NEAR-TERM GEOTHERMAL ENERGY
SUPPLY CURVES AND THE IMPACTS
OF TECHNOLOGY

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SUMMARY

This report presents near-term supply curves for both electric and non-electric applications of geothermal energy. These curves are based on energy production costs calculated using the GEOCOST⁽¹⁾ and GEOCITY⁽²⁾ models and are intended to represent current state-of-the-art technology.

The near-term supply curves include the high-temperature and intermediate-temperature hydrothermal resources identified by the USGS.⁽³⁾ We used the subsurface temperature, reservoir thickness, and heat content estimates made by the USGS to derive price-quantity relationships for geothermal electricity production, space heating, and process heating.

We also developed long-term supply curves which illustrate the potential shifts in the supply curve which would result from certain improvements in technology. The long term supply curves were drawn to show the impacts of individual technology improvements and also to show the cumulative impacts of combinations of technological advances. We show that through a combination of significant technological advances, most of the identified hydrothermal resources could become competitive with conventional energy sources for electric power production.

The results of a literature review to determine the range of values experienced or expected for most of the significant factors which have an economic influence on the utilization of geothermal energy are presented. From this data, typical values were selected to represent the base line conditions for this study.

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NEAR-TERM GEOTHERMAL ENERGY SUPPLY CURVES AND THE IMPACTS OF TECHNOLOGY

INTRODUCTION

OBJECTIVE AND SCOPE

The purpose of this report is to derive near-term supply curves for both electric and nonelectric applications of geothermal energy and to determine the potential impacts of some improvements in technology. Based on temperature, depth, and heat content estimates found in USGS Circular 726⁽³⁾ for the identified hydrothermal resources, we derived price-quantity relationships for geothermal electricity production, space heating, and process heating. The U.S. Geological Survey plans to publish a revised version of Circular 726 early in 1979 to include their recent reassessment of the geothermal resources in the United States. At that time, we plan to update the resource data base and derive new curves if necessary. However, we believe this report represents the best available estimate of the near-term supply curves and will be useful for planning purposes in the interim.

This report is part of a larger study now in progress for the Department of Energy's Division of Geothermal Energy (DGE). The objective of this study is to develop supply curves for geothermal energy. In scope, the supply curves will include 1) all potential geothermal resources, 2) both electric and nonelectric applications, and 3) both near-term and long-term technology. The entire DGE geothermal R&D program will be evaluated to determine the potential shifts in the supply curves that would result from the successful completion or implementation of specific research and development programs, projects, and policies. This will be an undertaking of major magnitude which requires groundwork in all aspects of geothermal energy.

To derive the supply curves, we use two models, GEOCOST and GEOCITY. GEOCOST simulates the production of electricity from geothermal resources. GEOCITY simulates the transmission and distribution of geothermal energy for space and process heating. Both models have been described in previous

reports.^(1,2) The models have the advantages of providing internal consistency for comparative analysis of resources and technologies and of requiring all the assumptions used in the analysis to be made explicit. The derivation of supply curves requires establishing reference conditions and assumptions. These conditions and assumptions and their basis are discussed in detail in the report.

JUSTIFICATION

Supply curves are extremely important and useful aids to program planning and budgeting for natural resource development. They include all factors of economic importance: economic conditions, technological capabilities, legal and institutional considerations, and the assumed state of nature. These factors are fundamental to planning a resource development program. Supply curves, therefore, provide the comprehensive analytical framework needed for evaluating the impact of real or potential changes in economic conditions, technology, policies, and the assessment of natural resources. Potential shifts in the supply curves are basic to cost-effectiveness analyses of alternative program plans and policies.

PREVIOUS WORK

In previous work we had developed near-term supply curves for electricity generation from hydrothermal resources,^(4,5) geopressured resources⁽⁶⁾ and for nonelectric applications from intermediate-temperature hydrothermal resources.^(7,8) For the purposes of this study, "near-term" is defined as able to be built with today's technology and equipment. We had also, to a very limited extent, evaluated the potential shifts in the hydrothermal supply curves which would be caused by policy alternatives and technology improvements.

The hydrothermal supply curves were based on 1974 cost estimates and technical data available in early 1975. Costs have risen sharply since then and much more information is now available from the geothermal research, development, and resource assessment programs. Thus, an updating of these curves was in order. The updating would include current cost estimates, recent technology developments, and a reappraisal of the basic financial and technical assumptions.

The geopressured supply curves were developed about a year ago. They were based on 1975 resource assessment data and cost estimates. Although information is developing rapidly in the geopressured area, the crucial questions pertaining to well life, well cost, well flow rate, and methane content and price have not been resolved. Until they are resolved, our incremental cost analyses using the USGS development scenarios⁽³⁾ are probably the best basis available for deriving geopressured supply curves. Since considerable time will be required to resolve the current uncertainties and bring geopressured wells into production, the geopressured resource will be included only in the long-term supply curves.

About a year ago, we developed near-term supply curves for nonelectric applications for intermediate-temperature (90°C to 150°C) hydrothermal resources.^(7,8) These nonelectric supply curves will now be extended to include high-temperature (>150°C) hydrothermal resources. High-temperature hydrothermal resources are potentially valuable for both electric and non-electric uses and should be included in both supply curves. Lower-temperature resources, including normal gradient resources and convective hydrothermal resources below 90°C, are potentially usable for space heating in nearby communities. When data becomes available on these lower-temperature resources, they will be included in the near-term and long-term nonelectric supply curves, as appropriate.

Supply curves were lacking for electrical generation from hot dry rock, magma, and the Salton Sea resources. However, near-term supply curves were not appropriate for hot dry rock and magma since the technology required to exploit these resources will not be developed in the near-term. Also the technology required to develop the Salton Sea resource appears to be outside

the definition of near-term. Thus, the Salton Sea resource will be included only in the long-term supply curves, based upon successful completion of the DGE research programs at the Salton Sea.

To summarize, in this report we will derive near-term supply curves by (1) updating the previous hydrothermal electrical supply curves, and (2) extending the nonelectrical supply curves to high-temperature hydrothermal. These near-term supply curves will provide the basis for deriving long-term supply curves. Long-term supply curves, based on identified advances in technology, were nonexistent for all resources for both electrical and non-electrical applications. Although we plan to derive long-term supply curves in a subsequent report, we will illustrate the potential shift in the supply curve which would be caused by some realistic technology advances. We will also describe the analytic methodology and the basis for most of the important assumptions used in the analysis.

NEAR-TERM SUPPLY CURVE FOR ELECTRIC APPLICATIONS

We derived the near-term supply curve (Figure 1) for electrical applications of hydrothermal resources based on USGS resource assessment data. Each step in the curve is composed of one or more geothermal resources identified by the USGS, as indicated for several of the steps on Figure 1. Both high-temperature and intermediate-temperature resources were included up to an arbitrary cost ceiling of 100 mills/kWh. For the near-term we excluded the high-temperature hydrothermal resources in Alaska, the Salton Sea, and the National Parks. The technology implicit in this curve is discussed below. Figure 2 shows the smooth curve which we have drawn to represent the step function shown in Figure 1. Figure 2 will serve as the reference curve to illustrate the shifts which would be caused by potential technology improvements. It is easier to visualize shifts in price or quantity if the supply curves are smooth rather than step functions.

The supply curve is based on resource assessment work done by the USGS.⁽³⁾ Table 1 shows the characteristics of the identified high-temperature hydrothermal resources. The USGS estimated the subsurface temperature, the reservoir thickness, and the heat content of each reservoir. They also assumed a 25%

FIGURE 1. Near-Term Supply Curve for Electric Applications of Hydrothermal Resources

FIGURE 2. Near-Term Supply Curve for Electric Applications of Hydrothermal Resources

TABLE 1. High-Temperature Hydrothermal Reservoirs^(a)

Subsurface Temperature °C	Reservoir Thickness, km	Heat Content, ^(b) 10 ¹⁸ Calories	Recovery Factor, e _r	Electrical Potential, Mile Centuries
240	2.0	23.7	0.025	786
230	2.0	1.0	0.025	33
220	2.0	96.0	0.025	3185
214	2.5	3.6	0.025	119
210	2.7	1.9	0.025	63
210	2.0	2.6	0.025	86
200	1.5	6.2	0.025	206
190	2.5	1.1	0.02	29
190	2.0	11.0	0.02	292
185	1.5	0.8	0.02	21
180	2.0	13.8	0.02	366
180	1.4	1.0	0.02	26
175	2.0	24.0	0.02	637
175	1.5	0.8	0.02	21
170	2.5	3.4	0.02	89
170	1.6	0.9	0.02	25
165	2.5	1.1	0.02	29
165	1.5	1.3	0.02	35
160	2.5	2.2	0.02	58
160	2.0	17.0	0.02	451
160	1.3	0.8	0.02	21
155	1.5	0.9	0.02	24
215.1			6602	

^(a) Excluding National Parks, Alaska, The Geysers, and Salton Sea.

^(b) Above 15°C.

TABLE 1. Continued

	Subsurface Temperature, °C	Reservoir Thickness, km	Heat, ^(a) Content, 10 ¹⁸ Calories	Recovery Factor, e _r	Electrical Potential, MWe Centuries
<u>ALASKA</u>	210	2.0	0.9	0.025	30
	180	1.5	0.2	0.02	5
	155	2.0	0.3	0.02	8
	155	1.5	0.2	0.02	5
			<u>1.6</u>		<u>48</u>
<u>THE GEYSERS</u>	240	2.0	18.9	0.025	627
<u>SALTON SEA</u>	340	2.0	21.0	0.03	836
<u>NATIONAL PARKS (b)</u>	250	2.5	133.0	-	-
	240	1.0	6.3	-	-
	230	1.3	0.8	-	-
			<u>140.1</u>		

(a) Above 15°C

(b) Includes Yellowstone and Mt. Lassen National Parks, both of which are permanently withdrawn from exploitation.

recovery of the stored heat at the surface and an electrical conversion efficiency of 8% or 10%, depending on temperature, to estimate the electrical potential of each reservoir. We combined the individual reservoirs into the temperature/thickness categories shown in Table 1 for the purpose of deriving supply curves. Temperature strongly influences production costs. Thickness is a measure of the average drilling depth, which influences the cost of wells.

Table 2 shows the characteristics of the identified intermediate-temperature hydrothermal resources. The USGS also estimated the subsurface temperature, reservoir thickness, and heat content of each of these reservoirs. However, no estimates of electrical potential were made for the intermediate-temperature reservoirs since they are assumed to be attractive for direct heating uses only. Again, we combined the individual reservoirs into temperature/thickness categories in order to derive supply curves.

In deriving the supply curves we also assumed a 25% recovery of the stored heat at the surface, but we calculated the electrical conversion efficiency independently for each temperature category using the GEOCOST model and its simulation of the power cycle based on the thermodynamic properties of the geothermal fluid. This results in some differences in the electrical potential, but has the advantage in subsequent analyses of introducing the sensitivity needed to future changes in electrical conversion efficiency resulting from technology improvements.

We define near-term technology to consist of both steam and binary cycles operating at a 70% power plant load factor. Binary cycle plants apply to all resources with subsurface temperatures of 175°C or less. Steam cycle plants apply to all resources with temperatures greater than 175°C. The steam cycle uses flashing in the well bore and steam separation at the wellhead. The binary cycle uses isobutane as the working fluid. For the binary cycle, the well is driven by conventional downhole pumps which suppress flashing in the well bore. Conventional downhole pumps are assumed to possess the following characteristics:

TABLE 2. Intermediate-Temperature Hydrothermal Reservoirs

Subsurface Temperature, °C	Reservoir Thickness, km	Heat (a) Content, 10 ¹⁸ Calories
150	2.0	0.6
150	1.5	6.8
145	2.0	4.1
145	1.5	265.7
140	2.0	1.1
140	1.5	9.8
135	1.5	4.7
130	2.5	0.7
130	2.0	1.3
130	1.5	6.2
125	2.5	0.3
125	2.0	1.2
125	1.5	5.0
120	2.0	30.0
120	1.5	2.8
115	2.0	0.9
115	1.5	1.8
110	1.5	1.7
105	1.5	0.7
100	0.7	0.2
		<hr/> 345.6

(a) Above 15°C

maximum temperature limit	360°F (180°C)
maximum depth	1000 ft (0.3 km)
maximum flow rate	880 GPM (440,000 lb/hr)
life	9 months
efficiency	60%
cost	\$125,000

The supply curve is based on 1977 cost estimates. The supply curve was obtained by graphing the energy production costs calculated using the GEOCOST model, and is intended to represent current state-of-the-art technology. For comparison, under similar financial assumptions the cost of electricity from new nuclear and coal power plants coming on line in 1977-1978 is in the range of 20-25 mills/kWh, while the cost of electricity from new oil-fired power plants is in the range of 35-40 mills/kWh. Other reference conditions and assumptions used in deriving the supply curve are discussed later in the report.

NEAR-TERM SUPPLY CURVES FOR NONELECTRIC APPLICATIONS

The near-term supply curves for nonelectric applications include both high-temperature and intermediate-temperature hydrothermal resources. Figures 3-8 show the near-term supply curves for geothermal space heating at various distances from the wellhead, up to 50 miles away. These step-function curves indicate large blocks of similar hydrothermal resources available at a constant energy cost. Each step is composed of one or more hydrothermal resources which were identified by the USGS. Again, we drew smooth curves (Figure 9) for ease of comparison to represent the step functions.

The near-term supply curves for geothermal space heating represent the costs of supplying geothermal energy to the point of distribution of a district heating system; i.e., only reservoir and transmission costs are included. None of the curves contain any costs for the district heating distribution system. We have assumed a load factor of 0.35 and a reject temperature of 38°C. We have also assumed a pipe diameter of 30 inches. Larger pipes would have little effect on the unit cost of transmission,⁽⁸⁾ but smaller pipes could increase unit costs considerably.

*MBTU = Million BTU

FIGURE 3. Near-Term Supply Curve for Geothermal Space Heating at the Wellhead

FIGURE 4. Near-Term Supply Curve for Geothermal Space Heating 10 Miles From the Wellhead

FIGURE 5. Near-Term Supply Curve for Geothermal Space Heating 20 Miles From the Wellhead

FIGURE 6. Near-Term Supply Curve for Geothermal Space Heating 30 Miles From the Wellhead

FIGURE 7. Near-Term Supply Curve for Geothermal Space Heating 40 Miles From the Wellhead

FIGURE 8. Near-Term Supply Curve for Geothermal Space Heating 50 Miles From the Wellhead

FIGURE 9. Near-Term Supply Curve at the Point of Delivery for Geothermal Space Heating

Figures 10-15 show the near-term supply curves for geothermal process heating at various distances from the wellhead, up to 50 miles away. The smooth curves (Figure 16) represent the step functions of Figures 10-15.

The near-term supply curves for geothermal process heating represent the costs of supplying geothermal energy to the point of use. Because of the wide variety of potential process heating applications, these curves include only the costs of production and transmission to the plant site. We have assumed a load factor of 0.80, a reject temperature of 100°C, and a pipe diameter of 30 inches. The cost of energy for process heating is less than for space heating because we have assumed a much higher load factor on the process heating system.

Figures 3-16 are based on the high-temperature and intermediate-temperature hydrothermal reservoirs listed in Tables 1 and 2, excluding The Geysers, Alaska, the Salton Sea, and the National Parks. The quantity of energy available is based on 25% recovery of the stored heat at the surface and a 30-year production period. The USGS estimated the heat content above 15°C for each reservoir. For space heating only the heat above 38°C is usable (without heat pumps), so we reduced the USGS energy estimates to this 38°C base. For process heating applications we assumed only the heat above 100°C is usable, so we adjusted the USGS heat content estimates to this 100°C base. Comparison of Figures 9 and 16 shows that only about half as much geothermal energy is potentially available for process heating as is available for space heating, due to the difference in assumed reject temperatures.

In addition to the normal reservoir production costs, we have included 10¢/MBtu to account for the cost of submersible downhole pumps to suppress flashing in the wells. Since we assumed that conventional downhole pumps have a maximum temperature limit of 180°C, we only included the additional 10¢/MBtu for the resources with subsurface temperatures less than 180°C. We have also allowed a 10% investment tax credit and a 10% depletion allowance to the reservoir operation.

The transmission costs were calculated from the following equation:

$$TC = \left[\frac{(6399 \times F^{-0.443} \times T^{-1.456} - 0.25)}{LF} + 0.5 \right] \times D$$

FIGURE 10. Near-Term Supply Curve for Geothermal Process Heating at the Wellhead

FIGURE 11. Near-Term Supply Curve for Geothermal
Process Heating 10 Miles From the Wellhead

FIGURE 12. Near-Term Supply Curve for Geothermal Process Heating 20 Miles From the Wellhead

FIGURE 13. Near-Term Supply Curve for Geothermal
Process Heating 30 Miles From the Wellhead

FIGURE 14. Near-Term Supply Curve for Geothermal
Process Heating 40 Miles From the Wellhead

FIGURE 15. Near-Term Supply Curve for Geothermal Process Heating 50 Miles From the Wellhead

FIGURE 16. Near-Term Supply Curve at the Point of Delivery for Geothermal Process Heating

where

TC = transmission cost, \$/MBtu

F = fluid flow rate, 10^6 lb/hr

T = fluid temperature, °C

LF = load factor

D = transmission distance, miles

This empirical formula was derived from a curve fit of data points calculated using the GEOCITY model at several different combinations of the variables. Our transmission costs include the effect of fluid temperature drop with distance, based on an assumed ambient air temperature of 12°C. We also assumed no elevation change between the resource and the demand.

IMPACTS OF TECHNOLOGY

To illustrate the potential impacts of technology on the supply of geothermal energy, we developed supply curves for electrical production based on several sequential improvements in technology. The technology improvements which we analyzed are summarized in Table 3. We also constructed three scenarios (Table 4) based on combined technology improvements which dramatically illustrate how the long-term supply curves might shift with time. These cases and scenarios represent only some, not all, of the potential technology improvements now under development. As shown, the potential impact of combined technological improvements on the supply of geothermal energy is huge. All of the supply curves are based on development of the high-temperature hydrothermal reservoirs listed in Table 1 and the intermediate-temperature hydrothermal reservoirs listed in Table 2.

TABLE 3. Technologies for Cases 1-6*

Case

- 1 Steam cycle based on steam separation at the wellhead.
- 2 Conventional downhole pumps; steam cycle separation at the plant or wellhead, as applicable.
- 3 Conventional downhole pumps; binary cycle and steam cycle, as appropriate.
- 4 Advanced downhole pumps; steam and binary cycles, as appropriate.
- 5 Advanced downhole pumps; steam and binary cycles; 25% drilling cost reduction.
- 6 Advanced downhole pumps; steam and binary cycles; 50% drilling cost reduction.

*Cases 1-6 based on 80% load factor.

TABLE 4. Technologies for 1980, 1990, and 2000 Scenarios

Scenario

- 1980 Conventional downhole pumps; steam and binary cycles; 70% load factor.
- 1990 Advanced downhole pumps; steam and binary cycles; 80% load factor for high-temperature ($\geq 200^{\circ}\text{C}$) resources and 70% for all others; 25% drilling cost reduction for liquid-dominated resources and 15% for dry steam; 5% decrease in field development and power plant capital costs for high-temperature resources; 10% decrease in energy costs for all resources; 5% decrease in low-temperature ($<200^{\circ}\text{C}$) energy and power plant costs.
- 2000 Advanced downhole pumps; steam and binary cycles; 85% load factor for high-temperature resources and 80% for all others; 50% drilling cost reduction for liquid-dominated resources and 30% for dry steam; 10% increase in power plant conversion efficiency for high-temperature resources and 30% increase for low-temperature resources; 5% increase in power plant costs for high-temperature resources; 10% decrease in capital costs (field development and power plant) for high-temperature resources and 20% decrease for low-temperature resources; 25% decrease in energy costs for high-temperature resources and 30% decrease for low-temperature resources.

The purpose of Cases 1-6 is to illustrate the impacts of individual technological achievements. For example, Figure 17 shows the supply curve (price-quantity relationship) for steam separation at the wellhead. This is the only commercial technology in existence. Under this technology, 3900 MWe centuries of electrical potential will be available at or below a power cost of 100 mills/kWh. (We chose 100 mills/kWh as an arbitrary cutoff point.) The step function corresponds to blocks of geothermal resources with identical subsurface temperatures and reservoir depths. As an example, the 500-MWe-centuries block in the lower-left corner represents the dry steam resource at The Geysers, which yields the lower cost of power of all the hydrothermal resources.

Figure 18 shows the supply curve for the steam cycle at the plant using conventional downhole pumps to suppress flashing in the wells. With this technology, the electrical potential at or below 100 mills/kWh is about 4250 MWe centuries. The impact of conventional downhole pumps is to increase the supply of geothermal energy from 3900 MWe centuries to 4250 MWe centuries, or about 9%. The impact is limited to the upper end of the curve since conventional pump technology, as described previously, is limited to resources below 180°C. Above this temperature, flashing in the wellbore and steam separation at the wellhead occurs as in Case 1. This technology is currently available but not used because power generation from hydrothermal resources with subsurface temperatures less than 180°C is too expensive.

The cost improvements attributed to downhole pumps are derived from replacing large steam transmission lines with lower-cost water transmission lines. This cost savings is partially offset by the cost of the pumps. Based on information in the literature^(9,10) and previous work, we assumed that conventional downhole pumps have a maximum temperature limit of 360°F (180°C), a maximum depth of 1000 feet, a maximum flow rate of 880 GPM (440,000 lb/hr), and a nine month life. Based on vendor data obtained in a telephone conversation with Harold Samford of Peerless Pump in Montebello, California, we assumed an efficiency of 60% and a cost of \$125,000 per pump. Since the pump life is only nine months, its cost is treated as an operating cost. For a 50-MWe plant with an 80% load factor, the downhole pump cost is 0.48 mills/kWh per well, or about 16 mills/kWh for a 180°C resource using the steam cycle with flashing at the plant.

FIGURE 17. Supply Curve for Case 1

FIGURE 18. Supply Curve for Case 2

Figure 19 shows the supply curve for Case 3, which consists of the binary cycle (below 175°C) using conventional downhole pumps and the steam cycle above 175°C. The electrical potential below 100 mills/kWh increases to about 9000 MWe centuries, which shows that the binary cycle has a large potential impact on the supply of geothermal energy. The impact is restricted to the upper, currently uneconomic, end of the supply curve where conventional downhole pumps can operate.

Figure 20 shows the supply curve for Case 4, which consists of the steam and binary cycles using advanced downhole pumps. Based on information in the literature^(11,12) and previous work, we assumed that advanced downhole pumps possess the following characteristics:

Maximum temperature limit	464°F (240°C)
Maximum depth	1400 ft (0.4 km)
Maximum flow rate	880 GPM (440,000 lb/hr)
Life	2 years
Efficiency	60%
Cost	\$125,000

Thus, advanced downhole pumps are assumed not to have the temperature limitation that affects conventional downhole pumps and are also assumed to be less expensive per kWh due to increased operating lifetimes. For a 50-MWe plant with an 80% load factor, the cost for an advanced downhole pump is 0.18 mills/kWh per well, or about 6 mills/kWh for a 180°C resource using the steam cycle with flashing at the plant.

For this report we have assumed only minimal achievements in downhole pump technology to represent what we have called advanced downhole pumps. Actually, many further technology improvements are possible to increase the capabilities of these pumps. The Department of Energy's Division of Geothermal Energy has been funding downhole pump research programs for several years. Downhole pumps that are currently in the development stage are expected to be available within the next year or two and may be capable of handling up to 2000 GPM with a five-year operating life, according to Cliff McFarland, who manages DGE's downhole pump research program. In light of these expectations, our assumptions concerning downhole pumps are quite conservative.

FIGURE 19. Supply Curve for Case 3

FIGURE 20. Supply Curve for Case 4

Figures 21 and 22 are based on the same pump and power cycle technology as Figure 20, but they also include technology improvements which result in 25% and 50% drilling cost reductions, respectively. As these figures show, drilling cost reductions lower the cost of power for all resources, but the impact is greater for the higher cost resources because well costs account for a higher proportion of the costs for these resources. Cases 5 and 6 show only a small increase in supply since the technology improvements discussed above have lowered the cost of most of the hydrothermal resources identified by the USGS below 100 mills/kWh.

In Figure 23 we have plotted smooth curves to represent the 6 cases previously shown as step functions. The horizontal or vertical distance between any two curves shows the quantity or price difference due to some technological improvement. Figure 23 gives some perspective as to the relative magnitudes of shifts caused by the sequential introduction of the various technologies considered.

The purpose of Figures 24-26 is to illustrate simultaneous impacts of combinations of technological advances. Figure 24 shows the 1980 Scenario supply curve which is based on steam and binary cycles using conventional downhole pumps and operating at a 70% load factor. The 1980 Scenario corresponds to the near-term supply curve described earlier. According to the 1980 Scenario, there are about 8850 MWe centuries of electrical potential at or below a power cost of 100 mills/kWh.

The 1990 Scenario contains several potential technology improvements which dramatically reduce the cost of geothermal energy and slightly increase the quantity of geothermal power available under our arbitrary price ceiling (Figure 25). The 1990 Scenario includes such technological improvements as decreased capital costs due to a "learning - curve" effect coupled with mass production, and decreased energy costs due to well stimulation and risk reduction through improved methods of reservoir assessment. Also, the load factor has been increased to 80% for high-temperature ($\geq 200^{\circ}\text{C}$) resources to reflect improved equipment reliability and improved overall utilization of utility systems generating capacity.

FIGURE 21. Supply Curve for Case 5

FIGURE 22. Supply Curve for Case 6

FIGURE 23. Supply Curves for Cases 1-6

FIGURE 24. Supply Curve for 1980 Scenario

FIGURE 25. Supply Curve for 1990 Scenario

FIGURE 26. Supply Curve for 2000 Scenario

Figure 26 shows the large cost reductions possible for the year 2000 Scenario. The 2000 Scenario includes further technology improvements, such as increased load factors, increased power plant conversion efficiencies, and decreased capital and energy costs. Under the 2000 Scenario, the supply of geothermal electrical potential has been increased by about 16% over the 1990 Scenario. Part of this increase in supply is from new resources that would become available at a cost below 100 mills/kWh, and part of it is from the increased conversion efficiencies, which make more power available from the same resources that appeared in the 1990 Scenario.

INTERPRETATION OF RESULTS

In Figure 27 we have plotted smooth curves to represent the three scenarios previously shown as step functions. The horizontal or vertical distance between any two curves shows the quantity or price difference due to some combination of technological improvements. Figure 27 gives some perspective as to the relative magnitudes of shifts in the reference supply curve (1980 Scenario) caused by the technological combinations considered in the 1990 and 2000 Scenarios.

Combinations of technology improvements have the potential to substantially reduce the cost and increase the supply of competitive geothermal energy. Under current conditions, new base-loaded nuclear and coal power plants generate electricity at about 25 mills/kWh at the busbar. Similarly, new oil-fired plants would generate electricity at about 40 mills/kWh at the busbar. Using these costs for reference, under the year 2000 geothermal scenario almost all of the hydrothermal resources would become competitive with oil and about half would become competitive with coal and nuclear. This presumes, of course, that the energy costs from conventional power plants remain constant in today's terms while the costs of geothermal energy decrease in response to technology improvements and economies of scale and mass production. The supply curves in Figure 27 are based only on the hydrothermal resources identified by the USGS in Circular 726 and do not include the prospective location of new geothermal resources. Similarly, they do not include the potential for technology improvements to lead to the commercial development of the high-salinity Salton Sea resource, hot dry rock resources, or geopressured resources.

FIGURE 27. Supply Curves for 1980, 1990, and 2000 Scenarios

IMPACTS OF POLICY IMPROVEMENTS

To illustrate the potential impacts of policy improvements on the supply of geothermal energy, we developed supply curves (Figures 28-31) for electrical production based on different percentage depletion allowances. Figure 28 shows the supply curve for the 1980 Scenario with no depletion allowance, Figure 29 shows the supply curve with 10% depletion allowance, and Figure 30 shows the supply curve with 22% depletion allowance. All of the supply curves are based on development of the high-temperature hydrothermal reservoirs listed in Table 1 and the intermediate-temperature hydrothermal reservoirs listed in Table 2.

With no depletion allowance, Figure 28 shows that about 4800 MWe centuries of electrical potential will be available at or below a power cost of 100 mills/kWh. Figures 29 and 30 show that with a 10% or a 22% depletion allowance, the supply available at a cost below 100 mills/kWh is about 8850 MWe centuries, a substantial (84%) increase over Figure 28.

In Figure 31 we have plotted smooth curves to represent the three step functions of Figures 28-30. The horizontal or vertical distance between any two curves shows the quantity or price difference due to the particular policy improvement made. Figure 31 gives some perspective as to the relative magnitudes of shifts caused by the increase in percentage depletion allowance. As shown in Figure 31, a 10% depletion allowance could lower the cost of power by 2 mills/kWh, while a 22% depletion allowance could lower the cost of power by 8 mills/kWh. The cost savings is a function of the resource quality. A 10% depletion allowance will decrease the energy production costs from the reservoir by 10%, but it will have no effect on the power plant costs. Thus, the overall reduction in cost of power depends upon the relative weights of the reservoir and power plant costs, which in turn depend on resource quality.

FIGURE 28. Supply Curve for 1980 Scenario with No Depletion Allowance

FIGURE 29. Supply Curve for 1980 Scenario with Ten Percent Depletion Allowance

FIGURE 30. Supply Curve for 1980 Scenario with 22 Percent Depletion Allowance

FIGURE 31. Supply Curves for 1980 Scenario with 0, 10, and 22 Percent Depletion Allowances

METHODOLOGY

The two aspects of a supply curve are price and quantity. For this study the quantity was derived from the geothermal resource assessment data of the USGS. For price we used our estimates of the production cost based on the resource conditions listed by the USGS. Our production cost estimates are sensitive to two resource characteristics, temperature and drilling depth. In previous work we have shown that temperature and well cost, which is related to depth, are two of the most important factors which affect the cost of geothermal energy. Other factors which affect the production cost estimates were held constant in this study.

We used the GEOCOST and GEOCITY models as our basic analytical tools. These models encompass the complete production process and require making explicit the assumptions used. The effect of changes in technology on the production costs can be evaluated rapidly and inexpensively for the entire range of geothermal resources within the systematic framework of these models. The changes in technology are entered into the models as changes to either the production function or the cost function. Changes which do not impact the production or cost functions, primarily those affecting supply and rate of utilization, are evaluated externally.

Production costs calculated with these models are based on life-cycle costing and include provisions for return on investment and taxes. Production costs were based on 1977 cost data. Other reference conditions and assumptions used in this study are described later.

The third aspect of a supply curve is the timeframe. Supply curves shift with time in response to changes in technology and changes in factor prices. In this study we determined the shifts caused by changes in technology. Factor prices were held constant.

Near-term supply curves are based on current or in-sight technology. Long-term supply curves are derived from the near-term curves by determining the shift caused by achieving certain technology improvements and goals.

REFERENCE CONDITIONS AND ASSUMPTIONS FOR HYDROTHERMAL RESOURCES

Our first objective was to establish the reference conditions and assumptions upon which the supply curves will be based, taking into account new information available since our original supply curves were derived. We conducted a literature survey to determine the best reference conditions and assumptions. The criteria for selecting the reference conditions and assumptions were best available data, consistency and comparability of results, and conformity, where possible, with traditional assumptions. Based on this survey, we used the following reference conditions and assumptions in deriving near-term and long-term geothermal supply curves, except where site-specific data was available.

WELL LIFE

We assumed a 10-year well life for steam-dominated reservoirs (e.g., The Geysers), but 15 years for liquid-dominated reservoirs.

A number of sources in the literature would support even longer well lives. For steam-dominated reservoirs, reasonable performance at a level greater than 50% of the original production rate has been observed for periods ranging from greater than 30 years (Larderello steam fields in Italy) to less than 8 years (The Geysers steam fields in California).⁽¹³⁾ McNitt⁽¹⁴⁾ and Towse⁽¹⁵⁾ are optimistic about reservoir performance in California and particularly for liquid-dominated systems in the Imperial Valley area and would predict well lifetimes in excess of 20 years. Existing geothermal wells in Iceland and New Zealand have produced from 20 to 40 years.⁽⁸⁾ Thus, the 15-year well life is somewhat more conservative than both past experience and many of the estimates appearing in the literature.

For high-temperature resources, the choice of well life is not too critical. The cost of power is essentially the same for a 250°C resource whether a 10-year life or a 20-year life is assumed. The difference would be greater for low-temperature resources. For example, the cost of power drops by about 10 mills/kWh for a 150°C resource as the well life is increased from 10 years to 20 years.⁽⁴⁾ Thus, our assumption of a 15-year well life

will not substantially affect the power costs for high-temperature resources, but it could introduce a 10% to 15% uncertainty in power costs for low-temperature resources.

WELL FLOW RATE

Based on the flow rate frequency curves which we constructed from U.S., Cerro Prieto, and Wairakei flow data, we used 440,000 lb/hr for liquid-dominated systems. The flow rates followed a normal distribution with a mean of 440,000 lb/hr and a standard deviation of about 200,000 lb/hr. In developing these curves, we eliminated several small wells in New Zealand with low flow rates because they aren't typical of U.S. production wells.

Many flow rates reported in the literature for wells in liquid-dominated systems are remarkable. For example, at Wairakei, New Zealand, more than half of the 60 production wells had original steam-water discharges averaging about 600,000 lb/hr for 8-inch diameter holes.⁽¹⁶⁾ At Namafjall, in northern Iceland, four wells are yielding 990,000 lb/hr of superheated water each, from which 530,000 lb/hr of steam is separated.⁽¹³⁾ In western Anatolia, Turkey, the yield per well is between 60,000 and 660,000 lb/hr of hot water, averaging 330,000 lb/hr.⁽¹³⁾ Information recently obtained from the Ahuachapan geothermal power plant in El Salvador showed average well flow rates of 576,000 lb/hr, with a variation from 236,000 lb/hr to 1,230,000 lb/hr among the ten producing wells.^(a)

Based on well flow data for steam-dominated fields, we used a flow rate of 150,000 lb/hr dry steam for the initial production rate from the 8.5-inch diameter wells at The Geysers.^(3,16) Presently, steam production at The Geysers ranges from 60,000 lb/hr in the shallower wells to over 300,000 lb/hr in the deeper ones. One source reports that a typical well produces 200,000 lb/hr of saturated steam.⁽¹⁷⁾ Another estimate of a typical typical well flow rate at The Geysers can be determined from a Shell Oil Company press release reported in the Wall Street Journal.

(a) R. DiPippo, "The Geothermal Power Plant at Ahuachapan, El Salvador, Central America - A Trip Report: June 14-19, 1978", C00/4051-30, Brown University, Providence, RI, June 1978.

Shell has completed six producing wells at The Geysers with a combined potential of 725,000 lb/hr steam. This converts to an average flow rate of about 120,000 lb/hr.

Flow rates for dry steam wells reported in the literature vary by an order of magnitude. At Larderello, Italy, the average well yield is about 50,000 lb/hr of steam, and perhaps 80,000 lb/hr at Monte Amiata, Italy. Individual wells may deviate considerably from these averages, and flows as large as 600,000 lb/hr have been reported. In February 1972, it was reported that several new wells were completed at Travale, Italy and that they were capable of producing at least 220,000 lb/hr each of dry steam.⁽¹³⁾

SPARE WELLS

Spare wells are provided to ensure the reliability of the energy supply. We used 20% excess producing wells to provide spare wells. This is lower than past experience at The Geysers or Cerro Prieto. However, in the future, spare capacity may be decreased further as the ability to predict reservoir performance increases.

Present development at The Geysers consists of 167 geothermal wells. A net generating capacity of 502 MW is provided by the steam produced in 75 of these wells.⁽¹⁶⁾ (There are about 55% excess producing wells.) The 75-MW Cerro Prieto geothermal plant is supplied by 18 of its 26 completed producing wells.⁽¹⁶⁾ (There are about 31% excess producing wells.) The San Diego Gas and Electric Company will add 20% spare capacity to the field production capabilities at their Miland Geothermal Test Facility.⁽¹⁶⁾ No spare wells are expressly provided at Ahuachapan.

DRY WELLS

We assumed that 20% of the producing wells drilled are dry or economically nonproductive. Different estimates of success ratios for development drilling have appeared in the literature, ranging from 66% to 90%⁽¹⁸⁾ (i.e., 10% to 34% dry wells). Approximately 90% of the development wells in The Geysers are successful.⁽¹⁶⁾

PRODUCTION WELL COST

The cost of drilling geothermal wells varies with depth and rock hardness, among other things. We have developed a drilling cost model which is sensitive to these factors. This model was used to estimate drilling costs on a systematic basis for the hydrothermal resources. Table 5 shows estimates of drilling costs derived from the model as a function of well depth for rock of medium hardness. These cost estimates compare favorably with data found in the literature.

TABLE 5. Drilling Costs as a Function of
Well Depth for Rock of Medium Hardness

<u>Depth,</u> <u>km</u>	<u>\$/ft</u>	<u>Total Cost,</u> <u>\$10³</u>
0.5	68	109
1.0	53	175
1.5	62	280
2.0	78	480
2.5	99	820
3.0	122	1100

In Tod Larson's paper on geothermal costs,⁽¹⁹⁾ he states that for a 5,000-foot well, Greider cites a range of \$365,000 to \$550,000. Larson also shows similar costs compiled by K. E. Brunot; here the cost range is \$400,000 to \$620,000 for a well depth of 6,000 to 8,000 ft.

Milora and Tester⁽²⁰⁾ show a well cost of \$486,000 for the hard basaltic rock at The Geysers. They also show a well cost of \$165,000 for the softer sedimentary rock of the Imperial Valley.

The following quote is from the Ben Holt/Procon case studies done for EPRI.⁽²¹⁾

The cost of the Heber wells of \$300,000 each is pretty close to our understanding of actual 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 we have no actual data. The cost of the Raft River wells of \$600,000 is close to actual published drilling costs for the area.

In calculating drilling costs for this study, we assumed that the rock surrounding the hydrothermal resources is of medium hardness (1125 kg/cm^2). Also, we assumed that the production wells are drilled on the average to the midpoint level of each reservoir. The drilling depth is calculated as a function of the USGS estimate of reservoir thickness by the following equation:

$$D = (3-T) + (T/2)$$

where

D = drilling depth, km

T = reservoir thickness, km, as estimated by the USGS, assuming that 3 km was the maximum exploitable depth.

INJECTION WELL COST

We used the drilling costs presented in Table 5 to represent injection well costs as well as production well costs. Estimates found in the literature for injection well costs vary from \$250,000 to \$1,000,000, depending on the site lithology. (22)

RATIO OF INJECTION WELL TO PRODUCING WELL FLOW RATE

We set this ratio equal to 1.8, which is a representative average of the values assumed by other geothermal researchers. Professor Bodvarsson (Oregon State University) suggests a ratio of 2/1 or even 3/1 based on El Salvador injection experience. Bill Ogle (Energy Systems, Inc.), after his visit to Japan last fall, indicated that a ratio of 1/1 was needed for the Japanese hydrothermal wells. Ben Holt⁽²¹⁾ estimates a ratio of 2/1 for geothermal sites in the Imperial Valley. Rotoflow Corporation uses a ratio of 1.5/1 as being a reasonable assumption based on data available in the literature.⁽²³⁾

WELL SPACING

We used 20 acres. Marshall Reed and Glen Campbell discuss development well spacing in their paper "Environmental Impact of Development in The Geysers Geothermal Field, USA."⁽¹⁶⁾ They state that "the bottom-hole locations of the wells will be a minimum of 330 meters from each other to prevent interference." This converts to a well spacing of about 21 acres/well. Cerro Prieto had interaction problems with 8-acre spacings and they are now going to 31 acres, according to a personal communication from Sergio Mercado (CFE, Mexico) to Ron Walter (Pacific Northwest Laboratory). Based on a map of Wairakei, the typical well spacing there is 16.5 acres. Based on a map of Otake, the well spacing there is 9 acres.

POWER PLANT SIZE

Based on our previous studies,⁽⁴⁾ we used 50 MWe for resources below 200°C and 100 MWe for steam-dominated resources (The Geysers) and other hydrothermal resources above 200°C. These sizes should correspond to near minimum power costs for resources of these qualities.

Similar conclusions were reached in a study done by the Futures Group for the National Science Foundation.⁽²⁴⁾

1. The initial capital investment required for dry-steam geothermal plants changes little from \$180 to \$200/kW for plants about 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 MW 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% to 90% of the electric production costs, electric production costs are a minimum for plants around 100 MW capacity.

POWER CYCLE VS. TEMPERATURE

Based on our recent analyses (Figure 32), the binary cycle appears more economic than the flashed steam cycle below about 175°C. However, the steam and binary cycles are closely competitive throughout the entire temperature range, and the "breakeven" temperature can vary substantially, depending on many factors.

For all resources with subsurface temperatures of 175°C or less, we assumed binary cycle plants. For all resources with temperatures greater than 175°C, we assumed steam cycle plants, even though the binary cycle appears to be less expensive over part of this temperature range according to Figure 32. But since the difference in cost between the two cycles at temperatures above 175°C is minimal, we elected to use the steam cycle because that technology has been proven. Also, the cost competitiveness of the cycles depends to a large degree upon the power plant capital costs, and in the binary cycle plant, these costs contain many uncertainties.

The following is a quote from State Policies for Geothermal Development.⁽¹⁸⁾

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.

Green and Laird make the following statement in LBL-2102:⁽²⁵⁾

The binary system becomes economically competitive only when used on low temperature brines (enthalpies less than 350 Btu/lb).

This enthalpy corresponds to about 190°C.

FIGURE 32. Power Cycle Versus Temperature

NONCONDENSIBLE GASES

For liquid-dominated resources, we assumed 0.1 weight percent non-condensible gases in the geothermal fluid at the reservoir wellhead. For steam-dominated resources, we used 0.7 weight percent. We assumed that the composition of the gases is 97% CO₂ and 3% H₂S.

Tables 6 and 7 show that the noncondensible gas contents of geothermal fluids vary from 0.01 weight percent to 6 weight percent. This wide range of values is explained by the following quote.

Both the total gas fraction in geothermal fluids and the relative concentrations of the constituents depend intricately upon the geochemistry of the underground reservoir. Carbon dioxide is invariably the main component (78% to 95%) with lesser concentrations of H₂S (1% to 17%), H₂ (1% to 13%), CH₄ (0% to 12%), N₂ (0.2% to 9%), and NH₃ (0% to 1.7%); and, occasionally, trace amounts of argon, ethane, H₃BO₃, HCl, HF, and SO₂. Reports from at least three fields indicate that the total gas fraction declines with exploitation. This, too, occurs in a complicated way: at Wairakei, for example, the total gas concentration decreased by 50% between 1960 and 1969 while the H₂S fraction remained virtually constant. (26)

INJECTION PRESSURE

We used an injection pressure of 215 psia, which is within the range of values reported in the literature.

According to Defferding's report, (29) injection fluids normally flow into the reservoir without pumping. The only exception mentioned in his report is Union Oil's experience at Niland, where injection pressures in excess of 200 psia were required.

The Ben Holt study for EPRI (21) states that the pressure required at an injection wellhead at Heber can increase to 415 psia. Injection pumps deliver spent water to injection well islands at about 215 psia, and a booster pump at each island can be used to raise the pressure to 415 psia.

The Bechtel study for ERDA (30) states that at Heber and at Niland the spent fluid is sent to the injection line as liquid at a pressure of 315 psia, which is the nominal pressure needed for injection.

TABLE 6. Noncondensable Gas Content of
Selected Geothermal Fields (27)

Field	Reservoir Temp., °C	Reservoir Fluid	Noncondensible Gas, wt. %
Larderello	245	Steam	5
The Geysers	245	Steam	1
Matsukawa	230	Mostly Steam	<1
Otake	200+	Water	<1
Wairakei	270	Water	<1
Broadlands	280	Water	~6
Pauzhetsk	200	Water	-
Cerro Prieto	300+	Water	~1
Niland	300+	Brine	<1
Ahuachapán	230	Water	~1
Hveragerdi	260	Water	~1
Reykjanes	280	Brine	~1
Mamafjall	280	Water	6

TABLE 7. Noncondensable Gases in
Geothermal Steam (28)

Site	Wellhead Temp., °C	Noncondensible Gas, wt. %
Hengill, Iceland	160	0.3
Hveragerdi, Iceland	160	0.1
Krysuvik, Iceland	160	1.3
Wairakei, New Zealand	195	0.01-0.5
Waiotapu, New Zealand	-	0.07-0.2
Larderello, Italy	190	4.5
The Geysers, California	175	0.7

TRANSMISSION MAINTENANCE RATE

We used 4% of the transmission system capital cost per year.

DISPOSAL MAINTENANCE RATE

We used 4% of the disposal system capital cost per year.

ROYALTY PAYMENT

We used 10% of the reservoir annual power sales.

According to Finn,⁽³¹⁾ federal geothermal leases are required to provide for the payment of a royalty of not less than 10% nor more than 15% of the amount or value of geothermal steam produced under the lease and sold or utilized by the leasee. All leases on Indian lands carry a 10% royalty of gross sales revenues. A 10% royalty payment is required by the State of California and the State of Idaho requires a royalty of not less than 10%.

According to Schlauch and Worcester,⁽³²⁾ royalties are 10% in Montana and New Mexico, and 10% to 15% in Alaska.

EXPLORATION, REGULATORY, AND LICENSING COSTS AND TIMING

It seems that regulatory costs and timing are site-specific, always fluctuating, and not easily generalized. Our best estimates, which have been incorporated into GEOCOST, are \$250,000 for the power plant EIS and \$50,000 plus \$10,000 per well for the reservoir EIR. The timespan assumed in GEOCOST from detailed exploration and lease acquisition to power plant start up is almost 10 years. This assumption appears to be somewhat conservative when compared with other estimates in the literature, so it probably contains enough contingency to cover regulatory and licensing delays.

Table 8 shows a comparison between the GEOCOST timeline and a similar timeline used in a JPL study.⁽³³⁾ The JPL timeline was based on detailed discussions with federal, state, and industry representatives. The GEOCOST time span from the start of exploration to the end of plant construction is 1.25 years longer than the JPL time span. Most of the difference is due to the 3.5 year production drilling time in GEOCOST versus 2.5 years in the JPL study.

TABLE 8. Simplified Geothermal Power Plant Timeline

Activity	Duration of Activity, yrs	
	GEOCOST	JPL
Detailed Exploration & Lease Acquisition	2.00	1.50 ^(a)
Exploration Drilling	2.00	2.00
Production Drilling	3.50	2.50
Plant Construction	2.25 ^(b)	2.50
TOTAL	9.75	8.50

(a) Includes the time necessary for generation of an Environmental Analysis Report (EAR) and/or Environmental Impact Statement (EIS).

(b) Plant construction actually takes 3 years, but the timing overlaps production drilling.

The following quotation describes a typical timing sequence at The Geysers.⁽³⁴⁾

Long-range planning and development of new geothermal units at The Geysers is influenced by PG&E's load and resource planning, contractual commitments with steam suppliers, and governmental regulatory requirements. Planning, engineering, and construction for a new unit requires about 5 years from management's decision to add a new unit to the start of commercial power generation. The 5-yr period includes a 6-mo siting and resource proving period, an 18-mo period for licensing and environmental review, a 1-yr detailed engineering and hardware-procurement period after approval is obtained, 1 yr for civil-structure construction, and a final year for electrical and mechanical construction and startup.

The 5-yr sequence of events at The Geysers, however, may not be an accurate representation of timing at other sites where there is no experience to date.

According to Schuller's report,⁽³⁵⁾ environmental reports are required for both federal and state actions for geothermal development in California. The National Environmental Policy Act (NEPA) requires an Environmental Impact Statement (EIS). The California Environmental Quality Act (CEQA) requires an Environmental Impact Report (EIR). At The Geysers, well-drilling EIR's can cost \$10,000 to \$30,000, while power plant reports can cost on the order of \$250,000.

The time involved in obtaining permits for drilling has varied tremendously across California. The maximum time has been about 30 months at The Geysers, while the minimum time has been 2 months in Imperial County. Schuller feels that the approval time at The Geysers should decrease since procedures are becoming smoother and mitigation measures are being applied. Also, once power production begins in the Imperial Valley, the permit-granting time will probably increase.

In May 1977, we evaluated the potential impact of streamlining regulatory requirements on geothermal development. We analyzed two cases. The "worst" case corresponded to the current situation in California. The "best" case incorporated policy improvements. The analyses showed that the policy improvements could cut two years from the total exploration and development time table. This would reduce generating costs by \$4 to \$13 billion (not discounted) for geothermal power plants built over the next 40 years. Thus, there is ample incentive to work towards such policy improvements.

FINANCIAL AND TAX ASSUMPTIONS

The reference conditions are based on production by private enterprise. Production costs are based on life-cycle costing and full cost recovery, which includes the direct costs of the factors of production, taxes, and financing costs. For electricity generation, the costs refer to the busbar. For non-electric applications, the costs refer to the point of delivery to the consumer. The analyses determine the unit cost of energy production, expressed in constant dollars.

Table 9 shows the financial and tax assumptions which we used in deriving long and short-term supply curves. The selection of appropriate financial and tax assumptions depends on the purpose or purposes for which the supply curves will be used. We have at least four possibilities: 1) to provide comparability with studies of other energy technologies on a national basis, 2) to provide comparability with other energy technologies on a regional basis, 3) to provide comparability with other technologies on a specific site basis, and 4) to provide comparability between geothermal resources only on a) a national basis, b) a regional basis, or c) a specific site basis. Our assumptions reflect the first possibility.

In this study, production costs for all resources are based on uniform reference costs and conditions rather than regional factors. This permits direct comparisons between resources and technologies on the basis of their characteristics. Regional cost factors vary in enormous detail. To define costs on a regional basis would be more costly and would complicate most comparisons. In addition, many regional cost differences will be compensating so that the overall variance will probably be small in comparison to the uncertainties in resource characteristics and design criteria at specific geothermal sites. However, since the supply curves are derived from specific geothermal reservoir data at identified sites, it will be possible later to disaggregate the supply curves on regional bases and recompile them using regional cost factors.

TABLE 9. Financial and Tax Assumptions

	Reservoir (%)	Power Plant (%)
Capital Structure		
Debt	42	59
Equity	58 ^(a)	41 ^(a)
Cost of Capital		
Debt	8.0	8.0
Equity	15.0 ^(a)	12.0 ^(a)
Cost of Capital ^(b)	12.1	9.6
Taxes		
State	7.0	7.0
Federal	48.0	48.0
Gross Receipts & Sales Tax	0.0	4.0
Investment - Tax Credit	10.0	10.0
Property Tax	2.5	2.5
Depreciation		
Tax Purposes	SYD ^(c)	SYD ^(c)
	Entire Life	Entire Life
Insurance	0.12	0.12
Other Tax Related Assumptions	Intangible Drilling Costs, Allowed 10% Depletion Allowance	

^(a) Combined, preferred and common equity

^(b) Weighted based on capitalization

^(c) Sum-of-years' digits

The financial and tax assumptions are important to geothermal energy costs because this technology is very capital intensive. These assumptions relating to geothermal energy supply costs are particularly important, since these are the costs which vary most with the quality of the resource and hence, will have the greatest impact on the supply curves.

We simulated the energy supply, the reservoir, as a large oil company. This is consistent with our previous studies and also consistent, to a large degree, with industry practice. We assumed that the power plant is operated by an entity with the financial structure of an investor-owned utility.

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