Geothermal Electricity Production

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This article is an attempt to evaluate the institutional and economic factors that will play a part in determining the future scale of geothermal development in the short term. To be complete, it would be necessary to evaluate technical factors also, such as probable developments in exploration techniques, the prevention of scale formation in hot water fields, the disposal of mineralized water, the use of geothermal energy in nonpower applications such as space heating and cooling and water desalination, and (for the long term) to evaluate the technology for the extraction of thermal energy from hot rock at depths of several kilometers. This article, however, is concerned only with the future scale of geothermal development, and since, in general, technology is developed and technical problems are solved when institutions which can command the finances required choose to solve them, a passing reference only to some of the technical problems mentioned above will be made here.

Over the past 2 years there has been an increasing concern over the continued availability of natural resources, the demand for which is growing and is expected to continue to grow at a high rate. At the same time, awareness of the environmental effects of unregulated use of natural resources has led in many countries to the establishment of legislation designed to control environmental damage and restrict the way in which natural resources, and in particular energy resources, can be developed and used. In the United States, for example, environmental considerations, coupled with the need to import increasingly large quantities of oil and natural gas, have led to reevaluation of the potential of indigenous energy resources, including geothermal energy resources. Since the present state of development of geothermal resources and their future prospects on a world scale are in many respects reflected in the situation in the United States, an analysis of that situation can be instructive for those who are also interested in geothermal development in other countries.

The development of geothermal energy on a significant scale has been the subject of much inquiry in the United States, and several estimates of the potential by the year 1985 or the year 2000 have been published, for example, by the U.S. Geological Survey (*1*), the National Petroleum Council (*2*), the Hickel Geothermal Resources Research Conference (*3*), and others concerned with geothermal resources development (*4*, *5*). There is general agreement about the total quantity of heat stored in the earth down to any particular depth, but there is very little agreement about how much of this heat can be exploited, and by what date any particular rate of exploitation can be achieved.

In the present state of technological development, we can say that exploitable geothermal resources consist of steam or hot water contained in permeable rock at a depth which can be reached by drilling. As this definition implies, there are two kinds of geothermal resource; one produces only steam at the wellhead and is said to be a "dry steam" or "vapor dominated" geothermal field; the other produces either hot water alone or a flashing mixture of hot water and steam and is said to be a "wet steam" or "hot water" geothermal field.

Dry Steam Geothermal Fields

The first geothermal field to be developed was a dry steam field at Larderello, Italy, where the present generating plant, operated by the National Electricity Board, has a capacity of 380 megawatts. Another dry steam field has also been developed in Japan, at Matsukawa, where a 20-Mw plant which serves the Tohoku Electric Power Company began operation in 1961.

In the United States, the first geothermal power production began from a dry steam field at The Geysers near San Francisco. At The Geysers, expansion of steam production by the Magma Energy and Thermal Power companies together with the Union Oil Company as operator is now progressing at a rate equivalent to 110 Mw each year; the Pacific Energy Corporation was reported recently to have agreed to supply the Pacific Gas and Electric Company with steam for an initial 55-Mw plant, and the Signal Companies have undertaken the sale of further steam supplies at a rate equivalent to 135 Mw each year to Pacific Gas and Electric. The total installed capacity at The Geysers field will be 900 Mw in 1976 (*6*). The ultimate capacity of this field has been estimated to be more than 1000 Mw.

The cost of a geothermal production well drilled to 8000 feet (2400 meters) is about \$250,000, excluding mobilization costs. Production from such a well in a dry steam field can range to over 100 tons of steam per hour at a pressure of 10 atmospheres and a temperature over 200°C. The price paid for such steam at The Geysers field, for example, was about \$0.30 (United States) per ton (\$0.003 per kilowatt-hour) in 1970. The cost of disposing of the condensed steam after use was an additional \$0.05 per ton of steam produced, also paid for by the power company. If the alternative source of power is an electric power plant burning fuel oil, then the opportunity cost of geothermal steam at 200°C is about \$1 per ton when fuel oil costs \$7 per barrel.

The three fields already mentioned, one each in Italy, the United States, and Japan, are the only dry steam fields to have been developed so far, and this type of field therefore appears to be less common than the hot water type. From the point of view of electric power production, it will be unfortunate if further exploration confirms that this is so, since dry steam field operation is relatively simple, and in economic terms highly competitive with alternative sources of electric power.

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Hot Water Geothermal Fields

The first hot water or wet steam field to be developed for the production of electric power was the Wairakei field in New Zealand, where a 192-Mw generating plant is operated by the New Zealand Electricity Department. Other hot water fields now producing electric power are in New Zealand at Kawerau, in Japan at Otake, in the Soviet Union at Pauzhetska and Paratunka, in Iceland at Namafjall, and in Mexico at Cerro Prieto.

Operation of a wet steam field for electric power production differs from that of a dry steam field because a geothermal well in a hot water field, while producing steam in quantity comparable to that from a well in a dry steam field, also produces hot water which may be three times the weight of the steam produced. All wet steam fields that are used to generate electric power by using steam turbines therefore have centrifugal separators to separate the steam and water. The steam is then handled in the same way as the steam produced in dry steam fields, and the water is taken by pipe or by channel to a disposal point. If the geothermal water has been "double-flashed"—that is, if the water from the first steam-water separation is allowed to flash at some suitable lower pressure and the steam and water are again separated—then the water to be disposed of will have a temperature close to 100°C and will amount to about 70 percent by weight of the water originally produced. This hot water can then be used for heating or cooling at a cost which is lower than those of alternatives, if demand is concentrated in a market located within a few miles of the geothermal field. If there is no such demand for heating or cooling, and the mineral content of the geothermal water is not of value, then the residual water must be discarded. Three methods of disposal have been adopted or tested in the past. In New Zealand, where the salinity of the geothermal fluids is about one-tenth the salinity of seawater, and is therefore relatively low, the geothermal water is simply discharged into a large neighboring river, with negligible environmental effects. In El Salvador, Central America, the occurrence of a geothermal brine with a salt content about half that of seawater, and the relatively small flow of the neighboring river during some seasons, have led to the study of a plan to carry the rejected water some 30 km by channel to the sea. A third method of disposal, some aspects of which were tested experimentally in El Salvador, is to reinject the water beneath the surface. In El Salvador geothermal water at a temperature of 160°C was continuously reinjected for 6 months. The maximum rate of reinjection achieved without pumping was of the order of 800 tons per hour into a single well which had a production casing 9⅝ inches (~ 24½ cm) in diameter and was drilled to a depth of roughly 900 m. The tests carried out in El Salvador were in all respects successful, but further tests are needed to establish that disposal by reinjection of large quantities of geothermal water can be achieved on a 20-year or 50-year basis. In particular, tests are required to establish criteria for siting reinjection wells so that they can contribute recharge water to the reservoir under exploitation without degrading the thermal quality of the geothermal water being produced from the area of steam production.

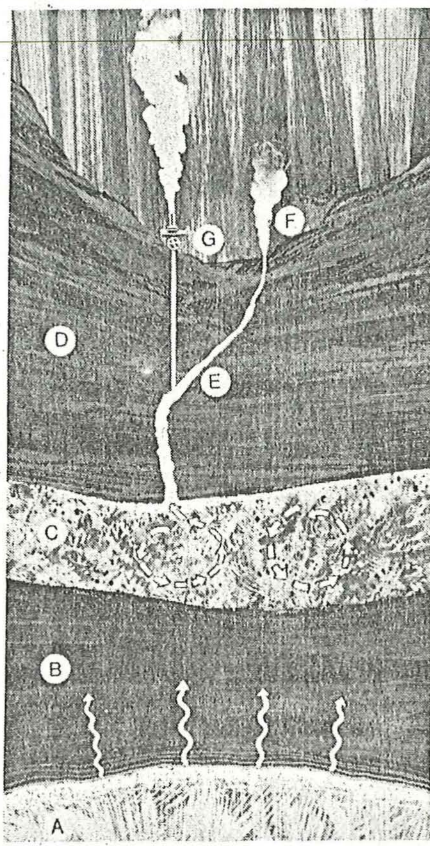

Fig. 1. Geothermal field. (A) Magma (molten mass, still in the process of cooling). (B) Solid rock; conducts heat upward. (C) Porous rock; contains water that is boiled by heat from below. (D) Solid rock; prevents steam from escaping. (E) Fissure; allows steam to escape. (F) A geyser, fumarole, or hot spring. (G) Well; taps steam in fissure. [Source: Pacific Gas and Electric Company, San Francisco]

An average production well in a hot water field drilled to 3000 feet (915 m) costs about $150,000. Production from a geothermal well in a hot water field with a reservoir temperature near 230°C may be about 400 tons of steam and water per hour. If this water is allowed to flash in two stages then 72 tons of steam at 5 atm and 154°C and 48 tons of steam at 0.8 atm and 93°C can be obtained. Depending on the turbine and the inlet pressures used, this steam can generate about as much power as the well in a dry steam field which delivers 100 tons of dry steam per hour at 200°C. Since the wells are commonly more shallow and therefore drilling costs are lower, it may appear that the cost of electric power from wet steam fields should be less than that from dry steam fields. However other factors have to be considered, such as the increased turbine cost involved in using larger quantities of low-pressure steam [the turbine section using steam at 1 atm and below costs twice as much as the section using higher-pressure steam (7)] and the cost of disposal of the relatively large quantities of geothermal water. The cost of disposal by reinjection, for example, was estimated in one case to be from $0.029 to $0.047 per ton of water produced, which would add roughly $0.097 to $0.157 per ton to the cost of producing the steam. But even with the higher disposal costs for wet steam fields, the electricity produced still remains competitive with that produced in thermal stations.

Economics and Rate of Development

The National Petroleum Council has estimated that U.S. geothermal resources can be developed to supply 1,900 to 3,500 Mw of electric power by 1985. The Hickel Conference, on the other hand, has estimated the developable potential as 132,000 Mw by 1985. Other estimates are 2,400 to 16,000 Mw, assuming a 25-year life for the resource (4). According to the largest of these estimates, geothermal resources could supply almost 20 percent of the power needed in the United States in 1985, and according to the smallest of them only about 0.5 percent, a difference of almost two orders magnitude. This is a very considerable difference, but at the present time, fortunately, there appears to be no certain way to determine which estimate is more nearly correct. Given existing technology, the presence or absence of hot water or steam at depth can be proved only by drilling. So far, there has been relatively little exploration drilling in the United States, or indeed in any other country.

If the average geothermal production well yields steam at a rate equivalent to 5 Mw, then 26,000 productive wells will be needed to produce 132,000 Mw in 1985. Koenig (8) reported that, at the end of October 1969, geothermal drilling to a depth of more than 3,000 feet (900 m) had taken place at ten locations in the United States and that fluid at a temperature higher than 180°C was encountered at four of these, but because of scaling and environmental problems only one of them, The Geysers field, where dry steam was encountered, has been developed for electric power production. The total number of wells drilled in these ten locations was 119, of which 73 were located at The Geysers field. Most of the wells at The Geysers are producers. In the United States, then, at ten locations where drilling has taken place, discoveries were made at four (although electric power production is under way at present at only one of these) and about 60 percent of the wells drilled can be classed as producers. If the same success ratio is maintained, then the total number of wells required in the United States by 1985 to produce 132,000 Mw will be about 42,000, or 3,800 per year starting in 1974. This can be compared with the yearly total of onshore oil well completions in the United States, which in 1969 was about 30,000, or about eight times the yearly number of geothermal wells needed. If the cost of the average geothermal well is estimated, conservatively, at $150,000 and lease, rental, and exploration costs are assumed to be in the same ratio to drilling costs as they were for the onshore oil industry in 1969, then a total expenditure on geothermal exploration and drilling of the order of $10 billion will be required to produce steam equivalent to 132,000 Mw by 1985. This implies an annual investment of risk and development capital equal to roughly 15 percent of such expenditure by the oil industry in the United States in 1969.

Table 1. Capital investment in fuel production.

Fuel	Initial investment (per kilowatt)	Reference
Persian Gulf oil	$ 2.80	(9, 10)
U.S. onshore oil	81.40	(9, 11)
U.S. geothermal steam	75.40	(12)
North American U_3O_8	4.00	(13)

An obvious question to ask is whether geothermal drilling, if it continues at the present rate, will achieve the steam production projected by the Hickel Conference. Sources close to the industry estimate that there may be ten drilling rigs at work continuously in the United States at present, indicating an average drilling rate of 60 to 100 geothermal wells per annum; this is only about one-fortieth of the rate required to meet the Hickel projections. Or, to look at it another way, to drill 42,000 wells by 1985 beginning with an annual rate of 100 in 1973 will require an annual increase of 50 percent in the number of wells drilled continuing through 1985.

Institutional Factors and Development

If geothermal power is as competitive economically as suggested above, then it may be asked why relatively little geothermal drilling is now taking place in the United States. Several answers to this question have been given. It has been pointed out that the major geothermal resources of the United States are located in the western states, where 60 percent of the geothermally prospective areas are federal land which has not yet been released for geothermal exploration and development. Federal leasing requirements are more onerous for known geothermal resources areas (KGRA's) than for other prospective areas, and since many nonfederal prospective areas are adjacent to federal lands, there is a reluctance on the part of geothermal operators to carry out exploration drilling and prove geothermal resources in these areas because the adjacent federal lands may then be reclassified as KGRA's.

In the past, two industries have mobilized and deployed risk capital for natural resource development on the scale now required for geothermal de-

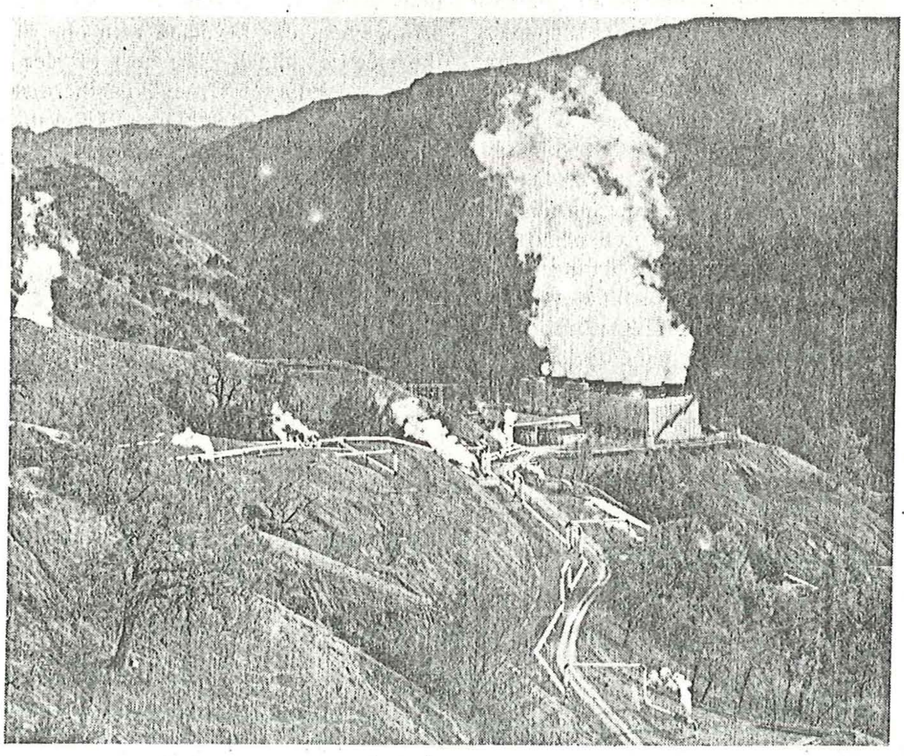

Fig. 2. Generating units at The Geysers geothermal power plant, Sonoma County, California. In the foreground are steam pipes with expansion loops. The loops allow the pipe to contract when the plant has to be shut down and to expand on start-up. The steam condensate rising from the row of five low stacks at the left marks the location of blowdown valves. When the plant has to be shut down, the steam escapes through these valves. The steam at the upper left comes from a natural fumarole. [Source: Pacific Gas and Electric Company, San Francisco]

velopment. These are the mining and oil industries. It might be expected that the oil industry in particular could now easily move an appreciable part of its resources from oil to geothermal exploration and development. Yet this has not occurred, at least on the scale needed to meet the Hickel projections. The reason may be that, while oil (and also minerals) may be traded nationally and internationally, geothermal resources cannot be, but must be used close to where they are produced for the generation of electric power or to supply thermal energy. In the United States only a public utility may sell electric power, and so the oil companies should seek the utilities in some form of partnership in geothermal development if power production is the objective, yet this kind of association is not customary for the oil companies and may tend to inhibit their activities in the geothermal field.

At the risk of some oversimplification, it can be said that our main sources of energy now and in the short term future are the hydrocarbons, with, in the background, the possibility that nuclear fission may be developed into a significant energy source. It is instructive to examine the investment costs and relative profitability of these energy sources. The approximate average capital investments required to extract energy sources from the ground without refining are given in Table 1.

It is interesting to note that the initial capital investment in fuel production per kilowatt for uranium is almost as low as that for Persian Gulf oil, but the relatively high cost of nuclear generating plants and operating and environmental problems appear to have held down demand, prices, and profitability for uranium ore producers.

If it may be presumed that the production of onshore oil in the United States is a profitable industry, then the costs quoted in Table 1 indicate that, even if the profit margin per barrel for Persian Gulf oil is smaller than for U.S. oil, companies with access to Persian Gulf or comparable overseas oil and U.S. markets (in general, the major companies) may find it more profitable to invest in the production of that oil rather than alternative domestic energy sources such as geothermal steam. On the other hand, oil companies without access to the Persian Gulf or similar sources of oil may find geothermal steam production worth considering if a suitable arrangement can be made with one of the electric utilities. The cost of electricity produced from geothermal steam was about $0.0053 per kilowatt-hour at The Geysers field in 1970. For comparison, the cost of electricity from an oil-fired thermal generating plant in California was $0.01 per kilowatt-hour when fuel oil cost $3.50 per barrel, and from a nuclear generating plant it was about $0.012 per kilowatt-hour.

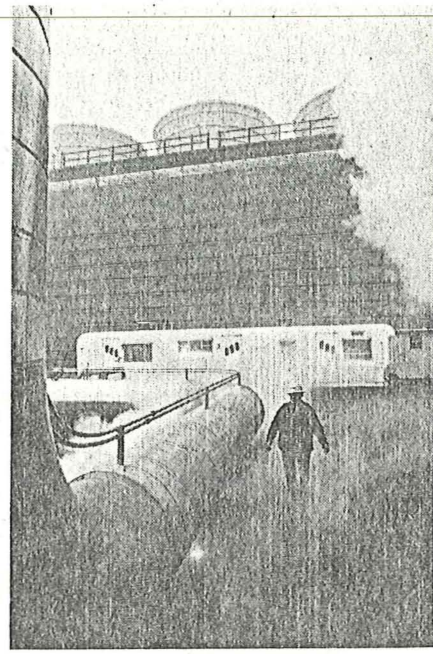

Fig. 3. Part of a 53,000-kilowatt generating unit at The Geysers geothermal power plant, Sonoma County, California. The big pipe is carrying steam to the turbine generators. Completion of this unit in 1973 brought the capacity of the plant up to 396,000 kilowatts. [Source: Pacific Gas and Electric Company, San Francisco]

The utilities, if they are to generate substantial quantities of geothermal power, will need to adjust to the concept of building generating plants in multiples of small units (55 Mw is the output of the largest geothermal unit now in operation) close to the geothermal field rather than close to the center of demand, with the disadvantage that long transmission lines may be required in some cases. The utilities themselves, if they chose to mobilize and deploy risk capital, could enter the field as steam producers. However, if the utilities did choose to diversify into the development of primary energy sources, it would remain for them to assess the relative profitability of offshore oil and gas compared to geothermal steam.

Some industries, such as aluminum, which are now facing electric power shortages in the United States, could develop geothermal power resources for their own consumption in order to achieve security of supply.

Two factors that have not been discussed in relation to geothermal energy development are matters which are of concern at the national level—these are security of supply and foreign exchange costs for imported fuels. Since geothermal energy must be consumed domestically and involves no recurrent foreign exchange costs, these two factors might lead to government policies favoring the development of geothermal resources. Such policies might be implemented either by some form of legislation favoring geothermal energy or by direct government action in exploring for and developing the resources, which then would be exploited by the utilities.

Many of the factors influencing the development of geothermal resources in the United States affect other countries also. Any country which is a net importer of energy would do well to examine its geothermal energy potential, and even countries which export oil and gas might consider whether geothermal energy could substitute for oil or gas at a lower cost and whether there may be some special application, such as space heating or cooling, or the production of desalted water or of hydrothermal minerals, where geothermal resources have a role to play. That geothermal energy is cheaper than alternatives in many cases is certain, and the prospect of rising prices for oil and gas and other energy sources in the future means that its competitive position is unlikely to change. That geothermal resources will continue to be developed successfully and profitably seems certain, but what is uncertain is whether in the United States the industry will receive the massive investment it needs to achieve the Hickel projections.

The likely scale of geothermal development in the United States is difficult to determine. There is no tradition of exploration for and development of fuels by the state, and the oil and mining companies, in the past the investors of risk capital in natural resource development, may not find investment in geothermal energy as profitable as investment in Middle Eastern or other oil resources. The come will depend on the policy sions of governments as well as institutional and financial factors in the United States, on how the and mining companies and the utili- react to the problems and chal- es of geothermal energy develop- at. In other countries, particularly eloping countries, where the separa- between the sectors of the econ- engaged in resource development in electric power generation may be so clear-cut, or where the state itself more active, geothermal re- rces may have a part to play in stituting at lower cost for oil, coal, nuclear fission to meet future energy ls.

References and Notes

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8. J. B. Koenig, *Geothermics* (Special Issue No. 2) (1972), p. 1.
9. M. A. Adelman, *The World Petroleum Market* (Johns Hopkins Univ. Press, Baltimore, Md., 1972).
10. This is the average investment per initial daily barrel delivered to a loading terminal in the Persian Gulf. An investment of roughly $38 per kilowatt in tanker capacity is required to deliver oil to the United States, but this investment need not be made by the company which produces the oil.
11. This is the average investment per initial daily barrel of U.S. onshore oil. Prices are from Adelman (*9*).
12. It is assumed that the average geothermal well costs $150,000 and delivers a steam production equivalent to 5 Mw, that the ratio of drilling to total development costs is 1/1.6, and that 60 percent of the wells drilled are producers.
13. W. M. Gilchrist, *Mining Eng. (N.Y.)* **21**, 30 (1969). The investment cost in mine development and mining plant construction is taken to be $20,000 per annual ton of U_3O_8 produced. A burnup of 3,000 megawatt-days per ton of uranium, a ratio of 1.7 tons of uranium per megawatt electric of generating plant, and a generating plant load factor of 0.75 are assumed. The cost of supplying the initial charge of unenriched uranium, in a form suitable for use in a reactor, is about $50 per kilowatt. See, for example, L. R. Haywood, J. A. L. Robertson, J. Pawliw, J. Howieson, L. L. Bodie, *Proc. U.N. Int. Conf. Peaceful Uses At. Energy 8th* (1972), pp. 185–214.