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Capital and Electric Production Costs for Geothermal Power Plants

HERBERT E. KLEI and FRANK MASLAN

Abstract Electric power generation from geothermal wells is projected to increase within the immediate future. Plant sizes were optimized to show that there is little incentive to build plants above 100 MW in size. Power production costs were calculated for dry-steam, hot-brine, and hot-rock wells, and were found to lie between 4 and 8 mills/kWh.

If geothermal energy is "nature's teakettle," then the geothermal power plant must be the teacup to contain and utilize it. Although geothermal power plants have been in operation for most of the century, their size continually increases as the demand for power becomes more pressing. Generally, the economy of scale should make the unit costs decrease by some exponential factor as the size increases. However, with geothermal systems, the piping and steam-gathering costs can become more important in the larger systems, thus making the use of larger plants questionable. In an effort to find some optimum plant size, the capital and electric production costs were computed for a range of power plant sizes. The greatest uncertainty is in the prediction of geothermal field life, well life, and the probability of drilling a successful well. Until these areas are investigated more fully, cost predictions will have considerable deviation.

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There are three types of possible geothermal wells, all at various stages of development. Dry-steam wells produce dry steam and represent the primary source of commercialized energy at this time. Such wells are found in the Geysers field in California and at Larderello, Italy. These wells are prime geothermal energy sources since the energy is in the form of steam which can easily be fed into a turbine-generation system. Dry-steam wells, however, are not the major form of geothermal energy. Hot-brine deposits are much more numerous and represent largely an undeveloped potential. The hot brine is highly corrosive and presently is flashed to give low-pressure steam, thus recovering about 60–80% of the available energy of the brine. Very few hot-brine plants have been built. Therefore, long-term costs on equipment and wells are not yet available. The third geothermal source is hot-rock wells. If holes are drilled into the crust of the earth, the internal heat can potentially be utilized. The wells will be fed water, which will be heated by the hot rocks, and then handled as either dry-steam wells or hot-brine wells, depending on whether the flashing occurs at the surface or within the well. To date no hot-rock wells have been drilled. Costs and capacities of these wells are largely conjecture and await demonstrated results.

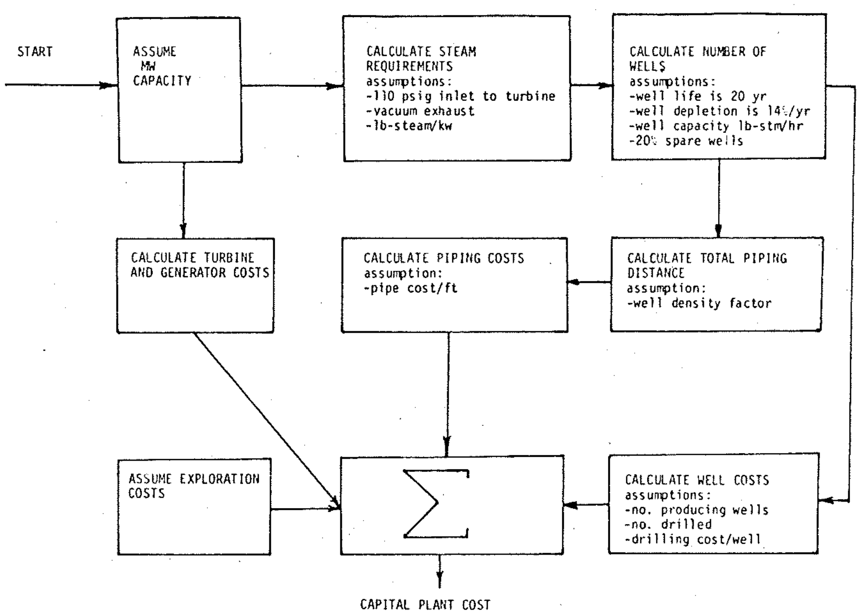

Figure 1. Calculation flow sheet.

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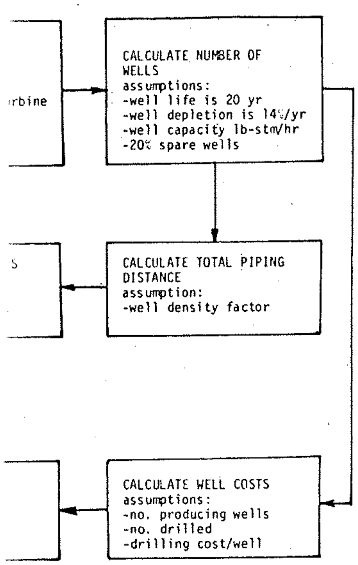

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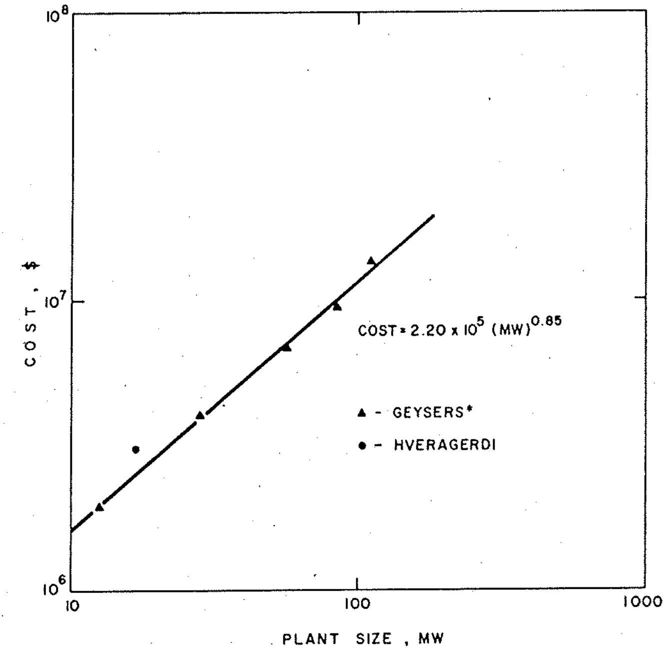


Figure 2. Capital cost for dry-steam turbine generator. *Data on Geysers from Kaufman (1970).

Dry-Steam Wells

The calculation of the capital investment for a geothermal producing site is outlined in the top section of the flow sheet shown in Figure 1. Four basic blocks of information were added together to obtain the required capital investment: turbine and generator costs, exploration costs, well costs, and piping costs.

Turbine-Generator Costs

Some turbine-generator cost information for steam-producing wells is available for the Geysers installations (Kaufman, 1970). The Geysers field has been expanded several times, and each time larger units have been added. The Geysers plant cost is plotted in Figure 2, which indicates a scale-up factor of 0.85, in agreement with the assumption of Armstead (1970). The line through the Geysers data, rather than the higher cost curve of Armstead, was used in succeeding calculations. This cost is assumed to include everything located at the plant site, principally the generators, turbines, transformers, and cooling towers. Once the capacity of the plant is assumed in megawatts, then the turbine-generator costs can be calculated.

Number of Producing Wells Required

The number of wells required is governed by many unknown factors about which certain assumptions must be made. The steam requirements of the plant must first be calculated. For this system, a pressure of 110 psig of steam is assumed to be available at the turbine inlet, while the turbine exhaust is under vacuum. The amount of steam required from the Geysers field is 2 million lb/hr per 110 MW or 18.2 lb/kW. This value is within the general range of 15-20 lb/kW reported from steam wells. After the steam requirements are determined, a number of assumptions regarding the well must be made, the two most important of which are well production capacity and well placing density. The steam production rate from the Geysers field varies between 40,000 and 300,000 lb/hr/well at about 125 psig. For this system, a rate of 100,000 lb/hr/well was assumed, thus giving a well energy yield of 5.5 MW/well. A reserve capacity of 20% in the number of wells was assumed.

The output of two Geysers wells (Kruger and Otte, 1973) with time was plotted on semilog paper, and the output of the wells was found to decrease at a rate of 14%/yr. Therefore, the reserve would be used up within the first year, necessitating a constant drilling of new wells at the rate of 14%/yr. The well life is assumed to be 20 years, after which the output would have become negligible.

The initial number of wells is

$$N = \frac{\text{capacity (MW)}}{5.5\ \text{MW/well}} \times 1.20 \tag{1}$$

The total number over 20 yr is

$$N_T = \frac{\text{capacity (MW)}}{5.5} (2.8 + 1.20) \tag{2}$$

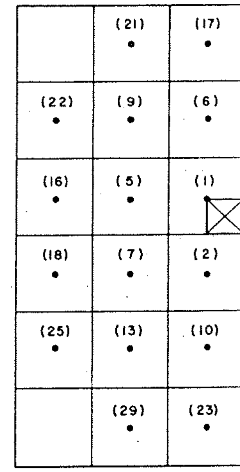
Well Costs

After the number of wells has been determined, the initial well cost becomes

$$\text{Well cost} = \frac{N \times \text{(cost/drilled well)}}{\text{(no. of producing wells)/(no. of drilled wells)}} \tag{3}$$

Assuming a cost of \$200,000/well hole and 80% success of drilling a producing well, we have

$$\text{Well cost} = \$250{,}000 \times N \tag{4}$$



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Piping Costs

It is assumed that as new well existing field. In addition, it is well per 40 acres, which is t cost will increase for the late This increase will tend to w network for several wells is sh

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Equation 5 gives the radius o distance from the station to slope of 2 on the log-log points are the measured distai

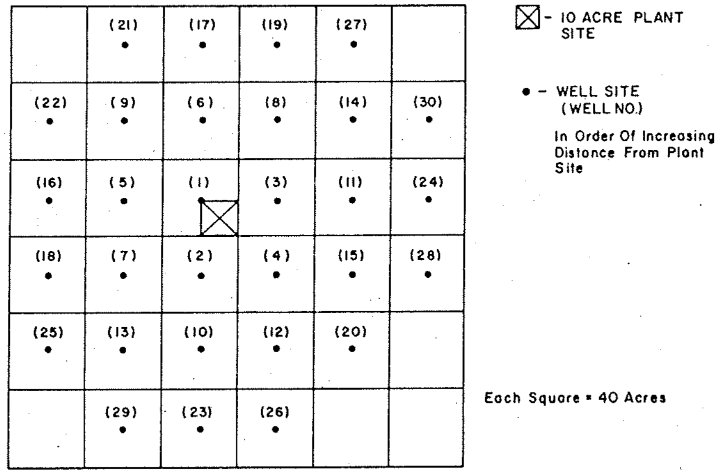

Figure 3. Grid for well placement.

Piping Costs

It is assumed that as new wells are needed they are drilled at the perimeter of the existing field. In addition, it is assumed that the wells are drilled at a density of 1 well per 40 acres, which is typical for the Geysers field. Therefore, the piping cost will increase for the later wells and as the capacity of the plant increases. This increase will tend to wipe out any advantage of larger plants. A grid network for several wells is shown in Figure 3.

The distance of each well from the station and the cumulative distance of all wells from the station are given in Figure 4. The distance of each well from the central turbines was predicted by circular geometry to be

$$N = \text{area} \times \frac{\text{number}}{\text{area}}$$

$$= \pi r^2 \times \frac{1}{40 \times 43{,}560}$$

$$= 1.80 \times 10^{-6} r^2 \qquad (5)$$

Equation 5 gives the radius of the circle necessary to contain the N wells, or the distance from the station to the Nth well. As seen in Figure 4, the line has a slope of 2 on the log-log paper as predicted from Equation 5, where the points are the measured distances given in Figure 3.

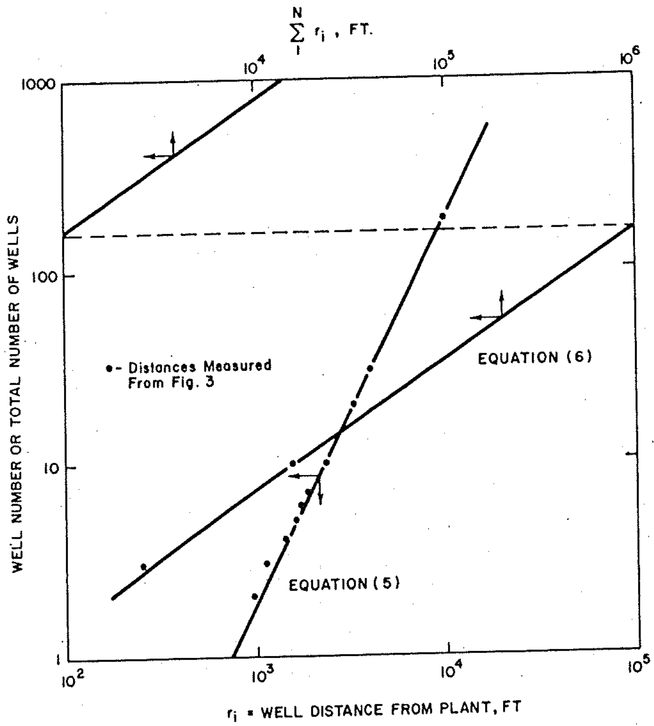

Figure 4. Well distances from power station.

The cumulative distance may be obtained by solving Equation 5 for r and summing over the desired number of wells. Thus

$$r_i = 745\sqrt{n_i}$$

$$\sum_{i=1}^{N} r_i = 745 \sum_{i=1}^{N} \sqrt{n_i}$$

$$\sum_{i=1}^{N} r_i = 745\left(\frac{2}{3}N^{3/2} + \frac{\sqrt{N}}{2} - 0.245\right) \tag{6}$$

Equation 6 is plotted in Figure 4, and the sum of the well distances approached it closely for $N > 4$.

The pipe mains are assume at full capacity. The laterals diameter. The 30-in. pipe is a cost of the 16-in. pipe is $4. needed per well to connect to

Piping cost =

Field Exploration Costs

The cost of developing a fiel million (Greider, 1973; Rec U.N. studies at $3.0 million represents costs more in line are fixed and must be wri becomes a major capital item

Well Flow Characteristics

Since the well has a perform approximated by

where H^0 = well-head press pressure; n = exponent char. 1.7 for the Geysers field). If t it is possible that the well-he at the turbines to cause an a 100,000 lb/hr. Taking G^0 = Equation 8 we find

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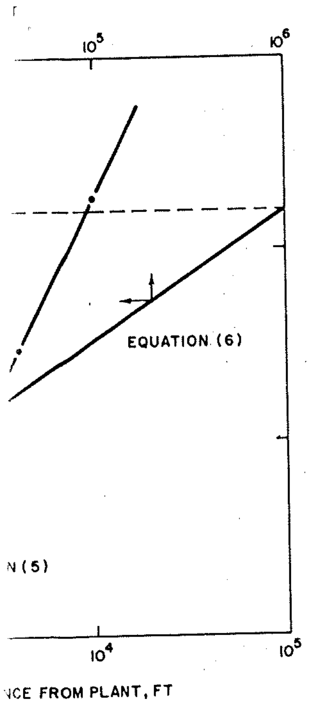

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e sum of the well distances approached

The pipe mains are assumed to be 30 in. in diameter and to service four wells at full capacity. The laterals from the well to main are assumed to be 16 in. in diameter. The 30-in. pipe is assumed to be installed at a cost of \$88/ft, while the cost of the 16-in. pipe is \$43/ft. It is also assumed that 200 ft of 16-in. pipe are needed per well to connect to the 30-in. main. The piping cost becomes

$$\text{Piping cost} = \$22 \times \sum_{i=1}^{N} r_i + (\$43 \times 200) \times N \qquad (7)$$

Field Exploration Costs

The cost of developing a field is relatively constant at between \$0.5 and \$1.25 million (Greider, 1973; Reed, 1973), although Armstead (1973) quotes several U.N. studies at \$3.0 million. The \$1.25 million figure was chosen because it represents costs more in line with the Geysers field. Since the exploration costs are fixed and must be written off against the producing wells, exploration becomes a major capital item in small plants.

Well Flow Characteristics

Since the well has a performance curve similar to a centrifugal pump, it may be approximated by

$$\left(\frac{H}{H^0}\right)^n + \left(\frac{G}{G^0}\right)^n = k \qquad (8)$$

where H^0 = well-head pressure at no flow; G^0 = well flow rate at atmospheric pressure; n = exponent characteristic of a particular well. $1.5 \leqslant n \leqslant 1.85$ (n = 1.7 for the Geysers field). If the well is located sufficiently far from the turbines, it is possible that the well-head pressure could be sufficiently above the 100 psig at the turbines to cause an appreciable decrease in flow rate below the assumed 100,000 lb/hr. Taking G^0 = 110,000 lb/hr and H^0 = 480 psig, by differentiating Equation 8 we find

$$\frac{dG}{dH} = -\left(\frac{G^0}{H^0}\right)^n \times \left(\frac{H}{G}\right)^{n-1}$$

$$= -88 \text{ lb/hr/psig}$$

For a 16-in. pipeline carrying 100,000 lb/hr of steam, the pressure drop at 110 psig is about 0.25 psig per 100 ft of pipe. If we take 10,000 ft as the maximum distance from a well, the maximum pressure drop between well and plant becomes 25 psig. Therefore, from Equation 8 we see that the maximum drop in capacity for a well is $88 \times 25 = 2200$ lb/hr or about 2%, which is assumed to be negligible.

Capital Costs for Dry Steam

The capital investment for N wells to satisfy the first-year production is shown in Figure 5. The required capital investment in dollars per kilowatt continues to decrease over the capacity range of 10–400 MW. However, it is very insensitive to capacity over the range of 100–400 MW, reaching a plateau of \$180/kW. Therefore, there is little incentive to expand to plants with capacities larger than 100 MW. It should be emphasized that these figures are the capital investment for only the first year of operation, after which the well capacity should be expanded by 14%/yr, and that these additional wells will be further from the turbines and hence more expensive than the wells they replace. The required total capital investment over 20 years for N_T wells is summarized in Figure 6.

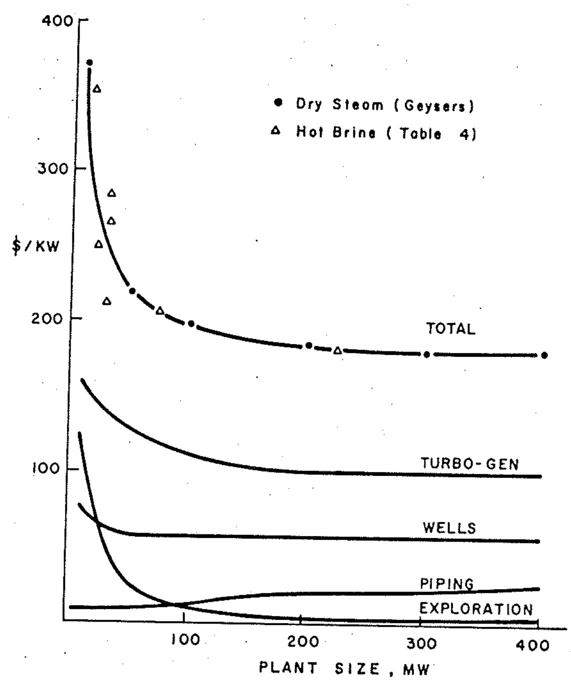

Figure 5. Initial capital cost.

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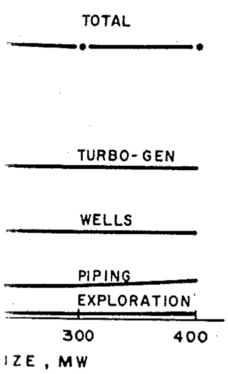

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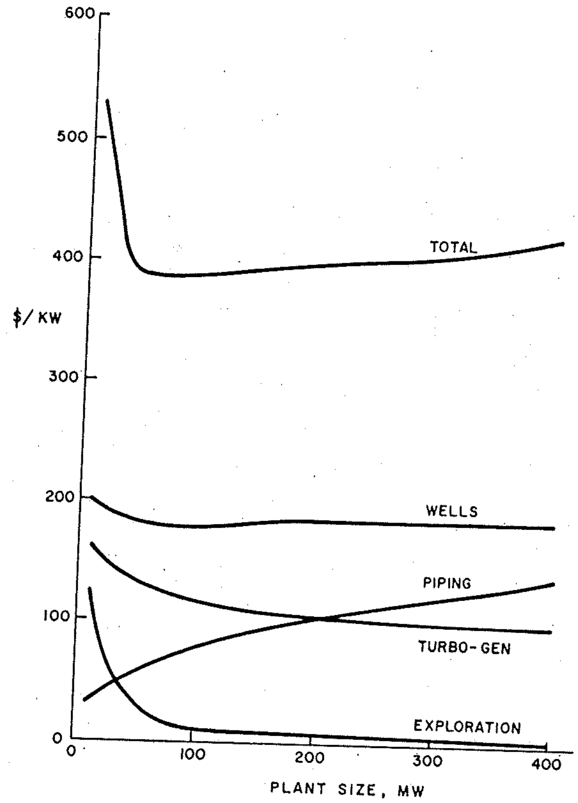

Figure 6. Total capital investment for 20 years, steam-producing wells (Geysers).

Here we have a minimum between 50 and 100 MW, in contrast to the previous case where no minimum occurred.

There are several ways to budget and treat future capital investments reserved for the new wells (Greider, 1973). They can be treated as an operating expense and charged against production costs in the year in which they were spent. They also can be discounted to give their present worth, and the discounted value can be added to the initial amount. In this study we chose the latter method. If the discount factor is taken to be 8%, it will equal the competing rate of inflation that Pacific Gas and Electric (PG&E) is estimating at 8%/yr. Therefore, inflationary increases in costs will consume the interest on the money, and future dollar costs equal present dollars. The total capital cost of the plant over the future 20 years in present dollars is given in Figure 6. It is interesting to note that, after several scale-ups, PG&E has settled on module units of 100–110 MW for several additional units through 1976, which indicates that it is designing near the optimum.

Production Costs for Dry Steam

Current projections of future production costs and methods of figuring them are outlined in the application of PG&E to the Public Utilities Commission of the State of California, dated July 24, 1973, for unit No. 14 at the Geysers field. PG&E's costs are based on purchasing the steam necessary to run the turbine generators, and therefore the well and piping costs must be accounted for in the manufacturing cost analysis of a grass roots plant. Table 1 gives the manufacturing cost of electricity at the generation site for a 110-MW plant running at a 90% operation factor. The cost of electricity is largely determined by the required capital investment per kilowatt, and as such only one production cost is necessary near the minimum in Figure 5 of 110 MW, which is the same as the PG&E application.

The projected cost of 6.33 mills/kWh compares with that of 8.35 mills/kWh from the PG&E application. The difference between the two figures is due to the method of calculating the steam cost to the generators. The cost of steam to PG&E is set by contract to fluctuate with the price of crude oil, and may bear

Table 1
Production Costs for Dry-Steam Wells[a]

1. Total capital investment (in millions)		$21.45
2. Direct costs (in millions per year)		
a. Installation of new wells		$ 1.073
b. Effluent disposal (0.5 mill/kWh)		0.434
c. Additional depreciation of initial wells (10-yr straight line)		0.77
3. Fixed charges [% of capital investment (Pacific Gas and Electric Company, 1973)]		
a. Return and depreciation	9.79	
b. Taxes and insurance	2.22	
c. Property taxes	2.03	
d. Insurance	0.09	
	14.13	$ 3.035
4. General (in thousands $)		
a. Operation	$ 55	
b. Maintenance	80	
c. General expense	40	
	$175	$ 0.0175
Total annual cost (in millions)		$ 5.330
5. Production cost for generated power (mills/kWh)		6.33

[a]Based on a 110-MW plant with a 90% operation factor.

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Hot-Brine Wells

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no relationship to the cost of steam production in the field. The recent rise in crude oil prices may have been anticipated in PG&E's application. In Table 1 the steam costs are listed under "Direct costs" as covering the installation of new wells as well as the depreciation of the initial wells over a ten-year period. A charge for effluent waste disposal is also included. Since the amount of depreciation under line 3a of Table 1 is based on a 29-year life, the additional depreciation over ten years of the initial wells was included in line 2c to more truly reflect the useful life of the well. If a company owns its own wells, the cost of electricity should be in the 6–7 mill range instead of in the 8–9 mill range projected by PG&E. In any case, these costs are well below the 1980 projected costs for all sources of power except enriched uranium, where costs of 5.1 mills/kWh are projected. As a result, geothermal power will be very competitively priced relative to other energy sources.

Hot-Brine Wells

The chances of hitting a hot-brine field as opposed to a dry-steam field (e.g., the Geysers field) are estimated at 20:1; the former therefore represent a larger source of potential geothermal energy. Unfortunately, the corrosion and scaling of equipment by the hot brines have seriously limited their utilization. In order to extract the energy from the hot brines, three general recovery methods have been considered: flashing the brine to obtain 20–30% of the brine water as steam, heat transfer to a secondary fluid such as isobutane or Freon for use in the power cycle, and the total flow of the flashed steam and hot brine to a turbine capable of handling the two-phase flow. Since the basic elements of capital investment in all these processes are similar to those for the dry-steam units, the effect of size on capital investment should be similar and should reach a plateau in the 100–200 MW range. The initial capital investment required for a geothermal plant with brine wells is comparable to that for the dry-steam facilities, as seen in Figure 5.

Several detailed cost estimates have been prepared for these three brine methods; they are summarized in Table 2. The references cited in the table gave a wide range of depreciation rates, and hence a range of production costs was found for similar size plants. However, the electric generation costs for all schemes were below those predicted for the dry-steam wells, primarily because to date the hot-brine wells have not decreased their output with usage. In the dry-steam wells the production decreased about 14%/yr, while the rate of brine flow has remained constant. This decreased replacement cost can show up directly as lower electric energy costs. The amount of flashed steam available per well from brine wells is very close to that found in the dry-steam fields, such as the Geysers field in California. Table 3 gives the amount of flashed steam per

Table 2
Geothermal Brine Energy Costs

Process	*Size (MW)*		*Capital investment ($/kW)*	*Operating costs ($/yr)*	*Production costs (mills/kWh)*	*Source*
Brine flash						
Brine at 600 Btu/lb	28		214	677,000	2.80	U.S. Department of the Interior, 1971
Brine at 600 Btu/lb	22.6		251	838	4.77	Green and Laird, 1973
Brine at 550 Btu/lb	192	(Wairakei)			5.14	Armstead, 1973
Brine at 510 Btu/lb	75	(Cerro Prieto)	208 (17% overhead)		8.00	
	30	(Otaka)	288	1,427,000	6.53	
Secondary fluid						
Brine at 600 Btu/lb	14.1		354	761,000	6.82	Green and Laird, 1973
Two-phase turbine						
Brine at 600 Btu/lb	28		264	1,050,000	4.70	Green and Laird, 1973
Brine at 562 Btu/lb	220		180	3,134,000	3.30	Austin, Higgins, and Howard, 1973

Table 3
Power Outputs from Brine Wells

Location	*Flashed steam (lb/hr)*	*Megawatts per well*	*Source*
Imperial Valley, California (21,000 brine bbl/day at 125 psig)	118,000		Otte, 1970
Wairakei, New Zealand	43,700	3.2	Commissioner, Ministry of Energy Resources, 1970
Cerro Prieto, Mexico	110,000	5.0	
General		3.8	Austin, Higgins, and Howard, 1973
	100,000	5.0	Armstead, 1973
Geysers, California (dry-steam well)	96,800	5.3	Armstead, 1973

well and the megawatts per well for several known fields; it shows that approximately 5 MW/well of flashed steam are available for both brine and dry-steam wells. Therefore, it is not surprising that the brine and dry-steam plant costs in Figure 5 are comparable.

Before accepting the figures of Table 2 too strictly, one should realize that brine-flashing plants are the only ones presently operating at Cerro Prieto, Mexico, and Wairakei, New Zealand. The heat exchangers for the secondary cycles as well as the turbines for two-phase flow will be subject to severe corrosion and scaling problems, which can wipe out any possible thermodynamic increase in energy recovery from the brine.

Hot-Rock Wells

Methods to extract energy from hot rock are largely centered around the method proposed by the Los Alamos Scientific Laboratory (Brown, Smith, and Potter, 1972). Two holes are to be drilled into the hot-rock regions of the earth's crust, and the region between the holes will be hydrofractured, a common practice in the oil industry. Water will be pumped down one hole, will permeate the hot rock, and will exit through the other hole at a temperature of about 300°C. The pressurized water will be heat exchanged with both steam and isobutane in secondary cycles, with the secondary fluid sent to the same type of turbine-generator system as in the dry-steam unit. If a secondary fluid is not desired, the hot water could be flashed and the steam sent to the turbine generators. Since no hot-rock wells have been drilled and operated, it is difficult to project power costs for this method. The well depths are projected to be

Table 4
Electric Generating Costs from Hot-Rock Geothermal Plants[a]

Type	Plant size (MW)	Capital costs ($/kW)	Generating costs (mills/kWh)
300°C rock, steam and isobutane cycles, four holes	100	186	4.7
175°C rock, isobutane cycles, ten holes	100	316	8.0

[a]Data from Brown, Smith, and Potter, 1972.

between 20,000 and 60,000 ft, and 4–10 times the depth of present dry-steam or brine wells. The present limit to our drilling technology is about 30,000 ft, which restricts the regions of the country to be examined. In addition, little is known about the heat recharge rate to such a rock formation that will sustain a steady removal of heat from it. With these uncertainties taken into consideration, some projections of hot-rock power costs have been made and are given in Table 4. Capital and electric generating costs are comparable to those in both the dry-steam and hot-brine systems. Until actual hot-rock wells are dug and evaluated, a large degree of uncertainty will govern hot-rock costs.

Conclusions

1. The initial capital investment required for dry-steam geothermal plants changes little from $180–200/kW for plants above 100-MW capacity.
2. When the total investment in replacement wells over 20 years is added to the initial capital investment, the total reaches a minimum for plants between 50- and 100-MW capacity.
3. Since the amount of flashed steam per well obtained from hot-brine wells is close to that obtained from dry-steam wells, and since the initial capital investments for both systems are the same, conclusions 1 and 2 also hold for hot-brine wells.
4. Since the level of capital investment determines 80–90% of the electric production costs, electric production costs are a minimum for plants around 100-MW capacity.
5. The electric production costs of a 110-MW plant are between 6 and 8 mills/kWh for both dry-steam and hot-brine systems.
6. The hot-rock well systems are projected to have electric generation costs between 4 and 8 mills/kWh, although these costs are largely conjecture.

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