present, their distribution, and population sizes;
(2) Determination of critical ecological characteristics, that is, characteristics of the environment that play a unique or particularly important role to a species and thus are critical to their survival;
(3) Identification of any species present classified as "endangered" or "threatened;"
(4) Life cycle characteristics;
(5) Nutritional requirements and susceptibility to disturbances of any critical, threatened, or endangered species present.

Examination of the environment prior to development must be followed by monitoring to detect possible changes during development and subsequent operations. The early identification of impacts can prevent unnecessary and extreme harm, and the information gathered can be of potential use in other research areas.

More widespread understanding of the importance of early study and more diligence in applying sound management practices appear to be the greater needs in protecting natural biological systems.

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Survey of World Geothermal Development

The material for this chapter has been based upon *Proceedings of the Second United Nations Symposium on the Development and Use of Geothermal Resources*, May 1975, (PB 262 501, PB 262 502 and PB 262 503) prepared by Lawrence Berkeley Laboratory, University of California. The voluminous reference material included in the *Proceedings* has been omitted in these excerpts.

WORLD GEOTHERMAL DEVELOPMENT

The material for the following sections has been based upon "Present Status of World Geothermal Development," prepared by Energy Section, Centre for Natural Resources, Energy and Transport, United Nations.

Although the use of geothermal hot water for balneological purposes has been known for hundreds of years, the utilization of geothermal energy for the production of electricity and the supply of domestic and industrial heat dates only from the early years of the twentieth century. For 50 years the generation of electricity from geothermal energy was confined to Italy and interest in this new and specialized technology was slow to spread elsewhere. In 1943 the use of geothermal hot water for space heating was pioneered in Iceland although it was not until 1969 that electricity was first produced from geothermal steam in that country.

During the decade following 1950, intensive exploration work was undertaken in New Zealand, Japan, and the United States, which led to the commissioning of geothermal power stations in 1958, 1961 and 1960, respectively. Thus, prior to 1950 there was comparatively little global activity in geothermal energy and despite the excellent prospects existing in many developing countries they were for the most part unaware of their potential in this field.

recovery period, however, the land is not totally sterile; some animal species can forage on germinating seedlings. Careful plant design and road placement can avoid excessive disruption of the land surface during geothermal development. Avoidance of the "edge" and critical areas such as breeding grounds, salt licks, wetlands, and surface water bodies can help keep the immediate environment biologically productive.

Erosion and Sedimentation: Disturbance of the surface soil of an area through erosion interferes with the fertility of the soil and its ability to retain moisture. Topsoil, the most fertile part of the soil structure, is often covered over or dumped. Small root systems are turned over and soil structure is altered, causing additional erosion as the soil is loosened. Erosion lowers soil fertility and thus reduces the food available to support the surrounding environment. Soil erosion also increases sediment loads in surface waters, which, in turn, reduces the quality of streams and their capacity to support aquatic organisms. Nutrients in the soil are leached away to the stream beds, accelerating stream eutrophication.

Sedimentation in critical parts of streams, such as spawning areas, can increase turbidity, which reduces the penetration of light in the water. This makes it difficult for fish to find food and for aquatic vegetation to grow. In addition, concentrations of mercury and other trace metals frequently found in sediments have been related to concentrations found in fish and aquatic vegetation living nearby.

The problems of erosion and the resulting sedimentation of waterways have proven to be particularly troublesome at The Geysers, because the drilling sites are located on steeply sloping hillsides which receive high rainfall. But even in this setting, the adverse effects can be greatly reduced through measures designed to control erosion, preserve the topsoil, channel any runoff into an appropriate treatment system, and quickly restore the vegetation of temporarily cleared sites.

Water Effluents: Water pollutants resulting from geothermal activity (drilling muds, geothermal fluids, and heat from condensed steam) can have severe effects on aquatic animal life and vegetation if runoff or discharges enter streams. Numerous elements and compounds, particularly hydrogen sulfide, chlorine, ammonia, boron, arsenic, mercury, and such heavy metals as lead and silver, are toxic to aquatic vegetation and fish at varying concentrations. Each of these may be present in geothermal fluids or drilling muds. Most freshwater fish are also sensitive to rapid changes in pH or temperature.

Drilling muds and cuttings normally are disposed of in a dump during test drilling and production. Accidental discharges may, however, occur, and reach bodies of water. The severity of their effects depends largely upon their chemical constituency and the duration of the discharge (3).

Geothermal fluids, particularly in hot-water fields, are often highly saline, contain heavy metals, and have very high temperatures. In Wairakei, New Zealand, a hot-water field where reinjection techniques are not practiced, the composition of disposal in the nearby river and lake was analyzed (19). High levels of arsenic, mercury, sulfur dioxide and hydrogen sulfide were found in the water, the aquatic vegetation, and the fish (e.g., mercury compounds at levels toxic to

humans, 0.5 mg/kg or 0.5 ppm, were found in trout weighing more than 1.25 kilograms). Two large fish kills have been noted in the nearby lake and the number of trout in the immediate area of the plant has been reduced, although they have become more abundant just upstream and downstream. Lake Aratiatia, below the Wairakei plant, has fewer phytoplankton and zooplankton species, the first links in the food chain for fish in the lake.

The development of adequate reinjection techniques for hot-water systems will help protect the environment from the adverse effects of geothermal fluids. The development of an adequate reinjection technology will be particularly significant in areas where economically valuable or sensitive fish, wildlife, or vegetation exist, such as in the tidal basins along the coast of Texas and areas of the western U.S. where fragile desert ecosystems can be disrupted easily and restored only after long periods of time, if ever.

Air Pollutant Emissions: Gaseous emissions from dry-steam fields contain a number of potentially dangerous products, including hydrogen sulfide, carbon dioxide, and trace amounts of radioactive gases. Studies to measure the buildup of these emissions in vegetation, aquatic organisms, and animals are just being initiated. Recent studies of the egg and fry of rainbow trout, for example, indicate that this species is vulnerable even to very low concentrations of hydrogen sulfide (above 0.006 ppm) (19).

In-stream concentrations of hydrogen sulfide at Wairakei have probably exceeded these limits; botanists have reported filamentous sulfur bacteria, which thrive only in the presence of sulfide growing in nearby lakes. Recently completed studies supported by the National Science Foundation and the Fish and Wildlife Service report previously unsuspected damage by hydrogen sulfide to coniferous trees and some types of shrubs and plants. They also report highly variable sensitivity in vegetation; the most sensitive appear to be immature plants and plants under stress from aridity (20)(21).

Sulfur dioxide, in particular, could have especially adverse effects in humid areas, where it oxidizes to sulfur trioxide and sulfuric acid. Millions of research dollars have been spent to determine the detrimental effects of sulfur compounds in the atmosphere. Compounds have been shown to "acid rain" or "acid snow" (a reduction in the pH of precipitation), which can burn the leaves of trees and shrubs, as well as heighten the acidification of water bodies. The acidification of lakes has, in turn, been related to the widespread destruction of fish habitats (22).

Another possible hazard results from trace amounts of radioactive elements present in geothermal emissions. While radon and other radioactive elements have been studied to determine their effects on humans and animals, the possibility of radioactive substances becoming concentrated in the fatty tissues of organisms and transmitted through the food chain as a result of geothermal development has not been investigated. The probability of such an occurrence is, however, judged to be moderate or slight (22).

Steam emissions can also have more direct and immediate effects. Trees in The Geysers area have been scalded; birds and other wildlife that come in contact with the steam are also in danger of being burned.

The decade to 1970 was marked by a greater realization of the benefits of geothermal energy, particularly following the United Nations Conference on New Sources of Energy which was held in 1961. This meeting, attended by representatives of many developing countries helped to publicize the possibilities of utilizing geothermal energy as an indigenous means of producing electricity. From 1964, rising interest in geothermal development was characterized by the starting of many preliminary investigation projects, particularly in developing countries.

A growing interest in the development of geothermal energy was the result of its demonstrated economic advantages over the utilization of fossil fuel alternatives. Geothermal power stations were seen to be more economical in small sizes and less capital-intensive than conventional plans and this was of particular interest to many developing countries having small electricity systems and many competing demands for their limited capital resources.

At the end of 1973 events took place which had a dramatic impact on the global energy scene. The restriction of oil supplies and quintupling of world oil prices abruptly changed the economic base which had governed the international energy economy. These conditions caused consequences of such magnitude that energy problems have since become a major concern both of governments and the international community.

In the light of this situation, strenuous efforts are being made throughout the world to develop those indigenous energy resources which will substitute for imported oil supplies. Geothermal energy is one such resource which in suitable locations now offers even more attractive economic possibilities for replacing oil in the generation of electricity and the supply of heat.

In many developing countries, electricity systems are still too small to support nuclear power stations large enough to be economical and this alternative cannot, therefore, be pursued. However, the exploitation of geothermal energy in those small developing countries situated in volcanic regions may assume greater relative importance than in larger and more developed nations. In addition, the comparatively small size of geothermal power stations is better suited to the present scale of electricity supply systems in most developing countries.

For the foregoing reasons, the exploitation of geothermal energy in suitable developing regions of the world is likely to assume increasing importance. As will be seen from the following survey, the utilization of geothermal resources is taking place mainly in developed countries. However, it can be anticipated that, under the stimulus of current conditions in the international energy field, the transfer of appropriate technology and experience to developing countries will proceed on an urgent basis and will result in rapid progress.

The exploitation of geothermal energy can be reviewed by subdividing it in accordance with the basic characteristics of the heat source. Thus, the following status review of geothermal energy resources can be conveniently considered by placing them into the categories of:

(1) dry steam fields;
(2) wet steam fields; and
(3) hot water fields.

DRY STEAM FIELDS

Although dry steam fields appear to be much less common than wet steam fields, they account for the greater part of the electricity now being produced geothermally.

Italy

The use of dry steam for electricity production was pioneered at the Larderello geothermal field and development in Italy had resulted in an installed generating capacity of 384 MW by 1970. The use of large quantities of geothermal steam over a period of many years, particularly in the boraciferous region near Larderello, has necessitated a continuous well drilling program to maintain the output from existing power stations.

In view of the difficulties encountered in increasing steam supply from the Larderello and Monte Amiata areas, considerable attention is being given to enhancing electricity production by replacing atmospheric turbines with condensing units. These will have lower specific steam consumptions and allow more electricity to be generated from the available steam. As part of this program, a new 15 MW condensing turbogenerator was added to the Serrazzano power station at Larderello during March 1975. Any substantial rise in the use of geothermal energy in Italy must depend upon the discovery of new fields and, to this end, the State Electrical Power Board and National Research Council are participating in joint efforts to explore promising areas.

During the course of such an exploratory program at Travale, 20 km southeast of Larderello, a well was drilled in 1972 having a production capacity of 15 MW. In 18 months this well was coupled to a 15 MW atmospheric turbine and has operated continuously as a remote-controlled base load power station.

In 1973 a new discovery of steam was made near Mt. Volsini, 50 km southeast of Monte Amiata, and deep drilling is proceeding with a view to the installation of a 15 MW turbogenerator similar to that installed at Travale.

The drilling of five wells at Alfina, 110 km north of Rome, has established the presence of a water dominated field, and a water-steam separation plant is under construction.

Further exploration will begin shortly in the pre-Appenine belt lying between Larderello and Naples and it is expected that at least 10 wells will be drilled annually for the next five years. The total installed capacity of geothermal generating plants in Italy stands at 420.6 MW.

Japan

Japan has considerable geothermal resources which, while consisting mainly of wet steam, include an important dry steam field at Matsukawa. Japan's first geothermal power station was commissioned at this location in 1966 with a capacity of 22 MW. After overcoming various problems it is now operating successfully as is evidenced by its 1973 generation load factor of 94%. Plans have been made to extend the capacity of Matsukawa to 90 MW.

During the course of a survey, the Electric Power Development Company of Tohoku located a dry steam field at Onikobe on the island of Honshu. Production at this field is being obtained from 10 wells at a depth of only 30 m and work is under way on a power station installation of 25 MW capacity which was to be in service during 1975.

United States

The only dry steam development in the United States at present is The Geysers field in California and this is being rapidly exploited. The speed of development can be gauged from the installed generating capacity which was reported to the Pisa Symposium in 1970 as 78 MW and stands at 500 MW, making it the largest geothermal power plant in the world. The rapidity with which plant capacity has been increased is due to a considerable extent to the use of the largest sizes of geothermal turbogenerators to be found anywhere. Six have been installed with capacities of 53 MW while the unit commissioned in January 1975 has a capacity of 103 MW.

Rapid progress has also been assisted by gearing development to the reservoir study results which have been accepted, thereby avoiding the empirical well testing previously carried out over long periods.

Since The Geysers plant is linked to a large interconnected electricity network, there will be no difficulty in operating it at a high load factor. This will result in the maximum savings from displacing the output of power stations burning expensive fuel oil.

WET STEAM FIELDS

Wet steam fields occur more frequently than dry steam fields and although they have been less important for the production of electricity, it is anticipated that the current upsurge in geothermal development on a global scale will discover many such fields and thereby increase their relative importance.

Japan

Japanese experience with the production of electricity from wet geothermal steam dates from 1967 with the commissioning of the Otake power station in Kyushu. Geological conditions throughout the country are particularly favorable for the occurrence of geothermal energy resources, and the impact of the present world energy situation has provided a strong developmental stimulus to further exploration.

The 13 MW Otake power station was followed by a 10 MW installation in 1973 at Onuma which supplies electricity for the use of the Akita factories of the Mitsubishi Company.

Kyushu Electric Power Company has begun an exploration project at Hatchobaru near the existing Otake power station. Wet steam has been found at a depth of 1,000 m and seven wells are in production. A geothermal power station of 50 MW capacity was expected to be in service during 1976. Present indications are that this field will be able to support a generating plant totaling 200 MW.

Further development has been indicated at Katsukonda which is situated between Matsukawa and Onikobe. Exploration has been successful and a 50 MW power station has been planned. It is expected that this field will eventually be capable of supporting a 200 MW installation.

It must be added that considerable attention is being focused at present in Japan on environmental quality and the development of geothermal energy is consequently taking place against a background of environmental constraints.

New Zealand

Following the successful development of the geothermal resources at Wairakei and Kawerau, exploration was extended to other areas of New Zealand. Of these, the most promising was found to be situated at Broadlands where maximum temperatures of up to 295°C were found together with high well yields. The development of this geothermal field for electricity production was delayed by the discovery of a large natural gas field which was utilized in preference to geothermal steam. Under the changed conditions which have prevailed in the overall energy field during the recent past, priority has been given to the development of Broadlands up to a capacity of 120 MW.

Mexico

Geothermal exploration commenced during 1960 in the Cerro Prieto region of northern Mexico. Production wells were subsequently drilled to an average depth of 1,300 m and each produces the equivalent of 5 MW of power. Following the successful testing of the field, two 37.5 MW steam turbogenerators were installed in March 1973. Although some degree of calcification has been experienced with the production wells, this has not been excessive and operating experience with this installation has been good.

Drilling of further wells would double the size of the power station. During the course of the drilling program steam was located at a depth of 2,000 m at a temperature of 344°C. It has been estimated that the area exploited by producing wells is capable of supplying up to an ultimate capacity of 400 MW.

Iceland

Present conditions in the international energy field have focused renewed attention on geothermal exploration and a new steam field was located at Svartsenti in southwestern Iceland as a result of an exploration project which started in 1972.

In the northeastern part of Iceland at Krafla, a steam field has been evaluated from the results obtained by drilling exploration wells. As a result of these preliminary tests it was decided to commence drilling production wells during the summer of 1975 with a view to the construction of a power station consisting of two 30 MW generators.

Chile

Geothermal exploration in Chile began in 1967 under the aegis of a United Nations technical assistance project and reconnaissance surveys were carried out in the three areas [illegible] El Tatio, Puchuldiza and Polloquere. As a result of this reconnaissance, [illegible]ed geological, geochemical and geophysical exploration surveys were undertaken in Puchuldiza and El Tatio. Following this work the El Tatio area was selected for exploration drilling, and from 1970 to 1972 six 4" diameter wells were completed to 600 m. The highest temperature encountered was 240°C and the maximum steam production was equivalent to approximately 1 MW per well.

This slim hole exploration program was followed in 1973 by the drilling of seven 8" production wells to a maximum depth of 1,800 m. These wells encountered permeability problems and although two produced steam equivalent to 7 MW each, the performance of the others was disappointing.

At the end of 1974 exploration was resumed at Puchuldiza. During 1974 a feasibility study was commissioned, directed toward the construction of a 15 MW power station to utilize the steam available. It is hoped that further drilling will enable the plant capacity to be increased to 20 MW. In view of the need for potable water in Chile, arrangements were made with the government of the United Kingdom to finance a pilot desalination plant which was connected to one of the small exploration drill holes. This plant is being used to evaluate the possibility of corrosion and scaling problems arising in large-scale desalination plants based on geothermal hot water.

The government of Chile has set up a National Geothermal Enterprise to be responsible for controlling the production and commercial aspects of geothermal energy development.

El Salvador

A geothermal survey was started in El Salvador in 1965 under a United Nations technical assistance project. In 1969, work was concentrated on the Ahuachapan geothermal field where the highest temperature located was 237°C. In this phase of the project five wells were drilled which proved to have sufficient steam for a 30 MW power station.

Water disposal posed a problem at this site since use could not be made of the Paz River because of the quantity of effluent envisaged for a large-scale development of the field and the downstream use of the river for crop irrigation. Considerable attention was therefore given to the question of reinjecting well effluent into the reservoir and a suitable reinjection system was constructed and successfully tested in December 1970 to take the full output of one of the production wells. Continuous reinjection at a rate of 91 l/sec was carried out for almost six months during 1971 without noticeable silica deposition inside the well or interference with the temperature of producing wells located only 400 m away.

A reservoir study carried out in 1971 estimated the Ahuachapan reservoir at 40 km³ with a minimum energy reserve of 5,000 MW years based on single stage flashing. As a result of this evaluation it was recommended that the field be initially developed in three stages of 30 MW each. It was also considered feasible, on the basis of the field tests, to reinject into the local reservoir at 150°C.

In 1971 a power station feasibility study was prepared and recommended the initial installation (1975) of a 30 MW geothermal power plant.

The government of El Salvador planned to install a second 30 MW unit during 1976, followed by a third in 1979.

Turkey

In 1967 a geothermal exploration project was commenced in Turkey under the United Nations Technical Assistance program. Initial scientific surveys carried out under this project identified nine geothermal prospects in Western Anatolia. During the course of more detailed investigations a deep borehole drilled in 1968 revealed the existence of a wet steam field at Kizildere. Twelve other wells were subsequently drilled in this area between 1968 and 1971, directed toward the evaluation and development of the field. Of these wells, eight were suitable for production and the highest temperature encountered was 206°C.

Unfortunately, the flashing of the hot water during its passage up the well bore released carbon dioxide causing calcium carbonate to deposit as scale in the well and in the surface equipment. The rate of scaling was so rapid as to restrict steam flow over a short period of time and prevent economical operation of the wells for power production.

In view of the importance of this problem, special tests were carried out with a view to the establishment of some practical operating regime which would allow the field to be used for power production. The best suggestion was directed toward keeping the geothermal fluid in a liquid phase by pumping it out of the well at a pressure high enough to avoid flashing. However, this solution would have required the use of deep-well pumps operating at a depth of 400 m. Since this was beyond the scope of current experience, the idea has been abandoned until such time as future progress in this field improves its feasibility.

Although it has not been possible to proceed with the development of the Kizildere field for the large scale production of electricity, a pilot greenhouse scheme was started in October 1972. Under this project a 1,000 m² plastic greenhouse was erected close to one of the production wells and heated by air blown through a radiator through which borehole water was circulated under pressure to prevent scaling.

More recently, geothermal exploration work has been carried out in Turkey close to the city of Afyon. A short distance from the city, wells drilled into the Omerli hot springs have located water at 100°C. In view of the possibilities of using this hot water to supply heat to the city of Afyon, a deep drilling program was commenced during 1974. The first well drilled under this program resulted in the production of 20 l/sec of water at 100°C.

HOT WATER FIELDS

It has been established that some parts of the world contain considerable deposits of hot water which form large reservoirs of low-grade heat. Although in many cases this heat cannot be used economically for the direct production of electricity, it can be a cheap source of space heating where climatic conditions enable it to be used at sufficiently high load factors. It is becoming increasingly recognized that the use of geothermal water for space heating is to be preferred to the burning of a highly refined petroleum product at 1000°C in a power station boiler if the end product is to be air at 21°C.

In view of the climatic conditions needed for the development of space heating, the exploit[illegible] of geothermal hot waters has so far been concentrated in Iceland, Japan, [illegible].S.R., Europe and the U.S.A.

Iceland has a long history of utilizing geothermal hot water for space heating and this interest has been maintained during the course of the last five years. Space heating for the city of Reykjavik is now supplied completely from geothermal sources. In addition, the hot water supply system is being extended to three communities totaling 75,000 people in the vicinity at Reykjavik.

In addition to a history of the balneological use of geothermal hot water extending over hundreds of years, Japan has used this heat source widely for hothouses, fish farming and animal raising.

It has been estimated that hot water may be found in over 20% of the area of U.S.S.R. territory. Considerable development of this resource has already taken place and geothermal hot water is being used to supply district heating, domestic hot water, greenhouses, and animal husbandry installations. In addition, the use of the binary cycle for the production of electricity from hot water was pioneered by the U.S.S.R with the commissioning of the Pauzhetka power station in 1967.

The considerable deposits of hot water in the sedimentary Hungarian basin have been utilized for many years for district and industrial heating schemes as well as hothouses and animal rearing.

In some instances hot geothermal water has been located as a result of drilling oil exploration wells; examples are Romania, Czechoslovakia, and the Paris basin. In Romania, geothermal hot water is being used on a pilot basis for greenhouses and the methane obtained from the water is being utilized to supply peak heating demands. In Czechoslovakia, geothermal hot water is supplying a pilot greenhouse installation and the United Nations has given advice on proposals for using geothermal heat in district heating. This proposal is of particular interest in that it involves an examination of the feasibility of feeding geothermal hot water into the existing district heating scheme of Bratislava.

In the United States a small geothermal district heating scheme has been in operation for many years at Klamath Falls, Oregon.

OTHER EXPLORATION PROJECTS

Ethiopia

During 1970 a geothermal exploration project commenced in Ethiopia under the United Nations Technical Assistance program. The first phase of this project was directed toward identifying hydrothermal areas in the Ethiopian Rift system and assessing their relative technical prospects for detailed exploration and subsequent development. During the course of the survey many gas and water samples were collected and analyzed and the results were presented in the form of a technical report.

As a result of this survey, areas of special geothermal promise were identified in the Lakes District, the Awash Valley and the Northern Danakil Depression. The

second phase of this project initiated in October 1974 has been formulated to contain proposals for geotechnical studies in the Lakes District leading to the selection of drilling sites and the drilling of production wells sufficient to supply a pilot power station with a capacity of up to 10 MW. Since the Lakes District is comparatively close to Addis Ababa there will be no difficulty in absorbing the output from such a geothermal power station in the Addis electricity network.

Concurrently, with the carrying out of detailed geophysical and geochemical investigations in the Lakes District, an economic feasibility study will be undertaken to assess the possible economic impact of developing geothermal energy in the other two regions. The cost benefit analysis obtained from this study will be of considerable assistance to the government in deciding on the priorities for subsequent geothermal development work.

India

Since 1973, geothermal investigations have been carried out in India at Puga Valley, Ladakh. As a result of this work steam and hot water at temperatures up to 130°C were found in some shallow wells from 30 to 90 m deep. To utilize this geothermal fluid and also obtain valuable operating experience, the government plans to install a 1 MW pilot geothermal power plant.

The United Nations will carry out a technical assitance project in geothermal resource exploration for the government of India. In this project, further investigative work will be undertaken in the trans-Himalayan region as well as the area of West India to the south of Bombay.

Indonesia

Since the Pisa Symposium, the compilation of an inventory of geothermal areas has been continued by the Geological Survey of Indonesia with technical assistance from New Zealand. As part of this program, six exploratory holes were drilled during 1972 at Dieng in central Java. In March 1974 the Indonesian State Oil Company (Pertamina) accelerated surveys in Java and Bali and these have now been completed in West Java at Banten, Kamojang and Derajat.

At the end of 1974, deep drilling was commenced at Kamojang and two wells were successfully completed. On the basis of the results achieved at Kamojang plans were made for the construction of a power station having a capacity of at least 30 MW. The deep drilling program is being extended to cover a more detailed investigation of the Derajat and Dieng areas.

Kenya

A program of geothermal exploration was commenced in Kenya during 1970 as a United Nations technical assistance project. After preliminary exploration tests, a production drilling program started at the end of 1973 and continued for over a year. Of the four wells drilled in this phase, the first did not produce but the second had an initial flow equivalent to approximately 6 MW. The output from the remaining two wells was low, in the range of 1 to 2 MW, and the general indications are that permeability may present a problem at this location.

Testing [illegible]ng carried out on wells 2, 3 and 4 with a view to obtaining detailed informa[illegible]n reservoir behavior. The government of Kenya has bought a drilling rig and intends to continue a reservoir assessment program.

The high cost of generating electricity from oil-fired power stations in Kenya has improved the competitive position of geothermal energy and it is anticipated that a geothermal power station would be economical even with comparatively modest well outputs.

Philippines

Exploration projects have been carried out by the Union Oil Company of America in the Tiwi and Los Banos areas of Luzon. Both projects have been successful in locating steam, and production wells are being drilled. On the basis of results achieved the government has placed firm order for the supply of four 50 MW turbogenerators for two separate power stations.

Concurrently with developments in Luzon the government of New Zealand is providing assistance with geothermal exploration at Leyte. Indications are that it may be possible to generate up to 100 MW from this geothermal area.

INDUSTRIAL USE OF GEOTHERMAL STEAM

Geothermal steam is being used for industrial processes in two countries. Iceland which posses a diatomite drying plant, and New Zealand, where geothermal steam is used for a wood pulping mill, several small industries and a hotel air conditioning system. Despite the present conditions in the energy field occasioned by fuel oil price rises, there does not seem to be any pronounced upsurge in interest for the industrial use of geothermal steam.

Although geothermal steam and hot water are obtainable in abundant quantities, they cannot be transmitted over long distances and must therefore be used relatively close to the well head. Since industrial processes also need raw materials, their development in geothermal areas must depend upon the geographical coincidence of raw material and heat sources.

In addition, the proximity of a market for the final product is also of considerable importance. These locational restrictions explain why geothermal steam has not been more widely used for industrial processes.

It is clear from the foregoing that the industrial use of geothermal steam is dependent upon an integrated approach covering all the various aspects involved. In some instances, particularly in developing countries, it is possible to envisage such an approach.

For example, the development of a geothermal field could result in the production of cheap power, which in turn would allow the use of pumped irrigation to support agricultural and animal raising industries. Such industries could then create a demand for industrial steam for crop drying and food processing.

GEOCHEMICAL TECHNIQUES IN EXPLORATION

The material for this section has been based upon "Summary of Section III—Geochemical Techniques in Exploration," by A.H. Truesdell of U.S. Geological Survey.

Geothermal fluid chemistry finds its widest application in exploration. Exploration activities have resulted in chemical data on thermal fluids from springs and wells throughout the world. Methods for estimating subsurface temperatures have been proposed based on chemical and isotopic analyses of surface and well discharges. Chemical indices based on trace constituents of spring fluids and deposits, altered rocks, soils, and soil gases have been proposed as aids to geothermal exploration. Chemical models of interaction of geothermal fluids with reservoir rocks have been constructed. Studies of alteration in geothermal systems have aided exploration and exploitation. Finally, studies of geothermal rare gases suggest that although most are atmospheric in origin, excess ^3He in some systems may come from the earth's mantle.

Chemical studies also assist in the exploitation of geothermal resources. Analyses of produced fluids indicate subsurface temperatures and production zones. Problems of scale deposition, corrosion of piping, and disposition of environmentally harmful chemical substances in geothermal fluids have been studied and solved in some applications. Plans continue for the recovery of valuable chemicals from geothermal fluids.

Mahon's Classification

Mahon characterizes geothermal fluids as originating from volcanic and subvolcanic geothermal systems, which may be either water or steam systems, and from nonvolcanic geothermal systems. Volcanic water systems are usually characterized at depth by waters of the neutral sodium chloride type which may be altered during passage to the surface by addition of acid sulfate, calcium or bicarbonate components.

The concentration of chloride may range from tens to tens of thousands of ppm. The origin of the water itself is dominantly meteoric, and the concentrations of readily soluble components such as Cl, B, Br, Li, Cs, and As are related to their concentrations in the rock, to the subsurface temperature, and possibly to contributions from deep fluids related to the volcanic heat source. Other less soluble constituents such as SiO_2, Ca, Mg, Rb, K, Na, SO_4, HCO_3 and CO_3 are controlled by subsurface temperature, mineral solubility, mineral equilibria, and pH. Gases in these systems normally include CO_2, H_2S, H_2, CH_4, N_2 and inert gases, with CO_2 predominant, and constitute 0 to 5% by weight of the deep fluid.

The near-surface fluids of volcanic steam (vapor-dominated) systems are low in chloride (except for fundamentally unrelated high-temperature volcanic fumaroles with HCl). They contain only elements soluble in some form in low-pressure steam (H_2S, CO_2, HBO_2, Hg, NH_3). The gases are similar to those in volcanic water systems. Because of their relative rarity and because vapor rather than liquid is produced (although liquid may predominate at depth), the geochemistry of these systems is not well understood.

Nonvolcanic geothermal systems have a wide range of water compositions and concentrations, from dilute meteoric waters to connate waters, metamorphic waters, and oil field brines. The controls on their compositions are less well known than those of volcanic waters.

Arnórsson's Classification

Arnórsson classifies Icelandic thermal fluids as related to (1) temperature, (2) rock type, and (3) influx of seawater. Low-temperature waters (<150°C) are the result of deep circulation in regions dominated by conductive heat flow (up to 4 to 5 hfu, which is above average for most of the world) and are characterized by low dissolved solids contents (200 to 400 ppm) and gases dominated by nitrogen. Higher temperature waters (>200°C) result from intrusions of igneous rocks and are characterized by higher dissolved solids contents (700 to 1,400 parts per million) and by gases with large amounts of CO_2, H_2S and H_2. Fluids in silicic rocks tend to be higher in Cl and other dissolved solids than fluids of the same temperature in basaltic rocks if seawater is not involved.

Classifications of Ivanov and Kononov and Polak

Ivanov proposed a classification of thermal fluids based on gas contents, which has been expanded by Kononov and Polak. Fluids directly related to volcanic processes are characterized either by H_2S-CO_2 gases and acid sulfate or acid sulfate-chloride waters in the oxidizing zone or by N_2-CO_2 gases and alkaline sodium chloride waters in the reducing zone. Fluids related to thermometamorphic processes have high CO_2 gases and carbonated waters, which may in part be connate. Fluids of deep circulation but outside of volcanic and thermometamorphic zones have N_2 gases and dilute sodium chloride-sulfate waters.

Kononov and Polak further divide volcanic fluids into "geyseric" with H_2-CO_2 gases and "riftogenic" with H_2 gases, which occur in spreading centers and characterize the highest temperature (>300°C) geothermal systems. It is only in "riftogenic" fluids that anomalous contents of ^3He and H_2S with $\delta^{34}S$ near zero are expected. Parts of this classification are applied in detail to Icelandic thermal fluids by Arnórsson, Kononov and Polak.

Although this classification may need modification based on the chemistry of fluids in drilled systems, it has the advantage of focusing attention on geothermal gases, which deserve more study. The occurrence of excess ^3He in the hydrothermal fluids of Kamchatka, Lassen, and Hawaii and of Yellowstone $\delta^{34}S$ values near zero suggests these fluids are "riftogenic" when, in fact, they are far from present spreading centers.

Classifications of White

Reviews by D.E. White of mineral and thermal water chemistry have greatly influenced most workers in this field. Space does not allow adequate description of his water classification schemes, which have evolved as more chemical and isotopic data became available. In brief, meteoric waters dominate shallow crystal circulation and mix with more saline deep waters of all types,. Meteoric waters may also circulate deeply under the influence of magmatic heat and receive additions of NaCl, CO_2, H_2S, and other substances from rock leaching,

thermal metamorphism, and possibly magmatic fluids. These moderately saline sodium chloride deep waters of volcanic association undergo near-surface rock reactions and atmospheric oxidation to form the range of observed surface volcanic waters. Oceanic water is incorporated in marine sediments and, by extended low-temperature reactions, becomes evolved connate water.

Deep burial and higher temperature reactions cause expulsion of highly altered metamorphic waters from rocks undergoing regional metamorphism. Magmatic water has been dissolved in magma but may have various ultimate origins. The existence of juvenile water new to the hydrologic cycle is certain, but its recognition is doubtful. Recent work by White and his coworkers has elaborated the chemical distinctions between hot water and vapor dominated systems and demonstrated the existence of thermal water of nonmeteoric origin in the California Coast Ranges.

Geothermometers

Where fluids from geothermal convection systems reach the surface in springs or wells, the chemical and isotopic compositions of these fluids may indicate the subsurface temperature and flow patterns, as well as the recharge source, type of reservoir rock, and other important parameters of the system. Component concentrations or ratios that can be related to subsurface temperatures are called geothermometers. Chemical geothermometers may be quantitative, so that specific subsurface temperatures may be calculated, or qualitative, so that only relative temperatures may be inferred.

Quantitative Chemical Geothermometers: The theory of quantitative chemical geothermometers has been discussed by Fournier, White, and Truesdell. These thermometers depend on the existence of temperature-dependent equilibria at depth which are quenched or frozen during passage to the surface.

Because the widely-used Na:K geothermometer fails at temperatures below 100° to 120°C and yields improbably high temperatures for solutions with high calcium contents, an empirical NaKCa geothermometer was proposed by Fournier and Truesdell. NaKCa temperatures have been found to be close to quartz-saturation temperatures for thermal springs of Nevada by Hebert and Bowman, but Na:K temperatures appear to be equally accurate for 200° to 300°C low-calcium well discharges, and may correctly indicate fluid temperatures and movement in drilled systems.

The cation (Na:K and NaKCa) geothermometers are useful in initial evaluations of the geothermal potential of large regions because they are less affected by re-equilibration and near-surface dilution than are the silica geothermometers.

Cation geothermometers, although empirical, apparently depend on equilibria between thermal waters and aluminosilicate minerals original to the host rock or produced by alteration. If equilibrium is not achieved, or if the mineral suite is unusual, misleading temperatures may be indicated. Thus, cation geothermometers must be used with caution in geothermal systems involving seawater, because in many of these, equilibirum with rocks probably is not reached because of resistance to chemical change of the concentrated solution and apparent temperatures close to those indicated by cold seawater. However, in some high temperature geothermal systems, seawater does appear to have nearly equilibrated with rock and indicated temperatures are close to those observed in drill holes. Acid sulfate springs in which silica and cations are leached from surface rocks are not suitable for chemical geothermometry, although acid sulfate chloride waters of deep origin give reasonable indicated temperatures. Cation (and silica) geothermometers may also give misleading results when applied to waters in highly reactive volcanic rocks, especially those rocks with high contents of potassium or to warm waters that emerge in peat-containing soils.

Although many other high temperature chemical equilibria exist, most of these equilibria are affected by subsurface conditions other than temperature, reequilibrate rapidly, or are affected by other reactions during ascent to the surface. These equilibria can, however, be used as qualitative geothermometers and, in specialized circumstances, as quantitative geothermometers.

Mixing Models: Although mixing of thermal waters with cold near-surface waters limits the direct application of chemical geothermometers, the dilution and cooling resulting from mixing may prevent reequilibration or loss of steam and allow the calculation of deep temperatures and chemical conditions.

The warm spring mixing model depends on the assumption of conservation of enthalpy and silica and on the nonlinear temperature dependence of quartz solubility. The boiling spring mixing model depends on assumed conservation of chloride and enthalpy and reequilibration with quartz after mixing. Proper application of these mixing models depends therefore on the fulfillment of a number of assumptions, the validity of which should be considered in each case. The accuracy of mixing model calculations depends to a great degree on measurement or accurate estimation of the chemistry and temperature of local cold subsurface water. For these calculations, as well as for isotope hydrology, collection and analysis of cold waters should be an important part of a geochemical exploration program.

Components other than silica and chloride may be used in mixing models. The temperature and salinity of a hypothetical concentrated high temperature component have been calculated by Mazor, Kaufman, and Carmi from ^{14}C contents and by Mizutani and Hamasuna from sulfate and water isotopes.

Qualitative Geothermometers: Qualitative geothermometers may be applied to spring waters and gases, fumarole gases, altered rock, soils and soil gases. Ratios and contents of dissolved hot-spring constituents and gases resulting from high temperature reactions, but not susceptible to quantitative temperature calculation, are useful for indicating subsurface flow paths when siting wells.

The most important application of qualitative geothermometers is in preliminary exploration over large areas. "Blind" convection systems may exist or surface fluid flows may be inconspicuous or difficult to distinguish from nonthermal sources. In these cases, it may be possible to analyze surface fluids for distinctive "geothermal" components.

Isotope Hydrology and Thermometry

Isotope compositions and rare gas contents of geothermal fluids have been used

to indicate sources of recharge, time of circulation, fluid mixing, and subsurface temperatures.

Hydrology: A major discovery resulting from early measurements of the oxygen-18, deuterium, and tritium contents of thermal fluids was that local meteoric water overwhelmingly dominates recharge of most geothermal systems.

In general, radioactive isotopes have not been successful in indicating the circulation times of geothermal systems. This results from the generally long circulation times involved (except for some Larderello steam), which are usually beyond the range of tritium dating; from the large quantities of metamorphically produced old CO_2, which prevent use of ^{14}C measurements; and from the common admixture of young near-surface waters with old deep waters in surface thermal discharges. Recent improvements in low-level tritium analysis may improve the situation. The radioactive ^{39}Ar isotope has a half-life of 269 years, which allows a dating range of 50 to 1,000 years, and has been used successfully to estimate a <70-year age for water in a Swiss thermal spring. This analysis, although difficult, should also be possible for drilled high-temperature geothermal systems.

Geothermometry: Certain isotope geothermometers equilibrate more slowly than chemical geothermometers and are capable of indicating temperatures in the deeper parts of geothermal systems. By considering a number of chemical and isotopic geothermometers with various rates of equilibration, it may be possible to calculate the temperature history of a thermal water.

Although gas isotope geothermometers are the only ones available for vapor-dominated systems, they leave much to be desired as practical exploration tools for hot-water systems. Equilibrium may be achieved only below drillable depths (CO_2-CH_4) or continue up to the sampling point (H_2-CH_4, H_2-H_2O), and most geothermal gases (especially from hot springs) are so low in methane that collection and separation are difficult.

For hot-water systems the most useful proven isotope geothermometer may be the fractionation of oxygen isotopes between water and its dissolved sulfate, which appears to equilibrate in geothermal reservoirs at temperatures as low as 95°C, and to reequilibrate so slowly during fluid ascent to the surface that evidence of temperatures above 300°C is preserved in some hot-spring waters.

In the rather special circumstances where water and steam phases may be separately analyzed, or steam analyzed and water isotopes estimated from other samples, the liquid-vapor fractionation of deuterium or ^{18}O may be used to estimate temperatures of phase separation. This has been done at Wairakei, Campi Flegrei, Italy; Kawah Kamojang, Indonesia; and White Island, New Zealand.

Rare Gas Studies: Rare gases (He, Ne, Ar, Kr, and Xe) have been analyzed in geothermal fluids and shown to indicate the source of water recharge and, less certainly, the mechanism of steam loss. Ne, ^{36}Ar, Kr, and Xe are not produced in rocks and do not undergo chemical reactions. However, they are affected by phase changes and their distribution between liquid and vapor is temperature dependent. For this reason, their contents in geothermal waters that have not boiled indicate that recharge waters are meteoric and allow calculation of temperatures of last equilibration with the atmosphere.

In syste h subsurface boiling, the water phase is depleted in gases and their cor. .ation patterns may indicate dilution and boiling mechanisms.

An Example of Exploration Geochemistry

The role of chemistry in geothermal exploration is well illustrated by investigations at El Tatio, Chile that were made in conjunction with geological and geophysical studies by New Zealand and Chilean scientists with United Nations support. El Tatio lies at an altitude of 4,250 m in the high Andes. There are over 200 hot springs, most of which boil (at 85.5°C at this altitude) and deposit sinter and halite. Many of these springs were analyzed for major and minor components and some, along with cold springs and snow samples, were analyzed for ^{18}O and deuterium. Fumaroles were analyzed for gases.

The analyzed spring waters showed narrow ranges of Cl:B and Na:Li ratios, indicating homogeneous thermal water at depth. Waters of the northernmost spring group were rather uniform in composition, with 8,000±200 ppm chloride, SiO_2 contents of ~260 ppm, and Na:K weight ratios near 8.2. To the south and west, spring waters have lower SiO_2 contents, high Na:K ratios, and Cl contents of about 4,000 to 6,000 ppm, indicating mixing with near-surface waters.

Direct application of chemical geothermometers to high-chloride spring waters indicated minimum subsurface temperatures averaging 160°C from quartz saturation, 167°C from Na:K ratios, and 205°C from NaKCa relations. Maximum indicated temperatures were 189°C (quartz saturation), 210°C (Na:K), and 231°C (NaKCa). The boiling-spring mixing model of Truesdell and Fournier, not yet developed at the time of the original investigations, can be applied to these spring waters assuming that those to the north were not diluted and that those to the south and west were mixtures with cold dilute water ($t = 4$°C, $Cl = 2$ ppm).

Average calculated subsurface temperatures are 208°C, but the maximum indicated temperature of 274°C is considered to be a better indication of the maximum aquifer temperature. Some of the high-chloride El Tatio springs issue at temperatures below boiling, and warm-spring mixing calculations, assuming cold waters of 4°C and 25 ppm SiO_2, indicate an average subsurface temperature of 269°C (standard deviation 13°C).

The patterns of Cl contents, SiO_2 contents, Na:K ratios, and Na:Ca ratios were interpreted to indicate that cold near-surface drainage from the east was entering a shallow aquifer in the western and southern areas, and diluting high-chloride water rising from greater depths.

Deuterium analyses of the thermal waters agreed with the general picture of near-surface mixing, but suggested that the deep recharge was from higher elevation precipitation with lower deuterium values. Cold water samples from the higher mountains to the east also tended to have lower deuterium values than local precipitation and were considered possible recharge waters.

Fumarole gas analyses also suggested movement from east to west, but at shallower depths. Eastern fumaroles had much higher contents of CO_2 and H_2S than other gases, and higher ratios of $H_2S:CO_2$. Quantitative interpretation of gas concentrations is difficult because of the effects of rock reaction and fractional

separation into steam. In general, gases tend to decrease in CO_2 and H_2S content and in $H_2S:CO_2$ ratio with lateral flow. In retrospect, more weight should have been given to the fumarole chemistry in siting exploratory wells.

On the basis of resistivity surveys and spring chemistry, six slim holes were drilled to about 600 m depth. In the west and northwest, holes 1,2 and 4 encountered maximum temperatures of 212° to 230°C with temperature inversions toward the bottoms of the wells. In wells 3 and 6, in the southwest, temperature inversions were not found and 254°C was measured in well 3. Seven production wells were located near well 3, and the best of these (well 7) tapped fluids of 263°C.

A shallow (about 170 m) aquifer at 160°C was encountered in the Trucle dacite, which is probably where mixing with near-surface water occurs to produce the lower chloride waters of the western and southern springs. Deeper aquifers in the Puripicar ignimbrite (500 to 600 m) and the Penaliri (Salado) tuffs and breccias (700 to 900 m) were at about 230° and 200° to 260°C, respectively.

Comparison of drill hole and spring analyses indicates that the most concentrated spring waters are undiluted samples of the deep thermal fluids. The quartz saturation, Na:K and NaKCa geothermometer temperatures are low, indicating considerable subsurface reequilibration. The mixing calculation temperatures are, however, surprisingly accurate.

Lateral subsurface flow from east to west, indicated by water isotopes, and fumarole gases, was confirmed by drill hole measurements. Tritium contents of drill hole fluids suggested that the subsurface transit time was 15 years (unusually short for geothermal waters), but small additions of young near-surface water would also explain the results. The early resistivity survey did not indicate lateral flow, and a resurvey was made after the exploratory holes were drilled. This showed a much larger anomaly that could be interpreted as due to deep lateral flow.

Two chloride inventories were made to estimate the total heat flow from the heat:chloride ratio of the thermal waters, which was established from drill hole fluid temperatures and chloride contents. These were not very accurate because of salt accumulation at the surface, but indicated a heat flow of 30 to 50 x 10^6 calories per second.

El Tatio is very favorable for the application of geochemical methods because there are a large number of springs with rapid flow from the thermal aquifer, and the surface chemistry indicated subsurface conditions with reasonable accuracy. Gas and isotope analyses correctly suggested subsurface flow patterns, and chemical geothermometers and mixing models predicted temperatures at increasing depths in the system.

GEOPHYSICAL METHODS IN EXPLORATION

The material for this section has been based upon "Geophysical Methods in Geothermal Exploration," by G. Pálmason of National Energy Authority, Iceland.

A few ysical methods may be said to be well established in geothermal work, t. ; proved their usefulness in numerous geothermal exploration projects. But improvements are needed, and in recent years there has been a marked effort to test new methods or new variants of older methods.

The strategy of geothermal exploration is often somewhat hampered by a lack of understanding of the geothermal systems, and by the variability of the geological environment. The hot zones beneath surface thermal fields constitute the outlets of more extensive systems, about which very little is known as regards vertical and horizontal extent.

Most exploration work in known geothermal fields is concerned with mapping the geometry of the relatively shallow upflow zone, but it is also possible that the deeper parts may be quite as attractive from an exploitation point of view as the shallower parts. In fact some of the deeper systems may be entirely without an upflow zone; they may be hidden. The most suitable methods of investigating such systems would in part differ from those most suitable for the shallower zones.

A further complication is the thermal state of the fluid, whether one is dealing with a vapor-dominated system or a hot-water system. Some physical bulk properties of a porous rock, for example, resistivity and density, would be quite different if steam replaced the hot water in the pores. Such ambiguities, like many others in the interpretation of geophysical data, have to be resolved by drilling.

Heat Flow (Thermal Gradient)

Anomalous surface heat flow by conduction may be used as an indicator of water convection at depth. The heat flow can be found by drilling shallow holes and measuring the temperature profile and the thermal conductivity of the core rock. In order to interpret the heat-flow values in terms of water convection, it is necessary to know the normal regional heat flow pattern as undisturbed by hydrothermal activity. The average heat flow of the earth is 1.5 hfu (62.7 mW/m^2), but relatively large systematic variations occur between different geological provinces. The highest values occur near diverging plate boundaries as, for example, in Iceland on the Mid-Atlantic Ridge, where "normal" values are considered to be in the range 1.7 to 7.0 hfu depending on distance from the axial zone.

In New Zealand and in Japan a different pattern is found with high values on one side of the volcanic zone and low values on the other side. Such a pattern appears to be characteristic of the so-called subduction zones.

Heat-flow surveys may be suitable for exploring the boundaries of a hydrothermal field. In a uniform geological environment only gradient measurements are needed, but when the thermal conductivity varies from one hole to another, it may be necessary to take this into account. In some cases, variations in thermal conductivity may be estimated from the borehole geological logs.

When geochemical indicators of reservoir temperature are available, the gradient measurements may allow an estimate to be made of the minimum hole depth needed to reach the reservoir.

Geothermal gradient or heat-flow surveys are useful for detecting weak heat-flow anomalies, some 5 to 10 times the normal heat flow values, which may be associated with convecting water at relatively great depth. When the heat loss through the surface is greater than about 100 times the normal heat flow, as occurs within hydrothermal areas simpler and less expensive methods may be used to map the shallow temperature field.

Mapping of the temperature at a depth of, say, one meter is useful for the purpose of estimating the natural heat flux from a hydrothermal area, as has been done in great detail in New Zealand. As an exploration tool for guiding site selection for deep drilling, the shallow temperature surveys are of limited value because of the low effective depth penetration. They are also rather time consuming.

Thermal gradient surveys have been used in several countries. In Italy a hole depth of about 35 m has been used, but in Iceland a depth of about 100 m is considered necessary. The depth needed will depend on the geological conditions in each area. When the surface rocks are very permeable in a considerable depth as in many areas of active volcanism, gradient surveys may not be practicable at all.

There are several examples demonstrating the usefulness of gradient surveys in geothermal exploration. In Iceland in the low-temperature area within the capital, Reykjavik, gradient surveys have markedly guided the selection of sites for deep production drilling. The gradient surveys have outlined four areas of anomalously high surface gradient up to 500°C/km. Production drilling in three of these areas has been successful, yielding water at temperatures of 90° to 140°C.

A more recent example is from Marysville, Montana, where a heat flow anomaly was discovered in an area with no known hot-spring activity. A favored interpretation of the anomaly was that it was due to a cooling intrusion at depth. Subsequent drillings encountered water at 95°C showing that the anomaly is due to convecting hot water at depth.

Aerial Infrared Surveys

Infrared aerial surveys of thermal areas in several countries indicated that the threshold sensitivity of the method for detecting abnormal heat flows was in the range 150 to 700 hfu, that is, roughly 100 times the normal heat flow. The main reason for this relatively low sensitivity is the high noise level caused by variations in the thermal properties of surface materials, which affect the thermal radiation sent out. The radiation comes from a very thin surface layer and the method has therefore practically no depth penetration.

It is possible that a more refined processing of the infrared data can lower somewhat the threshold limit for detection of geothermal anomalies. The infrared method has an important application in mapping the surface distribution of hydrothermal activity. The imagery may be of help in relating the configuration of the hot areas to large-scale structural features, for example, faults or calderas, which may control the discharge of hot fluids to the surface. Furthermore it provides a record of surface activity which may be compared with similar records at a later date to study the effect of exploitation on the surface thermal manifestations.

Electrical Resistivity Surveys

Electrical resistivity surveys have been used in geothermal exploration for over 25 years. Initially they were made with the classical Wenner or Schlumberger electrode configuration using dc current. The depth of penetration was small. In recent years there has been a marked effort to test various other methods, both dc and electromagnetic, partly in an attempt to increase the depth penetration under the conditions of low near-surface resistivities which usually occur in hydrothermal areas, and partly in an attempt to find faster and cheaper methods for reconnaissance surveys of relatively large areas.

There is a great variety of methods that can theoretically be used to map the subsurface resistivity distribution and the problem is to select the most suitable method from the point of view of field operations, processing of the field data, and interpreting the results.

Geothermal reservoirs are often, but not always, characterized by low resistivities. The resistivity depends on a number of parameters, the most important of which are porosity, salinity of the interstitial fluid, and temperature. The effect of a temperature change is greatest at low temperatures, less than 100°C and becomes small above 200°C. In the deeper parts of a hydrothermal system the resistivity is therefore more affected by porosity and salinity variations than by temperature.

An increasing resistivity with depth in a geothermal system may mean that the porosity changes from, for example, intergranular or vesicular porosity to fracture porosity, which is not necessarily adverse from the point of view of fluid production. The effect of temperature is probably greatest in horizontal profiling where lateral variations in resistivity are mapped.

Controlled-Source DC Methods: These methods are the most common ones in geothermal exploration. Electric current is sent into the ground through a pair of electrodes, and the resulting potential difference across another pair or pairs of electrodes is measured. Apparent resistivities are calculated directly from relatively simple formulas. Depth soundings are carried out by varying the electrode distances, and interpretation in terms of a vertical resistivity structure is usually made by means of a set of theoretical curves.

For shallow resistivity surveys any one of the electrode arrays can be used. The Schlumberger array is the most convenient one for depth soundings. It has certain operational advantages over the Wenner array in that fewer movements of the electrodes are required. Furthermore it allows the effect of irregular lateral resistivity variations to be detected and corrected to a certain extent. This may be important in geothermal work. For horizontal profiling, the Wenner array is more convenient because of the regular electrode separations.

The practical limitation on the depth penetration of the Schlumberger array is the long wire needed for the current electrodes. If the resistivity is low, a very high current is needed to obtain a measurable voltage between the potential electrodes. Furthermore, in hydrothermal areas, a very long electrode array usually means that lateral resistivity variations are affecting the measurements, thus making interpretation difficult. Often the maximum current arm of the Schlumberger array is limited to 1 to 2 km in geothermal work.

Dipole arrays avoid some of the difficulties associated with deep Schlumberger soundings in geothermal areas. Very high currents are needed, several tens of amperes, but these are more safely used with short current-electrode separations than with long ones. Under favorable conditions a depth penetration of several kilometers is easily achieved.

Controlled-Source Electromagnetic Methods: In recent years a considerable effort has been made to test the suitability of various electromagnetic methods in the exploration for geothermal resources. These methods have been used in mineral exploration for a long time. In geothermal work the requirement of depth penetration is usually greater than in mineral exploration. This means that lower frequencies have to be used and consequently the equipment becomes somewhat bulkier.

Primary external electromagnetic fields induce eddy currents and secondary fields in a conducting earth. The secondary fields can be detected by a variety of source-receiver arrangements. Depth soundings are made by varying either the source-receiver distance or the frequency. Interpretation is usually carried out by a comparison with calculated models, often consisting of horizontal layers.

Natural Field Methods: Natural electromagnetic fields caused by thunderstorm activity (frequency >1 Hz) and micropulsations in the earth's magnetic field (frequency <1 Hz) are affected near the surface by the resistivity distribution in the underlying rocks. The depth effect depends on the frequency. Where and when these fields are sufficiently strong in the frequency range of interest, they can be used to explore the resistivity distribution in the depth range of importance in geothermal exploration.

There are essentially three variants of the natural field methods which have been used and appear to be promising in geothermal exploration. They are (1) the ordinary low-frequency magnetotelluric method, utilizing frequencies below about 1 Hz; (2) the audio-frequency magnetotelluric (AMT) method, which utilizes frequencies above 1 Hz, mainly in the range 8 Hz to 20 kHZ, and (3) the telluric method. The first two are depth-sounding methods. They might perhaps be classified together, but because of the different frequency ranges the measuring techniques are different. The third method is a horizontal profiling method primarily.

In the magnetotelluric methods one measures the two perpendicular horizontal components of the electric and magnetic fields in the incoming radiation. After spectral analysis or narrow-band filtering an apparent resistivity is calculated.

The ordinary or low frequency magnetotelluric method is useful for probing to very great depths, from a few to one hundred km or more. Its place is therefore, mainly in regional work where information is sought on deep crustal resistivity which may be related to temperature and possible heat sources. The method has been used for this purpose, for example, in Iceland, and gives results in good agreement with those predicted from regional heat flow studies and model calculations.

In geothermal exploration the direct usefulness of the low-frequency magnetotelluric method is limited because of the large probing depth and a consequent insensi. to shallower resistivity variations. A much more promising method appears to be the audio frequency magnetotelluric (AMT) method which employs frequencies mainly in the range 8 Hz to 20 kHz. The lower part of this range appears to be especially suitable under the conditions commonly found in geothermal areas. Surveys with this method have been reported from geothermal areas in New Zealand, Hawaii and Nicaragua.

The instrumentation for an AMT survey is relatively simple, consisting of two narrow-band tuned voltmeters of high sensitivity, measuring the output from a pair of electrodes and from an induction coil. By varying the tuning frequency, a set of apparent resistivity values is obtained, which can be interpreted by a comparison with theoretical curves, or, approximately, using the skin depth as a depth indicator. Where the electromagnetic noise in the audio-frequency range is sufficiently strong and continuous, the AMT method appears to be a rapid and inexpensive tool for reconnaissance surveys of geothermal areas.

The third natural field method, the telluric method, is mainly suitable for reconnaissance of horizontal resistivity variations. It is based on the assumption that telluric currents flowing in extensive sheets are affected by lateral variations in the resistivity structure, which can be caused, for example, by variations in geological structure or by hydrothermal systems. The method requires the simultaneous measurement of the telluric electric field at two stations. From the ratio of the amplitudes of the electric field at the two stations, inferences may be drawn about variations in the underlying resistivity structure. By keeping the base station fixed and moving a field station about, one can thus map resistivity variations in a qualitative way.

The method appears to be a convenient one for regional surveys in order to detect areas worthy of more detailed exploration by dipole methods.

Self-Potential Surveys: A natural field method which may be useful in the study of hydrothermal areas is the self-potential method. Recent surveys in several hydrothermal areas have established that electrical dc field anomalies are commonly found associated with hydrothermal activity. One explanation of such electric fields is that they are associated with the movement of conducting geothermal fluids (streaming potentials), when cation enrichment of the water takes place by preferential adsorption of the anions by the rock, leading to a positive self-potential anomaly over a zone of upward moving water.

Structural Methods (Gravity, Seismic, and Magnetic Survey Methods)

Gravity Surveys: These are relatively easy to make in the field, but they are dependent on good elevation control, and this may be the main cost item in the collection of the data. In areas of rugged topography the terrain corrections may be large and time-consuming to make. Therefore, the gravity survey method is most suitable in areas of smoothly varying relief. One of the more useful properties of gravity anomalies is that they allow an estimate to be made of the total anomalous mass causing the anomaly, even though absolute density contrasts are not known.

Gravity surveys in geothermal areas in different geological environments appear to indicate that the sources of gravity anomalies may be (1) hydrothermal altera-

tion of reservoir rocks; (2) a high proportion of intrusives; and (3) structural features, for example, faults, calderas, basement structure.

In the New Zealand geothermal areas, positive gravity anomalies are considered to be due to rhyolitic domes and to hydrothermal alteration of the reservoir rocks. In the Imperial Valley of California a correlation has been noted between positive gravity anomalies and high heat flow. The gravity effect is considered to be due to metamorphism of the sedimentary reservoir rocks. In Iceland, the high-temperature areas are often associated with major volcanic centers, and positive gravity anomalies commonly found in such areas have been interpreted to be due either to a high proportion of intrusives or to metamorphism, or both.

There appear to be sound arguments for including a gravity survey in any major geothermal exploration program, in particular in areas of smooth relief and poor geological exposures.

One other important use of gravity measurements in geothermal work is connected with exploitation. Withdrawal of fluid from a hydrothermal system may lead to net mass transfers that affect the gravity values measured in the area. Such changes can be very conveniently monitored by measuring the gravity values at a set of fixed bench marks in the area under exploitation, as has been done at Wairakei. The method is cheap and rapid, and is likely to become a standard procedure in any major exploitation of geothermal fields.

Seismic Refraction Method: Seismic refraction appears to be quite useful in volcanic areas, especially for structural studies in conjunction with gravity surveys, since the two physical properties, density and seismic velocity, are empirically related. If a gravity survey shows an anomalous mass distribution, it cannot be unambiguously interpreted in terms of structure without further information. A seismic refraction survey is likely to provide such information, for example, on the depth to the anomalous mass.

Refraction profiles have been measured across some of the high-temperature areas in Iceland as part of a regional survey of seismic crustal structure. A seismic boundary at a depth of about 1 km has been correlated with a geological section in a drill hole in the Reykjanes thermal field. It is of some interest that aquifers appear to be more abundant in a deeper high-velocity ($v_p \approx 4.2$ kilometers per second) material than in a shallower lower-velocity material ($v_p \approx 3.0$ kilometers per second) which is more porous. A similar result, that the highest-porosity rocks are not always the most productive ones, has been reported from the Kawerau geothermal field in New Zealand.

A disadvantage of the seismic refraction method is that explosives or equivalent sources of seismic waves are needed in the field. It is advisable that refraction surveys be preceded by gravity surveys, which may indicate anomalous structures as well as help in planning the refraction survey.

Magnetic Surveys: These have been carried out in many geothermal fields. Their use can be either as a structural method or as a method of mapping changes in the magnetization of rocks caused by the hydrothermal fluids. Magnetic anomalies in New Zealand geothermal fields have been interpreted as being due to a conversion of magnetite to pyrite. Such an effect would remain in extinct hydrothermal systems.

Opinion has been divided on the usefulness of magnetic surveys in geothermal exploration. The magnetization of different rock units may be quite variable, especially in volcanic areas. Alteration effects in a hydrothermal system would affect a large volume of rock, and the best way to detect such effects is by an aeromagnetic survey, which is less affected by near-surface rocks than a ground survey would be.

There is no doubt that distinct magnetic anomalies are associated with many high-temperature geothermal fields. Examples of this are the Námafjall and Krafla fields in northern Iceland; but it is also known from other areas that such anomalies are not always present. Test profiles on the ground should therefore be made before one decides on an extensive aeromagnetic survey in a geothermal exploration program.

Magnetic ground surveys have been used extensively in low-temperature fields in Iceland for tracing hidden dykes and faults that often control the flow of thermal water to the surface. Drill holes are then sited so as to cut the dyke at a certain depth. In some cases, the dykes or faults act as barriers to horizontal flow and may then form a boundary of the hydrothermal system in one direction.

Microearthquake Surveys

Surveys of microearthquake activity (magnitude of 1 to 3) in some tectonically active and volcanic areas have shown that geothermal fields are often characterized by a relatively high level of such activity. A very extensive study of this kind has been made in the Reykjanes peninsula in southwest Iceland.

This area is a part of the axial zone of the Mid-Atlantic Ridge, and includes three high-temperature geothermal fields. Continuous recordings for more than three years have confirmed the earlier indications that the geothermal fields have a fairly consistent microearthquake activity of 3 to 30 events per day, with a focal depth range of 2 to 6 km. The intermediate parts of the axial zone also have a high microearthquake activity, but here the events are more distributed in swarms, with quieter periods in between.

The value of microearthquake surveys for geothermal studies is at present somewhat limited by a lack of understanding of the mechanism causing these events. The microearthquakes may be tectonic in origin, and their depth distribution controlled by the temperature distribution. It is also conceivable that they are somehow related to a penetration of water into hot rock. It appears that the main use of microearthquake surveys may be to try to predict the depth of water circulation in hydrothermal systems, something which cannot easily be done with other methods.

Ground Noise Surveys

A high noise level is invariably found in geothermal fields, decreasing with distance from the surface activity. Spectral analysis of the noise shows that surface activity produces noise with frequencies above about 10 Hz. An example is Old Faithful with a spectral range of 8 to 24 Hz. Lower frequencies, down to about 1 Hz, are also usually found and are postulated to be due to deeper water convection. In high-heat-flow areas in the Imperial Valley, which are without

surface thermal activity, most of the noise energy is in the frequency range 0.5 to 5 Hz. Ground noise surveys have been made in areas where hydrothermal activity is known from surface manifestations or other geophysical surveys.

Applicability to Different Depth Ranges

The geophysical methods used in geothermal exploration can be discussed and compared on the basis of various criteria such as rapidity, cost, simplicity of field operations, data processing, interpretation, and so on. It appears to be useful also to discuss them in relation to the depth range that each one is suitable for probing. Such a division will of course not be distinct, but may still be of some use. The depth ranges will be denoted as shallow (0 to 200 m), intermediate (200 to 2,000 m), and deep (more than 2,000 m).

For shallow investigations, the greatest variety of methods is available. Such investigations aim to define the area of hot ground associated with surface thermal activity. They have no place in the search for hidden reservoirs.

An aerial infrared survey is the most convenient and rapid method of mapping surface activity, especially in areas that are little known and are not masked by vegetation. The shallow temperature field is best explored with conventional Schlumberger resistivity profiling. A rapid, low-cost reconnaissance may also be provided by the electromagnetic (EM) gun and the audio-frequency magnetotelluric (AMT) method, although at the present time there is less experience available with these methods in geothermal work than with the conventional dc resistivity methods.

At intermediate depths, the Schlumberger and dipole dc methods appear to be the most suitable ones for outlining low-resistivity zones. The dipole methods can be used either as depth-sounding or as profiling methods. Considerable experience has been gained in using them and in interpreting the measurements. Electromagnetic controlled-source methods may prove to be suitable also, but much less experience has been gathered so far with them. Of the natural field methods the telluric profiling appears to be an effective reconnaissance tool. Aeromagnetic surveys may be feasible if test profiles on the ground indicate variations in the magnetic field that may be associated with a thermal zone at depth.

Heat-flow or gradient surveys are particularly suitable in the search for hidden reservoirs or for exploring the boundaries of a thermal field. They are expensive because drill holes are needed, but they give unambiguous indications of thermal anomalies. They are effective only where the surface rocks are of low permeability.

All of the structural methods may be useful for mapping anomalies whose sources are at intermediate depth. Their usefulness depends on the particular geological environment under consideration.

For deep investigations of hydrothermal reservoirs several methods can be used, but their resolution is smaller than at shallower levels. Gradient surveys for predicting temperature at depth are suitable in impervious surface rocks, and dipole dc methods are suitable for probing the resistivity to a depth of a few kilometers if the shallower resistivities are laterally not very inhomogeneous. The low-frequency magnetotelluric method permits probing resistivity variations from a few kilometers to very great depths.

Of the structural methods, the gravity and seismic refraction methods are particularly suitable for studying deep structures, which may be of importance for controlling the flow of water, or as heat sources. A gravity survey would normally come first because it is cheaper. If major structural anomalies are indicated they can be studied further by seismic methods. An interpretation based on both gravity and seismic measurements is much more reliable than if based on only one of these methods.

In connection with deep investigations the microearthquake survey should be mentioned. Focal depths of microearthquakes may give an indication of the depth of circulation of hot water, although this needs to be confirmed by independent methods. It appears that in order to have a reliable estimate of the average behavior of microearthquake activity, a recording time of several months may be needed.

DRILLING TECHNOLOGY

> The material for this section has been based upon "Geothermal Drilling Technology," by W.C. Maurer of Maurer Engineering Incorporated.

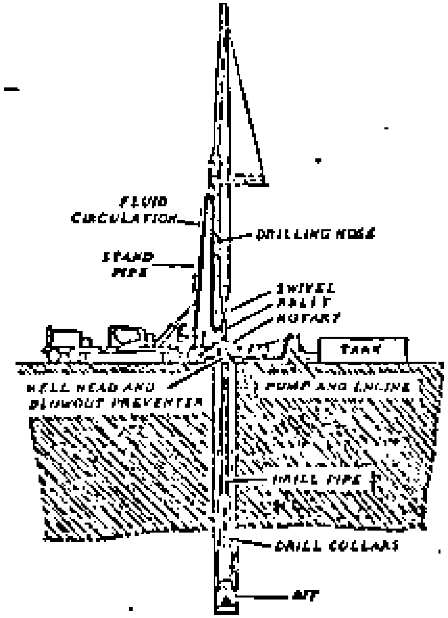
Geothermal Drilling System

Geothermal wells are currently drilled using conventional oil field drilling rigs as shown in Figure 2.1. The drill pipe and bit are rotated at speeds of 30 to 350 revolutions per minute by the rotary table at the surface. Drilling mud is pumped down the inside of the drillpipe and up the well bore annulus, carrying the rock cuttings to the surface. Water-base drilling fluids containing bentonite clay, barite and other chemicals are used to transport the cuttings, cool the bit, prevent the hole from sloughing, and prevent formation fluids from entering the well bore. These weighted water-base muds have a temperature limitation of about 500°F; improved fluids are needed for drilling geothermal wells hotter than 500°F (260°C).

Drill Bits: Most geothermal drilling employs roller bits with hardened steel teeth or tungsten carbide inserts. The steel used in roller bits is drawn at temperatures of 400° to 450°F; therefore, these bits lose much of their strength when they are operated at temperatures in excess of 500°F. This leads to rapid failure of the bearings and steel teeth, and loss of inserts with the insert bits. Insert retention is a problem at high temperatures because steel has a much higher thermal coefficient of expansion than tungsten carbide, and therefore the steel expands and reduces the compressive stresses holding the inserts into the cutters.

Premium roller bits contain sealed lubrication systems which utilize rubber rotating seals to hold the grease in the bearings. These rubber seals have temperature limitations of 300° to 400°F and therefore improved seals are needed for high-temperature geothermal drilling. Improved high-temperature lubricants are also needed.

FIGURE 2.1: GEOTHERMAL DRILLING



Source: Petroleum Extension Service, *Lessons in Drilling*

Diamond bits can drill at temperatures in excess of 1000°F, but they drill most formations much slower than roller bits so their use is not a satisfactory solution to the high-temperature bit problem.

Blowout Preventers: Blowout preventers are used to control bottom hole pressures and prevent blowouts from taking place when formation fluids (oil, gas, or water) flow into the well bore. This occurs when the fluid pressure in the well bore is less than the formation fluid pressure. Failure of the blowout preventer in this situation will result in loss of control of the well.

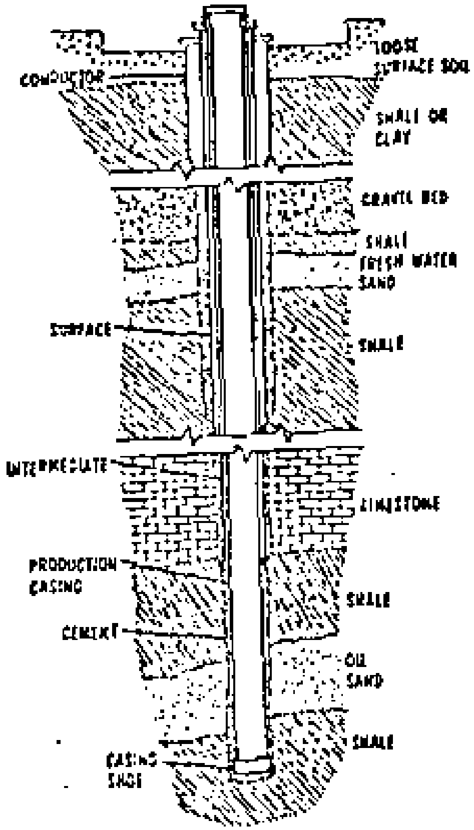
The blowout preventers utilize either rubber annular bags or rams which seal against the drill pipe. In the event there is no drill pipe in the hole, the preventers seal off the entire hole area.

The elastomers used in these blowout preventers have a temperature limitation of about 250°F (123°C) which is not adequate for controlling high-temperature geothermal wells.

Logging Tools: Electric logging tools are used to measure temperature profiles and to determine the properties of geothermal reservoirs. Three basic types of logging tools are used: electric, acoustic, and radioactive. These logging tools have temperature limitations of 400° to 500°F, depending upon the type of tool, and therefore improved high-temperature logging tools need to be developed for high-temperature geothermal wells at 500° to 700°F (250° to 370°C).

Cementing: Several strings of casing are usually required in geothermal wells in order to control formation fluids and to prevent excessive sloughing of the formations into the well bore. These connective casing strings are cemented into the well as shown in Figure 2.2.

FIGURE 2.2: CASING STRINGS



Source: Petroleum Extension Service, *Lessons in Drilling*

Good cement jobs are needed in order to seal off the formation fluids and to prevent a blowout from occurring in case the blowout preventer must be closed to control the well. Cements have reportedly been developed which have a temperature limitation of 600°F (320°C) which should be adequate for most geothermal wells.

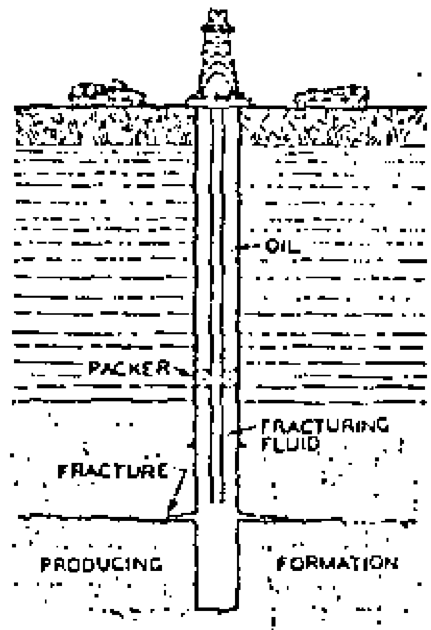
Perforating: Some geothermal reservoirs will be produced through open hole completions, whereas others will be produced from cased formations. In the latter case, perforating guns utilizing bullets or shaped charges are used to shoot

holes through the steel casing and into the formation. Perforating guns are currently limited to temperatures less than 500°F. Improved perforating tools must be developed for hot geothermal wells (that is, 500° to 700°F).

Packers: Packers are utilized in wells for many reasons including drill-stem testing. These packers are inflated hydraulically or mechanically to seal against the casing or well bore and isolate the fluids on either side of the packer. The elastomers used in these packers have a temperature limitation of about 450°F.

Hydraulic Fracturing: Hydraulic fracturing will be an important factor in the productivity and the economics of most geothermal reservoirs. Hydraulic fracturing consists of pumping a fluid into the well at pressures which exceed the in-situ stresses in the rock. Once the in-situ stress is exceeded, fractures are formed which can propagate several thousand feet from the well bore as shown in Figure 2.3.

FIGURE 2.3: HYDRAULIC FRACTURING



Source: Petroleum Extension Service, *Lessons in Drilling*

After the fractures are formed, sand, glass beads, or other proppants are pumped into the fracture with a viscous fluid. When the pressure is released, the fractures are propped open by these materials. The resulting propped fractures produce highly permeable flow channels for the fluid to flow from the reservoir into the well bore.

Improved high-temperature fracturing fluids and proppants must be developed for high-temperature geothermal wells since existing frac fluids are limited to temperatures of about 300°F. Improved propping techniques may have to be developed for hot geothermal wells since some formations undergo more deformation at these higher temperatures.

Downhole Drilling Motors: Downhole drilling motors are used in directional wells for sidetracking and for many other reasons in oil and gas wells, they will also be needed in geothermal wells.

Two types of hydraulic drilling motors are used, turbodrills and dynadrills. Turbodrills can be used at higher temperatures, but they rotate at speeds of 500 to 1,000 rpm whereas roller bits operate most effectively at speeds of 50 to 250 revolutions per minute. Bit life is greatly reduced at these high speeds. Dynadrills rotate at lower speeds (250 to 500 rpm), but they contain a rubber stator which has a temperature limitation of 350°F (177°C). Improved high-temperature drilling motors are therefore needed for geothermal drilling.

LASL Well

Los Alamos Scientific Laboratory (LASL) has drilled a 9,619-ft geothermal well of which 7,200 ft was hard dense granite. This well is cited because it illustrates the need for improved geothermal drilling equipment, and it shows examples of two improvements. Tricone insert roller bits were used to drill the granite formations in this well.

Difficulties were encountered with the first insert bits used in the granite due to insert breakage, loss of inserts, and loss of gauge on the bits. These first bits drilled 4 to 5 ft/hr and wore out after drilling about 250 ft. Different bit designs and insert materials were tested, resulting in improved bits which drilled over 600 ft at rates of 8 to 9 ft/hr. This improved bit performance greatly reduced the drilling cost in this well.

LASL also experienced difficulties in coring granite with diamond bits. These diamond core bits, which cut a 4.5 inch (114 mm) diameter core wore out after coring about 11 ft. These bits cost $11,000 which corresponds to a bit cost of $1,000/ft of core. Much of the granite was fractured. This fractured granite contributed to the short life of both the core bits and the roller bits.

Because of the high coring costs, LASL developed a four-cutter insert roller core bit. These roller core bits drilled 15 ft before they wore out. They cost about $3,000 each, which corresponds to a bit cost of $200/ft compared to $1,000/ft with the diamond core bit. In addition to the reduced bit cost, the roller core bits drilled faster, thereby reducing the drilling time and the rig cost. The roller core bits cut smaller cores (54 mm diameter) than the diamond core bits, but these smaller cores were adequate for geological and core testing purposes.

Development of these improved bits resulted in increased drilling rates and reduced drilling costs in the LASL wells. This is an example of the type of improvement that is needed for geothermal drilling and shows that improvements can be made provided new materials and techniques are tested.

Various organizations are conducting research on more than 30 drilling techniques. These drills remove rock by four basic mechanisms: (1) melting and vaporization, (2) thermal spalling, (3) chemical reactions, and (4) mechanically-induced stresses.

Melting and Vaporization Drills

Several devices are capable of heating rocks to the 2000° to 4000°F required to melt them, including: (1) lasers, (2) electron beams, (3) plasmas, (4) electric arcs, and (5) subterrenes.

These high-temperature drills have potential for drilling into magna, lava beds, and other extremely hot reservoirs which cannot be drilled with conventional rotary drills. Figure 2.4 shows a schematic of a laser drill which is capable of drilling holes in any rock. Electron beams are also capable of melting holes in rock. Such a device is shown in Figure 2.5. Plasma drills (Figure 2.6) are also used to melt holes in rock.

FIGURE 2.4: LASER DRILL

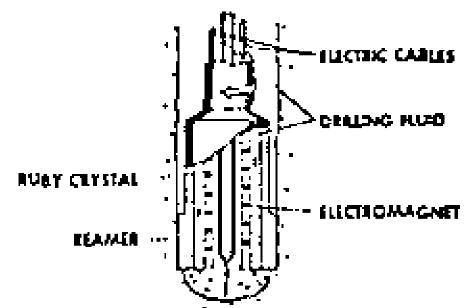
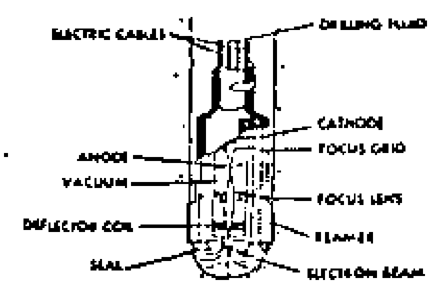
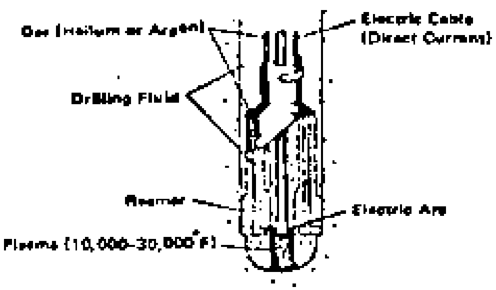


FIGURE 2.5: ELECTRON-BEAM DRILL



Source: Maurer, *Novel Drilling Techniques*, 1968

FIGURE 2.6: PLASMA DRILL



Source: Maurer, *Novel Drilling Techniques*, 1968

LASL is field-testing subterrene drills which melt rock. Subterrenes can be of either consolidating or extruding types. The consolidating subterrenes drill porous rocks by melting the rock and pushing it aside in a dense glass layer which lines the hole. This glass lining acts as a casing to seal off the formation fluids and to prevent the rock from sloughing into the well bore.

The extruding subterrenes are used to drill dense rock which cannot be drilled by consolidating subterrenes. The molten rock passes up through the center of the extruding subterrene where it is solidified into small particles and then removed upward through the center of the drill stem by the drilling fluid.

Thermal Spalling Drills

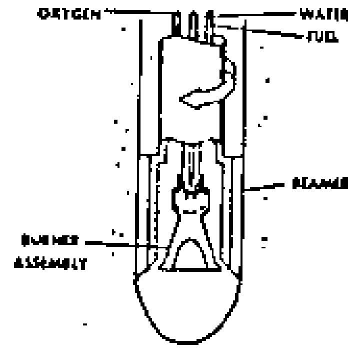
When some silicate rocks such as taconite are heated to 700° to 1100°F, high thermal stresses cause the surface to flake off in thin spalls. Drills which thermally spall rock include: (1) jet-piercing, (2) rocket-exhaust, (3) electric-disintegration, (4) high-frequency electric, (5) microware, (6) induction, and (7) pulsed electron. The devices described above which melt and vaporize rock are also capable of spalling rock, since the spalling temperature of rock is lower than the melting temperature.

A drill which has found widespread application is the jet-piercing drill shown in Figure 2.7. This drill burns fuel oil and oxygen to produce a flame temperature of 4300°F. Jet piercing drills penetrate taconite at rates up to 40 ft/hr. The Russians have extensively tested rocket-exhaust drills (Figure 2.8) which are similar to jet-piercing drills, except that they burn more exotic fuels, thereby producing a higher temperature flame and higher drilling rates.

Microwave drills (Figure 2.9) operating at frequencies of 1000 to 3000 MHz are capable of heating and spalling holes in rock. Induction drills (Figure 2.10) operating at frequencies of 200 to 500 kHz are able to heat and spall holes in rocks having high-magnetic susceptibility.

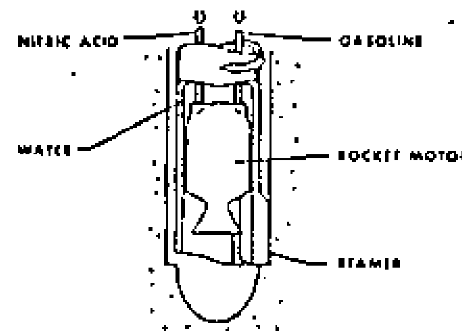
Intense beams from pulsed electron beams (Figure 2.5) spall holes in rocks within microseconds. These spalls are generated by the intense heat which expands the rock at the surface.

FIGURE 2.7: JET-PIERCING DRILL



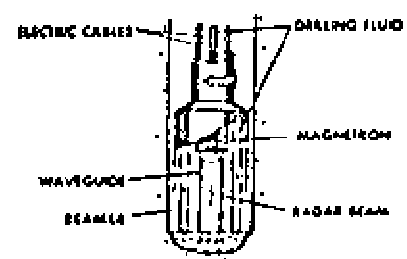
Source: Rubow, *Mines Magazine*, March 1956

FIGURE 2.8: ROCKET-EXHAUST DRILL



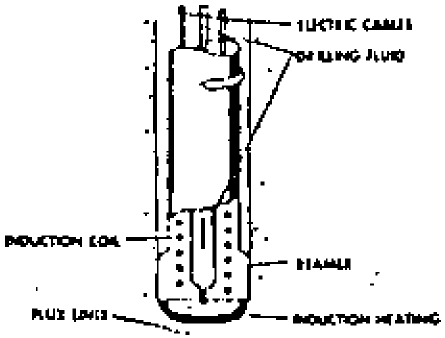
Source: Shapir, All-Union Res. Inst. for Drilling Tech., U.S.S.R., *Proc.* No. 10, 1963.

FIGURE 2.9: MICROWAVE DRILL



Source: Steudel, *Glückauf-Forschungshefte*, April 1965

FIGURE 2.10: INDUCTION DRILL

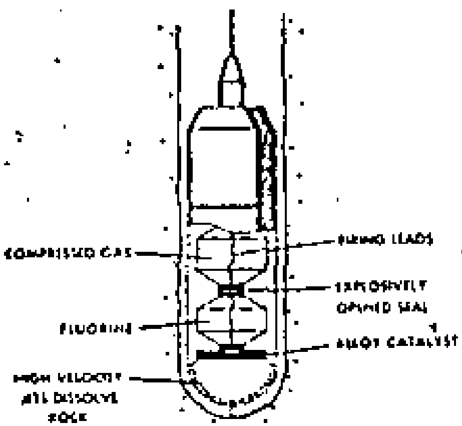


Source: Epshteyn, et al, 1960, Translation No. 62-11712, U.S. Dept. of Commerce

Chemical Drills

The third group of novel drills are those which utilize highly active chemicals to drill the rock. Figure 2.11 shows a chemical drill using fluorine that is used in the petroleum industry to cut through steel casing and to drill rock. High cost of the chemicals prevents these drills from being used on a large scale.

FIGURE 2.11: CHEMICAL DRILL



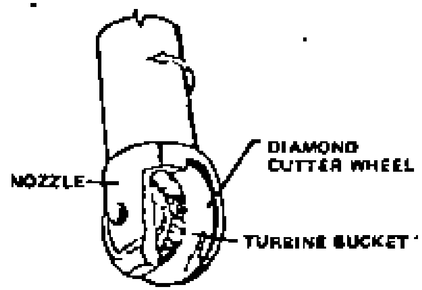
Source: Ledgerwood, *Jour. Petroleum Tech.*, April 1960

Mechanical Drills

The last group of novel drills are those which remove the rock by mechanically induced stresses. These drills include: (1) turbines, (2) explosive, (3) pellet impact, (4) implosion, (5) ultrasonic, (6) spark, (7) downhole replaceable bit, (8) continuous chain drill, (9) terra drill, and (10) erosion.

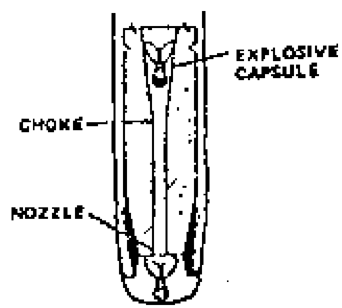
High-speed turbine bits (10,000 rpm) have been tested in oil wells. These bits (Figure 2.12) were not economical because of the low efficiency of the turbine. Explosive drills have been extensively tested in oil wells in both the Soviet Union and in the United States. With the Russian drill (Figure 2.13), explosive capsules were pumped in the hole bottom at 5 to 10 second intervals and detonated upon impact with the rock. Drilling rates up to 40 ft/hr were obtained in oil wells with this drill.

FIGURE 2.12: TURBINE BIT



Source: Cannon, AIME Meeting, Fall 1957

FIGURE 2.13: SOVIET EXPLOSIVE DRILL

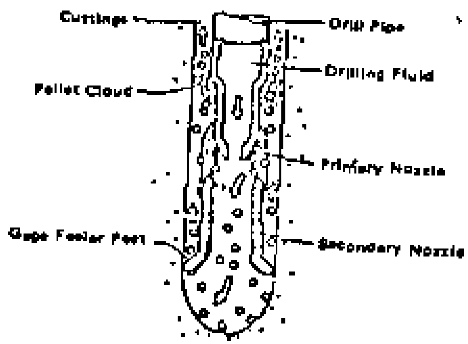


Source: Ostrovskii, *Deep-Hole Drilling with Explosives*, 1960

The pellet-impact drill shown in Figure 2.14, was also tested in oil wells. Nozzle-directed steel pellets were used to break the rock. These pellets remained at the hole bottom and were recirculated through the bit by the aspirator action of the primary and secondary nozzles. Implosion drills (Figure 2.15) and ultrasonic drills (Figure 2.16) can also be used to drill rocks.

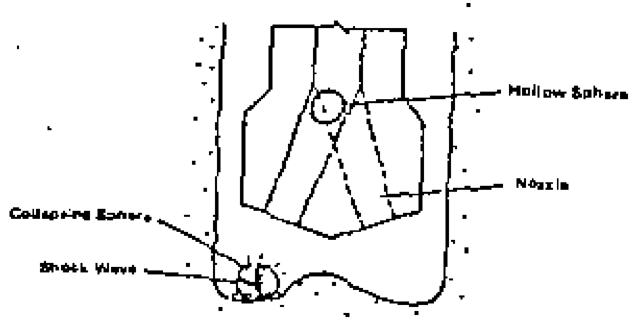
Spark drills (Figure 2.17) utilize the intense pressure pulses (100,000 to 300,00 psi) generated by high-voltage spark discharges (20 to 100 kV) to drill rock. Sandia Laboratories has tested a spark drill.

FIGURE 2.14: PELLET-IMPACT DRILL



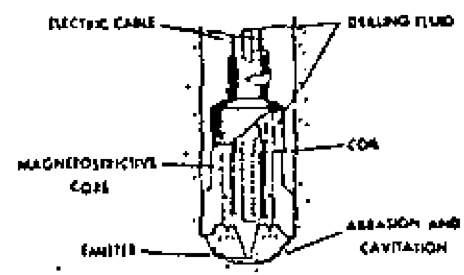
Source: Eckel, Deily, and Ledgerwood, *AIME Trans.* v. 207, 1956

FIGURE 2.15: IMPLOSION DRILL



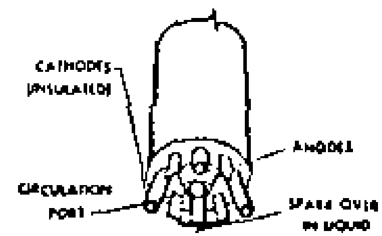
Source: Ostrovskii, *Deep-Hole Drilling with Explosives,* 1960

FIGURE 2.16: ULTRASONIC DRILL



Source: Neppiras, *Ultrasonic Machining, Modern Workshop Technology,* Part 2, 1959

FIGURE 2.17: SPARK DRILL



Source: Titkov et al, *Neft. Khoz.,* U.S.S.R. v. 35, no. 10, 1957

Changeable Bit Drills: Sandia also tested a downhole changeable bit. This bit contains a series of new cutter heads so that as one wears out, a new one can be cycled into position without pulling the drill pipe from the well.

Sandia is developing a continuous chain bit. The chain contains diamond or tungsten carbide drag elements which cut the rock. When one set of cutters becomes dull, the chain is rotated so that a new set of cutters is exposed on the bit face and drilling continues. This is repeated until the 5 or 10 sets of cutters on the chain are worn out, and then the bit is retracted from the well.

Projectile Drills: Sandia tested the Terra drill. With this system, projectiles are fired into the rock ahead of the bit (up to 12-inch penetration) to fracture the rock and allow it to be more easily removed by the roller bit. In preliminary tests, the Terra drill penetrated Madeira limestone approximately twice as fast as conventional roller bits. This system has potential use in geothermal wells, especially in hard rock.

Erosion Drills: High-pressure erosion drills have potential for drilling geothermal wells faster and cheaper than conventional drills. Exxon Production Research Company in conjunction with eight other major oil companies is developing an erosion drilling system utilizing high-pressure bits. In preliminary tests, drilling mud was pumped through these bits at pressures up to 15,000 psi utilizing high-pressure frac trucks. Conventional oil field Triplex mud pumps have been modified to operate at these high pressures, thereby eliminating the need for renting frac tracks.

These tests demonstrated that high-pressure erosion bits can drill oil wells two to three times faster than conventional bits. In one test high-pressure bits (10,000 to 15,000 psi) drilled the interval from 2,300 to 6,000 ft in a production well in 24.2 rotating hours as compared to 66.6 rotating hours for conventional bits (2,000 psi). This high-pressure drilling system has potential for making major reductions in drilling costs in both oil field and geothermal wells.

SPACE AND PROCESS HEATING

The material for this section has been based upon "Summary of Section IX—Space and Process Heating," by H.C.H. Armstead.

The direct use of geothermal heat for space heating and domestic hot water supply, industrial processes, or for husbandry can be highly efficient, since the losses incurred are not imposed by the laws of thermodynamics but only by such imperfections as must inevitably arise from insulation losses, drains, and terminal temperature differences in heat exchangers. These imperfections can be controlled within economic constraints; they are not dictated by natural laws.

Another important fact is that the sources of high-enthalpy natural heat at present accessible to man and which are suitable for power generation are believed to be far less abundant than those of lower-enthalpy fluids which can be used for other purposes. Furthermore, practical applications can be found to cover a very wide spectrum of temperature extending down to about 30°C for balneology, biodegradation, and fermentation, and even down to about 20°C for fish hatcheries.

Finally it should not be forgotten that a very large proportion of the world's energy consumption is in the form of heat, rather than electricity. In short, geothermal energy is far too versatile an asset to be used for power generation only. It is also very much less polluting than heat produced, as is mostly now done, by the combustion of fuel.

A city of about 90,000 inhabitants such as Reykjavik can be almost fully supplied with all its domestic and commercial heating requirements without smoke and by means virtually innocent of any other form of pollution. This is an advantage that is shared by no other form of heat supply except hydroelectric and solar energy.

Iceland

The volume of building space in Reykjavik heated geothermally increased from 10.3 to 15 million m^3 between 1968 and 1974, an average growth rate of about 6.4%/yr. The city is now virtually "saturated" with geothermal space heating, only about 1% of the buildings do not have it. The Reykjavik area alone has a thermal load demand of about 385 MW, and the sales of heat energy in 1973 amounted to more than 1.5×10^9 kWh, equivalent to an annual load factor of about 44.5%.

The 45-year history of the Reykjavik city heating system began i ,0. In 1975 11,000 buildings and about 90,000 people enjoyed this public service. Although new thermal areas have been brought in to meet this tremendous growth, the originally exploited fields are still producing at undiminished capacity after nearly half a century.

The capital city, however, is not the only Icelandic area to be served with geothermal heating. Eleven other independent areas serve about 13,500 additional people with domestic heat, while a further 26,000 people are being added; and a system is being planned to provide more than 10,000 additional people with heat in the Reykjanes Peninsula under the Svartsengi project. By the time these plans have been executed, more than 137,000 people will be served with geothermal heat in their homes and the total heat load will be equivalent to nearly 680 MW. By then, more than half the population of Iceland will enjoy the benefits of this service, and it is aimed to extend the proportion to 60 to 65%.

Einarsson states that the district heating schemes of Iceland use geothermal waters at 80° to 120°C, though in one case that has been operating for 30 years, the temperature is as low as 56°C. Such low- and moderate-enthalpy fields are preferred to high-enthalpy fields, as the fluids generally have much lower mineral and gas content. The Svartsengi project, however, will have to use high-enthalpy saline steam and hot water at 167.5°C. A dual purpose power-heating project is under consideration for Nesjavellir; this project will use a high-temperature field (260°C bottom-hole temperature) and will produce 69 MW of power (net).

Einarsson also examines the economics of district heating and shows a parametric graph of costs based on water temperature, pipe diameter, and transmission distance. This shows a range of costs (presumably at 1975 levels) from 4.3 to 15 mills/kWh (thermal); the lower figure represents 150°C water at the wellhead (no transmission), and the higher value represents 100°C water transported over 39 km in a 10-in pipe. Intermediate temperatures, larger pipe diameters, and shorter transmission distances would produce intermediate cost figures. The costs generally compare favorably with fuel oil heating except perhaps where the temperature is low, the pipe diameter small, and the transmission distance great.

On average, the price of geothermal heating in Iceland was 50 to 60% of that of oil heating before 1973 and is now 25 to 30%. Geothermal energy supplied Iceland in 1975 with about 2200 GWh (thermal)/yr for space heating; this saves Iceland about 300,000 tons/yr of imported fuel oil.

Arnórsson et al give a technical description of the Svartsengi district heating project for supplying a few population centers in the Reykjanes Peninsula and also the Keflavik International Airport. This project represents a thermal load of 80 MW (100 MW, according to Einarsson). The wells at Svartsengi produce highly saline water together with steam at about 210° to 230°C, and this is chemically unsuitable for direct heating. Fresh water is therefore heated by the geothermal fluids and is transmitted hot to the load centers, thus obviating most of the chemical problems.

Four different heating cycles were studied, but one in which steam and fresh water are mixed in two stages and subsequently heated and flashed, so as to degas the mixture, has been chosen as the most suitable. Fifteen kilowatts of electric power for auxiliary supplies is a by-product of the process.

Thorsteinsson describes the redevelopment of the Reykir hydrothermal system, which has been exploited since 1944 for district heating in Reykjavik, 15 to 20 km distant. Before 1970 this area produced about 300 l/sec at 86°C by free flow and was the principal source of heat of the integrated system until 1959. After the development of two other areas within the city limits, Reykir's share of heat production fell to 38% of the total. Now the Reykir field is being redeveloped by drilling larger bores to depths of 800 to 2,043 m and equipping them with submersible pumps.

Production had already increased to 850 l/sec at 83.5°C by January 1975, and is expected ultimately to exceed 1,500 l/sec with a fall in water level of 60 to 70 m from the 1970 steady-state level. Drawdown tests have been performed and the characteristics of the aquifer deduced. The effects of tides and earthquakes have also been studied.

United States

Although there are no sizable towns or cities in the U.S.A. that use only geothermal heat, there are nevertheless some interesting developments in the western states of Idaho and Oregon. In Boise, Idaho, a small geothermal space heating scheme was established in the Warm Springs residential area as long ago as 1890. At one time this scheme supplied about 400 homes and businesses, but it has recently declined to 170 homes fed with 77°C water pumped from two wells 130 m deep.

A study is in progress for establishing a Demonstration Space Heating Project, sponsored by the Energy Research and Development Administration (ERDA) and under the direction of the Idaho National Engineering Laboratory (INEL) and in collaboration with Boise State University and the Idaho Bureau of Mines and Geology, for geothermally heating a group of public buildings in the city of Boise. At present, the annual fuel bill for heating these buildings is $225,000, and this figure is expected to rise.

The two wells now feeding the Warm Springs area have shown no decline in productivity in more than 80 years, and the chemical quality of the water is good. The study will cover environmental and chemical aspects, the conversion of existing installations, and various methods of waste disposal including infiltration through sand and gravel pits, reinjection wells, discharge to the existing irrigation system, discharge into the Boise River, and cycling to greenhouses, fish hatcheries, and so on. The cost of the study is estimated at about $2 million.

Lund, Culver, and Svanevik describe the exploitation of the geothermal waters at Klamath Falls, Oregon, a project which has provided space heating since the turn of the century. About 400 holes of depths ranging from 27 to 580 m are used to heat about 500 buildings (and incidentally, swimming pools, a milk pasteurization plant, and snow melting facilities for roads). Some of the wells are artesian, with a pressure of about 5 psi. The total heat load is about 5.6 MW.

Estimated costs are given for different numbers of households per well and are compared with fuel and electrical heating as alternatives. Initial investment for a single well is usually from $5,000 to $10,000, and the annual operating costs are less than $100. Where several householders share the same well, geothermal

heating is shown to be competitive. A large scale district he... project on the lines of the Reykjavik system is being studied, as it is obvious that only a small portion of the total local heat potential is being tapped. Additional uses for the heat, for husbandry and industry, are also being considered. The well temperatures vary from 38° to 110°C. Downhole "hairpin" heat exchangers are commonly used in order to minimize corrosion, with city water as the circulating fluid; circulation is usually effected thermosyphonically. Four steam wells have been struck, and these too are used with heat exchangers.

France

Coulbois and Herault state that the French administration is seeking to encourage the use, for domestic heating, of hot waters discovered in the French sedimentary basins in the course of oil prospection during the last 20 years, in particular in the Dogger aquifer near Paris. Since the depths at which these hot waters occur range from 1.5 to 1.8 km and the temperatures vary from 55° to 77°C, it would appear that the areas of interest may be regarded as "nonthermal," having temperature gradients (assuming surface ambient temperature of 15°C) only of the order of 30°C/km, which can be regarded as "normal." The water salinity varies from 8 to 30 g/l (NaCl) and traces of H_2S are present.

Heat exchangers are therefore considered necessary so that clean secondary water may be used as the heating medium. Reinjection is necessary in order to avoid surface pollution from the saline well waters after having yielded up their heat, and also to conserve both fluid and heat for recharging the aquifer. The authors examine the problems theoretically from the economic and technical aspects, stress the high capital cost of geothermal heating, and suggest that geothermal energy is suitable for background heating to be supplemented with another heat source for boosting at times of high demand.

New Zealand

Shannon reports that the extraction of geothermal heat in Rotorua for domestic heating purposes has steadily increased since the first successful bore was sunk there in 1935. There are more than 700 registered bores in that city, ranging from 50 to 1,200 ft in depth and from 2 to 6 inches in casing diameter. Temperatures vary from 49° to 177°C, and pressures are experienced up to 175 psig. These pressures are sufficient to ensure delivery to the places required without pumping. Chemical deposition has been something of a problem, but deep bores generally give less trouble than shallow.

After the heat has been extracted from the geothermal fluid, the cooled waters are disposed of in soak bores, vented at high level to dispose of the H_2S. Heat exchangers are obligatory in view of the noxious ingredients in geothermal fluids which could escape from valves and pipe joints.

The author discusses the choice of suitable materials for the various component parts of the heating system, presents drawings of some of these parts, and discusses controls. He also gives particulars of a scheme for heating a complex of government buildings, representing a total thermal load of nearly 14.6 MW. Finally he gives some cost data which show that although the capital cost of geothermal heating is 16 and 44% higher than for coal- and oil-fired heating respectively, the annual running costs are 30.5 and 71% lower respectively at present fuel price levels. Geothermal heating thus pays for itself in 15.5 and 39.5 months when compared with oil and with coal heating respectively.

India

Experiments are being conducted in two Himalayan areas. The occurrence of geothermal energy in Ladakh coincides with very severe climatic conditions, but unfortunately the natural heat is found at present only in some of the most sparsely populated parts of the world, in particular at Puga in southeastern Ladakh where the population density is only 0.8/km^2. Here, at a height of 4,500 m above sea level, the winter temperature sometimes falls to −40°C. Nevertheless, steam and hot water are found at depths of only 20 to 30 m, and an experimental test rig has been set up to test the suitability of geothermal space heating.

Behl, Jegadeesan, and Reddy describe the local conditions, the test equipment, and the results obtained. Some empirical knowledge has been acquired from the tests regarding building insulation and the corrosive properties of the thermal fluids. The authors explain how the Government of India has also conducted some successful greenhouse heating experiments at Chumathang, also in Ladakh.

U.S.S.R.

Dvorov and Ledentsova, recognizing the complexity of the variables which govern the economics of geothermal space heating, have presented a paper in which the component cost factors are analyzed separately—borehole production, local heat distribution, waste disposal, heating systems, and longer distance heat transmission. Different secondary variables are considered in each case as may be applicable—drilling costs, bore yields, bore spacing, bore fluid temperature, pattern of demand, transmission distance, local fuel costs (in competition), climatic conditions, and so on.

Different heat distribution systems, heating schemes, and devices are also considered. Graphs are given showing the interrelationship of some of these variables. The authors broadly conclude that simple local geothermal heat distribution schemes can at present be competitive with traditional fuel heating only when the thermal fluid temperature is 85°C or more, the temperature change does not exceed 45°C, the local distribution distance does not exceed 5 km, and the ambient air temperature is not less than -8°C. Borehole costs should not exceed 100,000 to 130,000 rubles, or 150,000 in rare cases.

Long distance transportation can be economical up to 35 to 40 km if drilling costs are exceptionally low, for example, 50,000 rubles per bore. Drilling costs in the range of 80,000 to 120,000 rubles per bore reduce the economical transmission distance to about 5 km, or perhaps 8 to 10 km under very favorable conditions of high well yields and very expensive fuel alternatives.

The authors mention the enormous heat reserves in the Soviet Union, but point out that in many areas the waters are highly mineralized and sometimes the temperatures are rather low. Different schemes are described for dealing with highly mineralized waters and for moderate temperature waters; these involve heat exchangers and supplementary fuel heating. The authors al[illegible]scribe a scheme which makes possible the use of low temperature fluids in combination with a heat pump, and a complex system involving both a boiler unit and a heat pump using the lithium bromide process which permits the use of air conditioning in summer. The possibility of recovering rare elements from highly mineralized waters, after yielding up their heat in heat exchangers, is mentioned. The authors stress the fact that high sophistication and complexity may adversely affect the economics of heating schemes and their reliability of operation.

Process Heating—Farming, Refrigeration, and Balneology

The expression "process heating" is used here very broadly to cover all nonpower uses of geothermal energy other than space heating and hot-water supply, even (paradoxically) refrigeration and air conditioning.

Geothermal heat can, of course, be used for a variety of agricultural and horticultural purposes, for fish breeding and for animal husbandry, all of which may loosely be termed "farming." Refrigeration is also closely related to farming as a means of preserving foodstuffs, and this too is a process that can be effected by means of geothermal energy. Much of the application of geothermal energy to farming is no more than a form of space heating, for example, greenhouse and soil warming. The word "balneology" too may be extended to cover its medical counterpart of "crenotherapy."

Behl, Jegadeesan, and Reddy describe how the use of geothermal heating under glass has produced very promising results even in the inhospitable climate of Ladakh. The authors also state that a refrigeration plant is being planned to exploit the Manikaran geothermal field in the Parbati Valley, Himachal Pradesh, in the Himalayas. This district abounds in orchards and potato farms, and it is intended to install a 100-ton cold storage plant, using the ammonia-water absorption process, to preserve the local produce.

The residual waters will be used for space heating and to warm swimming pools, as the area is frequented by tourists and by pilgrims. A small hydroelectric plant is to be included in the project so that the whole complex may be self-supporting. A small pilot 10- to 15-ton refrigeration plant will form the first step in this project.

Einarsson briefly mentions agricultural and balneological applications of geothermal energy, and states that there are now 140,000 m^2 in Iceland under glass, geothermally heated. He also mentions space cooling, or air conditioning and mentions that he has proposed the establishment of a district cooling system for Managua, Nicaragua, to be adopted while the city is being rebuilt after its destruction in the devastating earthquake of 1972.

Chiostri devotes his paper to the medico-balneological applications of geothermal energy. The oldest geothermal industry in history is the use of natural hot or warm waters, for pleasure or for alleged medical reasons. The word crenotherapy has been coined for the technique of curing and alleviating diseases by means of thermal waters.

Chiostri broadly discusses the whole subject of crenotherapy and clearly believes that it is of very real value. He mentions that in Italy alone 15 million people were treated at more than 200 thermal clinics in 1971, and that in the U.S.S.R. more than 10 million people are treated annually with thermal waters. Several other countries have also built up impressive "spa" industries. Apart from the health aspects of the matter, there is no doubt that thermal spas are responsible for having built up tourism on a large scale in many parts of the world. An international catalogue of all medicinal waters throughout the whole world is proposed.

MULTIPURPOSE DEVELOPMENTS

The material in this section has been based upon "Summary of Section X—Other Single and Multipurpose Developments," by R.C. Barr of Earth Power Corporation.

Yuhara and Sekioka have used linear programming for an economic analysis of multipurpose utilization of a vapor-dominated reservoir in the Siramizu-gawa area near Sounkyo, Hokkaido, Japan. Utilization is shown in three stages. The primary stage is for electrical generation; the secondary stage for space heating, greenhouses, and snow-melting on roads; and the third stage for mineral baths. The most important elements for the commercialization of a geothermal system are the quality of geothermal resources, transportation of geothermal fluid, utilization for power generation, utilizations other than power generation, waste disposal, and environmental conservation.

Water desalinization at the East Mesa field in the Imperial Valley of California conducted by the U.S. Bureau of Reclamation is described by Fernelius. Information is provided on the five deep exploration wells at the East Mesa anomaly, together with results from production tests and information dealing with scaling and corrosion. Two distillation desalting units have been installed at East Mesa, together with a multistage flash unit and a vertical-tube evaporator. The design criterion for this equipment is 200°C; however, the maximum temperature of the geothermal waters is 166°C. It is indicated that electric power generation will most likely be required to supplement the costs for the desalinization program.

Palmer, Forns, and Green consider the concept of locating a geothermal electric power plant on the sea floor at continental-shelf depths. The waste heat would be contained in the sea floor, which in turn would provide a preferred site for certain species of fish and crustacea such as the rock oyster, shrimp, and the "spiny lobster."

The basis for the proposition of locating geothermal power plants on the sea floor is derived from studies for siting nuclear power plants in coastal zones. Using the United States as an example, studies indicate that within a coastal belt 80 km wide, 40% of the population lives on 6% of the land and that land contains job sites for 42.6% of the industrial sector.

Because siting a nuclear power plant in a coastal zone precludes multiple uses of this land, it is contended that an offshore, underwater geothermal plant would permit multiple uses of the coastal lands. Offshore experience in oil and gas drilling and heat pipe technology developed by the Hughes Aircraft Company is cited in support of the required underwater technology.

The compatibility of an onshore geothermal power plant with m e uses may be envisioned from the other papers in this section.

Gutman describes the use of geothermal waters for the soilless growing technique called hydroponics. No wells were required. Gutman states, "The spent water with some nutrients is discharged into the natural drainage system where it irrigates the natural alkaline soil and induces growth of grains and grasses from windborne seed, which previously were unable to germinate due to the toxicity of the alkaline soil."

The paper by Lúdviksson explains the concept of multiple uses of geothermal energy for electrical production at temperatures between 180° and 200°C and for processing agricultural products, marine products, and various raw materials using geothermal steam at temperatures ranging from 100° to 180°C. At temperatures from 40° to 100°C geothermal hot water may be used for horticulture, animal husbandry, health resorts, and space heating. At temperatures less than 30°C fish farming may benefit.

Lúdviksson presents an operating analysis for an electrohorticultural complex. This includes a market analysis for vegetables, flowers, and so on, both for domestic consumption and export, and the capital costs for constructing a growing facility. The principal cost of the growing facility is the glass and framework. It may be interesting to learn whether a low quality glass could be manufactured using the electricity from the complex and the silica precipitate from the geothermal brine. The analysis excludes the costs for electrical generating facilities but assumes that one-half of the electricity produced will be sold in the marketplace. The electrical production is considered necessary for artificial lighting.

The Reykjanes Peninsula in Iceland is an area of abundant and readily accessible geothermal resources as evidenced by the many surface manifestations. Lindal describes the activities of the Sea Chemicals Complex on this peninsula, a project initiated by the National Council of Iceland in 1966. The project was designed to coordinate the exploitation of indigenous Icelandic resources. Principally, these are hydraulic power, heat from geothermal energy, seawater, and industrial raw materials which are found in geothermal fluids. Presently under consideration by the Icelandic government are facilities for the commercial recovery of salt, potash, and calcium chloride from the geothermal brines.

During the last four years of the investigations a well was kept flowing in order to observe production rates and possible changes in the chemical composition of the brine. The depth of the well is not given. The rate of production of the first year was 85 kg/sec. The production then declined to 68 kg/sec in the second year, 57 kg/sec in the third year, and remained the same thereafter. The chemical composition did not change. Mineral recovery was achieved through separation by evaporation and fractional crystallization. The minerals present in the brines were found to attain a solid form in the following order: silica, sodium chloride, potassium chloride, and calcium chloride.

An evaporator was constructed to assist in removing the water in order to concentrate the fluid. Geothermal steam from the test well was the source of heat for the evaporator. Silica and calcium sulfate buildup of scale commonly associated with geothermal production is not considered to be a problem. Buildup of scale did, however, inhibit the heat-transfer coefficient in the evaporator when oxygen was permitted to enter the system. By purging the oxygen, the heat-transfer coefficients are expected to remain satisfactory.

The most extensive technical work accomplished by the Sea Chemicals Complex is the preparation of magnesium chloride from seawater as a feed to electrolytic magnesium cells for the ultimate manufacture of magnesium. Inexpensive soda ash processed by geothermal steam is a key component in the manufacturing system envisioned. The production of sodium metal, chlorine, and caustic soda have also been studied. Because magnesium and sodium metal as well as other products such as ammonia can be produced using electrolytic processes, additional attention should be given to electrolysis using power generated by geothermal energy.

Geothermal Development Complex

A conceptualized geothermal development complex might consist of an electric power generating facility, with a portion of the electricity used internally and the balance sold into a transmission grid. The electricity would be used within the complex conventionally by residents and for many energy-intensive manufacturing processes such as smelting and electrolysis for the manufacture of ammonia. Some steam could be diverted from the power station for process use or water desalinization. Hot wastewater could be used for space heating in buildings, greenhouses, and/or to hydroponically produce food.

Low-quality greenhouse glass could possibly be produced with precipitated silica in electric ovens. Otherwise arid lands could be made tillable with wastewaters and ammonia-based fertilizers from the electrolytic processing plant. Perhaps the hot water could be piped under intercomplex roads to keep them snow-free. Mineral baths would be an ideal place for residents to contemplate other productive activities for the geothermal development complex.

While the vision of a geothermal development complex is appealing, the demand (value) for electricity and associated costs may economically preclude multipurpose uses in areas such as the United States. In such areas it may be desirable to reinject the geothermal fluids at their highest temperature in order to maintain or prolong reservoir life. Reinjection would also maximize individual well lives and inhibit production declines.

Development of Geothermal Energy in California

The material for the following section has been based upon a report by C.D. Fredrickson of Jet Propulsion Laboratory, California Institute of Technology (N78-18528).

RESOURCE KNOWLEDGE

California is particularly rich in geothermal resources. They include not only the more familiar hydrothermal systems typified by those under development at The Geysers in Northern California and in the Imperial Valley but also hot-igneous (i.e., magma and hot dry rock) and conduction dominated (i.e., near-normal-temperature gradient) systems which may ultimately prove to be much more extensive and valuable than the hydrothermal systems. A summary of the heat content (heat in ground above 15°C without regard to recoverability) of California's geothermal resources based on United States Geological Survey (USGS) estimates is given in Table 3.1.

TABLE 3.1: CALIFORNIA'S GEOTHERMAL RESOURCE BASE

Resource Type	Identified	Undiscovered
	........Quads*........	
Hydrothermal		
Vapor-dominated (steam)	75	75
Liquid-dominated (hot water)		
High temperature (>150°C)	650	2,000
Intermediate temperature (90° to 150°C)	30	120
Hot-igneous	14,700	55,000
Conduction dominated		
Near normal gradient	>635,000	0
Geopressured	Unknown	Unknown

*1 quad = 10^{15} Btu and is equivalent to approximately 170 million barrels of oil or 50 million short tons of coal.

Source: Reference (1)

The h[illegible]mperature hydrothermal systems (i.e., those having temperatures over 1[illegible]) are especially important because of their potential for near term commercial development for electrical power generation.

The identified hydrothermal resources in California are located in and around "Known Geothermal Resource Areas" (KGRAs). A KGRA, as defined in the rules and regulations implementing the Geothermal Steam Act of 1970 (PL 91-581), "is an area in which the geology, nearby discoveries, competitive interests, or other indicia would, in the opinion of the Secretary of the Interior, engender a belief in men who are experienced in the subject matter that the prospects for extraction of geothermal steam or associated resources are good enough to warrant expenditures or money for that purpose."

There are 23 such designated areas in the state. The USGS has the responsibility of assessing the nation's geothermal potential. Their initial assessment was released in 1975 (2). It identifies 62 hydrothermal resources in California with estimated temperatures greater than 90°C; 46 below 150°C and 16 greater than 150°C. Those resources above 150°C are of commercial interest for the generation of electrical power. Twenty eight of the 62 identified resources are associated with the state's KGRAs. Of the 23 KGRAs, only 5 have no identified hydrothermal systems. Here "identified" is used in the context of having been included in the USGS assessment. (It should not be inferred that no resource exists if not listed in the USGS assessment.) These five include Bodie, Beckwourth Peak, Ford Dry Lake, Glass Mountain and Saline Valley KGRAs.

On the basis of its volcanic nature and the large number of lease applications, Glass Mountain KGRA appears to be a very promising geothermal area, but has yet to be completely assessed. There are thermal springs located near the Saline Valley KGRA. Bodie, Beckwourth Peak and Ford Dry Lake were established as KGRAs on the basis of overlapping geothermal lease applications. Based on the available USGS data, then, the identified electrical potential in the state is in excess of 19,000 MWe distributed in 9 KGRAs. These are listed in Table 3.2.

TABLE 3.2: CALIFORNIA KGRAs WITH IDENTIFIED ELECTRICAL ENERGY POTENTIAL

KGRA	Electrical Energy Potential (MWe for 30 years)
1. Mono-Long Valley	6100
2. Coso Hot Springs	4500
3. Salton Sea	2800
4. Lake City-Surprise Valley	2100
5. Geysers-Calistoga	1750
6. Heber	970
7. East Mesa	500
8. Brawley	330
9. Lassen	150
	19200

Source: N78-18528

There are large uncertainties in the resource estimates. It is im[illegible] to recognize that the USGS assessment was based on the limited data ava[illegible] at the time the survey was performed (prior to 1975). As the USGS has indicated (3), no single estimate of geothermal energy from a particular area included in the assessment should be relied upon as an established fact. For some areas the information was relatively good; for others it was very poor at the time the estimate was made. To illustrate the paucity of data, of the 46 identified resources with the temperatures between 90° and 150°C, 37 have limited extent data (i.e., subsurface areas and thickness) as do 8 of the 16 identified systems above 150°C.

While the estimated geothermal potential of the state is large, only a small fraction of that potential has been confirmed by deep drilling and reservoir confirmation tests. Table 3.3 summarizes by KGRA and subregion, the geothermal wells which have been drilled in the state (4)(5).

TABLE 3.3: GEOTHERMAL WELLS IN CALIFORNIA

KGRA	Total Wells
Geysers	
Geyser-Calistoga	
Main Field	213
Other	16
Knoxville	0
Little Horse Mountain	0
Lovelady Ridge	0
Witter Springs	0
Other	2
Imperial	
Brawley	6
Dunes	1
East Mesa	12*
Glamis	0
Heber	16
Salton Sea	28
Ford Dry Lake	0
Other	3
Eastern Sierra	
Bodie	0
Coso	1
Mono-Long Valley	13
Randsburg	1
Saline Valley	0
Other	2
Northeast	
Beckwourth	1
Glass Mountain	0
Lake City-Surprise Valley	9
Lassen	1
Wendel-Amedee	6
Other	2
Central Coast	
Sespe	0
Total	333

*Includes 6 Bur wells

Source: References (4)(5)

Two-th of the wells drilled are associated with the development of The Geyse am field. In the past few years, there has been limited exploratory drilling outside of The Geysers and Imperial Valley, due in a large part to limited leasing of promising federal lands. With the exceptions of the Geysers, Heber, Brawley, East Mesa, Salton Sea, Surprise Valley and Long Valley KGRAs, the existence and extent of geothermal reservoirs has yet to be confirmed by deep drilling. On the basis of the number of wells and reservoir assessment activities, it is estimated that on the order of 2100 MWe have been proven; 1200 MWe in The Geysers, 600 MWe in the Imperial Valley and less than 100 MWe in Long Valley and Surprise Valley as is indicated in Table 3.4. Additional resources can be inferred from the extrapolation of geologic and well data. It is the proven resource on which utility commitment is based.

TABLE 3.4: ESTIMATED PROVEN RESOURCE POTENTIAL

KGRA	USGS Assessment Data, MWe	Proven Resource, MWe*
Geysers Calistoga	1750	1200
Brawley	330	200
East Mesa	500	200
Salton Sea	2800	100
Heber	970	200
Mono-Long Valley	6100	300
Surprise Valley	2100	50
Coso	4500	50
Lassen	150	0
	19200	2100

*Considerably more resource potential can be inferred from the proven wells and geologic data.

Source: N78-18528

It is expected that further exploration will show a significant number of additional geothermal fields in the state with electric energy potential besides those listed. Further exploration also could considerably modify the estimates for the sites identified. Future discoveries, according to the USGS, could be possibly five times the volume and heat content of the high temperature systems (>150°C) already identified. These discoveries could result from:

(1) New knowledge of the extent of an already identified system that appreciably increases its estimated volume.

(2) The temperature of an identified system being higher than first estimated (enough possibly to raise some of the 46 moderate temperature resources into the higher temperature category).

(3) The discovery of a previously unknown system.

DEVELOPMENT OUTLOOK

The viability of the steam resources is well established; 502 MWe are on-line at The Geysers with utility plans to expand development to an estimated 2000 MWe capacity in the 1985 time frame. Development is paced by the resolution of the

H_2S emission air quality problem and the resolution of land use . Both are receiving concentrated attention. On the other hand, the viability of the hot-water resources is not established. Little of the hot-water resource potential outside of the Imperial Valley has been proven by deep drilling. Studies (6) show that the cost of power from the identified hot-water resources are not now competitive with alternative sources of energy. In addition, there are large uncertainties in cost and in understanding of performance characteristics which need to be resolved. As a result, there is only limited commitment to the hot-water resources at this time.

There are active research and development projects in the Imperial Valley to demonstrate the technology and to reduce cost and performance uncertainties. These include both test facilities and pilot plants. In addition, a commercial-scale, 50 MWe demonstration plant is under consideration. While these projects will contribute significantly to increasing user confidence, they in themselves will not be sufficient either to establish the viability of power generation from hot-water resources or to assure the necessary commitments to achieve growth.

Conditions on Commitment: The commitment of three primary groups is necessary to assure a rapid increase in geothermal electrical utilization growth; the exploration companies, the utilities and the public (and the regulatory agencies representing the public).

Because of the large associated costs, there is little incentive for exploration companies to pursue vigorous deep drilling programs without some assurance that the resource will be used in a timely fashion. There is only limited utility commitment to the use of geothermal energy outside of the economically attractive Geysers steam field. Therefore, one of the keys to increasing the exploration rate for the hot-water resources is increased commitment by the utilities. Utilities do recognize that the hot-water resources are potentially attractive sources of electrical power. Many are actively considering the geothermal energy option in their growth plans. However, because of the high projected costs and uncertainties, they are reluctant to commit at this time.

The use of geothermal energy is a new technology to most utilities and as a result, it poses significant economic, environmental, technical, and socio-political concerns and uncertainties as compared with established energy options. This is particularly the case with the hot-water resources and to some degree even with The Geysers steam field. The utilities do acknowledge the number of excellent supportive technology development programs and studies on the utilization of geothermal resources and that the results to date are very encouraging. However, such studies and technology development programs are not sufficient for utility commitment; the technical unknowns and economic and environmental uncertainties associated with geothermal energy are just too large at this time. The four major concerns are:

(1) Reliability of operation.

(2) Assurance of reservoir capacity and lifetime.

(3) Economics of a geothermal plant compared with alternatives.

(4) Confidence in development schedules (i.e., freedom from lengthy environmental and regulatory delays).

As a result, utility personnel concerned with geothermal energy generally feel that, outside of The Geysers steam field, geothermal energy will not be considered as ... le alternative to fossil-fueled and nuclear plants by a utility company's ... d of directors until its reliability and economics are proven by a full scale demonstration plant. Such a plant would help place the utilization of geothermal energy on an equivalent confidence base to those of oil, nuclear energy and coal. In addition, the utilities will require that reservoir capacity and lifetime for each geothermal power plant be demonstrated by deep drilling and confirmation tests prior to their commitment.

The third group which must also commit to geothermal developments is the affected public and the associated regulatory agencies. Many localities and regulatory agencies have limited experience with geothermal energy. As a result they are understandably reluctant to approve geothermal developments without knowing the potential impact. The universal desire on the part of those agencies and the local communities is that all geothermal development proceed in an orderly, controlled manner consistent with local desires; minimizing any potential adverse impact. Both the California Environmental Quality Act (CEQA) and the National Environmental Protection Act (NEPA) assure that such concerns are addressed and resolved in the regulatory/approval process.

COMMON REGIONAL DEVELOPMENT REQUIREMENTS

Reducing the Cost of Geothermal Power

The achievement of any growth scenario for geothermal energy utilization will be predicated on the fundamental assumption that the cost of power produced from geothermal resources will be competitive with the cost of power produced from coal-fired or nuclear plants. Comparative cost data are given in Table 3.5 (6).

TABLE 3.5: COMPARISON OF COSTS FOR FUTURE GENERATING FACILITIES (Constant 1976 Dollars)

Type	Estimated Total Capital Investment ($/kWe)	Estimated Price of Electricity at Busbar (mills/kWh)
Nuclear Power Plant (LWR)	720-830	29
Conventional Oil-Fired Power Plant (Low-Sulfur Oil)	350-400	34
Combined Cycle (Oil-Fired) Power Plant (Low-Sulfur Oil)	275-350	32
Coal-Fired Power Plant	570-600	29
Hydrothermal Power Plant		
Steam	250-280	20
Hot Water	520-800	47

Source: Reference (6)

While there is no unanimity of opinion among the various investigators who have estimated the probable cost of electric power from hot-water resources, the range of estimated power cost runs from 40 to 150% more than the cost from other energy alternatives on the basis of current policies and technology. There are, of course, large uncertainties in these estimates; no hard data exist on power plant costs for hot-water systems, or on field development costs. F... , the requirements of specific sites can introduce major differences in projected power costs from resources of similar characteristics.

Costs of Geothermal Power: The cost of geothermally derived power consists of two major components: (1) the power plant construction and operation cost, and (2) the fuel cost. The portion of the busbar cost of power ascribable to power plant construction and operations cost depends on the actual cost of construction, the fraction of this cost that is borrowed and the interest rate on the loan, the fraction that is invested from the utility's capital and the rate of return on that investment allowed by the regulatory agency, the period of amortization of the plant, the anticipated plant availability factor (i.e., the fraction of time the plant will be on-line), and the anticipated cost of operations. Each of these factors will vary for a given project.

Currently, there are no hot-water geothermal power plants in the United States on which to base either costs or plant availability. Foreign plants such as those in Mexico and New Zealand will be an aid to some technology development but will not yield usable costing data.

Estimates of the cost of construction of geothermal hot-water plants have varied widely, from as low as $150/kWe to as high as $750/kWe (7). SRI, in its economic analysis (6), assumed a figure of $650/kWe, which at a 15% rate of return, a 0.80 plant availability factor, and a 30-year plant lifetime, translates into a busbar power cost ascribable to power plant costs of 18.7 mills/kWh. For this analysis, JPL will assume a probable range of 18 to 24 mills/kWh for this portion of the cost of power.

The other part of the cost of power is ascribable to fuel costs, i.e., what the developer charges the utility for the geothermal fluids. This depends on an even larger and more uncertain set of factors: the per-foot cost of drilling, the depth and quality of the resource, the cycle efficiency of the power plant, the tax treatment of costs and revenues, the time between investment and start of return, the required rate of return, the anticipated life of a well, and the anticipated power plant availability factor.

The resultant wide spread in busbar cost of electricity ascribable to fuel cost is evident when busbar fuel cost is plotted versus flow rate for a variety of wellhead brine temperatures, for drilling costs of $400K, $600K, and $800K per well (6). The data illustrate the variability of potential resource cost and also the importance of achieving low well costs and high flow rates for the lower temperature resources. For the assumptions used (a rate of return of 20%, plant availability factor of 0.75, and 1977 tax policy), costs range from a low of about 15 mills/kWh for an exceptionally good well (275°C, 700K lb/h, 11.6 MWe) in an area easy to drill ($400K/well) to about 30 mills/kWh for what might be considered an average well (200°C, 500K lb/h, 3.9 MWe) in a moderately difficult drilling region ($600K/well), to over 70 mills/kWh for a poor well (175°C, 300K lb/h, 1.7 MWe) in a difficult drilling region ($800K/well).

To quantify the problem somewhat more, JPL has made a rough estimate of the cost-of-power range that might be expected for the various scenario prospects in the state, using relatively optimistic assumptions on flow rate and temperature. Because the resources in many of these areas are not yet confirmed by deep dr' and in the other areas well data is held proprietary, these estimates are perh. ...tter described as guesses, but they serve a useful illustrative purpose.

The assumptions used and the resulting power costs are presented in Table 3.6. Clearly, based on these assumptions, none of the hot-water resources are presently competitive with the other energy alternatives. Given that the assumptions prove valid, the cost of hot-water electric power will have to be reduced at least 10% to bring any hot-water resources to a competitive price, and by as much as 58% to bring all of the estimated resources into the competitive range.

TABLE 3.6: GEOTHERMAL ENERGY COST OF POWER ASSUMPTIONS

	Temperature (°C)	Flow Rate (klb/hr)	Power Plant Cost ($/kW)	Field Cost (k$/well)	Cost of Power (mills/kWh)
Salton Sea	300	500	low 500	500	33
Brawley			high 750	700	45
Mono-Long Valley	220	500	low 500	600	42
Coso Hot Springs			high 750	800	55
Lassen					
Heber	190	500	low 500	400	40
East Mesa			high 750	600	56
Geysers Hot Water	200	500	low 500	600	46
Glass Mountain			high 750	800	62
Diablo					
Surprise Valley	175	500	low 500	600	54
Wendel-Amadee			high 750	800	71

Source: N78-18528

Potential Actions to Reduce Costs: The cost of electric power produced from geothermal resources is determined by a number of factors, including most prominently:

(1) Power plant cost.
(2) Cost of field discovery.
(3) Cost of field development.
(4) Tax treatment of these costs.
(5) Tax treatment of revenues.
(6) Operations and maintenance cost.
(7) Plant availability factor.
(8) Investor rate of return.

Various action alternatives are available. They include reducing the basic costs themselves through improved technology, or reducing the impact of those costs on the price of power through tax treatment of costs and revenues and investor rate of return. These alternatives have varying lead times, price tags, effectiveness in stimulating investment in geothermal enterprises, and probability of success. A discussion of these alternatives follows.

Reducing Power Plant Costs — Power plant costs, according to the SRI report (6), can be expected to be about 40 to 45% major machinery costs, and 55 to 60% in engineering, field construction, and miscellaneous items such as piping, electrical wiring, meters and controls, etc. The latter costs are unlikely to be affected by R&D activities. Machinery costs could conceivably be reduced by the development of improved components, but until a plant is built and operated, true costs will not be known, and the impacts of hypothetical improvements will not be readily assessable. Consequently, R&D aimed primarily at reducing power

plant capital cost in itself is likely to prove ineffective in influencing ...ent conceptions of the future cost of geothermal power, and therefore present investment decisions.

Reducing the Cost of Field Discovery — The costs associated with discovering and proving out a geothermal field are estimated to contribute no more than 10 to 15% of the eventual cost of power. R&D efforts to improve exploration and reservoir assessment technology, while important for other reasons such as increasing investor confidence, or reducing regulatory agency workloads, cannot have more than a minor direct impact on the cost of power.

Reducing the Cost of Field Development — The cost of field development is a major contributor (30 to 50%) to the cost of power, and is amenable to reduction in a number of ways:

(1) Increased power plant cycle efficiency would reduce the number of wells required to support a power plant. R&D on improved heat exchangers, prime movers, and condensers could increase cycle efficiency as much as 20%, with a corresponding reduction in the number of wells required. Such technology will be expensive to develop and demonstrate on a commercial scale, and would probably not see commercial use before 1985. Post-1985, it should play a major role in making marginal fields economically attractive.

(2) Increasing the flow rate per well would also reduce the number of wells required to support a power plant. Where well flow rate is limited by formation permeability, well stimulation techniques can be developed. R&D efforts are being directed toward their development. Stimulation of geothermal wells is a unique problem, however, quite different from oil well stimulation, and the date such techniques might become available is difficult to predict. Where well flow rate is instead limited by choking in the borehole, development of suitable down-well pumps may provide a solution. DOE has been actively developing such pumps, and one has already been tested at Heber. It would not seem overly optimistic to count on the availability of such pumps by the early 1980s.

(3) Decreasing the time required for drilling would proportionately reduce the intangible element of drilling costs, estimated to be 50 to 70% of the total cost of field development. Improved drill bits, muds, and associated equipment can be developed within the R&D program, and would reduce drilling time. These improvements could be available by the early 1980s.

(4) Decreasing the manpower required through automation of the drilling process would have a similar effect on the cost of field development. Such a development would be difficult and expensive, and, if pursued, would probably not be available for widespread use before the late 1980s or 1990s.

R&D efforts are ongoing in almost all of these areas. While it is difficult to schedule advancements in technology, it is a reasonable assumption that, if the R&D program is vigorously pursued, a 20% reduction in field development cost should be achievable by the early 1980s, and a further 20% reduction by the late 1980s.

Changing the Tax Treatment on Costs — The allowance of the intangible drilling cost write-off for geothermal wells has the immediate effect of reducing that portion of the cost of power attributable to field development by 14 to 21%, depending on the percentage of the total cost written off. (14% corresponds to 50%, 21% to 70% intangible.) This measure is particularly attractive in that it provides more capital for exploration and is an important step in making geothermal energy resources competitive with other energy resources.

Changing tl... Treatment on Revenues — Provision of a 22% depletion allowance for ge... mal wells has the immediate effect of reducing that portion of the cost of power attributable to field development by about 17%, assuming a corporate income tax rate of 48%.

Operations and Maintenance Costs — Operations and maintenance costs represent 10 to 15% of the estimated cost of power. It is not anticipated that R&D will significantly impact these costs.

Plant Availability Factor — The cost of power is inversely proportional to the availability factor. Any increase in the availability factor directly reduces power cost. What the availability factor will be, however, will not be known until some operating experience with commercial geothermal power plants is obtained. R&D on the chemistry and mechanics of scale formation and scale control, on components and materials with improved lifetimes in geothermal environments, on scale removal, and on other related areas can be expected eventually to bring this factor up to the 80% range presently experienced at The Geysers. The present uncertainty in this factor is a major deterrent to utility commitment to hot-water geothermal power plants (and a major argument for the need for a cost shared demonstration plant).

Investor Rate of Return — The rate of return required by an investor is a major factor in the cost of power. In the case of the utilities, this is set by the Public Utility Commission (PUC). In the case of the field developers it is not rigid, but will vary according to the perceived risk of the enterprise, and the rate of return available from alternative investments. Most projections of the cost of geothermal power assume a 20% rate of return required on developer investments; this reflects a relatively high perception of risk. The actions discussed that tend to reduce the risk associated with geothermal investment and increase confidence will have some influence on the acceptable rate of return. If the acceptable rate of return could be reduced to 15%, it would decrease the cost of geothermal fuel by about 25%.

Reducing Performance and Cost Uncertainties—Liquid-Dominated Resources

The Need for a Demonstration Plant: There are considerable differences in the designs and operations of a geothermal plant using the relatively pure dry-steam resources of The Geysers and one using the hot-water resources. First hot water contains less available energy per pound than the steam, requiring more hot-water than steam for a given electrical output. Thus, a plant using hot-water operates at lower efficiency and is much more sensitive to variations in well and component (i.e., heat exchangers, pumps, turbine, condensers, etc.) performances.

Second, the dissolved solids in the hot-water present a much more severe corrosion and scaling environment which could reduce both component and well lifetimes and thus the plant availability factor.

Third, the behavior of the reservoir is expected to be different from the pure steam field experience and much more subject to plugging. There have been a number of design studies on the use of hot-water resources with wide variations in results. No commercial-scale generating plant has been built in the United States using these resources, although foreign plants such as those in Mexico and New Zealand may be of some usefulness.

a result of the large performance and cost uncertainties associated w... g the hot-water resources utilities are understandably reluctant to commit ... eir use without a full-scale commercial demonstration.

Demonstration Plant Design Alternatives: There have been considerable differences of opinion on the technology that should be used for a hot-water plant: flashed steam or binary. The flashed steam process is the most commonly used around the world and is based on technology such as that demonstrated at The Geysers. A mixture of brine and steam from the production wells enters the high pressure flash vessel where the pressure is reduced causing an additional fraction of the brine to vaporize. The brine and steam are then separated. The brine enters a low-pressure flash vessel where the pressure is further reduced thus generating more steam. The remaining brine and cooling-water blow-down are then reinjected.

The steam from the two flash vessels is introduced into a two-stage steam turbine and then is condensed. The condensate is returned to atmospheric pressure for use in the cooling tower. Performance uncertainties are based on such considerations as energy losses from in-well flashing of the brine and the effect of the corrosive brines (compared to pure steam) on component and turbine lifetimes. High noncondensable gas content could reduce the cycle efficiency sufficiently to preclude the economic use of a flashed steam process.

The binary system was conceived to get around the limitations of the flashed steam system. It uses the well flow to heat a separate, organic working fluid, such as isobutane, operating in a closed-loop Rankine cycle. The hot-water is pumped to the surface to prevent in-well flashing (and potentially large energy losses) circulated through the heat exchanger and reinjected into the reservoir. The heated working fluid is expanded through a hydrocarbon turbine, condensed and pumped back through the heat exchanger. Because the noncondensable gases are not circulated through the turbines they do not reduce turbine efficiency.

The advocates of the binary process feel that the substantial down-well pumping power requirements are more than offset by increased well flow rates and by much higher well head temperatures. Their studies show that the binary cycle is particularly promising for those resources with temperatures less than 200°C. It should be noted that the binary cycle involves more new technology than the flashed steam system and has yet to be demonstrated on a commercial scale (i.e., >50 MWe) anywhere in the world. Critical new technology includes the down-well pumps, efficient heat exchangers and the hydrocarbon turbine.

Demonstration Plant Siting Considerations: For a plant to be operational by 1981 it must be built on a proven resource. Over the past two years Electric Power Research Institute (EPRI) has been sponsoring a series of studies for site selection and design options for such a demonstration plant. Their studies showed that adequate resource data existed only for Heber in the Imperial Valley in California and Valles Caldera, New Mexico. However, as a result of more recent development Roosevelt Hot Springs in Utah and East Mesa in the Imperial Valley could also be considered as potential sites. Both Valles Caldera and Roosevelt Hot Springs have temperatures greater than 220°C. Both are associated with volcanic structure.

On t... ..her hand the temperatures of both Heber and East Mesa are near 190°C and are associated with sedimentary basins. Because of the differences in geologic structure and water temperatures it is questionable to what degree the technology and reservoir characteristics demonstrated at either Valles Caldera or Roosevelt Hot Springs would be applicable to the resource development in the Imperial Valley. (The results from a demonstration plant at either Roosevelt Springs or Valles Caldera might be very pertinent to geothermal developments at The Geysers, Long Valley or Coso Hot Springs which appear to be similar in resource characteristics.)

One of the difficulties with data correlation from site to site is that flashed steam technology could well be utilized at Roosevelt Hot Springs or Valles Caldera, while at the lower temperature of 190°C binary cycle technology would be required if the resource is to be economically competitive. The EPRI studies and subsequent analysis by SDG&E favor the binary cycle for Heber. [See "Heber, Valles Caldera and Raft River Comparison Studies."]

Demonstration Plant Support Recommendations: Because of the differences in reservoir properties and required technologies for the available sites (i.e., Heber and East Mesa as compared with Valles Caldera and Roosevelt Hot Springs) a demonstration plant with the characteristics of East Mesa or Heber is critical to the rapid development of the hot-water resources in the Imperial Valley, The Geysers, and subsequently in the remainder of the state. (SDG&E recently announced that it has signed a letter of understanding for the construction of a 50 MW plant to be located in the East Mesa Field.)

EPRI has sponsored design studies which support the development of a 50 MW binary-cycle demonstrations plant at Heber in cooperation with the San Diego Gas and Electric Company. According to SDG&E analysis the cost of construction of a 50 MW demonstration plant and its subsequent operation over a five year period would be in excess of $100 million. During the early years of plant operation it is expected that there will be considerable periods of time when the plant will be shut down for repair, retrofitting and special tests. As a result the cost of power from the plant during the early years of operation will be in excess of 100 mills/kWh. As problems are resolved and the availability factor increases the cost of power will drop. The categories of risks that could affect the plant availability include:

(1) Brine Supply
- (a) Reservoir productivity.
- (b) Well casings.
- (c) Down-hole pumps.

(2) Power Plant
- (a) Turbine-generator development.
- (b) Turbine-generator control.
- (c) Organic working fluid containment.
- (d) Scaling and corrosion.
- (e) Extended start-up.

The magnitude of the investment, the poor economics, and the technical risks associated with such a plant are too large for any one utility to absorb in its rate base. SDG&E feels that it is essential to spread the costs and risks of such an undertaking over a wider segment of the public than their immediate customers since all electricity users stand to benefit from a successful demonstration of geothermal energy. For these reasons SDG&E has been seeking support of up to 50% of the construction and operation costs from the federal or perhaps state government. Possible vehicles for this support are the DOE Demonstration Program and/or a special subsidy from the California Legislature.

Joint state-federal sponsorship of the demonstration project would provide a clear signal, not only to the utilities but also to the exploration companies, that there is a serious commitment by both levels of government to establish the commercial viability of geothermal energy. Finally, as indicated in the SRI analyses, a government supported demonstration plant would have two pertinent effects:

(1) It would ensure that commercialization decisions are not delayed by unresolved uncertainty about future costs.

(2) It would alleviate the problem of asking electricity consumers in a limited area to bear the costs of demonstrating a new technology that will benefit a larger group.

Streamlining the Environmental Review and Permitting Process

The Existing Process: Regulatory Requirements — The California Environmental Quality Act (CEQA) of 1970 and the National Environmental Policy Act (NEPA) of 1970 require environmental impact reports on any project which may have a significant effect on the environment. Air and water considerations are required under the Federal Clean Air and Water Quality Acts. Other environmental impacts also are covered including: flora and fauna (covering endangered species), archaeological, erosion, roads, seismic and tsunami impacts, land subsidence, noise, etc.

Because geothermal energy must be utilized essentially in situ, the approval of the drilling of a single well, if successful, implies the subsequent construction of a power plant. Thus, the application for drilling permits on private lands or the leasing of state and federal lands have caused the responsible local, state and federal agencies to prepare an Environmental Impact Report (EIR) under CEQA and an Environmental Analysis Report (EAR) or an Environmental Impact Statement (EIS) under NEPA. These reports consider not only the impact of the initial exploratory drilling project, but also the potential future development of a full power plant with the attendant total environmental review process.

On private and state lands the California Appellate Court has ruled that the EIRs on exploratory wells need not consider the impact of full development but just the environmental impact of the exploratory operations. On federal lands the Forest Service and Bureau of Land Management are considering an approach which would allow applicants the options of a lease without a pre lease environmental review with a stipulation that no surface occupancy can take place until the environmental review of such occupancy has been conducted.

Environmental impact considerations may apply again at the time of exploratory or characterization drilling permits or at plant certification reviews.

Responsible Agencies — The environmental review and permitting processes involve a multiplicity of federal, state and local agencies. In general, two levels and often three levels of government can be involved in the review and regulation of a given project. The public is involved and concerned at all steps with the right and power to act at any time through public and political pressure and through the courts.

Environmental documents must be prepared by two lead agencies: one for the exploration phase and one for the power plant with review of the document by both responsible and reviewing agencies. The lead agency has the principal responsibility for preparing environmental documents and for carrying out or approving a project which may have significant effect on the environment; responsible agencies have an approval right; reviewing agencies comment only.

Responsible agencies are required by law to review and certify the document's adequacy. They apply their own standards and require specific information necessary to satisfy their own regulations and permit requirements. If a responsible agency does not accept the lead agency's environmental document, it can require the preparation of additional information and further public review before approving the project and issuing a permit. Ideally, early consultation between responsible agencies and the lead agency should eliminate this need. Reviewing agencies review and comment (only) on environmental documents from their own specific areas of expertise.

At the local level other interested parties including members of the resident community and environmental groups may review and comment on geothermal projects through the public hearing process.

Numerous permits, which also require interagency review, are also necessary in addition to the environmental document. The primary permits include: the county land-use permits; the local Air Pollution Control District (APCD), Authority to Construct and the Permit to Operate; Regional Water Quality Control Board (RWQCB) waste discharge requirements; and the various drilling permits for each phase of resource development.

Lead Agencies — For geothermal exploration on private lands the appropriate county acts as lead agency responsible for the preparation of an environmental document as a condition of its land use permit for a given project. For exploration on state lands, the State Lands Commission (SLC) has lead agency responsibility. On federal lands the managing land agency is responsible; primarily the Bureau of Land Management (BLM) and United States Forest Services (USFS).

Drilling permits and operations are the responsibility of the Department of Oil and Gas (DOG) on private and state lands and the USGS on federal lands; they also require interagency review. The California Energy Resources Conservation and Development Commission (CERCDC) is the lead agency for the construction and operation of geothermal power plants on state and private lands. On federal lands this responsibility may be shared between CERCDC and the appropriate federal agency.

The process of environmental review under the protective acts is relatively new and in many localities geothermal development is pioneering its application. It is not surprising that there are growing pains and some apparent confusion in its early use.

Development Sequence — The general phases of the plant development cycle may be summarized as follows:

(1) Assessment and Land Acquisition: General geophysical assessments for likely prospects are made by industry or government followed by the acquisition of development rights. Environmental background data is collected and an EIR, EAR or EIS is prepared as appropriate for state, federal or private lands. Following environmental review the land is leased (federal or state) or exploratory drilling may start (private).

(2) Exploration: Drilling permits are obtained with appropriate review for exploratory drilling. For private land the EIR is approved at this time. Exploration deep-drilling proceeds. Usually several wells are required.

(3) Resource Characterization: Following a successful discovery, permits for resource characterization drilling and testing are obtained. Drilling and testing proceeds to determine the magnitude and characteristics of the resource. Utility commitment for commercial resource development is sought.

(4) Plant Certification: The developing utility seeks approval of the power plant addition. Included are the Notice of Intent (NOI) and Application for Certification (AFC) reviews. Generally, detailed plant design and the application for the field development permits proceed in parallel.

(5) Plant Construction: Production wells are drilled and the power plant is constructed.

The key regulatory steps are:

(1) The environmental review (EIR, EAR or EIS) and associated land use permits.

(2) Drilling permits for exploration.

(3) Drilling permits for characterization.

(4) Plant certification (NOI and AFC reviews), and drilling permits for production.

If the various reviews go smoothly (which generally has not been the case), the first plant can be brought on-line in approximately 8.5 years on private lands and 9.5 years on federal lands. The exploratory drilling and plant construction require 6 years. The various approvals and reviews account for the additional 2.5 to 3.5 years. The approvals can and have taken even longer.

Permitting Delays: For various reasons the regulatory process is arduous and time consuming. It is cited by industry as one of the main causes for the lack of geothermal energy development today. They would like to see it streamlined. The following are some of the reasons for delay:

(1) Interagency Coordination: With the multiplicity of agencies there are questions of jurisdictional authority and coordination associated with geothermal energy development. Each agency has responsibilities established by law. However, no agency has the duty or authority of coordinating the requirements of other agencies. Resulting delay is manifested in both multiple agency reviews of single regulatory steps and in the differing requirements of the various agencies associated with a prospective development area.

(2) Agency Resource Limitations: The preparation of a complete and detailed EIR, EIS or EAR places a heavy load on the resources (both manpower and dollars) of the lead agency which can result in a delay in completion of the review. Lack of clarity in priorities can compound the resultant delays. On private land the delay will occur when applying for an exploratory drilling permit or alternately on application for characterization drilling; on state or federal land it will occur prior to leasing or prior to characterization drilling. The agency resource problem is compounded on federal lands where the responsible agency may now be required to make a complete land management study of the entire area to be leased (Federal Land Policy and Management Act of 1976).

(3) Limited Environmental Background Data: Environmental review has been hampered by limited data on the resource itself and its environmental effects.

(4) Unclear Requirements: In many cases the requirements of the various agencies are nonstandardized, unclear and uncoordinated. Additionally, more data may be requested several times during the review process.

Impact of Permitting Delay: Even with the current low level of development in the state, the existing review requirements have saturated the limited staffs of the involved agencies and industry alike. However, if geothermal energy is going to be brought on-line at an increased rate, there will be a significant increase in lease applications, environmental reviews, drilling permits and notices of intent for power plant construction. If streamlining actions are not taken, the regulating process itself will be the factor that seriously constrains the geothermal energy growth rate.

For the most part industry is not seeking to avoid environmental requirements. Instead, they would like to see these requirements defined (and, if possible, standardized) so that they can take the necessary steps to comply and get on with their project. Industry is seeking assurance that these projects will be reviewed and acted on in a timely fashion. To this end members of industry have indicated that they would like to see some form of control over the regulatory process involving some or all of the following:

(1) Dealing with only one agency at each jurisdictional level.

(2) Each agency with geothermal jurisdiction to "show cause" why they should have such jurisdiction.

(3) Institution of a maximum time limit for processing permit applications, with extensions only for cause. (California has passed AB 884 which establishes time limits for decisions by responsible agencies.)

(4) A clear definition of data requirements.

(5) Concurrent permit application processing by each geothermal entity.

Permitting Program Recommendations: There is a general recognition and desire by the parties involved, both the agencies and industry, that the problems with the current regulatory-permitting process should be resolved. In November of 1976 the first step to this end was taken by the convening of a State-Federal Geothermal Regulatory Interface Workshop at Asilomar, California. Representatives of industry and local agencies also were in attendance. Topics covered included environmental reviews, well operations, power plant siting, nonelectric projects and water and air quality regulations. The workshop developed recommendations on improving the permitting process.(8).

Based on the results at Asilomar, two classes of actions are recommended: one directed at streamlining the permitting process and the second directed at developing the environmental data and criteria necessary to speed evaluation of the proposed projects.

Streamlining — First, it must be recognized that the agencies now involved in regulating geothermal development generally have jurisdictional authority and responsibility, established by law. As a result, in the oft-times proposed, one-stop permitting process is not feasible. Streamlining the process, if it is to occur, must be based on the knowledgeable cooperation and consent of the responsible agencies. To this end it is proposed that a joint state-federal interagency permit-

associated with the complete development process from 2.5 to 3 years to less than 1 year.

Environmental Data — The second set of actions is directed at gathering the environmental data necessary to evaluate the potential impact of the proposed development in a timely fashion. Development is paced by the need to gather the necessary environmental baseline data which takes over a year or more. Imperial County presently is completing a two year project directed at gathering the necessary baseline and environmental effects data which will allow them to act on geothermal developments without additional major delays. The four counties at The Geysers have requested federal government support for a two year program in that area. It can be anticipated that other areas will have similar needs. The cost of gathering the necessary environmental baseline data is high and generally beyond the means of local agencies. It has been suggested that the state and federal government subsidize the gathering of much of this data.

Finally, because of the need for environmental effects data throughout the state, it is suggested that a centralized source of geothermal environmental data be established and charged with the responsibility of gathering, indexing and distributing data from published reports, EIRs, etc. A centralized source will be effective only if it is responsive to user needs and can supply the needed data in the form required for timely decision making by the regulatory agencies.

Accelerating the Leasing of Federal Lands

Current Leasing Status: Timely access to the potential geothermal resources on federal lands is important to the state. Of the 1,400,000 acres of KGRA lands within the state 55% are under federal jurisdiction. It is estimated that the largest fraction of the state's geothermal potential and many of the more promising sites are on these federal lands. In the Geothermal Steam Act of 1970 Congress provided for geothermal leasing and development of federally administered lands. Under the act those lands associated with KGRAs are subject to competitive lease sales; the remainder to noncompetitive leasing.

However, the leasing of these lands has been slow. Regulations implementing the act became effective in January 1974. To 1977 only 109,000 acres consisting of 60 tracts in four of the state's KGRAs have been offered for competitive lease sales. Bids have been received and accepted on 26 tracts consisting of 36,600 acres. The KGRA lands leased are administered by the BLM; none are USFS lands. There have been 995 noncompetitive lease applications in California; 287 have been rejected and only 10 issued.

The process of issuing a lease on federal lands can take on the order of 28 months. A year is required to gather the necessary environmental background data for the lease block under consideration. Next an Environmental Analysis Report (EAR) is prepared, with appropriate federal agency input, which evaluates whether the proposed leasing and subsequent geothermal development would be done in keeping with established environmental and regulatory standards. In environmentally sensitive areas the EAR is generally not an adequate assessment and a more detailed EIS would be required. The EAR or EIS is then subject to public and further agency review and leasing stipulations prepared. This process determines if and where leasing of the lands included in the study area are to occur. (Normally only a fraction of the lands studied are offered for lease.) With the approval of the EAR or EIS lease sales are then held. As has been the case to date the process can be drawn out substantially where potential leasing activities have been challenged by the public as well as by the reviewing agencies.

The leasing process is time consuming and requires a substantial commitment of manpower and money. Geothermal leasing is just one of many of the responsibilities of the two key federal agencies; the BLM and USFS. In addition, it does not seem to have high priority. As a result leasing is hampered by the limited staff and funding within these agencies.

Scenario of Federal Leasing Requirements: Table 3.7 summarizes the leasing schedule requirements for JPL power and development projections (scenarios) and associated acres. (Acreage requirements assume 2,500 acres are required for each potential 200 MWe site and 10 potential sites are required for each successful site. On subsequent expansion of power resources it is assumed 5 potential sites are required for each successful site.)

TABLE 3.7: SCENARIO OF FEDERAL LEASING SCHEDULE

	Required Lease Date	Required Acres
1st Priority		
Long Valley "Grandfather" (USFS)	April 1978	20,000
Coso Hot Springs (USN/BLM)	November 1978	45,000
Geysers "Homestead Lands" (BLM)	January 1979	5,000
East Mesa Additions (BUR/BLM)	July 1979	17,000
Glass Mountain (USFS)	April 1980	45,000
Lassen (USFS)	April 1980	45,000
Wendel Amedee (BLM)	April 1981	4,000
2nd Priority		
Long Valley-Mono Additions (USFS)	April 1981	60,000
Glamis, Dunes, Ford Dry Lake (BLM)	June 1981	30,000
Beckwourth, etc. (USFS)	April 1983	75,000
Knoxville (BLM)	April 1984	25,000
Randsburg, Bodie, Saline Valley (BLM)	April 1984	25,000
Witter Springs, Cow Mountain (BLM)	April 1986	26,000
Lovelady Ridge, Little Horse Mountain, etc. (USFS/BLM)	April 1987	50,000
		416,000

Source: N78-18528

The first priority sites include those located primarily in the Eastern Sierra and Northeast subregions which are recognized as having large potential. Their development forms the basis for the large increase in geothermal power generating capacity in the post-1985 time period. Also included are 5,000 acres of homestead lands in The Geysers steam field which have been until recently tied up in litigation and Bureau of Reclamation (BUR) lands at East Mesa which are immediately adjacent to the Republic leases. The second priority sites include those with undefined resource potential and those which are smaller in size.

Their development would contribute to power on-line in the post-1[illegible] time period. At a recent meeting (9) with DOE and the BLM, USFS, and USGS the priorities and schedules derived from the scenarios were adopted as program goals.

Federal Leasing Program Recommendations: The timely leasing of the federal lands, particularly in the Eastern Sierra and the Northeast subregions, can be critical to establishing a significant geothermal energy option in California. A substantial increase in leasing activity can be realized providing:

(1) The leasing of geothermal lands in California receives a much higher priority within the BLM and USFS.

(2) The budgets and staffs of the responsible agencies are increased.

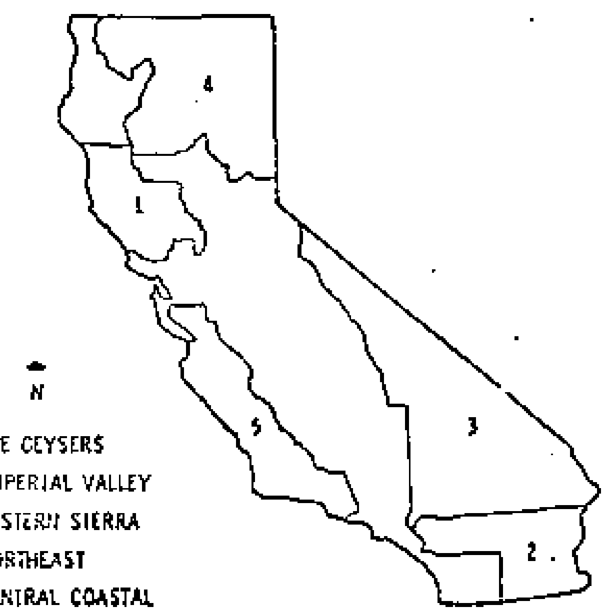
(3) Leasing priorities are based on resource potential.

(4) Compliances with other requirements (e.g., National Forest Management Act and the Wilderness Act) are not allowed to delay leasing activities.

SUBREGION DEVELOPMENT

The five geothermal resource subregions discussed below are shown in Figure 3.1.

FIGURE 3.1: GEOTHERMAL SUBREGIONS OF CALIFORNIA



Source: N78-18528

The Geysers Subregion

The Geysers subregion has the estimated potential of contributing over 2000 MWe of electrical generating capacity to the state's energy needs by 1985, 2650 MWe by 1990 and over 3600 MWe by the year 2000. Through 1985 most of the contribution will be from the steam resources. Post-1985 growth will be dependent on the development of the potentially large hot-water resources.

The subregion includes The Geysers-Calistoga, Lovelady Ridge, Knoxville, Little Horse Mountain and Witter Springs KGRAs and is located in portions of Colusa, Lake, Mendocino, Napa, Sonoma and Yolo counties about 120 kilometers north of San Francisco. The five KGRAs consist of about 420,000 acres with close to 380,000 in the Geysers-Colistoga KGRA. Over 300,000 acres are state and private lands. Of the 40,000 acres associated with the four smaller, outlying KGRAs approximately 22,000 acres are under BLM and USFS jurisdiction. There are considerably more federal lands outside the KGRAs under noncompetitive lease application. It is estimated that there are over 100,000 acres of land currently under lease in the subregion.(10).

The main Geysers field, in the Geysers-Calistoga KGRA, is a relatively unique dry steam resource with an estimated potential which could exceed 2000 MWe. Commercially, it is very competitive right now with other sources of energy. This is reflected in the high industrial interest and development of the field. Resource development has been underway for over 15 years. Over 200 geothermal wells have been drilled. When the Pacific Gas and Electric Company's unit 11 came on-line in 1974 it raised the installed electrical capacity to 502 MWe making it the largest geothermal installation in the world. The company has plans to add another 1396 MWe of capacity by 1985.

The California Department of Water Resources and the Northern California Power Agency are also interested in obtaining electric power from the Geysers region. There are strong indications that significant hot-water resources also are present in the subregion. A well at Sulphur Bank Mine produced hot water at a temperature of 186°C at 1,520 meters (11). The USGS lists numerous hot springs in the greater Geysers area. However, the extent of the hot-water resources has yet to be proven by deep drilling.

In recent years development at the Geysers has slowed. Unit 12, the first addition to be sought after the provisions of CEQA had gone into effect suffered considerable delays while the procedures and data requirements for the issuance of the necessary permits were being defined and the problems associated with hydrogen sulfide abatement were being resolved. In 1976 the development process was resumed and authority was granted to PG&E for units 12, 13, 14 and 15. The last of these units approved, unit 14, is expected to be on-line in 1979.

H_2S abatement has been a serious problem holding up the further expansion of The Geysers. An iron catalyst system was installed on unit 11. PG&E has initiated a retrofit program on the remainder of units 1 through 12. New processes will be installed on succeeding units. Under the Northern Sonoma County Air Pollution Control Districts (APCD) rule 56.1 enacted in 1976 (12), H_2S emissions in the current Geysers field, which were 1670 lb/h, must be reduced to 850 lb/h by December 31, 1978. Emission standards after 1979 will be determined by the district by December 31, 1978, based on a review of air quality, emissions

and meteorological data available at that time. It is important to the expansion of the steam field and the hot-water fields that these abatement programs be successful.

PG&E expansion plans originally were based on units 16 and 17 to be on-line by 1980. However, because of the delays associated with the approval of units 12 through 15 and the H_2S abatement problems they have slipped their schedule to 1981. The maintenance of the new schedule requires that applications for approval of units 16 and 17 be granted in 1979 (assuming successful resolution of the abatement problem). The geothermal resources for these two units have been proven.

The geothermal exploration for the further expansion of the steam field has concentrated on the Cobb Mountain area closest to the existing Geysers field in Lake County and in Sonoma County south of the current field. Most of the lands associated with the main Geysers field have been leased. There are, however, approximately 5,000 acres of federal homestead lands in this area to which the BLM has given high leasing priority. Because of the lack of resource assessment data there is uncertainty as to the need date of the leasing of the federal lands in the four outlying KGRAs. To have to lease all of the federal lands in these KGRAs on a short schedule is a real concern to the BLM and USFS for as many as 10 separate EISs could be required to lease the federal lands; more than their staff could handle (13).

There is a real possibility that all development activities on the further expansion at The Geysers could come to a complete halt. In recent years environmental concerns and land use conflicts have slowed the extension of The Geysers field into Lake County, a prime recreational area. Many of the residents and local regulatory agencies feel that the technology employed at The Geysers has been destructive of air quality, water quality, wild life habitat, and the landscape. A key issue in the subregion is the abatement of H_2S. Persons living downwind of the existing power plants complain of the rotten eggs aroma of H_2S and the noise of well testing. Another key issue is local control over development out of fear that:

(1) In the absence of a land use plan, economics will rule geothermal development with no consideration for the quality of life and no protection for sensitive ecological areas.

(2) Local viewpoints and inputs are not being heard or considered throughout the governmental review and approval process.

(3) Environmental laws are being ignored or are not being properly implemented.

(4) Potential nonelectric applications in their area will be ignored.

ı the spring of 1976 residents in the area formed the Lake County Energy ouncil, dedicated to the "intelligent development of energy resources in the ounty" (14). Membership now numbers more than 1,400 persons. During ıe summer of 1976 the Council instituted a lawsuit against proposed expansion ı Mt. Knocti. Many people in the area would favor delaying geothermal development until environmental concerns are resolvable.

ıe Department of Fish and Game has similar concerns relative to the protecon of wild life habitat and extensive fisheries in the area. The residents in the area, as represented by the Lake County Energy Council are disposed to go to court, as they have demonstrated, to obtain "controlled, intelligent" development.

The local agencies in general are hampered by an inadequate environmental base to support the timely analysis of proposed geothermal developments. To compound the problem these agencies are further hampered by both limited manpower and fiscal resources. A case in point is the current lack of adequate baseline meteorological data, ambient H_2S atmospheric data and reliable evaluation models for the local air pollution control district to monitor air quality and make projections necessary to assure that air quality standards will not be adversely affected by proposed developments.

Four counties in the subregion (Lake, Sonoma, Napa and Mendocino) have joined together and have initiated a Geothermal Resource Impact Projection Study (GRIPS) which will be the basis of reconciling geothermal development with other important land uses. CERCDC and DOE have provided funds and staff support for the initial phase of the GRIPS study. A part of the study is the development of needed environmental baseline data. The completion of this study is critical to avoiding further development delays in the subregion.

The Imperial Subregion

This subregion contains seven KGRAs: Brawley, Dunes, East Mesa, Ford Dry Lake, Glamis, Heber and Salton Sea. All are in Imperial County except Ford Dry Lake which is in the southwest corner of Riverside County. The geothermal resources of the Imperial subregion have the potential of beginning to contribute significantly to the state's energy needs by the mid 1980s.

Geothermal development activity is high in the Imperial Valley. The University of California at Riverside has conducted an active exploration program in the region since the early 1960s. Close to 70 wells have been drilled. As a result considerable data is available on the resource potential at Heber, Brawley, East Mesa and the Salton Sea KGRAs. These four KGRAs consist of over 220,000 acres of which 170,000 acres are private or state lands. The federal lands are located at East Mesa and the Salton Sea. It is estimated that over 140,000 acres currently are under lease by industry in the area including 12,000 acres of federal land at East Mesa.

Resource development at Heber is further advanced than any other hot-water resource in the state. Over 16 wells have been drilled and the resource has been estimated to be sufficient to support at least 800 to 900 MWe of electrical capacity for 30 years. The resource temperature is 190°C and of low salinity (i.e., <14,000 ppm). Four exploration companies are active in the Heber area: Chevron Oil, New Albion Resource Company (NARCO), Magma Power and Union Oil. Development of the resource dates back to August of 1973 when NARCO, Magma and Chevron Oil agreed to join in a test program to evaluate the potential for commercial development of the Heber field.

Because of the lower temperature of the reservoir (compared with Niland) the geothermal fluid must be pumped to the surface to maintain a sufficiently high flow rate and wellhead temperatures for efficient conversion. In 1974 installation of deep well pumps was completed and pumping and reinjection operations

were initiated by Chevron. Heat exchanger tests, supported by EPRI, were conducted in conjunction with the operation of the well pumps. The results of the tests, completed in December of 1974, were favorable and indicated that heat exchangers could be designed for operation over fairly long periods without excessive scale buildup. Chevron has continued its resource assessment activities at Heber in cooperation with NARCO and the Union Oil Company. In 1975 EPRI initiated a series of studies leading to a proposed 50 MWe geothermal demonstration plant at Heber based on the binary cycle. SDG&E would like to proceed with the construction and operation of such a plant at Heber which could go into operation in 1981.

The resource at East Mesa is similar to that at Heber with a temperature of 180° to 190°C and low salinity. The Bureau of Reclamation (BUR) has constructed a test facility at its site in the KGRA to evaluate the feasibility of desalinating of the geothermal brines. DOE, in cooperation with the BUR, has established a Geothermal Component Test Facility (GCTF) at East Mesa which is available to industry. Republic Geothermal and Magma Power have active resource development programs on their leases at East Mesa; Republic to the north of the BUR site and Magma to the south. Magma, in cooperation with NARCO, is proceeding with the development of a 10 MWe pilot plant using their Magmamax process. The pilot plant was scheduled to begin operation in 1978. Republic has been granted a federal loan guarantee for field development leading to a commercial power plant in the early 1980s.

The resource at the Salton Sea KGRA is potentially very large and hot (i.e., >250°C). However, because of the high salinity (220,000 ppm) utilization is paced by the development of suitable conversion processes, reservoir and well completion technology. Work on this technology dates back to 1973 at which time a small scale test facility was constructed at the Niland site in the KGRA. The facility used a binary system in which flashed steam and brine from a separator were passed through heat exchangers which would heat an isobutane working fluid.

The performance in both the steam and brine heat exchangers fell outside of design limits after 100 hours of operation due to excessive scaling. A redesign effort was initiated to improve the separation of the steam from the geothermal brine and to scrub the steam to remove entrained solids. In mid-1974 the new steam separation system was tested with very promising results. In July of 1975, DOE and SDG&E entered into a joint project agreement for the construction and operation of a Geothermal Loop Experimental Facility (GLEF) using a multiple flash binary cycle based on the redesigned steam separators. The GLEF will determine whether the highly saline brine can be extracted over long periods of time at sufficiently high temperature and whether the special heat exchanger equipment necessary to generate power from the highly saline geothermal resource will perform reliably.

Construction of the GLEF was completed in April of 1976 and the plant went into operation in early May. Operations to date have been successful. In 1979 DOE is planning to add a 10 MWe hydrocarbon turbine to the current test loop. DOE is considering the establishment of a well completion and extraction technology test facility at another site in the Salton Sea KGRA in cooperation with a consortium consisting of the Union Oil Co., Southern Pacific Land Company and the Southern California Edison Co. The effort is directed at developing and demonstr[illegible] the technology that will increase well life and sustain high flow rates. Republic Geothermal has been very active in the Westmoreland where they have drilled 6 wells.

At Brawley the Union Oil Company has drilled 6 wells. The resource is similar to that at the Salton Sea with a temperature greater than 250°C but of lower salinity (i.e., <90,000 ppm). The development of the resource will benefit from the technology developed in the Salton Sea KGRA but because of the lower salinity could probably proceed with commercial development sooner.

Unlike the situation at The Geysers the attitudes of those in the subregion are predominantly pro-geothermal development providing there are local controls. Imperial County has received a grant from the National Science Foundation (NSF) to develop a geothermal element for the County General Plan. Under this grant, the county is evaluating land-use plans, socio-economic impacts of geothermal development, probable environmental impacts and other related factors prior to any actual development. A great deal of information on the resource in Imperial County, and on the probable impacts of its development, has been generated in the past and continues to be generated.

A three-year, six-million-dollar background study of the county is now being conducted by the Lawrence Livermore Laboratory under DOE funding. Numerous other studies of a more specific nature are being conducted under public and private funds. As a result of these activities, and present favorable county attitudes, geothermal development in Imperial County, when it comes, is unlikely to face much local opposition. However, Imperial County is vitally concerned that the state or the federal government will ignore their county's desire for local control over developments in their area. Agreements between the responsible federal, state and county agencies need to be made to assure harmonious development.

A key issue that potentially could limit development is cooling water availability. The county will require that all geothermal fluids be reinjected to guard against subsidence which could affect the Valley's complex agricultural water drainage system. This means that cooling water must be made available from sources other than geothermal fluids. Cooling water availability has been cited as a major concern, although this concern is not universally shared by all investigators. The major source of water for the Imperial Valley is the Colorado River. The prime use of water is irrigation of the major agricultural developments of the area. Increasing the amount of water withdrawn from the Colorado, or diverting water from agricultural use do not appear to be acceptable solutions.

Withdrawing agricultural runoff water from the drainage system feeding the Salton Sea is the most commonly considered solution. Other possible solutions include the introduction of new cooling water sources or the development of new cooling technology.

Land-use conflicts were also a potential concern in Imperial Valley, since any substantial withdrawal of land from agriculture to meet the needs of geothermal development will probably be opposed. However, UC Riverside studies show that the potential conflict can be minimized by proper siting of drilling islands and power plants, and the routing of piping and transmission lines alongside existing roads. By such measures, withdrawal of land from agriculture can be kept within 1 to 2%.

The Eastern Sierra Subregion

Five KGRAs are located in the Eastern Sierra subregion: Bodie, Coso Hot Springs, Mono-Long Valley, Randsburg, and Saline Valley. Bodie and Mono-Long Valley KGRAs are in Mono County, Coso Hot Springs and Saline Valley in Inyo County, and Randsburg KGRA in San Bernardino County.

The Eastern Sierra subregion is unique in that although it potentially contains the largest resources in the state, over 10,000 MWe for 30 years (2) the existence of the resources generally has not been proven by deep drilling. The two major identified resources are at Long Valley and Coso Hot Springs. There have been extensive USGS geophysical and geological surveys in the Long Valley area. There also has been assessment work by the Navy at Coso where an exploratory well is being drilled.

The Mono-Long Valley KGRA is large; consisting of about 460,000 acres. Approximately 105,000 acres are under the control of the BLM and 290,000 acres by the USFS. Of the remaining 65,000 state and private lands, 55,000 acres of state lands are associated with Mono Lake.

There are three distinct resource prospects: Mono Lake in the northern portion of the KGRA, the Mono Craters in the central portion, and Long Valley in the south. The Long Valley area consists of up to 100,000 acres and is the center of current development interests. Exploration activities date back to the 1959 to 1962 time-period when Magma Power drilled 10 shallow exploration wells near Casa Diablo Hot Springs. The wells reached a maximum depth of 323 meters and a temperature of 178°C (11). In 1974 the BLM leased three blocks consisting of 5,500 acres in the Long Valley area. The blocks controlled by Chevron and Getty Oil have been under litigation on grandfather rights and as a result, no development has occurred. A well drilled in the third block by Republic Geothermal in 1976 was not successful. An additional lease block comprised of 4,000 acres of BLM lands and 26,000 acres of the USFS are under study in Long Valley. The necessary EIS is underway, however, its completion could be delayed.

Southern California Edison (SCE) is interested in the development of the Long Valley resource to supplement their limited, local power generating capacity. DOE has funded a study which could lead to the heating of Mammoth Lakes Village by geothermal fluids. This region is a very popular recreation area and, thus, is environmentally very sensitive. Private and local interests could induce significant delays or even denial of the leasing activity. In order to avoid unnecessary confrontations, the USFS and the BLM have initiated a strong public involvement program of potential geothermal developments.

Coso is a particularly promising resource which could be very large and hot. The KGRA is comprised of 52,000 areas: 8,000 private and state, 17,000 BLM and 27,000 under the jurisdiction of the U.S. Navy. The BLM did have plans for a lease sale of their 17,000 acres in 1978. However, they have revised their plans and are working with the Navy on a plan for the leasing of both the BLM and Navy lands which would minimize this potential impact on naval test range operations and possibly give the Navy first call on the power generated in times of emergency. The Navy and the BLM are working on a schedule which could make the lands available for leasing in the spring of 1979. In the meantime the

Navy is continuing with its resource confirmation program. There is a high industry interest in Coso.

The Northeast Subregion

The Northeast subregion includes five KGRAs scattered through five counties: Glass Mountain KGRA in Siskiyou County; Lake City-Surprise Valley in Modoc County; Lassen straddling the Tehama-Plumas County line; Wendel-Amedee in Lassen County; and Beckwourth Peak in Plumas County.

The development in this subregion is expected to benefit greatly from earlier developments in the remainder of the state. The timely leasing of the substantial federal lands will play an important role in the development of the subregion.

The Northeast subregion has been described by industry as "geologically very interesting." This is reflected in the large number of noncompetitive lease applications filed. There is only limited resource assessment data for the subregion. There are numerous hot springs in the area. However, the estimated resource temperature associated with each is generally less than 150°C which could prove to be attractive in nonelectric applications. The two identified resources with electrical potential are at Surprise Valley and at Morgan Springs in the Lassen KGRA. Of more than 195,000 acres close to 90,000 are USFS lands and 35,000 acres BLM lands.

Most industrial activity to date has centered in the Surprise Valley and Wendel-Amedee areas. There has been considerable nonelectric interest at Susanville in the Wendel-Amedee area. The reservoir of water underlying the town is being used for geothermal heating. At Hobo Wells the resource has been successfully used to heat greenhouses for raising tomatoes. Recently a DOE sponsored study was completed on the feasibility of developing the geothermal resources in the Susanville area to attract new industries, create employment opportunities and increase the local revenue base.

The resource of Surprise Valley is estimated to be large, over 2,000 MWe, with a temperature near 175°C. Wells drilled near Lake City in the early 1960s by Magma Power found a resource with a temperature of 160°C (11). Additional wells have been drilled in the 1970s by Magma, American Thermal Resources, and Gulf Oil Company but are either abandoned or idle. There are over 32,000 acres of private and state lands in the KGRA. The BLM offered 16 units and 34,000 acres of federal lands for lease in June of 1975. Bids were received and accepted on five tracts consisting of 10,000 acres. Currently there is little development activity in the area. The low resource temperature, the high drilling cost and the remoteness from major markets act as deterrents to near term development.

Glass Mountain must be considered as a prime resource on the basis of the large number of lease applications in the area. While not included in the USGS assessment the resource could be large with temperatures near 200°C. The Glass Mountain KGRA consists of 33,000 acres, all USFS lands. The original KGRA of 15,000 acres was established on extensive geological evidence in the Medicine Lake area. 18,000 acres were added on the basis of overlapping lease applications. There are numerous noncompetitive lease applications on lands adjacent to the KGRA. Because of the high industry interest the USFS has given leasing at Glass Mountain priority second only to Long Valley, and hopes to have the first block of leases let in the 1979-80 time period.

The Lassen KGRA located just south of the National Park also could be large with temperatures near 200°C. However, the two wells drilled at Kelley Hot Springs were not successful. Assessment and confirmation data on the true extent of the resource is lacking. The Lassen KGRA consists of 79,000 acres: 24,000 private and state; and 55,000 USFS. There have been noncompetitive lease applications on 17,000 additional acres outside the KGRA. There are no firm plans to proceed with the leasing necessary for development.

Shallow exploration wells drilled in the Wendel-Amedee area did not indicate temperatures substantially above boiling; however, temperatures at depth are not yet known. There is substantial industrial interest in the area. The KGRA consists of 17,000 acres with only 4,000 acres of federal lands. Noncompetitive lease applications have been filed on an additional 7,000 acres in the area. The EAR for the potential lease sale is in the review process.

Additional Prospects

The specific areas discussed do not constitute the extent of the state's geothermal potential. Instead it is expected that future exploration will expand the state's identified resource base considerably as a result of:

(1) New knowledge of the extent of an already indentified system that increases its estimated volume appreciably.

(2) The temperature of an identified system being higher than estimated.

(3) The discovery of a previously unknown system.

In the light of the limited extent of drilling that has occurred outside of the main Geysers steam field, the uncertainty on the current estimates is large. On the basis of the number of known sites in the state that were not included in the above discussion there is a high probability of substantial new discoveries. These known sites include other KGRAs, the Diablo region and numerous hot springs throughout the state (15) which were not included in the USGS assessment.

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DEVELOPMENT OF A TYPICAL GENERATING UNIT AT THE GEYSERS

The material for the following section has been based upon a paper by F.J. Dan, D.E. Hersam, S.K. Kho and L.R. Krumland of Pacific Gas and Electric Company in *Proceedings of the Second United Nations Symposium on the Development and Use of Geothermal Resources* (PB 262 503).

Since 1958 Pacific Gas and Electric Company (PG&E) and its steam suppliers have been developing the first commercial geothermal project for the production of electric power in the United States. Located at The Geysers in northern California, this project is the largest geothermal installation in the world.

Planning and Purchasing

New Unit Planning: When the PG&E system requirement for a new geothermal generating unit has been established, and the steam suppliers have confirmed the availability of sufficient steam reserves to support the planned facility, a final site is selected by the steam supplier and PG&E from among several alternatives. The thermodynamic cycle is chosen, and a preliminary system design is established during this phase.

The optimum size for a new unit is 100,000 to 150,000 kW. This is derived from the steam-field acreage that must be dedicated to a plant for a 30-year steam supply, and the limited distance that steam can be transported. Exact ratings will depend upon the manufacturers' equipment designs. The overall system design criteria establish the preliminary specifications for the major equipment. It is then possible to estimate the capital expenditure required to build the generating plant and associated transmission facilities and to submit a capital appropriation request for management approval.

Design and Equipment Purchasing: The first item to be purchased is the turbine-generator unit. This is the largest single equipment expenditure and it also determines the detailed design of the plant. Because of the lead times necessary to design and fabricate the turbine-generator and remaining equipment, the order must be placed about 3 years before the turbine-generator is needed for installation. Within several months of receiving the order, the turbine-generator supplier will furnish sufficient design data to allow PG&E to proceed wi... the supporting equipment design and specifications, and to devise the mechanical and electrical schematics. The major items that are ordered after purchasing the turbine-generator are the main and auxiliary power-system transformers, circuit breakers, transmission towers, substation equipment, the condenser and associated noncondensible gas removal system, condensate/circulating water pumps, auxiliary cooling water system pumps, cooling tower, and all of the necessary controls, instrumentation, and valves.

Final Design: Drawing Preparation — When the optimum power cycle has been designed, and with the outline dimensions of the major equipment items known and the final schematics available, detailed site, building, and equipment-layout design can begin. The building size and arrangement depends on the size and configuration of the systems to be housed. When these building and equipment layouts and the equipment vendors' detailed drawings are available, the final civil, mechanical, and electrical construction drawings are made.

Mechanical Engineering

A typical system diagram for a new 110,000 kW generating unit at The Geysers is shown in Figure 3.2. Steam enters the turbine at approximately 333° to 355°F (~179°C) and 114 psia. The steam ranges from dry saturated (338°F) to dry with about 17°F of superheat (355°F) at the turbine inlet, depending on the actual unit and location. The steam expands in the turbine, converting the thermal and pressure energy of the steam to mechanical energy, which is converted to electrical energy in the generator. Steam exhausts from the turbine at a pressure of approximately 4 inches of mercury absolute and a saturation temperature of 125°F and is condensed in a direct-contact condenser located below the turbine. Here cooling water is sprayed directly into the condensing steam.

From the condenser, the 120°F mixture of cooling water and condensate is pumped to the wet-cooling tower and cooled to 80°F. The cooling water-steam condensate cycle is completed as the cooling water flows from the cooling tower basin to the condenser under the driving force of gravity (elevation differences) and condenser operating vacuum head.

The water evaporated in the cooling tower is made up by steam condensate. The cycle has a net surplus of condensate under all conditions and no outside source of water is required. Excess condensate is reinjected into the geothermal steam formation by the steam producer.

Noncondensible gases entering with the steam, primarily carbon dioxide, nitrogen, ammonia, methane, hydrogen, and hydrogen sulfide, are continuously removed from the condenser by steam jet ejectors which require about 4% of the total incoming steam for operation. PG&E is conducting an extensive program to develop processes by which the malodorous hydrogen sulfide can be removed from these noncondensible gases before venting to the atmosphere.

Approximately 2 million pounds of steam per hour, total, from 15 wells are required for a plant with a gross rating of 114,000 kW. Power required for plant operation (pumps, cooling tower fans, and so on) is about 4% of gross or 4000 kW, giving a net power output of 110,000 kW. A typical cycle heat rate is between 21,000 and 22,000 Btu/kWh. This is high compared to that of

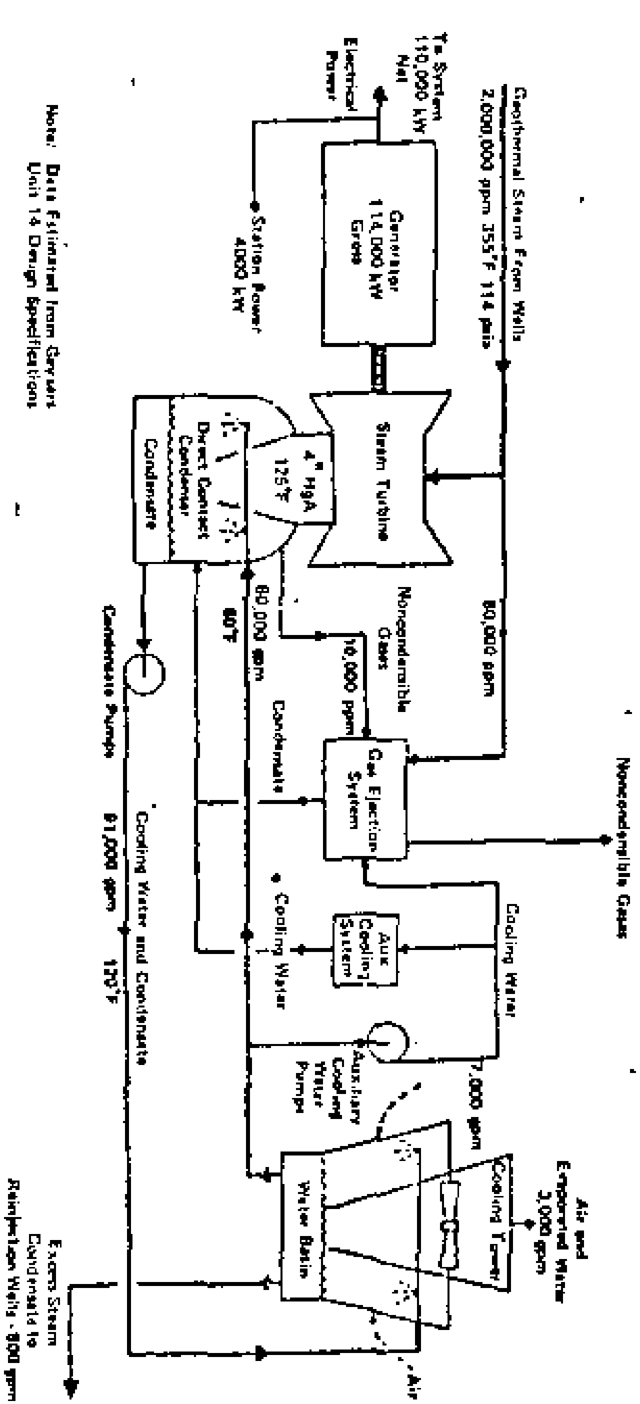


FIGURE 3.2: TYPICAL THE GEYSERS GEOTHERMAL POWER PROJECT SYSTEM CYCLE

modern fossil-fueled and nuclear power plants because of the much low... steam temperature available in this resource. However, using the dry geothermal steam directly as a working fluid gives the most thermodynamically efficient cycle at The Geysers.

The turbine back pressure maintained in the condenser is a function of the condensing temperature of the steam and this in turn is determined by the cooling-water temperature. Lower back pressures, achieved with lower cooling water temperature, could increase the power output of the turbine. However, the cooling water temperature is determined by the ambient wet-bulb temperature and by the efficacy of the cooling tower in approaching it. A closer approach improves the thermodynamic efficiency of the system, but the cooling tower cost increases markedly as the exiting cooling-water temperature approaches the design wet-bulk temperature. This higher cooling-tower cost in turn increases the cost of power.

On the other hand, a high back pressure would reduce the cooling-tower cost, but this would decrease the turbine power output and thereby increase the turbine-generator capital charge for each kWh generated. At The Geysers, the optimum back pressure for minimizing the cost of power ranges from 3.5 to 5.0 inches Hg absolute, depending on the turbine design.

Civil Engineering

The geothermal power plant structures consist mainly of a turbine building, turbine pedestal, and cooling tower. There is no boiler or accessory equipment as in a fossil-fuel plant. The turbine-generator pedestal is the largest structural element of the plant. Basic design criteria for the pedestal are:

(1) Alignment: Machine alignment must be maintained up to a tolerance of 0.020 inch under maximum assumed loading and temperature conditions, within the relative deflection limits imposed by the manufacturer.

(2) Transmission of Vibration: Foundation amplification must be less than unity to minimize the effect of out-of-balance forces in rotating parts on machine supports, the foundation, and adjacent structures.

(3) Resonance: Natural period of vibration, of the foundation or any part, in the fundamental mode or any higher mode likely to be excited by the machine operation, must be at least 20% higher or lower than normal machine operating speed.

The turbine-generator pedestal is a monolithic reinforced concrete structure consisting of a deep top deck supported by slender columns embedded in a stiff mat foundation, which rests on weathered fractured bedrock. The condenser sits on top of the mat foundation directly below the turbine, surrounded by the pedestal columns.

The geometry of the pedestal is determined by the requirements of the generating unit and the condenser. For a 110,000 kW unit, the average size is about 40 x 80 feet and 40 feet high. Because of its configuration, the pedestal is low-tuned; the vertical resonant frequency of the pedestal is below the running speed of the turbine-generator.

The pedestal is computer-analyzed with the STRUDL structural dynamics program. STRUDL is a lumped mass dynamic program suitable for analyzing multidegree of [illegible]am systems. In addition, PG&E has performed dynamic tests on a completed pedestal by forced vibration. This correlates the actual dynamic parameters of the completed structure with the values obtained from computer analysis.

To maintain maximum economy, the turbine building and the cooling tower are arranged with their long axes parallel, or alternatively in the form of a T, depending upon the site topography. The T arrangement is preferred, because the riser pipes in the condensate pumping system can be laterally supported by the end wall of the cooling tower, and the air movement on the broad-sides of the tower is not restricted.

The turbine building houses the turbine-generator, an overhead traveling crane, condenser, condensate pumps and other auxiliary equipment. The equipment in the building is arranged as compactly as possible to minimize the size of building and the costs.

For a 110,000 kW generating unit the building is about 80 x 160 feet and 65 feet high. Four operating levels are provided: (1) basement level for condensate pumps and condenser, (2) ground level for auxiliary equipment and laydown, (3) mezzanine level for electrical equipment and controls, and (4) operating level for turbine-generator and office. Lay-down space is provided at the operating floor for the original assembly of the generating equipment and for overhaul.

Structural design of the main steel framing of the building is based on the simple beam and column basis, with diagonal braces for the transmission of lateral forces to the reinforced concrete foundation. Trial studies have proven that this design is more economical than the rigid frame type of building. Seismic and wind-design criteria are governed by the Uniform Building Code, published by the International Conference of Building Officials, and adopted by the regulatory building authority. Seismic design by the static method is used in the analysis of the building. However, to keep up with current practice, PG&E is analyzing a typical building by the dynamic seismic analysis method.

The roof consists of a structural steel deck, designed to act as a horizontal diaphragm, that spans between roof beams. Horizontal braces between roof beams are therefore not necessary. Aside from the turbine-generator pedestal, the operating floor consists of a galvanized grating or a reinforced concrete slab on a steel deck form. The floor is supported by laterally-supported steel beams with welded studs penetrating the deck. The transmission of impact shock and vibration from the turbine-generator pedestal to the operating floor is reduced by the use of bearing pads manufactured from resilient material with great compressive strength, high damping, and long service life. These pads are placed in the beam-seat connections attached to the pedestal.

The building is enclosed by metal siding and painted in a color scheme chosen to minimize visual impact. The natural hues blend unobtrusively with the terrain in all seasons.

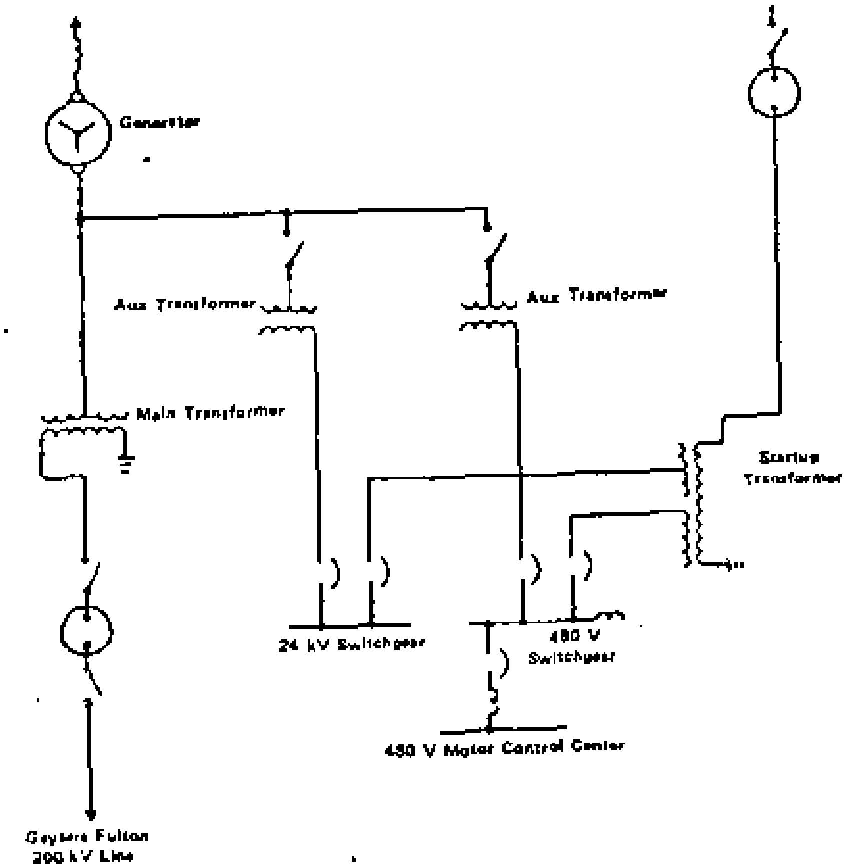
A 110,000 kW power plant site occupies about 6 acres, of which the required level area is about 4 acres. The area between structures and foundation pads for equipment is paved with asphaltic concrete. This provides parking and maintenance storage space, and reduces fire hazards from the surrounding vegetation.

The high annual rainfall at The Geysers area, with approximately 60 inches average and 100 inches maximum, requires a comprehensive site drainage system based on a 100-year storm flow. Paved ditches, culverts, catch-basins or check-dams are provided. The sides of drainage outfalls are lined with stone riprap or sacked concrete. Exposed sloped surfaces are reseeded by punched-straw or hydro-seeding methods. Erosion control and revegetation of the cut slope is enhanced by a serrated finish on the slope. Landscaping is carried out upon completion of the power plant construction. Plantings consist of native ground cover, shrubs, and trees, and are selected on the basis of adaptability, vigor, growth habit, and desired effect. An irrigation system is installed to ensure the survival and growth of the plantings during the dry seasons.

Electrical Engineering

A single-line diagram for a typical unit is shown in Figure 3.3. It should be noted that: (1) the main generator connections are still made with aluminum cable bus; and (2) a 2400-volt auxiliary power source has been added to supply larger pumps rated up to 1500 hp in the larger units.

FIGURE 3.3: TYPICAL SINGLE-LINE DIAGRAM



Source: PB 262 503

Startup power for the smaller generating units, up to and including unit 10, is provided by a generator breaker. The larger size of the later units has made it necessary to establish a new source of startup power for unit 11 and following units, because oil circuit breakers rated adequate for 110,000 kW are not available. The startup system connects each generating site with a regulated 21-kV distribution line. Power is supplied from three sources: one 7000-kVA, 13.8 to 22-kV transmission system; the main transformer, supplied by the 220-kV transmission system; and a three-winding transformer, at unit 12, which is a backup source supplying startup power for unit 12 and for other units when unit 12 is running.

The additional benefits of this separate distribution system are: (1) construction power is available at each new site; (2) a standby source is available when regular transmission lines are shut down; (3) the distribution line can be used for customer service (in this case, customers are mostly steam suppliers); and (4) the pole line is available for communication and supervisory systems.

The startup transformer for a typical 110,000-kV unit has the breaker on the high side, and breakers on the low sides are interlocked with the breakers from the auxiliary transformers. The startup transformer is sized such that it can replace, in case of emergency, any one of the auxiliary transformers.

In the future, when the output of The Geysers project is transmitted at both 230 kV and 115 kV, the present plans for startup power will apply only to those units on the 230-kV system. The smaller units on the 115-kV system will have the generator breaker; the larger units will have the separate startup system.

Control System

The Supervisory Control System has been developed into a complete, computer-based system to facilitate monitoring of all units by a single human operator. The system gives the operator an overall summary of each unit's operation, and signals any malfunctions. The operator may exercise certain control functions directly through the Supervisory Control System.

Because the operator travels from unit to unit, display consoles are located at each unit, with the master station at units 5 and 6. From the master station, signals are transmitted to the Fulton Substation, 22 miles away, where radio contact is maintained with the operator. Thus, communication is maintained while the operator is in transit between units.

The master station contains two cathode ray-tube displays, giving unit status and an alarms summary; a control console; a teletype events recorder; and a backup annunciator system. From each generating site, a remote supervisory annunciator transmits unit status, analog, and accumulator information to the master station. The master station retransmits to all remote units and to the Fulton Substation. This allows the roving operator to recall from any unit the full display of 20 alarm points from any other unit.

An average of 20 analog values is recorded from each unit. These include pressures, temperatures, levels, voltages, currents, and so on. One accumulator at each station stores kilowatt-hour meter information, which is reported to the PG&E Power Control Center in San Francisco. The master station controls the following functions for each unit: generator, power output, voltage regulation, main breaker, and main steam valve. A future communications link between the Power Control Center and the planned Geysers Substation will allow the direct transmittal of kilowatt and kilowatt-hour data, and may control loading of the transmission lines associated with The Geysers Power Plant.

Construction

Construction on a unit starts during the dry season after certification of the project is received. The construction of a typical 110,000-kW plant requires approximately 30 months. The work occurs in three major phases: (1) site preparation, (2) foundation and building construction, and (3) equipment installation.

The construction of a typical 110,000-kW plant, excluding transmission line and towers, requires about 4,000 yd³ of concrete, 270 tons of reinforcing steel, and 240 tons of structural steel. Excavation of a plant site is primarily a balanced cut-and-fill operation. The volume of excavated material ranges from 70,000 to 150,000 yd³.

Two to three months are required to clear and grade the site. This must be accomplished during the dry season to minimize site erosion. Excavation and placement of foundations require about 6 months. Concrete batch plants are set up at each site and removed after the turbine pedestal is constructed. Structural steel is shop fabricated in the San Francisco Bay area. Because skilled welders are not readily available in the remote Geysers area, structural field connections are bolted rather than welded. Erection of the structural steel requires about 3 months. The erection of the cooling tower overlaps the structural steel work and requires about 3 months to complete.

Electrical and mechanical equipment is delivered to the site about a year after site preparation begins. Major equipment components are assembled during the installation phase. The generator stator is the largest single piece of equipment, weighing about 140 tons for a 110,000-kW unit. Transporting the stator up the last 16 to 20 miles of winding mountain road takes about 48 hours. A large temporary crane is installed at the site to lift the major turbine-generator components into place. Assembly and installation of the plant equipment, piping, conduits, and cables take about 12 months. Testing and, finally, commercial operation of the unit begin about 2 years after the start of site preparation.

Salton Trough Brine Production and Conversion Processes

SALTON SEA CANDIDATE POWER CONVERSION SYSTEMS

The material for this section has been based upon a report by Bechtel Corporation (UCRL 13751).

The Systems

Bechtel Corporation is participating in the geothermal Power Conversion System Studies that are being conducted by the Lawrence Livermore Laboratory. These system studies will develop comparative performance and cost data for the leading candidate conversion systems operating from the Salton Sea high temperature, high salinity (HT/HS) geothermal resources.

The following criteria are suggested for use in evaluating these power conversion systems:

- Low bus-bar electric energy production cost (mills/kWh)
- High performance as measured by specific output (net kW/lb brine/hr)
- Environmental acceptability
- Advanced developmental status and minimal technical problems
- Avoidance of heat exchanger fouling as well as minimization of corrosion and scaling of process equipment
- Prevention of solids precipitation from brine in the system.

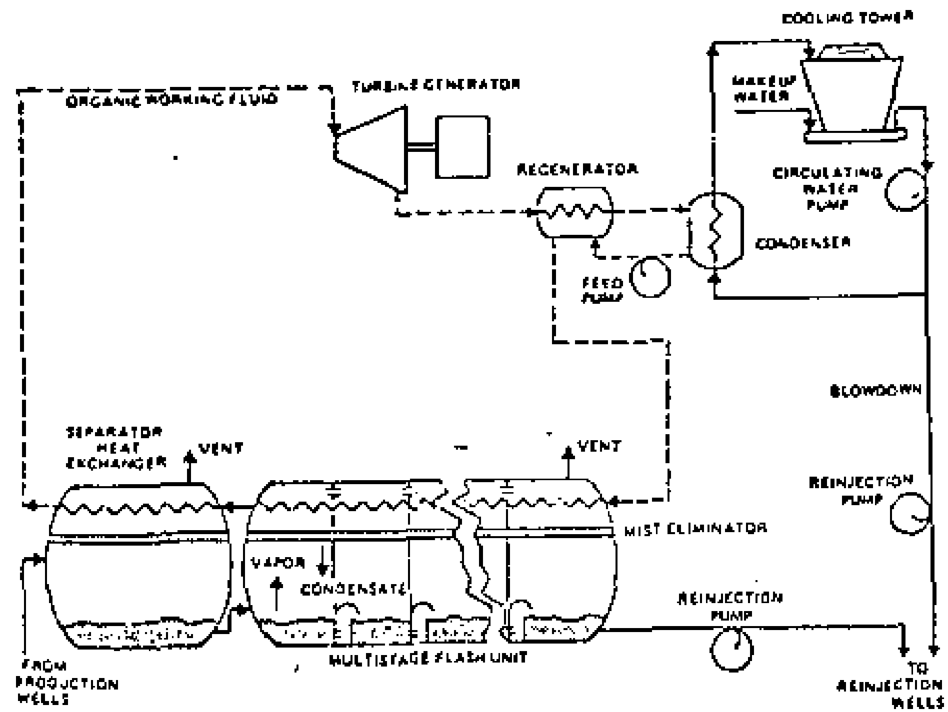
Table 4.1 lists the systems under consideration. They have been placed in priority order, based on a subjective appraisal of their technical merits. A schematic diagram is included as an illustration of each candidate system (Figures 4.1 through 4.9)

TABLE 4.1: CANDIDATE POWER CONVERSION SYSTEMS

Priority	Conversion System
1	Multistage Flash/Binary
2	Two-Stage Flash with Scrubbing
3	Total Flow
4	Multistage Flash/Direct Contact (Bechtel patented process)
5	Four-Stage Flash/Binary
6	Binary with Direct Contact Heat Exchangers
7	Hybrid—Flash/Binary
8	Hybrid—Flash/Total Flow
9	Flash/Dual Cycle Binary

Source: UCRL 13751.

FIGURE 4.1: MULTISTAGE FLASH/BINARY



Source: UCRL 13751

FIGURE 4.2: TWO-STAGE FLASHED-STEAM

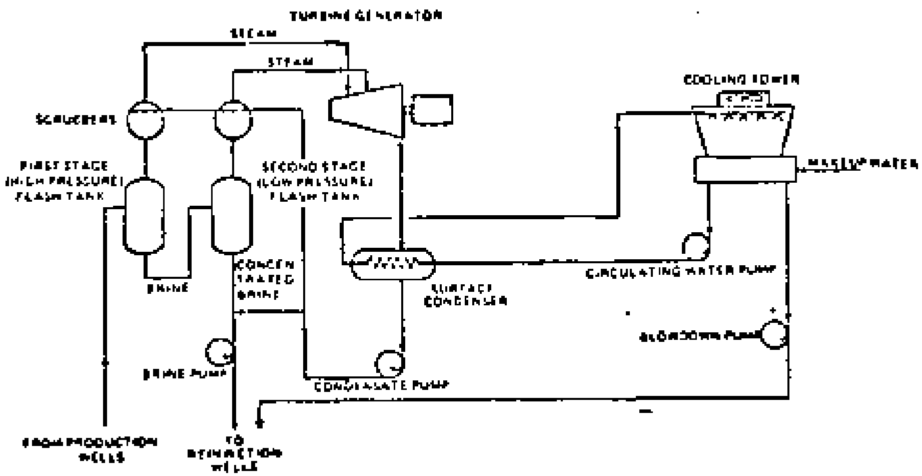
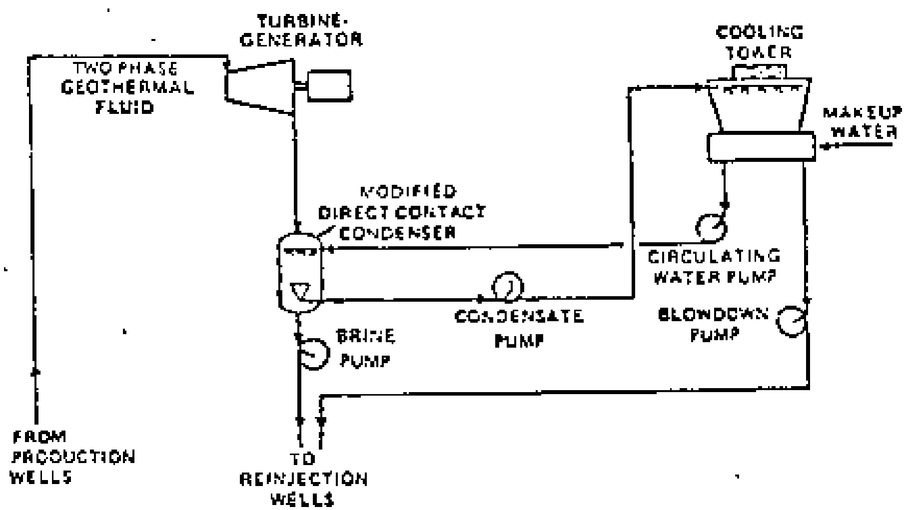


FIGURE 4.3: TOTAL FLOW



Source: UCRL 13751

FIGURE 4.4: MULTISTAGE FLASH/DIRECT CONTACT

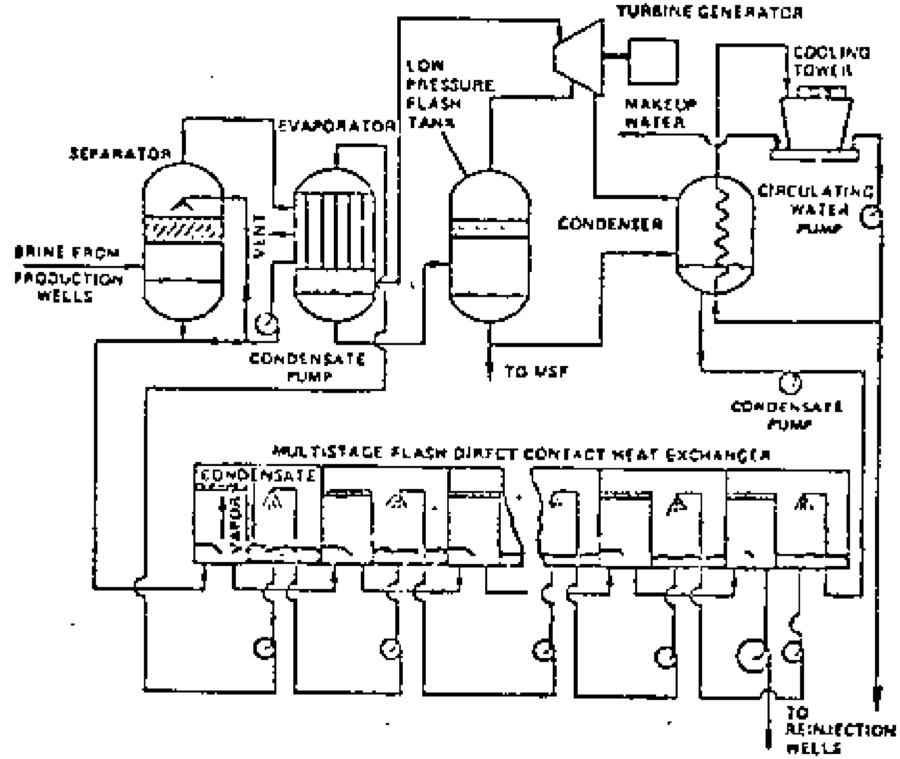
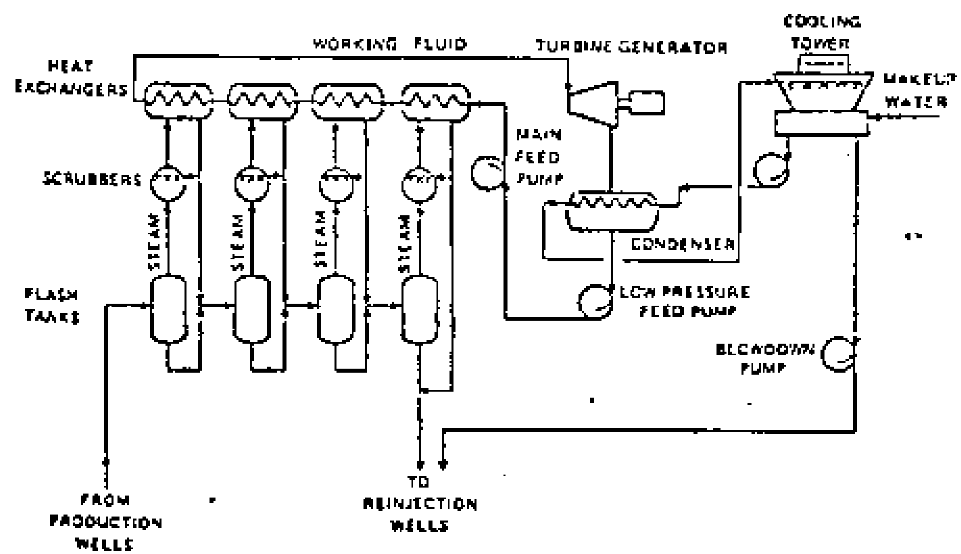


FIGURE 4.5: FOUR-STAGE FLASH/BINARY



Source: UCRL 13751

FIGURE 4.6: BINARY WITH DIRECT CONTACT HEAT EXCHANGER

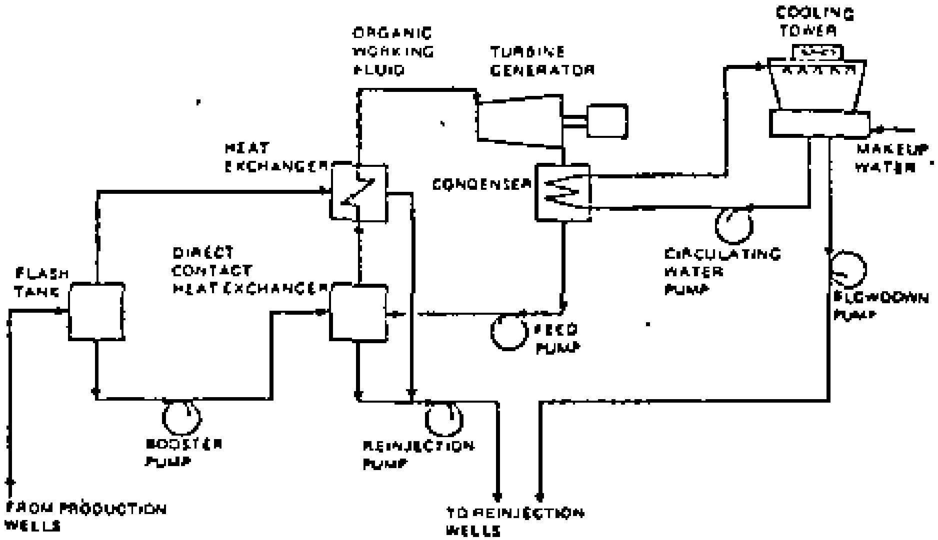
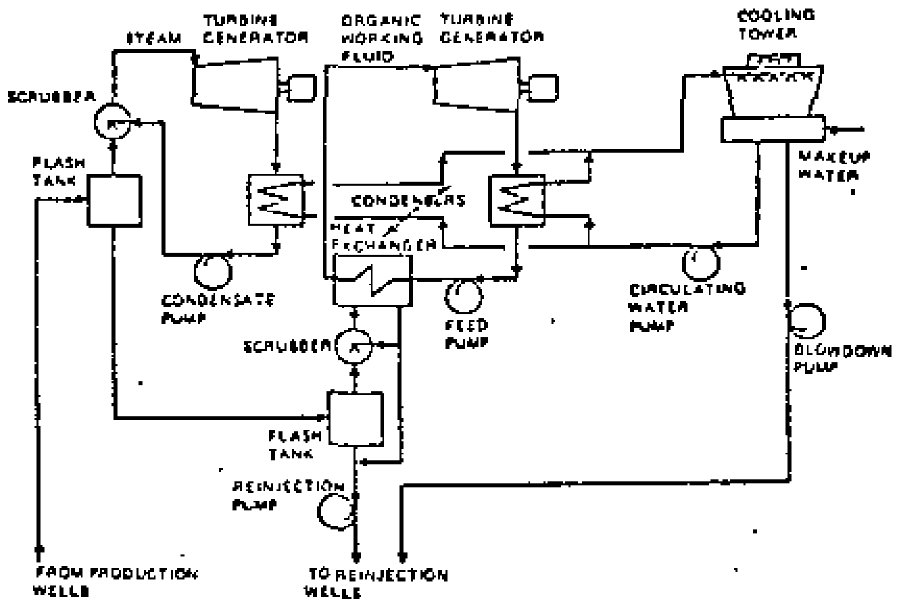


FIGURE 4.7: HYBRID—FLASH/BINARY



Source: UCRL 13751

FIGURE 4.8: HYBRID—FLASH/TOTAL FLOW

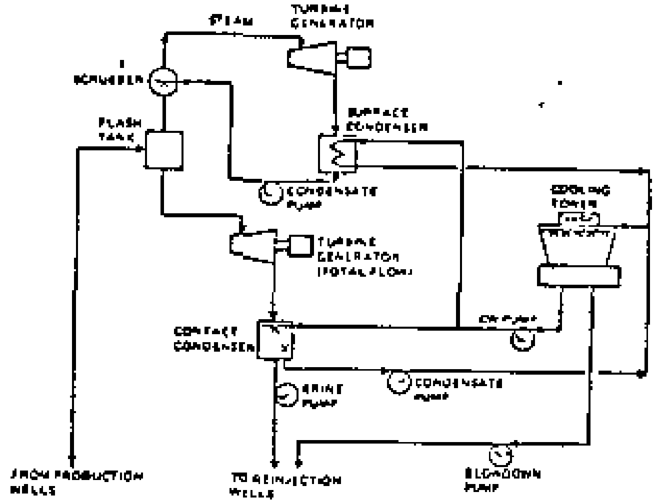
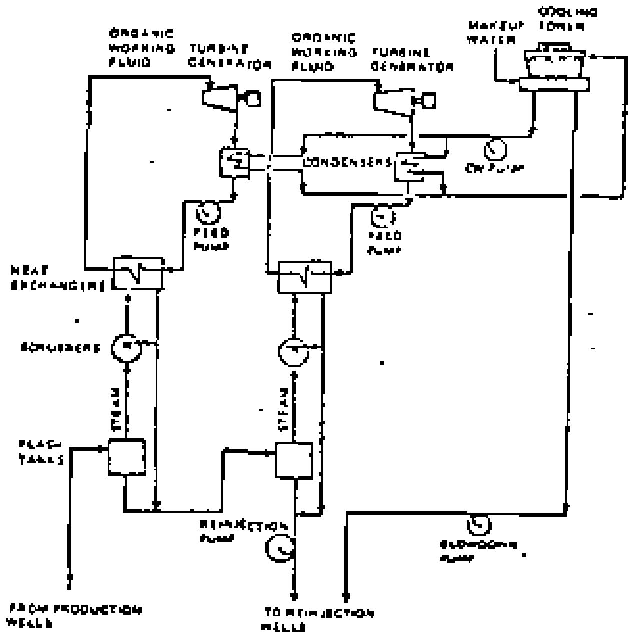


FIGURE 4.9: FLASH/DUAL BINARY



Source: UCRL 13751

Assumptions and Design Considerations

Major Power Plant Equipment:

- Equipment will be either conceptually designed (e.g., the multi-stage flash units) using practical performance characteristics obtained from experience or in consultation with suppliers of similar equipment, or will be selected from commercially available items (e.g., the cooling tower).
- Standard Bechtel power plant design practice will be followed in the selection and arrangement of plant equipment.
- Equipment will be fabricated and installed in accordance with applicable codes and standards that are accepted in the power plant industry.
- Safety aspects will be considered so that the equipment can be operated safely when normal industrial precautions are enforced.
- The plants will be designed to minimize auxiliary power requirements without adding excessively to plant investment costs.
- The high salinity and noncondensable gas content of the brine will be considered when designing the relative equipment. All vessels will be of carbon steel; a corrosion allowance will be added to the wall thicknesses.
- The choice of heat transfer tube materials and type will be related to the corrosive and fouling effects of the brine and noncondensable gases. Titanium will be specified for heat exchanger tubing in contact with brine vapor. For surface condensers where geothermal vapors are not present, 90:10 copper-nickel will be specified for the heat transfer tubing.
- The plants will be designed for 30-year life.

Auxiliary Systems: The following systems will be included in all power conversion system designs. The level of design detail will be limited to that necessary to support the overall conceptual design and cost estimating work.

- Turbine-generator auxiliaries include stop and control valves, hydraulic and lube oil systems, sealing system, controls and protection, generator cooling, and excitation and voltage control
- Fire water system
- Heating and ventilation system
- Instrument and service air supply system
- Crane (in turbine building)
- Cooling water treatment

Major Piping:

- Construction material for major piping (excluding cooling water) will be carbon steel.
- A corrosion allowance of ¼ inch will be added to the pipe wall thickness.
- Cooling water pipe material will be concrete.

- Maximum flow velocities will be:
  Liquids - 10 ft/s
  Vapors - 200 ft/s
- Constant pipeline length:
  Reinjection wells - 2 miles from power plant site
  Makeup water supply - 2.5 miles from power plant site.
- All large pipe, except circulating cooling water, makeup water and reinjection brine will be above ground and supported on adjustable pipe roll stands.
- Pipe insulation will be calcium silicate with a waterproof jacket.

Civil/Structural: In the civil/structural conceptual design, accepted engineering practices and design standards will be followed to establish a technically sound design.

Site:

- Presently used for agricultural purposes, therefore only minimal clearing and grubbing.
- Soil suitable for any fill requirements on site.
- With flat topography only minimal general excavation and grading.
- Water table, 5 ft.
- Allowable soil-bearing pressure, 1,500 psf.
- All foundations spread footing type without piling.

Structural:

- Turbine building — Rectangular structural steel with metal siding and roof. Floor slab at grade. Reinforced concrete turbine pedestal with elevated access deck.
- Control building — One story steel frame with concrete block walls, metal deck roof with concrete fill roof (includes control room, office, switch-gear room, battery room and diesel generator).
- Cooling tower — Reinforced concrete basin, wooden structure, plastic fill.
- Other structures — 60 ft square earth banked fire-water pond with steel frame pumphouse.

Other Facilities:

- Access roads, a sewage system and security.

Controls and Instrumentation: The control and instrumentation requirements will include the following—

- Provide efficient, reliable operation from a central control room to minimize operator requirements and to allow remote routine startup and shutdown of the plant.
- Use independent trip systems and redundant protection systems for personnel and equipment safety.

- ...ude a mini-computer for data logging and sequence of events recording.
- Use a "first out" annunciator system for alarm monitoring.
- Provide no extra instrumentation for experimental testing of processes.

Electrical Systems: The electrical systems will provide power to the local utility company's (Imperial Irrigation District) existing 92 kV network during normal operation, and to the plant auxiliary loads during normal operation, startup, and emergency conditions. The following systems will be included in all conceptual designs:

- Main Generation System — includes the main 13.8 kV generator unit, generator breaker and the main transformer which steps up to the 92 kV system.
- Auxiliary Electric Systems — includes the auxiliary transformer and its supply breaker, the 4.16 kV and 480 V subsystems, a standby diesel generator, batteries and dc systems, a lighting system, and a communication system.
- Plant-Utility Interface System — includes the switchyard and supports for the transmission lines to the plant site boundary.

Production and Reinjection Wells:

- Production wells will have 10⅜ inch casings and will be slant-drilled from production well islands to a nominal 6,000 ft depth.
- The wells will be naturally flowing at an assumed rate of 800,000 pounds per hour.
- Reinjection wells will have 10⅜ inch casings and will be slant-drilled from reinjection well islands to a nominal 6,000 ft depth.
- The pumped reinjection well flow will be assumed to be 1,600,000 pounds per hour.

Production and Reinjection Well Islands:

- Each 2 acre production well island, located adjacent to the power plant, will include the production wells (to a maximum of 24, including 4 spares), cold brine dump pit (for well startup), cold brine pump, and an insulated brine header, valves, and wellhead equipment.
- The reinjection islands will be located two miles from the power plant site. Each 2 acre reinjection well island will include the reinjection wells (to a maximum of 12, including 2 spares), an insulated brine header and wellhead equipment.

Environmental Considerations: The following environmental factors will be considered for all systems and mitigating measures will be taken to preclude undesirable environmental effects:

- Aesthetics — low, flat profile for plant.
- Ground surface subsidence — reinjection flow balanced with production flow, if necessary with supplementary river water. River water will be deaerated and reinjected by a well which is separate from the brine reinjection wells.

- Consumptive use of water — cooling tower makeup water and/or supplementary reinjection water will be required.
- Heat rejection — evaporation from the cooling tower will carry rejected heat to the atmosphere.
- Gas emission — noncondensable gases will be processed to an environmentally acceptable level.
- Liquid and solid emissions — all dissolved solids produced from the geothermal reservoir will be reinjected with the waste fluid deep underground. Cooling water blowdown will be deaerated for oxygen removal before being pumped to a separate reinjection well.

Standard System Criteria

This section specifies power plant design criteria that will be common to the calculation of heat and mass balances for all conversion systems. It also describes the computer program that will be used to calculate the heat and mass balances and constraints that will be applied to these calculations.

Plant Power

Net power output is 50 MWe.

Auxiliary power is calculated by program GEOTHM.

Miscellaneous (not itemized) auxiliary power requirements are 225 kW.

Fluid Properties

Brine

Thermodynamic properties based on Pitzer and Silvester "Thermodynamics of Geothermal Brines," (1) which model those of NaCl solutions.

Total dissolved solids (TDS) are 20% by weight of brine.

Noncondensable gases consist of CO_2, 1.5% by weight of brine, plus trace amounts of H_2S and NH_3.

Downhole brine temperature is 515°F and downhole pressure is 777 psia.

At plant site, supply brine is a mixture of liquid and vapor phases at 422°F and 315 psia.

Reinjection pressure is 315 psia at the plant site boundary.

Potential scaling constituents are PbS, FeS, SiO_2, and $BaSO_4$.

Steam

Thermodynamic properties based on Keenan and Keyes, "Thermodynamic Properties of Steam" (2).

Hydrocarbon Working Fluid

Selected from fluids contained in "Fluid Thermodynamic Properties for Light Petroleum Systems" (3).

.nodynamic properties based on "Fluid Thermodynamic Properties for Light Petroleum Systems" (3).

Noncondensable Gases

Thermodynamic properties are modeled using ideal gas relationships.

Turbine Generator

Steam Turbine

Expansion efficiencies are 80% for high pressure expansion and 75% for low pressure expansion.

Mechanical efficiency is 99.5%.

Hydrocarbon Turbine

Expansion efficiency is 85%.

Mechanical efficiency is 99.5%.

Total Flow Turbine

Present-day achievable engine efficiency is 45%.

Projected engine efficiency is 70%.

Generator

Sized with sufficient capacity to supply 50 MWe net power plus auxiliary electric power requirements.

Generator electrical efficiency is 99%.

Heat Exchangers

Heat exchanger surface area determined by calculated heat transfer coefficients based on specified allowance for fouling resistance.

Allowable pressure drops based on overall cost effectiveness.

Steam to Working Fluid (steam on shell side and working fluid on tube side).

Fouling factors are 0.001 hr ft² °F/Btu for hydrocarbon and 0.0005 hr ft² °F/Btu for steam.

The pinch point temperature difference is 20°F.

Hydrocarbons Condenser

Fouling factors are 0.001 hr ft² °F/Btu for hydrocarbon and 0.0005 hr ft² °F/Btu for cooling water.

Temperature approach is 15°F.

Direct Contact Condenser

Temperature approach is 10°F.

Surface Condenser

Temperature approach is 15°F.

Regenerator (Vapor on tube side and condensate on shell side)

Fouling factors are 0.001 hr ft² °F/Btu for both tube side and shell side.

Cooling System

Climatic conditions for Niland are based on data for Yuma, Arizona, obtained from "Evaluated Weather Data for Cooling Equipment Design" (4).

Mechanical draft evaporative cooling towers are used.

Cell dimensions are 36 feet long, 53 feet wide, and 60 feet high.

Design wet bulb temperature is 79°F.

The cooling tower approach is 8°F at the design wet bulb temperature.

The rate of evaporation loss is

$$\frac{0.95 \times \text{cooling load}}{h_{fg} \text{ at wet bulb temperature}}$$

h_{fg} = heat of vaporization

The rate of drift loss is 0.00005 times the flow rate of cooling water into the tower.

The number of cooling tower cells and the fan hp are determined from Bechtel Power Division criteria.

Cooling tower range is 25°F.

Makeup and blowdown flow rates are based on three cycles of concentration.

Alamo River is the source of makeup water and is 2.5 miles from plant site.

Pumps

Extra pumps for standby depend on reliability assessment.

Pump efficiencies are:

under 10 hp	60%
10-50 hp	70%
over 50 hp	80%

Piping

Seven percent drop in pressure between flash tanks and turbine inlet control valves (for steam turbine only).

Pressure drops in water or brine lines are one foot of head per 100 feet of piping length.

No heat losses in pipes.

References

(1) Silvester, L.F. and Pitzer, K.S., *Thermodynamics of Geothermal Brines*, Lawrence Berkeley Laboratory, University of California, LBL-4456 (January 1976).

(2) Keenan, J.H. and Keyes, F.G., *Thermodynamic Properties of Steam*, New York, John Wiley & Sons, Inc., First Edition (1937).

(3) Starling, K.E., *Fluid Thermodynamic Properties for Light Petroleum Systems*, Houston, Gulf Publishing Company (1973).

(4) Fluor Cooling Products Company, *Evaluated Weather Data for Cooling Equipment Design*, undated.

COMPARISC · BRINE PRODUCTION METHODS AND POWER CONVERSION PROCESSES

The material for the following sections has been based upon a report by D.G. Elliott of Environmental Quality Laboratory, California Institute of Technology (EQL Report No. 10).

Most (but not all) investigations of geothermal conversion processes have agreed that if wells producing dry steam are found, the use of the steam directly in turbines is the preferred means of developing mechanical or electrical power. Where a geothermal field produces hot water, however, (which may partially flash to steam in the well), this degree of unanimity is not found.

As early as 1970 public presentations were made which argued for the superiority of conversion systems which would use the produced geothermal water to heat a secondary working fluid, used in a Rankine cycle (thus binary cycle). Subsequent technical papers analyzed system performance and cost superiority. At the same time, however, analyses were published which concluded that binary processes had little to offer.

While in some of the geothermal literature the superiority of the binary process, particularly for lower temperature resources, is taken as assured, in the four hot water geothermal fields worldwide, where extensive commercial exploitation has begun (Wairakei, Cerro Prieto, Ahuachapan, Otake), only direct steam process is used.

While most existing geothermal wells are produced by self-flow, some have been pumped. This latter method, which is well matched to binary processes, is compared with self-flow (flashing) in the following analysis. Then a variety of direct and secondary conversion processes are compared. This was accomplished for wells typical of the Salton Sea KGRA. The same analyses were also carried out for a hypothetical case of equally high reservoir temperature but containing low salinity brine. To understand the relative efficacy of the various production and conversion processes for the more commonly-found lower temperature reservoirs, similar calculations were carried out for one such hypothetical case.

Electric power generation from geothermal brine requires, first, bringing the hot brine to the surface and then converting the heat to electric power (the term brine refers to the hot liquid which may have a composition ranging from pure water to 30% salt solution). The various methods of obtaining brine flow from the well fall in the category of brine production, and the various methods of converting the heat to electric power fall in the category of conversion processes. The latter can also be referred to as cycles, but process is a more accurate term because the brine flows only once through the conversion equipment and does not undergo a cyclic change.

Two brine production methods will be compared with respect to available power at the wellhead: self flowing (brine lifted by steam from vaporization of the brine), and pumped (brine lifted by a mechanical pump and kept in the liquid state). Five conversion processes will be compared with respect to fraction of available power converted to electric power: flash steam (steam turbines operating on steam from flash vaporization of the brine), dual steam (flash steam with two-phase expanders to recover the flash vaporization mechanical energy), total flow (two-phase expanders only), binary (heat transferred from the br[illegible] a secondary working fluid), and flash binary (heat transferred from flashed steam to a secondary working fluid).

PRODUCTION METHODS

Method of Calculation

The method of calculation for self flowing is summarized below. Given the reservoir temperature, brine concentration, and well depth, a flow rate is chosen and the well bottom pressure is calculated from the drawdown pressure factor, the decrease in well bottom pressure below reservoir pressure per unit flow rate (a number available from measurement or from reservoir theory).

Next, the location of the flash level where the pressure in the well reaches saturation is calculated taking into account the hydrostatic pressure difference and the friction pressure drop for given well diameter. The flow conditions at 1°C intervals between the flash level and the wellhead are then calculated by balancing pressure force against hydrostatic and friction forces and momentum change. The result is the temperature, pressure, and quality (fraction of total flow in the vapor phase) at the wellhead. The energy available from an isentropic expansion of unit mass of the wellhead product (after stagnation of the flow at constant pressure) to some specified rejection temperature is then calculated as the specific available wellhead power. Finally, multiplying the specific available wellhead power by the flow rate gives the total available wellhead power.

The method of calculation for pumping is summarized below. The type of pump assumed is one driven by a steam turbine using heat from the brine flowing up the well (1). Such a pump is characterized by a cooling factor which is the reduction in wellhead temperature per unit of pump pressure rise. The pump pressure rise required to maintain saturated liquid at the wellhead is calculated taking into account the drawdown pressure at the bottom and the hydrostatic and friction pressure drops in the well. The wellhead temperature is then calculated from the cooling factor, the required wellhead pressure is recalculated, and the procedure is repeated until the correct wellhead temperature is found. The specific available wellhead power and total available wellhead power are then calculated.

The thermodynamic properties of pure water and steam are taken from the Steam Tables (2). The thermodynamic properties of brine and of steam in equilibrium with brine are calculated by using data for brines in which the dissolved salt consists of KCl, $CaCl_2$, and NaCl in the ratio 1.00:1.95:3.55 by mass, typical of some geothermal brines in the Salton Sea area (3). The above methods of calculation are derived in EQL Report No. 10.

Well Constants

The main variables affecting wellhead available power are reservoir temperature and brine concentration. Drawdown pressure factor (at the low values required for practical wells), well-bottom pressure, and well depth have a lesser effect, and well diameter is restricted to a narrow range by available drilling techniques;

therefore, fixed values are used for those quantities (except for one example which will be presented of higher drawdown pressure). Table 4.2 lists the well constants adopted. The depth is 1,500 m (most geothermal wells have depths between 1,000 and 2,000 m). The inside diameter of the casing is 0.25 m, a typical value for production wells. Calculations are also made for a stepped diameter well with the casing diameter doubled to 0.5 m above the flash level.

Reservoir temperatures range from 150°C, about the lowest temperature considered feasible for geothermal electric power generation, to 300°C, about the highest temperature encountered. The reservoir pressure is assumed to be that due to the normal hydrostatic pressure of 20°C ground water at 1,500 m depth, namely 14.7 MPa (megapascals) or 2,130 psi. The drawdown pressure factor assumed is 25 kPa (3.6 psi) per kg/s, the value measured for a typical well (No. 1 IID in the Salton Sea area (4). The brine concentration varies from zero (pure water) to 30%, the largest usually encountered.

The volume of noncondensable gases in geothermal wells is usually not large enough to affect the flow conditions. In conversion processes the presence of noncondensables affects the ability to achieve vacuum condensing but does not otherwise greatly affect the power output. Therefore, noncondensables are assumed absent for purposes of calculating well flow and power output. The problem of condensing limitations due to noncondensables will be considered separately.

The skin friction coefficient, which is the ratio of wall shear to dynamic pressure (using the two-phase mixture density) is assumed to be 0.008, about twice the value for smooth pipe; this value gives the best agreement with data for a particular well (No. 1 IID). The value of slip velocity between the phases that gives the best agreement with the same data is zero. Heat transfer out of the well is assumed to be zero, a valid approximation at the large flow rates of interest.

The conversion process rejection temperature for calculating available power is assumed to be 45°C, a typical power plant condensing temperature. The cooling factor for pumping (the reduction in wellhead temperature per unit of pump pressure rise due to vaporizing the working fluid to drive the pump) is assumed to be 4°C per MPa (5°F per 100 psi). This factor is the lowest projected in Reference (1) and half the factor predicted there for early pumps.

TABLE 4.2: WELL CONSTANTS

Depth	1,500 m
Diameter (constant diameter well)	0.25 m
Diameter (stepped diameter well)	0.50 m from top to flash level or 750 m, whichever is less, and 0.25 m from there to bottom
Reservoir temperature	150° to 300°C
Reservoir pressure	14.7 MPa (2,130 psi)
Drawdown pressure factor	25 kPa (3.6 psi) per kg/s
Brine concentration [Reference (3) composition]	0 to 30%
Noncondensables	0
Skin friction coefficient	0.008
Interphase slip velocity	0

(continued)

TABLE 4.2: (continued)

Heat transfer out of well	0
Conversion process rejection temperature	45°C
Pump cooling factor for pumped well	4°C per MPa (5°F per 100 psi)

Effect of Stepped Diameter

With self flowing, the volume of steam increases rapidly near the top of the well due to the combined effects of increasing quality and decreasing pressure. The upper part of the well acts, therefore, as a throat, and the area at the top of the well is a dominating factor in setting the flow rate. Furthermore, the sonic velocity in two-phase mixtures is relatively low, 100 to 200 m/s at typical wellhead conditions. Consequently, the wellhead flow can easily reach sonic velocity. At that condition the well is said to be choked because any further reduction in pressure outside the top of the well casing will cause no further decrease in pressure inside the casing and no increase in flow rate. Choking is shown both experimentally and theoretically in Figure 4.10, which presents the flow rate of the No. 1 IID well (4) as a function of wellhead pressure. Based on the calculation method described above, the wellhead pressure at zero flow is 3.4 MPa (493 psi), and as the wellhead pressure is reduced the flow rate rises to a maximum of 64 kg/s at a wellhead pressure of 0.64 MPa (93 psi).

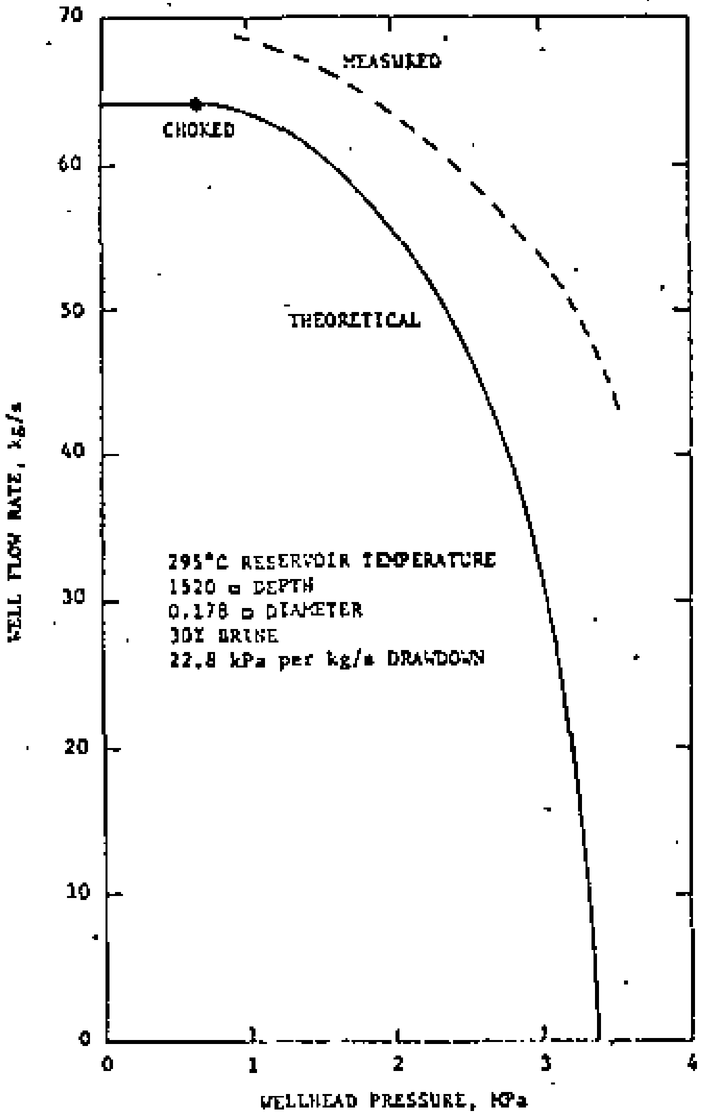
At that condition the velocity of the flow leaving the top of the casing is equal to the sonic velocity of 170 m/s in the two-phase mixture. Any further reduction of pressure (outside the top of the casing) gives no higher flow rate. The measured flow rate (dashed curve) from Figure 10 of Reference (4) shows the same behavior, although with a higher peak flow rate and higher zero-flow pressure than predicted by the theory.

The maximum available total power at the wellhead occurs just before choking when the velocity is about half of sonic. Figure 4.11 shows the variation of Mach number (ratio of flow velocity to sonic velocity) between the wellhead and the flash level for the well constants of Table 4.2 with 150°C reservoir temperature and zero brine concentration (pure water). For the constant diameter well the flash level is at a depth of 87 m for a flow rate of 55 kg/s, the flow rate giving the highest total available power at the wellhead. The Mach number for this flow rate, shown by the solid curve, rises rapidly to 0.1 in the first 10 m above the flash level, rises more slowly to 0.3 in the next 60 m, and increases rapidly to 0.5 in the last 17 m to the wellhead. If the flow rate is increased another 2% to 56 kg/s the Mach number increases to 1 at the wellhead.

If the diameter of the casing is doubled between the wellhead and the flash level a higher flow rate (121 kg/s) can be carried before choking occurs. The total available wellhead power peaks at 116 kg/s with the flash level at 300 m; the variation of Mach number with depth for that condition is shown by the dashed curve in Figure 4.11.

If the enlarged casing extends only part way to the flash level the effect on total available wellhead power is that shown in Figure 4.12. The total available wellhead power is 3.2 MW at the peak-power flow rate of 55 kg/s for the constant diameter well.

FIGURE [illegible]: COMPARISON OF MEASURED AND THEORETICAL TOTAL WELL FLOW RATE FOR NO. 1 IID WELL



Source: EQL Report No. 10

FIGURE 4.11: VARIATION OF MACH NUMBER WITH DEPTH

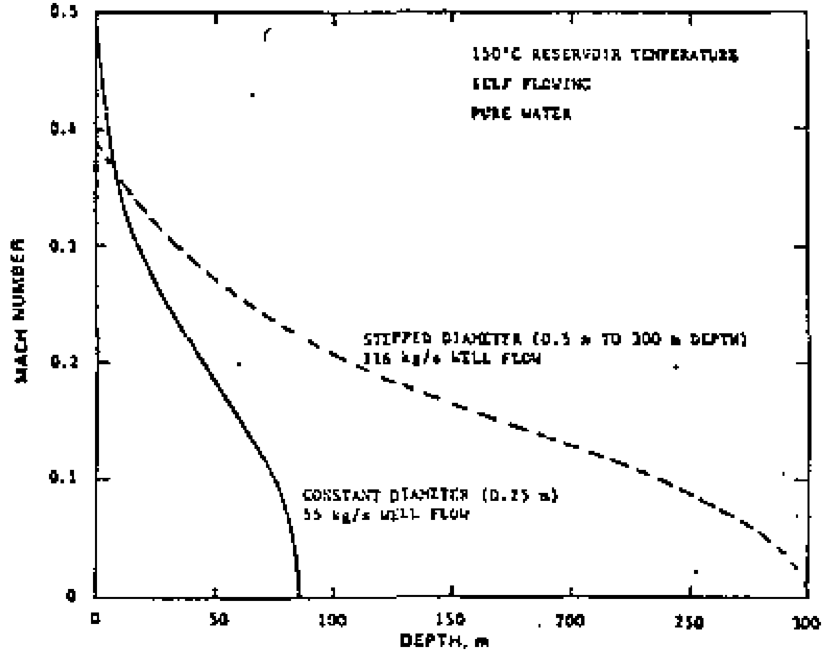
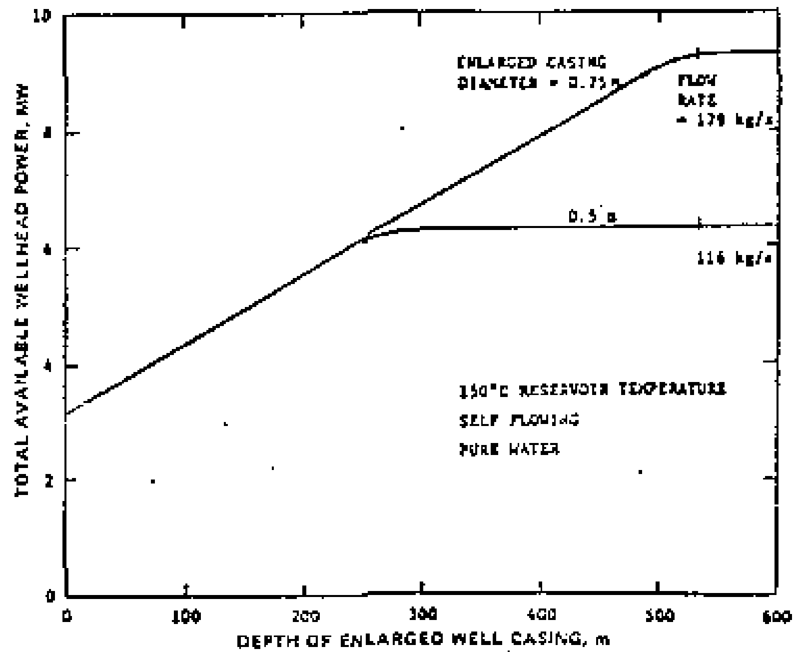


FIGURE 4.12: EFFECT OF ENLARGED CASING DIAMETER AND DEPTH OF ENLARGED CASING



Source: EQL Report No. 10

If the well diameter is doubled to 0.5 m between the wellhead and the flash level, the peak-power flow rate is increased to 116 kg/s and the available power is doubled to 6.3 MW. There is no gain from extending the enlarged casing below the flash level of 300 m; and if the enlarged casing does not reach the flash level the power is reduced in proportion.

If the casing diameter is tripled to 0.75 m between the wellhead and the flash level, the upper curve in Figure 4.12 shows that the peak-power flow rate is increased to 179 kg/s, the flash level is lowered to 500 m, and the available power is increased to 9.3 MW, almost three times the available power with constant diameter.

At higher reservoir temperatures the flash levels are deeper, approaching the bottom of the well at 300°C reservoir temperature. For this reason, the stepped-diameter cases are arbitrarily calculated for enlarged casing extending only to 750 m (half way to the bottom) if the flash level is below that depth. Table 4.13 gives the flash levels at the peak-power flow rates and the enlarged casing depths for the stepped-diameter wells.

TABLE 4.3: FLASH LEVELS IN STEPPED DIAMETER WELLS AT PEAK-POWER FLOW RATES

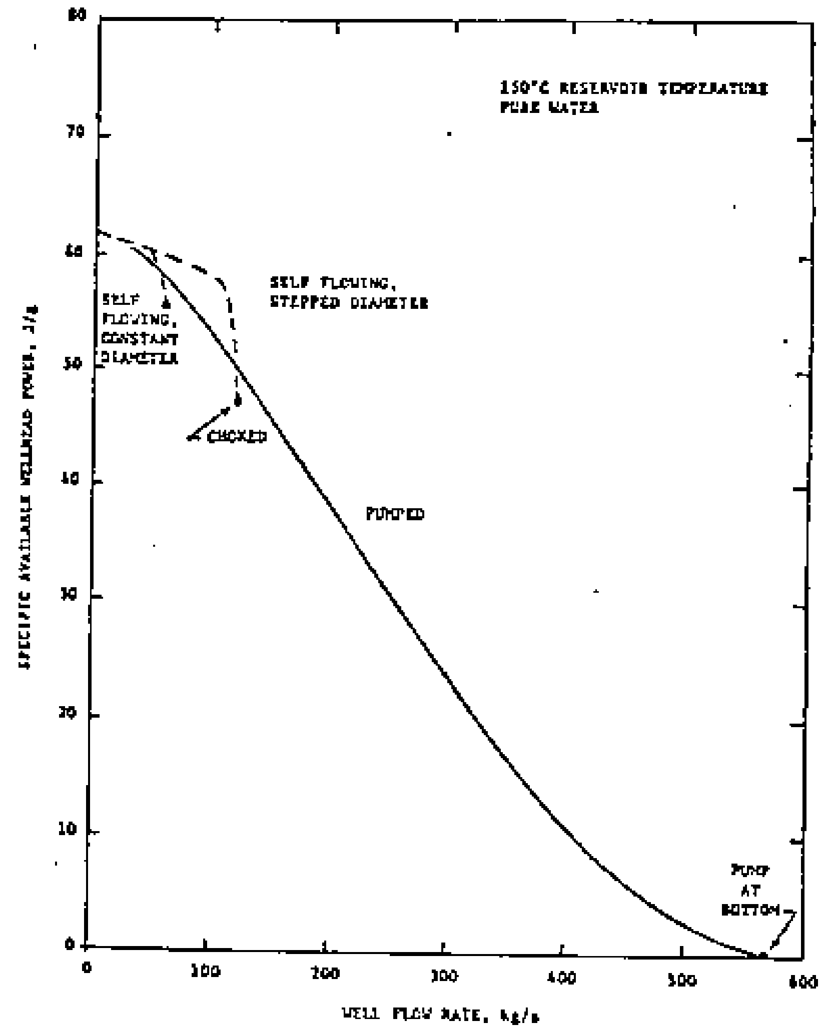
Reservoir Temperature (°C)	Brine Concentration (%)	Depth of Flash Level (m)	Depth of 0.5 m Diameter Casing (m)	Peak Available Power (MW)
150	0	300	300	6
200	0	660	660	22
250	0	950	750	43
300	0	1,400	750	61
150	30	400	400	2
200	30	640	640	10
250	30	920	750	23
300	30	1,270	750	37

Source: EOL Report No. 10

Effect of Flow Rate on Available Wellhead Power

The specific available wellhead power for 150°C reservoir temperature and zero brine concentration is plotted as a function of flow rate in Figure 4.13. At flow rates below 10 kg/s the well is self flowing with liquid at the wellhead, the well being pumped by the difference in density between the hot water inside and the cold ground water outside. The specific available wellhead power is 62 J/g (62 kW per kg/s). As the flow rate is increased with self flowing (dashed curves in Figure 4.13) the specific available wellhead power decreases due to friction and due to unrecovered kinetic energy (assumed lost except for the portion recovered as heat in stagnation of the flow at the wellhead). The constant diameter well chokes at 56 kg/s with the specific available wellhead power reduced to 55 J/g. The stepped diameter well chokes at 121 kg/s with the specific available wellhead power reduced to 47 J/g.

FIGURE 4.13: COMPARISON OF SPECIFIC AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 150°C RESERVOIR TEMPERATURE AND PURE WATER



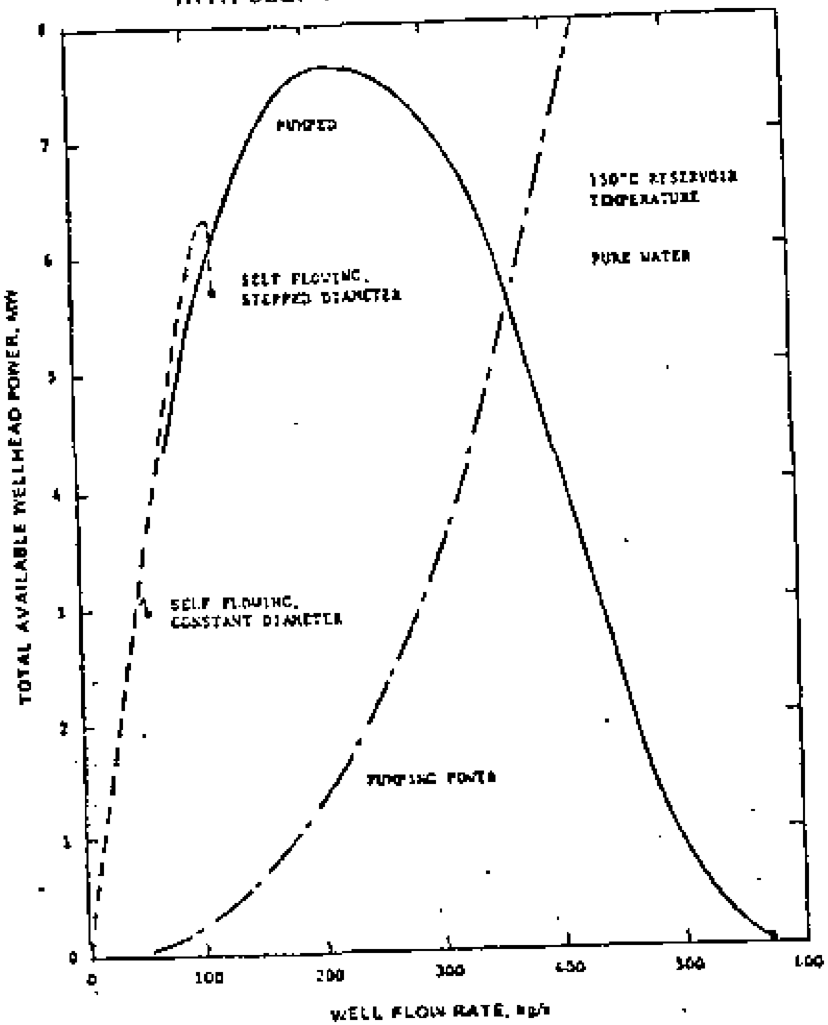
Source: EOL Report No. 10

The specific available wellhead power with pumping is shown by the solid curve in Figure 4.13. The specific available wellhead power decreases more rapidly with pumping than with self flowing because of the losses in converting the heat of the brine to mechanical pumping power (physically, the power lost is rejected from the condenser on the surface where the steam from the down-well turbine driving the pump is condensed). Thus, the losses in the pump and turbine are greater than the friction and kinetic energy losses with self flowing, until the self-flowing well approaches choking conditions.

As the flow rate with pumping is increased, it is necessary to locate the pump at increasing depths in the well for the pump inlet pressure to remain above saturation. As shown in Figure 4.13, the limiting case of the pump located at the bottom with inlet pressure equal to saturation pressure occurs at a flow rate of 570 kg/s. The specific available wellhead power at that condition is almost zero because the well flow must be cooled almost to 45°C to drive the pump. This is an impractical limiting case shown only for completeness.

Figure 4.14 presents the total available wellhead powers (the Figure 4.13 values multiplied by flow rate) as a function of flow rate for 150°C reservoir temperature and zero brine concentration.

FIGURE 4.14: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING.



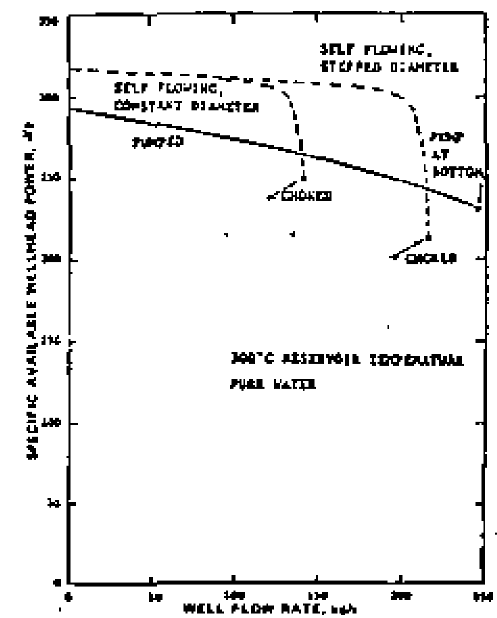
Source: EOL Report No. 10

For self flowing at constant diameter the total available wellhea ver reaches a maximum of 3.2 MW at 55 kg/s. The power drops to 3.1 MW when the well is choked at 56 kg/s (the increased flow rate is not enough to compensate for the increased friction and kinetic energy losses). For self flowing with stepped diameter (0.5 m diameter to 300 m depth and 0.25 m diameter from there to the bottom) the total available wellhead power reaches a maximum of 6.3 MW at 116 kg/s and drops to 5.7 MW when the flow is choked at 121 kg/s.

For pumping, the total available wellhead power increases more slowly with flow rate than for self flowing because of the more rapid decrease in specific available wellhead power. The total available wellhead power reaches a maximum of 7.6 MW at a flow rate of 210 kg/s and then decreases with further increase in flow rate because the pump-loop losses increase faster than the flow rate. At 210 kg/s the pumping power (volume flow rate times pump pressure rise), shown by the lower curve in Figure 4.14, is 1.3 MW; the pump must be at a depth of 600 m for saturation inlet pressure (and at a depth 20 to 100 m lower for practical inlet pressures).

The specific available wellhead power for 300°C reservoir temperature and zero brine concentration is plotted as a function of flow rate in Figure 4.15.

FIGURE 4.15: COMPARISON OF SPECIFIC AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 300°C RESERVOIR TEMPERATURE AND PURE WATER



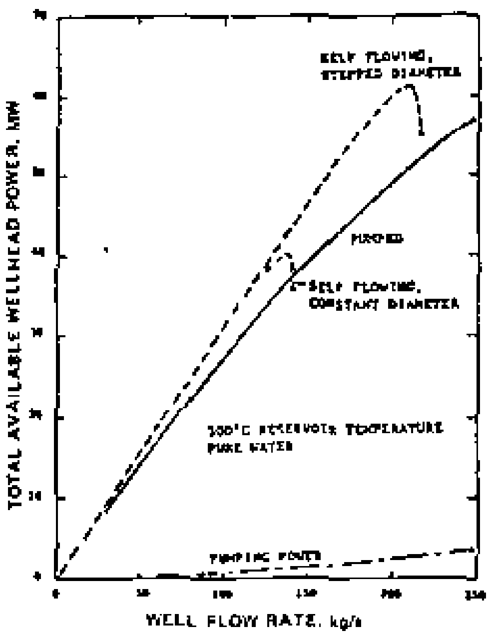
Source: EOL Report No. 10

T. wers are about five times higher than for 150°C reservoir temperature, the variation with flow rate is similar. At this temperature, the self-flowing well delivers vapor to the surface at all flow rates. The specific available wellhead power varies from 317 J/g at low flow rate to 250 J/g at choking with constant diameter and to 210 J/g at choking with stepped diameter (0.5 diameter to 750 m depth).

With pumping, a pressure rise of 3 MPa (440 psi) is required at zero flow to provide saturation pressure at the wellhead, and the specific available wellhead power is already reduced to 290 J/g. With increasing flow rate the specific available wellhead power decreases more rapidly than with self flowing (except near choking) and drops to 230 J/g in the limiting case with the pump at the bottom at saturation inlet pressure. The absolute decrease in specific available power with flow rate is about the same as at 150°C reservoir temperature, but the relative decrease is less because of the higher available power.

The total available wellhead power with 300°C reservoir temperature and zero brine concentration is presented in Figure 4.16. With self flowing the constant-diameter well provides 40 MW available power and the stepped-diameter well 61 MW. Pumping gives the same total available wellhead power as self flowing at constant diameter if the pumping power is 1.4 MW and the pump is at 1,200 meters depth, but even the limiting case of a 3.4 MW pump at the bottom gives less available wellhead power than self flowing with enlarged casing to 750 m.

FIGURE 4.16: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 300°C RESERVOIR TEMPERATURE AND PURE WATER



Source: EQL Report No. 10

The results for 30% brine concentration are shown in Figure. [illegible] through 4.20. The main difference compared with pure water is lower specific available power due to the lower enthalpy of the brine. In addition, the higher density of the brine reduces the peak-power and choking flow rates with self flowing at low reservoir temperature. With 150°C reservoir temperature and 30% brine concentration (Figure 4.18) the total available wellhead power with pumping can be six times as great as for self flowing at constant diameter and almost twice as great as for self flowing with stepped diameter.

FIGURE 4.17: COMPARISON OF SPECIFIC AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 150°C RESERVOIR TEMPERATURE AND 30% BRINE

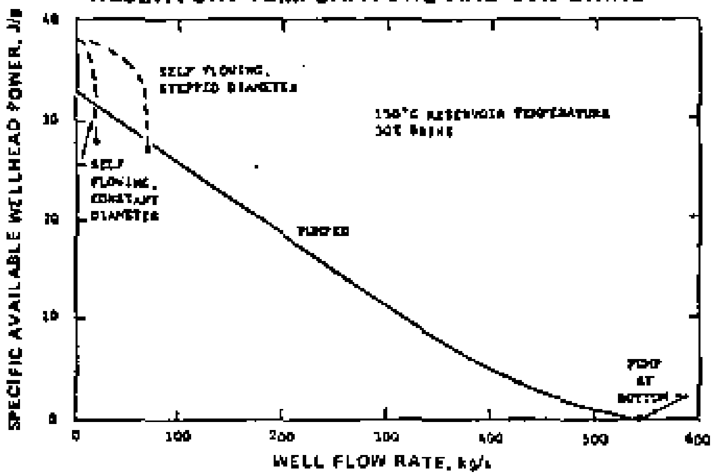
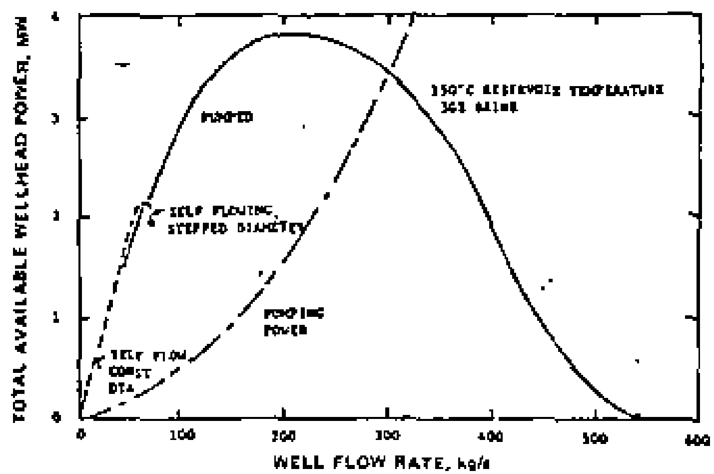


FIGURE 4.18: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 150°C RESERVOIR TEMPERATURE AND 30% BRINE



Source: EQL Report No. 10

However, low temperature high-salinity geothermal resources are known to exist. At 300°C and 30% brine (Figure 4.20) even a 5 MW pump at the bottom of the well gives only twice as much wellhead power as self flowing with constant diameter and negligibly more power than self flowing with stepped diameter.

FIGURE 4.19: COMPARISON OF SPECIFIC AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 300°C RESERVOIR TEMPERATURE AND 30% BRINE

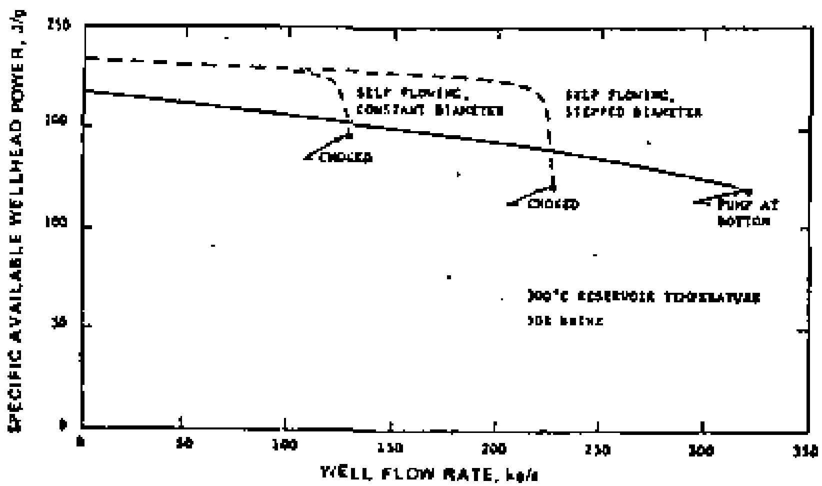
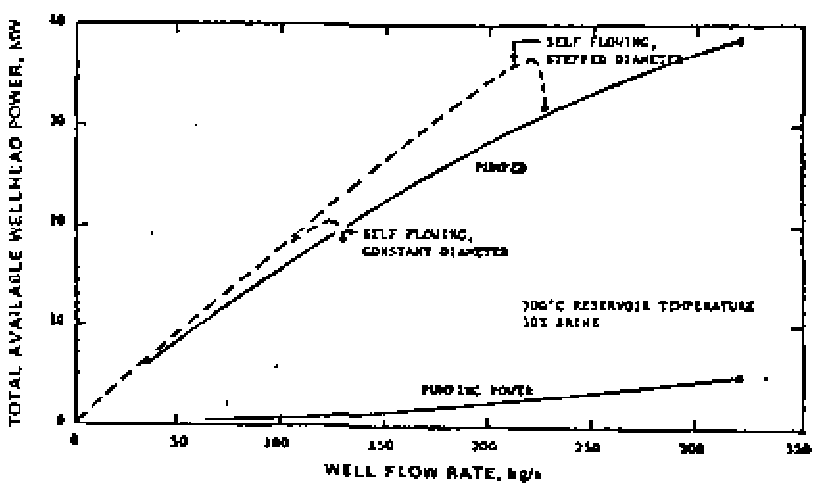


FIGURE 4.20: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER WITH SELF FLOWING AND PUMPING FOR 300°C RESERVOIR TEMPERATURE AND 30% BRINE



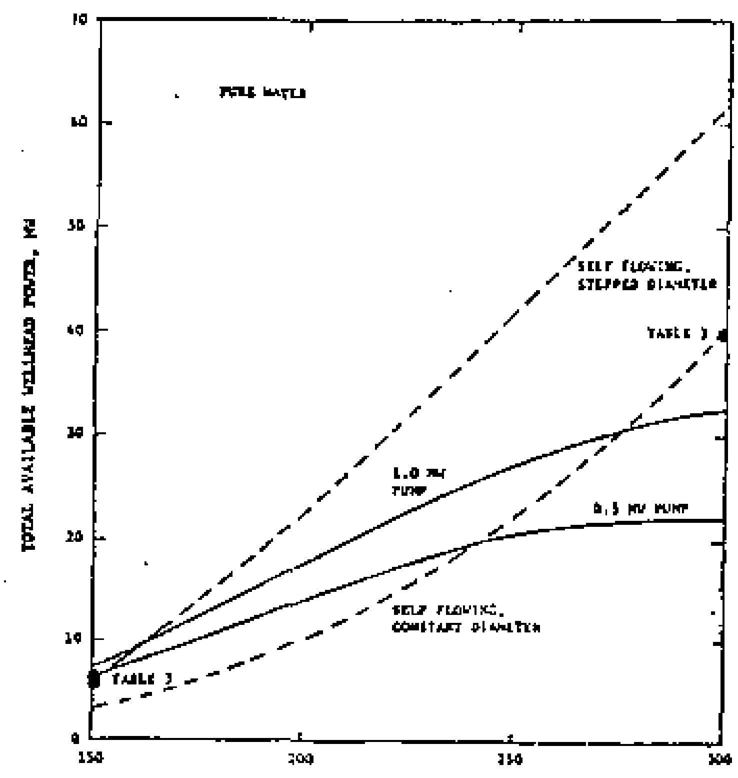
Source: EQL Report No. 10

Comparison of Available Wellhead Power for Self Flowing and F[illegible]ng

The best choice of flow rate for self flowing is the flow rate that gives maximum total available wellhead power, assuming there are no gains elsewhere from using lower flow rate. The best flow rate for pumping, however, will be at least slightly below the peak-power flow rate because reduced pump power and depth result. Perhaps the largest pump that can be installed in a 0.25 m diameter casing would provide 1.0 MW pumping power, and a more realistic size would be 0.5 MW (the test pump described in Reference (1) is designed for 0.1 MW pumping power in a 0.22 m diameter casing). The flow rates at pumping powers (volume flow rate x pressure rise) of 0.5 and 1.0 MW are, therefore, adopted as representing the flow rates for near-term and advanced pumping systems, respectively.

Figure 4.21 compares the total wellhead available power for self flowing at peak-power flow rate in constant diameter and stepped diameter wells (dashed curves) with the total available wellhead power for pumping with 0.5 and 1.0 MW pumping power (solid curves) as a function of reservoir temperature for zero brine concentration.

FIGURE 4.21: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER FOR SELF FLOWING (AT PEAKS) AND PUMPING (AT FIXED PUMPING POWERS) AS A FUNCTION OF RESERVOIR TEMPERATURE FOR PURE WATER

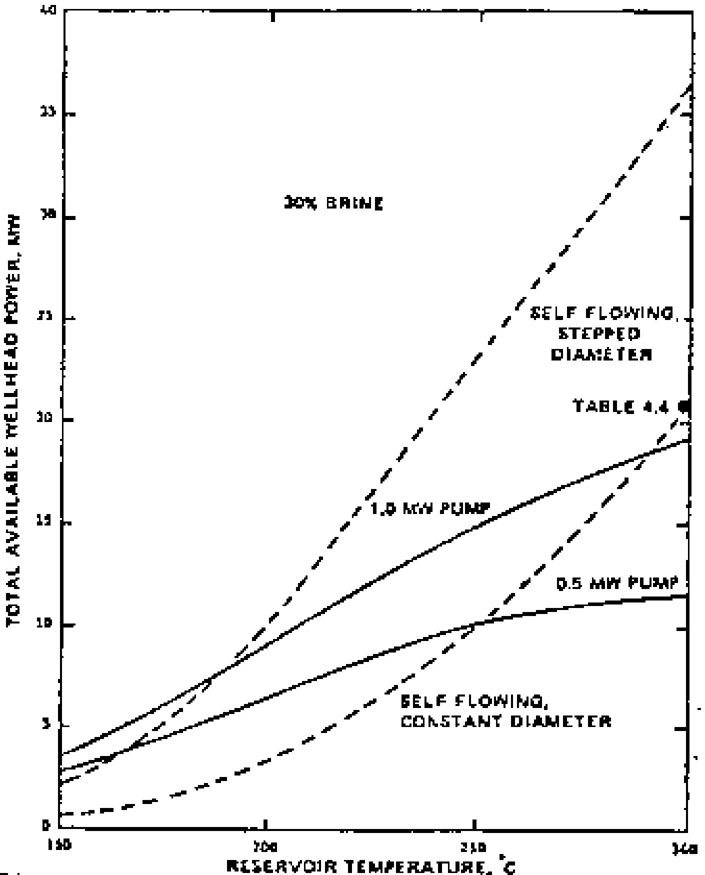


Source: EQL Report No. 10

With self flowing the total available wellhead power increases by a factor of 10 from 150°C to 300°C reservoir temperature, and the power with stepped diameter is twice that with constant diameter. With pumping the total available wellhead power rises only half as much as with self flowing, and the available power with a 1.0 MW pump is only 40% more than with a 0.5 MW pump. Compared with self flowing at constant diameter, the 1.0 MW pump provides higher powers at reservoir temperatures below 270°C and the 0.5 MW pump provides higher powers at reservoir temperatures below 240°C. Pumping provides little or no gain over self flowing with stepped diameter at any temperature.

Figure 4.22 presents the same comparisons with 30% brine concentration. The main difference is that with self flowing the total available power increases by a factor of 20, instead of 10, from 150°C to 300°C reservoir temperature, whereas the factor of increase with pumping is about the same as with pure water. The result is that at low temperatures pumping provides a greater increase in total available wellhead power, over self flowing, with brine than with pure water. However, no low-temperature, high-salinity geothermal resources are known.

FIGURE 4.22: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER FOR SELF FLOWING (AT PEAKS) AND PUMPING (AT FIXED PUMPING POWERS) AS A FUNCTION OF RESERVOIR TEMPERATURE FOR 30% BRINE



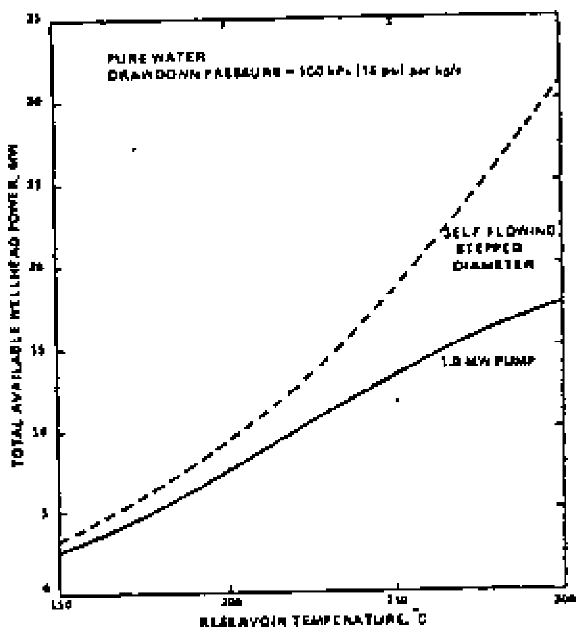
Source: EOL Report No. 10

The results for pumping, although calculated for a turbine-driven pump using cooling of the well flow, are also valid for a pump driven by mechanical, hydraulic, or electric power from the surface. In those cases, the power to drive the pump is taken from the conversion process output, and the resulting reduction in net output is about the same as the reduction in available wellhead power calculated here, for equal efficiency of conversion of heat to pumping power.

For example, at 200°C reservoir temperature the flow rate with 1.0 MW pumping power is 175 kg/s, the pump pressure rise is 5.0 MPa (700 psi), and the wellhead temperature is 180°C (due to the assumed 4°C per MPa cooling). The wellhead available power is 17 MW. If the pump is externally driven, the wellhead temperature is 200°C and the wellhead available power is increased to 22 MW. The pump pressure rise is increased 10% by the higher saturation pressure, requiring 1.1 MW pumping power. If the pump efficiency is 0.5 and the available wellhead power is converted to pump-drive power at 0.5 efficiency, the amount of available wellhead power used for pumping is 1.1/(0.5 x 0.5) equaling 4.4 MW. This leaves 17.6 MW of available wellhead power, about the same as with the pump driven by cooling of the well flow.

The comparisons between self flowing and pumping are not significantly affected if the drawdown pressure or static well-bottom pressure is changed. Figure 4.23 shows how the curves in Figure 4.21 change if the drawdown pressure factor is increased by a factor of four. The wellhead powers are cut in half, but the relationship between self-flowing and pumping is nearly the same.

FIGURE 4.23: COMPARISON OF TOTAL AVAILABLE WELLHEAD POWER FOR SELF FLOWING AND PUMPING WITH FOUR-FOLD INCREASE IN DRAWDOWN PRESSURE



Source: EOL Report No. 10

The flow [illegible] in Figure 4.23 range from 60 kg/s to 110 kg/s. Therefore Figure 4.23 also applies to a well with static bottom-hole pressure reduced to between 7.5 and 10.0 MPa, values that are only 51 to 68% of the hydrostatic pressure of ground water assumed in the previous calculations.

Summary

The comparisons between self flowing and pumping cast considerable doubt on the value of pumping. Above 225°C, pumping increases total available wellhead power by at most a factor of two compared with self flowing at constant diameter, and there is no increase compared with stepped diameter. At lower temperatures, pumping increases total available power by greater than a factor of two only with high brine concentrations that are not encountered at those temperatures.

The possible value of pumping in preventing flashing and resulting scale deposit in the well remains, but it does not appear that pumping is of significant value on an energy basis.

CONVERSION PROCESSES

Wellhead Conditions

For the comparison of conversion processes, four wellhead conditions are chosen that are representative of the extremes calculated in the previous section. The assumed wellhead conditions are given in Table 4.4 and also indicated on the curves of total available wellhead power in Figures 4.21 and 4.22.

The first wellhead condition is for self flowing at 150°C reservoir temperature with zero brine concentration and stepped diameter. The 150°C reservoir temperature represents the low end of the temperature range for geothermal electric power generation. Most brines at that temperature have salt concentration below 5% and can, therefore, be represented by pure water for power calculations. The stepped diameter requires enlarging the casing only to 300 m depth.

The second wellhead condition is for pumping at 150°C reservoir temperature and zero brine concentration with 0.5 MW pumping power. The pumping provides saturated liquid at the wellhead without vapor, and the 0.5 MW pumping power is a practical goal.

The third wellhead condition is for self flowing at 300°C reservoir temperature with zero brine concentration and constant diameter. The 300°C reservoir temperature represents the upper end of the temperature range available in geothermal reservoirs. Some brines at that temperature have low salt concentrations and can be represented by pure water for power calculations. A constant diameter provides high flow rate and stepped diameter is not needed.

The fourth wellhead condition is the same as the third except that 30% brine concentration is assumed.

TABLE 4.4: WELLHEAD CONDITIONS FOR CONVERSION PROCESS CALCULATIONS

	150°C Reservoir Temperature		300°C Reservoir Temperature	
	Self Flowing, Stepped Diameter, Pure Water	Pumped, 0.5 MW Pumping Power, Pure Water	Self Flowing, Constant Diameter, Pure Water	Self Flowing, Constant Diameter, 30% Brine
Temperature, °C	114	137	218	202
Quality	0.07	0	0.21	0.12
Pressure, MPa	0.16	0.33	2.23	1.25
Pressure, psi	23	48	323	181
Flow rate, kg/s	118	137	136	124
Specific available power, J/g	54	48	292	171
Total available power, MW	6.3	6.6	40	21

Source: EQL Report No. 10

Flash Steam Process

The most commonly used conversion process for power generation from brine is the flash steam process. Figure 4.24 shows a flash steam process with one stage. The flow leaving the wellhead enters a flash vaporizer where the pressure is reduced, causing part of the brine to vaporize. The mixture of brine and steam then enters a separator where the brine and steam are separated. The brine flows to a reinjection well or other disposal area. The steam flows to a turbine for power generation and is then condensed in a condenser. The condensate is pumped to atmospheric pressure for disposal or for use in the cooling tower. The flow from a pumped well consists entirely of liquid (designated L in the diagram), and the flow from a self flowing well consists of both liquid (L) and gas (G), the gas phase being steam. With two-phase wellhead flow the flash vaporizer may be omitted and the wellhead flow fed directly to the separator at wellhead pressure. The flash vaporizer, if used, consists of whatever provides the pressure drop between the wellhead and the separator; usually an orifice at the separator inlet is used.

The separator is any conventional type such as a cyclone separator. With high brine concentrations the steam line to the turbine may include scrubbers to remove entrained salts. The condenser is usually a contact condenser wherein water from the cooling tower is sprayed directly into the condensing steam. The condenser pumping may be accomplished by elevating the condenser above ground level or by using a mechanical pump. Any noncondensables in the steam must be pumped from the condenser to atmosphere by mechanical pumps or by steam ejectors using steam that would otherwise drive the turbine.

A flash steam process with two stages is shown in Figure 4.25. The brine from the first-stage separator flows to the second-stage flash vaporizer where the pressure of the brine is reduced to that of the steam leaving the first-stage steam turbine. The resulting steam and brine mixture is separated in the second-stage separator. The steam from the second-stage separator joins the steam leaving the first-stage turbine and flows to the second-stage turbine.

FIGURE 4.24: FLASH STEAM PROCESS WITH ONE STAGE

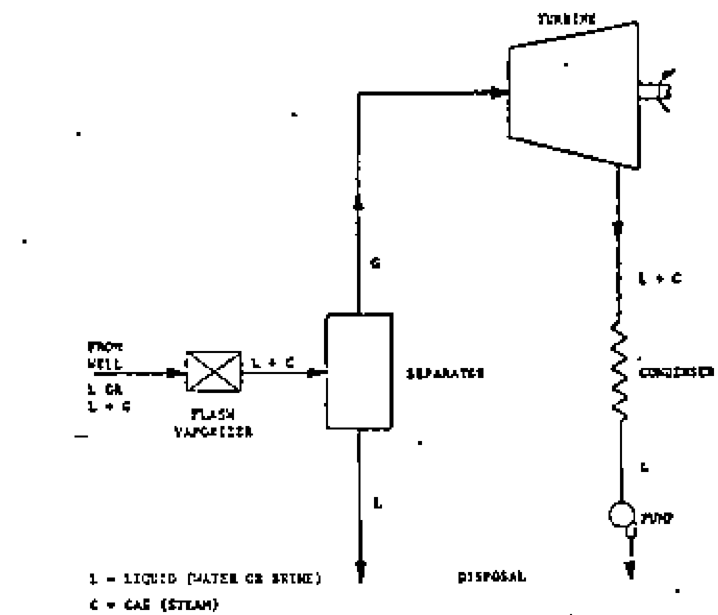
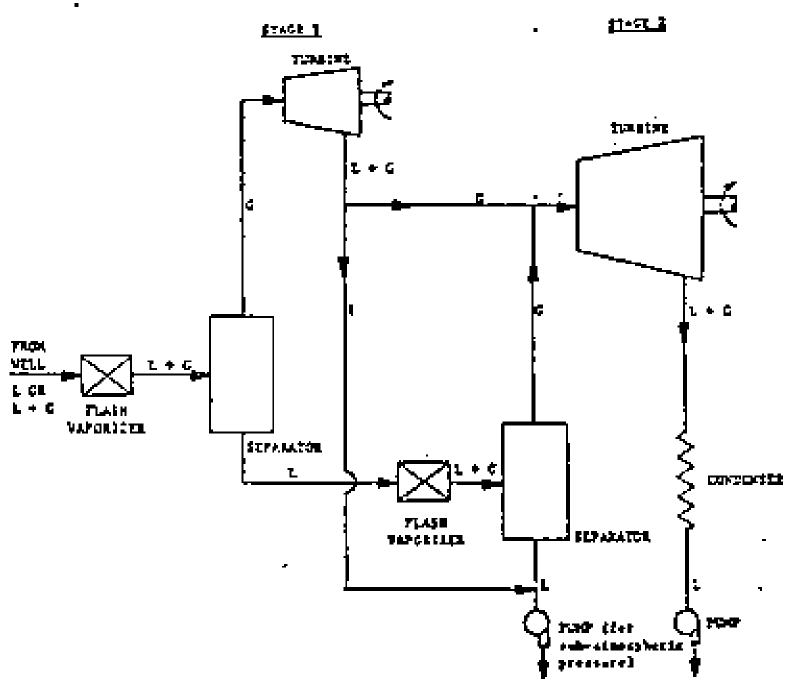
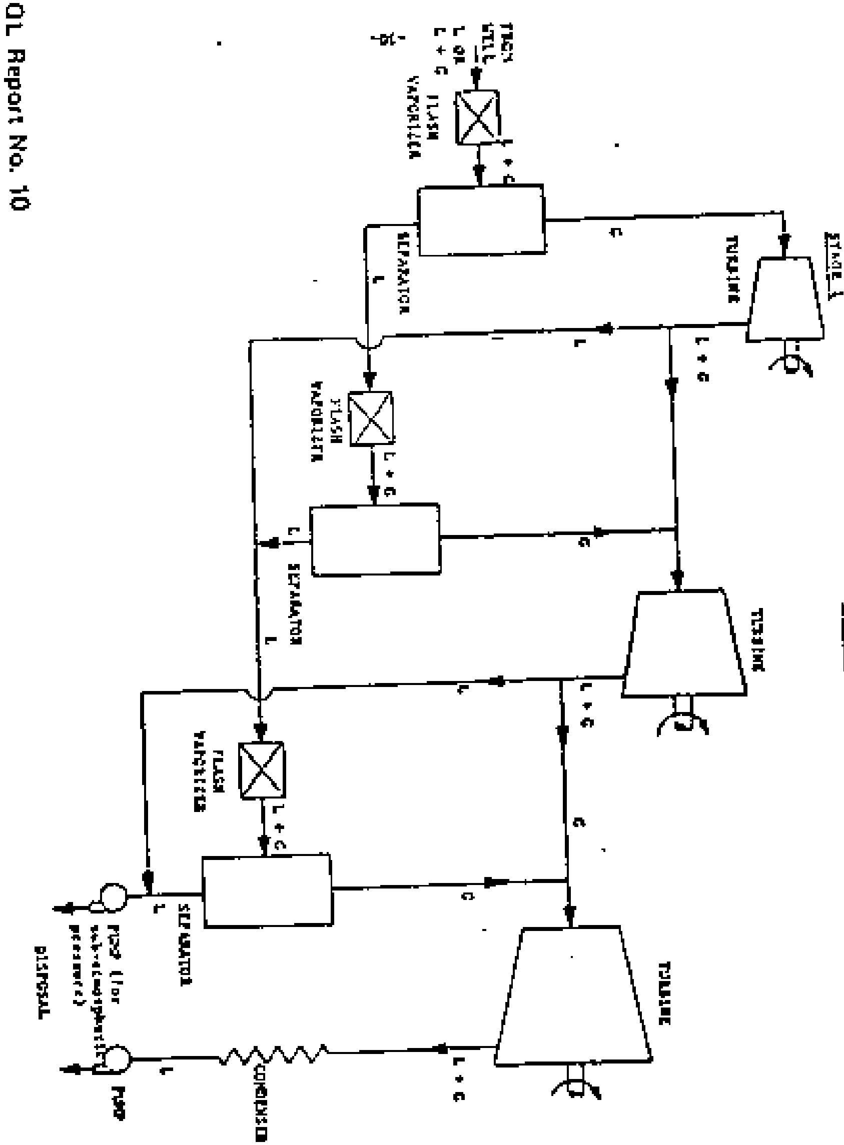


FIGURE 4.25: FLASH STEAM PROCESS WITH TWO STAGES



Source: EOL Report No. 10

FIGURE 4.26: FLASH STEAM PROCESS WITH THREE STAGES



Source: EOL Report No. 10

To minin... moisture in the second-stage turbine, the moisture leaving the first-stage turbine is separated and added to the brine leaving the second-stage separator. If the pressure in the second-stage separator is below atmospheric, a pump (or elevation above ground level) is required for removal of the separated brine.

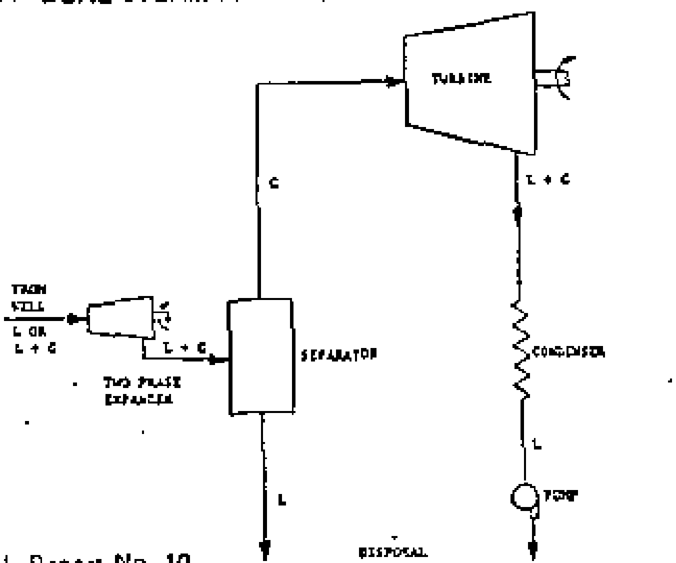
A flash steam process with three stages is shown in Figure 4.26. The pattern is the same as for the two-stage process. The gain achieved with multi-staging is that the brine leaving the last-stage separator is rejected at lower temperatures as the number of stages is increased, resulting in more of the brine energy being converted to turbine output power.

Dual Steam Process

When brine, or a brine and steam mixture, is flash vaporized, mechanical work is available from the expansion of the vaporizing mixture. That work is not utilized in the flash steam system; the work goes into accelerating the flow and is dissipated as heat when the flow is decelerated by friction and impact. It is possible to replace the flash vaporizer with a two-phase expander that provides the same pressure drop but extracts part of the available work as shaft power.

Figure 4.27 shows a single-stage process using a two-phase expander. The process is the same as the one in Figure 4.24 except that a two-phase expander replaces the flash vaporizer. The two-phase expander provides shaft power that can be used to generate additional electric power. At the same separator pressure as in the flash steam process, the exhaust from the two-phase expander has lower quality than the exhaust from the flash vaporizer, and the steam turbine power is, therefore, reduced. But the sum of the steam turbine power and two-phase expander power is always greater than for the flash steam process no matter how low the two-phase expander efficiency. The flash vaporizer can be considered as the limiting case of a two-phase expander with zero efficiency.

FIGURE 4.27: DUAL STEAM PROCESS WITH ONE STAGE



Source: EQL Report No. 10

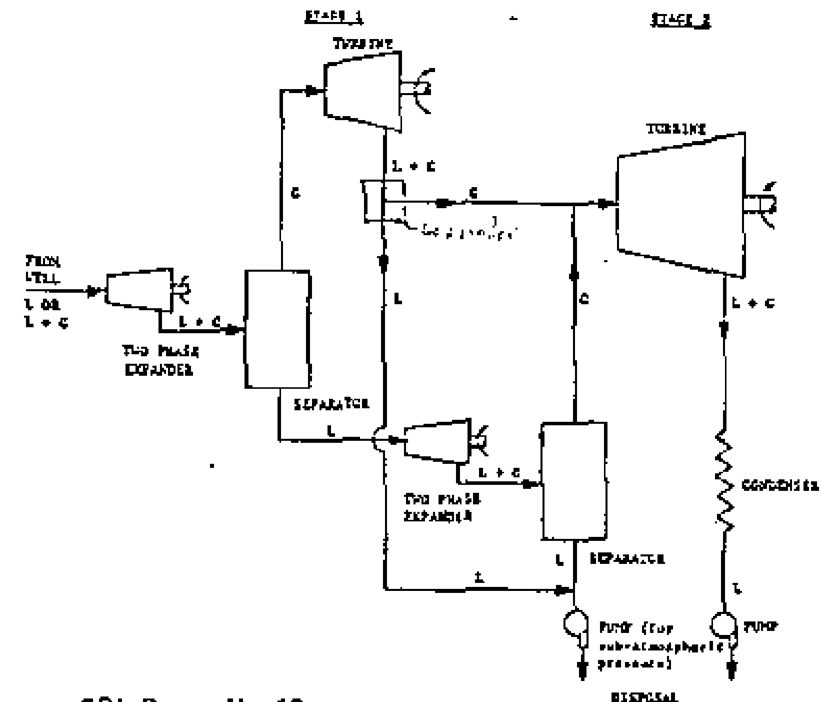
Since two types of expanders are being used in combination, the ... ess of Figure 4.27 is designated as a dual steam process. The dual steam process was first proposed by Laird (5).

A dual steam process with two stages is shown in Figure 4.28. As in the case of the flash steam process, the gain achieved with multistaging is that the brine leaving the last-stage separator is rejected at lower temperatures as the number of stages is increased.

The liquid leaving the last-stage separator is still at a higher temperature and pressure than the condenser, and additional mechanical work is available from expanding that liquid through an additional two-phase expander to the condenser conditions. A single-stage dual steam process with an exhaust liquid expander is shown in Figure 4.29. The added expander is shown exhausting into a separator at the condenser pressure, with the exhaust steam flowing to the condenser inlet and the exhaust liquid flowing to the condenser exit. This avoids problems of brine contamination of the condenser and cooling system.

With the exhaust liquid expander, all of the wellhead flow is rejected at condensing temperature. The process extracts all of the available energy from the wellhead flow, within the limitations of mechanical efficiencies, using only one steam turbine and two two-phase expanders. However, from the standpoint of limiting the volume flow rate in the two-phase expanders more stages may be desired. A two-stage dual steam process with an exhaust liquid expander is shown in Figure 4.30.

FIGURE 4.28: DUAL STEAM PROCESS WITH TWO STAGES



ource: EQL Report No. 10

FIGURI): ONE-STAGE DUAL STEAM PROCESS WITH EXHAUST LIQUID EXPANDER

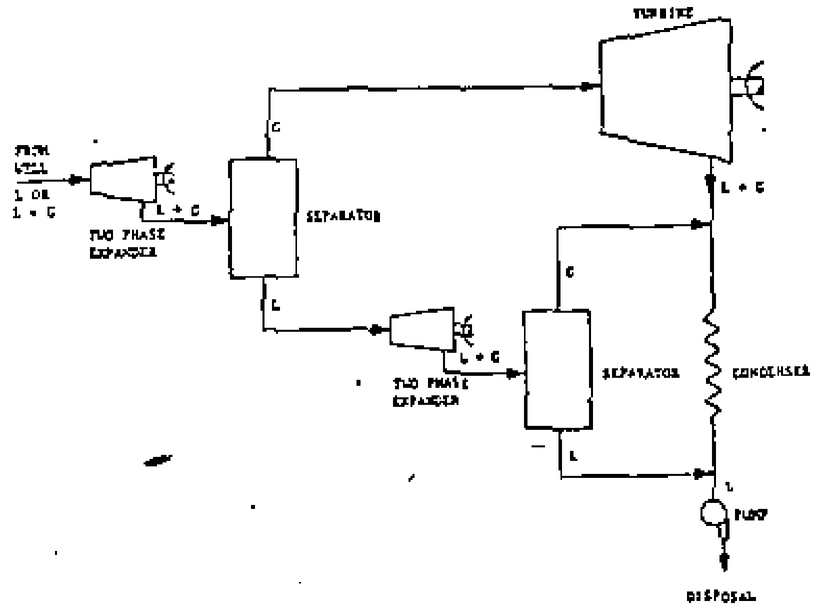
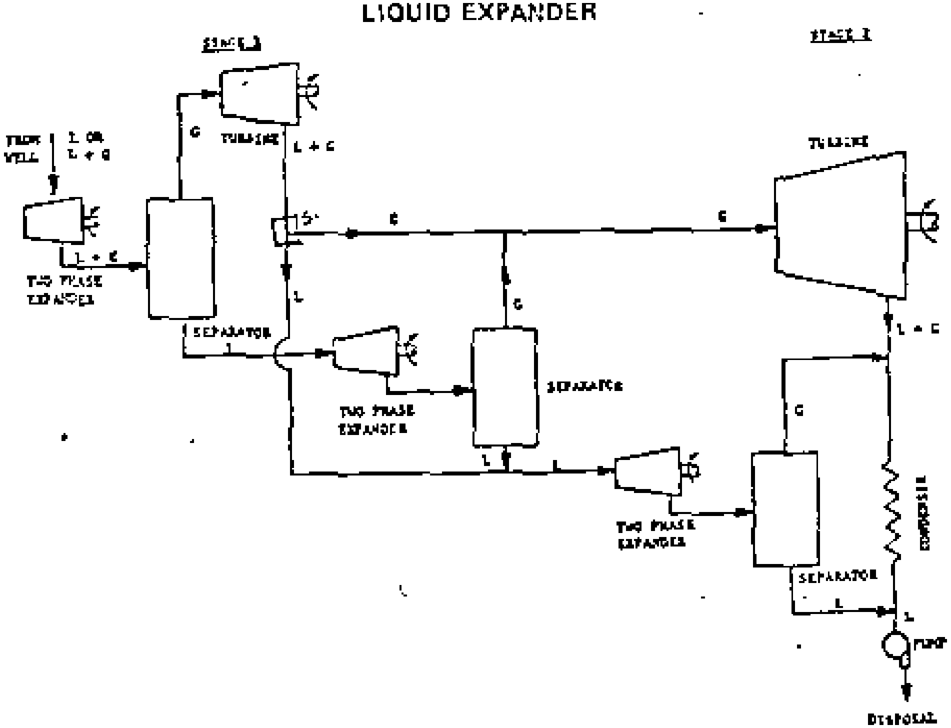


FIGURE 4.30: TWO-STAGE DUAL STEAM PROCESS WITH EXHAUST LIQUID EXPANDER

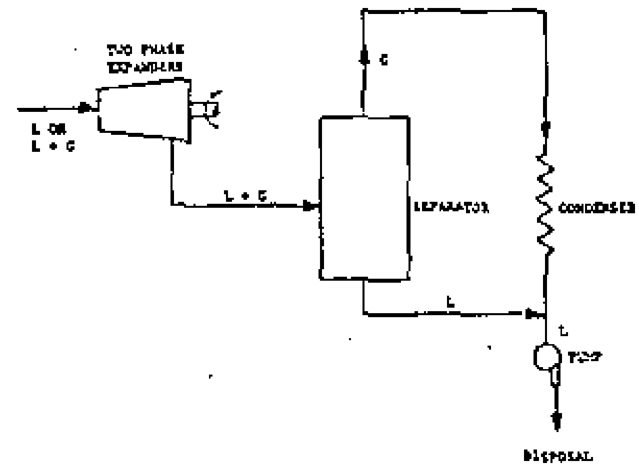


Source: EQL Report No. 10

Total Flow Process

Another method of expanding the entire wellhead flow to condensing temperature and extracting the available work is the total flow process (6). In the total flow process, shown in Figure 4.31, the entire wellhead flow expands through one or more two-phase expanders to the condenser conditions. Multistaging of the two-phase expanders may be used for mechanical reasons, but thermodynamically all of the recoverable energy can be obtained in a single stage.

FIGURE 4.31: TOTAL FLOW PROCESS



Source: EQL Report No. 10

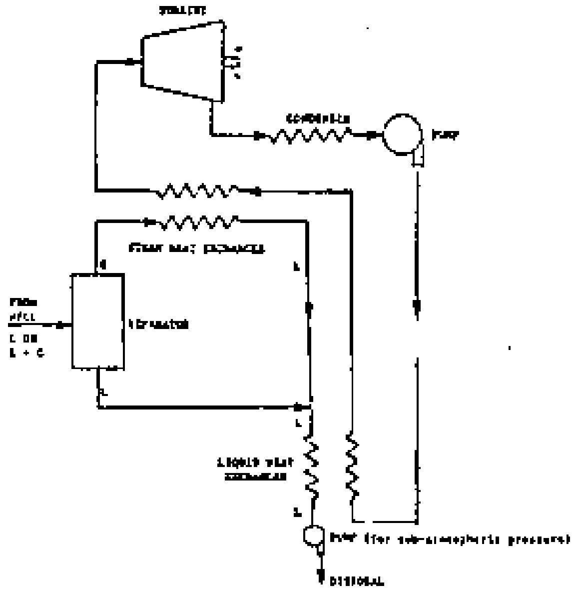
Binary Process

The binary conversion process uses the wellhead flow as a heat source for a separate closed-loop power cycle. Usually an organic working fluid operating in a Rankine cycle is considered. Figure 4.32 shows a binary process. The wellhead flow, if it is two-phase, enters a separator, and the steam leaving the separator enters the steam heat exchanger where the steam is condensed by heat transfer to the organic working fluid. The condensate then joins the brine leaving the separator and flows through the liquid heat exchanger where the liquid is cooled by further heat exchange to the organic working fluid. The liquid then flows to disposal, through a pump if necessary. If the wellhead flow is single phase, as with a pumped well, then no separator or steam heat exchanger is used.

The organic working fluid flows from the cold end to the hot end of the liquid heat exchanger and then through the steam heat exchanger, if used. The organic fluid then expands through the turbine, is condensed by heat transfer to atmosphere or to a cooling fluid, and is pumped back to the heat exchanger inlet.

A single-stage binary process can cool all of the brine to condensing temperature plus some minimum heat exchanger temperature difference, and multistaging is not needed.

FIGURE 4.32: BINARY PROCESS



Source: EOL Report No. 10

Flash Binary Process

High salt concentrations may cause fouling of the liquid heat exchanger in the binary process. The heat in the brine can still be recovered, however, by flash vaporizing the brine and using the steam in a series of steam heat exchangers. Such a flash binary process with one stage is shown in Figure 4.33. The well-head flow, after possible additional vaporization in a flash vaporizer, is separated, and the steam is used to heat the organic working fluid. The separated brine flows to the reinjection well or other disposal site. The heat exchanger in Figure 4.33 is both a steam and liquid heat exchanger. After the steam condenses in the first part of the heat exchanger the condensate (which is pure water) is cooled by further heat transfer to the organic working fluid.

A flash binary process with two stages is shown in Figure 4.34. The steam entering the first-stage heat exchanger is condensed, and the condensate is cooled to an intermediate temperature. The condensate is then throttled to saturation pressure (the mechanical work lost is negligible). The brine from the first-stage separator flows to the second-stage flash vaporizer where the pressure of the brine is reduced to that of the liquid leaving the first-stage heat exchanger. The resulting steam and brine mixture is separated in the second-stage separator. The steam from the second-stage separator joins the liquid leaving the first-stage heat exchanger and flows to the second-stage heat exchanger. The brine from the second-stage separator flows to disposal, through a pump if necessary. The liquid leaving the second-stage heat exchanger flows to disposal or is used in the cooling tower.

FIGURE 4.33: FLASH BINARY PROCESS WITH ONE STAGE

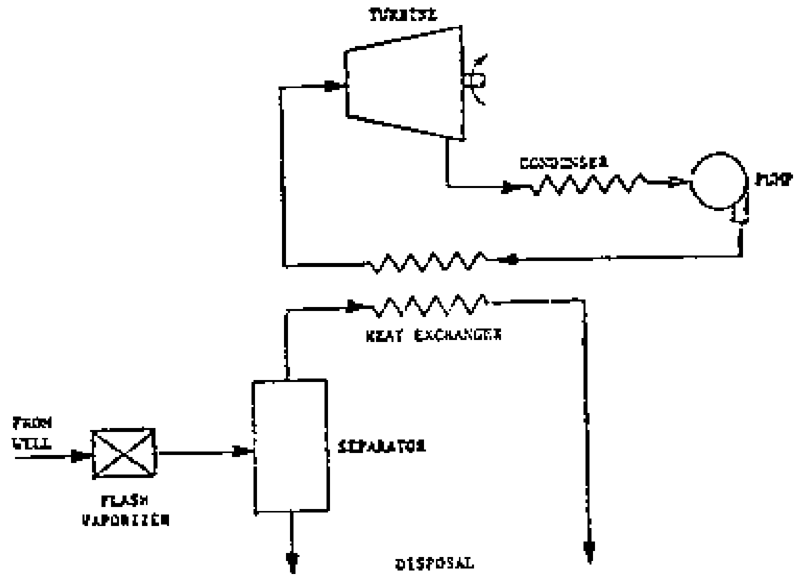
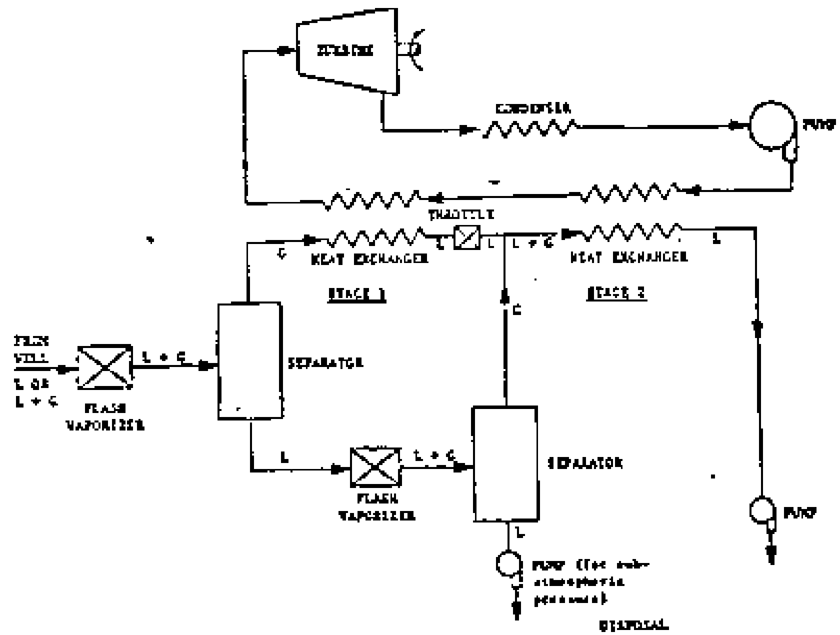


FIGURE 4.34: FLASH BINARY PROCESS WITH TWO STAGES



Source: EOL Report No. 10

Method lculating Power Output

The method of calculation for flash steam and dual steam is summarized below. The quantities specified are wellhead temperature, quality, and brine concentration; number of stages; steam condensing temperature; steam turbine and two-phase expander efficiencies; disposal and condenser pump efficiencies; and selection of optional exhaust liquid expander. The calculation procedure first assigns initial guesses to the turbine inlet temperatures in each stage. The flash vaporizer, or two-phase expander exit conditions are then calculated stage by stage together with the steam turbine exit conditions, steam turbine power output, and any two-phase expander power output. The powers for all of the stages are added to give the total electric power output. The calculations are then repeated with other turbine inlet temperatures until the optimum temperatures corresponding to maximum total output power are found, using a standard multivariate search routine.

The method of calculation for total flow is simply to multiply the wellhead available power by the assumed two-phase expander efficiency to obtain the output power. The method of calculation for binary and flash binary is summarized below. The quantities specified are wellhead temperature, quality, and brine concentration; number of stages; organic working fluid condensing temperature; disposal pump efficiency; temperature difference between the water or steam and the organic fluid at the inlets and exits of the heat exchangers; and selection of a liquid heat exchanger to give a binary, instead of flash binary, process.

The losses in the organic cycle are lumped together in a cycle efficiency factor which is the ratio of actual to ideal power output, the ideal power output being the output of a series of Carnot cycles receiving heat along the temperature curve of the organic fluid as it proceeds through the heat exchangers and rejecting heat at the condensing temperature of the organic fluid. The cycle efficiency factor is chosen to reflect turbine and pump losses and the effect of any heat rejection above the condensing temperature.

The calculation procedure for binary and flash binary processes first assigns an initial guess to the inlet temperature of the first-stage heat exchanger. The temperatures at the inlets of the other heat exchangers (if more than one stage is used) are then calculated, together with the organic working fluid flow rate, to set the temperature differences between the organic working fluid and brine at the inlets and exits of the heat exchangers to the specified temperature difference. The ideal power output of the organic cycle is then calculated. The inlet temperature of the first-stage heat exchanger is varied and the calculations repeated until the optimum temperature corresponding to maximum power output is found. The methods of calculation summarized above are derived in EQL Report No. 10. Table 4.5 presents the constants used in the conversion process calculations.

TABLE 4.5: CONVERSION PROCESS CONSTANTS

Steam Processes	
Steam condensing temperature	45°C
Steam turbine efficiency	0.7
Two-phase expander efficiency	0.6

(continued)

TABLE 4.5: (continued)

Pump efficiency	0.7
Disposal pressure	0.1 MPa (1 atm)
Binary Processes	
Organic fluid condensing temperature	45°C
Organic working fluid	isobutane
Pressure of organic working fluid in heat exchangers	4.14 MPa (600 psi)
Cycle efficiency factor	0.7
Temperature difference between water and organic working fluid at inlets and exits of heat exchangers	10°C (flash binary or binary with self-flowing well) 20°C (binary with pumped well)
Water disposal pump efficiency	0.7
Disposal pressure	0.1 MPa (1 atm)

Source: EQL Report No. 10

Comparison of Power Outputs

The results of the conversion process calculations are expressed as the power recovery fraction, which is the ratio of actual output power to available wellhead power.

Figure 4.35 compares the power recovery fraction of the different conversion processes for 150°C reservoir temperature and self flowing; the flow to the conversion processes is water and steam at 114°C and 0.07 quality (Table 4.4). The power recovery fractions are plotted as a function of the number of stages.

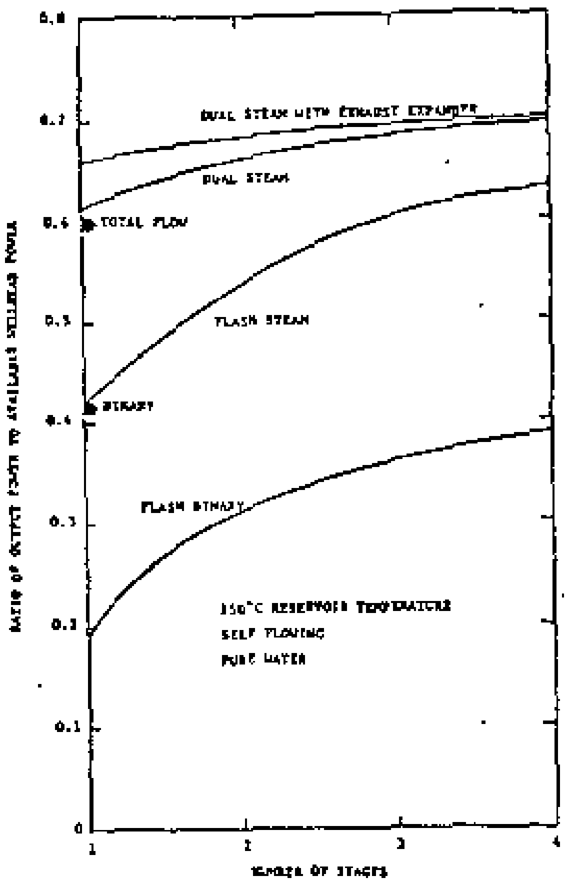
The highest power recovery fraction is obtained with the dual steam process using an exhaust liquid expander. The power recovery fraction varies from 0.66 with one stage to 0.70 with four stages. The reason for the increase is that the portion of the output power produced by the more efficient steam turbines increases from 60% with one stage to 90% with four stages.

The power produced by the dual steam system without an exhaust liquid expander is only slightly less. The power recovery fraction varies from 0.62 with one stage to 0.69 with four stages.

The total flow process has a power recovery fraction of 0.6, equal to the assumed efficiency of the two-phase expanders. The total flow process gives slightly less power than the single-stage dual steam process because the latter generates 35% of its power in the assumed more-efficient steam turbine.

The power recovery fraction of the flash steam process is next highest, varying from 0.42 with one stage to 0.63 with four stages. Thus, the dual steam and total flow processes give 50% more power than the flash steam process, as claimed for total flow in Reference (6), but only when compared with a single-stage flash steam process. Compared with a flash steam process of three or more stages, the total flow process gives the same or less power (at the assumed 60% efficiency of two-phase expanders), and the dual steam process gives only about 10% more power.

FIG. .35: COMPARISON OF POWER RECOVERY FRACTIONS FOR 150°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



Source: EOL Report No. 10

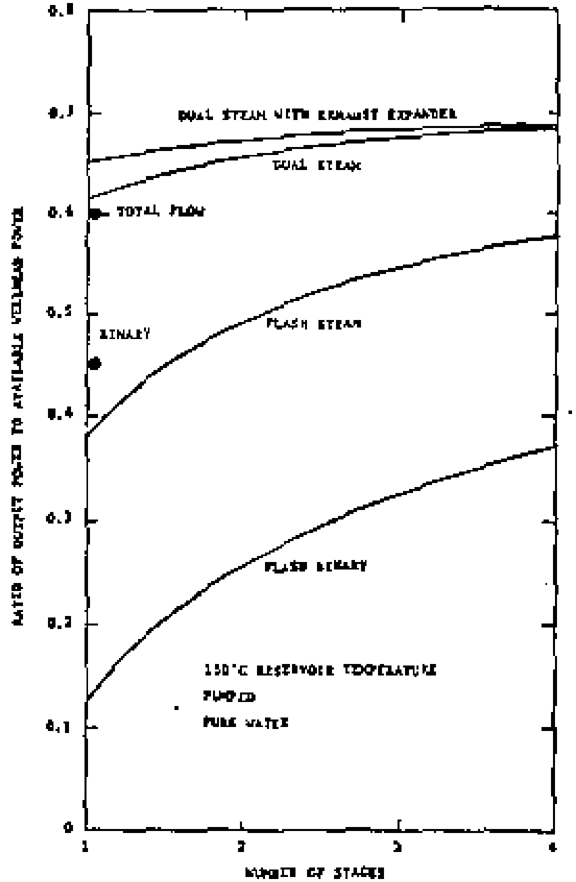
The power recovery fraction for the binary process, which is independent of the number of stages, is 0.42, the same as for the single-stage flash steam process. The lowest output power is from the flash binary process. The power recovery fraction varies from only 0.18 with one stage to 0.39 with four stages.

The reason for the increase in power recovery fraction with number of stages in the case of the flash steam and flash binary processes is the reduction in brine discharge temperature and, in the case of the flash binary process, the better matching of temperatures on the two sides of the heat exchanger.

Figure 4.36 compares the power recovery fractions for 150°C reservoir temperature when pumping is used; the flow to the conversion processes is saturated liquid at 137°C. The dual steam processes give essentially the same power re-

covery fractions as in the previous case with two-phase wellhead flow. The power recovery fraction for the total flow process is still 0.6. The flash steam process gives about 10% less power than with the two-phase wellhead flow. The binary process gives a power recovery fraction of 0.45, and the flash binary ranges from 0.13 to 0.37.

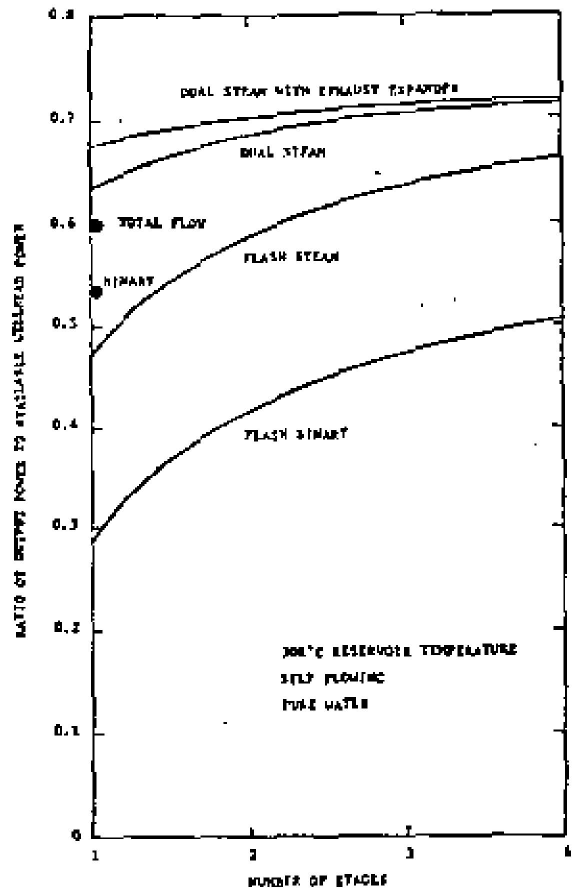
FIGURE 4.36: COMPARISON OF POWER RECOVERY FRACTIONS FOR 150°C RESERVOIR TEMPERATURE, PUMPED, PURE WATER



Source: EOL Report No. 10

Figure 4.37 compares the power recovery fractions for self-flowing pure water at 300°C reservoir temperature. The flow to the conversion processes is water and steam at 218°C and 0.21 quality. Again, the dual steam processes give 0.64 to 0.7 power recovery fraction, and the total flow process gives 0.6. The power recovery fractions of the flash steam process are closer to those of the dual steam and total flow processes at this higher temperature, ranging from 0.47 with one stage to 0.66 with four stages. The power for the binary process is

FIGURE 4.37: COMPARISON OF POWER RECOVERY FRACTIONS FOR 300°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



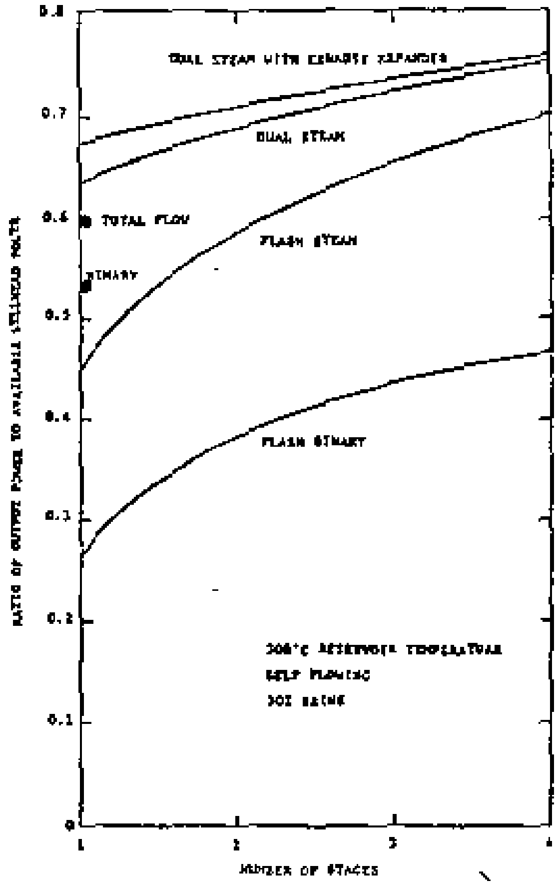
Source: EQL Report No. 10

slightly higher than that of the single-stage flash steam process but is lower for two or more stages of flashing. The flash binary process again has the lowest power recovery fraction ranging from 0.29 with one stage to 0.50 with four stages.

Figure 4.38 compares the conversion processes for self-flowing 30% brine at 300°C reservoir temperature; the flow to the conversion processes is brine and steam at 202°C and 0.12 quality. The effect of the high brine concentration is small, the power recovery fractions being essentially the same as for pure water.

To illustrate the heat exchanger temperature distributions in the binary processes, Figure 4.39 shows how the temperatures vary along the two sides of the heat exchanger for various water inlet conditions at 300°C reservoir temperature with

FIGURE 4.38: COMPARISON OF POWER RECOVERY FRACTIONS FOR 300°C RESERVOIR TEMPERATURE, SELF FLOWING, 30% BRINE

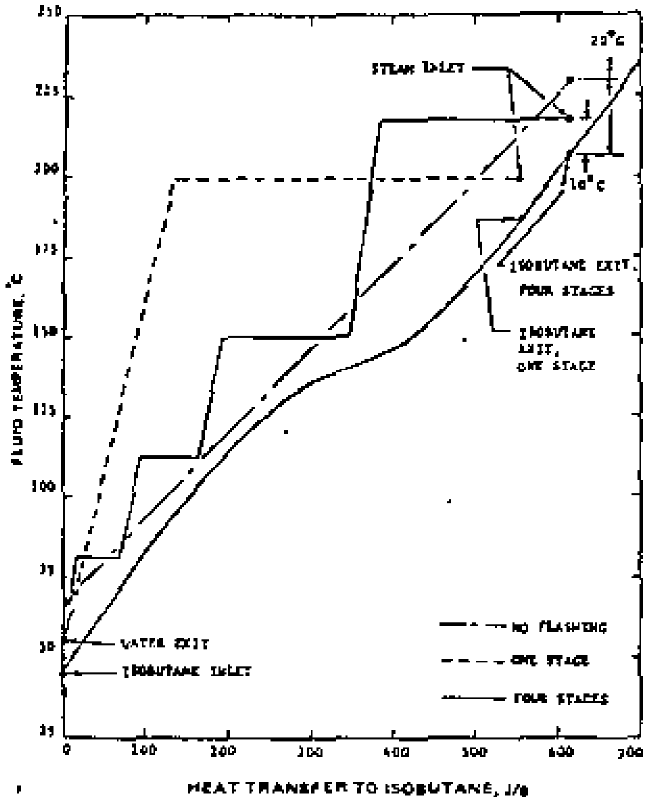


Source: EQL Report No. 10

pure water. The bottom curve shows the temperature rise of the isobutane as heat is added. The isobutane pressure is above critical, but the temperature still follows an S-curve analogous to the boiling region at lower pressures. The dashed curve shows the temperatures on the water side with one stage of flashing, and the stair-step curve shows the water-side temperatures with four stages of flashing; the higher final temperature of the isobutane and better matching of the temperatures accounts for the higher power recovery fraction of the four-stage system.

Because of the constant water-side temperatures during condensing, the temperature difference is always lowest at the ends of the heat exchangers and can be set to a low value such as the 10°C specified in the calculations with steam present. If a pumped well is used, however, with no flashing of the water, the water-side temperature follows a straight line from the inlet to the exit and

FIGURE 4.39: HEAT EXCHANGER TEMPERATURES FOR FLASH STEAM BINARY PROCESS WITH 300°C RESERVOIR TEMPERATURE, PURE WATER



Source: EQL Report No. 10

intersects the isobutane curve unless a temperature difference of at least 20°C is specified at the inlet and exit. This is the reason for specifying a larger temperature difference of 20°C for binary with a pumped well (Table 4.5).

Comparison of Condenser Heat Outputs

The amount of power generated per unit of condenser heat rejection is important as a measure of the cooling water consumption and cooling tower cost for given plant size. Figures 4.40 and 4.41 compare the ratios of power output to condenser heat rejection for self-flowing pure water at 150° and 300°C reservoir temperatures, respectively. The flash steam and dual steam processes have ratios of power output to condenser heat rejection of 9 to 10% at the 150°C reservoir temperature and 21 to 24% at the 300°C reservoir temperature. The total flow process has less favorable ratios of 8% at 150°C and 18% at 300°C. The binary and flash binary processes have still lower ratios of 5 to 6% at 150°C and 15 to 17% at 300°C.

FIGURE 4.40: COMPARISON OF POWER OUTPUTS PER UNIT CONDENSER HEAT REJECTION FOR 150°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER

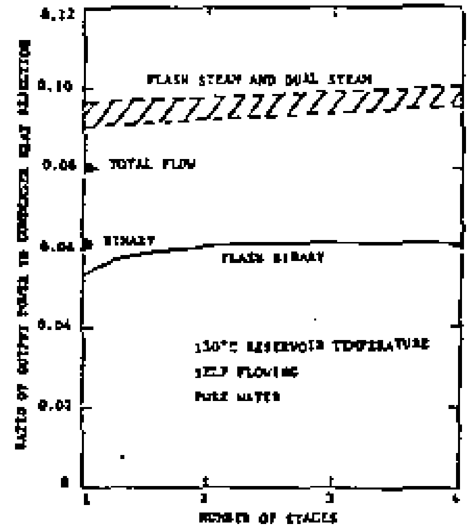
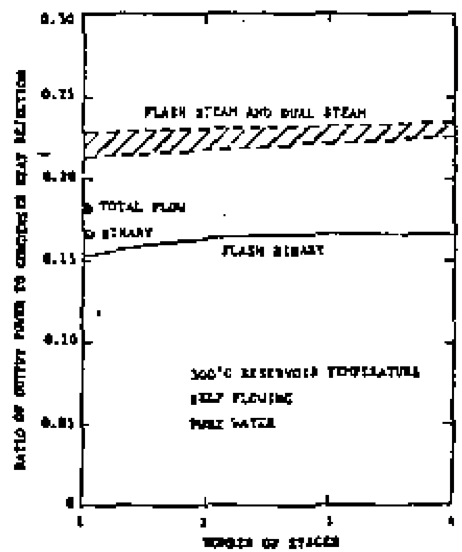


FIGURE 4.41: COMPARISON OF POWER OUTPUTS PER UNIT CONDENSER HEAT REJECTION FOR 300°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



Source: EQL Report No. 10

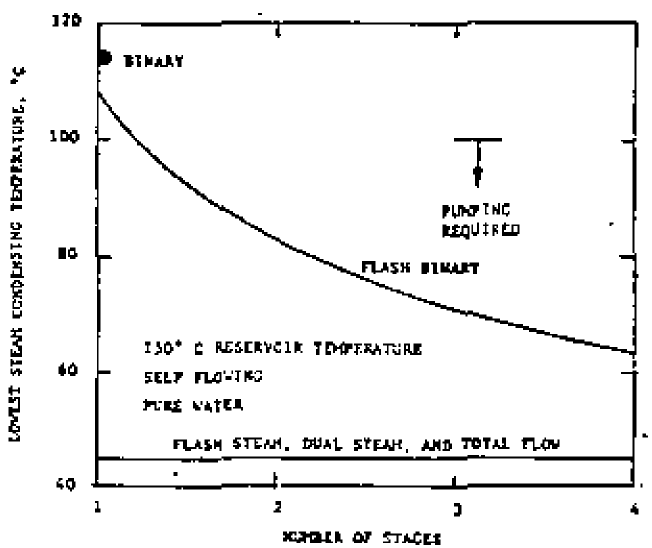
Comparison of Steam Condensing Temperatures

If the wellhead flow contains a large amount of noncondensable gases, it may not be possible to use vacuum condensing in the conversion process. At the least, vacuum pumps or steam ejectors will be required, and they will consume power. A comparison of conversion processes with noncondensables present will favor binary processes, because it is possible to transfer heat from the wellhead flow and cool the brine to any desired temperature without reducing the pressure. The conversion processes can be compared on the basis of lowest steam condensing temperature, as a measure of lowest pressure required and of pumping requirement for noncondensables.

Figure 4.42 compares the lowest steam condensing temperatures of the various conversion processes for 150°C reservoir temperature and self flowing. The lowest steam condensing temperature for the binary process is 114°C (the wellhead temperature) and for the flash steam, dual steam, and total flow processes at 45°C (the conversion process rejection temperature). The lowest steam condensing temperature for flash binary is 110°C with one stage but less than 100°C for two stages or more, requiring pumping of noncondensables.

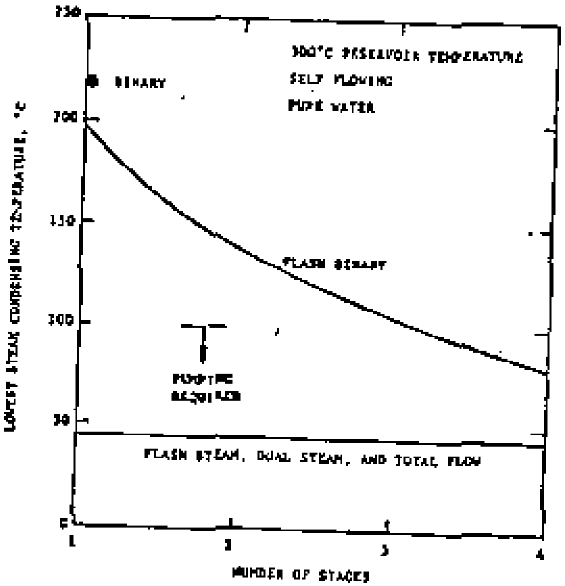
The lowest steam condensing temperatures are compared for 300°C reservoir temperature in Figure 4.43. Here, flash binary is more favorable with respect to condensing pressure than at the lower temperature, requiring below-atmosphere condensing only with more than three stages.

FIGURE 4.42: COMPARISON OF LOWEST STEAM CONDENSING TEMPERATURES FOR 150°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



Source: EQL Report No. 10

FIGURE 4.43: COMPARISON OF LOWEST STEAM CONDENSING TEMPERATURES FOR 300°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



Source: EQL Report No. 10

Two-Phase Expander Volume Flows

Two-phase expanders for the dual steam or total flow processes are likely to be more bulky machines for given volume throughput than steam turbines. The velocity of the two-phase flow is less than that of the steam flow in a steam turbine, and the fraction of the machine cross section that can be devoted to flow area may be less than in a steam turbine.

As in the case of steam turbines, by far the largest two-phase expander will be the lowest-pressure one, and the size and cost requirement for two-phase expanders for the processes using them can be compared, on a relative basis, by comparing the volume flow rates from the last-stage two-phase expanders. Figures 4.44 and 4.45 present such a comparison for 150° and 300°C reservoir temperatures, respectively. The volume flow rate leaving the last two-phase expander in the total flow process is 2.6 m^3 per kg of wellhead flow at 150°C and 6.2 m^3 per kg at 300°C; there is no change with number of stages.

The volume flow rate leaving the last two-phase expander in the dual steam processes is much smaller, only 1 m^3 per kg with one stage and 0.4 m^3 per kg with four stages at 150°C and 1-2 m^3 per kg with one stage and 0.5-0.6 m^3 per kg with four stages at 300°C. Compared with the total flow process, the volume flows for a two-stage dual steam process, for example, are only 25% as much at 150°C and 10% as much at 300°C.

FIGURE 4.44: EXIT VOLUME FLOW FROM LAST TWO-PHASE EXPANDER FOR 150°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER

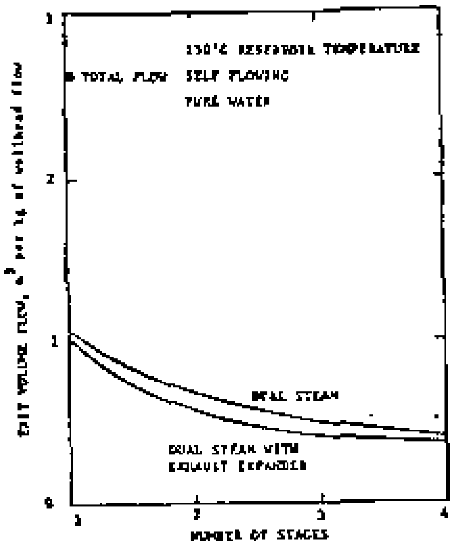
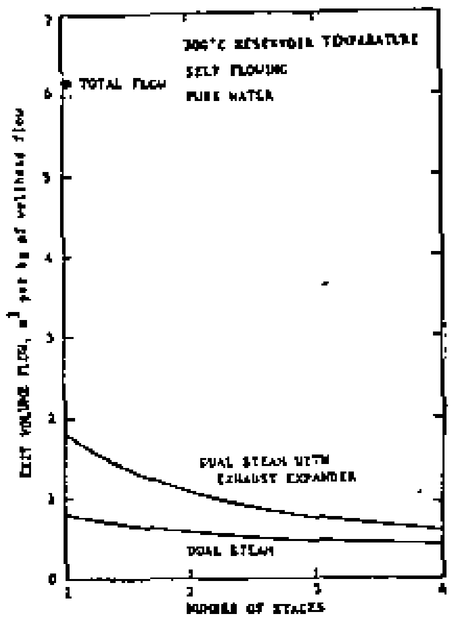


FIGURE 4.45: EXIT VOLUME FLOW FROM LAST TWO-PHASE EXPANDER FOR 300°C RESERVOIR TEMPERATURE, SELF FLOWING, PURE WATER



Source: EOL Report No. 10

The reason for the lower volume flows in the dual steam processes is the fact that most of the steam is handled by the steam turbines. The reason for the decrease in last-stage volume flow with increasing number of stages is that the last stage starts with saturated liquid at a lower temperature. If an exhaust liquid expander is used the exit volume flow may be higher, as in Figure 4.45, due to the lower expander exit pressure; but the volume flow may be the same or even less, as in Figure 4.44, if the reoptimization of stage temperatures for maximum power leads to a sufficiently lower inlet temperature to the exhaust expander.

Comparison with Other Studies

The results presented here agree with previous calculations for flash steam and flash binary processes (7) and for the binary process (8). Comparisons with the calculations of Reference (7) are presented in Table 4.6. The wellhead conditions assumed in Reference (7) correspond to a reservoir temperature of about 320°C. The steam turbine efficiencies assumed are slightly lower than used here and decrease with number of stages because no moisture removal is assumed between stages. Using the constants from Reference (7), the power recovery fractions calculated by the method used here are within 0.03 of the values calculated in Reference (7) for one-, two-, and three-stage flash steam and for two- and three-stage flash binary.

Comparisons with the calculations of Reference (8) are presented in Table 4.7. Reference (8) presents results for both an isobutane cycle and an advanced cycle denoted as the H-H cycle. The assumptions regarding heat exchanger temperature difference and turbine efficiency are not given, and the values assumed here are the ones in Table 4.5. The results are higher than the Reference (8) results for isobutane but agree within 0.04 with the results for the H-H cycle.

TABLE 4.6: COMPARISON WITH FLASH STEAM AND FLASH BINARY CALCULATIONS OF REFERENCE (7)

Wellhead conditions: 219°C temperature
0.175 quality
0.27 brine concentration

Condensing temperature: 38°C (steam)
46°C (isobutane)

Steam turbine efficiency: 0.673 (1 stage)
0.663 (2 stages)
0.657 (3 stages)

Conversion Process	Power Recovery Fraction	
	Reference (7)	Present Method
One-stage flash steam	0.49	0.46
Two-stage flash steam	0.55	0.57
Three-stage flash steam	0.62	0.63
Two-stage flash binary	0.37	0.36
Three-stage flash binary	0.41	0.42

Source: EOL Report No. 10

TABLE 4.7: COMPARISON WITH CALCULATIONS OF REFERENCE (8)

Condensing Temperature: 43°C

Wellhead Conditions			Power Recovery Fraction		
Temperature °C	Quality	Brine Conc.	Reference (8) (Table 4.5) Isobutane	H-H Process	Present Method Isobutane
177	0	0.10	0.66	0.69	0.69
232	0	0.18	0.58	0.71	0.66
182	0.083	0.14	0.48	0.55	0.57
204	0.207	0.30	0.39	0.53	0.50

Source: EQL Report No. 10

Summary

The relative ranking of the conversion processes with respect to power output is the same for all of the wellhead conditions considered: dual steam with exhaust expander the highest; dual steam without exhaust expander slightly lower; total flow slightly lower than single-stage dual steam; flash steam substantially lower with one stage, but equal to or higher than total flow and within 10% of dual steam with three or four stages; binary higher than single-stage flash, but lower than two-stage flash steam; and flash binary lowest, with no more than 50% power recovery fraction even with four stages.

The ranking with respect to lowest steam condensing pressure and noncondensable pumping requirement, however, is binary best, with highest pressure and no noncondensable pumping requirement; flash binary next, with condensing pressures ranging from above atmospheric to ~25% of atmospheric; and flash steam, dual steam, and total flow worst with condensing pressures ~10% of atmospheric.

Conclusions

The conclusions of this study are:

(1) The flow rate from a self-flowing well can be substantially increased by increasing well bore diameter at and above the flashing level.

(2) Self-flowing stepped diameter wells provide more wellhead power than pumped wells (for equal production zone diameters) at nearly all reservoir conditions.

(3) Multi-stage flash steam systems using steam turbines provide more output power than binary systems at all reservoir temperatures, using reasonable values for component performance.

(4) Total flow machines, used alone, offer no performance advantage as compared to multi-stage direct flash steam, unless efficiency of total flow devices can be increased above current projections.

(5) Two phase expanders in combination with steam turbines provide the highest output power.

These conclusions result from theoretical calculations of system performance. They do not include the effects of excessive noncondensable gas content in the reservoir fluid, considerations of scaling and corrosion, or cost and engineering characteristics of the various production and conversion methods. If verified, however, the concept of stepping well diameter may provide a very significant cost saving in the development of a geothermal field. The calculations indicate that flow per well might be increased by a factor of two, thus perhaps halving costs of well drilling for a given level of power.

Detailed engineering studies are now suggesting that binary conversion systems may be quite expensive, owing to the large heat exchangers, pumps and other plumbing required. If the cost of a binary system exceeds that of a direct steam system, and offers no performance advantage, as suggested by these calculations, the binary system may be of value only in very special circumstances.

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Heber, Valles Caldera and Raft River Comparison Studies

The material for the following sections has been based upon a report by B. Holt and E.L. Ghormley of Holt/Procon for Electric Power Research Institute, Inc. (PB 261 845).

This study consists of the assessment of the technical, economic and environmental feasibility of a 25 to 50 MWe plant in the Heber area of the Imperial Valley, California and the Valles Caldera area of New Mexico, using three state-of-the-art power conversion options: the flashed steam, binary and hybrid.

Also included is a parallel technical and economic (not environmental) study of the Raft River, Idaho, reservoir, which is taken to be representative of a low temperature, 149°C (300°F), reservoir. By selecting Raft River as a representative site in addition to the other sites, the development of the capital and operating costs associated with three different processes at three reservoir temperatures is accomplished. Valles Caldera is thought to be the hottest reservoir: 260°C (500°F); followed by Heber: 182°C (360°F); and then by Raft River: 149°C (300°F).

The economic analysis resulting from this work provides insight as to the relative merits of flashed steam and binary cycles with varying reservoir temperatures and provides useful information relating power generation costs to reservoir temperature.

SELECTION OF PLANT SIZE

It is clear that geothermal power plants come in relatively small sizes as compared with fossil fuel or nuclear plants. At The Geysers, for instance, a module is 110 MWe and at Cerro Prieto the initial installation is 75 MWe (two 37.5 MWe steam turbines). The main reason for this is an economic one. As single plants get larger, the cost of collection and reinjection of the fluids increases as more wells (both production and reinjection) are required. Also, the fluid transmission energy losses become greater.

Another reason is a technical/economic one. For example, no hydrocarbon expansion turbines have been built even in the 60 to 70 MWe range, although there appear to be no serious technical problems associated with scaling up existing designs. Or for that matter, if capacity should really turn out to be a limiting factor, multiple units may be installed on a common shaft at some economic penalty.

In either the 25 MWe or 50 MWe sizes of a binary cycle plant, one is already dealing with multiple units of major equipment. For example, the preliminary equipment selection at Heber provides for eight hot water/working fluid exchanger bundles, eight condenser bundles, eight hydrocarbon pumps, three cooling water pumps and 10 to 12 cells in the cooling tower. A 25 MWe unit would have about one half of the number of these units. Since individual exchangers, condensers, pumps and cooling tower cells are already as large as are readily available commercially, there is no advantage in terms of demonstrating technical and operational feasibility by building a plant larger than 25 MWe. Since one is also dealing with multiple wells, both production and injection, the same argument holds true for the field installation.

Moreover, from a technical and operational standpoint, there is little justification for building, e.g., a 60 MWe expansion turbine instead of a 30 MWe turbine. Once successful demonstration of a 30 MWe turbine has been demonstrated, scaling up from this size by a factor of two should be no problem.

Finally, a lot less money would be required to build the smaller plant (in the range of 60 to 70 percent of the cost of the larger plant), a saving in the case of Heber of eight to ten million dollars.

It appears that the decision should rest on economic factors. First of all, a major objective of the demonstration program is to demonstrate economic viability of power production from low salinity medium temperature hot water reservoirs. Moreover, if the demonstration plant could not generate electricity economically, there would be little incentive to keep it operating beyond a reasonable test period without subsidizing the operation.

By contrast, an economic operation would be self-supporting, would provide realistic cost data, and would encourage rapid development, not only of the reservoir on which the plant is located but also other reservoirs.

Based on data presented in the economic analysis, the cost of power from a 25 MWe binary plant at Heber as compared to a 50 MWe plant has been estimated. The base case estimate for the cost of power at Heber is about 35.2 mills/kWh. The corresponding figure for 25 MWe is 42.3 mills/kWh, an increase of about 20%. The assumptions used in making this calculation are as follows:

(1) Power plant capital cost is 61% of a 50 MWe plant.

(2) Power plant labor is constant.

(3) Power plant maintenance is proportional to capital.

(4) Power plant, water, chemicals and miscellaneous costs are proportional to capital.

(5) Transmission costs are constant.

(6) One-half as many wells are drilled.

(7) Surface installation is 60% of a 50 MWe estimate.

(8) Field labor cost is constant.

(9) Well maintenance is proportional to number of wells.

(10) Field maintenance is proportional to capital.

From the foregoing, it is apparent that there is a strong economic incentive to build a 50 MWe unit. Moreover, the larger unit will also more nearly comply with the objective of providing the utility industry with reliable economic data. For these reasons, a 50 MWe plant was selected as the preferred size.

HEAT REJECTION OPTIONS

Heat rejection per kWh from a geothermal power plant is higher than that from a fossil fuel or nuclear power plant because the thermal efficiency is lower. For example, the thermal efficiency of the Heber binary cycle plant is about 13%, as compared with a typical fossil fuel plant of 34%, and heat rejection per kWh from the geothermal unit is about 3.44 times that of the fossil-fueled plant. Thus, it becomes apparent that the method and cost of heat rejection is relatively a more important consideration in the design of geothermal power plants than in either fossil-fueled or nuclear plants.

Moreover, because the heat source is itself at a low temperature, the efficiency is very sensitive to the heat rejection temperature. In the range of temperature of interest, the net work produced is roughly proportional to the temperature difference between the heat source and the heat sink. There are three proven heat rejection options available: wet cooling, air cooling, and a combination.

Typically, wet-cooling towers can reduce the temperature of the recirculated cooling water to within 6°C (10°F) of the prevailing wet-bulb temperature, which is typically at least 11°C (20°F) less than the prevailing dry-bulb temperature.

Dry-cooling systems for heat rejection use finned heat exchanger tubes to transfer the heat from the process fluid to the atmosphere. The minimum temperature at which these systems can dissipate heat is typically 14°C (25°F) higher than the dry-bulb temperature of the air.

The third combination system is known as the wet-dry cooling system. As in the air-cooled system, the process stream is cooled by the passage of air through banks of extended surface exchanger tubes. As required, water is sprayed into the air flow, cooling the air flow by evaporation of the water to a temperature approaching the wet-bulb temperature. This type of unit is expensive and is usually used when cooling water is at a premium and where dry-bulb temperatures are excessive. Northern Africa and the Middle East provide such environments.

First consider a binary plant at Heber. One might design an air-cooled system for 40°C (105°F) dry-bulb which would allow a 54°C (130°F) condensing temperature, as compared to a wet-bulb temperature of 27°C (80°F) and a condensing temperature of 43°C (110°F) for a wet tower. The installed cost of the wet tower, including pumps and condenser, is about $4,000,000, as compared to the installed cost of a dry tower of about $13,000,000. The loss in cycle efficiency is about 10%, and the parasitic power requirements increase about 5 MWe. Thus, for a given plant size, power output is reduced about 20% and costs increased

about 20%. The net effect is a 50% increase in the unit cost per kW. Thus, if the plant costs $500/kW with wet cooling, it will cost at least $750/kW with dry cooling.

A similar analysis was made for a flashed-steam system. In this case, a circulating-water system is required to transfer heat from the condenser to the air cooler. The numbers come out about the same—a reduction in cycle efficiency, an increase in parasitic power consumption, and a sharp increase in installed cost per kW. The analysis was not further considered because it appears obvious that air cooling is not a viable alternative to wet cooling, and neither are combination coolers since they are even more costly than air coolers.

FLASHED STEAM PROCESS

Three factors strongly affect the process design of flashed steam geothermal plants. They are as follows:

(1) The temperature and composition of the geothermal brine.

(2) The characteristics of the available heat sink.

(3) The size and the characteristics of the turbines available for use with geothermal steam.

The initial temperature of the reservoir fluid determines both the quantity of steam which can be flashed from it and the temperature of the resulting steam. Dissolved solids also affect the amount of steam flashed. Flash calculations were done with a computer program which takes this effect into account. Of the geothermal fields under consideration, the most concentrated brine exists at Heber, about 15,000 parts per million. In this case, the steam flash is reduced approximately 3% by the dissolved solids.

It is usually practical to flash the reduced liquid a second time, using the secondary steam in lower stages of the turbine. Theoretically, it is possible to flash the brine an infinite number of times extracting more energy each time this is done. However, more than two stages appear to be impractical.

A preliminary analysis was made of a triple-flash system versus dual-flash for Valles Caldera conditions, based on 3-inch Hg back pressure. The slightly more efficient triple-flash required a four-flow machine (two separate casings) with at least six admission valves. The dual-flash required a two-flow machine (single casing) with only two admission valves. Turbine-cost differential would be approximately $4,000,000 in favor of dual-flash, plus additional savings on the turbine pedestal and the heat rejection equipment.

Heat Rejection

Plants with low initial steam temperature are very sensitive to the condensing pressure of the steam. The cooling tower size was estimated to provide a cold-water temperature within 10 degrees of the design wet-bulb temperature in each area. The overall efficiency of the plant is significantly improved if the temperature of the cooling water is low. In all cases it was assumed that adequate make-up water will be available to permit the operation of wet-cooling towers. The flashed steam plant produces adequate quantities of condensate which can be used for coo. .ower makeup water. Where wate. supplies are short, this condensate is a valuable commodity which would permit a flashed-steam plant to operate where other types of plants could not.

Steam Turbines

A survey was made of four domestic and two Japanese companies thought capable of providing turbines for this service. Of the domestic companies only one, General Electric Company, expressed interest in producing geothermal steam turbines in the 25 to 50 MWe range. Of the two Japanese companies, Mitsubishi and Kawasaki, the long lines of communications to their engineering departments made it impractical to carry out a cooperative study. Accordingly, turbine studies were conducted mainly with the General Electric Company.

Geothermal turbines operate under different conditions from conventional power plant turbines. Experience with The Geysers geothermal plants indicates that deposits form on the turbine buckets, subjecting the machines to more vibration than those in conventional service. Accordingly, General Electric uses extra rigid buckets which are not available in all sizes, the two largest being 42.7 cm (16.8") and 50.8 cm (20") long. These blade lengths determine the annular opening of the last stage, which in turn determines the maximum steam flow per case. As sonic velocity cannot be exceeded in the last-stage buckets, the steam flow in pounds per hour is a function, not only of the annular area, but also of the condensing pressure. Accordingly, turbines for the flashed-steam process are available only in discrete sizes.

Another turbine generator characteristic which enters into the process design is overall efficiency. This is calculated as the ratio of the generator output to the heat energy theoretically available. For initial steam conditions above 310 kPa (45 psia), overall efficiency is about 70%. Below 310 kPa, the efficiency falls off progressively to about 63% at 110 kPa (16 psia).

Process Flow

The first step in the design was to perform a series of two-step direct-flash calculations for each of the brines under consideration. These were done at a number of primary and secondary steam pressures chosen in relation to the initial brine temperature. The result was a matrix giving the amount of primary and the amount of secondary steam produced at each combination of first- and second-stage pressures.

The second step was to calculate the approximate steam flows to produce 55 MWe gross from each of the steam-flash calculations derived above. This was done by first calculating the theoretical steam rates for each expansion from a range of initial steam conditions to several condensing pressures. These were converted to "actual" steam rates by dividing them by estimated turbine efficiencies. It was then possible to calculate for each initial and final condition the primary and secondary steam flows from 1,000 pounds of brine and the resultant electrical generation. Finally, by dividing 55 MWe by this last figure, a factor for both brine and steam flows is obtained. For each plant, this calculation was performed in tabular form for a large matrix of primary steam, secondary steam and condensing pressures.

Turbine Selection

Using the preliminary calculations as a guide, GE turbine specialists selected for each case a number of operating conditions which appeared most favorable. For each of these they made turbine selections for which prices were then developed.

The prices for these preliminary selections were then evaluated in relation to reference brine costs and probable condenser and cooling tower costs. The results, while not rigorous, enabled a fairly optimum selection to be made in each case.

These selections were then recalculated by GE using more refined methods. Actual bucket selections were made and efficiencies calculated for stage-to-stage expansion. From this there was obtained for each case a good turbine selection with fairly accurate estimates of both steam flows and heat rejection.

Condensers

Once turbine configuration and exhaust steam flows were established, it was possible to investigate condenser and cooling tower possibilities. This was done with the cooperation of the Ingersoll-Rand Company which has furnished most of the steam condensers at The Geysers plant.

Before preliminary condenser designs could begin, however, some initial decisions had to be made, particularly with respect to materials. Because of the expected CO_2 and H_2S content of the candidate brines and in deference to experience at The Geysers, the following stainless steel selections were made for all cases:

	Type
Shell	316 L*
Nonwelded internals	316
Welded internals	316 L
Tube sheets	316**
Tubes	316

*Clad
**Clad on steam side only

The designers were given the option of tube diameters from 19 mm (¾ in) to 25.4 mm (1 in) with a tube wall thickness of 0.7 mm (22 BWG). For stainless tubes of these dimensions, water velocities of 7 to 9 feet per second are usually used in public utility power plants. An average value of 8 feet per second was selected. Assuming that an Amertap continuous mechanical cleaning system would be used with the cooling water, a condenser cleanliness factor of 0.85 was used for all cases.

A cold-water temperature compatible with the heat-sink characteristics was established. The condenser designer was given latitude with respect to the rise and allowed to use average public utility criteria for the cost of cooling tower installation and operation. The result in each case was reasonable condenser selection, rather than an optimized one.

Other Equipment

Cooling Towers: Wood cooling towers of public utility quality were specified for all sites. Cooling-water flow, cold-water temperature and range were determined by condenser selection.

Vacuum Pumps: Because of the gas content anticipated for each of the candidate brines, the removal of noncondensable gases from the condensers is a task in order of magnitude larger than in conventional public utility power plants. Further, the poor initial steam conditions make steam jet ejectors uneconomical in these applications. Vacuum pumps were sized to accommodate the expected gas flow from the brine plus the amount of air normally accumulated through leakage. Where cold-water temperatures are sufficiently low, the use of precondensers was investigated.

THE BINARY PROCESS

The binary process for producing electric energy from geothermal reservoir fluid involves the transfer of heat to a secondary, in-plant working fluid. The working fluid is expanded through a turbine to produce power. The expanded gas is then condensed in a battery of shell and tube condensers.

The working fluid is continually recirculated from the turbine to the heat source. The fluid is pumped to the shell side of a battery of shell and tube exchangers at an elevated pressure. Hydrothermal reservoir fluid flows from the production wells through the tubes. Heat is transferred from the reservoir fluid to the working fluid. Operation may be either in the subcritical or supercritical region. The spent reservoir fluid is pumped from the plant to injection wells.

Conversion Study Basis

The basis used in developing the binary process design for the three plant sites is defined below:

(1) Each plant is sized for a net output of 50 MWe. The generator will be sized with sufficient capacity to provide for in-plant electric power consumption.

(2) Hydrocarbon turbine-expander efficiency and generator efficiency are assumed to be 85 and 98%, respectively. Efficiency of the working fluid circulation pump is assumed to be 80%.

(3) Pressure drop across the operating fluid-reservoir fluid heat exchangers and hydrocarbon condensers is assumed to be 345 kPa (50 psi) and 21 kPa (3 psi), respectively.

(4) Design values of the wet-bulb and dry-bulb temperatures are based on temperatures which occur 1% of the time during the summer months.

(5) Operating fluid pressures are to be greater than atmospheric pressure to avoid air leakage into the process system.

(6) The minimum temperature difference between operating fluid and reservoir fluid in the heat exchangers will be 8°C (15°F).

The primary purpose of the above conditions and assumptions was to establish a uniform base of comparison for all three plant sites.

Selection of the operating fluid and operating conditions was determined for each site by a computer program, evaluating the thermodynamic properties of various systems. The emphasis was to minimize the reservoir fluid flow requirements.

Selection of Working Fluid

Light aliphatic hydrocarbons (such as propane, isobutane and isopentane) appear to be the best candidate working fluids for most geothermal applications. They have favorable thermodynamic properties, are thermally stable, noncorrosive, and available in large quantities at reasonable prices (about 50 cents per gallon).

The Freons may also be used. However, they offer no advantage in thermodynamic properties, are expensive (about $5 per gallon), and are thermally unstable. Their only advantage is that they are nonflammable.

A number of other candidate fluids have been suggested, including all of the obvious gases such as ammonia, sulfur dioxide, carbon dioxide and light aliphatic olefins. None appear to offer advantages over the light aliphatic hydrocarbons.

Another virtue of the aliphatics is that their thermodynamic and physical properties are very well known, and their properties may be accurately predicted. Accordingly, these studies were limited to the use of light hydrocarbons and the fluid composition was tailored to the reservoir.

THE HYBRID PROCESS

A hybrid power plant is a combination of two processes, the flashed steam process and the binary power cycle process. Reservoir fluid is flashed to produce steam at a relatively high pressure, which is used to drive a turbine-generator. The reservoir fluid is then used to heat the working fluid which drives a second turbine-generator.

The Flashed Steam Section

The design of a hybrid plant starts with fixing the pressure at which the steam is flashed from the reservoir fluid. High-pressure steam is desirable because the high pressure will improve turbine efficiency and reduce the turbine size and cost. The pressure that is chosen affects the relative sizes of the two parts of the plant, as well as the quantity of reservoir fluid required by the plant. For each plant, several different steam-flash pressures were investigaged to determine the most efficient generating condition for the plant.

The Binary Section

The flashing of the steam from the reservoir fluid results in cooling the fluid. The binary portion of the plant must utilize the residual heat in the reservoir fluid. Because the high temperature enthalpy in the brine was used to produce steam, the binary portion of the plant must have a lower thermodynamic efficiency than a binary plant which recovers all of the enthalpy from the brine. Each section of the plant is calculated by making an enthalpy balance on the reservoir fluid at the steam flash drum and sizing the individual portions of the

plant based on the energy available for conversion into electric power. It was assumed that minimum brine consumption, consistent with low hydrocarbon circulation represented the most economical operating condition for the plant. For each steam flash pressure that was considered, the quantity of reservoir fluid and the rate of hydrocarbon circulation were calculated. The relative sizes of the steam flash section and the binary section of the plant were established at the condition where both flow rates were minimized.

HEBER CONVERSION PLANTS

The Reservoir

The Heber geothermal reservoir is located in the southern part of the Imperial Valley at an elevation that is close to sea level. Summertime temperatures vary up to 49°C (120°F); one percent of the time during the summer months the wet-bulb temperature reaches or exceeds 27°C (80°F). This wet-bulb temperature was used for design. The area is level and devoted mainly to agriculture. The plant site is bounded by irrigation ditches which will supply makeup water to the plant. Roads and power lines are close to the site.

The reservoir fluid has a total dissolved solids content of 15,000 ppm. The bottom hole temperature is 182°C (360°F). Analysis indicates that if there is no heat recharge, the temperature of the reservoir will decline about 20°C (35°F) over a 25-year period at a sustained production rate of 200 MWe. This temperature drop of the reservoir fluid necessitates a plant design in which the circulation systems in the plant can be expanded to maintain a constant power production rate.

Thus far, minimal quantities of noncondensable gases have been observed in the reservoir fluid. Analyses that were performed on the reservoir fluids did not ascertain if noncondensable gases were present. For the purpose of this study it was estimated that the noncondensable gases would consist of 680 kg/hr (1,500 lb/hr) of carbon dioxide. Hydrogen sulfide was assumed to be present in the gas in the range of 100 to 1,000 ppm.

The EPRI-sponsored heat exchanger tests showed that the salts present in the fluid form scale at a negligible rate at temperatures above 132°C (270°F) but below that temperature fouling occurs at an increased rate. From their data the following tube-side fouling factors were estimated which were used in the design of brine-working fluid heat exchangers:

Temperature, °C	Temperature, °F	Fouling Factor
176-132	350-270	0.0001
132-80	270-176	0.0011
80-65	176-148	0.0033

These factors are tentative in that the results of a 22-day test have been extrapolated to predict a fouling factor suitable for one year's operation. Further tests should be conducted over a period of several months to confirm these figures.

The exchanger tests were conducted using titanium, 90% cupronickel and mild steel exchanger tubes. No corrosion was observed on the titanium tubes after 500 hours of exposure; some corrosion occurred to the cupronickel tubes after 200 hours testing; and slight pitting and surface decarbonization were observed

on the carbon steel tubes after 500 hours of testing. It is possible that the slight corrosion of the steel tubes had occurred prior to the test program. Chevron has indicated that corrosion during their test work was negligible. Accordingly, the use of steel in all equipment exposed to brine or flashed steam was specified, except steam turbines and surface condensers as noted above. Further corrosion tests with the Heber brine should be conducted before a final decision is made on plant materials.

Flashed Steam Plant

A process flow sheet of the flashed steam plant is shown in Figure 5.1 (page The hot reservoir fluid enters the plant at a flow rate of 4.54 M kg/hr (10.01 M lb/hr). Split into two parallel trains, the brine passes through the control valves into two flash drums at an absolute pressure of 374 kPa (54.3 psia).

The first-stage flash produces 392,000 kg/hr (864,000 lb/hr) of primary steam which passes through a steam separator before reaching the turbine at a pressure of 370 kPa (53.7 psia) and a temperature of 141°C (286°F).

The liquid from the first-stage flash drums flows to the second-stage flash drums where its pressure is reduced to 151 kPa (21.9 psia). The resultant flash produces 263,000 kg/hr (580,000 lb/hr) of secondary steam which flashes through a steam separator to a lower stage of the turbine at a pressure of 150 kPa (21.7 psia) and a temperature of 112°C (233°F).

The secondary-flash drums float on the line, their pressure varying with turbine-stage pressure and with demand. The flashed liquid flows from the second-stage flash drums to the suction of the injection pumps which return the liquid to the reservoir. Liquid level is maintained in the second-stage flash drums by a control valve on the pump discharge.

The turbine-generator is operated as a base-load unit under load control. The operator assigns a load to the generator, and the turbine must accept that load at constant speed. The turbine governor detects changes in load and adjusts admission valves on both the primary and secondary steam lines to satisfy the assignment. A separate emergency trip mechanism on the turbine shaft will close emergency stop valves on both primary and secondary steam lines if turbine speed exceeds 3,600 rpm by a given percentage.

Exhaust steam from the turbine passes directly into a surface condenser, where a back pressure of 13.5 kPa (4" Hg) is obtained under design cooling-water conditions. The condensate is pumped to the suction of the injection pumps. The condensate is added to the reduced brine to make the replenishment volume substantially equal to the volume of fresh brine delivered to the plant. Average temperature of this flow is 103°C (217°F).

Cooling water from an induced draft cooling tower enters the condenser at 35°C (95°F) and returns to the tower at 49°C (120°F). The hot cooling water temperature gives a minimum condenser approach of 2.7°C (5°F).

During the turbine selection process, other combinations of primary and secondary steam pressures were tried, but were less attractive economically. Higher pressures used more brine per kilowatt of power generated. Lower pressures

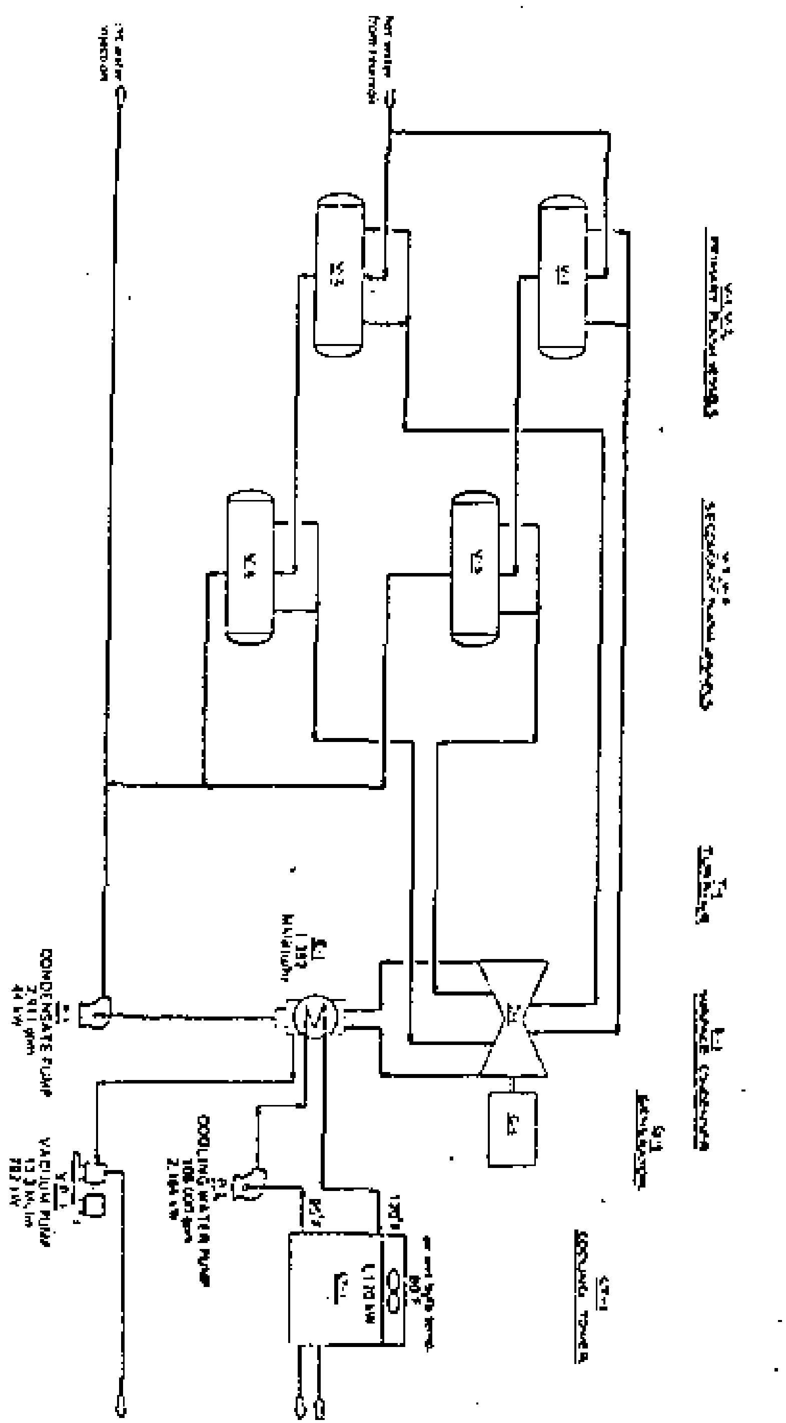


FIGURE 5.1: FLASHED STEAM POWER PLANT—HEBER

Source: PB 261 845

increased exhaust steam flow enough to require a four-flow turbine wi[illegible] casings and a jump in turbine cost alone of about $3,000,000. The contemplated reduction in brine production (about 3.5%) would not justify the increased capital expense. The primary and secondary steam conditions selected give the greatest power output possible from General Electric's largest double-flow, single-case turbine with a 4-inch back pressure.

Noncondensable gases and air leakage are removed from the system by six large vacuum pumps operating in parallel. The gases are discharged to a stack which is designed for dispersal of the hydrogen sulfide present.

A summary of pertinent design data is as follows:

Reservoir fluid	4.54 M kg/hr (10.01 M lbs/hr)
Generator output	55.0 MWe
Pumping work	3.2 MWe
Cooling tower work	1.1 MWe
Net output	50.7 MWe
Reservoir fluid/net kwh	90 kg (200 lbs)

When reservoir temperatures decline with depletion, initial electrical output can be maintained by increasing hot-water flow. Theoretically, a plant designed for the depletion condition of 163°C (325°F) would require 37% more hot water than one designed for the initial condition. However, operation of the base-case plant with 163°C hot water would require altered steam conditions to maintain proportional flows through the turbine stages. This would result in a 63% increased flow of hot water. Initial and final operating conditions are compared below:

	Initial	Final
Reservoir fluid	4.54 M kg/hr (10.01 M lbs/hr)	7.39 M kg/hr (16.3 M lbs/hr)
Primary flash pressure	370.2 kPa (53.7 psia)	317.8 kPa (46.1 psia)
Primary steam flow	392 M kg/hr (864 M lbs/hr)	386 M kg/hr (852 M lbs/hr)
Secondary flash pressure	149.6 kPa (21.7 psia)	165.5 kPa (24.0 psia)
Secondary steam flow	655 M kg/hr (1444 M lbs/hr)	666 M kg/hr (1468 M lbs/hr)
Spent water temperature	103 C (217 F)	109 C (228 F)

Binary Plant

A process flow sheet of the binary plant is shown in Figure 5.2 which follows. This flow sheet presents the heat and material balances for the initial reservoir conditions.

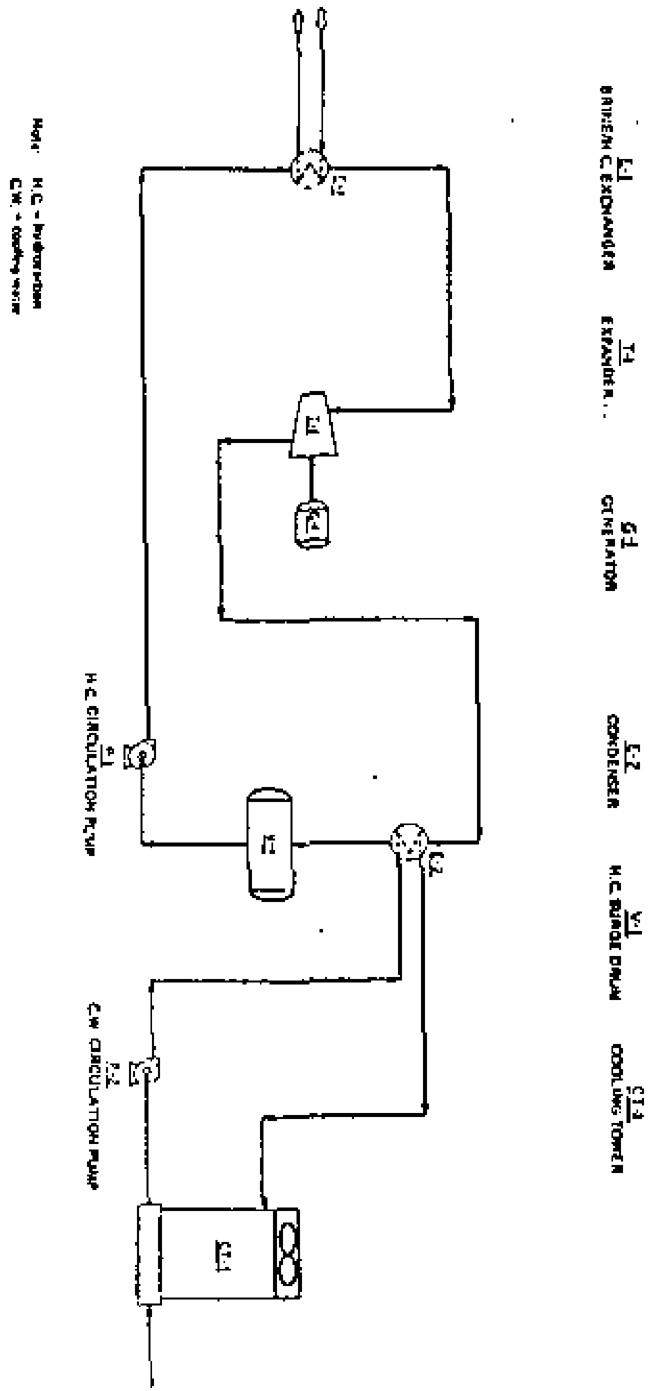


FIGURE 5.2: BINARY POWER PLANT—HEBER

Source: PB 261 845

Liquid isobutane is preheated and vaporized by exchange with the ... ne to a pressure of 4,137 kPa (600 psia) and a temperature of 149°C (300°F). The supercritical vapor drives an expansion turbine. The effluent vapor from the turbine condenser flows to an accumulator and is pumped back through the brine exchanger completing the circuit. A summary of the pertinent design data is as follows:

Reservoir fluid	3.149 M kg/hr (6.942 M lbs/hr)
Isobutane	3.702 M kg/hr (8.161 M lbs/hr)
Generator output	64.28 MWe
Pumping work	9.46 MWe
Cooling tower work	4.83 MWe
	50.00 MWe
Reservoir fluid/net kwh	63 kg (139 lbs)

The magnitude of the above flow requirements makes the use of parallel flow paths necessary or desirable in various sections of the process. Consequently, plant design includes the following parallel streams:

Equipment	Parallel Streams
Working fluid/reservoir fluid exchangers	2
Working fluid condensers	8
Working fluid accumulators	4
Working fluid circulation pumps	8
Cooling water circulation pumps	3

The heat exchangers are fixed-tube design with single-pass flow on both shell and tube side. The reservoir fluid is on the tube side. All steel construction is specified and fouling factors are as stated. The overall transfer rate is about 250 Btu/(hr)(ft^2)(°F). This relatively high rate combined with the economy inherent in fixed-tube sheet design results in a significant reduction in the cost of heat transfer equipment for this service as compared to former estimates.

It is anticipated that the exchangers will be cleaned either mechanically or chemically once per year during an annual turnaround. No provision has been made for permanent installation for cleaning.

Expander quotations were received from four vendors. Three were for axial flow designs, and one (Rotoflow) prepared a radial in-flow design. The Rotoflow offering was used, but further evaluations of expander offerings are necessary before a final selection is made.

The eight isobutane pumps are multistage vertical centrifugal pumps, 1,750 hp each. These pumps, as well as cooling-tower pumps and the cooling-tower fans are electrically driven.

Primary process control is based on the premise that plant output will vary with demand. Consequently, a load control with manual set point is included for the generator, controlling the isobutane flow rate to the turbine. Reservoir fluid flow rate is controlled by the temperature of the isobutane vapor. Adjustment of isobutane and reservoir fluid flow rates to each parallel train of hydrocarbon/reservoir fluid heat exchangers is manual. Adjustment of the isobutane vapor and cooling water flow rates to each condenser is also manual. Plant design provides for emergency overspeed shutdown of the turbine.

Preliminary field studies indicate that the well-fluid temperature at Heber will decrease as the reservoir is used. For the depleted condition, a mixture of 65% isobutane and 35% propane appears optimum, requiring a minimum increase in reservoir-fluid flow rate to produce 50 MWe of net power. A comparison of operating conditions for the base case (100% isobutane) and the depleted case follows:

	Base Case	Depleted Case
Reservoir fluid flow rate	3.1 M kg/hr (6.942 M lbs/hr)	4.5 M kg/hr (9.950 M lbs/hr)
Working fluid flow rate	3.70 M kg/hr (8.161 M lbs/hr)	5.0 M kg/hr (11.011 M lbs/hr)
Cooling water flow rate	43,000 m^3/hr (189,595 gpm)	44,500 m^3/hr (195,942 gpm)
Working fluid accumulator operating pressure	586 kPa (85 psia)	896 kPa (130 psia)

The increase in required flow rates for reservoir fluid and working fluid will necessitate future changes to the plant equipment. The number of brine-working fluid exchangers, hydrocarbon condensers, working fluid circulation pumps, cooling water circulation pumps, and cooling tower cells may increase. The turbine-expander is designed to operate under the conditions of the depleted case with a minimum change in parts.

The required design pressure for accumulators, working fluid side of the working fluid condensers and the case of the turbine will increase. The design pressures for the equipment furnished in the base case have been up-rated to meet this condition.

Piping as shown for the base case (major lines) will handle the increased flow requirements. Additional piping, instrumentation and electrical material (i.e., switch gear) will be required for the new equipment.

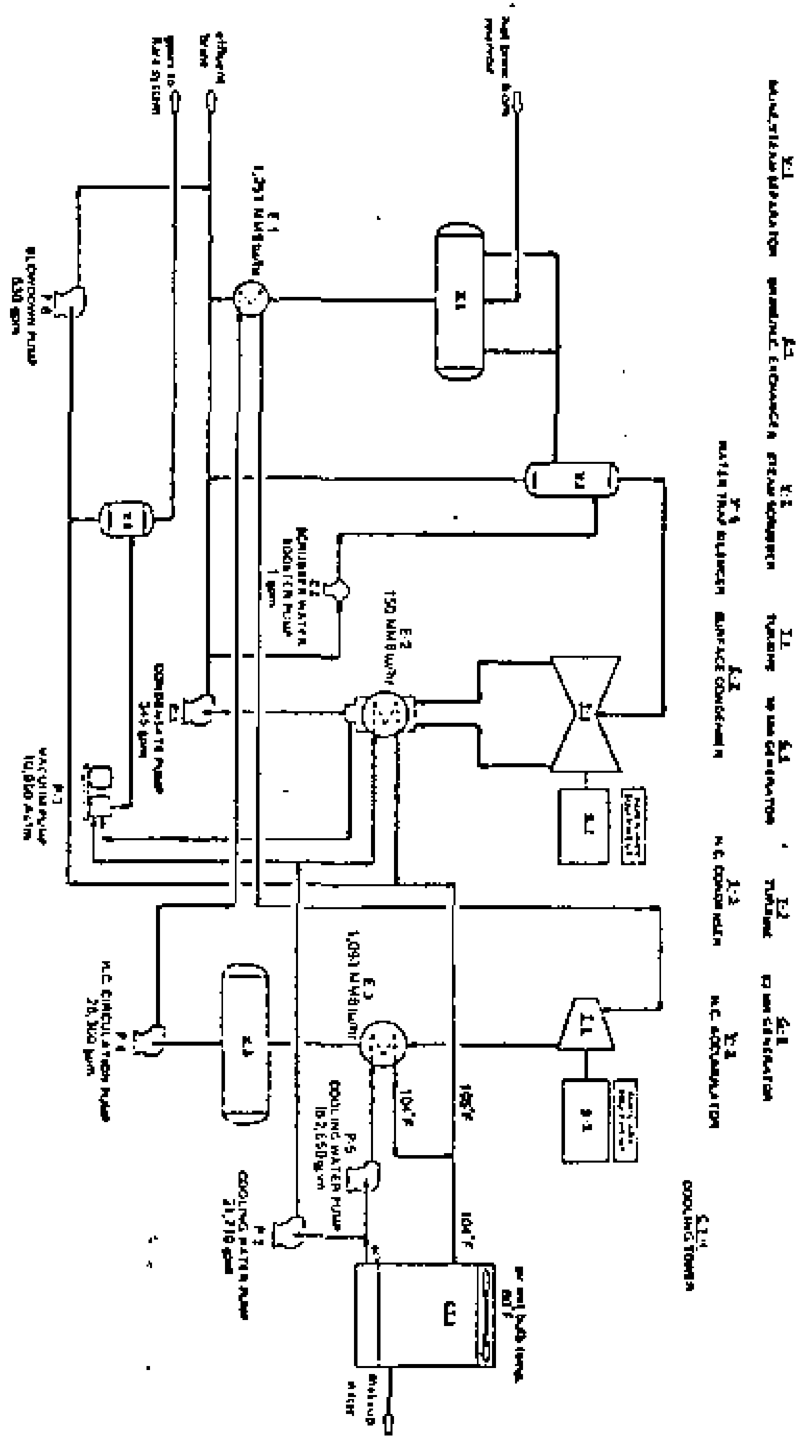
Thus, the plant is somewhat oversized for the beginning conditions but may be economically expanded to accommodate the depleted reservoir conditions.

Hybrid Plant

Isobutane was chosen as the working fluid in the binary section of the hybrid plant. The binary section is designed to generate 52 MWe, and the steam-flash unit will generate 10 MWe. The two generating units in the hybrid plant will produce a total net power of 50 MWe. The process flow diagram, Figure 5.3, shows the following operating conditions.

Reservoir fluid flow	3.3 M kg/hr (7.25 M lbs/hr)
Generator output	62.0 MWe
Pumping work	10.7 MWe
Cooling tower work	1.3 MWe
Net output	50.0 MWe
Reservoir fluid/net kwh	65 kg (145 lbs)

FIGURE 5.3: HYBRID POWER PLANT—HEBER



Source: PB 261 845

These conditions were chosen after having considered flashing temperatures between 160°C (320°F) and 171°C (340°F) in combination with isobutane expander inlet conditions ranging from 400 to 600 psia at temperatures between 127°C (260°F) and 149°C (300°F). The selected operating conditions optimize the power generated per well fluid flow rate.

Water-seal vacuum pumps were selected to remove noncondensable gases from the surface condensers because the seal-water condenses a large part of the entrained water vapor. Most of the cooling tower blowdown will be used as seal water. The noncondensable gases will be pumped into the flare system. The flare stack is designed for dispersal of the hydrogen sulfide present. The blowdown and seal water will be pumped into the effluent reservoir fluid to avoid contaminating the environment.

The basic process controls are the manual set point load controls at the two turbine-generator units. One of the two controls will reset the other. Since both units depend on the same source of reservoir fluid but have different response lags, the override will prevent both controls from fighting each other.

An isobutane vapor temperature control regulates the flow of reservoir fluid through the isobutane exchangers. A steam separator level control regulates the flow of reservoir fluid to the plant. All the parallel flow adjustments are manual. The isobutane circulation rate will change according to load pressure changes.

When the reservoir temperature declines below design conditions, operation of the conversion plant must be modified to maintain the power output of the plant. The steam flash pressure must be lowered and the brine rate increased to maintain a suitable flow of steam to the turbine.

In the binary portion of the plant, the working fluid would be changed from pure isobutane to a mixture of isobutane and propane. Additional heat exchangers and condensers may be required to maintain the power output of this section of the plant.

The brine rate to the plant must be increased to meet those added requirements. The exact rate of increase will depend on the capability of the turbines to adjust to the new conditions. It is estimated that the brine rate will increase 50 to 60% over the life of the plant.

Reservoir Facilities

The systems developed for the production of geothermal hot water, and the disposal of the spent water are based on premises set forth by Chevron Oil Company, developers of the Heber field. The process bases established by Chevron include:

Production:

(1) Directional drilling of all production wells required for a 50 MWe power plant will be concentrated in an area of about one acre.
(2) Production wells will be pumped at a rate of about 295 m^3/hr (1,300 gpm).

(3) Two alternate sand separators will be provided, each sized for a 1-minute residence of the total flow.
(4) An automatic bypass of the power plant will be provided sending hot geothermal water directly to the injection system.

Injection:

(1) Spent water injection is made through wells drilled at three islands uniformly spaced on one quadrant of the circumference of the reservoir having a radius of about 3,048 m (10,000 ft), its center at the power plant. In the complete development of a geothermal unit at Heber, three additional 50 MWe plants will be built. Injection islands for each of these plants will be located similarly in one of the other three quadrants of the circle around the power plants.
(2) Injection rate per well is 590 m^3/hr (2,600 gpm).
(3) Pressure required at an injection well head can increase to 2,861 kPa (415 psia).
(4) Injection pumps deliver spent water to injection well islands at approximately 1,482 kPa (215 psia). A booster pump at each island can be used to raise the pressure to about 2,861 kPa (415 psia).
(5) Automatic controls are provided at the injection wells to regulate the flow of liquid to each well.

Production Systems: In the design of the production piping systems in the flashed-steam system the lines are sized to accommodate the larger flow attending operation when the geothermal water temperature declines to 163°C (325°F). Each well is provided with a down-hole pump rated at 295 m^3/hr (1,300 gpm) and 2,069 kPa (300 psi) head.

Down-hole pumps are vertical shaft-driven centrifugals as offered by Peerless Pump Co. Bowl setting will be about 400 feet. The bearings will be a special Teflon type suitable for high temperature. The pump tubing will be flushed with filtered product for lubrication of line-shaft bearings.

To maintain a check on the operation, each well is provided with temperature, pressure and flow recorders. Discharge pressure is controlled by a pressure control valve on a line which recycles hot water back to the well.

The total hot water produced is alternately passed through one of two sand separators, each sized to provide 1-minute residence and a velocity of about 7 feet per second. Any sand entrained in the geothermal water from the wells is expected to drop out in the separator. The efficiency of sand separation is monitored by measuring the sand content of the water entering and leaving the sand separator. This is achieved by simultaneously passing equal flow slip streams of water entering and leaving the separator through test filters for a given time and measuring the sand trapped on the filters. Periodically, sand collected in a separator is flushed out through nozzles on the bottom of the separator to a sand disposal basin.

Should the power plant be unable to use the total hot-water flow, a bypass with an automatic pressure control valve passes water directly to the injection systems.

This avoids abrupt changes in the operation of the production wells and provides time for production adjustment or orderly shutdown.

The production piping system for the hybrid process at Heber is the same as that for the flashed-steam process. The following table summarizes the production flow and well requirements for the three processes at Heber.

	Field Conditions			
	Required Flow		Wells Required	
	Initial	End	Initial	End
Flashed Steam	4.5 M kg/hr (10.0 M lbs/hr)	7.4 M kg/hr (16.3 M lbs/hr)	16	21
Binary	3.1 M kg/hr (6.942 M lbs/hr)	4.5 M kg/hr (9.9 M lbs/hr)	12	19
Hybrid	3.288 M kg/hr (7.249 M lbs/hr)	5.81 M kg/hr (12.8 M lbs/hr)	13	21

Injection Systems: The geothermal water from the power plant is pumped back to the reservoir through injection wells. Two injection pumps are provided for the total flow which, for the flashed-steam process, varies from about 4.5 M kg/hr (10.0 M lb/hr) initially to 7.4 M kg/hr (16.3 M lb/hr) when the geothermal hot-water temperature declines to 163°C (325°F). The injection pumps have a discharge pressure of about 1,620 kPa (235 psia) and deliver the spent water to the farthest injection well island at about 1,482 kPa (215 psia). At each island a booster pump can be used to raise the pressure to the maximum 2,861 kPa (415 psia) at the well head for injection at 590 m^3/hr (2,600 gpm). Under initial field conditions only 7 wells are required at full injection rate, or all of the 10 wells could be used at an average rate of 422 m^3/hr (1,860 gpm). To give flexibility, provision is made to bypass the booster pump and inject water at 1,482 kPa (215 psia) pressure provided by injection pumps.

As required by Imperial County, the injection lines from the power plant to the injection wells are underground and are suitably coated and wrapped. At each well, the feed line is provided with a flow-control valve, temperature and pressure recorders and a flow-controller recorder.

The injection piping system for the hybrid process is the same as that for the flashed-steam process. The following table summarizes the injection well requirements for the three processes at Heber.

	Wells Required	
Process	Initial Field Condition	End Field Condition
Flashed steam	8	10
Binary	6	9
Hybrid	6	10

General Facilities

The following facilities are provided for each of the conversion plants.

Buildings: The main control building is 15 by 23 m (50 by 75 ft) and contains the control room, switch gear, laboratory and shop. The compressor building is 7.5 by 7.5 m (25 by 25 ft) and contains the air compressors and dryers. The cooling tower treatment building is 4.6 by 7.5 m (15 by 25 ft) and contains the chemical mixing vessels and injection pumps.

Fire Protection: The binary and hybrid plants use the cooling tower basin as a fire-water reservoir. An electric pump, a diesel pump and a jockey pump are provided along with automatic controls to start the main pumps in case the fire-water pressure drops. Each plant is provided with a fire-water loop around the plant with hydrants and fire monitors. Only local fire protection facilities are provided for the flashed-steam plant.

Flare System: The binary and hybrid plants are provided with a flare system that contains a knock-out drum, water seal, and a 125-foot flare stack.

Instrumentation: In addition to the controls and instruments for the piping and instrumentation, each plant and each field facility is provided with a data logging system which will monitor and record all pertinent variables. The system will be installed so that at a later date when multiple plants have been installed at the reservoir, a single computer can be installed to control all the plants.

Blow-Down Disposal: All plants are designed to dispose of contaminated process water such as cooling tower blow-down by discharging the fluid into the agricultural drains. No treatment facilities for the wastewater are planned.

VALLES CALDERA CONVERSION PLANTS

The Reservoir

The Valles Caldera hydrothermal reservoir is located in the northeastern corner of Sandoval County, New Mexico. The reservoir is located in mountainous terrain at an elevation of about 2,750 meters (9,000 feet). At this elevation, atmospheric pressure is 72.4 kPa (10.5 psia).

Air temperatures at the site range from 32°C (90°F) in summertime to as low as -40°C (-40°F) in the wintertime. One percent of the time during the summer months the wet-bulb temperature in the area exceeds a temperature of 17°C (62°F). This temperature was used for design.

The area is quite rough, with the geothermal wells located along the valleys created by Sulfur Creek and Redondo Creek. Access to the area is restricted, and roads to the site are indicated to be dirt.

The availability of water at the site is restricted by regulations of water rights as described in the Preliminary Environmental Assessment. The assessment suggests that water might be obtainable from Santa Clara Creek located in the northwest corner of Sandoval County, a distance of approximately 16 miles. There are no roads nor electric power in the area, and it would be necessary to bring the water line over a 3,000-meter (10,000-foot) maintain pass. The cost of this installation has been estimated to be in the range of 7.5 to 10 million dollars.

Condensate from the steam flash or hybrid plants could possibly be used as cooling tower makeup, providing that subsidence would not be a problem and provided that permission to do so could be obtained from the State of New Mexico. It has been assumed that water would be available at the plant site, and estimates do not include the cost of obtaining a suitable source of water.

Information furnished by the Electric Power Research Institute regarding the Valles Caldera reservoir fluid was interpreted as follows:

Total dissolved solids	5,000 ppm
Silica (SiO_2)	400 ppm
Bottom-hole temperature	260°C (500°F)
Noncondensable gases	low

Wells are self-producing, providing well-head fluid at the following conditions:

Temperature	182°C (360°F)
Pressure	1,034 kPa (150 psi)
Flow rate	113,400 kg/hr (250,000 lb/hr)

These data were used as a design basis.

No information was available on the corrosive characteristics of this fluid. Therefore, it was assumed that its properties would be similar to fluid from the Heber reservoir. Carbon steel is assumed to be a suitable material for piping and vessels.

The SiO_2 present in the fluid may cause scale to form on the heat-exchanger tubes of the binary and hybrid plants. Tests should be performed to determine the temperature level at which scale formation occurs. If scale formation is shown to occur, then the binary and hybrid plants could be designed to use flashed steam for heating. Because the fouling characteristics of the reservoir fluid were not known, the Heber fouling factors were used for the Valles Caldera binary and hybrid plants.

Some noncondensable gases occur in the flashed steam, but the concentration of gas in the reservoir fluid is not known. A high concentration of noncondensable gases necessitates a major investment in vacuum pumps for the flashed-steam and hybrid plants. It was assumed that the quantity of noncondensable gases would be the same as for Heber; i.e., 680 kg/hr (1,500 lb/hr). When accurate analyses of the noncondensable gases are available, this assumption must be reviewed and suitable equipment provided to remove the gases.

Similarly, the quantity of hydrogen sulfide present in the noncondensable gases was assumed to be in the range from 100 to 1,000 ppm. This quantity of gas can be safely dispersed by using a vent stack of adequate height. If the quantities of hydrogen sulfide present in the reservoir fluid preclude the use of a vent stack, then a sulfur-removal unit, such as a Stretford plant, should be added to the power plant.

The power conversion units and reservoir piping are designed on the basis that some degradation of the reservoir fluid will occur in the life of the plant. If the down-hole temperature of the reservoir declines, more fluid must be supplied to the plant to maintain a constant power output. Consequently, more wells must be drilled and operated. The plant and reservoir systems are designed for a 15% increase in flow which corresponds to a decrease in the down-hole temperature of 20°C (35°F).

Flashed-Steam Plant

Figure 5.4 is a process flow diagram of the Valles Caldera flashed steam plant. The hot reservoir fluid enters the plant at a flow rate of 1.8M kg/hr (3.96M lb/hr). The brine and steam pass into two parallel first-stage flash drums at a pressure of 1,055 kPa (153 psia). The first-stage drum produces 324,770 kg/hr (716,000 lb/hr) of primary steam which passes through a steam separator before reaching the turbine generator at a pressure of 1,055 kPa and a temperature of 182°C (360°F).

The liquid from the first-stage flash drums flows to the second-stage flash drums where its pressure is reduced to 232 kPa (33.7 psia). The resultant flash produces 169,192 kg/hr (373,000 lb/hr) of secondary steam which flows through a steam separator to a lower stage of the turbine-generator through a separate set of admission valves. The steam reaches the turbine at a pressure of 228 kPa (33.0 psia) and a temperature of 125°C (257°F). The secondary flash drums float on the line, their pressure varying with turbine stage pressure and with demand.

The flashed liquid flows from the second stage flash drums to the suction of the injection pumps which return the liquid to the reservoir. Liquid level is maintained in the second-stage flash drums by a control valve on the pump discharge.

The turbine generator is operated as a base-load unit under load control. The operator assigns a load to the generator, and the turbine must accept that load at constant speed. The turbine governor detects changes in load and adjusts admission valves on both the primary and secondary steam lines to satisfy the assignment. A separate emergency trip mechanism on the turbine shaft will close emergency stop valves on both primary and secondary steam lines if turbine speed exceeds 3,600 rpm by a given percentage.

Exhaust steam from the turbine passes directly into a surface condenser, where a back pressure of 10.1 kPa (3" Hg) is obtained under design cooling water conditions. The steam condensate is pumped to the suction of the injection pumps for disposal. The condensate is added to the reduced brine to make the replenishment volume substantially equal to the volume of fresh brine delivered to the plant. Average temperature of this flow is 103°C (218°F).

Noncondensable gases from the reservoir fluid and air leakage are removed from the condenser by two large vacuum pumps in parallel. The exhaust gas is discharged into a vertical stack which is designed to disperse the hydrogen sulfide contaminant.

A summary of pertinent design data for the flashed-steam plant is as follows:

Reservoir fluid rate, M kg/hr (lb/hr)	1.8 (3.96)
Generator output, MWe	56.0
Pumping work, MWe	1.9
Cooling tower work, MWe	1.1
Net output, MWe	52.0
Reservoir fluid/net kWh, kg (lb)	34 (76)

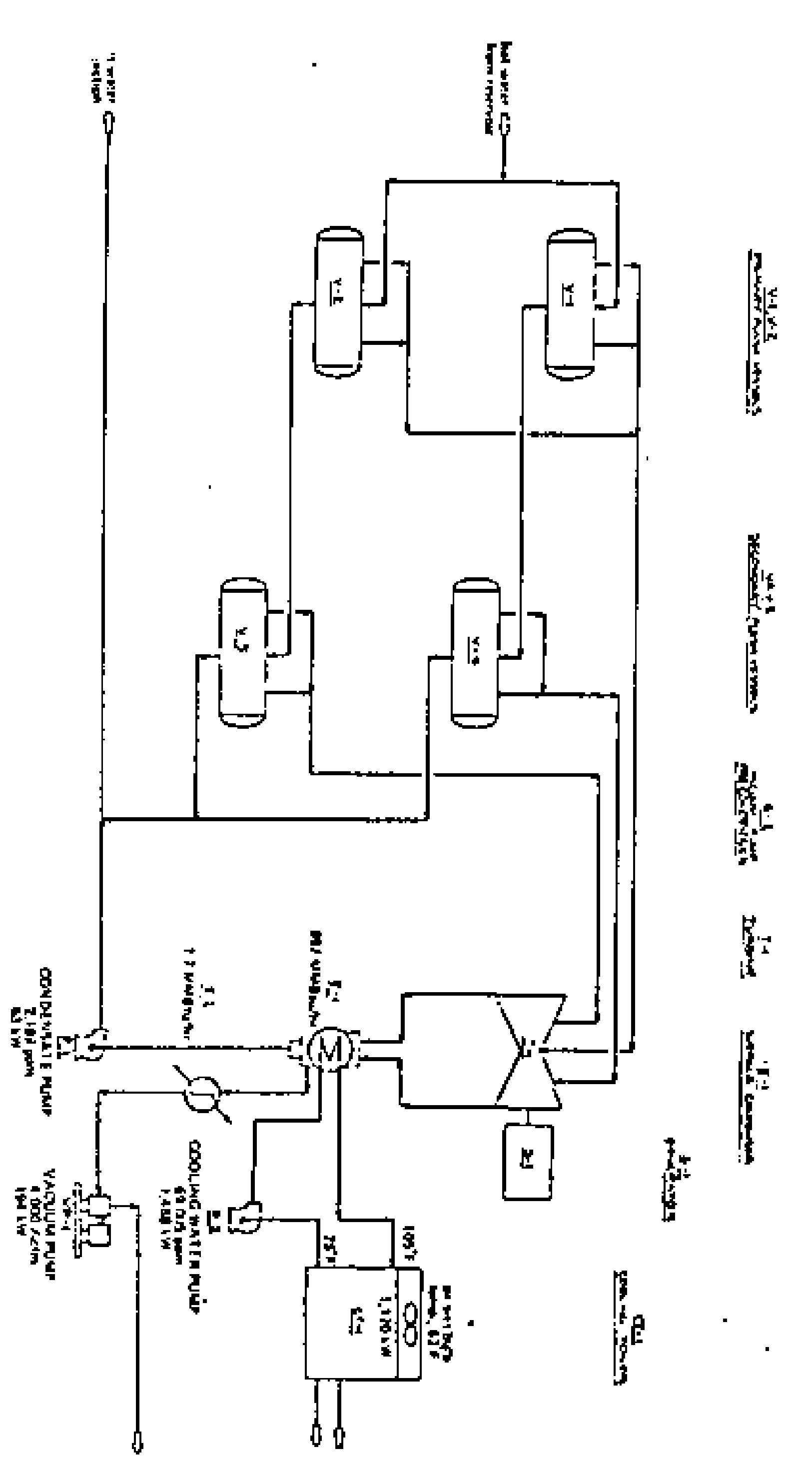


FIGURE 5.4: FLASHED-STEAM POWER PLANT—VALLES CALDERA

Source: PB 261 845

Binary Plant

The reservoir fluid at Valles Caldera flows naturally from the well, producing two phases at the surface in the following proportions, by weight: 15.3% steam and 84.7% hot water.

Because of the two-phase flow, the heat exchanger section of this plant differs from the Heber and Raft River binary plants. Separation of the steam and hot water is performed in a horizontal separator providing a minimum of 1-minute liquid residence time. The steam leaving the separator passes through a second-stage separator for removal of entrained condensate enroute to a hydrocarbon-steam heat exchanger. Condensate leaving the exchanger is mixed with the hot water from the separator, and this mixed stream is used to preheat the hydrocarbon stream. Noncondensable gases are continuously bled off from the condensate discharge stream and discharged into the flare system.

The Valles Caldera process flow diagram (Figure 5.5) provides material and heat balance details. Isopentane (optimized process) is used for the operating fluid in the binary process plant. The isopentane is pumped from the accumulator through the hydrocarbon-reservoir fluid exchanger and through the hydrocarbon-steam exchanger.

The heated isopentane in a subcritical condition is used to drive the expansion turbine. A generator output of approximately 56 MWe is required to provide for in-plant electric power consumption and produce a net output of 50 MWe.

Tests run on geothermal reservoir fluids at some locations have shown an increase in deposition of solids when the fluid is cooled. In the absence of specific test data on the reservoir fluid at Valles Caldera, the fouling factors observed with the Heber reservoir fluid were used. The hydrocarbon-reservoir fluid heat exchangers are designed with four units in series to facilitate cleaning.

A summary of the pertinent design data for the binary plant is as follows:

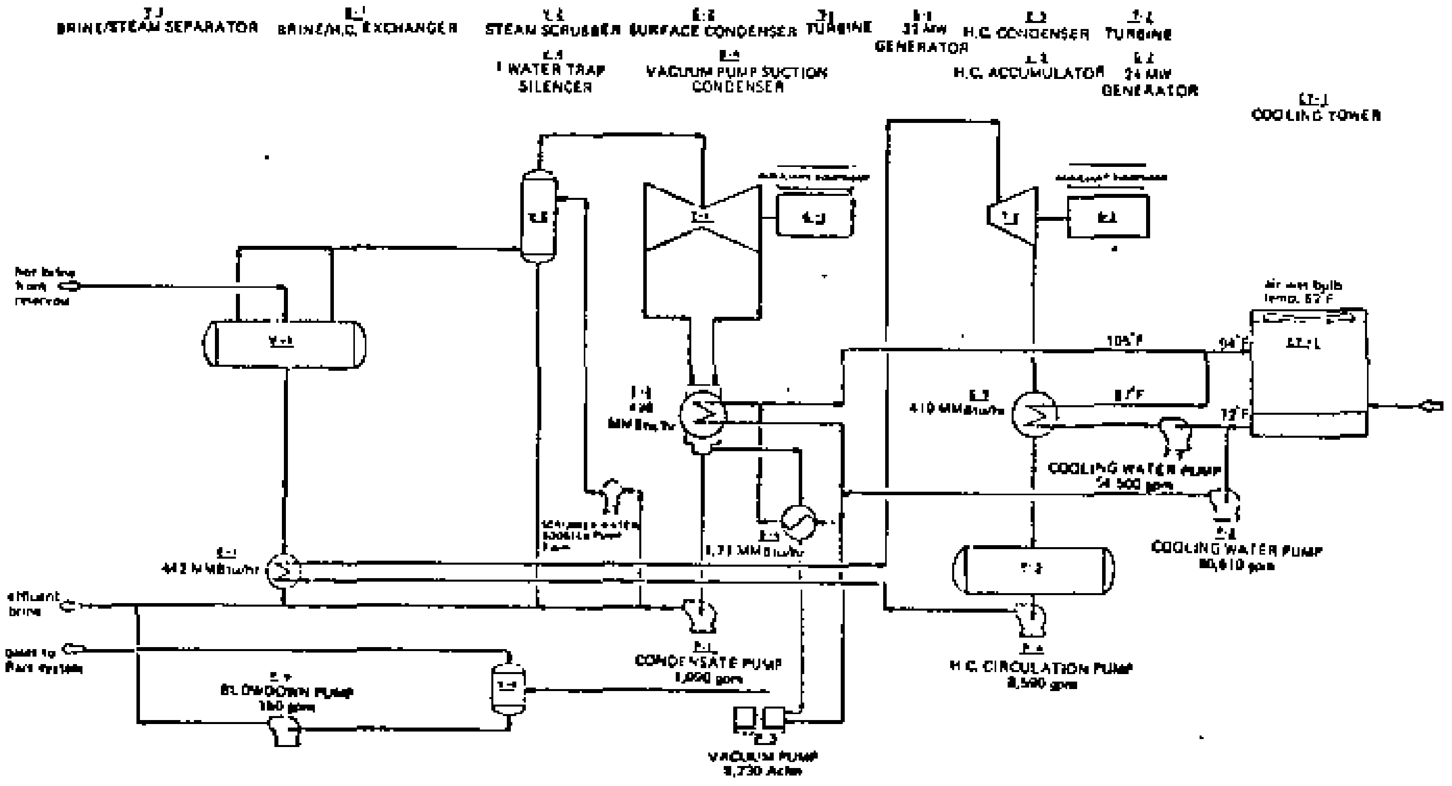
Reservoir fluid, M kg/hr (lb/hr)	1.19 (2.62)
Isopentane, M kg/hr (lb/hr)	2.10 (4.62)
Generator output, MWe	56.3
Pumping work, MWe	3.6
Cooling tower work, MWe	2.7
Net output, MWe	50.0
Reservoir fluid/net kWh, kg (lb)	24 (52)

Hybrid Plant

Isobutane was chosen as the working fluid in the base-case binary power cycle of the hybrid plant. The binary portion of the plant will generate 24 MWe, and the steam unit will generate 32 MWe. The two generating units in the hybrid plant will produce a total net power of 50 MWe.

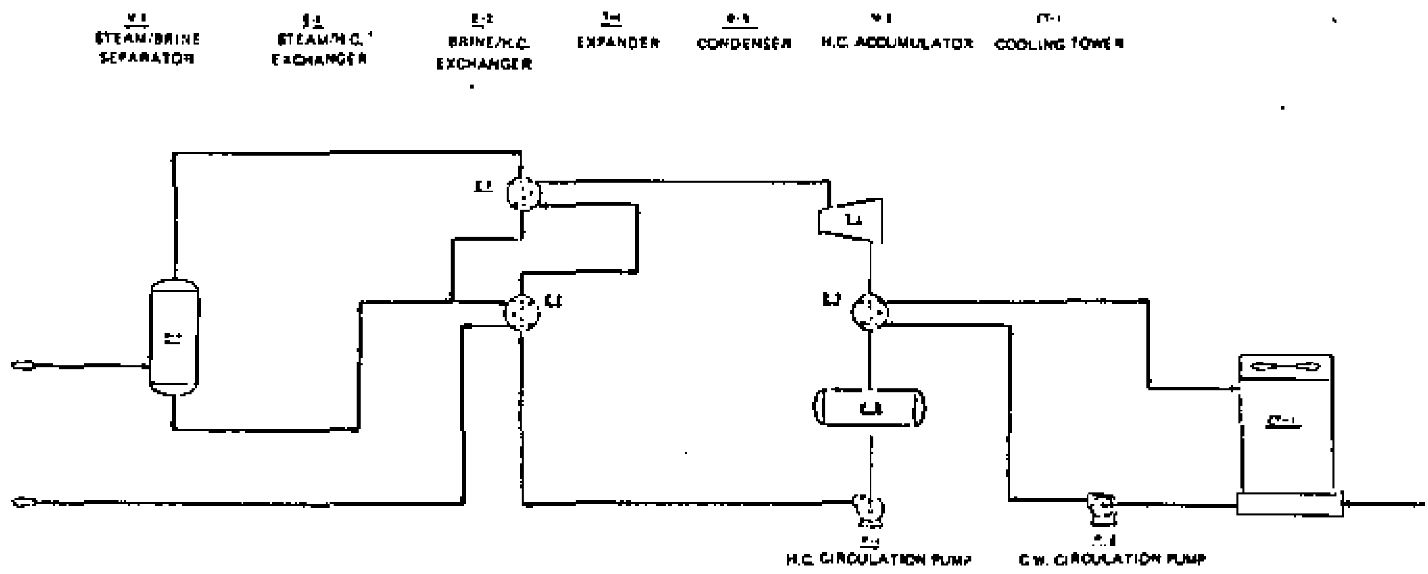
The process flow diagram, Figure 5.6, shows the plant operating conditions.

FIGURE 5.6: HYBRID POWER PLANT—VALLES CALDERA



Source: PB 261 845

FIGURE 5.5: BINARY POWER PLANT—VALLES CALDERA



Source: PB 261 845

The relative sizes of the steam and binary sections of the plant were chosen after having considered a steam temperature of 182°C (360°F) in combination with isobutane expander inlet conditions ranging from 2,758 to 4,237 kPa (400 to 600 psia) at temperatures between 137°C (280°F) and 160°C (320°F).

The selected operating conditions represent a compromise between those providing maximum power generation per well fluid flow rate and those requiring a minimum isobutane circulation rate. The noncondensable gases will be dispersed in the flare system. Wastewater will be pumped into the effluent reservoir fluid to avoid contaminating the environment. A summary of the pertinent design data for the hybrid plant is as follows:

Reservoir fluid rate, M kg/hr (lb/hr)	1.36 (3.0)
Generator output, MWe	56.0
Pumping work, MWe	4.6
Cooling tower work, MWe	1.4
Net power, MWe	50.0
Reservoir fluid/net kWh, kg (lb)	27.2 (60)

Reservoir Facilities

The systems developed for production and injection of geothermal fluid at Valles Caldera, New Mexico, are based on conventional vertical drilling of the wells at a spacing of 30 acres per well. Based on square plots, the distance between wells is approximately 349 meters (1,145 feet). The production wells in this field are self-flowing, and the fluid at the well head is a mixture of steam and geothermal water.

The preceding description of the production scheme at Heber, California applies for the most part to Valles Caldera, except that special flow meters are required for the measurement of two-phase flow. Also, the removal of sand, if any, in the geothermal fluid is achieved in the first-stage steam separator of the power plant.

The geothermal fluid flow and the number of wells required for the three processes evaluated at Valles Caldera for initial and final conditions are listed in the following table.

Process	Required Flow		No. of Wells	
	Initial	End	Initial	End
Flashed steam	1,796 M kg/hr (3,959 M lbs/hr)	2,036 M kg/hr (4,489 M lbs/hr)	16	18
Binary	1,459 M kg/hr (3,217 M lbs/hr)	1,621 M kg/hr (3,574 M lbs/hr)	13	15
Hybrid	1,362 M kg/hr (3,002 M lbs/hr)	1,532 M kg/hr (3,378 M lbs/hr)	12	14

The scheme for injection of spent geothermal fluid at Valles Caldera is basically the same as that at Heber. However, the distance from the power plant to the nearest edge of the injection field is 1,524 meters (5,000 feet) instead of 3,048 meters (10,000 feet) used by Chevron at Heber, and the wells are spaced at 30 acres per well. Injection well requirements are summarized in the table on the following page.

Process	No. of Wells Required	
	Initial Field Condition	Final Condition
Flashed steam	4	4
Binary	3	3
Hybrid	3	3

RAFT RIVER CONVERSION PLANTS

The Reservoir

The Raft River hydrothermal reservoir is located in south central Idaho, approximately 40 miles southeast of Burley. The area lies along the Raft River Valley at an elevation of about 1,400 meters (4,800 feet). At this elevation the atmospheric pressure is 82 kPa (12 psia).

Air temperatures at the site range from 38°C (100°F) in summertime to as low as -34°C (-30°F) in the wintertime. The wet-bulb temperature in the area reaches or exceeds a maximum of 18°C (65°F) one percent of the time during the summer months. This temperature was used for design.

The area is rugged with mountains reaching to about 3,000 meters (9,800 feet) elevation. U.S. Highway 30 is a three-lane highway which comes close to the geothermal plant site. Water for makeup to the cooling tower will be taken from the Raft River or from surface wells.

Production wells and injection wells have been allocated 30 acres of ground area per well. Injection wells will be located on the cooler areas of the geothermal anomaly.

The Raft River reservoir fluid has the following general characteristics: total dissolved solids, 2,000 ppm; bottom-hole temperature, 149°C (300°F). The following noncondensable gases are present in the fluid:

Gas	Cc (STP) per Liter of Brine	Mol %
H_2	0.53	1.4
He	0.1	0.1
N_2	32.0	81.8
O_2	0.1	0.25
Ar	0.7	1.7
CO_2	5.8	14.8
SO_2	–	0.1
	approx. 39.1	approx. 100

The geothermal producing wells must be pumped to achieve high production rates. It has been assumed that the differential pressure required to produce the wells is 2,068 kPa (300 psia) and that the pressure required to inject the brine will increase to 2,758 kPa (400 psia) at the well head. The same pumping rate of 295 m^3/hr (1,300 gpm/well) as at Heber has been used.

The corrosion and fouling characteristics of the Raft River reservoir fluid were not known. Therefore, it was assumed that the fluid would have the same characteristics as the Heber reservoir fluid. The use of steel was specified in all the equipment exposed to the reservoir fluid or flashed steam, except the steam turbines and surface condensers, where stainless steel is used.

Flashed Steam Plant

A process flow diagram of the flashed-steam plant is shown in Figure 5.7. The hot reservoir fluid enters the plant at a flow rate of 7.39 M kg/hr (16.3 M lb/hr). The brine flows into the first-stage flash drums at a pressure of 290 kPa (42 psia). The first-stage flash produces 241,000 kg/hr (532,000 lb/hr) of primary steam which passes through a steam separator before reaching the turbine-generator at a pressure of 284 kPa (41.2 psia) and a temperature of 132°C (270°F).

Liquid from the first-stage flash drums flows to the second-stage flash drums where its pressure is reduced to 114 kPa (16.6 psia). The resultant flash produces 391,900 kg/hr (864,000 lb/hr) of secondary steam which flows through a steam separator to a lower stage of the turbine-generator through a separate set of admission valves. The steam reaches the turbine at a pressure of 112 kPa (16.3 psia) and a temperature of 103°C (218°F). The secondary flash drums float on the line, their pressure varying with turbine stage pressure and with demand.

Exhaust steam from the turbine passes directly into a surface condenser, where a back pressure of 6.77 kPa (2" Hg) is obtained under design cooling water conditions. The steam condensate is pumped to the suction line of the injection pumps for disposal. The condensate is added to the reduced brine to make the replenishment volume substantially equal to the volume of fresh brine delivered to the plant. Average temperature of this flow is 98°C (208°F).

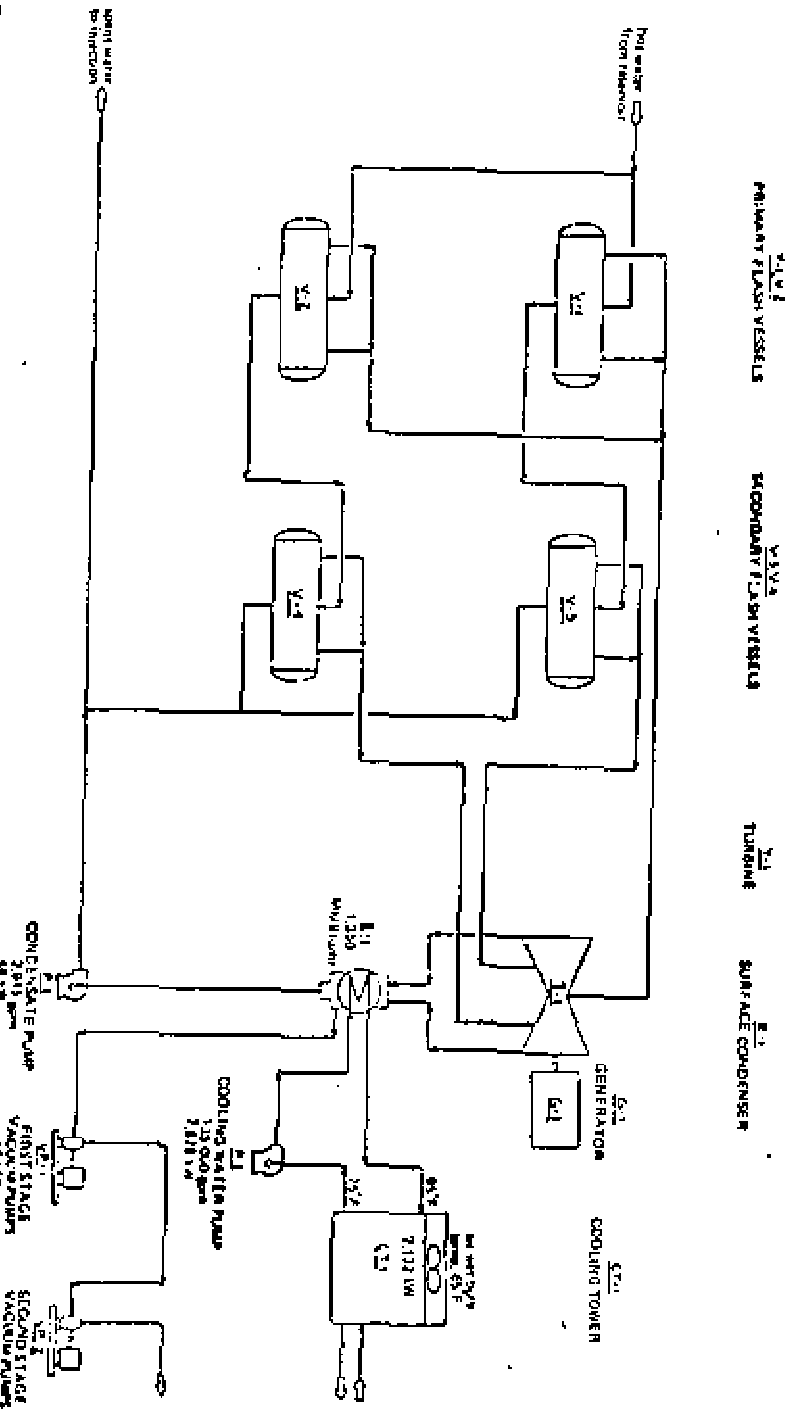
The cooling-water temperature was established at 5.5°C (10°F) above the design wet-bulb temperature. This is the minimum practical cooling tower approach and results in an expensive tower. However, a parametric study in which cold-water temperature was raised slightly, 1.7°C (3°F), increased the cost of the condenser more than it reduced the cost of the cooling tower. Similarly, another study in which the condensing pressure was raised slightly to 15 kPa (2.2" Hg) produced a loss of efficiency and an increase in brine consumption. The prospective cooling tower capital cost saving was more than offset by increased brine costs and increased cooling tower fan horsepower.

Turbine selection was difficult for the plant. With the limitations on bucket size mentioned earlier, 55 MWe of output could be obtained only with a four-flow, two-case machine. The maximum output attainable with a two-flow turbine was about 38 MWe.

Noncondensable gas flow has been estimated at 406 kg/hr (903 lb/hr) based on a brine analysis. These gases are removed from the condenser with vacuum pumps. Because of the low condensing pressure, 13.8 kPa (2" Hg), two stages are required. There are four large first-stage pumps and two medium-size second-stage pumps. A stack is provided for the dispersal of the noncondensable gases.

A summary of pertinent design data for the plant is shown on the page following the process flow diagram.

FIGURE 5.7: FLASHED-STEAM POWER PLANT—RAFT RIVER



Source: PB 261 845

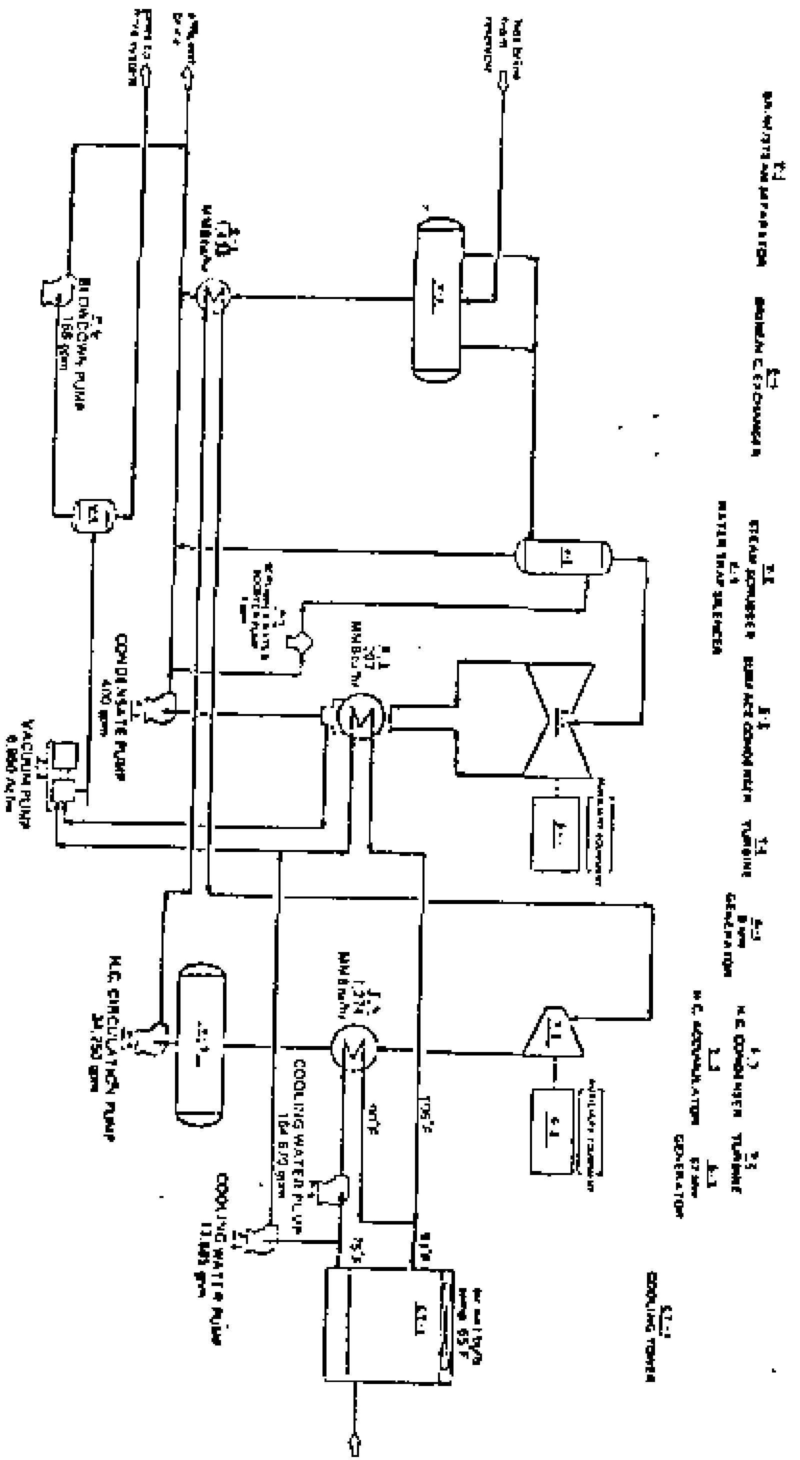


FIGURE 5.9: HYBRID POWER PLANT—RAFT RIVER

Source: PB 261 845

The production and injection piping schemes are generally the same as at Valles Caldera. At Raft River only initial field conditions are considered, since any decline in the reservoir temperature would result in an excessive increase in plant and operating costs. Flows and well requirements are summarized in the following table.

Process	Required Flow of Well Fluid	No. of Wells Required Production	Injection
Flashed steam	7.4 M kg/hr (16.3 M lbs/hr)	27	13
Binary	5.0 M kg/hr (11.0 M lbs/hr)	19	9
Hybrid	5.4 M kg/hr (11.9 M lbs/hr)	20	10

ECONOMIC FEASIBILITY

Capital Costs

Capital cost estimates for the three Heber conversion options and for one Heber field installation are presented in Tables 5.1, 5.2, 5.3 and 5.4. These estimates are made on the basis that a single contract would be let for design, procurement and construction and, therefore, represent the installed cost ready for operation.

Major equipment costs (i.e., pressure vessels, heat exchangers, pumps, cooling tower, turbine and generator) were based on vendor quotations. Construction items (i.e., concrete, piping, structural, instruments, painting, electrical, insulation, paving, roads, fencing and buildings) were based on material takeoffs and 1976 unit prices of such materials. Indirect field costs and home office services are based upon experience in building facilities of similar size and complexity.

The estimates include a contingency of 6% and an escalation of 10%.. The latter figure is expected to be sufficient to cover increases in labor, materials and other costs which may occur between the first quarter of 1976 and the completion of the proposed plant in early 1980.

The power plant costs for each process at Heber are as follows. These costs exclude the cost of land and any costs incurred by the owner associated with design and construction.

	Million Dollars
Flashed steam	26.8
Binary	28.5
Hybrid	36.6

The cost of the surface installation for the binary plant at Heber is estimated to be $7,800,000. This cost includes the down-hole pumps, the injection pumps, production piping, injection piping and related installations. The cost of completed production and injection wells is excluded. The cost is based on end-of-run conditions and is, therefore, somewhat higher than would actually be incurred at the start.

Table 5.5 presents capital costs for the power plants and transmission installations at each site.

Reservoir fluid rate, M kg/hr (lb/hr)	7.4 (16.3)
Generator output, MWe	55.0
Pumping work, MWe	3.7
Cooling tower work, MWe	2.1
Net power, MWe	49.2
Reservoir fluid/net kWh, kg (lb)	150 (331)

Binary Plant

Because of the low reservoir temperature, a mixture of 50% isobutane and 50% propane was used for the operating fluid in the binary process plant at Raft River, Idaho. A generator output of approximately 68 MWe is required to provide for in-plant electric power consumption and produce a net output of 50 MWe.

The Raft River process flow diagram (Figure 5.8) shows material and heat balance details for the plant. This plant is characterized by the high circulation rate of process fluids required to produce 50 MWe of power. Ten parallel hydrocarbon circulation pumps are needed to meet the process flow requirements. In other respects, the plant is similar to the Heber binary plant. A summary of pertinent design data for the plant is as follows:

Reservoir fluid rate, M kg/hr (lb/hr)	5.0 (11.0)
Hydrocarbon fluid rate, M kg/hr (lb/hr)	4.8 (10.6)
Generator output, MWe	67.5
Pumping work, MWe	15.9
Cooling tower work, MWe	1.6
Net power, MWe	50.0
Reservoir fluid/net kWh, kg (lb)	100 (220)

Hybrid Plant

A mixture of 50 mol % propane and 50% isobutane was chosen as the working fluid in the binary power cycle of the hybrid plant because of the low temperature of the reservoir fluid. The binary section is designed to generate 57 MWe, and the steam flash unit will generate 9 MWe. The selected design conditions optimize the power generated per well fluid flow rate.

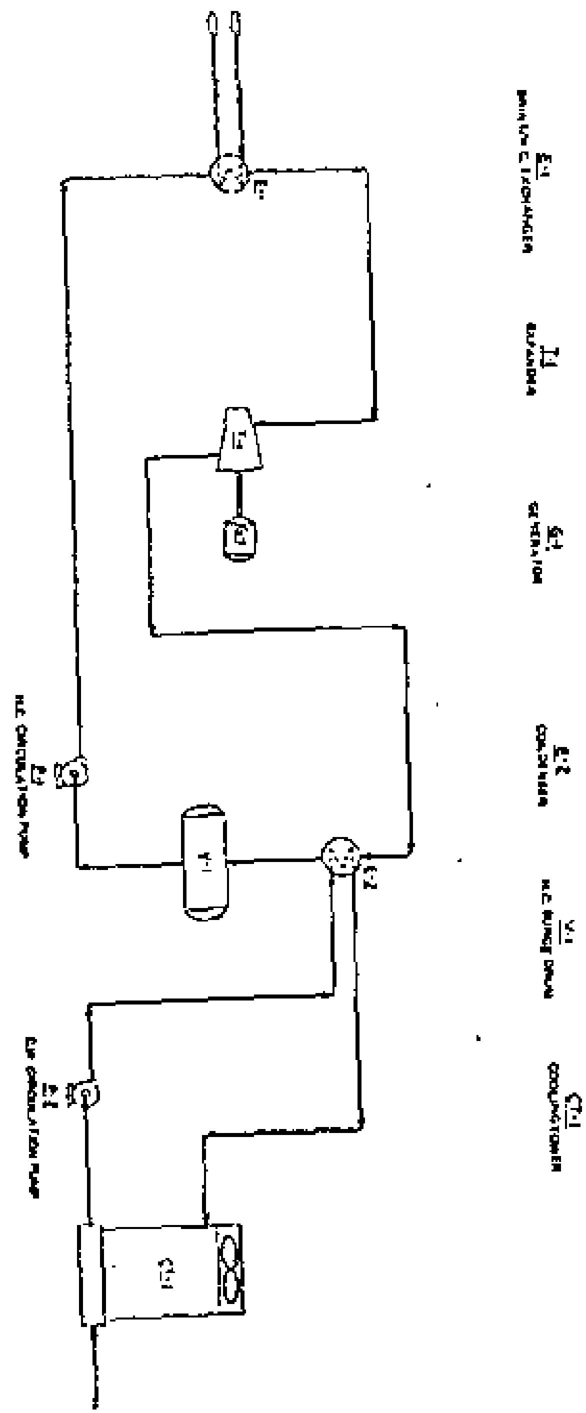
The process flow diagram (Figure 5.9) shows the plant operating condition. This plant, like the binary plant, is characterized by high flow rates of the process fluids. A summary of this pertinent design data for the plant is as follows:

Reservoir fluid rate, M kg/hr (lb/hr)	5.9 (11.9)
Generator output, MWe	66.0
Pumping work, MWe	13.5
Cooling tower work, MWe	2.5
Net power, MWe	50.0
Reservoir fluid/net kWh, kg (lb)	108 (238)

Reservoir Facilities

At Raft River, the production and injection wells are drilled at a spacing of 30 acres per well. The production wells are self-flowing, but down-hole pumps are used to boost the flow to the design rate of 1,300 gpm per well

FIGURE 5.8: BINARY POWER PLANT—RAFT RIVER



Source: PB 261 845

TABLE 5.1: CAPITAL COSTS–HEBER BINARY PLANT

ACCOUNT	Materials	Subcontract	Labor	TOTAL
1100 Columns (incl. trays)				
1200 Pressure Vessels	213,000			213,000
1300 Heat Exchangers	2,700,000			2,700,000
1400 Furnace/Heaters				
1500 Pumps	1,132,000			1,132,000
1600 Boilers				
1700 Cooling Towers		1,800,000		1,800,000
1800 Turbine & Generator	3,700,000			3,700,000
1900 Tanks				
2800 Other	155,000			155,000
Labor			200,000	200,000
TOTAL MAJOR EQUIPMENT	7,900,000	1,800,000	200,000	9,900,000
3100 Concrete	200,000		210,000	410,000
3200 Pipe, Valves, Fittings	1,640,000	60,000	1,000,000	2,700,000
3300 Structural Steel	400,000		200,000	600,000
3400 Instruments	360,000	60,000	40,000	460,000
3500 Painting		50,000		50,000
3600 Electrical	1,225,000	650,000		1,875,000
3700 Insulation		255,000		255,000
3800 Paving, Roads, Fences & Misc.	20,000	80,000	100,000	200,000
3900 Buildings		200,000		200,000
TOTAL CONSTRUCTION ITEMS	3,845,000	1,355,000	1,550,000	6,750,000
DIRECT FIELD COSTS	11,745,000	3,155,000	1,750,000	16,650,000
Indirect Field Costs	471,000	245,000	2,208,000	2,824,000
TOTAL FIELD COSTS	12,216,000	3,390,000	3,958,000	19,474,000
8100 Home Office Services				3,119,000
SUB-TOTAL				22,593,000
9500 Sales Tax on Material				707,000
9700 Fee & Contingency				2,600,000
Escalation				2,600,000
TOTAL SELLING PRICE				$28,500,000

Source: PB 261 845

TABLE 5.2: CAPITAL COSTS–HEBER FLASHED-STEAM PLANT

ACCOUNT	Materials	Subcontract	Labor	TOTAL
1100 Columns (incl. trays)				
1200 Pressure Vessels	285,000			285,000
1300 Heat Exchangers	1,280,000			1,280,000
1400 Furnace/Heaters				
1500 Pumps	451,000			451,000
1600 Boilers				
1700 Cooling Towers		1,600,000		1,600,000
1800 Turbine & Generator	6,880,000	200,000		7,080,000
1900 Tanks				
2800 Other – Vacuum Equip. and etc.	406,000			406,000
Labor			400,000	400,000
TOTAL MAJOR EQUIPMENT	9,300,000	1,800,000	400,000	11,500,000
3100 Concrete	200,000		350,000	550,000
3200 Pipe, Valves, Fittings	750,000	10,000	400,000	1,160,000
3300 Structural Steel	200,000		100,000	300,000
3400 Instruments	300,000	100,000	50,000	450,000
3500 Painting		50,000		50,000
3600 Electrical	950,000	425,000		1,375,000
3700 Insulation		200,000		200,000
3800 Paving, Roads, Fences & Misc.	10,000	100,000	90,000	200,000
3900 Buildings		200,000		200,000
TOTAL CONSTRUCTION ITEMS	2,410,000	1,085,000	970,000	4,465,000
DIRECT FIELD COSTS	11,710,000	2,885,000	1,370,000	15,965,000
Indirect Field Costs	468,000	144,000	1,749,000	2,361,000
TOTAL FIELD COSTS	12,178,000	3,029,000	3,119,000	18,326,000
8200 Home Office Services				2,971,000
SUB-TOTAL				21,297,000
9500 Sales Tax on Material				703,000
9700 Fee & Contingency				2,400,000
Escalation				2,400,000
TOTAL SELLING PRICE				$26,800,000

Source: PB 261 845

TABLE 5.3: CAPITAL COSTS–HEBER HYBRID PLANT

ACCOUNT	Materials	Subcontract	Labor	TOTAL
1100 Columns (incl. Trays)				
1200 Pressure Vessels	272,000			272,000
1300 Heat Exchangers	2,115,000			2,115,000
1400 Furnace/Heaters				
1500 Pumps	1,135,000			1,135,000
1600 Boilers				
1700 Cooling Towers		1,600,000		1,600,000
1800 Turbines & Generators	5,000,000			5,000,000
1900 Tanks				
2000 Other - Vacuum Equip. and etc.	498,000	50,000		548,000
Labor			271,000	271,000
TOTAL MAJOR EQUIPMENT	9,020,000	1,650,000	271,000	10,941,000
3100 Concrete	200,000		440,000	640,000
3200 Pipe, Valves, Fittings	2,160,000	59,000	2,206,000	4,425,000
3300 Structural Steel	562,000		354,000	916,000
3400 Instruments	425,000	171,000	41,000	637,000
3500 Painting		50,000		50,000
3600 Electrical	1,317,000	701,000		2,018,000
3700 Insulation		333,000		333,000
3800 Paving, Roads, Fences & Misc.		300,000		300,000
3900 Buildings		324,000		324,000
TOTAL CONSTRUCTION ITEMS	4,664,000	1,938,000	3,041,000	9,643,000
DIRECT FIELD COSTS	13,684,000	3,588,000	3,312,000	20,584,000
Indirect Field Costs	547,000	179,000	3,870,000	4,596,000
TOTAL FIELD COSTS	14,231,000	3,767,000	7,182,000	25,180,000
9200 Home Office Services				4,003,000
SUB-TOTAL				29,183,000
9500 Sales Tax on Material				820,000
9300 Fee & Contingency				3,300,000
Escalation				3,300,000
TOTAL SELLING PRICE				$36,600,000

Source: PB 261 845

TABLE 5.4: CAPITAL COSTS–HEBER BINARY FIELD INSTALLATION

ACCOUNT	Materials	Subcontract	Labor	TOTAL
1100 Columns (incl. Trays)				
1200 Pressure Vessels	70,000			70,000
1300 Heat Exchangers				
1400 Furnace/Heaters				
1500 Pumps	1,411,000			1,411,000
1600 Boilers				
1700 Cooling Towers				-
1800 Compressors				
1900 Tanks				
2000 Other	1,000			1,000
Labor			53,000	53,000
TOTAL MAJOR EQUIPMENT	1,482,000		53,000	1,535,000
3100 Concrete	13,000		18,000	31,000
3200 Pipe, Valves, Fittings	884,000	20,000	677,000	1,581,000
3300 Structural Steel				
3400 Instruments	281,000	149,000	25,000	455,000
3500 Painting				
3600 Electrical	190,000	440,000		630,000
3700 Insulation		10,000		10,000
3800 Paving, Roads, Fences & Misc.		217,000		217,000
3900 Buildings				
TOTAL CONSTRUCTION ITEMS	1,368,000	836,000	720,000	2,924,000
DIRECT FIELD COSTS	2,850,000	836,000	773,000	4,459,000
Indirect Field Costs	114,000	41,000	727,000	882,000
TOTAL FIELD COSTS	2,964,000	877,000	1,500,000	5,341,000
9200 Home Office Services				888,000
SUB-TOTAL				6,229,000
9500 Sales Tax on Material				171,000
9300 Fee & Contingency				720,000
Escalation				780,000
TOTAL SELLING PRICE				$7,900,000

Source: PB 261 845

TABLE 5.5: POWER PLANT AND TRANSMISSION CAPITAL COSTS
(All Figures in $ K, Estimated)

	Power Plant	Transmission
Heber		
Binary	28,500	500
Flashed Steam	26,800	500
Hybrid	36,600	500
Valles Caldera		
Binary	26,500	1,900
Flashed Steam	28,100	1,900
Hybrid	37,600	1,900
Raft River		
Binary	32,300	3,600
Flashed Steam	35,900	3,600
Hybrid	39,800	3,600

Source: PB 261 845

Plant costs were estimated from the Heber estimates by prorating the cost differences in each category of work and each piece of equipment. These differences were adjusted to reflect local conditions. Estimates of transmission costs assume that at Heber the power is transmitted to a load center at El Centro; at Valles Caldera the power is transmitted to Los Alamos (about 20 miles); and at Raft River the power is transmitted to Burley (40 miles). Estimates of surface installations are shown in Table 5.6. It was expected that power plant capital costs at Valles Caldera would be lower than at Heber because the reservoir is hotter. However, they are somewhat higher in all cases, attributable to the high cost of construction in the area. If these same plants were built at Heber, installed costs would be 15 to 20% lower.

Table 5.6 presents an estimate of the initial capital requirements to develop the three reservoirs for each of the three processes at each site. The estimates include the cost of producing wells, injection wells, dry holes and surface installations. The cost of the Heber wells of $300,000 each is fairly close to well costs in the relatively easy drilling characteristics of the Imperial Valley. The cost of the Valles Caldera wells of $700,000 each is much higher because of far more difficult drilling conditions (young volcanic formations, deep wells, remote locations). In this case, the well costs are nothing more than educated guesses, since there was no actual data. The cost of Raft River wells of $600,000 is close to actual published drilling costs for the area.

In each case, it was assumed that about 20% of the development wells will be dry holes. Again, this figure is an educated guess and could easily be low for a young volcanic formation like Valles Caldera. Total well costs vary from a low of $5.9 million for the Heber binary process to a high of $24.2 million for the Raft River flashed steam plant. The surface installation costs (including down-hole pumps for Heber and Raft River) vary from a low of $5.9 million at Heber to a high of $18 million at Raft River.

Field Operating and Maintenance Costs

Table 5.7 presents estimates of field operating and maintenance costs for the nine cases.

TABLE 5.6: ESTIMATED INITIAL FIELD CAPITAL COSTS*

Item	Heber Binary	Heber Flash	Heber Hybrid	Valles Caldera Binary	Valles Caldera Flash	Valles Caldera Hybrid	Raft River Binary	Raft River Flash	Raft River Hybrid
Producing wells									
Number of wells x cost/well	12 x 300	16 x 300	13 x 300	11 x 700	14 x 700	12 x 700	17 x 600	25 x 600	22 x 600
Cost	3,600	4,800	3,900	7,700	9,800	8,400	10,200	15,000	13,200
Injection wells									
Number of wells x cost/well	6 x 300	8 x 300	6 x 300	2 x 700	3 x 700	3 x 700	8 x 600	12 x 600	11 x 600
Cost	1,800	2,400	1,800	1,400	2,100	2,100	4,800	7,200	6,600
Dry holes									
Number of wells x cost/well	2 x 250	3 x 250	2 x 250	2 x 600	2 x 600	2 x 600	3 x 500	4 x 500	3 x 500
Cost	500	750	500	1,200	1,200	1,200	1,500	2,000	1,500
Well cost	5,900	7,950	6,200	10,300	13,100	11,700	16,500	24,200	21,300
Surface installation**	5,900	6,400	6,000	6,500	8,300	7,700	13,000	18,100	17,000
Total field cost	11,800	14,350	12,200	16,800	21,400	19,400	29,500	42,300	38,300

*All costs in $ K.
**Includes down-hole pumps at Heber and Raft River.

TABLE 5.7: ESTIMATED FIELD OPERATING AND MAINTENANCE COSTS*

Item	Heber Binary	Heber Flash	Heber Hybrid	Valles Caldera Binary	Valles Caldera Flash	Valles Caldera Hybrid	Raft River Binary	Raft River Flash	Raft River Hybrid
Field labor (including overhead and G&A)	253	253	253	253	253	253	253	253	253
Producing well maintenance	368	491	398	337	428	368	521	767	675
Injection well maintenance	393	524	393	131	190	190	524	788	721
Surface installation maintenance	236	256	240	130	166	154	620	721	680
Down hole surveys	18	24	19	13	17	15	25	37	33
Miscellaneous supplies	40	53	46	50	50	50	60	60	60
Purchased Power	665	885	702	120	190	190	1,050	1,654	1,386
Totals	1,973	2,486	2,050	1,040	1,302	1,228	2,953	4,181	3,808

*All figures in $ K/yr.
Source: PB 261 845

TABLE 5.[illegible]: ESTIMATED POWER PLANT LABOR COST

POSITION	NO. OF JOBS	RATE $/MONTH	RATE $/MONTH
OPERATORS	9	1,000	9,000
LABORER	1	750	750
ELECTRICIAN INSTRUMENT SPECIALIST MECHANIC	2	1,200	2,400
OFFICE MANAGER	1	1,000	1,000
SUPERINTENDENT	1	2,000	2,000
	14		15,150
	OVERHEAD*		11,120
	TOTAL MONTHLY COST		27,210
	ANNUAL COST:		$327,000

*Overhead includes fringe benefits, field burden and G&A expense.

Source: PB 261 845

Cost of Geothermal Power

In estimating the cost of geothermal power delivered to a utility load, it was assumed that a privately owned producer would sell thermal energy to an investor-owned public utility who would own and operate the power plant and transmission lines. Thus, there are three elements of cost to be considered.

(1) Producer's selling price of thermal energy to the utility.

(2) The utility's cost of generating electricity.

(3) The utility's transmission cost to a load center.

There is a minimum selling price below which a producer would not receive an adequate return on his investment and/or an adequate incentive to continue an exploration program and therefore would not enter into a contract to sell thermal energy. There is also a maximum price which a utility can afford to pay for the thermal energy.

The Problem: The problem to be addressed is two-fold in scope. The first aspect is to estimate the cost of geothermal power for three processes at the three sites. The estimates must be made on a consistent basis so that comparisons are valid. The second aspect is to explore various fuel-pricing strategies and to evaluate the effect of these strategies on the cost of geothermal power. The approach to each of these problems is set forth in succeeding sections.

Production Risk Factors: The business of exploring for and developing a geothermal hot water reservoir is similar in all major respects to exploration and development of an oil field. In both cases exploration involves the gathering of geologic and geophysical data to select promising sites for leasing and subsequent exploratory drilling, followed by an analysis of the reservoir potential. In both cases, development and production involves drilling of wells and construction of above-ground facilities to collect the reservoir fluids for sale to the customer. The major differences are as follows:

(1) The geological and geophysical methods used successfully in oil and gas exploration are not necessarily useful or may require some adaptation to be useful in a geothermal environment.

(2) Drilling technology is about the same, except for the effect of temperature and the problems associated with drilling through rock rather than sedimentary formation.

(3) Oil and gas may be transported to market and both are sold in national and international markets through well-established marketing channels, whereas geothermal energy must be sold to a utility who will build the power plant in the producing field. Thus, the producer can get no income from a geothermal reservoir until the power plant is built and operating.

(4) The utility must have confidence that the reservoir will furnish thermal energy for an extended period of time (normally 30 years).

(5) Title to the geothermal water is not well established, unlike oil and gas reservoirs where there is seldom the problem of ownership.

Thus, the risk factors are different between exploration and development of oil and gas on the one hand and geothermal reservoirs on the other hand, but the same cost-of-service approach used in the oil industry may be used for estimating the cost of fuel.

A computer program was developed which calculates the cost of geothermal power delivered to a load center. The first element of this cost is the calculation of the selling price of energy (i.e., the fuel cost) to the utility.

Estimation of Fuel Cost: In estimating the selling price of fuel to a utility, the cost-of-service approach was used. In this approach, the capital investment and operating costs associated with the development of the field are estimated. Then a selling price for the thermal energy which will give the producer a return on investment commensurate with the risks is estimated. The following procedure is built into the program to determine the cost of fuel for a particular case:

(1) *Reservoir Requirements* — The amount of electrical power desired and the energy conversion process utilized will determine the amount of geothermal fluid required at a given site. A knowledge of the reservoir characteristics will indicate the necessary number of production and injection wells, the field layout and the required collection and distribution piping. With this information, the various costs involved with bringing the field into production can then be estimated.

(2) *Capital Investment* — The capital investment for a geothermal project is the money required by the project for which a return on investment is expected. For the purposes of this investigation, it is assumed that none of these funds are obtained by borrowing. The components of the capital investment are as follows:

The estimate of the field staff portion of the operating and maintenance costs is shown in Table 5.8. The annual cost of the field staff including salaries, benefits, field office burden and G&A is estimated to be $253,000. This cost has been considered to be a constant for all cases.

TABLE 5.8: ESTIMATED FIELD STAFF COST (ALL FIELDS)

POSITION	NO. OF HIRES	RATE $/MONTH	RATE $/MONTH
FIELD OPERATORS	4	1,000	4,000
ROUSTABOUT	1	1,000	1,000
ELECTRICIAN INSTRUMENT SPECIALIST MECHANIC	2	1,200	2,400
FOREMAN	1	1,400	1,400
OFFICE MANAGER	1	1,000	1,000
MECHANICAL ENGINEER	0.5	1,800	900
PRODUCTION ENGINEER	0.5	1,800	900
	10.0		11,700
	OVERHEAD*		9,360
	TOTAL MONTHLY COST		21,060
	ANNUAL COST		$253,000

*Overhead includes fringe benefits, field burden and G&A expense.

Source: PB 261 845

Producing well maintenance costs are estimated from suggestions made by Chevron for Heber as follows:

(1) Each producing well is acidized once per year at a cost of $10,000.
(2) Major remedial well work is done once every four years for each well at a cost of $80,000.
(3) Two of the original wells will be abandoned by the end of the project at a cost of $50,000 per well.

The annual cost for the Heber binary case is $368,000. Costs for all other cases were prorated by the number of wells.

Injection well maintenance costs were estimated on the following basis:

(1) Each injection well is stimulated once per year at a cost of $75,000.
(2) Major remedial well work is done once every two years for each well at a cost of $80,000.

(3) One injection well will be abandoned by the end of the project at a cost of $50,000.

Costs for all other cases were prorated by the number of wells.

Annual surface-installation maintenance (labor and materials) is calculated at 4% of the initial capital cost for Heber and Raft River, where the wells are pumped, and 2% at Valles Caldera, where they are not. Down-hole surveys are figured at $1,000 per year per well.

The cost of pumping electricity was figured at 2.0 cents per kWh. For the pumped wells this cost represents about one-third of the total operating and maintenance expense.

Total field operating and maintenance expense varies from $1,040,000 per year for the Valles Caldera binary plant to a high of $4,181,000 for the Raft River flash plant. The monthly operating and maintenance costs (excluding power) per well are in the range of $6,000, nearly twice as high as would be expected for a typical oil well.

Power Plant Operating and Maintenance Costs

Table 5.9 presents estimates of power plant operating and maintenance costs for the nine cases.

TABLE 5.9: ESTIMATED PLANT OPERATING AND MAINTENANCE COST
(All Figures in $ K/yr)

	Heber			Valles Caldera			Raft River		
Item	Binary	Flash	Hybrid	Binary	Flash	Hybrid	Binary	Flash	Hybrid
Labor cost	327	327	327	327	327	327	327	327	327
Maintenance (labor and materials)	670	536	737	530	562	752	648	718	796
Cooling water and chemicals	253	258	251	178	200	183	308	271	295
Miscellaneous	60	60	60	50	50	50	60	60	50
Totals	1,200	1,171	1,360	1,085	1,139	1,312	1,331	1,380	1,468

Table 5.10 is an estimate of the cost of power plant labor, including salaries, benefits, field office burden and G&A expense. Labor cost is a constant for all cases.

Annual maintenance costs are figured as 2% of the initial plant cost. Cooling water makeup for Heber is purchased at $3.50 per acre-foot. Cooling water treatment chemicals are estimated to cost $20,000 per month at Heber, based on Imperial Irrigation District's expenses at their El Centro plant. The total cost of cooling water and chemicals is estimated to be $253,000 for the Heber binary plant. Costs for all other cases are prorated by cooling tower duty. Total operating and maintenance costs are about 3 mills/kWh for all plants.

(a) Exploration and Land Acquisition Costs: This represents the money spent in geological and geophysical research, exploratory drilling, bonus payments, and other costs involved with establishing the presence of an exploitable geothermal reservoir. Since the reservoir will typically be sufficiently large to supply more than one power plant, only a proportional amount of this charge is assigned to the project under consideration. These costs are incurred prior to the field development phase.

(b) Well Drilling Costs: The costs of a drilling program to provide the required production and injection wells are continuously disbursed during the program. The program culminates in the startup of the power plant.

(c) Working Capital: Working capital is required as of the startup of the power plant. The working capital is sufficient to pay one month's expenses, and is returned at the termination of the project.

(d) Capital Additions: An additional annual drilling cost is required to provide additional wells in the field to offset the effects of a declining reservoir. Typical decline rates and project lives indicate a capital requirement equal to the initial drilling costs but disbursed evenly over the life of the project.

The capital investments listed above are expected to return a profit commensurate with the risks involved in a geothermal venture. To account for the time value of money, the discounted cash-flow method is used to determine the annual revenue requirements.

(3) *Expenses* — Several types of expenses are incurred during the operation of a producing geothermal field. These fall into two classes: cash expenses and book expenses. The book expenses are not deducted from the revenues but are used in determining the taxable income for federal and state income taxes.

(a) Cash Expenses:

Royalty Payment — Royalty payments are typically 12.5% of the gross revenues.

Operating Expenses — Annual operating expenses include labor, maintenance, supplies, utilities, etc.

(b) Book Expenses:

Depreciation — Depreciation for tax purposes is calculated by the sum-of-the years-digits method for a tax life of 15 years. Depreciation for bookkeeping purposes is calculated by the sum-of-the-years digits method over the life of the project.

Intangible Drilling Expenses — These expenses are deducted in the year incurred. Since most of the drilling activities occur before any taxable income is produced by the project, it is assumed that the producer can take advantage of this deduction elsewhere to the credit of the project. Although this deduction is currently in use in the oil industry, there is some question as to whether it will also be available to the geothermal industry.

Depletion Allowance —This deductible expense, similar to depreciation, is assumed to be 22% of gross revenue. However, it has not been ruled applicable to geothermal in general.

(4) *Taxes* — Federal, state and local taxes will be paid by the project. The federal and state income taxes are paid according to the net taxable income. A federal investment tax credit of 10% is deducted from the federal income tax. The credit is based on the tangible, depreciable assets of the project. The state and local real property taxes are generally charged according to the value of the real property. This is judged to be a function of the revenues produced by that property. Thus, these taxes are usually a percentage of the gross revenues. They are treated as an ad valorem tax of 10% in this study.

(5) *Annual Cash Flow* — The cash flow is the sales revenues minus taxes and expenses not including depreciation. Since there is also an annual capital addition, this is also subtracted from the cash flow. The cash flow is then discounted at the desired rate of return to a present worth at the beginning of power plant operations. The annual sales revenue is adjusted iteratively until the sum of the discounted cash flows equals the capital investment at the start of power plant operations. The sales revenue then becomes the cost of energy to the power plant.

Any of the parameters in the program can be easily altered to allow sensitivity studies.

Estimation of Power Conversion and Transmission Costs: The balance of the program calculates the power conversion and transmission costs to a load center, using a method of economic analysis used by public utilities. By this method, the delivered power cost is the sum of the energy cost, the utility's fixed charges, the operating and maintenance cost, and the electrical transmission cost. The fixed charges are each expressed as a percentage of the invested capital. They are:

(1) *Return on Investment* — Current capital requirements are in the range of 11 to 13%.

(2) *Income Tax* — The method used takes the expected annual taxes over the life of the power plant including provisions for investment tax credit and interest deductions and converts them to a uniform annual "levelized" expense. An interest rate of 9% is used with a 50/50 debt/equity ratio.

(3) *Depreciation* — The depreciation expense is often calculated by the straight line method, but for economic analysis the sinking-fund method is generally used. The program can use either method, but the base case uses the sinking-fund method (at the rate of return).

(4) *Ad Valorem Tax* — This accounts for the various property and ad valorem taxes. A typical value is 2.5% of capital cost.

(5) *Administrative and General Expense* — This is typically 1% of capital cost.

(6) *Insurance* — This is typically 0.1% of capital cost.

The operating and maintenance costs will vary depending on type and location of plant. The transmission costs are divided into fixed charges and operating costs. The fixed charges are calculated in the same manner as the power plant fixed charges.

The program gives the annual delivered power cost and also uses the load factor (typically 85%) and the plant size to determine the unit power cost (mills/kWh). Also included is a printout of the yearly cash flows for the geothermal field.

Base-Case Results: The first task is to compare delivered power costs for the nine base cases. These comparisons should be done on a consistent basis in order to obtain good relative values, but may not represent best absolute values. These cases are based on the following assumptions:

Project life, yr	25
Exploration cost, K $	800
Lease bonus payment	none
Producer's DCF rate of return, %	15
Utility rate of return, %	12
Depletion, %	22
Write-off of intangible drilling expense, %	70
Write-off of dry-hole expense, %	100

The producer's capital costs and operating and maintenance (O&M) costs, together with the utility's capital costs and O&M costs, were taken for each case from Tables 5.5, 5.6, 5.7 and 5.9. Other input data were taken as the typical values reported in the preceding section. The results are tabulated in Table 5.11.

The Heber binary case shows the lowest fuel cost of the three Heber cases (16.69 mills/kWh) and the lowest power cost (35.22 mills/kWh). The flashed-steam cost at Heber is about 2.9 mills higher than the Heber binary, while the hybrid is about 5.3 mills higher than the Heber binary.

At Valles Caldera, the binary cost is again the lowest (33.69 mills) by a larger margin (5.86 mills) over the flashed steam. The hybrid cost is the highest of the three (42.99 mills).

At Raft River, the binary cost is lowest (55.17 mills) by a substantial margin (about 15 mills) over the other two.

Fuel costs are low at Heber (16.69 mills) for the binary case, reflecting the relatively high well productivity and the relatively low cost of drilling. Binary fuel costs at Valles Caldera are slightly lower than at Heber, even though well costs are much higher ($700,000 versus $300,000), and well productivity is much lower; i.e., 113,000 kg/hr (250,000 lb/hr) versus 295,000 kg/hr (650,000 lb/hr). These increases are offset to a large extent by the decreased brine requirements of 1.19 M kg/hr versus 3.1 M kg/hr (2.62 M lb/hr versus 6.9 M lb/hr).

Raft River costs are high in all counts, reflecting the low temperature of the reservoir as compared to the others.

Utility fixed charges plus O&M expenses vary from a little over 18 mills (Heber binary) to a little over 20 mills (Raft River binary). This variation is not nearly as great as the variation in fuel cost for the best cases, 16.0 mills to 32.8 mills. Fuel cost expressed as ¢/M Btu extracted is in the range of 60¢/M Btu at Heber, increasing to about 80¢/M Btu at Valles Caldera, or over $1.00/M Btu at Raft River.

Hybrid systems were eliminated from further consideration since hybrid costs were higher than the others. It should be noted in passing that, although the hybrid fuel cost was low at the three sites, the power plant was the most expensive. One reason for the high-cost power plant is that separate turbine-generator installations were provided for both the flash-steam and binary sections of the plant. If it were possible to put both turbines and a single generator on one shaft, the capital cost would be reduced considerably. This prospect requires further study.

Raft River costs are important as an indication of costs which may be expected in developing low-temperature reservoirs. It is clear that such reservoirs must be highly productive to be economic power sources.

Heber vs Valles Caldera: The best case at Valles Caldera is about 1.5 mills lower than the best case at Heber. Cost projections at Valles Caldera are more speculative than at Heber. For one thing, there was no reliable data on field development costs, and these costs could either be higher or lower than estimated by a substantial margin. Optimistic assumptions were probably made relative to the cost of providing cooling water, the scaling and corrosion tendencies of the brine, and the noncondensable content of the brine. Any one or a combination could lead to substantial increases in power plant cost. Valles Caldera power costs were probably understated and the cost of power at that reservoir is likely to be greater than projected. For this and other reasons attention was focused on the Heber reservoir.

Sensitivity Analysis: The power costs presented in Table 5.11 are expected to give good relative values between reservoirs and between processes, but are not necessarily valid in absolute sense. Accordingly, a study was made of the effect of changes in key variables entering into the economic model. These comparisons were limited to the Heber binary plant and are tabulated in Table 5.12.

> Case 2 assumes that field capital and operating costs were overestimated by 20%. The effect is to reduce the fuel cost from 16.7 to 13.5 mills and the power cost from 35.2 to 32.0 mills.
>
> Case 3 assumes that field capital and operating costs were underestimated by 20%, in which case fuel cost and power cost increase by 3.2 mills.
>
> In case 4, it was assumed that no wells will be drilled during the life of the project, thereby reducing fuel cost by 0.8 mill.
>
> In cases 5 and 6, the producer's rate of return was varied down to 10% and up 20%. The lower rate of return reduces fuel cost 3 mills, and the higher rate of return increases fuel cost by 3.5 mills.
>
> In case 7, the effect of eliminating both depletion and intangible write-off is to increase fuel cost by 4.1 mills.
>
> In case 8, the effect of eliminating depletion is to increase the fuel cost by 1 mill.
>
> In case 9, the effect of eliminating the intangible write-off is to increase fuel cost by 2.2 mills.
>
> In cases 10 and 11, the effect of reducing project life to 20 years or increasing to 30 years is relatively small: plus 0.4 mill in the first instance, and minus 0.2 mill in the second instance.
>
> In cases 12 and 13, the effect of reducing the power plant rate of return to 10% and increasing it to 14% was examined. In the first instance, the effect is to decrease the power cost by 2.5 mills, and in the second instance, to increase power cost by 2.6 mills.

From the foregoing, it is apparent that the prediction of power costs may vary widely depending on the particular set of assumptions entering into the calculation:

TABLE 5.11: ESTIMATED GEOTHERMAL POWER COST–BASE CASES

Case	Brine Rate K lb/hr	Fuel Cost ¢ per K lb Brine	Fuel Cost ¢ per M Btu	Power Cost (mills/kWh) Fuel	Fixed Charges	Operating & Maintenance	Transmission	Total
Heber								
Binary	6,942	12.0	57.5	16.69	15.03	3.22	0.28	35.22
Flashed Steam	10,010	10.3	71.7	20.53	14.13	3.14	0.28	38.08
Hybrid	7,248	11.9	60.2	17.26	19.30	3.65	0.28	40.49
Valles Caldera								
Binary	2,620	30.6	74.7	16.03	13.72	2.91	1.03	33.69
Flashed Steam	3,959	26.1	86.4	20.65	14.53	3.33	1.03	39.54
Hybrid	3,017	31.5	86.0	18.99	19.45	3.52	1.03	42.99
Raft River								
Binary	11,042	14.9	91.8	32.80	16.83	3.57	1.97	55.17
Flashed Steam	16,318	14.3	155.2	46.61	18.70	3.67	1.97	70.95
Hybrid	11,917	17.8	140.2	42.42	20.73	3.94	1.97	69.06

Source: PB 261 845

TABLE 5.12: SENSITIVITY ANALYSIS–GEOTHERMAL POWER COST (BASIS: HEBER BINARY)

Case	Conditions	Power Cost (mills/kWh) Fuel	Fixed Charges	Operating & Maintenance	Transmission	Total
1.	Base Case (includes depletion and intangibles write-off)	16.7	15.0	3.2	0.3	35.2
2.	Lower Field Capital and Overhead & Maintenance - 20%	13.5	15.0	3.2	0.3	32.0
3.	Higher Field Capital and Overhead & Maintenance - 20%	19.9	15.0	3.2	0.3	38.4
4.	Field Decline - 0%	15.9	15.0	3.2	0.3	34.4
5.	Field Rate of Return - 10%	13.7	15.0	3.2	0.3	32.2
6.	Field Rate of Return - 20%	20.2	15.0	3.2	0.3	38.7
7.	No Depletion & Intangibles	20.8	15.0	3.2	0.3	39.3
8.	Depletion Only	17.6	15.0	3.2	0.3	36.1
9.	Intangibles Only	19.9	15.0	3.2	0.3	38.4
10.	Project Life - 20 Years	17.1	15.2	3.2	0.3	35.8
11.	Project Life - 30 Years	16.5	15.0	3.2	0.3	35.0
12.	Power Plant Rate of Return - 10%	16.7	12.6	3.2	0.2	32.7
13.	Power Plant Rate of Return - 14%	16.7	17.6	3.2	0.3	37.8

Source: PB 261 845

Shaft-bearing wear has been minimized by pumping filtered water from the surface down the bearing tubing, thereby protecting the bearings from contact with the well fluid. Suitable materials are available for fabrication of the bowls, impellers and pump bearings. Various difficulties were experienced by Chevron at Heber using the same type of pump and solved more or less successfully.

Other pumps have been proposed which would eliminate the shaft lubrication problem. The different technical approaches are as follows:

> A down-hole turbine pump and exchanger. Fresh water is vaporized by exchange with the well fluid, and the steam produced is expanded in the turbine to pump the brine to the surface.
>
> A down-hole pump operated by a down hole electric motor.
>
> A down-hole pump and hydraulic motor driven by water pumped from the surface.

Improvements in the state-of-the-art are needed as well as new developments. For these reasons, down-hole pumping is a technical weakness.

Scale Deposition

The deposition of scale on heat exchanger tubes occurs when geothermal fluids are cooled to their saturation point. A series of tests were performed at the Heber reservoir in 1976 to measure the effect of scale deposition on heat exchanger performance. The results of these tests indicated that scale deposition does occur on the tubes. The amount of scale formed during the tests was small, but it was sufficient to show that the rate of formation increased as the temperature of the brine was reduced. The tests varied in length, but the longest one was 22 days, and the data from this relatively short-range test were extrapolated to predict performance over a year. Further extended duration heat exchanger tests appear justified to establish the rate of deposition of scale as a function of temperature and time.

Corrosion

Each of the geothermal fluids differ from one another in salinity, pH and concentration of anions and cations. Even different wells in the same reservoir can produce fluids with different chemical properties. The corrosive characteristics of each reservoir should be established before the final materials selection for the plant takes place. Tests should be conducted for a sufficient length of time to identify if oxidation, stress corrosion, or pitting could be expected in the plant. Different materials should be tested to establish what degree of corrosion protection would be needed. Corrosion work could most expeditiously be carried on concurrently with scale deposition tests.

Hydrogen Sulfide Disposal

Most geothermal fluids contain carbon dioxide along with small quantities of hydrogen sulfide. The amount of hydrogen sulfide can vary from trace amounts to significant percentages which exceed allowable limits for atmospheric disposal. If the fluid is flashed to produce vapor, these gases will be released and must be removed from the system. Most processes that are designed to absorb hydrogen sulfide will also absorb the carbon dioxide. An exception is the Stretford process which will do the job, but this process is complex and equipment is costly.

SUMMARY OF CONCLUSIONS

It is feasible to proceed with the design, construction and operation of a 50 MWe hydrothermal power plant with reasonable expectation of success, but not without some technical and economic risks. The risk is greater than that which a utility might normally take, but is acceptable as a "first-of-a-kind" research and development undertaking.

Of the geothermal reservoirs studied in detail, demonstration plants appear to be technically and environmentally feasible at Heber, California; Valles Caldera, New Mexico; and Raft River, Idaho; and economically feasible at Heber and Valles Caldera.

Heber is the best all-around choice for the demonstration site because the characteristics of the geothermal fluid contained in that reservoir are more representative of other hydrothermal resources in the United States.

The binary cycle appears to be the best choice of conversion technology for the demonstration plant, particularly at Heber because it has broader application to moderate temperature reservoirs, 150° to 200°C, and will give utilities at least one option for the development of this resource type after the technology has been demonstrated on a commercial scale.

Optimization studies are not yet complete, but it appears that a working fluid mixture, as opposed to a pure fluid, will be needed to optimize binary cycle operation, with the mix depending upon working temperatures.

For economic reasons, the capacity of the power plant should be approximately 50 MWe.

There appear to be no overriding environmental constraints; however, present data and analytical techniques are not adequate to fully evaluate seismicity, subsidence and hydrogeology. The impact in each case is estimated to be small, and the estimates are thought to be conservative.

A commercial size demonstration plant with a research and development orientation during the early life of the plant, followed by commercial operation after debugging is complete, is needed to resolve the problems of technology adaptation and optimization, heat exchanger and turbine scale-up, materials, and scale control. It is also needed to verify reservoir performance modeling techniques and to study geotechnical environmental aspects of geothermal production.

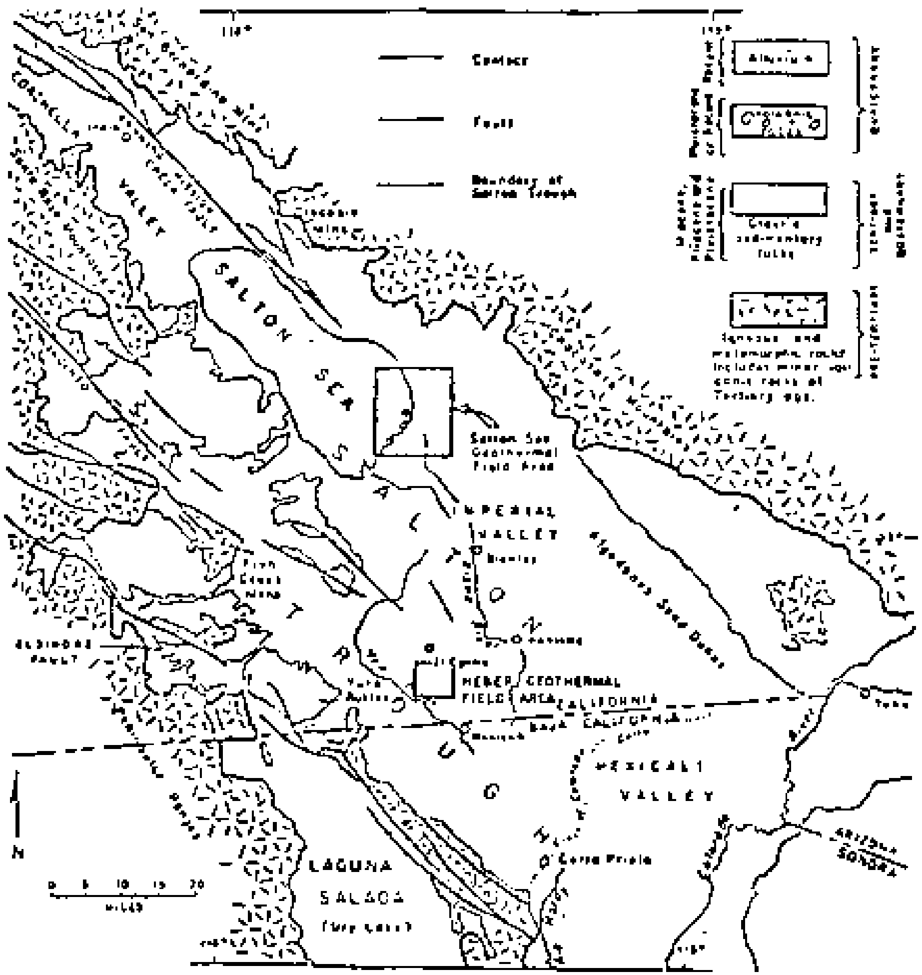
Dry cooling and wet-dry cooling would impose a severe cost penalty if used.

GEOTECHNICAL ENVIRONMENTAL ASPECTS OF GEOTHERMAL POWER GENERATION AT HEBER

> The material for this section has been based upon a report by Geonomics, Inc. (PB 280 848) for Holt/Procon, work sponsored by Electric Power Research Institute, Inc.

The Imperial Valley is an area of high regional heat flow, intensive crustal deformation, high seismicity and subsidence and numerous geothermal anomalies. It is one of the most seismically active areas in the United States. The sediments at the Heber Anomaly are dominantly Quaternary deltaic sands and shales derived from Colorado River sources and persist to a depth of 2.5 km (8,203 ft). The basement at Heber is at a depth of approximately 7 km (22,967 ft). A geologic map of the Salton Trough is shown in Figure 5.10.

FIGURE 5.10: GENERAL GEOLOGIC MAP OF THE IMPERIAL VALLEY (1)



Geologic map of the Salton Trough.

Source: PB 260 848

Hydrology

The Imperial Fault separates brackish central valley waters from fresher waters to the east and thus explains some of the incomplete ground water mixing. Deep clay deposits separate shallow and deep ground water systems and tend to make the central valley waters saltier and more stagnant than eastern or western waters. It has also been noted that artesian waters exist only east of the Alamo River.

The flow rate of Imperial Valley wells is variable and depends on the location and depth of the well. Many shallow wells at eastern and western valley margins have flowed greater than 0.063 m^3/sec (1,000 gpm) whereas central valley shallow wells have produced only a fraction of this. This is partly why the extensive irrigation system was needed in the Imperial Valley. Deep wells in the central valley, however, flow as well or better than deep wells at the valley margins. Adequate sampling of these wells is not yet available, however, to clearly establish a pattern.

With regard to chemical constituents, the principal Imperial Valley waters can be categorized as:

- Basin-edge waters which strongly resemble Colorado River source waters.
- Shallow central valley waters which are somewhat more saline and richer in carbonate.
- Deep valley waters which tend to be more saline but resemble basin-edge waters in ionic ratio.
- Hydrothermal water which tends to have elevated silica, pH, metal salts and salinity.
- Hypersaline geothermal brines which contain unusually high salinities and are confined to the Salton Buttes.

The geothermal brines of the Imperial Valley do not differ greatly from deep waters in the area except for the addition of metal salts and the dissolution of carbonates. The shallow ground water at Heber is vastly different from the deeper hydrothermal waters, which is probably due to the presence of the clay cap rock.

Geothermal waters are produced at a depth of 600 to 1,900 meters (1,968 to 6,232 feet) with sodium chloride being the dominant dissolved constituent. Table 5.13 presents chemical analysis data from five geothermal wells. The pH of these waters varies from 6.8 to 7.4. Silica concentrations are low enough to avoid scaling at the well bore and surface pipes. Trial production and injection operations at Heber have not shown any corrosion or scaling problems to date.

It has been estimated that between 50 to 60 producing wells and 20 to 30 injection wells will be required for a 200 MWe net electricity plant at Heber. A development of this nature could alter the underground water flow pattern. However, considering the effective hydrologic separation between the geothermal reservoir and the shallow ground water system at Heber, the only likely changes are the diversion of deep water from other areas and increased salinity of deep aquifers through salt water reinjection. The projected extent of such changes is minor.

Only t of hydrogen sulfide have been reported from wells and the amount of other noncondensable gases in the Heber geothermal water is minimal. However, this is not the case with the noncondensable gases at the Cerro Prieto, Mexico geothermal facility, which contains CO_2 and H_2S concentrations of 1,000 and 300 ppm, respectively.

TABLE 5.13: CHEMICAL QUALITY OF WATER, HEBER GEOTHERMAL RESERVOIR, IMPERIAL VALLEY, CALIFORNIA

Parameter*	Nowlin #1	Holtz #1	Holtz #2	C.B. Jackson #1	J.D. Jackson #1
Total Dissolved Solids (TDS)	14,100	13,168	16,330	15,430	15,275
SiO_2	120	268	187	267	268
Li	6.6	4	4.2	2.8	3.4
Na	3,600	5,500	4,720	4,668	4,563
K	360	220	231	181	157
Ca	880	1,042	1,062	891	781
Mg	2.4	5.6	23	4.7	3.8
Cl	9,000	7,420	8,242	8,320	8,076
SO_4	100	100	148	152	150
CO_3	4	NA	NA	NA	NA
HCO_3	20	NA	NA	NA	NA
F	1.6	1.7	1.5	0.9	0.6
B	4.8	4.1	8	4.8	5.2
Fe	0.9	15	5	20	10
Mn	NA	0.9	0.9	1.3	1.9
Pb	0.1	1.6	0.6	0.6	0.9
Zn	0.68	0.3	0.1	0.4	0.5
Cu	0.2	0.5	0.4	0.4	0.4
Ba	NA	6	3	3	3
Sr	NA	37	42	32	36
Al	0.04	35	12	0.5	18
Ag	NA	NA	NA	NA	NA
La	4	NA	NA	NA	NA
pH	7.1	NA	7.4	5.8	6.5

*Except pH, all parameters are in parts per million.

Source: PB 260 848

Seismicity and Subsidence

The United States Geological Survey (USGS) and California Institute of Technology (Cal Tech) have permanent seismic monitoring stations located throughout the Imperial Valley. These organizations also have portable seismic monitoring equipment that can be moved to an area after a large magnitude event and record the sequence of after-shocks. Chevron Oil Company plans to establish a closely spaced seismic net to gather information on background seismicity and the relationship the proposed geothermal production might have on seismic activity. This project is scheduled to run continuously throughout the period of power production.

The U.S. Coast and Geodetic Survey, in cooperation with the USGS, has developed an extensive program to monitor ground motion through the Imperial

Valley. This program calls for triangulation and leveling surveys throughout the valley every two years and more frequently if geothermal production becomes a reality in the valley. In addition, a private leveling survey was completed by Chevron Oil Company in the Heber area. The 1974-1975 survey measured the relative elevation change in the Heber area for a period of one year.

As stated previously, the Imperial Valley is characterized by a high level of seismic activity and a large amount of strain release. Since 1900, 12 earthquakes have registered greater than Magnitude 6 on the Richter Scale. A large concentration of seismic events has occurred in the Salton Trough along faults of the San Andreas System. Smaller shocks and earthquake swarms are also very common for faults in the San Andreas System. The Imperial Valley fault system is moving right laterally at the cumulative rate of approximately 8.0 centimeters per year (3.1 inches per year). This is a 20-year average and is by no means occurring at a constant rate.

Earthquakes occurring along the San Andreas fault system typically have focal depths of 5 to 8 kilometers (3 to 5 miles), which is approximately the basement-sediment interface. A limiting depth for hypocenters in the valley is about 12 to 15 kilometers (6 to 9 miles) because at depths greater than this, sufficiently high temperatures cause the rocks to move plastically in response to stress. In the geothermal areas of the valley this limiting depth is lower.

Several studies have shown that there is a correlation between microearthquake activity and geothermal anomalies. In the Imperial Valley, the correlation is unusually high. High levels of microearthquake activity are found at Salton Buttes, North Brawley and East Mesa. To date, it is unknown whether such a relationship also exists at Heber. In any case, several remarks can be made about earthquakes in the valley's geothermal areas:

> Shocks are generally smaller in magnitude and more frequent in geothermal areas than other areas in the same tectonic setting.
>
> Faults related to the microearthquakes may serve as conduits for circulating brines. At the Salton Buttes, for example, it was observed that CO_2 wells began emitting large quantities of gas just after earthquakes in the 1930s.
>
> Earthquake focal depths are usually shallower in geothermal areas than in areas outside, implying that microearthquakes are related to geothermal processes. Also, the amplitude of earthquakes within geothermal areas appears to be smaller than outside.

The possibility of triggering earthquakes by geothermal production and reinjection is of some concern. Although existing producing fields at the Geysers, California and Wairakei, New Zealand have long been associated with earthquake activity, production has not been hampered by earthquakes and no associations have been drawn between geothermal production and earthquake activity. Regional tectonics, the stress field and the rock properties at Heber are vastly different from those areas that have experienced earthquakes due to fluid injection from oil field and waste injection wells.

In the Heber area the effect that production might have on earthquake activity may only be speculated. Withdrawal of fluids may alter the deep ground water pattern and perhaps even the surface flow rate. The effect of these alterations on the tectonic stress regime is unknown. Any attempt to determine these effects, and the effects of fluid reinjection, will require several years of continuous seismic and geodetic monitoring during which background seismicity and the location of active faults must be established.

The Imperial Valley is an area of high regional strain release and the Heber area is part of this high belt. The Heber region could expect between 64 and 256 equivalent Magnitude 3 earthquakes every 30 years. The same amount of strain would be released by 10 to 40 Magnitude 4, 2 to 10 Magnitude 5, or 0.25 to 2.0 Magnitude 6 earthquakes, or by aseismic creeping.

Adequate data do not exist on the local stress pattern and the strength of the formation at Heber to allow predictions regarding possible injection-induced seismicity. However, it appears unlikely that injection of waste brine will significantly increase seismicity in the Heber area; no faults have been detected as yet under Heber and the increase in pore pressure around injection wells will not be excessive because of the relatively high permeability of the Heber reservoir. If a major earthquake occurs, it will most likely occur along one of the major active faults in the area. The location of the more active faults with respect to the proposed plant location is as follows:

Fault	Distance to Plant Site km (mi)
Imperial	11 (6.8)
Brawley	23 (14.3)
San Andreas	38 (23.6)
Elsinore	27 (16.8)
San Jacinto	6.5 (4.0)

The Imperial County and the Los Angeles County building codes recommend a design acceleration of 0.25 *g* for an area classified as Zone 3 (high seismic hazard). According to those codes, the Heber area is classified as Zone 3. However, the U.S. Department of the Army publication *Seismic Design of Buildings* defines Heber as a Class 4 (extremely hazardous) area and recommends that buildings be designed for an acceleration of 0.375 *g*. This design is 50% more conservative than that required by the Imperial County regulations. Due to the proximity of these faults to the proposed plant site, the more conservative design criteria of 0.375 *g* seem to be justified.

Ground subsidence and lateral movement have been observed at other sites where fluid withdrawal has not been accompanied by fluid reinjection. In the Imperial Valley, however, ground motion and subsidence exist as part of the tectonic background. The valley is moving horizontally in a complex manner with the central portion of the valley subsiding at a rate of about 1.5 centimeters (0.6 inch) per year relative to the surrounding mountains. A leveling survey by Chevron Oil Company suggests that the Heber area is moving up slightly with respect to El Centro, but the dominant motion has been a downward tilting northward and eastward.

Land subsidence problems related to the proposed geothermal development at Heber can only be speculated at this time. Because of the fact that the geothermal fluid would be reinjected after heat extraction, any subsidence due to brine production is likely to be small and most likely no larger than that due to tectonic causes. The effect of subsidence is not likely to prove a significant environmental concern.

At this time, reliable estimates of future subsidence in the area of the Heber geothermal reservoir cannot be made until the reservoir has been operated for a period of time and the corresponding land survey results studied. Without this information, results from computer models are considered to be the next best source of information available, provided that the input reservoir parameters properly represent the reservoir.

There are other means for estimating future subsidence. One such method has been developed by Geertsma (2) and by Raghaven and Miller (3). In operating the Heber reservoir, the rate of fluid injection and fluid production will be the same and the overburden pressure has been assumed to be fixed. Geonomics (4) has indicated in the past that the reservoir pressure drop due to the production of water for a 200 MWe plant will be on the order of 6.8 to 20.4 atm (100 to 300 psia) around the well bores. Away from the wells, the pressure drop will be much smaller. An average pressure drop for the entire reservoir should be less than 6.8 atm (100 psia).

The overall net productive thickness of the reservoir has been assumed to be 734 m (2,408 ft). Using these data, the compaction was estimated at 0.12 m (0.4 ft). Assuming the reservoir has the shape of a cylindrical disc of constant thickness with its axis vertical and without considering the variation of drawdown pressures with respect to time or for any time lag in subsidence, the subsidence has been estimated to be 0.21 m (0.7 ft).

Considering the gross assumptions that have been used, these values are at best only an indication of the possible true magnitude and should be considered to be conservative. The true average value is probably less. The subsidence possibility is minimal over most of the reservoir, but localized subsidence around the producing wells can be significant.

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Materials and Scale Management Studies

CONCRETE POLYMER MATERIALS

The material for this section has been based upon a report by L.E. Kukacka of Brookhaven National Laboratory (BNL 22684).

The availability of durable and economic materials of construction for handling hot brine and steam is a serious problem in the development of geothermal energy. Corrosion and scale incrustations have been encountered in all geothermal plants, and to various degrees, adversely affected plant life times and power output (1). General guides to materials selection for oxygen-free geothermal systems have been published by Shannon (1). At a temperature of 120°C and pH <6, the use of expensive materials such as titanium, zirconium, and Hastelloy C is suggested.

Severe corrosion of carbon steel occurs in aerated geothermal fluids at a temperature of 60°C. The corrosion rate in aerated systems is reported to be 100 times greater than in oxygen free geothermal fluids (2). As a result, all condensate and cooling water piping at The Geysers is constructed of stainless steel or plastic-lined material. It is also necessary to coat all concrete surfaces that come in contact with water with coal-tar epoxy compounds or synthetic rubber (3). The corrosion rate of carbon steel is highly dependent upon the pH of the brine. At the predicted pH of 4.0 for oxygen-free Salton Sea brines and a temperature of 50°C, a service life of >15 yr is estimated (1). At a pH of 4, the estimated service life is 2 yr.

Electrochemical attack due to high-sulfate-containing soils present in many parts of the western states may restrict the use of carbon steel pipe in the development of medium temperature geothermal reservoirs. Durable and low-cost piping systems with minimum thermal losses are essential.

Concrete polymer materials are a series of composite materials which have strength and durability characteristics far superior to those of portland cement concrete. As a result, two of these materials, polymer impregnated concrete and

polymer concrete, are beginning to be utilized throughout the world in applications where portland cement cannot be used or where severe maintenance problems occur. Recent results from laboratory and field tests indicate that the composites may be applicable to many parts of geothermal processes.

Polymer impregnated concrete (PIC) consists of a precast portland cement concrete impregnated with a monomer system that is subsequently polymerized in situ. The polymer tends to fill the porous void volume of the concrete, which results in significant improvements in strength and durability properties. Polymer concrete (PC) consists of an aggregate mixed with a monomer or resin that is subsequently polymerized in place. The techniques used for mixing and placement are similar to those used for portland cement concrete. After curing, a high strength (>10,000 psi), durable material is produced. A third type of material, a further development of PIC, is also being applied. This is a precast concrete that has been partially impregnated to a finite depth with a monomer that is subsequently polymerized.

The feasibility of using concrete polymer composites as materials of construction for handling hot brine and steam was demonstrated in 1972 (4). As part of this work the concrete liner on a vertical tube evaporator at the Office of Saline Water Desalting Facility in Freeport, Texas was partially impregnated to a depth of approximately 0.25 in. The results from these tests indicated that the composites had long-term stability in seawater at 177°C and in acid solutions. Based upon these results, a research program to develop the composites for use in geothermal systems was started in April 1974.

High temperature PC systems have been formulated, and laboratory and field tests performed in brine, flashing brine, and steam at temperatures up to 240°C. Results are available from field exposures of up to 12 months in four geothermal environments. Tests at two other sites have recently been started. The results from these studies are summarized below.

Production Methods

Polymer Impregnated Concrete (PIC): The concrete polymer composite that has yielded the greatest improvements in structural and durability properties is PIC. High quality PIC can be made from concretes with a variety of compositions. For best results, the use of standard-weight concrete containing a good quality aggregate is recommended. The following processing cycle has been used to produce specimens with compressive strengths as high as 32,000 (4): (1) oven dry to constant weight at 150°C; (2) evacuate to approximately 30 inches Hg and maintain for 30 minutes; (3) introduce monomer under vacuum and subsequently pressurize to 10 psig, pressure soak for 60 minutes; (4) remove monomer; (5) remove and place section in water or, for large sections, back-fill impregnator with water; and (6) polymerize monomer containing chemical initiator in situ with hot water.

If the above method is used to impregnate samples fabricated from a concrete mix that produces specimens with a compressive strength of 5,000 psi, compressive strengths >20,000 psi are generally obtained. Design values for PIC that cover the range of monomer systems used and many types of concrete have been published by Cowan (5). These values are as follows: compression, 15,000 psi; direct tension, 1,000 psi; modulus of rupture, 1,300 psi; shear, 750 psi; modulus of rupture 6×10^6 psi, and Poisson's ratio 0.2.

Flammability tests patterned after ASTM D 635-68, *Flammability of Self-Supporting Plastics,* have been performed on PIC and on the polymers themselves (4). The results indicated that while the polymers support combustion according to this test, the composities are either self-extinguishing or do not burn at all.

Equally significant improvements in durability have been obtained. Resistance to abrasion and cavitation are enhanced. The water absorption is reduced to $>99\%$ and the resistance to attack by hot brine, distilled water, acids, and freezing and thawing is enormously improved.

PIC is relatively impermeable to chlorides and its potential for preventing reinforcing steel corrosion and surface scaling has been demonstrated in tests performed by the Federal Highway Administration (6). After 267 daily salt applications, the maximum chloride concentration found at a depth of 1 inch was negligible.

Partially Impregnated Concrete: Partially impregnated concrete is a variation of PIC which is designed for durability rather than high strength. This permits a savings in the account of monomer as compared with fully impregnated concrete. Laboratory tests have indicated that a penetration depth of 1 inch is adequate to prevent chloride penetration into the concrete. Good resistence to abrasion and scaling is also obtained.

Several techniques for the partial impregnation of concrete have been utilized in laboratory and field tests. Two processes, treatment of all surfaces and of one surface, have been described (7)(8). The former can be accomplished by simply soaking dried concrete in low viscosity monomers such as styrene or methyl methacrylate. The depth of penetration varies linearly with the logarithm of the soak time (9).

Field-applied methods for penetrating horizontal and vertical concrete surfaces to depths up to 2 inches have been tested (10)(11). The most effective method for treating a horizontal surface is to place a thin layer (approximately ¼ inch) of dried sand over the surface prior to the application of monomer. The aggregate acts as a wick for the monomer, therefore, longer soak periods are possible without excessive evaporation. Soak times of approximately 6 hours are required to give a penetration of 1 inch. This method has recently been used to impregnate full-size bridges in four states (10) and to repair a highly deteriorated spillway at a dam in Idaho (11).

The walls of a water-outlet tunnel at the Idaho dam that were damaged by cavitation/erosion were also repaired by partial impregnation. In this work the monomer was contained in a pressurized soak chamber that was attached to the tunnel wall during the impregnation step. Soaking for 4 to 6 hours was required to produce a 1 inch depth of penetration. Polymerization of the monomer was initiated by heating with hot water to a temperature between 65° and 100°C. After more than 1 year in service, little damage to the impregnated surface was apparent.

Polymer Concrete: PC consists of an aggregate mixed with a monomer which is subsequently polymerized in place. The techniques used for mixing and placement are similar to those used for portland cement concrete, and after curing, a high-strength durable material is produced. The important process variables are monomer-type, aggregate size distribution, and polymerization method. These

and other topics such as placement and finishing techniques, additives, and safety requirements are given in References (12) and (13).

Depending upon the monomer and type and size of the aggregate, specimens can be produced with compressive strengths up to 20,000 psi. Full strength is attained immediately after the polymerization reaction is completed. Depending upon the concentrations of promoter and initiator and the ambient temperature, this time can vary from a few minutes to 4 hours. Other structural property values include a tensile splitting strength of 1,400 psi, modulus of elasticity of 5.3×10^6 psi, and a Poisson's ratio of 0.23. The creep characteristics of PC are similar to those of normal weight concrete.

Products currently being made from PC include piling, pipe, curbstones, acid storage tanks, pump beds, facades, gutters, and sanitary basins.

High Temperature Formulations

Work is being performed to develop PC formulations that can be used as container materials for high temperature geothermal fluids. Two monomer formulations, 60 wt % styrene 40 wt % trimethylopropane trimethacrylate (TMPTMA) and 50 wt % styrene-33 wt % acrylonitrile-17 wt % TMPTMA, show promise after long-term tests. Both systems can be polymerized using chemical initiators and heat or by chemical initiators and promoters. The styrene-TMPTMA mixture appears suitable for temperatures up to approximately 150°C while the latter has given good results up to approximately 240°C.

Two other monomer systems have been developed which may further extend the operating temperature range, but only limited testing has been performed. The onset of decomposition of polymer containing 50 wt % styrene-32.8 wt % acrylonitrile-9 wt % TMPTMA-8.2 wt % polyphenylene oxide is 262°C. The use of 30 wt % styrene in conjunction with 60 wt % triallyl cyanurate and 10 wt % polyphenylene oxide produces a polymer that starts to decompose at 286°C.

The durability of PC to geothermal fluids is highly dependent upon the composition of the aggregate. Materials such as quartz, silica, fly ash, and portland cement are being investigated. All of the aggregates have been used in materials which have good durability at temperatures >218°C. Above this temperature, only PC materials containing an aggregate consisting of silica and portland cement have been durable to brine and steam.

Laboratory and Field Evaluations

Laboratory Evaluations: Tests to measure the mechanical and chemical resistance properties of concrete polymer materials are being performed. The tests are conducted in autoclaves at conditions simulating environments in which field tests are in progress or being planned. The facility consists of 10 autoclaves which were designed for continuous operation with brine or steam at 220°C and 2 other pressure vessels rated at 280°C.

Testing of two PC formulations, 60 wt % styrene-40 wt % TMPTMA and 50 wt % styrene-33 wt % acrylonitrile-17 wt % TMPTMA, in a 25% concentration of synthetic Imperial Valley brine at 177°C was in progress for 631 days. The formulations consist of 12 wt % of the monomer mixture and 88 wt % of a 90 wt %

silica sand-10 wt % portland cement aggregate. Polymerization was initiated using 2% benzoyl peroxide by weight of monomer and heating to 80°C.

The results of compressive strength measurements made on the specimens as a function of time are given in Table 6.1. The specimens were exposed to 25% brine at 177°C. As noted, both series exhibited initial reductions in strength, probably due to the decomposition of low molecular weight fractions of the polymer. Similar trends have been noted for most of the systems evaluated to date. Strengths measured after exposure for 466 days were essentially the same as those measured after 63 days. Visual inspection after 631 days indicated no cracking or other signs of deterioration.

TABLE 6.1: COMPRESSIVE STRENGTH OF POLYMER CONCRETE

Monomer System Exposure Time (days)	PC No. 1	PC No. 2
	. . Compressive Strength (psi) . .	
0	9,600	10,900
63	4,450	7,000
142	3,900	6,100
280	4,352	7,567
466	4,355	7,511

Notes: PC No. 1, 60 wt % styrene-40 wt % TMPTMA.
PC No. 2, 50 wt % styrene-33 wt % acrylonitrile-17 wt % TMPTMA.
Aggregate, 90 wt % sand-10 wt % portland cement.
Specimen size, 0.75" diameter x 1.5" long.
Strengths measured at 20°C.

Source: BNL 22684

Tests in an environment simulating the well-head conditions in Niland, California (25% brine, 238°C) were also conducted. One sample consisted of a monomer mixture containing 50 wt % styrene-33 wt % acrylonitrile-17 wt % TMPTMA. After exposure for 203 days, no deterioration was apparent.

Two samples contained 55 wt % styrene-36 wt % acrylonitrile-9 wt % TMPTMA and 52 wt % styrene-35 wt % acrylonitrile-13 wt % TMPTMA, respectively. After exposure for 180 days, neither sample exhibited deterioration. Compared to a control strength of 16,940 psi the compressive strength of one of these samples was 16,240 psi.

An evaluation of specimens at conditions simulating those at Raft River, Idaho (400 ppm brine at 150°C) and more severe than those at Klamath Falls, Oregon is also being made. Two inch cubes and prototype sections of 3.5 inch diameter pipe are being tested. A section of pipe with a burst pressure of 400 psi after exposure for 140 days showed evidence of attack.

A serious problem associated with the conversion of the energy content of hypersaline geothermal systems to electric power is precipitation of amorphous silica and other phases that can ultimately cause scaling of the power plant equipment. The rate of polymerization of monomeric silica is dependent upon pH, temperature, salinity, silica concentration, and the presence of solids. Work at Lawrence

Livermore Laboratory (14) has indicated that a reduction of pH levels over the range 5.0 to 1.6 resulted in complete elimination of scale over the temperature range 220° to 105°C.

Tests are in progress to determine the feasibility of using concrete polymer materials in high temperature-low pH environments. Two tests are in progress.

Three samples of PC were exposed to a pH 3 hydrochloric acid solution at 20°C for 300 days. No evidence of attack on the PC was apparent and the concrete control exhibited only a small weight loss. The temperature was then raised to 90°C. Evidence of attack on the concrete control was immediate and after 40 days a 21% weight loss was measured. The PC weight remained constant. The three PC samples were then exposed to a pH 1 hydrochloric acid solution at 90°C. After 21 days, the concrete control had a weight loss of 19%. No evidence of corrosion of the PC as determined by weight change and pH measurements has been detected after exposure for 200 days. A test in pH 1 hydrochloric acid at 200°C was started. After 14 days in test, no attack was evident.

A potential application for PC is as a liner material for piping and process vessels. Therefore, tests have been performed to determine the effect of thermal shock on the bonding between PC and steel. In one study a 0.5 inch thick PC liner containing 60 wt % styrene-40 wt % TMPTMA was placed on the inside of an 8 inch diameter steel pipe. The surface of the pipe was sandblasted prior to application of the PC. The pipe was subjected to 18 temperature cycles between 0° and 100°C, 11 cycles from -57° to 100°C, and 7 cycles from -57° to 150°C. No cracking of the PC or loss of bond was apparent.

Field Evaluations: Tests have been initiated at The Geysers, Baca Wells, Klamath Falls, Raft River, East Mesa, and Niland. The status of each of these programs is summarized below.

The Geysers: Tests are in progress to determine the durability of PC when exposed in a well-head chamber to dry steam at 238°C. A preliminary test series was completed in September 1975 which indicated that the materials had high strength and low permeability after exposure for 90 days (15).

Based upon these data, a second series of samples was placed in test during November 1975. Two monomer systems, 50 wt % styrene-33 wt % acrylonitrile-17 wt % TMPTMA and 55 wt % styrene-36 wt % acrylonitrile-9 wt % TMPTMA were tested. Aggregate composition and polymerization method are other variables in the test series.

Samples have been evaluated after exposure for 90, 180, and 365 days. All samples containing an aggregate consisting of 90 wt % silica sand-10 wt % portland cement have shown good durability. Composites containing other aggregates failed. The average compressive strength of specimens exposed to the test conditions for 1 year was 4,200 psi, approximately 50% of the control but in fair agreement with a value of 4,900 psi that was measured after a 90-day exposure.

Baca Wells: A test to determine the durability of PC to flashing brine at a temperature of approximately 160°C was performed at Baca Wells, New Mexico. The total exposure time was 180 days. The test series consisted of two monomer mixtures, 60 wt % styrene-40 wt % TMPTMA and 50 wt % styrene-33 wt %

acrylo... -17 wt % TMPTMA, mixed with an aggregate consisting of 90 wt % silica sand and 10 wt % portland cement. Three different polymerization methods were utilized.

The specimens were found to be in good condition after the 180-day test. Two samples which contained the 60 wt % styrene-40 wt % TMPTMA mixture polymerized using benzoyl peroxide and dimethyl aniline, were slightly cracked. All of the other materials were crack-free.

Tests performed on the samples included dimensional stability, weight change, water absorption, and compressive strength. Little if any changes in the dimensions and weight were detected. Compared to the controls, all of the samples containing styrene-TMPTMA had strengths which were essentially unaffected by the exposure. The samples containing styrene-acrylonitrile-TMPTMA polymerized by promoters and initiators were also unaffected. The other samples exhibited slight strength reductions and increases in absorption. These strengths were in the same order as those obtained after 180 day exposures at The Geysers (approximately 4,500 psi).

Klamath Falls: Samples of concrete polymer materials have been exposed to low temperature geothermal fluids at Klamath Falls, Oregon. Field testing was started in November 1975. Forty-eight cylindrical specimens of PC and PIC were placed into wells at temperatures ranging between 27° and 99°C. Samples were removed for evaluation after exposure for 90, 180 and 360 days.

All of the specimens were found to be crack-free. The results from compressive strength and water absorption tests indicate that both properties are independent of the exposure temperature. The water absorptions remained constant throughout the test. Reductions in compressive strength ranging between 14 to 18% were noted for samples exposed for 180 days. Beyond that time, the strengths remained essentially constant.

Raft River: Concrete polymer materials may have application in medium temperature geothermal systems where piping with low-cost, minimum thermal losses, and durability to internal and external environmental conditions is essential. Geothermal fluids meeting this condition (temperature approximately 150°C) exist in the Raft River Valley region of Idaho where testing of concrete polymer materials has been started.

In one experiment, twenty 2 inch diameter x 0.25 inch thick cement discs, impregnated with 60 wt % styrene-40 wt % TMPTMA, were subjected to the fluid in an attempt to measure the resistance of PIC to abrasion. After 70 days in test, no deterioration of the PIC was apparent. Severe attack was noted on several metallic samples.

Testing of PC samples in the Raft River Mobile Corrosion, Deposition, and Component Test Laboratory was started in September 1976. The test conditions are as follows: temperature 135°C, flow 200 gpm, and pressure 130 psi. Only the results from samples exposed for 90 days are available. These data indicate trends similar to those obtained in the other field tests; slight reductions in strength, dimensional stability, and constant water absorption.

East Mesa and Niland: Test programs were initiated in the Imp... Valley of California at East Mesa and Niland. At East Mesa 48 hollow cylindrical PC samples are being exposed to flowing brine at a temperature of approximately 160°C. The test was started in March 1977.

A total of 24 specimens have been placed into test in six environments at Niland. The samples are located in 220°C brine at the inlet to the first steam separator, the brine and stream effluent from the first separator, brine and steam effluent from the second steam separator, and at the steam/brine interface in the second separator. The test was started in April 1977. At the time BNL 22684 was written, test results were not available.

Potential Applications

Based upon the test data obtained, several potential applications for concrete polymer materials in geothermal processes are apparent. The results from preliminary economic studies indicate that large cost benefits can be accrued by use of PC-lined carbon steel components as replacements for stainless steel, tantalum, and Hastalloy in condensate piping systems, reinjection lines, and steam separators. Uses of PC or PIC in cooling towers, district heating systems (16), and to protect concrete surfaces also appear cost effective.

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CHEMISTRY OF SCALE FORMATION

The material for this section has been based upon a paper by H.L. Barnes and J.D. Rimstidt of Ore Deposits Research Section, Pennsylvania State University, presented at The Second Workshop on Materials Problems (PB 261 349).

The Fundamental Equilibrium Reaction

The basic reaction controlling silica solubility is:

$$(1)\qquad SiO_2 + 2H_2O \longrightarrow H_4SiO_4(aq.)$$

The validity of the stoichiometry of this reaction is well established for several reasons. Many studies, including the most recent by Seward (1974), show that H_4SiO_4 is the dominant aqueous silica species and ionization of H_4SiO_4 is unimportant as long as the pH is less than 9 at 25°C, or not more than 2 pH units above neutrality at higher temperatures; consequently $H_3SiO_4^-$ is a negligible species in virtually all geothermal solutions. (Because silica is not an ionic solute, it is improbable that electrostatic removal could be effective.) There is also no complexing of silica to form soluble alkali silicates or polymers at equilibrium unless the pH is much above the normal range, as summarized by Fournier (1973). Furthermore, by correlating against temperature, the silica solubility expressed in the complete equilibrium constant of Marshall (1972), it was found that the coefficient for H_2O in reaction (1) is unequivocally 2 up to at least 360°C. The equilibrium constant for the solubility controlling reaction is:

$$(2)\qquad K_T = a_{H_4SiO_4}/a_{SiO_2}a^2_{H_2O}$$

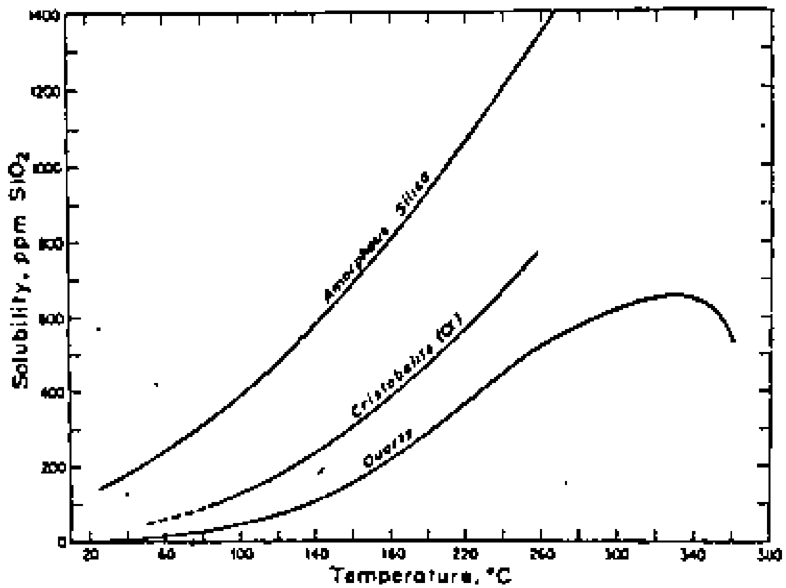
where K_T is the equilibrium constant at a particular temperature, T, and a_i represents the activity of the particular reactant, i. This means that the concentration of silica in solution, essentially $a_{H_4SiO_4}$, is a linear function of the product:

$$(3)\qquad K_T \times a_{SiO_2} \times a^2_{H_2O}.$$

Next consider the magnitudes of each of these factors and their influence on equilibrium silica concentration.

Dependence of Solubility on the Equilibrium Constant: An increase in the equilibrium constant, K_T, with temperature causes a concomitant increase in the activity of silica in solution, all other factors of product (3) remaining constant. The result of the temperature effect on the equilibrium constant is shown on Figure 6.1. At each temperature, exactly the same value of K_T applies to each of the three curves, the only difference between them being that a_{SiO_2} differs among the solid phases.

FIGURE 6.1: TEMPERATURE EFFECT ON EQUILIBRIUM CONSTANT



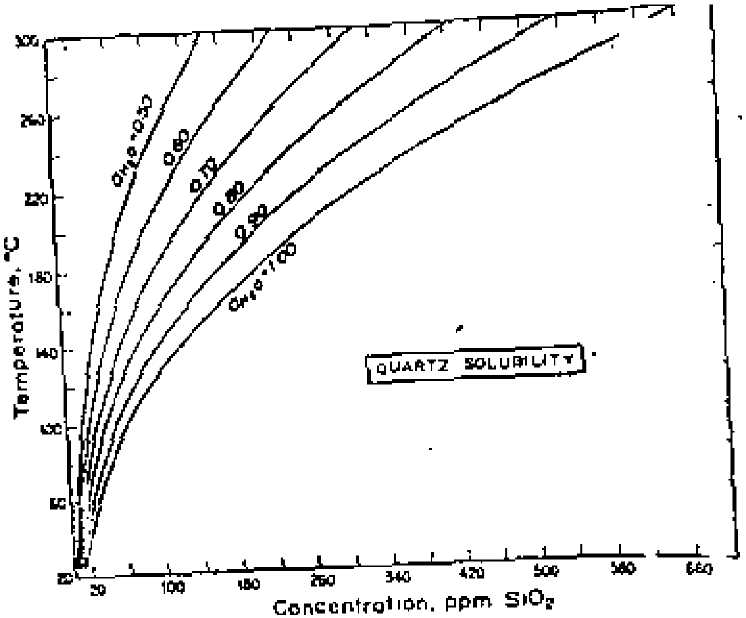
Source: PB 261 349

Dependence of Solubility on Source Rocks: Clearly, equilibrium constant (2) tells us that, at a fixed temperature, the solubility of silica is a linear function of a_{SiO_2}. In turn, a_{SiO_2} in the rocks contributing silica to the solution depends upon the structure of the silica mineral present and also on its grain size and degree of disorder. If the grain size is less than 1 µm, or if the solid is highly disordered, both of which occur in amorphous silica, for example, then surface energy becomes important and the solubility is increased. However, such surface energies are only transitory at temperatures above about 300°C because of the rapid rate of recrystallization. It is for this reason that the solubility curve for amorphous silica on Figure 6.1 is not valid above approximately this temperature.

The effect of a_{SiO_2} is evident in the silica concentrations in waters derived from different types of rocks in the geothermal reservoir. Where glassy volcanics or amorphous silica are present, then both a_{SiO_2} and associated silica concentrations are comparatively very high as in Figure 6.1. If volcanics containing cristobalite are present, then the solubility is lower but still high. Lowest concentrations are found where quartz is the dominant silica mineral in the reservoir rocks, but the concentration still depends on whether this quartz is fine-grained (less than 1 µm) or has a coarse grain size, which causes the lowest solubility among silica minerals.

Dependence of Solubility on Salinity: The third factor which controls silica concentration in product (3), besides K_T and a_{SiO_2}, is the activity of water, and here the dependence is not linear, but on $a^2_{H_2O}$. Figure 6.2 illustrates this dependence for quartz.

FIGURE 6.2: QUARTZ SOLUBILITY



Source: PB 261 349

Note that a decrease in a_{H_2O} from 1.0 to 0.7 lowers silica solubility by about half at any temperature and for any silica mineral. Therefore, the proportional decrease in solubility accompanying a particular Δa_{H_2O} can be read from Figure 6.2 and applied to the other minerals of Figure 6.1 at the same temperature. The type and concentration of solutes present determine a_{H_2O} as shown below.

a_{H_2O}	NaCl Molality (%)	$CaCl_2$ Molality (%)
0.9	2.8 (14)	1.6 (15)
0.75	*6.2 (27)	–
0.7	–	3.4 (22)
0.5	–	5.0 (36)
0.3	–	*7.2 (44)

*Saturated at 25°C.

Although the values of a_{H_2O} given here are exact for low temperatures, they generally change only by Δa_{H_2O} of 0.1 to 0.2 up to 300°C for a particular solute concentration, and normally toward higher (more ideal) a_{H_2O} approaching 1.0. Because high concentrations occur in many geothermal fluids, a_{H_2O} may vary considerably. At 300,000 ppm total dissolved solids (30 wt %), a_{H_2O} would be expected to be between 0.6 and 0.7 depending on the specific solutes present.

There are some important implications of this table and Figure 6.2. Additives used to try to prevent silica deposition must lower a_{H_2O} and decrease the equilibrium solubility. In fact, even those additives that might tie up silica in a soluble complex must be used (at reasonable pHs) in such high concentrations (owing to their weak affinity for silica), that the effect on a_{H_2O} would be expected to override the complexing effect to give a net solubility decrease. Furthermore, such large quantities of water would have to be treated to prevent silica deposition that additives are unlikely to be economically feasible.

A second implication of Figure 6.2 is that dilution of a moderately concentrated brine by cleaner water efficiently increases silica solubility due to the dependence on $a^2_{H_2O}$. For example, if the initial a_{H_2O} = 0.8 and the solution is diluted by 10% with clean distillate, the net increase in dissolved silica can be about 20%, depending on the temperature and salts dissolved. Consequently, silica fouling can be effectively retarded by diluting concentrated geothermal brines to lower the degree of silica saturation. If a down-hole pump were operated on steam, then the steam also would be a beneficial diluent for this purpose.

Mineralogy of Silica Scale: The silica phase that will precipitate is controlled by the degree of supersaturation at the temperature of deposition. For example, if supersaturation lies between the cristobalite and quartz curves of Figure 6.1, then any precipitation must be of quartz. This figure also shows that if the water were saturated with quartz in the reservoir at 225°C, then depending on the kinetics of the particular system, amorphous silica could precipitate at 100°C, or cristobalite at 180°C; furthermore, if the solution were saturated in amorphous silica, then this is the phase that would be expected to precipitate at any temperature. It is also evident that during cooling, cristobalite could form easily after initial saturation in the reservoir with either quartz or cristobalite, or, alternatively, after dilution of an amorphous-saturated solution.

Reliability of Solubility Data

To prepare Figure 6.1, the solubility data available from nine sources (included in the references), were correlated and these have been tested for consistency against the complete equilibrium constant

$$K_E = K_T - 2\log(\text{molarity of } \overline{H_2O}). \quad (4)$$

There is excellent agreement among those quartz data that are based on equilibrium that has been established by bracketing through an approach from opposite directions; such studies include Mackenzie and Gees (1971) with 4.4 ppm silica at 20°C, Crerar and Anderson (1971) for data at 180° to 330°C, plus several other investigations at temperatures above 250°C where reaction rates are more rapid. Therefore, the quartz curve seems to be well established. The cristobalite curve is supported by fewer data and has an added problem because at roughly 250°C, there is a transition in structure from α to β, so that measurements above and below the transition are not easily correlated.

However, the curve for amorphous silica is least well known because at low temperatures, reaction rates are so slow that equilibrium solubilities cannot be achieved and, above about 250°C, the solid begins to rapidly recrystallize to a more stable form during solubility measurements. Therefore, this curve is probably not valid above 300°C due to the rate of recrystallization.

Kinetics of Silica Deposition

There are very few studies providing useful data on the rates of silica deposition. Nevertheless, for a first approximation, some unpublished data plus results from Van Lier, Debruyn, and Overbeck (1960) were combined to calculate the rates of dissolving and precipitating of quartz. The rate of dissolving at temperature, T, is given by:

$$\left(\frac{a(SiO_2)}{at}\right)_T = K_d\left(\frac{S}{V}\right) \tag{5}$$

where K_d is the rate constant for dissolving, and (S/V) is the ratio of the surface area of quartz to the volume of solution in which it is dissolving. Similarly, the rate of precipitation is:

$$\left(\frac{a(SiO_2)}{at}\right)_T = K_p(SiO_2)\left(\frac{S}{V}\right) \tag{6}$$

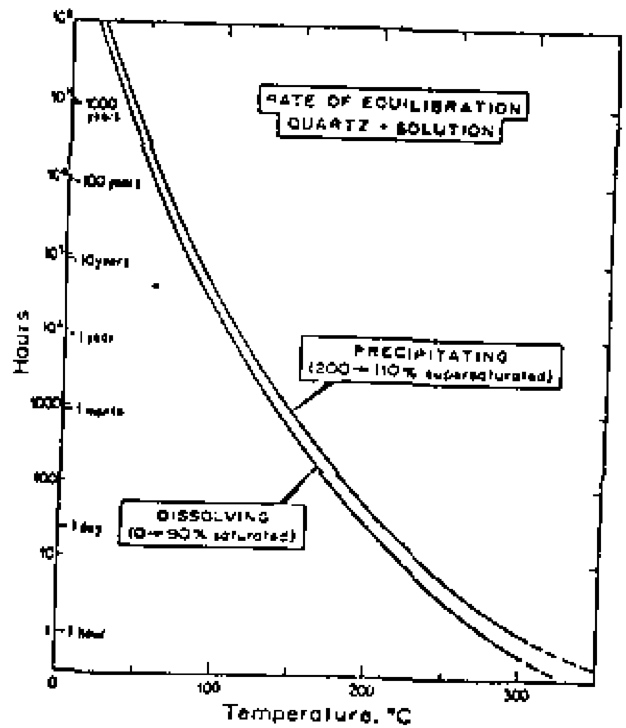
Note that dissolving is independent of the silica concentration (SiO_2) in equation (5), i.e., zero order, but that silica deposition, as shown by equation (6), is concentration-dependent and first order.

From preliminary values of K_d and K_p, the time necessary to reach 90% of the equilibrium concentration of silica starting with either no quartz dissolved or with 100% supersaturation was calculated. The (S/V) values selected were 8 cm^2/ml for precipitation and 15 cm^2/ml for dissolving; these values are probably appropriate for reactions in the geothermal reservoir but are certainly high for flow-through piping. As a consequence, rates in piping and heat exchangers will be less than those of Figure 6.3, but can be easily approximated from these curves for other environments in view of the linear dependence on (S/V).

This dependence of rate on surface area is a principle that has been applied in preventing scale formation in the U.S.S.R. Chernozubov and coworkers (1965) have described using finely ground particles (<100 μm) of the composition of incipient scale for this purpose. The particles are counterflowed through a brine to act as nuclei to collect precipitation during brine distillation and are effective in lowering the degree of supersaturation. This method has been used since 1963 in a plant providing desalinated water from the Caspian Sea for the city of Shevchenko. Although it is effective for removing the dominant solutes of $CaSO_4$ and $CaCO_3$, it has not yet been effective for silica, probably due to high costs associated with longer path lengths needed for the relatively slow rates of reaction of silica.

Rates of either dissolving or precipitating quartz become very slow below about 150°C in pure water, and it is likely that changes in (S/V) of geothermal systems would decrease the rates of Figure 6.3 further. However, many scattered observations show that both rates can increase markedly if crystobalite, or especially amorphous silica, are involved or if the solution is saline. The mineralogic effect is explicable because the rates increase with a_{SiO_2} of the solids; the dependence of the rates on $a^2_{H_2O}$, in contrast, should result in their decrease instead of the catalysis reported. Perhaps by determining the mechanisms of the silica reactions, the chloride effect could be explained.

FIGURE 6.3: RATE OF EQUILIBRATION–QUARTZ + SOLUTION



Source: PB 261 349

There is more than an academic incentive to investigate these mechanisms because if increased a_{Cl^-} causes catalysis, then there is hope that other solutes might retard the rates. The rates are already slow enough that silica fouling takes place at Cerro Prieto, for example, after the solutions leave the power plant. A small retardation of rates elsewhere could solve the silica problem of most geothermal systems.

Optimism in expecting to control rates of silica scaling must be tempered by the complexity of this physical chemistry, and of geothermal systems. Rates of scale deposition are complicated functions of temperature, temperature gradients, flow rate, turbulence, silica concentration, surface roughness, and concentration of suspended solids and other solutes.

Summary

This review indicates that several methods hold promise for effectively controlling silica scale formation. Equilibrium relations show that the initial solubility of silica is repressed where high solute concentrations, such as NaCl or CO_2, are present either naturally or by addition. More important, silica solubility in brines can be increased significantly by dilution so that the addition of condensate may be sufficient to prevent fouling.

Kinetic factors are largely unexplored, but it is clear that minimizing sites for nucleation is useful; this may be done, for example, by preventing early precipitation of carbonates which are effective nuclei for silica, and by reducing roughness on immersed surfaces. The fact that high salinity catalyzes rates of silica deposition suggests that investigation of the reaction mechanisms of precipitation might lead to an anticatalyst useful in slowing deposition enough that it would occur only downstream from the power plant.

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SCALE DEPOSITION

The material for this section has been based upon a paper by E.F. Wahl of Occidental Research Corporation presented at the Second Workshop on Materials Problems (PB 261 349).

For good design to prevent scaling, the relationships between brine composition, process conditions, and scale deposition should be made available. The composition of brines being processed by geothermal utilization plants varies with location and temperature because of the varying nature of the chemical composition of the material in the earth's crust. The total dissolved solids in these brines varies between 1,000 and 400,000 ppm. The lowest temperature geothermal

source which can be economically utilized is uncertain at present while the upper limit of temperature of geothermal deposits as presently exploited is in the neighborhood of 300°C. Because there are still active volcanos in the earth's crust, one would expect that ultimately higher temperature sources will be used.

As hot brine is drawn from geothermal wells and flows through the piping systems of geothermal energy utilization plants, there will be pressure and temperature changes, boiling with phase changes, and turbulence in the liquid stream. In addition, the brine will come in contact with various materials of construction. The result is that the hot salt solution will undergo an intricate chemical and physical time history. In some cases scale deposition will eventually shut down the system, in other cases there will be no deposition, and in still others the deposition will be so great the system will be inoperable. The complexity and consequent difficulty of determining the relationship between brine chemistry, process conditions, and scale deposition will be exemplified by some examples (1).

Effect of Brine Constituents on Silica Deposition

The effect of the calcium and magnesium content of the brine on the deposition of predominantly silica deposits on a cooled metal surface is shown in Table 6.2. This shows that the addition of calcium and magnesium to a brine has more influence on the deposition of the scale than the doubling of the silica content. It is known that silica forms silicate deposits with various cations. Iron and aluminum are both known to be significant in this regard. Thus the study of deposition from geothermal brines is a complex situation because of the influence of various cations.

TABLE 6.2: SILICA SCALE DEPOSITION ON A COOLED PROBE, LABORATORY BATCH EXPERIMENT, SYNTHETIC BRINES

Experiment No.	Brine Composition Ca mg/l	Mg mg/l	HCO_3 mg/l	SiO_2 mg/l	Probe Temp. °F	Scaling Amount
2	None	None	None	200	90	None
4	None	None	None	400	90	Slight
15	900	69	None	300	90	Moderate

Source: PB 261 349

Differences Between Synthetic and Real Brines

The deposition of scale from synthetic brines, Table 6.3 and East Mesa brine, Table 6.4, was studied using the scaling test unit shown in Figure 6.4. The deposition of scale on the probe wall was measured by the heat transfer rate which in turn was determined by measurements of the temperatures and flow rates of the coolant and brine as shown schematically in Figure 6.5. For the synthetic brine, the deposition was predominately silica. A mathematical model, shown in Figure 6.5, was derived assuming that the rate of deposition depends on the driving force between the solution and the cooled surface. As shown in Figure 6.6, the data were correlated quite well using this model.

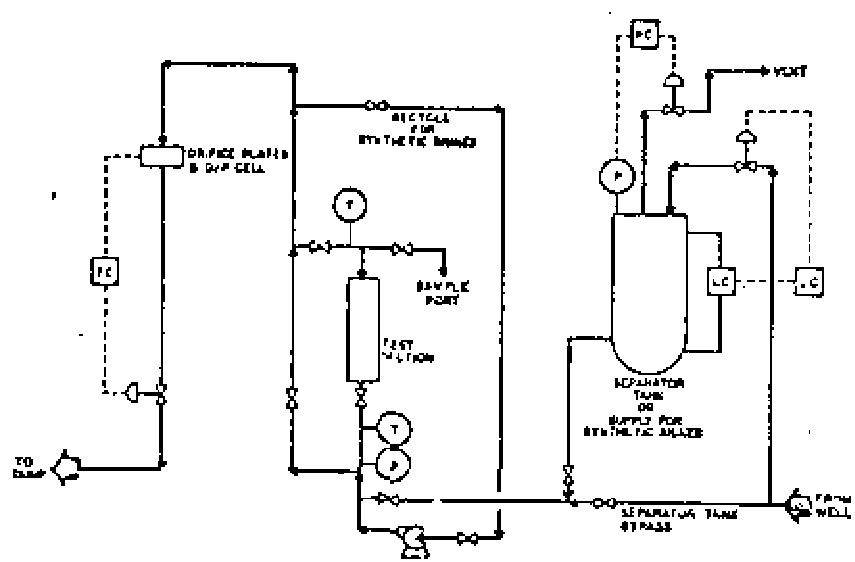
TABLE 6.3: DESCRIPTION OF SYNTHETIC GEOTHERMAL BRINE

Component		Compound Used to Synthesize Brine	
Name	mg/l	Name	Grs/l
Na	10,000	NaCl	25.43
K	1,200	KCl	2.29
Ca	300	$CaCl_2 \cdot 2H_2O$	1.10
Mg	23	$MgCl_2 \cdot 6H_2O$	0.193
Li	15	LiCl	0.091
Br	10	$NaBrO_3$	0.019
SO_4	10	Na_2SO_4	0.015
B	20	H_3BO_3	0.115
HCO_3	500	$NaHCO_3$	0.687
SiO_2	500	$Na_2SiO_3 \cdot 9H_2O$	2.360
Cl	17,150	Total Chloride From Above	

TABLE 6.4: TYPICAL BRINE FROM EAST MESA WELL 6-1

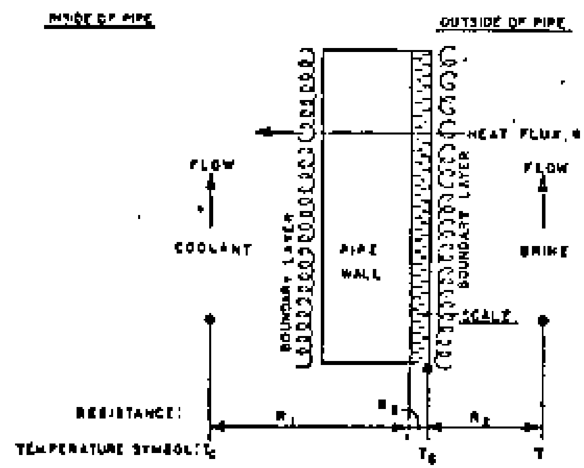
State:	Liquid, clear, colorless		
Temperature:	280°F		
Pressure:	88 psig		
Solution saturated pressure:	65 psig @ 280°F		
Density @ 25°C:	1.011		
pH:	5.4 to 6.0		
Total dissolved solids	24800 mg/l	Li	54 mg/l
Cl	14000 mg/l	Mg	16 mg/l
Na	7050 mg/l	SiO_2	286 mg/l
K	850 mg/l	CO_3	300 mg/l
Ca	770 mg/l	SO_4	173 mg/l
Fe	1 to 16 mg/l	S^{-2}	<1 mg/l
Sr	135 mg/l	BO_4	36 mg/l

FIGURE 6.4: SCHEMATIC OF SCALING TEST UNIT



Source: PB 261 349

FIGURE 6.5: SCALING RATE MODEL



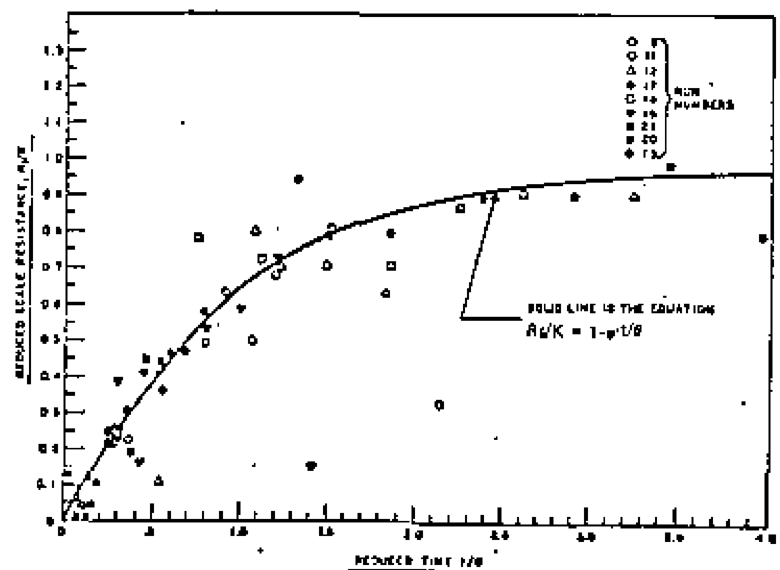
MATHEMATICAL MODEL: $R_s = K(1-e^{-t/\theta})$

WHERE: t = TIME

K/θ = SCALING PARAMETER

R = HEAT TRANSFER RESISTANCE

FIGURE 6.6: CORRELATION OF SCALE RESISTANCE TO HEAT TRANSFER FOR SYNTHETIC BRINE TESTS



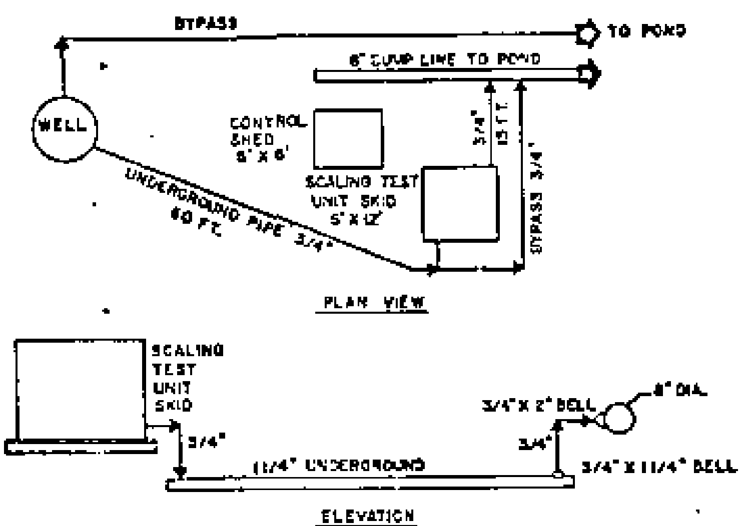
Source: PB 261 349

After the synthetic brine tests this scaling test unit was taken to the East Mesa Test site of the U.S. Bureau of Reclamation to study the deposition from the brine of well 6-1. Although the composition of this brine is similar to that of the synthetic brine, the results were substantially different. Calcite was found to be the predominant scale, and the rate of deposition was dependent on process conditions and relatively independent of the driving force between the bulk solution and the cooled or heated surface. The brine from East Mesa well 6-1 flowed through the underground pipe to the test unit and then to an eight inch dump line as shown in Figure 6.7.

The well had perforations that covered various strata underground. Scale deposition was observed at two points. One was in the test section and the other was in the ¾ inch dump line between the test unit and the eight inch dump line. Build-up of scale in the exit line was demonstrated by the increasing pressure drop across the exit line, Figure 6.8, which indicated that the exit line was almost totally plugged after three days of operation.

A decrease in heat transfer due to scale operation, Figure 6.9, again shows that the deposition was sufficient in three days time to be significant from an operational standpoint. In both cases the deposition rate was constant whereas the synthetic brine data follows an expotential curve, thus demonstrating the difference in the deposition mechanism. On the other hand, deposition from this brine was such that the deposition of scale in the test unit could be kept at zero under certain controlled conditions as shown below.

FIGURE 6.7: PLOT PLAN OF SCALING TEST UNIT INSTALLATION AT EAST MESA WELL 6-1



Source: PB 261 349

FIGURE 6.8: PRESSURE DROP ACROSS EXIT LINE FOR RUN 201

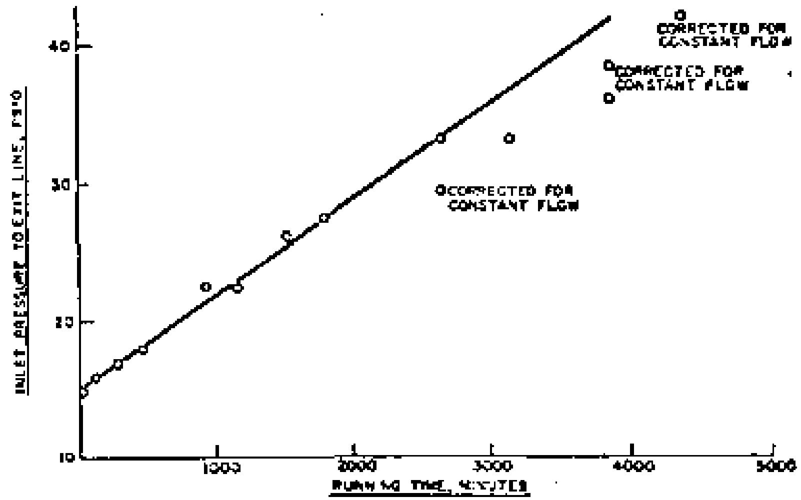
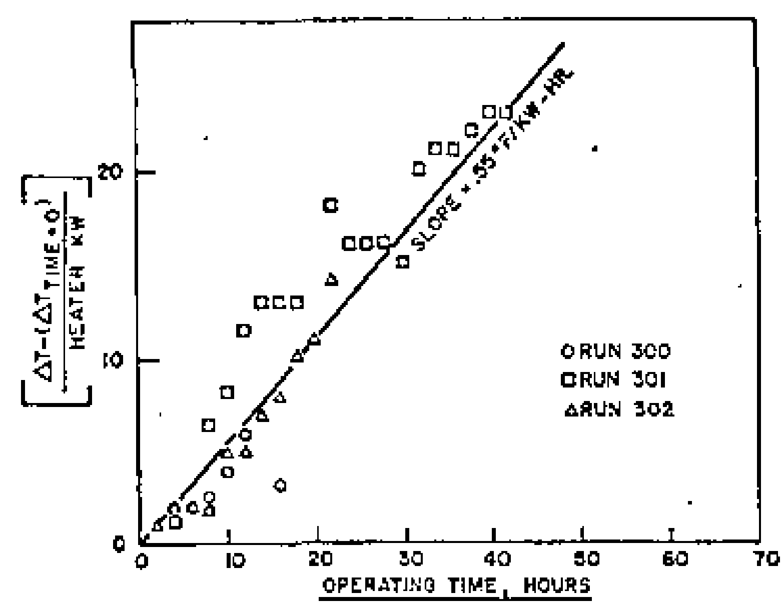


FIGURE 6.9: HEAT TRANSFER SCALE RESISTANCE FOR RUNS 300 TO 302



Source: PB 261 349

Effect of Pr...ss Conditions

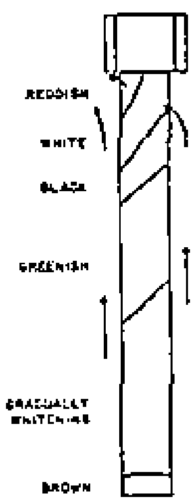
The type and location of the scale deposits is related to the flashing of some steam and dissolved gases from the brine. The last line in Table 6.5 shows that for runs 201-203 the maintenance of pressure and the prevention of flashing prevents the deposition of calcium carbonate in the test unit. However, at the exit of the scale test unit where the brine flashed into the dump line, calcium carbonate scale formed at a rapid rate.

With a slight degree of flashing, runs 205 and 303, the calcite formed on the test probe and a silica scale formed in the exit line. With a higher degree of flash as shown by the upper lines of Table 6.5, both an iron-silica and a calcite scale formed in the test unit.

Composition of the scales collected is shown in Table 6.6. This table indicates that the scale deposit is predominately a mixture of iron and silica, or calcium carbonate or a mixture of the two. Other components are present in less than one weight percent quantities each.

The physical appearance of the scales varies in color and appearance as shown in Table 6.7. This variation occurs even in one run as is shown in Figure 6.10 for a two foot section of the test probe, indicating that slight differences in process conditions cause changes in the deposition. The colors vary all the way from reddish to white at the top, black on through green in the middle, and black to white on to brown at the bottom as shown in this figure. The deposit of white material seems to be predominent on the down stream side of the probe as the fluid went up against the probe and out through the exit line. The scale at the bottom end of the probe is more uniform circumferentially, although there seems to be a slight trend for the color changes to parallel that at the top of the probe. The scale is very hard but the black underlying scale is soft and easily removed. The black underlying scale is very thin. After drying for one week, the scale flaked off readily.

FIGURE 6.10: APPEARANCE OF SCALED PROBE FROM RUN 207



Source: PB 261 349

TABLE 6.5: RELATIONSHIP BETWEEN SEPARATOR OPERATION AND TYPE, RATE AND LOCATION OF SCALING

Data Averaged Over Runs	Separator Pressure (psig)	Temperature Drop (°F)	Brine Acidity (pH)	Scaling Rate: Probe (mg/min)	Scaling Rate: Exit Relative*	Type of Scale Located: On Probe	Type of Scale Located: At Exit
207	12.2	30.5	6.83	4.8	1	$CaCO_3$, SiO_2, Fe***	–
208	12.8	31	6.75	0.001**	1	$CaCO_3$, SiO_2, Fe***	–
102-105	13	28.5	–	0.01***	?	–	–
301-302	14.4	24.4	–	3.0	1	$CaCO_3$, SiO_2, Fe***	–
303	20.4	23.5	6.78	11.5	1	$CaCO_3$	SiO_2, Fe
205	26	15.5	6.24	0.01	1	$CaCO_3$	SiO_2, Fe
201-203	–	–	5.80	0.	20	None	$CaCO_3$

*Based on pressure increase and/or weight of scale deposited.
**The low scaling rate in these runs is due to the relatively short duration of the runs.
***SiO_2, Fe scale could be $2(SiO_2 \cdot 2H_2O)Fe(OH)_2Fe(OH)_3$:

TABLE 6.6: CHEMICAL COMPOSITION OF SCALES FROM WELL 6–I BRINE

	Run	Na	Cl	CO_3	Ca	Fe	SiO_2	Si	Mg	Mn	SO_4	K	S	Sum*	Sum**
								wt %							
Probe	102	0.74	0.81	28.80	14.60	21.00	15.02	0.21	0.31	0.60	–	0.12	0.02	82.31	104.10
Probe	205	5.55	–	–	20.90	6.20	0.05	0.40	0.30	–	–	–	–	–	–
Pyrex pipe	205	0.43	–	56.81	31.50	6.70	0.10	0.40	0.10	–	–	–	–	96.04	100.18
Control valve stem	205	0.12	–	55.74	34.90	6.40	0.20	0.60	0.10	–	–	–	–	96.06	102.08
Probe bottom third	207	0.11	0.26	52.40	29.00	7.23	7.00	0.61	0.11	0.52	0.29	0.03	–	92.56	98.16
Probe top third	207	0.13	0.74	54.18	30.30	6.33	1.20	0.62	0.10	0.52	0.32	0.02	–	93.96	98.53
Separator entry	207	0.11	0.16	54.25	33.10	2.55	0.04	2.44	0.04	0.17	0.21	0.01	–	93.98	96.09
Probe	300	3.34	3.91	47.57	27.80	3.79	8.40	0.39	0.13	–	–	–	0.02	93.35	99.49
Probe, unheated part	301	0.16	0.17	50.33	30.30	8.00	0.24	0.40	0.20	0.55	–	0.01	0.04	96.40	101.41
Probe, heated part	301	0.09	0.11	57.40	30.70	7.62	0.11	0.44	0.20	0.51	–	0.01	0.02	97.21	101.82
Probe	302	0.87	–	11.48	6.11	24.50	29.80	–	0.20	–	–	–	–	72.96	105.73
Probe top	303	0.10	0.01	57.42	33.20	6.40	0.38	0.50	0.20	–	–	–	–	98.21	102.34
Exit line	204/5	1.50	0.02	–	0.87	27.20	28.20	0.10	0.30	–	–	–	–	58.19	91.64
Molecular weight	–	22.99	35.45	60.01	40.08	55.84	60.09	87.62	24.31	54.93	96.06	30.10	32.10	–	–

*Of determined components listed in table.
**Assuming 2.5 mols OH per mol Fe and 2 mols H_2O per mol SiO_2.

urce: PB 261 349

TABLE 6.7: PHYSICAL DESCRIPTION OF SCALES

Run No.	Sample Location	Appearance	Ease of Removal
101	probe	black	flaked/scraped
102	probe	brown black	scraped
103	probe	brown black	scraped
200	probe	brown powdery scale	scraped off
202	probe	tan film	easily wiped off
203	probe	discoloration like metallic oxidation	easily wiped off
204	probe top	very light black film	easily wiped off
204	probe bottom	greenish brown film	easily wiped off
205	probe	very fine black coating similar to carbon black	easily wiped off
204/5	exit pipe	1/32 inch thick hard glass like black	requires chipping
206	probe top	tan coating, powdery	easily wiped off
206	probe bottom	nodular or crystal build-up plus tan coating	easily wiped off
207	probe	see Figure 6.7	hard and adhering tightly
300	probe	brown black	flakes off
301	probe	brown black	flakes off with light scraping
302	probe	brown black	flakes off with light scraping
303	probe	translucent tan	flakes off readily

Source: PB 261 349

Complexity of the Deposits

The x-ray diffraction pattern of some of the scales shows that the scale from runs 300 and 102 was calcite, and for runs 204 and 205 (which was chemically shown to be predominately an iron-silica deposit) was an amorphous scale deposit. From run 300, however, the x-ray diffraction pattern has not been successfully identified. Comparisons of scale deposits show that slight variations in composition and/or process conditions vary the nature of the deposit. Furthermore, the mechanism must be different for apparently slight variations since sometimes the deposit is uniform and sometimes nodular.

Reference

(1) Wahl, E.F., et al., *Silicate Scale Control in Geothermal Brines*, OSW Final Report, September 1974, OSW Contract No. 14-30-3041.

MATERIALS RESEARCH

The material for this section has been based upon a paper by P.B. Needham, Jr. and Staff of the Corrosion and Electrometallurgy Research Group, College Park Metallurgy Research Center,

U.S. Bureau of Mines prepared for The Second Workshop on Materials Problems (PB 261 349).

An objective of the Bureau of Mines' geothermal program is to evaluate the corrosion and scaling resistance of commercially available metals and alloys in geothermal brine environments. This is done in order to determine the best materials for construction of plants designed for the extraction of mineral values, conversion of energy, and the desalinization of brine waters.

Laboratory Studies

Corrosion Tests: The results of laboratory corrosion tests have shown that Hastelloy C-276 and E-Brite 26-1 were the most corrosion resistant in deaerated geothermal brines (250,000 ppm TDS) under well head conditions (230°C, 450 psi) (1). However, with the addition of 100 ppm O_2 to the brines, the behavior of Hastelloy C-276 differed markedly. The U-bend stress-corrosion specimens developed cracks which initiated, in nearly every case, at nonmetallic inclusions on the specimen surfaces. These inclusions dissolved in the oxygenated brine leaving a sizable pit; they subsequently became enlarged and led to a gross deterioration of the sample surface.

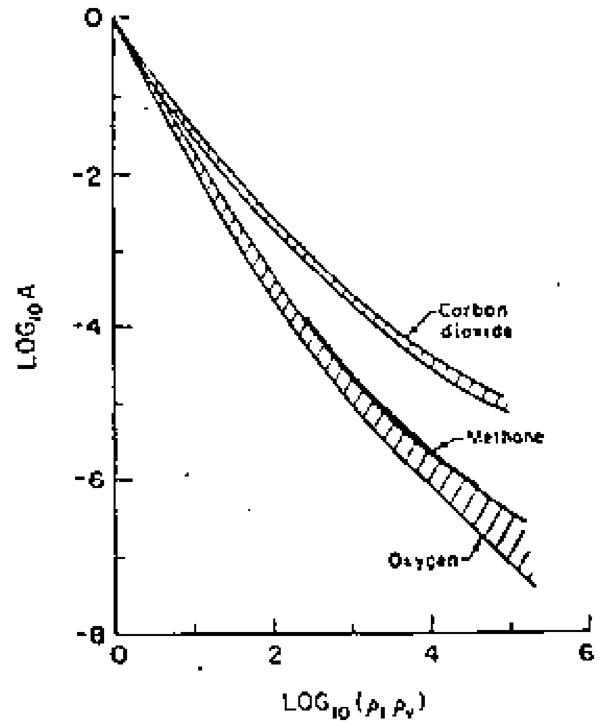
The weight-loss samples, otherwise uncorroded, had tiny, black, dendritic growths in isolated areas of the sample surface. Examination showed these to be also at the sites of inclusions which were partially dissolved from the surrounding metal matrix. The total attack of the Hastelloy C-276 weight-loss and stress-corrosion samples was confined to the boundary of these inclusions. Discussions with the manufacturer have resulted in the tentative conclusion that the inclusions were Al_2O_3 formed during aluminum deoxidation of the molten metal.

Gas Solubility: The solubility of oxygen has been measured in simple sodium chloride brines (up to 5.4 M), in a synthetic geothermal brine typical of the concentrated brines of the Niland, California, area, and in geothermal brine obtained from Mesa 6-1 at the Bureau of Reclamation well-site on the East Mesa near Holtville, California (2). The solubility of CO_2 has been measured in simple sodium chloride brines (up to 2 M) and in a synthetic Niland, high salinity brine.

The solubilities were obtained from the solution freezing point up to 310°C. Literature data on the solubility of methane in water has been corrected. All solubility data have been correlated, (Figure 6.11) in terms of the distribution function, A, and the density ratio (ρ_l/ρ_v), where $A = N_l/N_v$, the ratio of the mol fraction, N, of the dissolved gas in the liquid (l) and vapor (v) phases, and (ρ_l/ρ_v) is the ratio of the densities of the two phases. Extrapolation of the data to higher temperature is readily accomplished since $A = 1$ and $(\rho_l/\rho_v) = 1$ at the critical temperature of the solution and, at high temperatures, the curves are nearly linear.

The cross-hatched area represents the range of values observed for the various solutions ranging from pure water (the upper boundary) to the most concentrated brines (the lower boundary). It can be seen that methane and oxygen in pure water have similar solubilities. The addition of salt to the water leads to a reduction in gas solubility and is commonly known as salting-out.

FIGURE 6.11: DISTRIBUTION FUNCTION FOR PURE GASES IN WATER AND BRINES



Source: PB 261 349

In the case of oxygen, the salting-out effect on the distribution function is small at high temperatures but becomes appreciably larger at low temperatures where the density ratio (ρ_l/ρ_v) is large. Gases that hydrolyze, interacting strongly with water (such as carbon dioxide), have substantially higher solubilities than either methane or oxygen. Fitting the solubility data to

$$\log A = \sum_{i=1}^{4} B_i [\log(\rho_l/\rho_v)]^i$$

gave the coefficients in Table 6.8 for oxygen, carbon dioxide, and methane. Since A = 1 at $(\rho_l/\rho_v) = 1$, B_0 was set at 0.

The coefficients vary smoothly with the salt content of the solutions, thus permitting easy interpolation for brines of other composition. The relative error is defined here as the standard deviation of the quotient of the difference between the experimental and the fitted values.

TABLE 6.8: SOLUBILITY COEFFICIENTS

Solution	Coefficients B_1	B_2	$B_3 \times 10$	$B_4 \times 10^3$	Relative Error %
A. Oxygen					
Water	-1.503	-0.241	1.028	-9.18	6.2
0.9 M NaCl	-1.733	-0.082	0.643	-6.22	5.1
3. M NaCl	-2.020	0.106	0.175	-2.56	4.6
5.4 M NaCl	-2.186	0.198	-0.045	-0.90	8.0
Niland brine	-2.207	0.259	-0.258	1.27	8.6
Holtville brine	-1.808	0.025	0.279	-0.26	5.5
B. Carbon Dioxide					
Water	-1.243	-0.090	0.455	-3.86	5.3
0.5 M NaCl	-1.449	0.115	-0.150	2.68	2.7
1.0 M NaCl	-1.580	0.185	-0.282	2.85	4.8
2.0 M NaCl	-1.773	0.343	-0.759	7.48	9.0
Niland brine	-1.611	0.098	0.077	-1.27	5.5
C. Methane					
Water	-1.575	-0.180	0.889	-8.31	0.7

Source: PB 261 349

The solubility data can be transformed into the more familiar K vs (1/T) coordinates, where K is the Henry's law constant and (1/T) is the reciprocal temperature. This is done using the steam tables, the density data for the brine, and by assuming the vapor and liquid phases behave ideally. In this case,

$$K = \frac{P}{N} = P_{H_2O}/zA$$

where P is the partial pressure of the dissolved gas in the vapor phase; N is the mol fraction of the dissolved gas in the liquid phase; P_{H_2O} is the vapor pressure of water in equilibrium with the solution; and z is the compressibility factor for the water vapor.

The results for oxygen, expressed in this way are given in Figure 6.12. The curves correspond to the following solution: (1) water, (2) low-salinity (15,000 ppm TDS) brine, (3) 0.9 M NaCl, (4) 31 M NaCl, (5) high-salinity (25,000 TDS) brine, and (6) 5.4 M NaCl. T_f represents the freezing point of water; T_c, the critical temperature. The results for carbon dioxide are given in Figure 6.13. The curves correspond to: (1) water, (2) 0.5 m NaCl, (3) 1.0 m NaCl, (4) 2.0 m NaCl, and (5) high-salinity brine.

The temperature dependence of the salting-out coefficient is shown in Figure 6.14 for oxygen and carbon dioxide. The behavior of these gases differs in two distinct ways. At high temperatures, carbon dioxide solubility is affected much more strongly by the presence of dissolved salts than oxygen. At low temperatures (around 35°C) the salting-out of carbon dioxide goes through a maxima; this is due perhaps to hydrate formation. At intermediate temperatures the gases behave similarly, exhibiting minima in salting-out in the same range of temperatures as the Henry's law constants exhibit maxima.

FIGURE 6.12: HENRY'S LAW CONSTANT FOR OXYGEN

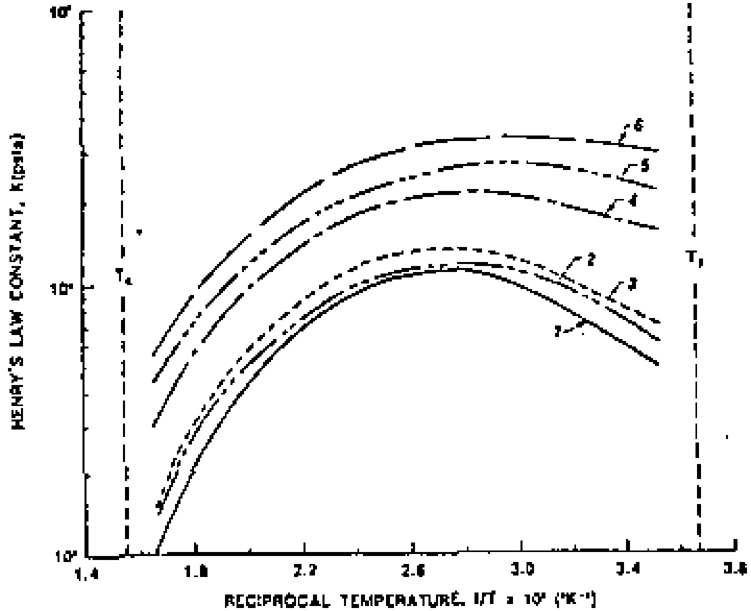
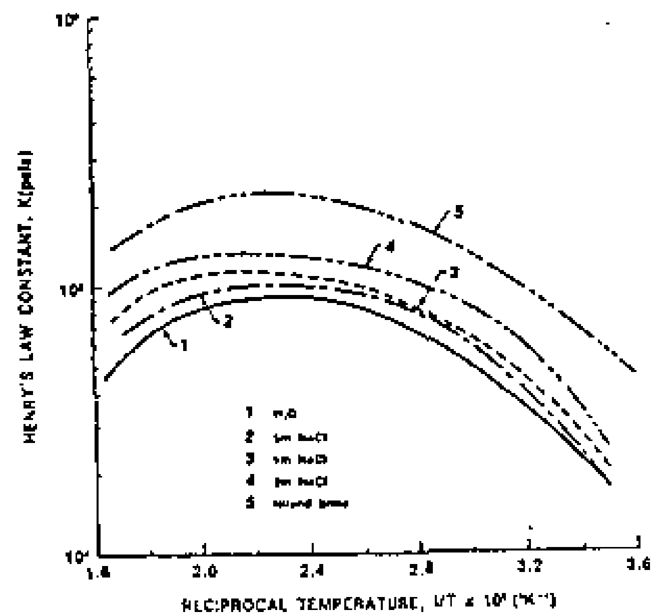
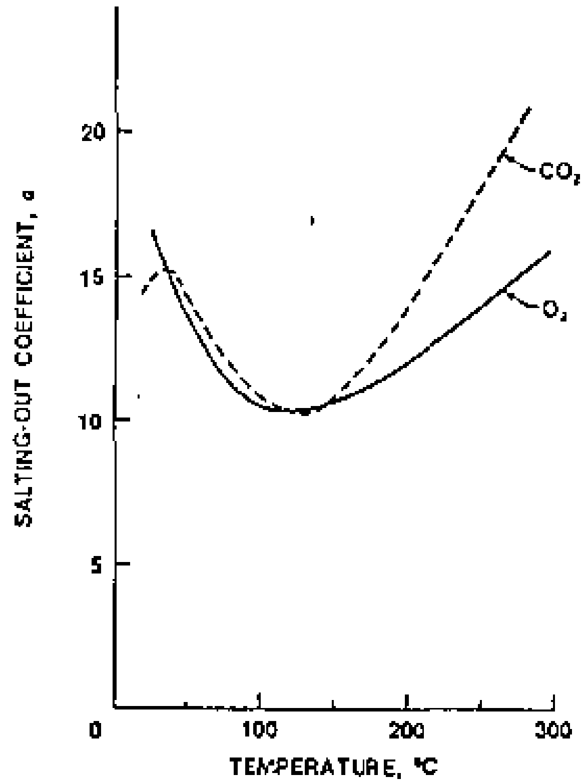


FIGURE 6.13: HENRY'S LAW CONSTANT FOR CARBON DIOXIDE



Source: PB 261 349

FIGURE 6.14: SALTING-OUT COEFFICIENT (MOL FRACTION BASIS) FOR OXYGEN AND CARBON DIOXIDE IN BRINES



Source: PB 261 349

Field Study–Salton Sea Geothermal Field

A 500-hour testing series was conducted during the Spring of 1974 at the geothermal test site of the San Diego Gas and Electric Company. This series consisted of two experimental packages. One package containing carbon steel, 4130 steel, Inconel 625, and Hastelloy C-276 was installed into a 50 psi, 150°C concentrated brine line. The second package containing the same alloys was installed into the 50 psi, 150°C separated steam line. In the brine test, the samples were exposed tangential to, and normal to the direction of flow.

On completion of the test, the materials were returned to CPMRC for evaluation. In addition to calculating the corrosion rates of the test materials, the scale which formed on each material was submitted for chemical analysis, characterization by proton excited x-rays (PEX), and examination by scanning electron microscopy. The corrosion rates measured for these tests are shown in Table 6.9 on the following page.

TABLE 6.9: CORROSION RATES (Mils/Year)

	Brine	Steam
Carbon Steel	113	92
4130 Steel	27	109
Inconel 625	0.1	0.1
Hastelloy C-276	0.6	0.0

Source: PB 261 349

Hastelloy C-276 and Inconel 625 showed little visual evidence of corrosion; their surfaces still exhibited the original machine markings. On the other hand, the surfaces of the carbon steel and 4130 steel were dull gray and had a matted finish. In addition, the carbon steel samples exhibited some shallow pitting. Bulk chemical analyses of the scales are shown in Table 6.10 and indicate that silicon, iron and lead are the principal metal constituents.

TABLE 6.10: CHEMICAL ANALYSES OF THE SCALE FORMED ON SAMPLES EXPOSED TO THE CONCENTRATED BRINE

Element	Weight Percent	Element	Weight Percent
Ag	0.05-0.53	Mn	0.57-6.51
Al	0.30-1.20	Pb	4.42-7.21
Cu	0.57-6.51	Si	15.10-24.40
Fe	7.78-19.70	Zn	0.14-1.88

Source: PB 261 349

Proton-excited x-ray analyses of the outermost 2000 A of the scales yielded somewhat different results. PEX results indicated that the carbon steel and 4130 steel samples had high iron concentrations in the surface region of the scale, whereas the Inconel 625 and Hastelloy C-276 alloys showed no detectable iron or other alloying elements in the surface region of the scale, containing, instead, only the solids soluble in the brine. This suggests that, for steels, the corrosion products continually build up with the scale. The oft-quoted opinion that a little bit of scale will inhibit the corrosion process does not appear to be true.

Scanning electron microscope studies showed that the scale on all of the alloys was highly porous and would therefore not present a barrier to diffusion of the brine to the metal surface. In fact, SEM studies of the carbon steel surface after removal of the scale showed a rough, severely corroded surface; studies of the Hastelloy C-276 surface showed a smooth, virtually corrosion-free surface. This result correlates nicely with the PEX results and substantiates the conclusions about the nonprotective nature of geothermal brine scales on steels.

Field Study—East Mesa Geothermal Field

More sophisticated test equipment was developed since the original field tests at the SDG&E site. This equipment consists of a Materials Test Facility (MTF) to study materials in five typical process environments of a geothermal resource recovery plant, and a Mobile Chemistry Laboratory (MCL) for continuous onsite

analysis of the brine chemistry. Both systems are located at the Bure[au of] Reclamation's East Mesa Geothermal Test Facility in the Imperial Valley of California.

Corrosion Tests: The first 60-day series of corrosion and scaling studies at Mesa 6-1 on the East Mesa Field began on July 22, 1975. This 60-day series was to provide four 15-day, two 30-day, and one 60-day set of samples. The system functioned smoothly until the first set of one hundred, 15-day samples was removed and another set installed. On the 21st day of the series, however, the system had to be shut down due to failure of the well (Mesa 6-1). The MTF was placed into a standby mode designed for this type of interruption.

The first set of samples was returned to the College Park Metallurgy Research Center where they were photographed, and the electrical resistances of the scale were measured. Resistances ranged from 10^4 Ω (well-brine scales) to 10^7 Ω (steam scales). All samples (with the exception of the aluminum) were then cleaned with a solution of concentrated HCl and Sb_2O_3. The aluminum 5005 samples had to be cleaned with concentrated HNO_3 and 3% HF at 50°C. The HCl solution had negligible attack on the base metals, while the HNO_3-HF solution attacked the aluminum base metal at a rate of 0.016 g/min.

Some of the scales had to be mechanically removed after chemical treatment, especially to remove the scale from deep pits. The samples from the well-brine and flasher #1 (F1) brine loops effervesced upon HCl immersion, indicating carbonate scale, a fact subsequently confirmed by x-ray diffraction. The samples from the flasher #2 (F2)-brine and F1 steam loops were covered with very thin, black, silicate scale that was difficult to remove.

The cleaned samples were weighed, and Table 6.11 shows the corrosion rates obtained for the 10 alloys tested. During the 15-day test period the average chloride content for F1 was 5,000 ppm and for F2 was 50 ppm.

TABLE 6.11: FIFTEEN-DAY MTF TEST AT BOR GEOTHERMAL WELL MESA 6-1

Metal	Corrosion rate (mils per year)				
	Well-brine	Flasher #1		Flasher #2	
		Brine	Steam	Brine	Steam
Carbon steel	3.2	2.4	2.1	3.3	3.1
4130 steel	1.9	1.6	1.3	1.2	2.5
430 stainless steel	.1	.5	.0	.2	.0
316 L stainless steel	.0	.0	.0	.1	.1
E-Brite 26-1	.0	.0	.0	.1	.1
5005 Aluminum	57	21	29	*	.0
Titanium-0.67 Ni	.0	.0	.0	.0	.0
Inconel 625	.0	.0	.0	.0	.0
Hastelloy S	.0	.0	.0	.0	.1
Hastelloy C-276	.0	.0	.0	.0	.0

*Specimens covered with adherent black scale that could not be removed. Scale analyzed as Fe, Si, Cu, Mn, and Ag with Fe and Si as major constituents.

Source: PB 261 349

Microscopic examinations for pitting and crevice corrosion showed that aluminum 5005, carbon steel, and 4130 steel exhibited crevice corrosion under the insulating washers used in mounting the samples. Type 316 stainless steel and Hastelloy S exhibited some localized breakdown in passivity, which was characterized by very small areas of corrosion. Hastelloy C-276 and E-Brite 26-1 showed very little evidence of corrosion.

In general, the corrosion rates shown in Table 6.11 are similar to those reported in the 15-day laboratory studies in 3% synthetic brines. The corrosion rates observed for carbon steel, however, were only one-eighth of those obtained in the laboratory studies and may have been due to some protection offered by the scale formed on the metal surface. It is not yet clear why the scale from the lower-salinity well at the East Mesa Site is more protective than the scale formed in the higher-salinity well at the Niland SDG&E site.

Brine Chemistry: On-site chemical analyses of the brine from Mesa 6-1 have clearly demonstrated the dependence of the brine chemistry on the operating conditions of the well; flow-rate, total operating time, and well-engineering changes.

Mesa 6-1 underwent extensive down-hole reperforation in May 1975. Studies showed a substantial change in the brine chemistry of Mesa 6-1 after reperforation. Large fluctuations in the chloride and carbonate concentrations were measured, while the pH was essentially unchanged (Table 6.12). Chemical equilibrium in the well was reestablished early in July 1975 and remained relatively constant.

TABLE 6.12: AVERAGE MONTHLY VALUES FOR MESA 6-1

Date	Cl^- (ppm)	HCO_3^- (ppm)	pH
April 1975	15,020	254	5.7
August 1975	11,908	367	5.6

Source: PB 261 349

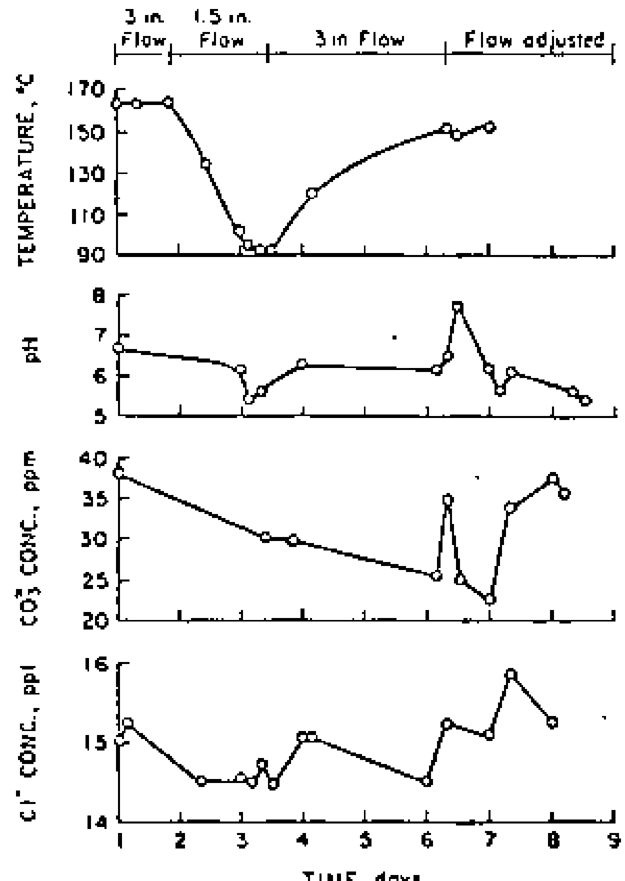
Values obtained during June reflected the large chemical instabilities subsequent to reperforation. The value for August reflects the equilibration of the well chemistry after 12 weeks of operation. Only continual, onsite determinations can accurately reflect the chemical dynamics of a geothermal well. Analyses by atomic absorption are shown in Table 6.13 for Mesa 6-1 brine before and after reperforation. Background corrections have been made for Ba, Ca, Cu, and Pb to determine any error in the adsorption readings due to brine-matrix interferences. All background readings were 1% or less, indicating that no major interferences due to the brine composition were present.

The data in Tables 6.12 and 6.13, particularly for the July-August period, represent only a preliminary analysis. Continuous onsite analysis has also shown that there is variation in the chemistry of a given well for differing flow conditions. This is illustrated by Figure 6.15, which shows the variation in temperature, pH, $CO_3^=$, Cl^- in Mesa 6-1 (July 1975) over a 7-day period during which the well flowrate was adjusted each day.

TABLE 6.13: CONCENTRATION RANGES OF 11 ELEMENT[illegible] GEOTHERMAL WELL-BRINES FROM MESA 6-1 (ppm)

Element	April 1975	August 1975
Na	8,500 to 10,000	5,950 to 6,310
Ca	690 to 780	565 to 913
K	540 to 670	598 to 648
Si	103 to 139	107 to 160
Ba	35 to 40	12 to 17
Fe	-	3.0 to 13
Cu	-	8.1 to 8.5
Al	< 50	1.2 to 3.8
Mn	4 to 10	.6 to .9
Ag	< 1	-
Pb	< 1	.5 to 1.0

FIGURE 6.15: VARIATIONS IN BRINE CHEMISTRY CAUSED BY CHANGING OPERATING CONDITIONS OF MESA 6-1



Source: PB 261 349

Comparison of Mesa 6-1 and Mesa 6-2: In April 1975, prior to reperforation of Mesa 6-1, comparative analyses were made between Mesa 6-1 and 6-2. These wells are approximately a quarter of a mile apart. Differences are illustrated by Tables 6.14 and 6.15.

TABLE 6.14: TYPICAL CONCENTRATION RANGES OF NINE ELEMENTS IN GEOTHERMAL BRINES FROM MESA 6-1 AND 6-2 WELLS

Well	Na	K	Ca (ppm)	Ba	Ag	Pb	Mn	Al	Si
6-1	8,500-10,000	540-670	690-780	40-35	<1	<1	4-10	50	103-139
6-2	<5,000	45- 60	<200	<10	<1	<1	4-<1	<50	101-119

Source: PB 261 349

TABLE 6.15: pH, CHLORIDE, AND CARBONATE CONCENTRATIONS MESA 6-1 AND 6-2 BRINES

Well	Cl- (ppm)	$CO_3^=$	pH
6-1	15020 ± 690	31.3 ± 6.0	5.7 ± 0.8
6-2	710 ± 50	254 ± 9	7.2 ± .9

Source: PB 261 349

References

(1) Carter, J.P., and Cramer, S.D., "Corrosion Resistance of Some Commercially Available Metals and Alloys to Geothermal Brines," *Corrosion Problems in Energy Conversion and Generation, ECS*, pp. 240-250, Oct. 1974.

(2) Cramer, S.D., "The Solubility of Oxygen in Geothermal Brines," *Corrosion Problems in Energy Conversion and Generation, ECS*, pp. 251-262, Oct. 1974.

TESTS AT NILAND AND HEBER

The material for this section has been based upon a paper by H.K. Bishop of San Diego Gas and Electric Company, prepared for The Second Workshop on Materials Problems (PB 261 349).

Niland

At Niland, flow testing of one production well was conducted in April, 1972, for about ten days to obtain preliminary data about this reservoir and well. The brine temperature and pressure at the production was found to average 375°F and 150 psig. Observed well-flow was 400,000 lb/hr mass flow of which approximately 324,000 lb/hr was liquid, 64,000 lb/hr was steam and 12,000 lb/hr was noncondensible gases. Total dissolved solids in the fluid averaged 225,000 ppm. The bottom hole temperature was 510°F at a depth of 2,250 ft.

Results of the tests were encouraging enough to warrant further tests and to proceed with a preliminary process design that would allow fuller evaluation of reservoir characteristics and equipment.

A binary cycle was selected using a combination of steam and liquid heat exchangers which would transfer heat energy to a working fluid such as isobutane. A direct steam turbine cycle was investigated, but was rejected because of the high volume of noncondensible gases.

Preliminary process design for a nominal 10 MW geothermal test facility was prepared. But before constructing the test facility, additional field tests were performed which would simulate phase separation and the heat transfer conditions in the full scale test facility. The separator and heat exchangers used in these field tests were small scale versions of the test facility equipment. Distilled water was supplied to the shell side of the heat exchanger and geothermal brine to the tube side. One inch titanium tubes were used. The purpose of this test was to determine if heat could be extracted from the brine in a shell and tube heat exchangers for a reasonable period of time without fouling.

Scale build-up, averaging 0.060 inch thick, was observed after 100 hours exposure to geothermal brine. The major constituents of these scales were silica (SiO_2 38%), iron sulfide (FeS_2 23%) and lead sulfide (PbS 11%).

During these heat exchanger tests, other research was conducted to determine (a) how to stop or retard the deposition of scale by varying operating conditions; and (b) procedures, frequency and costs of removing scale deposits from heat exchanger tubes. Commercial chemical inhibitors, coagulants, and chelating agents were injected into the brine before it flowed through the heat exchanger. No improvement in performance was observed.

A titanium tube, coated with a proprietary fluorocarbon coating, was also tested in a heat exchanger utilizing brine. The coating provided no protection against scale deposition. Post-test inspection of the tube's internal surface revealed the coating had completely disappeared.

Additional test work was conducted at the Niland field in 1974 to develop and evaluate methods of separating steam from the geothermal brine. In these tests, the brine and steam were passed through redesigned separators, scrubbers, and heat exchangers to determine if scrubbing the steam would eliminate the severe scaling problems which were experienced earlier.

Fluid from the producing well entered the first stage drum-type separator at 150 psig and 375°F. Approximately 5,000 lb/hr of steam flowed out of the top of the first stage separator to a labyrinth scrubber where it was cleaned and then directed to a heat exchanger.

Brine flowed from the bottom of the first stage separator to the second stage (drum-type) separator operating at 50 psig. Steam flowing at 2,300 lb/hr out of the top of this separator entered the second stage (labyrinth-type) scrubber where it was cleaned and then flowed through a heat exchanger. Steam purity achieved in the separator was 100 to 200 ppm. From the scrubbers 10 to 20 ppm steam could be obtained.

Process piping used for these field tests was mild steel. Both general corrosion and some shallow pitting was observed. No severe corrosion was observed during the two years of intermittent field tests. Failures (perforations) of the reinjection line were attributed to outside attack where the line came in direct contact with the soil or to a defective weld.

Heber

In the Heber field, SDG&E has conducted heat exchanger tests to determine the characteristics of this brine, especially scale deposition during the heat exchange process.

The test unit consisted of four heat exchangers in series to extract the geothermal fluid heat energy. Since the well fluid is pumped to the surface, there is no need for a flash drum. This all-liquid mode simplified the operation and control of the test unit. Tests indicate the heat exchangers may operate as long as 6,000 hours before performance drops to unacceptable levels. Both steel and titanium tubes were evaluated with the titanium tubes exhibiting less deposition. A majority of the deposition on the steel tubes was corrosion products.

CORROSION PROBLEMS AT CERRO PRIETO

The material for this section has been based upon a paper by Alfredo Manon M. of Comision Federal De Electricidad, Mexico prepared for The Second Workshop on Materials Problems (PB 261 349).

From 1969 to 1970 a corrosion test program was carried out jointly by the Comision Federal de Electricidad of Mexico and the Tokyo Shibaura Company of Japan. The main purpose of these tests was to confirm the corrosion resistance of previously selected materials used for the construction of the power plant which was ordered in 1968.

Corrosion Test Results

Corrosion in Steam: The corrosion rate of carbon steel in nonaerated steam was 0.04 mm/yr (0.0016 in/yr) which is very satisfactory for the turbine casing and piping (Table 6.16). The effect of aeration was an increase to 0.065 mm/yr (0.0026 in/yr) (Table 6.17). Slight pitting was detected on 12 Cr steel and on 12 Cr-Mo-W steel used for turbine buckets where they were exposed in nonaerated steam (0.024 mm/yr), but the corrosion rate was less than 0.01 mm/yr (0.0004 in/yr).

The effect of aeration was an increase of ten times in the corrosion rate and more than seventy times in the pitting rate. These materials were not sensitive to stress corrosion in nonaerated steam (Table 6.18), but in aerated steam 12 Cr-Mo-W steel showed failure and 12 Cr steel showed microscopic cracks (Table 6.19). Both steels showed no change in tensile strength and showed 4 to 6% decrease in yield strength after exposure to nonaerated steam (Table 6.20). The effect of aeration on tensile and yield strength was remarkable on 12 Cr-Mo-W steel (Table 6.21).

TABLE 6.16: CORROSION IN NONAERATED STEAM

Material	Corrosion rate mm/yr	Pitting rate mm/yr	Corrosion rate change (days) 30	60	90	120	150
12 Cr	0.0100	0.024	0.0041	0.0085	0.0059	0.0127	0.0162
12 Cr-Mo-W	0.0040	0.024	0.0080	0.0041	0.0048	0.0039	0.0042
1 Cr-Mo-0.25 V	0.0400	-	0.023	0.022	0.029	0.059	0.040
3.5 Ni-1.75 Cr-Mo-V	0.0160	0.120	0.017	0.014	0.011	0.012	0.016
12 Cr-0.2 Al	0.0190	-	0.0003	0.0051	0.0280	0.015	0.019
15 Cr-1.7 Mo	0.0046	0.150	-	0.0023	0.0049	0.0041	0.0046
1 Al-1.5 Cr-0.25 Mo	-	0.970	-	-	-	-	-
Aluminum	-	-	-	-	-	-	-
ASTM A285	0.0400	-	0.110	0.051	0.046	0.040	-

Source: PB 261 349

TABLE 6.17: CORROSION IN AERATED STEAM

Material	Corrosion rate mm/yr	Pitting rate mm/yr	Corrosion rate change (days) 30	60	90	120	150
12 Cr	0.100	1.70	0.10	0.14	0.10	0.10	0.10
12 Cr-Mo-W	0.069	1.60	0.12	0.36	0.04	0.07	0.07
1 Cr-Mo-0.25 V	0.210	-	0.50	0.28	0.20	0.14	0.21
3.5 Ni-1.75 Cr-Mo-V	0.340	0.70	0.29	0.52	0.16	0.16	0.34
12 Cr-0.2 Al	0.110	-	0.06	0.15	0.09	0.10	0.11
15 Cr-1.7 Mo	0.014	1.20	0.00	0.02	0.01	0.01	0.01
1 Al-1.5 Cr-0.25 Mo	-	0.55	-	-	-	-	-
Aluminum	0.083	2.90	-	0.03	0.04	0.10	0.08
ASTM A285	0.065	-	0.18	0.12	-	0.10	0.06
Deoxidized copper	0.510	-	1.03	0.91	0.66	0.52	0.51
Stellite #6	0.057	2.70	0.18	0.12	-	0.10	0.06

Source: PB 261 349

TABLE 6.18: STRESS CORROSION IN NONAERATED STEAM

Material	No. of failed specimens	Observations
12 Cr	0 of 3	
12 Cr-Mo-W	0 of 3	
1 Cr-Mo-0.25 V	2 of 2	Microscopic cracks were observed.
3.5 Ni-Cr-Mo-V	-	
12 Cr-0.2 Al	0 of 3	
15 Cr-1.7 Mo	0 of 3	
Aluminum	0 of 3	
Deoxidized copper	0 of 3	

Source: PB 261 349

TABLE 6.19: STRESS CORROSION IN AERATED STEAM

Material	No. of failed specimens	Observations
12 Cr	0 of 3	Microscopic crack
12 Cr-Mo-V	2 of 2	100% failure
1 Cr-Mo-0.25 V	1 of 2	50% failure
3.5 Ni-Cr-Mo-V	0 of 3	Intergranular corrosion
12 Cr-0.2 Al	0 of 3	Intergranular corrosion
15 Cr-1.7 Mo	0 of 3	
Deoxidized copper	2 of 2	Failure due to general corrosion

Source: PB 261 349

TABLE 6.20: TENSILE STRENGTH, YIELD STRENGTH AND 2" % ELONGATION IN NONAERATED STEAM

Material	†T.S.B.E. Kg/mm²	T.S.A.E. Kg/mm²	Y.S.B.E. Kg/mm²	Y.S.A.E. Kg/mm²	E.B.E. %	E.A.E. %
12 Cr	74.4	73.3	61.9	59.4	19.6	20.1
12 Cr-Mo-V	101.1	101.2	84.4	79.5	15.6	16.3
1 Cr-1 Mo-0.25 V	84.3	83.5	68.4	67.5	17.3	16.3
3.5 Ni-Cr-Mo-V	89.5	88.8	76.9	78.6	17.3	17.3
12 Cr-0.2 Al	61.3	60.4	37.7	38.5	25.1	27.6
15 Cr-1.7 Mo	49.1	47.8	31.2	29.2	31.1	32.1
Aluminum	-	30.8	-	-	-	10.8
Deoxidized copper	27.2	23.8	24.5	21.9	23.1	8.5

†T.S.B.E. = Tensile strength before exposure
T.S.A.E. = Tensile strength after exposure
Y.S.B.E. = Yield strength before exposure
Y.S.A.E. = Yield strength after exposure
E.B.E. = Elongation before exposure
E.A.E. = Elongation after exposure

Source: PB 261 349

TABLE 6.21: TENSILE STRENGTH, YIELD STRENGTH AND 2" % ELONGATION IN AERATED STEAM

Material	†T.S.B.E. Kg/mm²	T.S.A.E. Kg/mm²	Y.S.B.E. Kg/mm²	Y.S.A.E. Kg/mm²	E.B.E. %	E.A.E. %
12 Cr	74.4	74.6	61.9	54.6	19.6	12.8
12 Cr-Mo-V	101.1	93.7	84.4	68.9	15.6	4.8
1 Cr-1 Mo-0.25 V	84.3	82.1	68.4	63.7	17.3	13.2
3.5 Ni-Cr-Mo-V	89.5	83.1	76.9	69.7	17.3	10.9
12 Cr-0.2 Al	61.3	56.2	37.7	38.2	25.1	20.2
15 Cr-1.7 Mo	49.1	47.7	31.2	28.7	31.1	25.4
Aluminum	-	-	-	-	-	-
Deoxidized copper	27.2	-	24.5	-	23.1	-

†T.S.B.E. = Tensile strength before exposure
T.S.A.E. = Tensile strength after exposure
Y.S.B.E. = Yield strength before exposure
Y.S.A.E. = Yield strength after exposure
E.B.E. = Elongation before exposure (%, 2")
E.A.E. = Elongation after exposure (%, 2")

Source: PB 261 349

Decrease in endurance limit of both materials after exposure to n... ...ated steam was observed (15 to 19%) (Table 6.22). The erosion-corrosion resistance in high velocity steam was acceptable in both materials (Table 6.23).

TABLE 6.22: FATIGUE AFTER EXPOSURE IN NONAERATED STEAM

Material	Endurance limit Kg/mm² Before Exposure	Endurance limit Kg/mm² After Exposure	Decrease of Endurance Limit %
12 Cr	40.5	33.0	18.5
12 Cr-Mo-W	48.0	41.0	14.6
1 Cr-1 Mo-0.25 V	36.5	26.5	27.4
3.5 Ni-Cr-Mo-V	44.0	27.0	38.6
12 Cr-0.2 Al	26.5	21.5	18.8
15 Cr-1.7 Mo	25.5	22.5	11.7

Source: PB 261 349

TABLE 6.23: EROSION IN HIGH VELOCITY STEAM

Material	Weight Loss After Exposure (Grs.) 30 days	60 days	90 days	120 days	150 days
12 Cr	0.0227	0.0272	0.0940	0.1361	0.0717
12 Cr-Mo-V	0.0008	0.0019	0.0335	0.0546	0.0259
1 Cr-Mo-0.25 V	0.0415	0.0569	0.2770	0.4072	0.2789
3.5 Ni-Cr-Mo-V	0.0322	0.0320	0.1761	0.1974	0.1466
12 Cr-0.2 Al	0.0072	0.0143	0.0666	0.0494	0.0372
15 Cr-1.7 Mo	0.0065	0.0039	0.0358	0.0572	0.0331
Stellite #6	0.0014	0.0077	0.0433	0.0665	0.0486
1.0 Al-1.5 Cr-0.25 Mo	0.1421	+0.1335	+0.1362	+0.1144	+0.1076
ASTM A285	0.0997	0.0650	0.3090	0.3354	0.3784
Naval Brass	0.0266	0.0454	0.2138	1.3366	0.4467
Low carbon steel	0.0863	0.0594	0.7721	0.1770	0.2268
AISI Type 304	0.0006	0.0001	0.0067	0.0150	0.0101

Source: PB 261 349

The average corrosion rate in nonaerated steam of 12 Cr-0.2 Al steel used for nozzle partitions on the turbine was 0.019 mm/yr (0.0008 in/yr) and the corrosion rate of 15 Cr-1.7 Mo steel was only 0.005 mm/yr (0.0002 in/yr) (Table 6.16). The effect of aeration was lower on 15 Cr-1.7 Mo than on the 12 Cr and 12 Cr-Mo-W steels (Table 6.17). Neither material was sensitive to stress corrosion in nonaerated and aerated steam (Tables 6.18 and 6.19), but the 12 Cr-0.2 Al steel showed intergranular corrosion in aerated steam. The tensile and yield strength decreases after exposure in nonaerated steam were similar to 12 Cr and 12 Cr-Mo-W steel (Table 6.20). The effect of aeration on tensile and yield strength was less remarkable than that on 12 Cr and 12 Cr-Mo-W (Table 6.21). Decrease in endurance limit on these materials was similar to 12 Cr and 12 Cr-Mo-W steel (Table 6.22). The erosion-corrosion resistance was better than 12 Cr steel and similar to 12 Cr-Mo-W steel (Table 6.23).

The corrosion rate of 1 Cr-1 Mo-0.25 V steel was similar to the corrosion rate of carbon steel in nonaerated steam (Table 6.16). The corrosion rate of 3.5 Ni-Cr-

Mo-V steel was less than that of 1 Cr-Mo-0.25 V steel, but intergranular corrosion was observed on the first when it was exposed under stress. The endurance limit decrease was greater with low alloy than with 12 Cr steels especially on 3.5 Ni-Cr-Mo-V, where a 39% decrease was observed. The aeration effect increased the corrosion rate twenty times on 3.5 Ni-Cr-Mo-V and only five times on Cr-Mo-V steel.

The nitrited steel (1 Al-1.5 Cr-0.25 Mo) showed a partial spalling, but showed good corrosion resistance in aerated steam. Aluminum was not corroded in nonaerated steam, but in aerated steam it showed a higher pitting rate (2.9 mm/yr) (0.114 in/yr). Stellite showed severe cavities when exposed in aerated steam, but this result is unreliable, possibly due to foreign matter in aerated steam.

Corrosion in Condensate: The corrosion rate in high velocity condensate was too high for materials commonly used in heat exchangers, such as deoxidized copper (0.64 mm/yr; 0.025 in/yr), naval brass (0.22 mm/yr; 0.009 in/yr) and carbon steel (0.70 mm/yr; 0.028 in/yr) (Table 6.24). A high penetration rate was observed on aluminum (3.65 mm/yr; 0.14 in/yr) and 12 Cr steel (0.85 mm/yr; 0.03 in/yr) in high velocity condensate.

18 Cr-8 (AISI Type 304) steel showed the best corrosion resistance in condensate; general corrosion, pitting and stress corrosion cracking were not detected. Epoxy coatings cured at high temperature showed no deterioration in low velocity condensate after 150 days exposure. Low velocity condensate results are given in Tables 6.25, 6.26 and 6.27.

TABLE 6.24: CORROSION IN HIGH VELOCITY CONDENSATE

Material	Corrosion rate mm/yr	Pitting rate mm/yr	Corrosion rate change (days) 30	60	90	120	150
Deoxidized Copper	0.640	*	0.19	0.83	0.73	0.64	-
Aluminum	0.370	3.65	0.06	0.12	0.29	0.35	0.37
Naval Brass	0.220	*	0.04	0.20	0.22	0.21	0.22
AISI Type 304 (18-8)	0.0003	no corrosion	0.00	0.00	0.00	0.00	0.00
AISI Type 410 (12 Cr)	0.080	0.85	0.00	0.02	0.09	0.20	0.08
Low carbon steel	0.700	*	-	1.14	0.90	0.88	0.70

*General Corrosion

TABLE 6.25: CORROSION IN LOW VELOCITY CONDENSATE

Material	Corrosion rate mm/yr	Pitting rate mm/yr	Corrosion rate change (days) 30	60	90	120	150
Deoxidized copper	0.240	no pitting	0.16	0.19	0.30	0.22	0.24
Aluminum	0.004	1.16	0.04	0.13	0.02	0.08	0.00
Naval Brass	0.072	no pitting	0.14	0.12	0.11	0.09	0.07
AISI Type 304 (18-8)	0.0008	no pitting	0.02	0.00	0.00	0.00	0.00
AISI Type 410 (12 Cr)	0.015	0.57	0.05	0.05	0.04	0.03	0.01
Low carbon steel	0.310	no pitting	0.62	0.42	0.34	0.33	0.31

Source: U.S. Patent PB 261 349

TABLE 6.26: STRESS CORROSION IN LOW VELOCITY CONDENSATE

Material	Specimens Tested	Specimens Failed
Deoxidized copper	4	0
Aluminum	2	0
Naval Brass	3	0
AISI Type 304 (18-8)	3	0
Low carbon steel	3	0

Source: PB 261 349

TABLE 6.27: TENSILE STRENGTH, YIELD STRENGTH AND 2" % ELONGATION AFTER EXPOSURE IN LOW VELOCITY CONDENSATE

Material	†T.S.A.E. Kg/mm²	Y.S.A.E. Kg/mm²	E.A.E. %
Deoxidized copper	23.8	23.6	21.0
Aluminum	31.7	-	7.3
Naval Brass	43.4	33.2	24.8
AISI Type 304 (18-8)	65.5	33.9	70.5
AISI Type 410 (12 Cr)	58.1	35.6	27.3
Low carbon steel	37.2	18.5	37.7

†T.S.A.E. = Tensile strength after exposure
Y.S.A.E. = Yield strength after exposure
E.A.E. = Elongation after exposure (2" %)

Source: PB 261 349

TABLE 6.28: TEST CONDITIONS (Average of 150 Days)

Nonaerated steam	
Pressure, kg/cm² (61 psig)	4.3
Temperature, °C (°F)	147 (296)
CO_2, % (weight)	1.95
H_2S, % (weight)	0.20
Cl^-, ppm	13.3
Moisture, % (weight)	0.7
Aerated steam	
Pressure, atmospheres (14.7 lb/in² abs)	1
Temperature, °C	70
CO_2, %	1.6
H_2S, %	0.16
Cl^-, ppm	7
Moisture, %	0.7
High velocity steam	
Pressure, kg/cm² (psig)	4 (56.8)
Temperature, °C (°F)	140 (284)
CO_2, %	1.95

(continued)

TABLE 6.28: (continued)

H_2S, %	0.20
Cl^-, ppm	13.3
Moisture, %	0.6
Velocity, m/sec (ft/sec)	130 (426)
Condensate, low velocity	
Pressure, atmospheres	1
Temperature, °C	40
Cl^-, ppm	50
pH	6.8-7.0
Velocity, m/sec	0.0005
Condensate, high velocity	
Pressure, atmospheres	1
Temperature, °C	45
Cl^-, ppm	60
pH	6.4-7.3
Velocity, m/sec	0.5

Source: PB 261 349

General Conclusions: The test results showed that it is not necessary to use special high grade corrosion resistant materials if corrosion rates are properly evaluated. Carbon steel can be used for casing and piping conducting nonaerated steam. Decrease in mechanical properties was more remarkable than corrosion rate with 12 Cr steel, and it is therefore important to consider in the design the allowable stress and separation from resonance for 12 Cr steel turbine buckets.

For nozzle partitions, 15 Cr-1.7 Mo steel is preferable to 12 Cr-0.2 Al steel. For turbine rotors of geothermal plants, 1 Cr-1 Mo-0.25 V steel is recommended. In low and high velocity condensate environments, it is preferable to use 18 Cr-8 Ni steel.

Corrosion on Well Casings

Although no corrosion failure of casings has been proved, there are some facts which can help to guide future research on this subject.

Pitting: Pitting and general corrosion inside the production casing has been insignificant due to the absence of oxygen in the geothermal fluids and to the probable protective effect of iron sulfide and silica scale. This has been observed on recovered casings and on surface water-steam transmission pipes.

External and internal corrosion of casings close to the surface has been observed. The most important corrosion was found on the surface casings in the area where the level of ground water (brine) fluctuates.

Galvanic Corrosion: Galvanic corrosion has been detected in several well casings close to the surface, where two or more casings were put in contact without (or with poor) insulation. On the other hand, resistivity logs made on the geothermal wells and on the surface for exploratory purposes showed a big difference in resistivity with depth. Such variations constitute the basis for galvanic corrosion cells in metallic structures. Additional corrosion cells may occur in casings as a

result of poor bonding of the cement to the casing. Interconnectio. areas of different potential creates galvanic corrosion cells.

Stress Corrosion: Foster, Marshall and Tombs (1961) demonstrated that casing steels H40 and K55 are sensitive to stress corrosion in a cold hydrogen sulfide environment. This condition exists in the wells that are in the repair stage. The casing of the M-5 well of Cerro Prieto, for example, cracked when cold water was injected (1965).

Erosion: Erosion has been frequently observed in surface installations where there was a sand-water-steam flow at high velocity. The combined effect of cavitation and sand content on the production casing joints is not well known, but it can be serious.

Corrosion in the Power Plant

Corrosion on Turbines: After two years of operation, the turbines have been inspected on two occasions, showing no corrosion or cracks on buckets. At the sixth stage of blades, the Stellite coating was found in very good condition, and only a little erosion was observed on the silver used to solder the Stellite to the 12 Cr steel. The main problem present was the silica deposition on the first stage of nozzles and buckets. This problem can be explained by the poor separation of water and steam in the well separators and in the secondary separators close to the turbines.

Corrosion in the Cooling Water System: The main corrosion problem (pitting and local corrosion) has been observed in the cooling water system. The most important problem was in the oil and hydrogen coolers, due to the possibility of contamination of the oil or hydrogen streams from holes in the heat exchanger tubes. Originally these tubes were made of aluminum, but due to the high pitting rate, they were changed to AISI-type 304 steel and again pitting was observed. Finally, they were replaced by titanium tubes, with good results. (Actually only two coolers have AISI-type 304 tubes.)

On the other hand a high penetration rate was observed on the unprotected inside surfaces of carbon steel valves and pipes. No significant corrosion rate was found in the barometric condensers, which were protected with epoxy coating, but some areas of the coating were damaged by erosion.

The barometric pipes that discharge a mixture of condensate steam and cooling water from the second stage intercondensers to the hot well have been replaced by fiberglass-epoxy pipes due to the high corrosion rate observed on the originally-installed carbon steel pipes.

Another problem observed was the deterioration of the upper part of the concrete canal that conducts the hot water from the hot well to the cooling tower's pumps.

One fact that is important to mention is that bacteria of the genus Thiobacillus, also called sulfur bacteria, were found in the cooling water. Some members of this group can carry out oxidation of H_xS to H_xSO_x. This explains the low pH originally found in the cooling water. This low pH was controlled with sodium hydroxide, and the bacteria were controlled with chemical bactericides.

The bacteria's presence also explains the difference between the AISI-type 304 pitting rate obtained in corrosion tests and the higher pitting rate found in the oil and hydrogen coolers.

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CORROSION STUDIES AT THE GEYSERS

The material for this section has been based upon a paper by F.J. Dodd and W.C. Ham of Pacific Gas and Electric Company prepared for The Second Workshop on Materials Problems (PB 261 349).

Description of the Facility

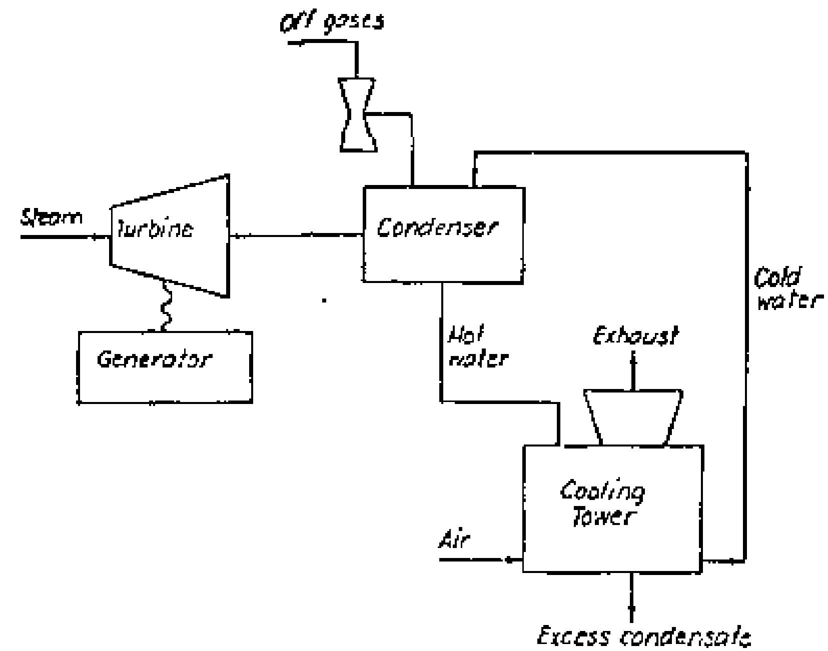
The largest geothermal power installation, and the only such facility in the U.S. is The Geysers Geothermal Steam Power Plant of the Pacific Gas and Electric Company, electric generating system. The plant is located approximately 80 miles north of San Francisco in the Mayacmas mountains of northeastern Sonoma and western Lake Counties. The first unit of the facility was placed in commercial operation in 1960. There are 10 commercially operating units at the plant with a total capacity of 396 MWe. Continued expansion is planned, and the plant capacity is expected to reach 908 MWe.

The Geysers steam is fed directly into the turbine in all the units. The turbine exhausts to a barometric condenser on Units 1 through 4 and a direct contact condenser on Units 5 through 10. From the condenser, the combined cooling water and condensed steam is then pumped into cooling towers. Water from the tower basins is returned to the condenser as cooling water because there is very little make-up water available for the circulating water system. A typical schematic for The Geysers units is shown in Figure 6.16.

Corrosion at The Geysers was considered prior to the construction of the first unit and has been the subject of continuing concern and experimentation ever since. Selection of materials for construction of the first units was based upon a corrosion testing program performed in a model plant using corrosometer and atmospheric exposure techniques. The model plant tests resulted in selection of austenitic stainless steels and aluminum for the condensate system and aluminum for line hardware.

PG&E's intensive R&D efforts to control emissions of hydrogen sulfide (H_2S) gas have resulted in a test program of chemically treating the condensate to remove this noncondensible gas. It was recognized that chemical additions could seriously affect the corrosivity of the condensate. Therefore, after a promising method was developed for H_2S abatement, and the study reached the pilot plant stage, a condensate corrosion study was conducted concurrently. This paper discusses this study.

FIGURE 6.16: TYPICAL GEYSERS POWER PLANT



Source: PB 261 349

The Condensate System

The circulating condensed Geysers geothermal steam is a milky light blue-gray color. The composition of the condensate fluctuates considerably and is known to be dependent upon atmospheric conditions and the particular group of wells from which it originated. The mineral concentrations in the recirculating condensate systems are from four to six times those found in condensed geothermal steam.

As discussed previously by Allen (1), a promising chemical treatment developed for removal of H_2S involves primarily an addition of iron to the condensate in the form of $Fe_2(SO_4)_3$. Although the concentration can vary from 2 to 50 ppm, an average concentration of 30 ppm Fe is maintained. While both the iron and sulfate concentrations in the treated system are increased, the pH remains approximately 7.5. Because the condensate chemistry is low in heavy metals, some increase in corrosion rates was expected.

Corrosion with Iron Addition

A corrosion testing program was initiated in Unit 1 while it was operating with the iron addition. The preliminary results of these tests as reported by Dodd (2) indicated an increase in corrosion rates. The corrosion tests exposed 2¼-inch diameter stationary nonstressed metal disc coupons of various alloys spaced ¼-inch apart on an insulated center pin.

Eight sets of coupons each containing 19 alloys were installed in the condenser of Unit 1 in November, 1972. Four sets of the coupons were installed in the hot well, and four sets of the coupons were installed near the top of the barometric condenser. These two locations generally represent the range of environments material will experience in condensers. The hot well coupons were submerged in a relatively low water velocity area. The coupons mounted near the top of the barometric condenser were above the water line and subjected to a washing-mist environment. Two sets of coupons were removed from the hot well in March 1974 and the results reported by Dodd (2). The remaining two sets of coupons in the hot well were removed in June, 1974.

In March, 1974, when the first coupons were removed from the hot well, the barometric condenser coupons were no longer in place. These coupons apparently dislodged during the exposure and dropped to the condenser floor where they were found and removed for analysis in June, 1974. These coupons were, therefore, subjected to both the submerged and the mist exposure conditions. Although the coupons were exposed to the two exposure conditions, the corrosion data are considered meaningful. These data are included in the report and identified with the original installation location near the top of the barometric condenser. Results reported were averages of the coupons analyzed.

Coupons were cleaned and evaluated for overall corrosion by weight loss in accordance with ASTM G-4. The maximum pitting depth was measured at the deepest pit observed in relation to the original surface. The average pitting depth was determined by taking a random traverse across the specimen and averaging the depths of all pits encountered. Crevice pitting depth was determined by measuring the corrosive attack under the center pin spacers.

Results

Corrosion rates measured on coupons exposed to recirculating condensate with the iron addition are given in Table 6.29. Corrosion rates measured on coupons exposed to recirculating condensate prior to the iron addition are included in Tables 6.30 and 6.31 for comparison. In general, most corrosion rates were accelerated with the iron addition. Except for some of the austenitic stainless steels and copper alloys, the corrosion experienced was greater in 1½ years with the iron addition than in the four years without it. Perhaps the most significant data are the increase in corrosion rate with time shown for most alloys in Table 6.29.

Stainless Steels: The Type 316 Carpenter 20Cb3 and 17-4 PH stainless steels experienced minimal corrosive attack. The sensitized 316 exhibited some pitting when exposed to the circulating condensate with the iron addition. Type 304 stainless steel exhibited significant pitting in both the sensitized and solution-annealed conditions. Both the general corrosion rate and rate of pit penetration of Type 304 were increasing significantly with time.

TABLE 6.29: UNIT I

	Top of Barometric Condenser, 588 Days with Iron Addition					Hot Well with Iron Addition, 483 Days*					Hot Well with Iron Addition, 685 Days*				
Material	Corrosion Rate* (in/yr)	Pitting (inches)*: Maximum	Pitting (inches)*: Average	Pitting (inches)*: Crevice	Remarks	Corrosion Rate* (in/yr)	Pitting (inches)*: Maximum	Pitting (inches)*: Average	Pitting (inches)*: Crevice	Remarks	Corrosion Rate* (in/yr)	Pitting (inches)*: Maximum	Pitting (inches)*: Average	Pitting (inches)*: Crevice	Remarks
Type 316 SS	<0.0001	–	–	–	–	<0.0001	–	–	–	–	<0.0001	–	–	–	–
Type 316 SS (sensitized)	<0.0001	–	–	–	–	<0.0001	0.003	0.002	–	–	<0.0001	0.006	0.003	–	–
Type 304 SS	0.0003	–	–	–	–	<0.0001	–	–	–	–	0.0007	0.015	0.005	–	–
Type 304 SS (sensitized)	0.0014	0.011	0.005	–	Pits on edge	0.0003	0.015	0.007	0.003	–	0.0009	0.025	0.008	0.005	Extensive pitting
Carpenter alloy 20 Cb3	<0.0001	–	–	–	–	<0.0001	–	–	–	–	0.0001	–	–	–	–
Type 410 SS	0.0024	>0.061	0.017	**	Perforated	0.0035	>0.061	–	**	Perforated	0.0034	>0.061	0.018	0.006	Perforated
Type 430 SS	0.0022	>0.049	0.010	**	Perforated	0.0019	>0.049	–	**	Perforated	0.0035	>0.049	0.017	0.001	Perforated
17-4 PH SS	0.0001	–	–	–	–	<0.0001	–	–	–	–	<0.0001	–	–	–	–
Cor ten	>0.0108	–	–	–	–	0.0179	–	–	–	–	0.0168	–	–	–	Broad depressions
Ductile iron	>0.078	–	–	–	Matrix completely corroded	0.0785	–	–	–	–	>0.078	–	–	–	Matrix completely corroded
Gray iron	>0.073	–	–	–	Matrix completely corroded (graphitized)	0.0220	–	–	–	–	>0.073	–	–	–	Matrix completely corroded (graphitized)
Ni resist type II	>0.006	–	–	–	Some graphitization	0.0059	–	–	–	–	>0.0076	–	–	–	Some graphitization
1100 Aluminum	0.0009	0.020	0.012	0.010	Broad pit attack	0.0011	0.012	0.006	**	–	0.0008	0.025	0.014	0.006	Broad pit attack
2024 Aluminum	0.0015	>0.050	0.015	0.019	Perforated, broad pit attack	0.0009	0.033	0.022	0.018	–	0.0006	0.044	0.025	0.009	Broad pit attack
3003 Aluminum	0.0013	0.032	0.012	0.014	Broad pit attack	0.0006	0.003	0.006	0.004	–	0.0008	0.009	0.007	0.013	Broad pit attack
6061 Aluminum	0.0055	0.030	0.016	0.012	Broad pit attack	0.0007	0.023	0.010	0.002	–	0.0009	0.017	0.011	0.007	Broad pit attack
Monel 400	0.0016	–	–	–	–	0.0003	–	–	–	–	0.0004	0.008	0.005	**	–
90-10 CuNi	0.0144	–	–	–	–	0.0007	–	–	–	–	0.0014	–	–	–	–
Admiralty	0.019	0.039	–	0.027	–	0.0005	–	–	0.002	–	0.0004	0.001	0.001	–	–

*Reference (2). **Incipient.

Source: PB 261 349

Material	Top of Barometric Condenser Without Iron Addition* 1,378 days: Corrosion Rate (in/yr)	Pitting, inches: Maximum	Average	Crevice	Remarks	Hot Well Without Iron Additions* 1,378 days: Corrosion Rate (in/yr)	Pitting, Inches: Maximum	Average	Crevice	Remarks
Type 316 SS	<0.0001	none	none	none	–	<0.0001	none	none	none	–
Type 316 SS (sensitized)	<0.0001	0.001	–	0.007	–	–	–	–	–	–
CS8 N Cast SS	<0.0001	none	none	none	–	<0.0001	none	none	none	–
Type 304 SS	<0.0001	0.004	0.001	none	–	<0.0001	none	none	none	–
Type 304 SS (sensitized)	<0.0001	0.012	0.010	0.004	–	–	–	–	–	–
CS8 Cast SS	<0.0001	none	none	0.004	–	<0.0001	none	none	none	–
Type 409 SS	<0.0001	0.020	0.013	0.014	–	0.0001	perf.	perf.	perf.	–
Type 410 SS	<0.0001	0.036	0.009	perf.	–	<0.0001	perf.	perf.	0.008	–
Type 430 SS	<0.0010	perf.	perf.	perf.	Numerous perf.	0.0001	perf.	perf.	–	–
17.4 PH SS	<0.0001	0.006	0.004	none	–	–	–	–	–	–
Carpenter alloy 20 Cb3	<0.0001	none	none	none	–	<0.0001	none	none	none	–
Type II Ni resist	<0.0027	0.015	–	–	Broad shallow depressions	0.0020	0.016	0.008	–	Broad shallow depressions
3% Ni gray iron	<0.0038	–	–	–	Graphitized	0.0059	0.100	–	–	Broad depressions
Gray iron	<0.0036	–	–	–	Graphitized	>0.0070	–	–	–	Graphitized
Ductile iron	<0.0058	0.100	–	–	Broad pits	0.0126	–	–	–	–
Mild steel	>0.0062	–	–	–	Specimen gone	<0.0061	–	–	–	Specimen gone
Monel alloy 400	<0.005	–	–	–	–	0.0022	–	–	–	Specimen thin
10A1 5 Ni bronze	<0.0018	–	–	–	–	0.0002	0.0005	0.0004	0.0008	–
85-5-5-5 bronze	<0.0016	–	–	–	General attack	–	–	–	–	–
6061 Aluminum	<0.0001	0.005	0.004	0.015	–	0.0001	0.030	0.015	0.015	–
121 Aluminum	<0.0004	0.025	0.020	perf.	–	–	–	–	–	–
744	<0.0001	–	–	–	–	–	–	–	–	–

*Reference (3)

Source: PB-261-349

TABLE 6.31: PRE-H_2S ABATEMENT PROGRAM (WITHOUT IRON) HOT WELL

	590 Days*: Corrosion Rate (in/yr)	Pitting (inch): Maximum	Average	Crevice (inch)	Remarks
Type 316 SS	<0.0001	–	–	–	–
CF 8M cast SS	<0.0001	–	–	–	–
Type 304 SS	<0.0001	–	–	Incipient	–
CF 8 cast SS	<0.0001	–	–	0.008	–
Carpenter alloy 20 Cb3	<0.0001	–	–	Incipient	–
Type 409 SS	0.0002	0.045	–	0.045	Perforations
Type 410 SS	0.0001	0.036	–	0.009	Perforations
Type 430 SS	0.0003	0.031	–	0.031	Perforations
Type II Ni resist	0.0009	0.009	0.007	0.007	–
3% Ni gray iron	0.0084	–	–	–	–
Gray iron	0.0080	–	–	–	–
Ductile iron	0.0143	–	–	–	–
Mild steel (1010)	>0.0143	–	–	–	Corroded away
Monel alloy 400	0.0021	–	–	–	–
6061 aluminum	0.0001	0.018	–	0.017	Crevice corrosion
10A1 5 Ni bronze	0.0001	–	–	0.006	–

*Reference (3)

Source: PB 261 349

Type 17-4 PH continued to exhibit virtually no attack. This is a martensitic precipitation hardening stainless steel commonly used for pump shafts at The Geysers.

The ferritic and martensitic stainless steels, such as 403, 410, and 430, appear to have such high pitting and general corrosion rates that they would not perform satisfactorily in the condensate systems. The corrosion rate of Type 430 stainless steel also appears to be increasing with time when exposed to condensate with the iron addition.

Cast Irons: The ductile, gray, and Ni resist cast irons all exhibited high corrosion rates. A particular problem with these materials is that the matrix graphitizes and/or dissolves. These materials then, although looking sound, cannot support any load. The cast irons tested also showed rapidly increasing corrosion rates when exposed to the condensate with the iron addition.

Carbon Steel: Carbon steel has an extremely high corrosion rate and is not suitable for use in contact with Geysers condensate.

Aluminum Alloys: Aluminum alloys are unsuitable for use in the condensate system because of their susceptibility to excessive pitting attack in the presence of the iron addition.

Copper Alloys: Copper alloys suffered severe sulfide attack before the addition of iron. With the iron addition, the attack is irregular, being somewhat reduced where the coupons were completely submerged and unchanged, or accelerated where they were not.

Corrosion Mechanisms

Data obtained in this study appear to correlate reasonably with corrosion mechanisms presented by Greco and Wright (4) and Rogers and Rowe (5). Rogers and Rowe developed a theory in which the corrosion rates of steels in H_2S brine systems are initially low and the cathode in the electrochemical reaction is an easily polarized hydrogen electrode of high potential. As corrosion proceeds, iron sulfide is deposited on the surface and acts as a low potential cathode. They were able to show experimentally that iron sulfide not only had a low potential, but was also difficult to polarize.

Relatively little surface area of such a cathode is required to maintain the anodic iron surfaces in an active condition and high corrosion rates result. The addition of iron to the circulating condensate system results in the production of iron sulfide which is present in concentration as high as 50 ppm. It is hypothesized that when this material is deposited on the surface of iron based alloys, more low potential polarization-resistant cathodic surfaces are introduced than there are anodic areas available to polarize them. The high corrosion rates observed at The Geysers, therefore, may be the result of a mechanism similar to that proposed by Rogers and Rowe.

The pitting attack observed on the austenitic stainless steels appears similar to that found when these alloys are exposed to chlorides or similar depassivating agents. This suggests that the iron introduced into the condensate is also a depassifier. When passivation is lost, austenitic stainless steels are susceptible to the same mechanism of corrosion as the less noble iron based alloys.

The reduction in corrosion rate observed on the copper alloy specimens with the addition of iron is most likely due to the corrosion inhibiting effect iron is widely recognized to have with these alloys. Under continuous submerged conditions, corrosion rates will be somewhat suppressed, but when not submerged, no protection can be realized. This effect should not, therefore, be relied upon in the circulating condensate system at The Geysers.

Examination of Condenser Cladding

In order to verify the corrosion rates obtained from the spool specimens, a visual examination of the interior of the barometric condensers at Units 1 and 2 was conducted. Unit 1 was used as a pilot plant for the iron addition study. Since Unit 2 had received no significant exposure to the iron addition, it is felt that this condenser was a valid control specimen for the examination.

Examination of the interior of the Unit 2 condenser revealed that the stainless steel cladding was lightly etched. No significant pitting was observed. The Unit 1 condenser had experienced approximately 1½ years exposure to the iron addition. The clad surface of this condenser was lightly etched and also contained numerous shallow pits. In addition, several pits approximately ¼-inch in diameter and up to 44 mils deep were observed. Since no similar pits were observed in the Unit 2 condenser, these pits were attributed to the iron addition.

Design specifications for these condensers indicate that the cladding is roll-bonded 316L stainless steel. Therefore, it appears that the pitting damage on the Unit 1 condenser significantly exceeds that predicted by the test spool coupons. The apparent lack of correlation between the type 316 stainless steel coupons and the observed performance of the condenser cladding is probably due to coupon size. The pitting in the condenser occurred at a relatively small number of locations in its surface. Since there are less than eight square inches of surface area in each coupon and several hundred square feet of surface area in each condenser, random pitting of the type observed would not necessarily be detected on the coupons. This information is applicable only to the type 316 stainless steel and does not reflect on the validity of the data obtained on other alloys tested.

References

(1) Allen, G., and McCluer, H.K., *The Hydrogen Sulfide Abatement Program at The Geysers Geothermal Power Plant.* Submitted for presentation at the Western Region Conference of the National Association of Corrosion Engineers, May 7-9, 1974.

(2) Dodd, F.J., *Effects of Hydrogen Sulfide Abatement Program on Corrosion at The Geysers.* Presented at Western States Corrosion Seminar, National Association of Corrosion Engineers, May 1974.

(3) Ham, W.C., *Materials and Corrosion, Geysers Geothermal Power Plant.* Presented at the Western Region Conference of the National Association of Corrosion Engineers, October 1972.

(4) Greco, E.C. and Wright, W.B., "Corrosion of Iron in an H_2S-CO_2-H_2O System," *Corrosion*, 18, 119t-124t (1962).

(5) Rogers, W.F. and Rowe, J.A., Jr., "Corrosion Effects of Hydrogen Sulfide and Carbon Dioxide in Oil Production, *Proc. Fourth World Petroleum Congress*, Rome, Section III, 479-499 (1955).

AUSTENITIC AND FERRITIC STAINLESS STEELS

The material for this section has been based upon a paper by J.R. Maurer of Allegheny Ludlum Corporation, prepared for The Second Workshop on Materials Problems (PB 261 349).

The Alloys

Two austenitic stainless steels which provide improved resistance to crevice and pitting corrosion are T-216 and AL-6X. The 200 series stainless steels contain greater amounts of manganese and less nickel than their 300 series counterparts. The AL-6X alloy containing 6+% molybdenum was specifically designed to be resistant to seawater pitting and crevice corrosion attack.

The ferritic stainless steels have never been as popular or widely used as the austenitic grades, primarily because of the difficulties encountered in fabricating these materials and their corrosion resistance which was generally inferior. Recent advances in production facilities, coupled with new alloy developments, plus the resistance of these materials to chloride stress corrosion cracking, has led to greater acceptance and usage of the ferritics. One group of ferritic stainless steels, covering a wide range of properties is 409, 439, 26-1S, 29-4, and 29-4-2.

The first three are alloys containing titanium for weld stabilization. The last two are vacuum melted materials with very low levels of carbon and nitrogen combined with high levels of chromium and molybdenum to provide good mechanical and excellent corrosion resistant properties.

The austenitic stainless steels, as a class, are characterized by good ductility and impact strength. T-216 and AL-6X are typical of alloys in this family although they do exhibit their own individual characteristics. These alloys have higher yield and tensile strengths in the annealed condition than T-304 or T-316. AL-6X work hardens similarly to T-316, whereas T-216 does not appear to work harden as rapidly.

The welding characteristics of these alloys are also similar to those experienced with other austenitic stainless steels. Both have been TIG and MIG welded and require no pre- or postweld heat treatments to prevent cracking or to restore ductility. Cleaning or descaling prior to welding is important and pickling to remove weld scale is desirable to insure optimum corrosion resistance. Tests of welded AL-6X condenser tubing demonstrated the excellent corrosion resistance of as-welded tubes to seawater environment, eliminating the need for postweld pickling for satisfactory performance in this environment.

One potential problem area for austenitic materials is the possibility of precipitating complex chromium carbide (sensitization) during welding or as a result of improper heat treatment which in time could lead to intergranular corrosion attack. Avoiding temperatures in the 800° to 1500°F range or rapidly cooling through this range is one means of minimizing this problem. Two other methods are using low carbon grades or stabilizing the alloy. AL-6X is normally made to low carbon levels. Indications are that the 200 series is not as susceptible to sensitization and can tolerate highest levels of carbon.

The ferritic stainless steels have sufficient ductility to permit forming without difficulty. As a class, they can be best typified by T-430 as to their forming characteristics. None of these alloys has the overall ductility demonstrated by the austenitic stainless steels, but a sufficient amount to permit even difficult forming operations.

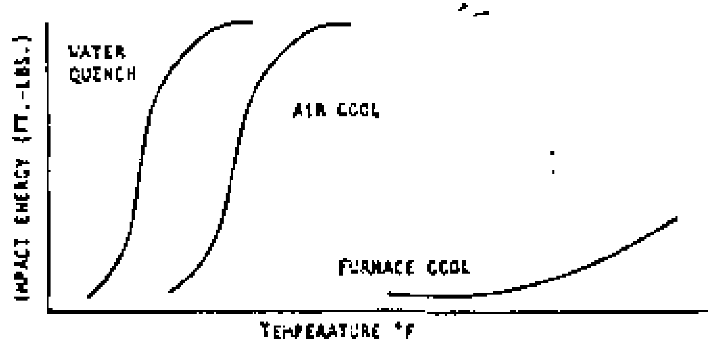
The ferritic stainless steels can be TIG and MIG welded, but require greater care than the austenitic stainless steels. Since they have not been used in welded applications to a great extent, lack of familiarity with these alloys could be the cause of many reported difficulties. While it is important to maintain cleanliness in all welding operations, it is particularly true in the case of those ferritics whose properties are dependent on low levels of interstitials (carbon or nitrogen). Proper shielding of the weld with gases to keep these elements away from the hot metal is vital. The stabilized versions should also be protected even though they contain titanium to tie up the carbon and nitrogen. When filler metal is needed, alloys of similar composition should be used.

The ferritic stainless steels are susceptible to a loss of ductility and impact strength when heated in the 650° to 1000°F temperature range. This is commonly known as 885 embrittlement. Because this condition results in the loss of room temperature ductility, consideration must be given to avoid processing and application problems. Avoiding this temperature range or fast cooling through it are two methods of minimizing the problem.

Another characteristic of the ferritic stainless steels which could affect their functional application is toughness as a function of impact testing. The impact strengths of these materials can be quite low at ambient temperatures, due to their relatively high ductile-to-brittle transition temperature (DBTT). This characteristic is affected by a number of variables, among them: carbon and nitrogen content, titanium additions, thickness, cooling rate and grain size.

Figure 6.17 illustrates the effect of one variable (cooling rates) on a ferritic alloy cooled after annealing for one-half hour at the specified temperature. This condition becomes an apparent problem when materials with DBTT higher than room temperature are subjected to impact loading. The low interstitial materials (29-4, 29-4-2) are less affected by this condition than the titanium-stabilized grades (409, 439, 26-1S) and, as a result, these latter materials are restricted to applications where thinner materials can be used. This restriction will not affect the use of these materials in most piping and heat exchanger applications.

FIGURE 6.17: EFFECT OF COOLING RATE ON IMPACT STRENGTH



Source: PB 261 349

General Corrosion Resistance

All the alloys mentioned in this review have generally good corrosion resistant properties. Their ability to resist corrosive media is dependent for the most part on the amount of chromium they contain as well as other alloying elements such as molybdenum, nickel, titanium and others. Other factors influencing corrosion resistance are crevices, temperatures, stagnation, oxygen supply, concentrations, stresses, surface preparation and cleanliness, heat treatment, and in most cases a combination of these and other factors.

All of the alloys listed have, with the exception of T-409, a resistance to atmospheric corrosion equal to or better than T-304. T-409 itself is resistant to a general corrosion attack in most atmospheric environments.

Table 6.32 provides corrosion test data for these alloys in seven different media. Included with these alloys are data for T-430, T-304, T-316, Alloy 20, Hastelloy C and titanium. All solutions are boiling and are the results of five 48-hour periods.

TABLE 6.32: CORROSION RESISTANCE TO BOILING SOLUTIONS–MPY

Alloy	10% Sulfamic	45% Formic	20% Acetic	10% Oxalic
430	144,000	84,700	3,000	6,450
304	1,360	1,715	300	570
316	75	520	2	56
Alloy 20	16	7	2	7
Hastelloy C	0	5	0	8
Titanium	285	873	0	950
26-1S	17	4	0	9
216	61	25	0	60
29-4	0	1	0	13
AL-6X	21	6	0	11
430	1	475	4	2,370

Alloy	65% Nitric	10% Sodium Bisulfate	10% Sulfuric
430	20	91,200	252,000
304	8	2,760	16,470
316	11	170	855
Alloy 20	8	11	43
Hastelloy C	450	8	17
Titanium	1	250	6,290
26-1S	4	8	74,000
216	14	15	948
29-4	6	9	52,180
AL-6X	32	14	330
439	31	1	230,000

Source: PB 261 349

These tests are part of a standard series of corrosion tests run to provide a comparative evaluation of a material's resistance to a broad spectrum of conditions. The tests serve as indications of where these materials might be used and where more comprehensive and detailed investigations are required prior to application.

It is worth noting at this point that the 29-4 alloy, while exhibiting excellent corrosion resistance to a number of environments, is severely attacked in sulfuric acid. A modification of this material, with an addition of 2% nickel, provides much better resistance to sulfuric acid attack at various temperatures and concentrations as shown in Table 6.33.

TABLE 6.33: SULFURIC ACID RESISTANCE

		Temperature		
Conc.		150°F	175°F	200°F
10%	316	7	13	18
	6X	6	4	7
	29-4-2	0	0	0
20%	316	16	70	148
	6X	9	5	13
	29-4-2	0	0	0
40%	316	536	1546	3023
	6X	7	10	19
	29-4-2	0	863	5731
95%	316	5	7	28
	6X	31	43	56
	29-4-2	5	16	13

Source: PB 261 349

Pitting and Crevice Corrosion

Pitting and crevice corrosion resistance of materials is an extremely important consideration in designing and specifying a materials system for many aqueous applications particularly those which involve high concentrations of chlorides such as seawater and some geothermal brines. Many successful applications have been made of the common austenitic and ferritic stainless steels in chloride-heavy environments, but it is important to recognize the problems and avoid them as much as possible.

Early efforts to develop a ferritic stainless steel with improved welding characteristics and pitting corrosion resistance to complement its inherent resistance to stress corrosion cracking led to the development of T-439. The addition of titanium to this alloy appears to improve its pitting corrosion resistance.

Pitting and crevice corrosion studies using specimens with a crevice in ferric chloride have been made on a large number of alloys. The test involves a rubber band stretched around a specimen and inert polymer blocks are inserted to help maintain a crevice and to add additional crevices. The specimen is then placed in 10% ferric chloride at room temperature for 72 hours.

A comparison of weight loss measurements can demonstrate the resistance of alloys to pitting and crevice corrosion. However, any sign of pitting or crevice corrosion indicates that a material is likely to experience problems in actual service, whereas absence of an attack is a strong indication a material will be suitable for extended service. Many people accept this test as an indication of how alloys will perform in seawater. Table 6.34 shows test results.

TABLE 6.34: 10% FERRIC CHLORIDE RUBBER BAND TEST 72 HOURS–ROOM TEMPERATURE

Alloy	% Weight Loss
AL-6X	0
29 Cr-4 Mo	0
Hastelloy C	0
Titanium	0
E8-26-1	0-0.01
216	0.2-0.45
26-1S	0.3-0.6
317	0.8-1.1
316	2.5-5.1
20Cb3	4.0-5.0
304	2.5-5.1

Source: PB 261 349

Another method of comparing the pitting corrosion resistance of alloys is to measure their breakthrough potential in various media. Table 6.35 lists the performance of various alloys in a solution containing 1,000 ppm chloride. It is evident that those materials containing the higher combinations of chromium and molybdenum provide better resistance.

TABLE : BREAKTHROUGH POTENTIAL

Alloy	Minimum Breakthrough Potential (Volts)
AL-6X	1.0+ (beyond range tested)
29 Cr-4 Mo	1.0+ (beyond range tested)
Hastelloy C	1.0+ (beyond range tested)
216	.95
Alloy 20Cb3	.55
316	.33
304	.22
430	.05

Source: PB 261 349

The severity of the corroding media affects results in this test. Increasing the chloride concentration from 1,000 ppm to 40,000 ppm lowers the minimum breakthrough potential to 0.94 V for AL-6X, 0.25 V for 316 and 0.18 V for 304.

Exposure tests of several of the new alloys have been made in utility steam surface condensers. T-439 tubes were tested in several fresh water plants where T-304 has been proven satisfactory. In salt water, T-216 and AL-6X indicate a much improved performance over T-316. Where tubes are permitted to foul or velocities are low, T-316 has failed in as short a time as two months. After four years' exposure to these conditions, tubes of T-216 contain a few micro pits and AL-6X is unaffected.

Stress Corrosion Cracking

Resistance to stress corrosion cracking is one of the most important attributes of an engineering material. As a class, the ferritics offer superior resistance to this form of corrosion attack. The alloys are not totally immune and it is apparent that small additions of nickel and copper can reduce the resistance of certain alloys to this form of attack, particularly in the more aggressive solutions such as boiling magnesium chloride.

Many people believe the boiling magnesium chloride test is too severe and does not adequately represent actual service conditions most frequently encountered. A more realistic test appears to be the wick test developed by Dana and DeLong (1)(2). A U-bend specimen is placed in contact with a glass wool wick which is partially immersed in a NaCl solution. An electric current is passed through the specimen to heat it and evaporate a portion of the solution, concentrating the NaCl on the hot stressed surface. Materials such as T-304 and T-316 fail the wick test. Others which fail in boiling magnesium chloride will pass the wick test. Among these are 20Cb3, AL-6X, and 29-4-2. Some stress corrosion cracking studies of the various alloys considered here provided the results shown in Table 6.36.

The results obtained in these studies are interesting. It would appear that materials such as AL-6X and 29-4-2, while susceptible to stress corrosion cracking, do have some inherent resistance. If the wick test is a satisfactory and realistic laboratory approach to actual conditions, these alloys can be used in a number of applications where pitting, crevice and stress corrosion resistance are required.

TABLE 6.36: STRESS CORROSION CRACKING STUDIES

Alloy	33% Lithium Chloride	42% $MgCl_2$	20% NaCl	50% NaOH	Wick Test
216	F	F	P	-	-
Al-6X	P	F	P	P	P
409	-	P	-	-	-
439	P	P	P	P	P
26-1S	P	P	P	P	P
29-4	P	P	P	P	P
29-4-2	P	F	-	-	P

P - Pass; F - Fail

Source: PB 261 349

References

(1) Dana, A.W., and DeLong, W.B., *Corrosion*, Vol. 12, Paper 309T (1956).
(2) Dana, A.W., *ASTM Bulletin No. 225*, p. 196 (Oct. 1957).

SILICA SCALING OF CERRO PRIETO

The material for this section has been based upon a paper by S. Mercado and J. Guiza of the Federal Commission of Electricity, Mexico, prepared for the Conference on Scale Management (COO-2607-4).

Description of the Geothermal Field

The Cerro Prieto geothermal field presents hydrothermal surface manifestations in an area of about 30 square kilometers, where the production zone is located. Thirty deep wells have been drilled in this field to a depth ranging from 700 to 2,000 m. Flow is obtained through preslotted casing or through gun perforated casing, after cementing the production casing, except 150 to 300 m of the bottom part, where the hot strata are located. High enthalpy water flows through these perforations and is conducted to the surface through the 7⅝" production casing.

As the water ascends through the production casing, the hydrostatic pressure diminishes and it partially flashes into steam. The flow through the valve tree is a water-steam mixture containing from 20 to 40% of steam. This mixture is admitted to a centrifugal Webre-type centrifugal separator, 54" in diameter. The steam is sent to the power plant and the separated water to an evaporating pond.

From 20 to 80 tons per hour of steam are obtained from each well at a pressure of 100 psig. 13 wells supply the necessary steam to maintain at full load two units of 37.5 MW each, at a steam rate of 9.4 kg/kWh.

Brine Composition and Its Relationship to Silica and Other Scaling Salts

A typical analysis of the brine extracted by the wells after being exposed to atmospheric pressure is shown in Table 6.37 on the following page.

TABLE 6.37: CHEMICAL ANALYSIS OF THE SEPARATED WATER OF WELL M-5

Element	Parts Per Million
Na	9,062
K	2,237
Li	38
Ca	520
Mg	1
B	14
SiO_2	1,250
Cl	16,045
Br	31
F	2
SO_4	6
CO_3	2
HCO_3	74
NaCl (Cl)	26,442
As	0.5
Fe	0.3
pH	7.7
Conductivity (mmhos)	32,200

Source: COO-2607-4

As can be seen from the table, the following relationship can be established.

Cations:

$$Na^+ > K^+ > Ca^{++} > Mg^{++}$$

Anions:

$$Cl^- > HCO_3^- > SO_4^=$$

By means of isotopic analysis of the geothermal fluid it has been established that the water from the geothermal reservoir is of meteoric origin and proceeds mainly from the Colorado River. The high concentration of dissolved solids is the result of the solubility action of the hot water on the sedimentary rocks acting for thousands of years, and reaching an equilibrium state or saturation with respect to some elements such as silicon, sodium and potassium. The geothermal fluids also contain substantial amounts of dissolved gases, mainly CO_2 and H_2S, and in minor amounts NH_3, H_2, and CH_4.

The high content of dissolved silica in the well brine is the result of dissolution of rock at high temperature, a fact experimentally verified by different investigators. The concentration of silica in solution increases with the temperature. It has been possible to establish that the fluid discharge by the Cerro Prieto wells is saturated with respect to silica at the temperature at which the brine is found. This fact has been utilized to determine the temperature and enthalpy of the hydrothermal brines with acceptable accuracy. In a similar manner, the brine is saturated with respect to carbonates at the temperature of the brine.

Due to the saturation condition of some of its components, deposition of scale occurs on the inside of the well casing as the geothermal fluid undergoes physical changes on its way to the surface. The scaling occurs physically when the high enthalpy water ascends through the production casing and the pressure at which it is subjected is reduced causing partial flashing of the water into steam. The zone of the casing where this change of phase occurs depends on the original enthalpy of the fluids.

Chemically, deposition occurs when the brine (originally saturated with respect to silica and carbonates at the initial temperature) becomes supersaturated as a portion of the water flashes into steam and the temperature of the brine is reduced by this change of phase.

CO_2 originally present in the brine is transferred to the steam when boiling is initiated. The initial equilibrium is disturbed and bicarbonates are precipitated as carbonates according to the following reation:

$$Ca(HCO_3)_2 \longrightarrow CaCO_3 + H_2O + CO_2\uparrow$$

Scaling problems of the production casing are more or less severe, depending on the zone where scale is produced and the depth of this zone. If, for instance, the deposit is formed in the production casing, rimming of the well restores the well output. If, however, the deposit is formed in the slotted portion of the casing, fluid flow is restricted and the slots cannot be cleaned by rimming. Scale may also occur in the surrounding ground scals, diminishing permeability with no means of cleaning.

Deposits similar to those formed in the production casing keep on forming in the separators, water piping, silencers and drains. Silica and other insoluble deposits are formed because water containing these salts is carried over the steam. This carryover is responsible for scales formed in condensate traps and on turbine blades.

HELICAL ROTARY SCREW EXPANDER

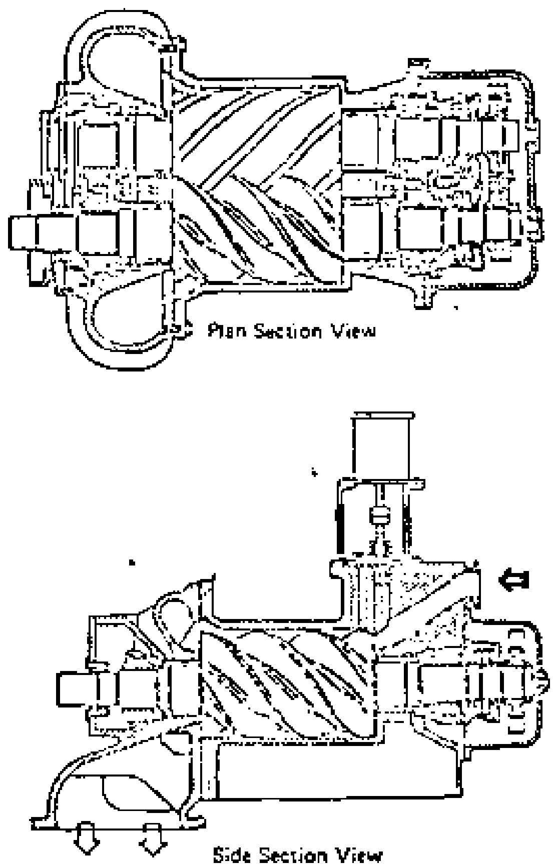
The material for this section has been based upon a paper by R.A. McKay of Jet Propulsion Laboratory and R.S. Sprankle of Hydrothermal Power Company, Ltd., prepared for the Conference on Scale Mangement (COO-2607-4).

At dry steam geothermal fields, the production of electricity is accomplished by removing entrained solids and then sending the steam directly to turbines which drive electric generators. A similar simple approach is possible at hot water fields by using an expander which can operate directly on hot untreated corrosive scale-forming geothermal brines or brine and vapor mixtures.

A positive displacement expander of the Lysholm type, employing two meshing helical rotary screws, has been under development by the Hydrothermal Power Company, Ltd., since 1971 for this application. Two small prototype models have been successfully demonstrated at three geothermal hot brine fields in southwestern United States and Mexico, using brines having dissolved solids ranging from 17,000 to 330,000 ppm. Precipitation and the deposition of scale is allowed to occur within the expander where it is used to advantage. A layer of scale, in thicknesses controlled by the geometry of the meshing rotors, provides erosion and corrosion protection and thermal insulation for all surfaces swept by the rotors. The buildup of scale fills leakage clearances and thus enhances the efficiency of the expander. The scale deposition also provides healing of surface damage to the rotors or case should it occur.

With some brines, the processes which occur within the expander significantly alleviate scale deposition in the waste line after expansion. The expander, planned principally for wellhead operation, influences scaling within the well and supply line only to the extent achieved by flow control at the expander entrance by means of the internal throttle control valve. A helical rotary screw expander is shown in Figure 6.18.

FIGURE 6.18: HELICAL ROTARY SCREW EXPANDER



Source: COO-2607-1

INHIBITING DEPOSITION OF SILICEOUS SCALE

The material for this section has been based upon a paper by J.Z. Grens and L.B. Owen of Lawrence Livermore Laboratory prepared for the Conference on Scale Management (COO-2607-4).

Lawrence Livermore Laboratory is developing the total flow process for efficient utilization of the thermal energy stored in high temperature-high salinity brines from the Salton Sea Geothermal Field (SSGF) for electric power production. Energy conversion is accomplished by flowing brine through mixed phase expanders and directing the high velocity exhaust jets onto the blades of an impulse turbine.

Previous field experience, however, at the Sinclair No. 4 site in the SSGF indicated that deposition of siliceous scale (heavy metal sulfides and iron-rich amorphous silica) in nozzles and on turbine blades would be a serious problem when hypersaline brine is flash evaporated. An experimental program, therefore, was established to develop scale control techniques. Preliminary results indicate that scaling is a pH-dependent process that can be inhibited when brine is acidified with hydrochloric acid.

A mobile field test unit has been established at the ERDA-SDG&E test site in the southwestern part of the SSGF. Brine from the Magmamax No. 1 well was flowed through a steam separator that isolated vapor and liquid fractions formed as the brine moved from the geothermal reservoir, up the wellbore to the surface. Although the separated liquid phase was used for the initial brine modification experiments, subsequent work will involve remixing of liquid and vapor fractions prior to chemical additions.

Average temperature and pressure of the brine were about 220°C and 265 psi, respectively. System through-put varied between 18,000 to 24,000 pounds of brine per hour. Flow through nozzles (8:1 expansion ratio, ¼-inch diameter throat) was 1.25 pounds of brine per second. The nominal pH of unmodified brine flowing from the separator varied from 5.5 to 5.8. Dissolved solids content of the brine prior to and after expansion through nozzles was 18 to 22 weight percent, respectively. Nozzles and wearplates were fabricated from Ti-6Al-4V alloy. Three independent nozzles were operated simultaneously. During each acidification run, at least one nozzle was always operated as a control station flowing unmodified brine.

Four experiments, each of 20 hours duration, were completed. Nominal scaling (copper sulfide, native silver, and iron-rich amorphous silica) from unmodified brine resulted in closure of up to 10% of the cross-sectional areas of the nozzle throats. Thickness of scale formed on wearblades ranged from 0.019 to 0.04 mm. However, when brine was acidified to pH 1.5, 2.3, and 4.0, scaling in nozzles was eliminated and substantially reduced on wearblades.

Acidified brine effluents remained clear several hours after collection. However, unmodified brine was slightly turbid when collected, with precipitates forming a few minutes after samples were taken.

LIQUID FLUIDIZED BED HEAT EXCHANGERS FOR CONTROLLING SCALE

The material for this section has been based upon a paper by C.A. Allen, E.S. Grimmett and R.E. McAtee of Idaho National Engineering Laboratory prepared for the Conference on Scale Management (COO-2607-4).

Experiments conducted several years ago at the Idaho National Engineering Laboratory indicated that heat transfer coefficients between surfaces and a liquid fluidized bed were higher than when no bed was present. These same beds prevented deposition on cold surfaces near saturated solutions. These observations led to the suggestion that a fluidized bed heat exchanger could be developed which would prevent the usual deposition of scale from geothermal brines when cooled.

Initial studies were conducted with artificial brines at the laboratory, and with hot brines flowing directly from geothermal wells at Raft River, Idaho. The first experiments were performed in approximately 4-inch diameter glass columns operating at atmospheric pressure. The heat transfer surfaces were made from 0.25-inch diameter tubing wound into spiral coils. Results from these tests showed that no scale deposited on heat transfer surfaces covered with a fluidized bed of sand particles, and that bed-to-tube coefficients doubled. These coefficients ranged from 4,000 to 4,500 $w/cm^2 \cdot {}^\circ C$, the higher coefficients obtained at the higher superficial fluidizing velocities which ranged from 0.02 to 0.045 m/sec.

Slightly higher coefficients were obtained in a 6-inch diameter pressurized exchanger using 0.5-inch diameter tubing wound into a spiral coil covered with a sand bed having 1.0 mm particles. The unit was operated for 60 days using Raft River water at a temperature of 135°C, containing approximately 2,000 milligrams per liter of dissolved salts. No scale deposited on the surfaces of the coil that was covered by the fluidized bed of sand.

Hot Dry Rock Project

The material for this chapter has been based upon a report by D.W. Brown and R.A. Pettitt of Geothermal Technology and Operations Group, Los Alamos Scientific Laboratory, (LA-UR-77-2028).

As a consequence of man's ever-increasing demands for energy and mineral resources, countless numbers of exploratory holes have been drilled deep into the earth's crust all over the world. Although the sought-for resources have most often not been found (the proverbial "dry" holes), what almost always has been found are bodies of essentially dry rock at elevated temperatures. In the Gulf Coast region of the United States, for example, typical bottom-hole temperatures for the deeper dry holes often approach or even exceed 200°C–a minimum temperature level which is considered feasible for the generation of electric power (1).

Such widespread drilling experience clearly attests to the existence, within presently attainable drilling depths, of vast regions of crustal rock at suitably elevated temperatures–suitable for many of our space heating and process heating needs, and oftentimes even for the generation of electric power. These identified regions of hot rock beneath the earth's surface represent, in fact, our most abundant and broadly distributed energy resource, if an economical and environmentally acceptable means of extracting a reasonable amount of the contained thermal energy can be devised. Such is the primary objective of the Los Alamos Hot Dry Rock Project.

HOT DRY ROCK POTENTIAL IN THE WESTERN UNITED STATES (2)

Although several regions of the eastern United States have recently been identified as having a significant potential for the development of hot dry rock geothermal reservoirs at moderate temperatures (3)(4), the greatest potential for this type of geothermal energy lies in the western third of the United States. If one considers the thirteen westernmost states including North and South Dakota, this region possesses a significant potential for the near-term utilization of man-made hot dry rock geothermal reservoirs.

The U.S. Geological Survey (5) has identified 1.8 million acres (2,000 square miles) of western lands as "having a significant potential for geothermal development," based primarily on an association with recent volcanism in the area. However, from a survey of all available regional heat-flow data, it has been estimated that a much larger and more widely distributed portion of this 13-state area—almost 95,000 square miles—is underlain, at depths of about 16,400 feet (5 kilometers), by hot rock at or above 550°F (290°C). It should be pointed out that these latter areas are not necessarily associated with recent vulcanism.

Using the numerous measured heat-flow values in conjunction with temperature vs depth predictive techniques, one is in a position to estimate, in a quasi-statistical fashion, the very large hot-dry-rock geothermal-energy potential for the western United States.

Table 11.1 lists the estimated probability, in the form of a percentage distribution, of a given temperature range for two specified depths—(16,400 and 19,700 feet)(5 and 6 km)—for the 13-state region being considered. A mean depth to basement of 8,200 feet (2.5 km) was used, along with appropriate mean-thermal-conductivity values for sedimentary rock (0.005 cal/cm-sec-°C) and crystalline basement rock (0.007 cal/cm-sec-°C).

TABLE 11.1: PROBABLE DISTRIBUTION OF HOT ROCK RESERVOIR TEMPERATURES FOR THE WESTERN THIRD OF THE UNITED STATES*

Probable Areal Distribution	Heat Flow Range HFU**	Reservoir Temperature Range Corresponding to a Drilled Hole Depth of: 16,400 ft (5 km)	19,700 ft (6 km)
20%	< 1.6	< 316°F (158°C)	< 356°F (180°C)
30%	1.6-2.1	316-397°F (158-203°C)	356-451°F (180-233°C)
33%	2.1-2.6	397-478°F (203-248°C)	451-545°F (233-285°C)
10%	2.6-3.1	478-560°F (248-293°C)	545-639°F (285-337°C)
7%	> 3.1	> 560°F (293°C)	> 639°F (337°C)

*Based on a mean sedimentary thickness of 2.5 km overlying the top of the crystalline basement rock.

**HFU = $\mu cal/cm^2$ sec, corrected for Pleistocene climatic effects.

Source: LA-UR-77-2028

From an examination of Table 11.1, one can conclude that a hot-rock reservoir temperature level in excess of 550°F (290°C) can be achieved by drilling to a depth of about 5 km anywhere within a 95,000-square-mile broadly distributed region of the western United States. This area is over 30 times greater than the total "Known Geothermal Resource Area" listed by the U.S. Geological Survey for potential naturally-occurring hot water or steam geothermal development.

Obviously then, if a practical, yet economical, method of extracting energy from these known reservoirs of hot rock can be developed, as appears probable based on the results of the Los Alamos Project so far, this hot rock geothermal resource is very large.

TECHNOLOGY (6)

The principal problems associated with developing this vast energy resource are primarily ones of economics and engineering. For any given geological setting—shallow or deep, sedimentary or igneous—which of the potentially available methods will be most efficient and economical, and at the same time environmentally acceptable?

Except in areas of active vulcanism, which are rare and appear somewhat hazardous for initial investigations, hot dry rock is normally encountered at considerable depths under thick insulating layers of cooler rock. Obviously, some method of in situ energy extraction is most appropriate for the development of this resource. For similar reasons, drilling appears certainly to be the obvious choice for entering the geothermal reservoir. Fortunately, drilling equipment and techniques are already available which are used more or less routinely to penetrate hot, hard rock to depths of the order of 20,000 feet (6 km), and which produce holes large enough in cross section for the significant transport of a heat transfer fluid. While improvements in drilling technology and economics would certainly be welcome, existing drilling technology is adequate for development of hot dry rock energy systems and must be the immediate basis of that development.

Typically, rocks are poor conductors of heat. Therefore, within the hot rock, a very large heat-transfer surface must be exposed if thermal energy is to be extracted from it at a high rate for a usefully long time. As a method of developing new surfaces, drilling is prohibitively expensive. An economical energy system requires in fact that drilling be minimized, and that the necessary heat-transfer area exist or somehow be created outside the borehole in the form of connected openings large enough to permit heat extraction from their surfaces.

It appears that the best possibility for efficient, economical extraction and transport of heat is to circulate a fluid from the borehole through these openings, in imitation of a natural hydrothermal system. And while other fluids would have advantages, particularly with regard to dissolution and reprecipitation of minerals, the total volume of fluid and the makeup requirements for fluid loss and thermal contraction of the rock are so great that a very inexpensive heat transfer fluid is evidently needed. Again in imitation of natural systems, water is the obvious fluid to be used for extraction and transport of the geothermal heat.

If the rock constituting the reservoir has a high natural permeability, as may be the case in porous sediments or fractured igneous or metamorphic rocks, injection of water from the borehole into the formation and circulation through it to extract heat should not be difficult.

The problems of confining the circulation to the region from which it is desired to extract heat and of recovering the heated fluid from the formation can probably be handled by the reservoir-management techniques which have been widely used for secondary recovery of petroleum. This, however, in general requires a stratigraphy in which at least the upward flow of the reservoir fluid is prevented and requires also the drilling of an array of holes in which injection holes are surrounded by recovery holes and vice versa. Very large energy extraction systems of this type are probably possible, but convincing small-scale experiments to demonstrate their feasibility will be hard to arrange.

At least initially, it appears simpler to investigate energy extraction from hot dry rock whose initial permeability is low. Here the problems of containing and recovering the fluid are replaced by those of producing flow passages and heat-transfer surfaces. Many options exist with regard to creation and operation of a heat-extraction system in such rock, including:

> creation of circulation paths by chemical leaching, by explosive fragmentation, by hydraulic fracturing, or by some combination of these methods;
>
> alternate injection and recovery of fluid through a single hole, or continuous circulation through coaxial pipes in the same hole, or continuous flow of the fluid between two or more holes;
>
> transport of the energy to the surface by steam, by hot water, by a mixture of the two, by a second fluid, or—using some type of conversion device—in a form other than heat.

Several of these possibilities appear to deserve investigation, in a variety of geologic environments. However, the only large-scale experimental study of systems of this type now in progress is the ERDA-supported Hot Dry Rock Geothermal Energy Project at Los Alamos Scientific Laboratory. Initially, this is an attempt to create a pressurized-water circulation loop in hot granite by hydraulic fracturing between two boreholes. The feasibility of drilling into, hydraulically fracturing, and containing pressurized water has been demonstrated in granite at depths up to 9,600 feet (2,930 meters) and temperatures up to 385°F (196°C).

HOT DRY ROCK GEOTHERMAL RESERVOIR

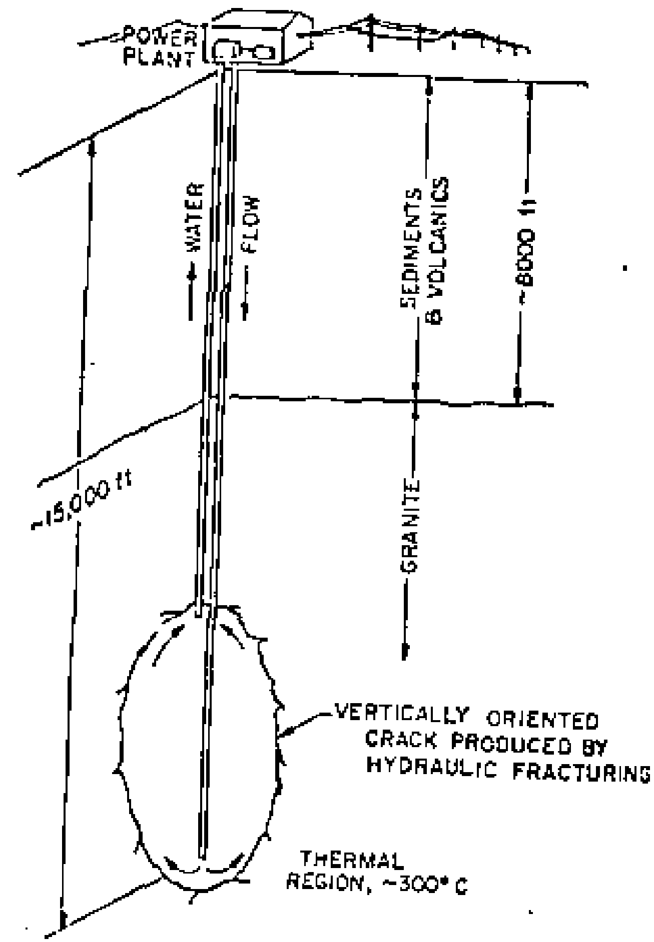
In the initial Los Alamos concept, a man-made geothermal reservoir would be formed by first drilling into a previously-identified region of suitably hot rock, and then creating within this hot rock a very large surface area for heat transfer using conventional, albeit large-scale, hydraulic fracturing techniques developed by the oil industry.

After forming a circulation loop by drilling a second hole into the top of the fractured region, as shown schematically in Figure 11.1, the heat contained in this reservoir would be convected to the surface by the buoyant circulation of water, possibly without the need for pumping. The water in the earth loop would be maintained as a liquid throughout by pressurization at the surface, both increasing the amount of heat transport up the second (withdrawal) hole, and enhancing the rate of heat removal from the fractured reservoir, when compared to steam.

Preliminary experiments and analyses indicate that thermal stresses resulting from the cooling of the hot rock in such a man-made reservoir may gradually enlarge the initial fracture system so that its useful lifetime will be greatly

extended beyond the planned 10 to 15 years provided by the original fractured reservoir. If these thermal stress cracks grow preferentially downward and outward into regions of hotter rock, as seems probable, the quality of the geothermal source may actually improve as energy is withdrawn from it.

FIGURE 11.1: HOT DRY ROCK GEOTHERMAL ENERGY SYSTEM PRODUCED BY DRILLING AND HYDRAULIC FRACTURING



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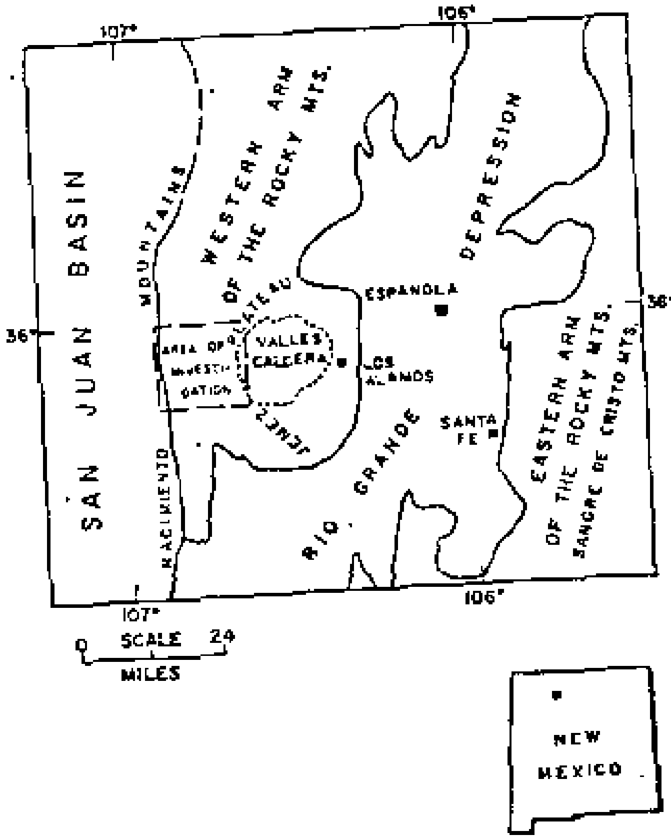
ITE SELECTION

he initial geothermal source demonstration area is located on the Jemez Plaeau, a part of the western arm of the Rocky Mountains that extends into orthern New Mexico (Figure 11.2).

FIGURE 11.2: MAJOR STRUCTURAL FEATURES AND AREA OF INVESTIGATION IN NORTH CENTRAL NEW MEXICO



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About a million years ago, the adjacent Valles Caldera was formed when a huge volcano erupted violently and then subsided into its own empty magma chamber. The Jemez Plateau is part of an apron of volcanic ash ejected during the eruptions. A subsequent series of smaller volcanic events is now represented by a number of rhyolite domes along the inner periphery of the caldera. As a result of this relatively recent volcanism, a large amount of heat is still regained in rocks underlying the entire area within a few kilometers of the surface.

In 1971, a field investigation was undertaken to determine whether a location accessible to the Laboratory could be found at which the geothermal gradient, geology, and hydrology indicated the probable existence of a usefully hot, dry geothermal reservoir at an economical drilling depth. Temperature-gradient measurements made in a series of holes drilled to depths of about 100 feet (30 meters) and the available geological, geophysical, and hydrological information suggested that such a reservoir might exist beneath the Jemez Plateau.

Additional field studies produced further encouraging evidence (7), including heat-flow measurements in holes drilled 650 to 1,000 feet (200 to 300 meters), which confirmed heat-flow values of about 5 heat-flow units (HFU) on the west side of the caldera. (HFU = μcal/cm²-sec. The worldwide average heat flow is 1.5 HFU.)

To investigate the feasibility of the LASL energy extraction concept and to verify the existence of a dry geothermal reservoir under the Jemez Plateau, a slim exploratory geothermal test hole (GT-1) was drilled in Barley Canyon on the west side of the caldera in 1972 to a final depth of 2,576 feet (785 meters). It penetrated about 500 feet (150 meters) into the basement granitic rock and reached a temperature of 212°F (100°C). The initial permeability of the hot basement rock was very low, so that it appeared capable of containing a pressurized-water circulation system, and of being fractured hydraulically at moderate pumping pressures.

On the basis of these studies and field experiments, a site on the Jemez Plateau about 20 air miles (32 km) west of Los Alamos was selected as being appropriate for development of the first hot dry rock energy experiment. This has been officially identified as the "Fenton Hill Site," or TA-57 (Technical Area 57). It is a gently sloping area on top of a mesa that was burned over in a forest fire in 1971, so site preparation involved minimal leveling and no destruction of standing timber. It is immediately adjacent to an all-weather state highway and to power and telephone lines, and is crossed by a forest road. Access is convenient, power is immediately available, and communications to and from the site are good.

Fenton Hill is situated on the Jemez Plateau about 1 mile (1.5 km) west of the outermost ring fault of the Valles Caldera and about 8 miles (13 km) west of the center of the caldera. The caldera, in turn, sits astride the western edge of the Rio Grande Rift (Figure 11.2).

The site is within a large coherent block bounded by faults and capped by the Bandelier Tuff, a welded ash flow. The closest fault with surface expression is the ring fault east of the site. About 2,400 feet (0.73 km) of Cenozoic and Paleozoic rocks overlie the Precambrian granitic rocks which form the basement of the Rio Grande Valley and the Jemez Mountains. The predominantly volcanic Cenozoic rocks consist of the Bandelier Tuff, the Paliza Canyon Formation and the Abiquiu Tuff. The Paleozoic rocks are mainly shales (Abo Formation) and the limestones (Magdalena Group) of Permian and Pennsylvanian age.

DRILLING AND TESTING PROGRESS

The Geothermal Energy Group at LASL was established March 1, 1973, and was given primary responsibility for the engineering aspects of the project, with scientific and engineering support to be provided by other Laboratory groups. It is the first project to investigate the feasibility of extracting geothermal energy from nonmolten hot rock in regions where the geothermal gradient is above normal but where neither natural steam nor hot water can be produced at economically useful rates from wells drilled into the geothermal reservoir.

To initiate large-scale field investigations of hot dry rock energy systems, the drilling of a second exploratory hole (GT-2) was begun in February 1974 at the Fenton Hill site. Many difficulties were encountered in drilling, cementing, and logging the hole; furthermore, it was necessary to drill the hole considerably deeper than originally anticipated to reach the target temperature of 392°F (200°C). Two heat flow values were obtained in GT-2 and GT-1. A heat flow of about 5 HFU was observed in the volcanic and sedimentary rocks; in the Precambrian rocks a value of 3.7 HFU was obtained. The difference apparently resulted from the flow of hot water along the Precambrian unconformity.

Hole GT-2

The problems encountered in drilling the Permian-age red beds and the Pennsylvanian age shales and limestones required that a string of 13⅜-inch diameter (35-cm) casing be set to a depth of 1,600 feet (488 meters). The Precambrian granitic surface was reached at 2,404 feet (733 meters) and a second string of 10¾-inch diameter (27.3-cm) casing was set from the surface to 2,535 feet (773 meters). Drilling continued to 6,700 feet (2,042 meters) using a 9⅝-inch diameter (24.4-cm) bits.

At this depth, a series of hydrology experiments was performed to determine the permeability of the lower granitic rocks. Hydraulic fracturing experiments were also conducted using methods and equipment developed by the oil-well services industry. Although the rock at this depth seemed to be broken by extensive natural fractures, water leak-off was slight.

As a result of these experiments, the Fenton Hill site was judged suitable for further development of the geothermal project. The hole was deepened to 9,619 feet (2,932 meters), and a 608-foot long (185-meter) liner was cemented into the bottom section of the hole to facilitate seating of packers for future fracturing experiments. A 38-foot (11.6-meter) section of hole was left uncased at the bottom. The equilibrium bottom-hole rock temperature was 386.6°F (197°C).

Later, additional fracture experiments were performed through perforations in the liner and in the open hole below the liner. A near-vertical, 400-foot radius (122 meter) fracture was thought to have been created near the bottom of the hole.

Hole EE-1

The second hole was located 252 feet (77 meters) northeast of GT-2. Drilling began in May 1975 and was completed in October at a depth of 10,053 feet (3,064 meters) and a bottom-hole temperature of 402°F (205.5°C). EE-1 was cased to 6,420 feet (1,957 meters) with three strings of casing, the deepest being 10¾ inches (27.3 cm) in diameter.

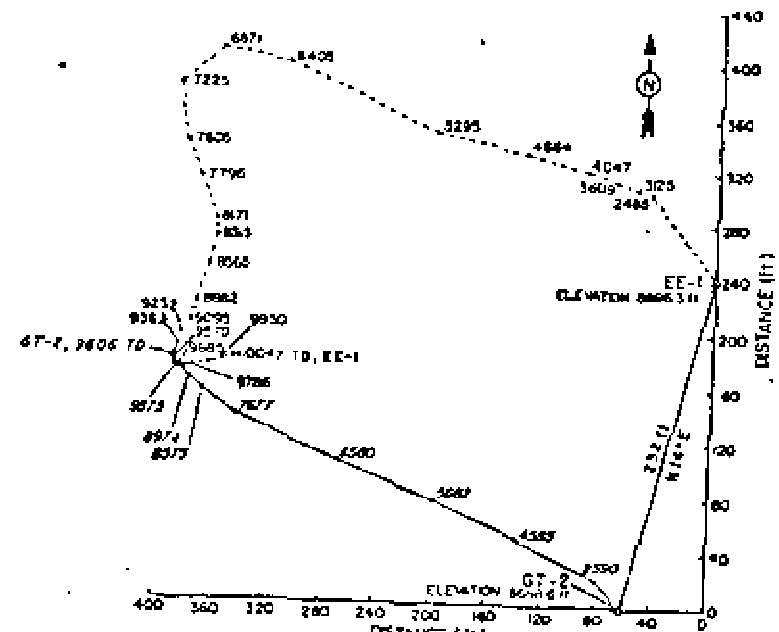
Directional drilling techniques were used below this casing to angle EE-1 toward the presumed fracture at the bottom of GT-2. EE-1 was directionally drilled below 8,866 feet (2,099 meters) to intersect the fracture zone at the bottom of GT-2. The hole was drilled through a 205° spiral, turning counterclockwise from an initial northwest heading to a northeast heading (Figure 11.3).

On October 14, 1975 flow between the two drill holes was established, creating for the first time a man-made connection in hot, nearly impermeable basement

rock. After circulation was established, EE-1 was cased to 9,600 feet (2,926 meters) with a 7⅝-inch diameter (19.4-cm) casing for subsequent pressurized flow and heat extraction experiments. Circulation tests between the two holes were then conducted to determine the dimensions and characteristics of the downhole reservoir system.

The predominant Precambrian rock in both holes is banded granitic gneiss. In one section, biotite schists are interlayered with the gneiss which is intruded by unfoliated monzogranite dikes. A relatively extensive and homogeneous biotite-granodiorite body was encountered at depth. Drill cores show numerous fractures, usually well sealed or healed.

FIGURE 11.3: PLAN VIEW OF PATHS OF DRILL HOLES



DIRECTIONAL DRILLING IN GT-2 AND EE-1, PLAN VIEW
(DEPTHS, IN ft, MEASURED FROM ELEVATION TAKEN AT CASING FLANGE NEAR GROUND LEVEL)

ource: LA-UR-77-2028

xcept for coring, all drilling in the crystalline basement was done with full-face icone rock bits. For standard drilling, the bit rotational speed was 40 rpm; r directional drilling, it was 250 rpm. Penetration rates ranged from 2.8 ft/h .9 m/h) to a maximum of 38 ft/h (11.6 m/h). The maximum standard drill- g interval for a single bit was 672 feet (205 meters) in 75 hours; the maximum rectional drilling interval was 115 feet (34.4 meters) in 5 hours. These two ues constitute the bulk of existing drilling experience in hot granitic rocks us- g conventional oil-field equipment.

Redrilling Hole GT-2

Because of inaccuracies in locating the fracture when the intersection was attempted, EE-1 missed the fracture by about 27 feet (8 meters). However, as a result of additional hydraulic fracturing experiments, the two holes were connected. The impedance to the flow of water in that fracture system was too high, though, for the proposed 10-MWt heat extraction experiment. Therefore, beginning in April 1977, GT-2 was directionally redrilled to connect it with a fracture produced from EE-1.

A cement plug was set in GT-2 at a depth of 8,300 feet (2,530 meters), and after several attempts, the hole was sidetracked using 9⅝-inch diameter (24.4-cm) diamond bits, followed by tricone bits. The first trajectory apparently intersected the EE-1 fracture near its upper edge, and the resulting impedance was still too high to be useful. A second sidetracking was successful in obtaining an impedance that appeared to be acceptable.

On June 3, 1977 during a 20-hour pumping experiment, cold water pumped down EE-1 at 1,000 psi (6.89 MPa) was heated to 266°F (130°C), and the rate of water recovery was 85% of the injection rate. The temperature and the recovery rate are expected to increase as the system is operated.

The hole was completed by cementing a string of 7⅝-inch diameter (19.4-cm) casing from 8,572 feet (2,612.8 meters) to the surface. [In a 96-hour circulating test run performed in September 1977, energy was extracted at a rate of 3.2 MWt with water temperature of 132°C.]

Heat Extraction Experiment

The 10-MWt heat extraction experiment (scheduled for 1978) will be conducted for several months to determine the mechanical, physical, and chemical properties of the reservoir and the heat exchange system. A schematic drawing of the surface facilities for such a test is shown in Figure 11.4. If it is successful, the system will be expanded to a 100-MWt experiment by drilling deeper to 12,500 feet (3,810 meters) where temperatures of 482°F (250°C) are expected.

Such a facility could produce enough electricity for 10,000 consumers and would provide unique and useful information on the design and construction of a small-scale electric generating plant that uses this new energy resource.

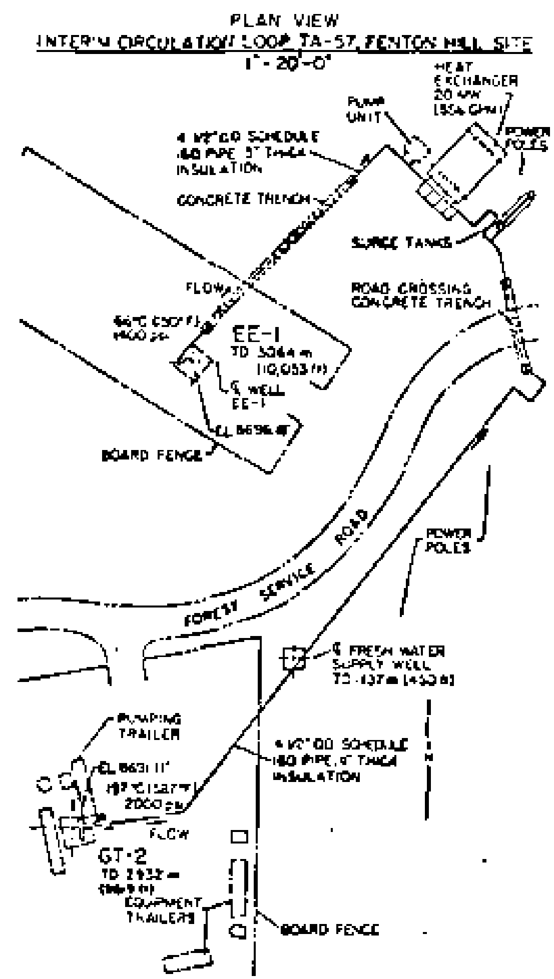
PROJECTED DEVELOPMENT (8)

Clearly, no commercial production of energy from hot dry rock geothermal reservoirs will be attempted until at least one energy extraction system has been operated long enough to demonstrate its usefulness and reliability and to evaluate in detail its behavior and economics. If the Los Alamos Project is successful, this may have been accomplished for one type of system by 1980. If that occurs, then the first demonstrations of the use of this type of geothermal energy both for generating electricity and for nonelectrical purposes could be in progress by 1981. These demonstration systems will probably be small, each producing on the order of 80 MWt or 10 MWe, and it will probably be necessary to operate them for 2 or 3 years before funds can reasonably be committed for

construction of commercial-scale systems. However, again assuming success in the pilot-scale operations, it is quite possible that two to four commercial plants might be in operation by 1990, producing perhaps 600 MWt and 80 MWe.

Thereafter, depending both on technical progress in the use of this and other forms of energy and on economic and environmental constraints, the rate at which new hot dry rock systems could be developed would be controlled primarily by the rate at which deep holes could be drilled into hot rock.

FIGURE 11.4: 10 MWt CIRCULATING LOOP



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ENVIRONMENTAL MONITORING

An environmental monitoring study of the project has been initiated and a report issued (9). Included in the report are descriptions of the work that has been done in three major monitoring areas: (1) water quality, both surface and subsurface; (2) seismicity, with a discussion of the monitoring strategy of regional, local, and close in detection networks; and (3) climatology. The purpose of these programs is to record baseline data, define potential effects from the project activities, and determine and record any impacts that may occur.

The development of the hot dry rock geothermal energy resource and associated energy extraction technology is a new field of endeavor, with no established environmental guidelines. It is doubtful if the problems encountered and solutions devised in traditional geothermal systems will apply directly to the hot dry rock development. Therefore, the impacts that are encountered in this project will be of particular value in making future environmental assessments for this type of energy resource development in other locations in different geologic settings. To date, there have been no unacceptable impacts on the environment in any of the three monitoring areas.

SUMMARY

Over the past 5 years the LASL HDR Project has progressed considerably. At LASL and under subcontracts with industry, many new instruments were developed to operate in the high-temperature (200°C), high-pressure (400 bar) environment downhole, including acoustic detectors, gyroscopic survey tools, a mechanical acoustic source, temperature probes, self-potential (SP) and induced-potential (IP) probes, and water samplers.

Major technical achievements have been made in developing and modifying diagnostic and analytical techniques for mapping and characterizing the hot dry rock reservoir. Directional drilling and hydraulic fracturing in hot granitic rock were just two of many "firsts" achieved. For a detailed description of this work see Reference (10).

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Proprietary Processes

CONVERSION SYSTEMS

Production of Power, Desalted Water and Inorganic Salts

The system of *L. Awerbuch and C.T. Draney; U.S. Patent 3,953,972; May 4, 1976; assigned to Bechtel International Corporation* includes a surface evaporator which allows a preheated distillate, freed of impurities, to be vaporized by the heat energy of the steam and/or brine from a geothermal well. The resulting vapor is used to drive a power unit such as a multistage turbine. The vapor exhausted from the power unit is condensed by any of a number of conventional means. A portion of the condensate is then recycled through the system, wherein it becomes the direct contact condensing medium for the vapor produced by flashing hot geothermal brine in a multistage flash evaporator through which the brine and the condensate are passing countercurrently.

The vapor thus condensed augments the aforesaid recycled condensate and, together, they constitute the aforementioned distillate entering the surface evaporator and carrying with it the heat energy extracted from the brine in the flash evaporator. The remainder of the condensate from the condenser may be withdrawn from the system and constitutes a product resulting from the practice of the desalination process. Residual brine is carried off from the multistage flash evaporator and contains retrievable salts and other valuable minerals.

Cooled Water as Bearing Lubricant

A major advance in the art of extraction and use of geothermal energy is reflected in H.E. Matthews' U.S. Patent 3,824,793, assigned to the Sperry Rand Corp. The Matthews process provides means for efficient power generation employing energy derived from geothermal sources through the generation of dry superheated steam and the consequent operation of subsurface equipment for pumping extremely hot well water at high pressure to the earth's surface. Clean water is injected at a surface station into the deep well where thermal energy stored in hot solute-bearing deep well water is used at a deep well station to

generate superheated steam from the clean water. The resultant dry superheated steam is used at the well bottom for operating a turbine-driven pump for pumping the hot solute-bearing well water to the station at the earth's surface. The water is pumped at all times and locations in the system at pressures which prevent flash steam formation. The highly energetic water is used at the surface station in a binary fluid system so that its thermal energy is transferred to a closed-loop surface-located vapor generator-turbine system for driving an electrical power alternator. Cooled, clean water is regenerated by the surface system and is reinjected under pressure into the well for operation of the steam turbine therein. Undesired solutes are pumped back into the earth via a separate well in the form of a concentrated brine.

The process of *K.E. Nichols; U.S. Patent 3,961,866; June 8, 1976; assigned to Sperry Rand Corporation* is an improvement over that of the Matthews patent and provides long life and efficient operation particularly of those parts of the system employing clean water reinjected into the well from the earth's surface, in particular for providing a lubricating fluid in fluid bearings supporting the rotors of the deep well turbine-pump system. As the clean lubricant flows toward the turbine-pump bearings, it is progressively heated, being unavoidably exposed to heat transferred from the rising pumped hot well water. The lubricant water is maintained, in part, in the fluid state because it is under high pressure so that it is not allowed to flash into steam. It is further desired that the water additionally benefits by cooling near its point of use so as fully to prevent its flashing or vaporization within the hydraulic bearings.

In some applications, the heat from the hot pumped well water may raise the lubricating water to a temperature near that of the well water. In these circumstances, very high pressures are required to prevent flashing of the lubricating well water within the bearings. In practice, subcooling merely by increasing the lubricating water pressure is not found to be practical as the well water approaches the critical temperature of the clean water of 704°F. Furthermore, the load capacity of the hydrodynamic bearings employed is proportional to the viscosity of the lubricant; thus, lower temperatures in the bearings provide increased load capacity, viscosity increasing with decreasing temperature.

The process accomplishes the desired result by making effective use of the exhaust steam from the steam turbine that drives the hot well water pump. This exhaust steam is significantly cooler than the pumped hot well water, in part because of the expansion and energy exchange process which transpires within the driving turbine. The low temperature turbine exhaust steam is therefore passed in heat exchanging relation with respect to the lubricating water, additionally cooling the latter.

The process of *H.B. Matthews; U.S. Patent 4,025,240; May 24, 1977; assigned to Sperry Rand Corporation* is an improvement in deep well geothermal systems of the kind described in the aforementioned U.S. Patent 3,824,793. There is provided an efficient means for the generation of electrical power at the earth's surface, using energy abstracted from the geothermal source. The apparatus includes means for the efficient generation of superheated steam and a steam driven pumping system at the well bottom operated for transfer of hot water to the earth's surface where its energy content is beneficially used for power generation. According to one feature of the process, the deep-well steam turbine and pump arrangements are supported in a system of hydrodynamic thrust and radial bearings with all bearing surfaces fully bathed in clean water serving as a lubricant and maintained under pressure so as to prevent entry of the corrosive and contaminated hot well water and the consequent ultimate destruction of bearing surfaces. Alternatively, a bearing configuration employing hydrodynamic bearing elements may be employed. A thrust ball bearing arrangement is provided that normally comes into play only when starting or stopping the turbine hot water pump system.

A further feature of the process permits use of surface-located apparatus for assuring efficient continuous operation of the power generation system, and also enables controlled starting and stopping of the subterranean steam turbine-pump apparatus. A further aspect of the process permits efficient steam generation in a confined annular volume lying between concentric vertical tubes; the feature causes a spiralling downward flow of steam and a diminishing population of water drops so that they both flow in close proximity to the hottest of the two tubes, thus improving the efficiency of steam formation.

Series of Flash Stages

The process of *T.K. Sherwood; U.S. Patent 3,972,193; August 3, 1976 assigned to Union Oil Company of California* comprises the steps of producing hot geothermal brine from a subterranean geothermal reservoir; passing the brine successively through a series of separate flash stages, each successive stage being maintained at a lower pressure than the vapor pressure of the brine entering that stage so that the brine is partially flashed to vapor in each stage; countercurrently flowing a working fluid successively through the series of flash stages in indirect heat exchange with the vapor produced in each flash stage so that the vapor condenses in each flash stage and the working fluid is progressively heated as it passes through the series of flash stages; and, then, utilizing the heated working fluid in a heat engine for the production of mechanical energy.

Exemplary heat engines include steam turbines, steam engines, gas turbines, and other prime movers capable of utilizing a heated working fluid in the production of mechanical energy. In the most practical application of this process, a turbine will be used to produce the mechanical energy to drive an electrical generator for the production of electrical power.

The process provides the important advantage of not allowing the hot geothermal brine to directly contact a heat exchange surface. Another important advantage is that mechanical energy can be produced without having brine-produced vapors fed to the heat engine. A further advantage is that the working fluid can be heated to a temperature very near the temperature of the produced geothermal brine. This is accomplished through the use of incremental pressure reductions in each successive flash stage. Because of the incremental reductions in pressure, the temperature of the brine is also only incrementally reduced, thereby allowing the countercurrently flowing working fluid to be progressively heated to a temperature near the temperature of the produced geothermal brine.

In the practice of this process, it is preferred that the temperature of the brine entering the first flash stage be above 250°F, most preferably above 350°F. Since one important benefit provided by the method results from the incremental reductions in vapor temperature, it is desired to maintain the pressures in the flash stages such that the brine is cooled by not more than about 35°F per flash stage, and preferably between about 1° and 10°F per flash stage. It is also preferred that the geothermal brine in the last flash stage be cooled to below about 150°F.

For High Temperature Source

The process of *P. Baciu; U.S. Patent 3,986,362; October 19, 1976* relates to a geothermal power device and process utilizable specifically with high temperature geothermal energy.

The process includes a passing of a heat exchange liquid medium to a geothermal source of predetermined elevated temperatures, passing a liquid state heat exchange medium from the geothermal heat energy source into a gas generator having a high pressure conduit extending therethrough in heat exchange relationship carrying, in heat exchange contact-isolation from the geothermal heat exchange medium, a supercritical operating coolant preferably ammonia, fed to the gas generator in the high pressure conduit in a liquid state and converted to a supercritical gaseous state of supercritical temperature and pressure and fed to a high pressure turbine.

The effluent of the high pressure turbine, in a gaseous state, at relatively high pressure conditions, is fed to an intermediate superheater through high pressure coils extending through interior space of the superheater having liquid sodium, preferably, in the interior space heated by the heat exchange media passed by another high pressure conduit extending also through the space interior of the superheater in isolated flow but heat exchange relationship therewith. Superheated ammonia from the intermediate superheater is fed to a low pressure turbine in which the temperature and pressure are reduced to low conditions, the effluent from the low pressure turbine being fed through a condenser and thereafter through a pump in a return cycle to the gas generator for the reheating to the gaseous supercritical state.

Direct Heat Exchange

W.F. Franz and H.V. Hess; U.S. Patent 4,043,386; August 23, 1977; assigned to Texaco Inc. provides a process for recovering heat from a hot geothermal brine which comprises:

(a) passing the hot brine in direct countercurrent contact with a relatively cool hydrocarbon liquid in a first heating zone whereby the brine is cooled and the hydrocarbon liquid is heated to an elevated temperature under sufficient pressure to maintain the brine and the hydrocarbon in liquid phase,

(b) withdrawing the heated hydrocarbon liquid from the first heating zone and passing it in direct countercurrent heat exchange with water in a final second heating zone whereby the hot hydrocarbon liquid is cooled and the water is heated to an elevated temperature and pressure and wherein step (b) is carried out under sufficient pressure to maintain the hydrocarbon and water in the liquid phase, and

(c) withdrawing the heated water from the second heating zone.

The water heated to an elevated temperature and pressure may be employed for a variety of heating requirements in process operations. For example, the heated water may be utilized in indirect heat exchange to heat refinery feedstocks, etc. Alternatively, the heated water withdrawn from step (b) above, may be passed through a pressure letdown valve thus forming steam useful in power generation in low pressure turbines or for a variety of other process heating operations.

Generally the temperatures of the hot incoming brine will vary from about 400° to about 750°F. In the first heating zone the relatively cool hydrocarbon liquid will be heated to a temperature of from 400° to about 700°F and the pressure maintained in the first heating zone which must be sufficient to maintain the brine and hydrocarbon in liquid phase, will vary from about 250 to 3,300 psi. In the second heating zone the water will usually be heated from about 100° to 600°F while the pressure in the second heating zone which must be sufficient to maintain the hydrocarbon and water in liquid phase will range from about 250 to 1,600 psi.

Multiple-Completion System

The multiple-completion geothermal system of the process of *A.T. Van Huisen; U.S. Patents 4,051,677; October 4, 1977 and 4,054,176; October 18, 1977* includes a plurality of geothermal wells, each having a first end converging toward and meeting at a first point and having a second end diverging from that point and terminating in a geothermal zone, each second end being spaced from any other second end of the geothermal wells. This system further includes a reservoir located at the first point receiving heated goethermal fluid from the second end of each well, outlet means connected to the reservoir for conducting the heated geothermal fluid in turn to separation means and energy conversion means. The system in accordance with this process also may include control means for sequentially activating production from each of the plurality of wells in sequence to promote movement of hydrothermal fluids within the geothermal zone.

Depending on the condition of the geothermal zone, the system may require further structure. In a wet geothermal zone, the fluid will operate as a carrier for the heat energy to deliver it to the surface under pressure. In the case of a dry geothermal zone or one containing a molten brine pool with insufficient pressure, the implantation of closed end heat exchangers at the ends of the wells requires means for conducting heat exchange fluid to the heat exchangers which may be connected to the turbine to return the condensate to the heat exchanger in a closed cycle loop. Heat transfer to the heat exchanger in a dry geothermal zone may also be enhanced by injection of water into the zone external to the heat exchanger to create hot fluid to increase the transfer rate of heat to the outside surface of the heat exchanger.

It is apparent that the system minimizes the amount of surface area needed for access to the subsurface geothermal zone, the amount of surface area needed for collection and conversion of the geothermal fluid to electrical energy and minimizes the external piping conduits and energy loss that would be entailed in the separate spaced drilling of multiple wells to tap and mine the geothermal energy in a known geothermal resource area. The system also includes provision for controlled collection of the energy and in a manner to promote convection and movement of the hydrothermal fluids to increase the rate of energy recovery and to decrease the possibility of scaling and fouling the external portions of the wells being utilized for collection and transfer of heat.

From Salt Formations

A method of obtaining geothermal energy from salt formations is provided by *S.J. Altschuler; U.S. Patent 4,052,857; October 11, 1977; assigned to The Dow Chemical Company* in which a well is drilled and cased into a suitable salt formation to a depth where the temperature is such that the salt behaves plastically. A weighted, closed end pipe is inserted into the well with its lower, closed end at about the bottom of the salt formation and thereafter an insulated open end pipe is inserted, after the weight has been removed from the closed end pipe, within the closed end pipe, thus forming a double pipe heat exchanger. A heat exchange fluid is circulated, usually in a closed loop, through the double pipe heat exchanger, an energy extracting means, such as, for example, a steam generator or an hydraulic turbine, and back through the heat exchanger.

This process utilizes two unique properties of rock salt; its relatively high thermal conductivity compared to almost all rock and its plasticity, the onset of which occurs at temperatures well below its melting point, i.e., from about 200° to 350°C which are expected to be found at depths of about 10,000 to 15,000 feet.

The thermal conductivity coefficient of rock salt formations is, for the most part, several times higher than the coefficients of sedimentary rock structures that overlie them. Thus, a salt dome will be an efficient conduit through which heat will pass from deep within the earth's crust and an anomaly which will be hotter than its surroundings at equal depths at least near its top. It is well within the capacity of modern borehole drilling techniques to reach those depths where the rock salt begins to exhibit plastic behavior.

Heating Organic Fluid in Geothermal Formation

G.B. Arnold; U.S. Patent 4,060,988; December 6, 1977; assigned to Texaco Inc. provides an in situ heat exchange process for heating an organic fluid, which can be, for example, a normally liquid hydrocarbon having from 4 to 10 carbons, in a geothermal reservoir formation penetrated by an injection well and a production well.

The process comprises injecting the fluid into the formation via the injection well, forcing the fluid through the formation with simultaneous heating and finally recovering the heated fluid via the production well. Utilizing heat exchangers at the surface, the heated fluid may be employed to supply process heating requirements for such diverse operations as preheating of refinery streams as exemplified by crude oil feed to distillation units, for salt evaporation, etc. or the heated fluid, preferably after removal of any brine derived from the geothermal formation, may be employed in gaseous form to operate turbine generators.

Use of Hydraulic Impulse Turbine

In the process of *J.R. Shields; U.S. Patent 4,063,417; December 20, 1977; assigned to Carrier Corporation* geothermally heated fluid is supplied in a nozzle of the first stage of a hydraulic turbine. The water constituent of the geothermally heated fluid is directed by the nozzle against the wheel of the hydraulic turbine to cause the wheel to rotate. A first generator is coupled to the wheel whereby rotation of the wheel results in the generation of electricity. A portion of the geothermally heated fluid passing through the nozzle flashes to a vapor phase. The vapor is delivered to the first stage of a vapor driven turbine. The vapor passes through the wheel of the turbine which results in rotation thereof. A second generator is coupled to the wheel of the vapor driven turbine whereby rotation of the wheel results in additional generation of electricity.

The hydraulic turbine is preferably of the impulse type. Preferably, the hydraulic impulse turbine includes more than one stage. The number of stages employed in the hydraulic turbines and steam turbines will vary as a function of the pressures at the inlet to the hydraulic and steam turbines and further as a function of the condensing water temperature at the steam turbine exhaust.

Preventing Absorption of Working Fluid

A power producing system employing geothermally heated fluid is described by *J.R. Shields; U.S. Patent 4,063,418; December 20, 1977; assigned to Carrier Corporation.* The geothermally heated fluid is supplied to a direct contact heat exchanger where it is passed in heat transfer relation with a working fluid. The working fluid is preferably an organic fluid of the type that is insoluble in a solution containing inorganic salts. The working fluid is vaporized and thereafter delivered to a prime mover wherein it is expanded to cause the prime mover to generate power. The expanded working fluid is exhausted to a second direct contact heat exchanger where it is passed in heat transfer relation with a relatively cold heat transfer medium comprising a salt solution wherein the working fluid is condensed.

The condensed working fluid is thereafter returned to the first direct contact heat exchanger for reuse in the cycle. A quantity of inorganic salts is mixed with either the geothermally heated fluid or the relatively cold heat transfer medium at a point upstream of the first and second direct contact heat exchangers to maintain the percentage by weight of inorganic salts in the geothermally heated fluid and the relatively cold heat transfer medium above a predetermined value to prevent the working fluid from being absorbed by the geothermally heated fluid or the relatively cold heat transfer medium.

The system takes advantage of the fact that an inorganic fluid such as isobutane is generally insoluble in a solution containing inorganic salts, such as sodium chloride, calcium chloride, or sodium sulfate. Preferably, the geothermal fluid should contain at least 10% by weight of inorganic salts.

Because of the vast amount of working fluid circulated per day in any commercial system employing geothermally heated fluid to vaporize a working fluid such as isobutane, the solubility of the isobutane in the geothermal fluid or in the condensing fluid has to be essentially zero. For example, if one part in ten thousand of the isobutane fluid is absorbed into the geothermal fluid or into the condensing fluid, the system may not be run economically. Thus, by maintaining the quantity of inorganic salts in the geothermal fluid and the condensing brine solution at a predetermined minimum value, the solubility of the working fluid into the two heat transfer brine media approaches zero. Thus, direct contact heat exchangers may be satisfactorily employed in geothermal fluid systems thereby improving the efficiency of such systems since the direct contact heat

exchangers will not suffer from clogging or other problems associ[ated w]ith surface or tube-in-tube condensers.

Producing Fresh Water and Electric Power

J.M. Edmondson and M.H. Smoot; U.S. Patent 4,091,623; May 30, 1978 provide a method and apparatus to provide fresh potable water and electric power from a source of natural brine by the use of energy derived from a geothermal source of pressurized fluid that is of a temperature of greater than 212°F.

In the first and simplest form of the process a borehole is formed in the earth adjacent a natural body of saline water such as the Salton Sea, which borehole has pressurized mineral-containing fluid discharging therefrom at a temperature of greater than 212°F. Valve means are provided to control the discharge of the pressurized mineral-containing fluid from the borehole.

A closed reservoir is provided to which saline water from the Salton Sea can flow, preferably by gravity. The reservoir is preferably insulated to retain heat within the confines thereof, the reservoir having pressurized fluid from the geothermal source discharging therein. Intermittently, water from the Salton Sea or other source of saline, aqueous liquid is discharged into the reservoir.

Pressurized fluid from the geothermal source has a sufficient heat content that it tends to flash into steam when discharged into the reservoir under reduced pressure, with the steam being discharged below the body of saline water from the Salton Sea that is in the reservoir. The pressurized fluid heats the combined water in the reservoir and transforms the same into steam which flows therefrom to a first heat exchanger where the steam is at least partially condensed to water by the cooling effect of water flowing through the first heat exchanger from the Salton Sea to the reservoir.

The partially condensed steam and condensate flows to a second heat exchanger where condensation of the steam to water is completed. The water accumulating in the second heat exchanger is by a pump or similar means withdrawn therefrom, and by the use of suitable valving, the water may be returned to the Salton Sea, or diverted for other uses such as irrigation, or the like.

In a second form of the process a reservoir is used to entrap extraneous material produced with the pressurized fluid from a geothermal source thereby providing clean steam. The steam discharging from the closed reservoir is used to transform a low boiling point liquid to pressurized vapor that is used to drive a gas turbine that is connected to an electric generator. The pressurized vapor discharging from the turbine is cooled in a heat exchanger to return the vapor to the liquid state, and the low boiling point liquid is recycled by a pump.

The pump in this form of the process may be driven by an electric motor that is furnished with electric power from the turbine-driven generator. In the second form of the process the steam condensate can be returned to the reservoir rather than diverted for other uses. Residual material is removed from the heating reservoir and returned by pump or similar means to the subsurface stratum containing the geothermal resource.

A third form of the process is, in effect, a combination of the first and second forms, with the third form providing electric energy as well as potable fresh water that is returned to the Salton Sea, or used for irrigation or other desired purposes.

A fourth form of the process is, in effect, a combination of all of the previously described forms with the addition of a means for separating the initial steam from the geothermal source, and using the heat from the initial steam to heat the vapors evolved from the low boiling point liquid.

Direct Contact with Working Fluid Below Its Critical Pressure

S.G. Woinsky; U.S. Patent 4,089,175; May 16, 1978; assigned to Occidental Petroleum Corporation provides a process for recovering energy from geothermal brines and other water-containing or hot water sources, the energy being recovered from the brine or hot water using a working fluid such as n butane. The working fluid is heated by the brine or hot water preferably in a direct contact heat transfer column. The heated working fluid is passed through an expander to produce work, which is used to generate electricity or drive equipment. The working fluid from the expander is condensed in a cooler. Condensed working fluid, water and uncondensed gas are separated in an accumulator. The cooling liquid working fluid is pumped from the accumulator to the heat transfer column to be heated and carried through the cycle repeatedly.

Cooled brine or water which heated the working fluid in the heat transfer column exits from the bottom of the column which acts as a liquid-liquid separator to minimize entrainment of the working fluid. This cooled brine or water withdrawn from the column is mixed with water separated from the working fluid in the accumulator, and is flashed at a pressure lower than that in the accumulator to flash off entrained and dissolved working fluid in the brine or water from the heat transfer column. The flashed working fluid is then compressed and fed to the cooler at the discharge from the expander, which is used to condense working fluid, and thus is recovered.

Uncondensible gases which are introduced into the system with the feed brine or hot water are vented from the system at the accumulator, and carry away some of the expanded working fluid. If desired, stripping of the cooled brine or water withdrawn from the column, with uncondensed gas from the accumulator for recovery of working fluid from such brine or cool water can be employed, if necessary, to further decrease the loss of working fluid in such exit brine or water.

Uncondensed gas is vented from the accumulator preferably under pressure control set for an economic balance between working fluid loss in the vent gas and energy recovery in the expander. If necessary, in order to decrease the loss of working fluid in the vent gas, the hot water or brine feed to the heat transfer column is initially degassed. This operation will decrease the amount of uncondensible vent gas from the accumulator, and the loss of working fluid therewith.

An important feature of the process resides in operating the heat transfer column so that the top of the column is in the subcritical pressure region of the working fluid close to or approaching the apex of the saturated vapor curve on the Mollier diagram for such fluid. This procedure provides a working fluid boiling zone at the top of the column. In view of the lower pressure of the resulting vaporized working fluid as compared to operation under critical or supercritical pressure

conditions, somewhat less energy is recovered per pound of workin d but more pounds of working fluid are circulated resulting in similar energy recovery per stage but a lower cold brine temperature. Advantages which can accrue from from operation under subcritical pressure conditions include simplicity of controls.

In normal operation, since the cooled brine or water exiting the column, and which is flashed off to recover entrained or dissolved working fluid, can still be at a relatively high temperature, in order to maximize the recovery of energy from the hot brine or hot water feed, two or more units of the basic system noted above can be employed in series, the flashed exit brine or water from one unit of the system serving as the feed to the heat transfer column of the second like unit, etc.

In such modification a different working fluid can be employed in the heat transfer column of the second unit from the working fluid in the heat transfer column of the first unit, in order to adjust the conditions of the hot working fluid in the second heat transfer column to a point near the apex of the saturation curve on a Mollier diagram and thus maximize energy recovery.

Hollow Heat Absorber

The process of *W.F. Ash and F.R. Ash; U.S. Patent 4,094,356; June 13, 1978* comprises a geothermal energy recovery system in which a working fluid is maintained in a closed cycle. The closed cycle includes a heat absorber at the bottom of the geothermal well, a heat exchanger within a water boiler or similar working device at the top of the well; and a supply tank interposed between the heat exchanger and the supply pipe. In this extremely simplified closed cycle system, the working fluid acts as its own pumping agent, and no vapor condenser is required.

The heat absorber is disposed at the bottom of the geothermal well, and is surrounded by a quantity of heavy drilling mud. The drilling mud protects the heat absorber from the corrosive action of geothermal vapors, acids, and the like. Extending upwardly from the heat absorber is a high pressure gas delivery pipe which is connected in turn to the input side of the heat exchanger. The output of the heat exchanger is connected to a working fluid supply tank. The supply tank is connected through a thermostatic valve to a supply pipe extending down into the well to the heat absorber.

It may be appreciated that the long supply pipe extending down into the well creates a rather high pressure head for the working fluid. The amount of working fluid entering the supply pipe and flowing into the heat absorber is controlled by the thermostatic valve, which senses the heat requirements within the water boiler.

The working fluid, which may be a Freon compound of predetermined density and boiling point, is quickly vaporized within the heat absorber and becomes a high temperature, high pressure gas. The hot gas has a very low density and rises quickly in the delivery pipe. The majority of the heat content of the gas entering the heat exchanger from the delivery pipe is in the heat of vaporization of the gas, and this heat is given up to the water boiler or the like as the hot gas condenses back into a liquid. The liquid then drains from the heat exchanger into the working fluid supply tank.

BRINE [illegible]UCTION AND WELL STIMULATION

Gas Lifting Brines

Air lifting used to be a popular method of pumping liquids but has largely been displaced in many previously favored applications by deep-well (down-hole) centrifugal pumps. The latter pumps are more economical and can handle corrosive and erosive liquids when appropriately designed and fabricated of suitable materials. However, simplicity and the absence of moving parts in contact with the liquid to be pumped remain as outstanding advantages of gas-lifting, particularly where economic considerations are not paramount.

The process of *E.L. Carlson, A.A. Gunkler, C.O.M. Miller and H.H. Paalman; U.S. Patent 4,017,120; April 12, 1977; assigned to The Dow Chemical Company* is the method of producing from a subterranean formation a hot brine containing a dissolved gas and from which mineral precipitation will tend to occur if the composition of the gas in the brine is substantially altered, the method comprising gas-lifting the brine to the surface of the earth through a well bore communicating with the formation, using a gas of essentially the same composition as the dissolved gas, including steam, and discharging the resulting gas/brine mixture from the well against a back pressure which is maintained at a level not substantially lower than the vapor pressure exerted by the brine at the temperature prevailing at the point of introduction of the lift gas in the well, thereby preventing substantial subsurface flashing or stripping of the brine.

In a preferred mode of operation, the lift gas is separated from the produced gas/brine mixture and is repressurized and recycled to the gas-lifting operation. In a particularly important mode of operation, the brine contains a dissolved mineral which will tend to precipitate if the temperature of the brine is lowered below the formation temperature by more than about x degrees, and heat is recovered from the brine, after the lift-gas is separated from it, (preferably indirect heat exchange) in an amount such that the temperature of the brine is lowered below the formation temperature by less than x degrees.

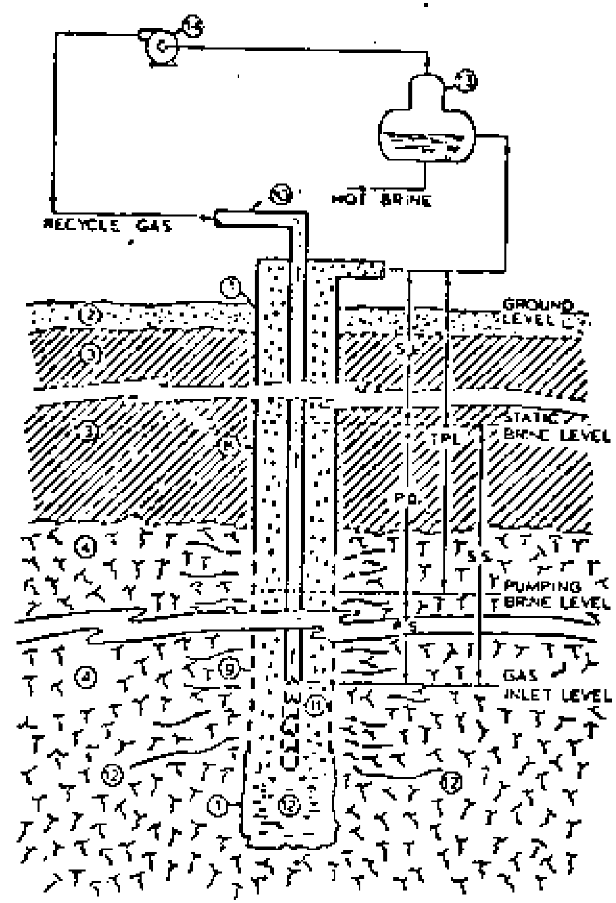
In the preceding mode of operation, the heat-depleted brine optionally is recycled to the geothermal aquifer through one or more wells sufficiently far from any production well to avoid substantial cooling of brine still to be produced, or is discarded.

In an alternative procedure, additional heat is removed from the produced brine so that its temperature is decreased by a total of more than x degrees, and the resulting cooled brine is worked up to recover at least those mineral components precipitated as a result of the additional heat removal, or is discarded.

Referring to Figure 12.1, a well-bore 1 is shown penetrating a layer 2 of surface sediments, a thickness of relatively impermeable cap rock 3 and an aquifer 4, the latter overlying bed rock and a magmatic intrusion. A well casing 8 is inserted in bore 1 and is pierced by openings (slots or perforations) 9 through which the brine 12 enters from the aquifer 4. Gas input tubing 10 passes through appropriate wellhead fittings (not shown in detail or numbered) and extends nearly to the bottom of bore 1. In the figure, the lower end of this tubing is shown as closed, the closure and adjacent wall sections being shown as pierced by openings 11. The produced brine/gas/steam mixture is passed to

a separator 13 from which a hot brine stream is withdrawn and [illegible]s and steam is taken overhead to a compressor 14. The compressed gas/steam mixture is recycled to the aquifer through gas inlet tube 10.

FIGURE 12.1: GAS LIFTING BRINES



Source: U.S. Patent 4,017,120

The static lift (SL) is the vertical difference between the static brine level (the level of the brine surface in the well when no brine is being produced) and the above ground level to which the brine must be raised for processing at the surface. The total pump lift (TPL) is equal to the static lift plus the pumping drawdown (PD), i.e., the amount that the brine level will have dropped when the brine is being pumped at a given rate. That is, TPL is the difference between the brine level when pumping and the processing level. The static submergence (SS) is the vertical difference between the static brine level and the

pumping gas inlet level. The pumping submergence (PS) is less than the static submergence by an amount equal to the drawdown. That is, the pumping submergence is equal to the vertical distance between the pumping brine level and the gas inlet level.

In order to specify initial operating parameters and size equipment for development of a given geothermal field, empirical data obtained from at least one test well will usually be required. In addition to test well data, geophysical and geochemical data are of considerable value, not only for selecting a test well site, but also in conjunction with test well data for specifying operating parameters and for selecting and sizing equipment. Particularly important for the latter purpose is a knowledge of the chemical compositions of both the brine and the gases associated therewith in the aquifer to be exploited.

More than one type of brine can occur within a given geothermal system and the composition of the thermal gases (other than steam) associated with a given brine type can vary. Three main types of thermal gases are discernible: (1) high nitrogen content; little or no active gases; (2) very high CO_2 and minimal H_2S and H_2 contents; and (3) high contents of H_2, H_2S and CO_2. Other constituents of thermal gases are methane, argon, ammonia and H_3BO_3.

The dependency of solubility equilibria between various mineral and gaseous components of brines on temperature and pressure (depth) is quite complex. Consequently, it is difficult to predict how much flashing or stripping of a given brine can be permitted to occur without experiencing in-well precipitation of silica, calcite, etc. Furthermore, operating parameters established for one well in a geothermal field may not necessarily be applicable to a second well. However, if essentially no flashing or stripping is allowed to occur in a test well, surface tests on the produced steam/gas/brine mixture will provide data from which initial operating conditions for the test well can be set.

Also, operating conditions for the next well in the same field can at least be estimated from the data by those skilled in the art. Such data include the temperature drop (represented as x elsewhere herein) which cannot be exceeded if the brine is to be produced and processed without causing mineral precipitation to occur. The numerical value of x does not have to be, but desirably will be, determined before sustained brine production is attempted.

The delivered cubic feet of air (V) required to bring a gallon of water to the surface by ordinary air-lifting can be estimated using the following empirical formula, developed by the Ingersoll-Rand Co. from practice:

$$(1) \qquad V = 0.8\,\frac{TPL}{C \log_e [(PS + 34)/34]}$$

where TPL is the total pumping lift (see Figure 12.1), PS is the pumping submergence and C is a constant which varies with the total pumping lift as shown in the table below.

TPL (ft)	10-60	61-200	201-500	501-650	651-750
C	245	233	216	185	158

An alternative equation, introduced by Goodman and Purchas, may be used to calculated V for ordinary air lifting. The equation is shown on the following page.

$$(2) \qquad V = \frac{TPL}{H_a} \log_e (1 + S/H_a)$$

In the equation $H_a = P_a/0.434$, P_a is atmospheric pressure, where S is the static submergence (SS in Figure 12.1) at initiation of lift and is the pumping submergence (PS in Figure 12.1) after lifting is established and TPL is defined above. The value of V obtained by equation (2) is considered as about a minimum for operability and is usually multiplied by a factor of about 2 to 4 to ensure good (~70 to 80%) lifting efficiencies. The absolute pressure, p, which must be applied to the lift gas is:

$$(3) \qquad p = P_a + 0.434S$$

The percentage submergence, (S x 100)/(S + TPL), decreases as the lifting requirement increases and can be calculated by the following equation:

$$(4) \qquad S/TPL = A^{(-B \times TPL)}$$

where A and B are constants, the values of which vary with TPL as follows:

$185 > TPL > 25$	$TPL > 185$
A = 5.2410	A = 2.8284
B = 0.01081	B = 0.003466

In order to avoid subsurface precipitation of dissolved minerals, it will usually be essential to maintain a back pressure (discharge pressure, p_d) on the gas/brine mixture which is at least high enough to ensure that steam flashing and stripping of dissolved gases do not occur to any substantial extent prior to egress from the well.

On the other hand, economic considerations dictate operating at the lowest possible lift gas pressure, i.e., at the minimum pressure needed to force through the gas pipe and well the amount of gas required to produce the desired gallons per minute of brine. If the minimum discharge pressure p_d which will prevent subsurface flashing is maintained, then both H_a and the total pumping lift will have to be increased by a minimal amount equal to $p_d/0.434$ and p (defined as above) will be equal to $P_a + 0.434S + p_d$. The minimum value of p_d will be essentially equal to the vapor pressure exerted by the brine (including dissolved gases) at the temperature at the point of introduction of the lift gas in the well.

The vapor pressure of the brine to be produced can be estimated by closing down the well as soon as it is finished and allowing it to come to equilibrium. The temperature of the gas above the static brine column will be lower than the temperature of the gas/brine mixture reaching the surface during production. Thus, the pressure measured this way will be lower than the vapor pressure which will be exerted by the brine under dynamic conditions and allowance should be made for this fact.

It should be noted that the factor, 0.434, used to convert pressures to equivalent heads of water must be multiplied by the specific gravity, g, of the brine in order to apply the foregoing equations to gas-lifting of hot brines. The average temperature of the flowing gas/brine mixture in the well will be higher than the average temperature of the static brine column. Accordingly, the value of g used should allow for this difference.

In order to maintain the gas pipe outlet at pressure p (defined as above), the compressor outlet pressure (the gas pipe input pressure) will have to be greater than p by an amount equal to the pressure drop (pf_1) due to friction within the gas pipe. Ordinarily, the gas pipe diameter and shape will be such that this friction loss will be relatively small. Allowance will also be necessary for the friction loss (pf_2) developed by the gas/brine mixture as it flows to the surface. This loss will effectively increase the total pumping lift required, as well as the gas pipe inlet pressure.

Thus, in applying either of equations (1) and (2), the value of TPL must include the discharge pressure and the latter friction loss and p must include the discharge pressure and both of the preceding friction losses. In summary, equation (2), for example, becomes:

(5)
$$V = \frac{TPL + \left(\frac{P_d + P_{f_2}}{0.434g}\right)}{\frac{P_a + P_d}{0.434g}} \log_e\left(1 + \frac{S}{\frac{P_a + P_d}{0.434g}}\right)$$

or

$$V = \frac{0.434g\ (TPL) + P_d + P_{f_2}}{P_a + P_d} \log_e\left(1 + \frac{0.434gS}{P_a + P_d}\right)$$

where P_d is the discharge or back pressure on the gas/brine mixture and pf_2 is the friction loss in the conduit through which the mixture rises to the surface;

(6)
$$p_c = P_a + 0.434gS + P_d + P_{f_1}$$

where pf_1 is the friction loss in the gas pipe and p_c is the compressor discharge pressure; and

(7)
$$\%\ \text{submergence} = A \exp\left\{-B\left(TPL + \frac{P_d + P_{f_2}}{0.434g}\right)\right\}$$

According to a well known rule-of-thumb developed from air lift experience, the cross-sectional area (in square inches) of the conduit (the annular space between the gas-pipe 10 and the casing 8, in the arrangement of Figure 12.1) carrying the gas/brine mixture to the surface should be equal to the brine discharge in gallons per minute, divided by a factor of from about 12 to 15.

Since the magnitude of the friction losses (for given casing and gas pipe dimensions) will depend on V (and on the brine production rate) a first approximation of V should be obtained by using ($TPL + p_d/0.434g$) in place of TPL and $(P_a + p_d)/(0.434g)$ in place of H_a, in equation (2). The friction losses pf_1 and pf_2 can then be estimated by conventional methods (see K.E. Brown, *Gas Lift Theory and Practice*, Petroleum Publishing Co., Tulsa, Okla., 2nd printing, 1973) of calculating such losses and a second approximation of V obtained using equation (6). Better values of pf_1 and pf_2 can then be calculated, and so on, until the difference between the value of V used to calculate pf_1 and pf_2 and the value of V obtained by using equation (6) becomes satisfactorily small.

There will generally be little point in attempting to obtain a perfect equality from equation (6) because the equation involves an unresolvable element of uncertainty. That is, the total pumping lift depends on the drawdown, which in turn depends on the resistance to brine flow within the formation at the contemplated production rate. The latter resistance cannot be predicted with much accuracy.

Accordingly, even the best values of V, p and % submergence obtainable from equation (7) must be regarded merely as approximations and it may not be possible to establish a desired production rate unless provision is made in advance for adjusting the submergence (adjusting the depth of the gas outlet in the well). Once a brine has been brought to the surface and separated from the lift gas, it can be utilized as a heat source by whichever of the several conventional methods appears to be most appropriate.

Use of Thermit Reaction

In the process of *L.S. Bouck; U.S. Patent 4,030,549; June 21, 1977; assigned to Cities Service Company* a structure and system for the transfer of energy between a locus in a borehole and a subterranean formation is formed by (a) drilling a borehole from the surface into the formation, (b) fracturing and propping the formation by injecting a fracturing and reactive slurry into the formation, the slurry comprising finely divided aluminum and a reactive metal oxide in a fluid carrier, (c) igniting the reactive slurry within the formation so that the aluminum and metal oxide components thereof react in a Thermit reaction to form a liquid metal within the fracture system formed in the formation by the fracturing and propping, and (d) allowing the liquid metal in the formation to cool and solidify within the fractured system.

Example: To illustrate the process, a well bore is drilled from the surface into a geothermically hot formation to a depth of 10,000 feet. The formation penetrated from well bottom to more than 500 feet above that point is a dense crystalline dry rock having a temperature of about 900°F. The well is cased and insulated from the overburden to a depth of 9,700 feet.

Thereupon, an aqueous based polymer thickened slurry containing finely divided particles of Al and Fe_3O_4 in a stoichiometric ratio of 8:3 is injected into the well at high pressure to effect extensive fracturing in the formation below the well casing. The reactive slurry injected also has sufficient propping agent included therein to hold the fracture system open. A sufficient amount of less dense slurry is then injected to further fracture the formation and move the reactive slurry below the cased portion of the well.

A pyrotechnic device is inserted downhole into the reactive slurry. Pressure is maintained on the well. The pyrotechnic device is ignited by electrical means thus igniting the reactive slurry. A Thermit or Goldschmidt aluminothermic reaction occurs in the reactive slurry forming molten iron and alumina slag. Extensive heat energy is evolved from the Thermit reaction forming an iron conductor fin network within the formation and extending to the locus of the well bore below the cased area. The formation in the locus of the well is allowed to cool and the molten iron solidifies in intimate contact with the formation forming a solid iron conductor fin network within the formation connected to the well bore.

Thereupon, the well bore is milled to hole bottom at a dimension approximately two-thirds of its original diameter. Thereupon, a pipe insulated on the interior a manway … of access and service. The vaporized fluids from the contactor are passed through a power-extracting gas expansion device, with the composition of the vapor being controlled to maximize the power extractable by the gas expansion device.

SCALE PREVENTION AND REMOVAL OF NONCONDENSIBLES

Scale Prevention

In U.S. Patent 3,935,102, there is described a system for extracting heat from hot unrefined water with the avoidance of detrimental effects caused by impurities contained in the water. The hot unrefined water is prevented from coming into direct contact with the surfaces of the heat exchanger used to boil a working fluid. Filters and like equipment are not needed. A heat transfer medium in the form of a housing containing porous material such as a bed of gravel or other granular material is used to transfer heat from the unrefined water to clean water which is then passed through the heat exchanger. Such a heat transfer medium will be referred to herein as an accumulator-type heat interchanger. The porous material is inexpensive and expendable and can even be easily cleaned and reused if desired.

In the system a volume of the hot unrefined water is passed through a housing containing porous material which picks up the heat of the water. A volume of clean water is then passed through the housing to pick up the heat from the porous material. The now heated clean water can then be passed through a heat exchanger without significant danger to the surfaces of the exchanger. The clean water can be recycled through the system many times, each time passing through the housing immediately after a volume of the unrefined water.

In another important aspect of the system of U.S. Patent 3,935,102, the source of the clean water may be the unrefined water which has been passed through the porous material. After being removed from the housing, the cooled unrefined water is delivered to a detention receptacle. Here it attains stabilization as many of the impurities settle to the bottom of the receptacle. The liquid which is left on the top of the receptacle is substantially free of impurities to the extent that what impurities are left in the liquid are not sufficient to unduly damage the surfaces of the heat exchanger. It is this substantially impurity-free liquid which is used as the clean water, yet no filtering, etc., is necessary.

A preferred embodiment of the system disclosed in U.S. Patent 3,935,102 provides for continuous operation of the system by the use of two housings containing porous material.

The entrance ends of the housings are alternatly connected to the sources of unrefined and clean water and each time the connections at the entrance ends are switched, the connections at the exit ends are also switched to alternately direct unrefined and clean water from the housings to the detention receptacle and the heat exchanger respectively.

J.S. Swearingen; U.S. Patents 4,054,175; October 18, 1977 and 3,951,794; April 20, 1976 provides an improved method for extracting heat from hot unrefined water containing scale-forming dissolved and dispersed impurities wherein the hot unrefined water is contacted with a heat exchange surface … rfaces. These heat exchange surfaces may be the surfaces of a conventional heat exchanger such as a tube and shell or they may be the surfaces of the porous material in an accumulator type heat interchanger. The improvement involves adding to the hot unrefined water prior to its contact with the heat exchange surface an agent capable of increasing the formation of non-scale-forming species of the scale-forming impurities whereby scaling and other solid build up on the heat exchange surface, particularly upon cooling of the water, is minimized. Non-scale-forming species are those which remain in solution or suspension in the unrefined water as it is passed through the heat exchange apparatus without forming scale and/or those which are harmlessly precipitated, e.g., solid non-scale particles which are small enough to remain in suspension in the moving water and be carried out of the heat exchange apparatus thereby.

In one embodiment of the process, there is added as the aforesaid agent, suspendible particles of finely divided solid material, preferably in the form of a suspension, which may be a slurry or dispersion, and more preferably, particles having the same or similar constituency as at least some of the impurities in the unrefined water. In carrying out this preferred aspect of the process, the particles are collected from cooled unrefined water subsequent to its contact with the heat exchange surface, and this is achieved preferably by directing the cooled unrefined water into a detention receptacle where it is held until it is stabilized by natural cooling and settling of precipitates and other solids of the impurities originally dissolved and dispersed therein.

Some additional generation of non-scale solids, e.g., precipitation of dissolved substances, may occur at this point due to further cooling of the water. At the bottom of the detention receptacle there is formed a portion of the water which is rich in these solid particles of impurities, and it is from this portion of the receptacle that the aqueous suspension of particles is collected and added to the hot unrefined water.

In another embodiment of the process, the preliminary accumulator-type heat interchange technique described in the aforementioned patent is employed which comprises passing a volume of hot unrefined water through a housing containing porous material whereby the heat of the unrefined water is given up to the porous material, passing a volume of clean liquid through the housing whereby the heat of the porous material is given up to the clean liquid and thereafter, preferably, passing the heated clean liquid through a heat exchanger whereby the heat of the clean liquid is extracted.

In connection with this embodiment, there is used as the clean liquid at least in part water from a substantially impurity-free portion of water which is formed at the surface of the previously defined detention receptacle which receives the unrefined water after it is passed, in this case, through the housing containing porous material.

In yet a further embodiment, there is provided a method wherein the hot unrefined water is derived from an underground geothermal cavity and the addition of finely divided particles to the hot unrefined water is accomplished by adding the particles to the water underground, preferably by injecting a suspension of particles directly into the bore of a geothermal well. Most preferably, the particles are added at a point in the well below a point where the hot unrefined is run to w[illegible] a few feet of well bottom. Water is injected into the annulus between the casing and the insulated tubing string passing down the annulus in the locus of the iron conductor fin network, forming steam, and then returning to the surface through the insulated tubing string to deliver high temperature and high pressure steam to the surface. The steam is employed to run a turbine which drives an electrical generator. Condensate is recycled to the well.

Preventing Flashing

C.H. Berg; U.S. Patent 4,059,156; November 22, 1977 discloses a method for the production of geothermal brines that avoids depressuring the brine below its flash point in the well bore and thereby avoids the scaling and plugging unavoidably experienced whenever high salt content brines are depressured, releasing carbon dioxide and upsetting their solubility equilibrium and precipitating calcium carbonate. The process avoids the flashing of the geothermal brine by injecting a lift fluid immiscible with and of substantially lesser density than the brine into the production tubing to form a column of a mixture of brine and lift fluid which has a sufficiently lesser density than the column of brine that the hydrostatic head of the column of brine raises the mixture to the surface from where it is withdrawn without flashing, separating the lift fluid and processing the brine for heat recovery.

When the brine is extremely hot, the pressure is maintained at higher levels to avoid flashing by an additional column of brine below the production level. This is provided by establishing a column of the geothermal brine a substantial depth below its production interval, installing a production tubing for a substantial depth in the column of brine and injecting a lift fluid which yields a higher pressure at the top of the well.

Use of Gas Generator Cartridge

Geothermal wells may be stimulated by means of explosives. More specifically, geothermal wells may be stimulated by means of shaped charges which blast pencil-shaped jets of liner material into rock strata, crushing and penetrating the rock, cement and tubing and allowing geothermal fluids to seep through from the perforated materials into the main bore hole of the well. However, when one wishes to utilize shaped charges to stimulate the production of geothermal wells one is faced with two problems—temperature and fluids under pressure.

The temperature near the bottom of a geothermal well where one normally wishes to blast is ordinarily extremely high. When a shaped charge is lowered into this high temperature a problem of preventing what is commonly called "cook-off" of the explosive arises.

The pressure of geothermal fluids in the depths of a geothermal well is ordinarily high. Shaped charges generally utilize cone-shaped liners which collapse when the explosive is detonated and focus the pencil-shaped jets spoken of above. When such a cone is filled with high-pressure goethermal fluid, the fluid interferes with the proper collapse of the cone and the jet does not get properly formed.

It has been found by *G.W. Leonard and C.F. Austin; U.S. Patent 4,053,509; December 20, 1977; assigned to U.S. Secretary of the Navy* that a gas-releasing

means such as a gas generator cartridge which reacts with geotherma[illegible] or a pyrotechnic cartridge may be utilized to combat the problems of temperature and fluid interference in geothermal well stimulation. According to this process, the gas-releasing means is utilized to pressurize a housing in which one or more shaped charges are suspended and keep geothermal fluid out as the housing and shaped charges are lowered into a well. The exclusion of geothermal fluid from the housing prevents the fluid from interfering with the proper collapse of shaped charge conical liners, i.e., interfering with jet formation, and also prevents geothermal fluid from being in near proximity to shaped charges where it can deleteriously affect the shaped charge performance temperaturewise, i.e., by causing "cook-off".

One example, although not by any means the only one, of a pyrotechnic cartridge is a cartridge based on sodium azide. One example of a material that will react with a geothermal fluid to produce gas is sodium. Both pyrotechnic cartridges and gas generator materials that will react with geothermal fluids are known.

Injecting Low Salinity Water

The process of *L.D. Christian; U.S. Patent 4,074,754; February 21, 1978; assigned to Exxon Production Research Company* is directed to a method for producing geothermal energy and/or minerals from subterranean high temperature and high salinity brine reservoirs in which fresh or low salinity water at ambient surface temperature is injected into the brine reservoir through a well; reservoir brine from the vicinity of the well bore is displaced; the injected water is heated by the reservoir heat and is then produced from the reservoir through the well. The volume of water to be injected in each injection-production cycle is selected on the basis of reservoir characteristics and overall project design. The well may be shut-in for a soak period following injection to permit time for the last water injected to be heated.

The injected water has a salinity ranging from zero to a selected amount such that when the water is produced from the reservoir, substantially no precipitation of salt occurs in the well bore.

Injection of Fluid

According to *I. Sheinbaum; U.S. Patent 4,079,590; March 21, 1978* the flow from geothermal wells is stimulated by injecting a liquid at selected levels in the well with the liquid having a boiling point below the temperature of the geothermal fluid at the levels of injection at the operating pressure at the levels of injection. The geothermal fluid and vaporized injected fluid from the well are applied to a system for extracting the heat energy as well as for cleaning sand and other well depositions that may accumulate in the geothermal well. The system may include a direct contact heat exchanger having either a vertical chamber or a horizontal chamber. The contactor has a plurality of zones including a boiler zone, one or more separation zones, and at least one heat exchange zone. The contactor may also include a wash zone and a flash zone.

In the wash zone there are advantageously included recirculation trays vertically spaced for washing the vapor to remove entrained substances, such as minerals dissolved in the fluid from the geothermal wells. The recirculation trays include water is accompli... by adding the particles to the water underground, preferably by injecting a suspension of particles directly into the bore of a geothermal well. Most preferably, the particles are added at a point in the well below a point where the hot unrefined water is becoming supersaturated by being cooled and/or concentrated as, for example, by being partly converted into steam.

In another embodiment there is provided a method wherein the agent added to the hot unrefined water comprises a reagent capable of generating non-scale solids of the impurities in situ. In the case of dissolved impurities this reagent may be capable of causing precipitation of a part of the dissolved impurities, preferably in the form of finely divided particles. In the case of dispersed colloidal impurities, the reagent may be one capable of causing agglomeration of part of these colloidal impurities. In either case this reagent is preferably added directly to the water while it is still underground in a geothermal water well.

A similar embodiment comprises adding to the hot unrefined water an agent capable of increasing the solubility of at least some of the dissolved impurities and/or of decreasing the degree of dispersion of some of the colloidal impurities, for example, an agent capable of raising the pH of the water. Again, the addition of such agents may take place directly in the geothermal water well bore. Still another similar embodiment comprises adding a chelating agent to the water.

There is also provided in accordance with the process a system for extracting heat from hot unrefined water containing dissolved and dispersed impurities comprising a source of hot unrefined water, a heat exchange means having an entrance end and an exit end, a means for conveying water from the source to the entrance end of a heat exchange means, a detention receptacle for receiving cooled unrefined water from the exit end of the heat exchange means and a means for recycling a supension, which may be a slurry or dispersion, of solid particles of the impurities from the cooled unrefined water in the detention receptacle for addition to the hot unrefined water at a point prior to its entry into the heat exchanger.

The heat exchanger may comprise either a conventional indirect contact heat exchanger, such as a shell and tube counterflow-type exchanger, or an accumulator-type heat interchange system comprising at least one housing containing porous material together with a source of clean liquid, means for selectively connecting the source of unrefined water and the source of clean liquid through the entrance end of the housing, a heat exchanger for extracting heat from the clean liquid and means for selectively alternately connecting the exit end of the housing to the detention receptacle and to the heat exchanger.

Preferably, the source of clean liquid is at least partially comprised of the substantially impurity-free water which is produced in the detention receptacle. In the most preferred aspect of this embodiment, there is also provided a second accumulator-type heat interchanger comprising a second housing containing porous material, which housing is of substantially the same size as the first housing and also has an entrance end and an exit end, means for selectively connecting the source of unrefined water and the source of clean water to the entrance end of the second housing, and means for selectively alternately connecting the exit end of the second housing to the detention receptacle and to the heat exchanger. Furthermore, it is advantageous to provide for recycle of the suspension of particles directly into a geothermal well supplying the hot unrefined water.

...n another preferred aspect of the system, the detention receptacle compr...ses at least two separate zones, including a first zone adapted for first receiving the cooled unrefined water and for permitting larger particles of impurities to settle, and interconnected therewith, a second zone adapted for receiving the cooled unrefined water subsequent to the first zone and for permitting finer particles of impurities to settle. The recycle system thus communicates with the second zone of the detention receptacle and withdraws a suspension or slurry comprising the finer particles.

Removal of Silica Using Ammonium Hydroxide

In the process of *V.H. Wilkins; U.S. Patent 4,016,075; April 5, 1977; assigned to Southern Pacific Land Company* ammonium hydroxide is added to steam and brine as they are produced at a high temperature and pressure from a geothermal well. The ammonium hydroxide will react with the dissolved aluminum and ferrous ions to form a gelatinous sludge precipitate of aluminum and ferrous hydroxides. This precipitated sludge formed in the brine will sweep the brine so that dissolved silica will adsorb on the surface of the sludge particles. It has been found that the degree of silica fixation, or removal, is dependent upon the pH of the brine. Enough ammonium hydroxide is added to the brine to increase the pH of the brine sufficiently so that the remaining dissolved silica will be below its saturation level in the brine at the temperature and pressure to which the brine is reduced for subsequent handling. The precipitated sludge is then removed from the brine so that the clarified brine can then be further processed.

Preferably the amount of ammonium hydroxide added to the brine is maintained at a level such that the pH of the brine is not raised above 7.0, since it has been found that the amount of additional silica removed at a higher pH level is small compared to the required increase of ammonium hydroxide. Additionally, maintaining the pH of the brine at 7.0 or below will minimize the removal from solution of the manganous ions as manganous hydroxide, so that the manganese can be later recovered from the brine.

Besides reducing the dissolved silica concentration to a nonscaling level, the increase in pH of the brine towards a neutral pH due to the ammonium hydroxide addition will also serve to minimize the corrosion of system surfaces exposed to the brine.

Addition of the ammonium hydroxide to the produced brine results in an increased ammonium ion concentration in the brine. Subsequent addition of a strong base, such as calcium hydroxide, to the brine will free ammonia and enable ammonium hydroxide to be recovered for reuse in the process. Although about 5 tons of calcium hydroxide are required to free 4 tons of ammonia from the brine, adding calcium hydroxide to the system for ammonia recovery is an important advantage since calcium hydroxide is less expensive than ammonium hydroxide.

Removing Dissolved Noncondensibles

In the process of *W.T. Matthews; U.S. Patent 4,026,111; May 31, 1977; assigned to The Dow Chemical Company* heat energy is more efficiently recovered from geothermal brines by preflashing the brine to remove dissolved, noncondensible gases before fla......g the brine to produce motive steam. Power requirements for removal of noncondensibles from turbine exhausts (in order to maintain adequately low exhaust pressures) are obviated. The heat content of the preflashed vapors may be largely utilized for superheating and reheating the motive steam.

Contamination Prevention

One main problem overcome by the apparatus and method of *E.H. Schwartzman; U.S. Patent 4,084,379; April 18, 1978* is the energy exchange which takes place without the ensuing contamination problem. This is accomplished by this process by employing such working fluids as propane, butane, n-heptane, ethane, ethylene, or mixtures thereof in such a manner as to blanket all of the surfaces of the components used in the energy exchange from the energy source fluid which contains the dissolved solutes.

Also, since this system employs essentially an evaporation process similar to that used in desalination systems, all of the solid type impurities are eliminated from the vapor used for extracting energy by the expansion process. The fluids used as the working fluid are chosen with respect to their thermodynamic properties in relationship to that required by the given inlet condition of the energy source fluid. In general, the light hydrocarbons or mixtures thereof are ideally suited for this purpose since they can be tailored to have both the desired thermodynamic characteristics and are almost completely immiscible in the energy source fluid.

However, since the working fluid may be slightly soluble in the energy source fluid (usually a solution of water) a very small portion of the working fluid is lost by being washed out with the spent energy producing fluid. This process further sets forth a system whereby this loss of working fluid is reduced to an insignificant amount by taking advantage of the salting out effect which occurs when a solute saturated water solution is used as the energy fluid source. The salting out effect is the phenomenon whereby the solubility of the working fluid in the energy producing fluid is greatly reduced when the energy producing fluid is saturated by a solute. In some instances where the energy producing fluid is not saturated, it might be necessary to stage the given process whereby a heavier hydrocarbon working fluid (which is substantially insoluble in the unsaturated energy producing fluid) is used to transfer the energy to an artificially saturated energy producing fluid in order to take advantage of the salting out effect.

A convenient salt such as calcium chloride may be used to obtain the desired effect by saturating water whereby the given solution is then used with a light hydrocarbon working fluid to obtain the power by expansion as previously mentioned. This solution of water saturated with calcium chloride also eliminates any corrosion which is normally associated with the common sodium chloride solutions usually encountered.

Furthermore, this process, by the use of combinations as set forth, can be employed in such a manner that the noncondensible gases such as hydrogen sulfide and carbon dioxide plus the dissolved air if any, can be separated out and conveniently disposed of prior to the power extraction portion of the system and thereby prevent any corrosion effect on the power producing components. Also, these undesirable noncondensible gases can be reinjected into the spent energy source fluid and thus disposed of without any contamination or pol. . of the surrounding environment.

MEASURING AND DETECTION TECHNIQUES

Heat Flux Transducers

The process of *H.F. Poppendiek and P.T. Meckel; U.S. Patent 4,003,250; January 18, 1977; assigned to Thermonetics Corporation* relates to improved means and techniques for measurement of heat flow from a source far below the earth's surface.

A geothermal heat flux transducer is provided which includes a plurality of insulating slats on which Constantan wire is wound and each half turn is coated with a silver layer to produce a hot junction and a cold junction per turn of wire. The slat with wire thus coated is assembled with insulating material between adjacent slats such that silver coatings on adjacent slats face each other and also uncoated wire half turns on adjacent slats face each other. This allows a multiplicity of thermal junctions thus formed to be assembled in a small package which may be suspended in earth bore holes in mine shafts or otherwise below or above ground for measurement of heat flow emanating from sources far below the earth's surface.

Variable heat flow occasioned by diurnal and/or seasonal variations are accounted for in ascertainment of that steady heat flux flowing from geothermal sources alone. The transducer is of special dimensional proportions with parts specially related both structurally and thermally.

Predicting Geothermal Gradients

E.B. Reynolds; U.S. Patent 4,008,608; February 22, 1977; assigned to Continental Oil Company provides a method of predicting the geothermal gradient of subterranean strata by determining velocity trends in the strata and comparing same with the velocity trends of formations for which geothermal gradients have previously been determined and plotted on semilogarithmic paper as a family of curves of velocity trends versus geothermal gradients comprising: (a) determining the velocity trend at various depths of a wave propagated through the subterranean strata, (b) plotting the velocity trend versus depth on semilogarithmic paper to generate a curve, and (c) comparing the curve obtained with a family of similar curves of known geothermal gradients. The velocity trends can be established by acoustic logging, check shot velocity surveys, or seismic velocity analysis.

Locating Sources by Conductivity-Temperature Analysis

W.L. Sayer; U.S. Patent 3,805,587; April 23, 1974 describes a method and apparatus for locating subterranean sources of geothermal energy characterized by discharging test energy into the earth at a depth sufficient to be substantially insulated from surface temperature variations, removing heat from the earth at the discharge position to establish a sphere of cooling at the discharging position subject to heat from the geothermal source, and detecting changes in the conductivity of the earth between the discharging position and a plurality of detecting position. ...r near the surface. The detecting positions are equally spaced about an axis of reference extended from the discharging position vertically to the surface. The azimuthal orientation of the source of geothermal heat from the axis is determined from changes in the conductivity of the earth between the discharging position and the detecting positions incident to geothermal warming of the sphere of cooling.

WELL CASING SEAL

A geothermal energy transfer and utilization system makes use of thermal energy stored in hot solute-bearing well water to generate a thermal working fluid from an injected flow of clean fluid. The working fluid is then used for operating a turbine-driven pump near the well bottom for pumping the hot solute-bearing water in liquid state to the earth's surface, where it is used by transfer of its heat content to a closed-loop generator-turbine alternator combination for the beneficial generation of electrical power. The deep well pump system is supported within the well casing pipe from the earth's surface by a turbine exhaust conduit.

H.B. Matthews; U.S. Patent 3,967,448; July 6, 1976; assigned to Sperry Rand Corporation describes an improvement facilitating ready installation and reliable operation of such geothermal systems; according to this process, there are provided means for the support of the deep well geothermal pump system within the well casing from the earth's surface by the pump-driven turbine exhaust steam conduit. In view of the differential expansion effects on the relative lengths of the casing extending downward from the earth's surface and the exhaust steam conduit contained therein, a particular flexible seal arrangement was provided between the suspended geothermal pump system and the well pipe casing.

A first element of the improvement provided a vertical, smooth cylindrical sealing surface at the desired location for the deep well apparatus by means previously sealed to the well casing pipe. A second element assured easy assembly of a second seal interfacing the cylindrical sealing surface and suspended from the hot water pump so as to permit sliding motion of the seal in the prevailing hostile environment.

It is necessary to provide an efficient seal of some kind between the brine pump and the well casing; otherwise, a differential pressure would never be built up across the brine pump impeller. While the seal of U.S. Patent 3,967,448 has certain established advantages for this purpose, it is complex and expensive. This expensive design will seal against very high differential pressures and is effectively leakproof, while some leakage may actually be permitted. The packer used requires a large-diameter casing, whereas casings of more conventional dimensions are less expensive and evidently preferred. The fixed packer is relatively expensive to buy and to insert, adding considerably to the time required for deployment of the equipment in the geothermal well. The fixed packer must be drilled out when it is to be removed.

The process of *H.B. Matthews; U.S. Patent 4,050,517; September 27, 1977; assigned to Sperry Rand Corporation* is an improvement facilitating ready installation and reliable operation of geothermal systems, including geothermal energy retrieval systems of the kind described above. The process affords rea..., and less expensive installation of deep well geothermal apparatus. The deep well apparatus is supported within the well casing pipe from the well heat at the earth's surface by the pump-driving turbine exhaust conduit. Alternatively, the working fluid conduit may serve as the suspension. Differential expansion effects are accommodated by a sealing arrangement mounted on the geothermal pump itself before it is lowered into the well and having seal interfaces directly mating with the interior surface of the well casing when deployed at the well bottom. An arrangement is provided for protecting elements of the flexible seal during lowering of the pump and its associated seal system into the well and then for automatically deploying the seals in their operating condition.

DRILLING COMPOSITION

P.W. Fischer, J.C. Jones, D.E. Pyle and S. Pye; U.S. Patent 4,013,568; March 22, 1977; assigned to Union Oil Company of California provide a composition and method of use for drilling a well into a subterranean formation containing a geothermal fluid at a temperature of about 350°F or above comprising circulating through the well during drilling a gas-containing drilling fluid comprising a mixture of water or brine, a gas, a corrosion and erosion inhibitor, a lignite to control fluid loss, a salt of a high molecular weight acrylic acid polymer to improve the wall-building and cuttings-carrying properties, and optionally, a foaming agent.

Example: Two offset wells are drilled from the surface to a depth of about 100 feet above the geothermal zone using a rotary bit and conventional aqueous clay-containing drilling mud. It is known from previous wells drilled in the area that when aqueous clay-containing drilling fluid is used to drill the geothermal zone, substantial drilling fluid is lost to the formation resulting in partial plugging of the zone by the drilling fluid. This plugging decreases the rate at which geothermal fluids can be produced following completion of the well.

In the first of the two test wells, drilling is continued while injecting down the drill string 1,000 cubic feet per minute of air and 150 gallons per minute of an aqueous solution containing 150 gallons per minute water and 0.4 pound per barrel of an erosion and corrosion inhibitor prepared by first mixing together 75 weight percent water, 10 weight percent diethylenetriamine and 15 weight percent of an acidic triester prepared by the condensation of triethanolamine and dimerized linoleic acid and then diluting with additional water in the proportion of about 30 gallons of inhibitor to each 10 barrels of water.

The well is drilled through the geothermal zone and completed in the usual manner. During the above-described drilling operation, the occurrence of considerable lost circulation of the aerated drilling fluid to the formation is noted.

In the second of the two test wells, drilling is continued by injecting down the drill string the same aerated drilling fluid described above except that the aqueous solution is an aqueous dispersion which includes, in addition to the above-described ingredients, 3 pounds per barrel lignite and 1 pound per barrel of the sodium salt of an acrylic acid polymer having an average molecular weight of around 25,000. The well is drilled through the geothermal zone and completed in the usual manner. During the drilli... this second test well, there is less lost circulation than when using the aerated drilling fluid used in the first test well.

USE OF GEOTHERMAL WELL HEAT TO EFFECT CHEMICAL REACTION

The process of *G.H. Gill; U.S. Patent 4,085,795; April 25, 1978* provides a method for converting geothermal energy into a more useful form, such as a liquid fuel or the like, so it can be stored and shipped easily for use in other locations. A chemical reaction vessel, made of a corrosion resistant material, is placed in a geothermal well, or in the effluent therefrom. The reaction vessel has an input and a discharge pipe to flow the reactants through a catalyst in the reaction vessel. The fluid in the well is circulated, if necessary, for better energy flow and temperature control.

One chemical reaction which is well suited to the process is the catalytic conversion of carbon monoxide and hydrogen to methanol. This reaction takes place in the pressure range of 100 to 600 atmospheres and at temperatures from 250° to 400°C, although where the temperatures are below 250°C there is still a reaction between dissolved carbon monoxide and hydrogen. The chemical reaction vessel is lowered into a geothermal well of suitable temperature so it is immersed in the well fluid. The chemical reactants are fed to the chemical reaction vessel under the necessary pressure to react with the catalyst within the chemical reaction vessel.

The resulting product, such as methanol, is discharged through a discharge pipe into any suitable container for storage and subsequent transportation to the use area. It is not necessary that there be a flow of fluid from the well, as a well drilled into hot rock would also be effective as long as there is effective thermal contact with the rock and the chemical reaction vessel. The thermal contact could be accomplished with uncirculated fluids. Also, since the pressure used in the chemical reaction is quite high, the external pressure of the fluids in a deep geothermal well lessens the design requirements of the chemical reaction vessel.