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The Economics of Geothermal Electricity Generation from Hydrothermal Resources

**Prepared for the U.S. Energy
Research and Development Administration
under Contract E(45-1):1830**

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PACIFIC NORTHWEST LABORATORY

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U.S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

Under Contract E(45-1)-1830

Printed in the United States of America
Available from

National Technical Information Service

U.S. Department of Commerce

5205 Port Royal Road

Springfield, Virginia 22151

Price: Printed Copy \$5.50; Microfilm \$2.25

THE ECONOMICS OF GEOTHERMAL ELECTRICITY
GENERATION FROM HYDROTHERMAL RESOURCES

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Key

TABLE OF CONTENTS

LIST OF FIGURES	i
LIST OF TABLES	ii
1.0 INTRODUCTION	1
2.0 SUMMARY AND CONCLUSIONS	2
3.0 METHODOLOGY	2
3.1 OBJECTIVES	3
3.2 REFERENCE CONDITIONS AND ASSUMPTIONS	4
3.3 SENSITIVITY ANALYSES	5
4.0 POWER COSTS FOR REFERENCE CASES	5
4.1 REFERENCE CASES	5
4.2 DISTRIBUTION OF POWER COSTS	6
4.2.1 Power Costs Related to Powerplant Capital Costs	7
4.2.2 Distribution of Energy Supply Costs	10
4.3 INITIAL CAPITAL REQUIREMENTS	12
4.4 SENSITIVITY ANALYSIS OF REFERENCE CASE B	12
4.5 CASH FLOW	16
5.0 SENSITIVITY OF THE COST OF GEOTHERMAL ENERGY TO RESOURCE AND OPERATING CHARACTERISTICS	19
5.1 WELLHEAD TEMPERATURE	19
5.2 FLOW RATE	22
5.3 WELL COST	22
5.4 WELL SPACING	25
5.5 WELL REPLACEMENT RATE	26
5.6 POWER CYCLE	27

TABLE OF CONTENTS (continued)

5.7	STEAM CONTENT	28
5.8	STEAM TEMPERATURE	29
5.9	POWERPLANT CAPACITY	30
5.10	NONCONDENSIBLE GASES	33
5.11	PLANT EFFICIENCY	34
5.12	LOAD FACTOR	34
5.13	HEAT TRANSFER COEFFICIENT	37
5.14	ISOCOSTS FOR LOW SALINITY HYDROTHERMAL RESOURCES	40
REFERENCES		43

LIST OF FIGURES

1	Cumulative Cash Flow for Reservoir Development and Operation (Reference Case B)	17
2	Cumulative Cash Flow for Powerplant Construction and Operation	17
3	Cumulative Cash Flow for Reservoir Development and Operation (Reference Case C)	18
4	Cumulative Cash Flow for Powerplant Construction and Operation (Reference Case C)	18
5	Effect of Temperature on Power Cost	20
6	Effect of Temperature on the Available Cost Allocation for Energy Supply Under Constrained Total Power Costs	23
7	Effect of Flow Rate on the Cost of Power	23
8	Effect of Well Costs on the Cost of Power	24
9	Effect of Well Spacing on Power Costs	25
10	Effect of Well Replacement Rate on Power Cost	26
11	Effect of Steam Content on Power Costs	29
12	Effect of Steam Temperature at the Wellhead on Power Costs	30
13	Effect of Powerplant Capacity on Power Costs	31
14	Economies of Scale for Geothermal Powerplants	32
15	Effect of Noncondensable Gases on the Cost of Power and Net Power Output of a Well	33
16	Effect of Load Factor on Power Costs	35
17	Cost of Power as a Function of Heat Transfer Coefficient	38
18	Cost of Power as a Function of Inverse Heat Coefficient	39
19	Isocosts for Hydrothermal Resources at a Well Cost of \$150,000	41
20	Isocosts for Hydrothermal Resources at a Well Cost of \$300,000	41
21	Isocosts for Hydrothermal Resources at a Well Cost of \$500,000	41

LIST OF TABLES

1	Financing and Tax Assumptions	4
2	The Reference Cases	6
3	Distribution of Total Power Costs	7
4	Distribution of Power Costs Related to Powerplant Capital Costs	7
5	Plant Capital Cost Distribution	9
6	Distribution of Energy Supply Costs	11
7	Initial Capital Requirements (\$/kWe Net)	12
8	Results of Sensitivity Analysis for Reference Case B (Reference Case B Power Cost = 28.2 Mills/kW-hr)	13
9	Cumulative Cash Flow Requirements Prior to Power Production (\$ Millions)	16
10	Effect of Temperature and Flow on Power Production from Geothermal Wells	21
11	Fixed and Variable Costs for Geothermal Power Generation	36
12	Effects of Variable Heat Exchanger Performance	37

THE ECONOMICS OF GEOTHERMAL ELECTRICITY GENERATION FROM HYDROTHERMAL RESOURCES

1.0 INTRODUCTION

Electricity is produced from only a few high quality geothermal resources throughout the world. However, rapid escalation in the energy costs plus advances in geothermal energy recovery technology make lower quality geothermal resources more economically feasible. Thus, geothermal energy should become a much more important and widespread energy source for electricity production. Its rate of growth will depend on finding new, economically recoverable resources.

This report has two purposes: 1) to analyze the sensitivity of geothermal power costs to important resource characteristics, energy recovery technologies, and economic factors, and 2) to determine the probable lowest cost energy recovery methods for specific geothermal resource characteristics. This information, in combination with resource availability data,⁽¹⁾ is important in assessing the economic value of different geothermal resources from which quantitative estimates of the supply curve for geothermal energy can be derived.

This report is limited to electric power generation from low salinity hydrothermal resources. Both steam and binary cycle power recovery technologies are included.⁽²⁾ The power costs are calculated using GEOCOST, a computer program for geothermal cost analysis.⁽³⁾ Power costs are expressed as the "bus bar" generating cost of electricity and do not include electrical transmission and distribution costs. Costs are expressed in constant 1974 (December) dollars. At recent inflation rates these costs would more than double by 1985 when large increases in geothermal capacity from new resources are expected. Of course, comparisons with other energy costs should be based on consistent economic assumptions, including a constant dollar basis. Powerplant costs used in this report have probably escalated 15-20% between the base period and the publication date.

2.0 SUMMARY AND CONCLUSIONS

The most important factors affecting the economics of geothermal electricity production are the wellhead temperature or enthalpy, the well flow rate, and the cost of the wells. The capital cost of the powerplant is significant, but not highly sensitive to these resource characteristics. The optimum geothermal plant size will remain small, usually in the 50-100 MWe range. Therefore, the opportunities for achieving significant cost reductions through "economies of scale" are small. The steam and binary power cycles are closely competitive; the binary cycle appears better when the brine temperature is below 200-230°C, and the flashed steam cycle appears better above this range. Geothermal electricity production is capital intensive; over 75% of the generation costs are fixed costs related to capital investment.

Technological advances are needed to reduce costs from marginal geothermal resources and thus to stimulate geothermal energy development. Significant reduction in power costs would be achieved by reducing well drilling costs, stimulating well flow rates, reducing powerplant capital costs, increasing powerplant efficiency and utilization, and developing more effective exploration techniques for locating and assessing high quality resources.

3.0 METHODOLOGY

This report is based on calculations using the GEOCOST model. This computer program was developed to provide rapid and systematic calculations of the variation in geothermal power costs with important resource, power recovery, and economic factors. The computer program simulates the geothermal power production processes. Cost functions developed for GEOCOST calculate the capital costs and operating expenses for commercial powerplants using the resource characteristics and power conversion technology specified for each simulation. These cost functions generate the cash flow requirements over the economic life specified for the simulation.

Using discounted cash flow analyses, GEOCOST calculates the unit cost of energy for the specified input conditions. The unit cost of energy is the most appropriate common unit for comparing energy costs from alternative sources, either geothermal or nongeothermal.

Besides the unit cost of energy, the output from GEOCOST consists of the distribution of the components of the energy cost, including powerplant and reservoir equipment costs and operating expenses. GEOCOST also calculates many other factors related to the design, performance, and operation of the powerplant and reservoir, such as the number of wells required, fluid flow rates, thermodynamic conditions, internal electrical consumption and net plant output.

3.1 OBJECTIVES

One objective of this study was to analyze the sensitivity of geothermal power costs to several resource and operational parameters. This is discussed in section 5.0 for hydrothermal resources in general, and in section 4.4 for a specific reference case.

The most important resource parameters were geothermal fluid temperature, well cost, flow rate per well, well life, noncondensable gas content, and steam content. The most important operational parameters are plant size, load factor, power cycle, and well spacing. Many of these factors are interrelated. For instance, in a given reservoir, flow rate and well life may be affected significantly by operational choices of well spacing and production rate, while the steam content and temperature of the geothermal fluid may be affected by choices of operating pressure and downhole pumping. However, both the natural characteristics of the reservoir and economic considerations limit the operational choices and determine the optimum configuration.

Another objective was to determine the optimum combination of plant size and power cycle for specified resource and economic conditions since this combination would be most representative of the value of a resource. This is treated in sections 5.6 and 5.9.

Another objective was to determine the contributions to the cost of geothermal energy of the important factors of production. This is discussed in section 4.2.

3.2 REFERENCE CONDITIONS AND ASSUMPTIONS

We selected the reference conditions shown in Table 1 for this study. These economic and financial conditions, which are common to all cases, would be typical of a large oil company operating the reservoir and an investor-owned utility operating the powerplant. The taxes are a composite, typical of the western states.

TABLE 1. Financing and Tax Assumptions

	<u>Reservoir (%)</u>	<u>Powerplant (%)</u>
Capitalization		
Debt	42	59
Equity	58	41
Bond Interest Rate	8	8
Return on Equity	15	12
Federal Income Tax Rate	48	48
State Income Tax Rate	7	7
Property Tax Rate	2.5	2.5
Royalty Payment	10	--
Revenue Tax Rate	--	4

Other assumptions, common to all cases, include self-pumping wells. If pumping were to be required, the cost and power consumption of the pumps would have to be included in the analysis, increasing the energy supply cost. An optimum trade-off exists between the costs associated with pumping and the benefits of the energy received from the added flow. All cases assume mechanical draft cooling towers and reinjection of the geothermal brine. In all cases exploration costs were assumed to be constant and contribute the equivalent of 0.7 mills/kW-hr to the cost of power. Injection wells were assumed to cost the same as producing wells. Injection wells were assumed to be capable of handling twice the flow of

the producing wells. All cases assume that dry wells will equal 20% of the producing wells, and will cost two-thirds of the cost of producing wells. All cases assume that 20% excess producing wells are required. Royalty payments are assumed to be 10% of the revenues of the reservoir. The reference value for other important parameters is shown later in Table 8 in section 4.4 which describes the sensitivity of power costs for reference case B.

The study has also assumed that the brines would have low scaling and corrosion rates. In general, material costs are based on carbon steel. The average overall heat transfer coefficient is assumed to be $\sim 200 \text{ Btu/hr/ft}^2$ in the binary cycle heat exchanger.

3.3 SENSITIVITY ANALYSES

The sensitivity analyses are based on a consistent set of assumptions using primarily the reference cases described in section 4.1. Most of the analyses are based on the binary cycle using isobutane as the working fluid, but several analyses are based on the steam cycle for comparison. In these sensitivity analyses, one parameter is varied at a time holding the others constant. The comparative analysis of the cost of power from real geothermal resources is, of course, more complex and depends on the interrelationships of many variables.

4.0 POWER COSTS FOR REFERENCE CASES

4.1 REFERENCE CASES

The three reference cases were selected to represent a broad range of resource characteristics and costs of power (Table 2). Case A represents a geothermal resource that would be competitive with nuclear or coal powerplants. Case A-s uses the steam cycle and Case A-b uses the binary cycle. Case B represents a marginal resource. Case C represents a clearly uneconomic resource. These cases are used to demonstrate how the cost of power is distributed among its components and to identify which cost items make the most significant contributions to the total cost.

Case B, the marginal resource is then analyzed in greater detail to determine which parameters have the greatest influence on cost of power.

TABLE 2. The Reference Cases

Case	Surface Technology	Wellhead Temp. (°C)	Well Flow Rate (10 ³ lb/hr)	Cost Per Well (\$ 1,000)	Plant Size (MWe)		Total Cost of Power (Mills/kW-hr)
					Gross	Net	
A-s	Steam; 2 Plant Flash	250	750	500	55	53.0	17.2
A-b	Binary/ Isobutane	250	750	500	55	46.1	19.5
B	Binary/ Isobutane	200	500	500	55	44.5	28.2
C	Binary/ Isobutane	150	250	500	55	45.9	85.3

The internal power consumption influences the comparison of these reference cases. The total cost of power from the plant is the generating cost at the busbar for each unit of net output for that system. Power used internally is not available for sale. The internal power consumption is much higher for the binary cycle (Cases A-b, B, and C).

4.2 DISTRIBUTION OF POWER COSTS

The total cost of power for each case can be divided into two categories: powerplant costs and energy supply costs (Table 3). Nearly all the powerplant costs are associated with the initial capital required to build it. Only a small percentage of the total is required to operate the plant. The energy supply cost is a significant part of the total and its significance grows as resource quality decreases (i.e., going from Case A to Case C).

TABLE 3. Distribution of Total Power Costs

	<u>Case A-s</u> (Mills/kW-hr)	<u>Case B</u> (Mills/kW-hr)	<u>Case C</u> (Mills/kW-hr)
Powerplant			
Capital	7.1	8.2	9.2
Operating Expenses	.3	.4	.4
Energy Supply	9.8	19.7	75.7
TOTAL	<u>17.2</u>	<u>28.2</u>	<u>85.3</u>

4.2.1. Power Costs Related to Powerplant Capital Costs.

The distribution of power costs related to the powerplant capital cost is shown in Table 4. Much of this power cost goes to the return on and pay back of the initial plant capital. Taxes and other costs related to plant capital make up the balance. All costs related to powerplant capital are equivalent to a fixed charge rate of about 17%.

TABLE 4. Distribution of Power Costs Related to Powerplant Capital Costs

	<u>Case A-s</u> (Mills/kW-hr)	<u>Case B</u> (Mills/kW-hr)	<u>Case C</u> (Mills/kW-hr)
Initial Plant Capital	4.5	5.1	5.7
Interim Capital Replacements	.1	.2	.2
Property Taxes and Insurance	1.2	1.3	1.5
State Revenue Taxes	.3	.3	.4
State Income Taxes	.1	.2	.2
Federal Income Taxes	.9	1.1	1.2
TOTAL	<u>7.1</u>	<u>8.2</u>	<u>9.2</u>

The increase in initial plant cost as we go from Case A to Case C shows the sensitivity to decreases in geothermal fluid temperature. Case A-s is a steam plant. Binary plants were used in Cases B and C because that technology yields a lower cost of power than steam plants at the lower geothermal temperatures. However, for both systems, costs increase with lower geothermal temperatures. The steam plants become more expensive because the steam flow must be greater for lower temperature fluids. The binary plants become more expensive because the isobutane flow must be greater with lower temperature geothermal fluids. The size of the major components of each plant type is based on these flow rates: when flow rate goes up, so does size and cost.

The distribution of the initial powerplant costs for three reference cases is shown in Table 5. The turbo-generators, heat exchangers, and condensers account for most of the variation among the reference cases. This is due in part to the differences in temperature, and in part to differences in the type of powerplant.

The system in reference Case A-s uses a steam plant. The brine is delivered to the plant and flashed in two stages to produce steam for the turbine. The turbine contributes about 33% of the total plant capital for this case (Table 5, Case A-s). The buildings and support equipment add another 10%. The cooling tower is 9% of the total. The condenser contributes 7% to the total. Together administration, engineering and other indirect costs comprise 15% of the total capital cost for all plants.

A binary plant is used in Case B. The geothermal fluid is brought to the plant and run through a heat exchanger. Its heat is transferred to the isobutane working fluid which then drives a turbine. The turbine cost in this case contributes only 13% to the total (Table 5, Case B). The heat exchanger is the largest single cost item at 21% of the total. The condenser is second, ahead of the turbine, at 14% of the total. The buildings and support equipment are 10% of the total. The cooling tower contributes 8%.

A binary plant is also used in Case C. The heat exchanger is still the largest single cost item. It constitutes 20% of the total (Table 5, Case C). However, both the condenser and turbine, at 17% and 15% of the

TABLE 5. Plant Capital Cost Distribution

<u>Account</u>		<u>Case A</u> <u>(\$ Millions)</u>	<u>Case B</u> <u>(\$ Millions)</u>	<u>Case C</u> <u>(\$ Millions)</u>
1.0	Powerplant			
1.1	Piping, Insulation, & Pumps	.43	.19	.21
1.2	Crane	.19	.19	.19
1.3	Turbo Generator	5.05	1.92	2.58
1.5	Vapor Generator (Boilers)	—	3.15	3.47
1.6	Flashers (Plant Located Units)	.79	—	—
1.7	Auxiliary Heat Exchangers		.36	.47
1.9	Misc. Process Support Equipment	.13	.13	.13
1.10	Instrumentation and Controllers	.66	.14	.15
1.12	Electrical Support Equipment	.72	.72	.72
1.16	Condenser	1.04	2.08	2.95
1.17	Installation Testing	.17	.17	.17
1.18	Buildings, Foundations, & Support Equipment	1.57	1.57	1.57
1.19	Gas Ejectors (Steam Driven)	.16	—	—
1.99	SUBTOTAL 1.0	<u>10.92</u>	<u>10.62</u>	<u>12.60</u>
2.0	Heat Rejection System (Cooling Towers)			
2.1	Cooling Tower System (Forced Draft Wet)	1.36	1.22	1.22
2.99	SUBTOTAL 2.0	<u>1.36</u>	<u>1.22</u>	<u>1.22</u>
3.0	Switch Yard			
3.99	SUBTOTAL 3.0	.78	.78	.78
5.0	Other Costs			
5.1	Engineering & Design	1.31	1.26	1.46
5.2	Administration & Indirect Costs	1.04	1.01	1.17
5.99	SUBTOTAL 5.0	<u>2.35</u>	<u>2.27</u>	<u>2.63</u>
	TOTAL POWERPLANT COST	15.40	14.88	17.22
	Installed Unit Cost \$/kWe Gross	280	271	313
	\$/kWe Net	293	335	375

total respectively, contribute more to total cost in this case than in Case B. This demonstrates their greater relative sensitivity to decreases in resource quality. The buildings and support equipment and the cooling tower are 9% and 7% respectively.

4.2.2. Distribution of Energy Supply Costs.

Energy supply cost can be distributed into several sub-categories (Table 6). The increase in the cost going from Case A to Case C is far greater for the energy supply than it is for the powerplant (comparing the totals in Table 6 to those in Table 4). This is because both fluid temperature and flow per well are decreasing. Plant costs are only slightly affected by the decrease in temperature. Energy supply costs are greatly affected by both.

As the temperature decreases, the total flow required to sustain the rated electrical output goes up. This means more wells. As the flow per well decreases, the number of wells required increases. The size and length of the transmission system also increases with the total flow requirement and number of wells.

The greater number of wells and larger transmission system increases the total field development costs. The other categories (with the exception of exploration) are related to some or all of the initial field development costs. The net effect is that energy supply costs are very sensitive to changes in resource quality.

The power consumed in the system also affects the energy supply costs. Total energy supply cost is the charge to the plant for all thermal energy delivered. A part of that thermal energy is converted to electricity and then used internally. The charge for the power consumed internally is a significant part of the total energy supply cost for Cases B and C (Table 6).

TABLE 6. Distribution of Energy Supply Costs^a

	<u>Case A-s</u> (Mills/kW-hr)	<u>Case B</u> (Mills/kW-hr)	<u>Case C</u> (Mills/kW-hr)
Exploration	.7	.7	.7
Field Development	2.8	5.0	21.1
Producing Wells	(1.4)	(2.8)	(12.4)
Fluid Transmission	(.4)	(.6)	(2.3)
Fluid Disposal	(.8)	(1.2)	(4.8)
Non-Producing Wells	(.1)	(.4)	(1.6)
Field Operation	3.1	5.6	23.4
Producing Wells	(.7)	(1.1)	(4.0)
Fluid Disposal	(0.9)	(2.1)	(9.2)
Fluid Transmission	(.5)	(.7)	(2.8)
Other	(1.0)	(1.8)	(7.4)
State Income Tax	.1	.2	.9
Federal Income tax	.9	1.5	6.1
Royalty Payment	.9	1.4	5.6
Bond Interest	.5	.8	3.0
Subtotal	<u>9.10</u>	<u>15.3</u>	<u>60.6</u>
Charge for Internal Power Consumption	.4	3.6	12.1
Subtotal	<u>9.4</u>	<u>18.9</u>	<u>72.7</u>
Revenue Taxes (4%) Related to Energy Supply	.4	.8	3.0
TOTAL	<u>9.8</u>	<u>19.7</u>	<u>75.7</u>

^aTotals may not add because of rounding.

4.3 INITIAL CAPITAL REQUIREMENTS

The initial capital requirements for these cases range from \$396/kWe net for Case A to \$1113/kWe net for Case C (Table 7). The reservoir's share of this total grows with the increasing number of wells and size of transmission system resulting from the decline in resource quality as we move from Case A to Case C. The differences among the powerplant capital cost for these cases are much smaller.

TABLE 7. Initial Capital Requirements (\$/kWe Net)

<u>Case</u>	<u>Reservoir</u>	<u>Powerplant</u>	<u>Total</u>
A-s	102	291	393
A-b	110	329	439
B	189	335	529
C	738	375	1113

4.4 SENSITIVITY ANALYSIS OF REFERENCE CASE B

The cost of power for reference case B, 28.2 mills/kW-hr, is based upon many assumptions. The effect of large changes in some of these assumptions is shown in Table 8. In some instances the value of a parameter is varied. In others, a cost which was included in the reference case is eliminated. The impact of each change is measured by the change in the cost of power from the reference case.

To compare the relative impacts of each assumption, we have borrowed the term elasticity from economics and broadened its use.

Elasticity as used here is derived from the following formula:

$$\text{elasticity} = \frac{\% \text{ reduction in the cost of power}}{\text{absolute value of the \% change in the parameter.}}$$

This focuses on the magnitude and not on the direction of the impact. Thus, the elasticity will be negative only when the cost of power increases as a result of the change. As always, the elasticity depends upon where you measure it. If the relationship between the two parameters is not

TABLE 8. Results of Sensitivity Analysis for Reference Case B
(Reference Case B Power Cost = 28.2 Mills/kW-hr)

Parameter	Reference Value	New Value	% Change in Parameters	% Reduction in Power Cost	New Power Cost (Mills/kW-hr)	Elasticity
						% Reduction in Cost of Power Per % Change in Parameter
Wellhead Temperature	200°C	250°C	+ 25	19	22.9	.76
Cost of Capital		(reduced by 1/2)	- 50	31	19.4	.62
Cost per Well	\$500,000	\$300,000	- 40	20	22.64	.50
Well Flow Rate	500,000 lb/hr	750,000 lb/hr	+ 50	17	23.3	.34
Plant Capital	\$14.9 million	\$7.5 million	- 50	14	24.1	.28
Internal Power Consumption	10.5 MWe	5.25 MWe	- 50	11	25.2	.22
Taxes	(All tax rates reduced by 1/2)		- 50	10	25.3	.20
Cost of Transmission & Disposal Systems		(reduced by 1/2)	- 50	9	25.6	.18
Reinjection Costs	Reinjection	No Reinjection	-100	16	23.6	.16
Well Life	10 years	20 Years	+100	10	25.3	.10
Excess Producing Wells	20% of Production Wells	5% of Production Wells	- 75	6	26.4	.08
Cooling Tower	Included	Excluded	-100	6	26.5	.06
Operating Expenses		(reduced by 1/2)	- 50	3	27.3	.06
Royalty Payments	10%	0	-100	5	26.7	.05
Dry Wells	20% of Production Wells	5% of Production Wells	- 75	4	27.1	.05
Exploration Costs	Included	Excluded	-100	4	27.1	.04
Plant Life	30 years	40 years	+ 33	1	27.9	.03
Transmission & Disposal Systems Maintenance Rate	.05	.025	- 50	1	27.9	.02
Intangible Write-off	Allowed	Not Allowed	-100	-10**	30.9	-.10**
Plant Life	30 years	20 years	+ 33	- 5**	29.5	-.15**

**Indicates an increase in cost of power

linear, the elasticity will vary. The elasticities in Table 8 apply only to Case B; some of the elasticities may be appreciably different for the other reference cases. The sensitivity of power cost for the other reference cases is described in section 5.

The relative impact of the parameters is ranked according to elasticity. The most important parameter is wellhead temperature. The cost of power exhibits the highest elasticity, 0.76, to changes in this variable (Table 6). A 25% increase in temperature results in a 19% lower cost of power.

The higher temperature reduces costs in several ways: There is more energy per pound of fluid so less fluid is required by the plant which means fewer wells and a smaller transmission system. The isobutane flow is lower for a higher geothermal temperature, which reduces the size of the major capital components at the plant. Also, less pumping is required for reduced isobutane flow and for the cooling water. Internal power consumption goes down, net power output goes up and, therefore, cost of power is reduced.

Flow rate per well is another reservoir characteristic which has a high elasticity -- 0.34. Flow rate has less impact on the cost of power than does temperature, partly because it influences only reservoir costs. For a given plant size a higher flow per well reduces the number of wells required and the size of the transmission system. Thus, reservoir costs go down, but plant costs are unchanged.

The cost per well also has a high elasticity -- 0.50. Well costs are expected to vary over a wide range, depending on the location, depth, and geology of the geothermal resource. As described later, the elasticity increases for lower quality resources and decreases for higher quality resources. Because of this, the well cost will probably be the single most important determinant of the commercial viability of marginal geothermal resources.

The cost of capital has the second highest elasticity -- 0.62. This demonstrates that geothermal power production is heavily capital dependent. Capital is required for the wells, fluid transmission system, and the power-

plant construction. The significance of capital is further emphasized by the 0.28 elasticity of powerplant capital cost. The high elasticities related to capital also show that policies which affect the cost of capital will have significant effect on geothermal power costs.

The potential impact of policies which are intended to stimulate development of the geothermal industry can also be evaluated in this way. For instance, providing incentives by reducing taxes will be moderately effective (elasticity for taxes is 0.2). Specifically, the write-off of intangible drilling expenses, as allowed in the reference case, holds the cost of power at 28.2 mills/kW-hr. If this were not allowed, the cost of power would increase 10% to 30.9 mills/kW-hr. However, a policy intended to stimulate development by the reduction of royalty payments would not be as effective. If royalty payments were eliminated, there is only a 5% reduction in the cost of power (for Case B).

Another variable of interest, plant operating life, demonstrates the effect of the nonlinearity of elasticity present in some variables. If plant life was assumed to be 40 years instead of 30 years, cost of power would be reduced only 1% (an elasticity of 0.03). However, if plant life is assumed to be 20 years instead of 30 years, the cost of power would increase 5% (an elasticity of 0.15). As the plant life gets even shorter, the elasticity accelerates and the cost of power increases rapidly.

For purposes of perspective, parameters which have less significance are also considered. For example, if it is assumed that the mechanical draft cooling system is not needed (which also reduces the internal power consumption), the cost of power would only be reduced by 6%.

Elasticity is a useful concept for identifying the areas where cost saving measures would be most effective. This can aid in developing effective research programs, policies, and legislative actions which stimulate the development of the geothermal industry.

4.5 CASH FLOW

The cash flow requirements associated with Cases B and C are shown in Figures 1-4. These are cash outflows from the beginning of reservoir development through the life of the powerplant; offsetting revenue generation begins in year 6. In each figure, the total cash flow is divided into two components - the direct costs for development, construction, and operation and related indirect costs for taxes, royalties, insurance, and return on capital investments. Note that the cumulative cash flow for reservoir development and operation for Case B (Figure 1) is much less than for Case C (Figure 3). By comparison, the cumulative cash flows for powerplant construction and operation for Case B (Figure 2) are only slightly less than for Case C (Figure 4). The powerplant cash flows exclude expenses for the energy supply which, of course, are derived from the reservoir cash flows. The cumulative cash outflow requirements prior to the start of power production and revenue generation (Table 9) illustrate the heavy initial investment that would be required to develop the uneconomic reservoir (Case C).

TABLE 9. Cumulative Cash Flow Requirements
Prior to Power Production (\$ Millions)

	<u>Case B</u>	<u>Case C</u>
Reservoir Development	14.5	59.0
Powerplant Construction	14.8	17.5
TOTAL	<u>29.3</u>	<u>76.5</u>

FIGURE 1. Cumulative Cash Flow for Reservoir Development and Operation (Reference Case B)

FIGURE 2. Cumulative Cash Flow For Powerplant Construction and Operation

FIGURE 3. Cumulative Cash Flow For Reservoir Development and Operation (Reference Case C)

FIGURE 4. Cumulative Cash Flow For Powerplant Construction and Operation (Reference Case C)

5.0 SENSITIVITY OF THE COST OF GEOTHERMAL ENERGY TO RESOURCE AND OPERATING CHARACTERISTICS

Power costs are very sensitive to the wellhead temperature, flow rate and well cost. These three parameters in combination determine, to a large extent, the economic value of a geothermal resource. These parameters and others are evaluated below in terms of their effect on the cost of power. The other parameters include well spacing, well replacement rate, steam content, noncondensable gas content, plant size, power cycle, plant efficiency, and load factor. Unless otherwise stated, the reference values for the unspecified parameter are those shown in Table 8. The conditions for the reference cases are described in section 4.1.

5.1 WELLHEAD TEMPERATURE

Power costs vary inversely with wellhead temperature (Figure 5). At lower temperatures small changes in temperature have a larger impact on power costs, while at the higher temperatures the impact is smaller. Temperature in combination with the well flow rate sets the available power output from a well (Table 10). This is a dominant factor in determining geothermal energy costs. The thermodynamic efficiency of the power cycle increases with temperature, and the size and cost of many powerplant components vary inversely with temperature. The optimum plant size increases with temperature; this is discussed later.

In this study the wellhead temperature of the geothermal brine is assumed to be the same for all producing wells. The wellhead temperature is considered independently of its relationship to the reservoir temperature. Temperature is assumed to remain constant over the life of the powerplant.

New geothermal powerplants to be competitive will face a limiting total power cost which is provided by the best alternative energy source, e.g., nuclear or fossil. As previously shown in section 4.2, geothermal power costs attributable to the powerplant alone, exclusive of the energy supply cost, increase as temperature decreases. However, under a limiting total power cost, the costs available for the geothermal energy supply decrease with resource temperature to offset the rising powerplant costs.

FIGURE 5. Effect of Temperature on Power Cost

TABLE 10. Effect of Temperature and Flow on Power Production from Geothermal Wells

Wellhead Temperature °C	Wellhead Flow Rate 10 ³ lb/hr	MW (Thermal)/Well ^(a)		MWe/Well		Electrical Conversion Efficiency % ^(b)	
		Maximum	Actual	Gross	Net	Gross	Net
125	250	14.3	11.9	.5	.4	4.2	3.4
	500	28.6	23.6	1.0	.8	4.2	3.4
	750	43.0	34.9	1.4	1.2	4.0	3.4
150	250	17.7	14.6	.9	.7	6.2	4.8
	500	35.4	29.2	1.8	1.5	6.2	5.1
	750	53.1	43.0	2.6	2.2	6.0	5.1
200	250	24.6	20.0	2.0	1.6	10.0	8.0
	500	49.3	40.0	3.9	3.2	9.7	8.0
	750	73.9	56.0	5.5	4.5	9.8	8.0
250	250	32.0	26.0	2.9	2.4	11.2	9.2
	500	64.0	49.4	5.5	4.6	11.1	9.3
	750	95.9	70.5	7.9	6.6	11.2	9.4

(a) The maximum is based on the specified wellhead flow rate. The actual is based on the reduced average flow rate using 20% excess producing wells. The variation in conversion efficiency within a temperature category is caused by rounding to an integer number of wells.

(b) For binary isobutane cycle.

This is illustrated in Figure 6, using 30 mills/kW-hr as the assumed upper limit for power cost. In order to be competitive under these conditions, energy supply costs for lower temperature resources must be lower than for higher temperature resources; this might be achieved through higher well flows, lower drilling cost, more compact well spacing, longer well life, lower exploration costs, nearness to market, etc.

5.2 FLOW RATE

Power costs also vary inversely with well flow rate (Figure 7). Power costs are much more sensitive to flow rate at lower temperatures than at higher temperatures because the thermodynamic efficiency declines rapidly with temperature. As previously mentioned, well flow rate and temperature are two of the most important resource parameters in the cost relationship. The importance of the well flow rate to power cost is that, for a constant temperature, the power production potential from a well is proportional to flow rate. Therefore, the number of wells and the cost of the energy supply to the powerplant are directly related to flow rate. The cost of the fluid transmission system is also related to the well flow rate; lower flow rates require more wells and an increased length of transmission. This increase results in higher costs for pipe, higher costs for pumping where required, and higher energy losses. The cost of fluid transmission is part of the energy supply cost. Powerplant costs are not otherwise affected by the well flow except through the cost of the energy supply.

In this study, the initial well flow rate was assumed to be constant for each producing well. These flow rates are the maximum, initial flow rates. Compensation for decreases in flow rate with time is provided by replacement wells.

5.3 WELL COST

Other things being equal, power costs are directly related to the well cost (Figure 8). The effect of the well cost is much greater on lower quality (lower temperature and flow) resources. Since temperature and flow, to a large extent, are determined by nature, and since powerplant costs, as shown later, are not subject to wide variation, the well cost

FIGURE 6. Effect of Temperature on the Available Cost Allocation for Energy Supply Under Constrained Total Power Costs

FIGURE 7. Effect of Flow Rate on the Cost of Power

FIGURE 8. Effect of Well Costs on the Cost of Power

is probably the single most important determinant of the economic viability of a geothermal resource, particularly a lower temperature resource. The intercepts on the Y axis in Figure 8 (where the well cost is extrapolated to zero) show the relatively low variation in power cost attributable to all factors other than well cost for three geothermal resources of widely different quality.

Geothermal wells appear to cost about twice as much as oil and gas wells. The cost of oil, gas and geothermal wells is characterized by a high fixed "set-up" cost and a variable cost which increases with depth. The higher costs for geothermal wells are caused by many factors; the most important of which are the higher temperature, harder, and more-fractured state (according to R. Grieder of Chevron Oil Company) and remoteness which are characteristics of geothermal regions. Since 1973, drilling costs, or more correctly drilling prices, have increased at a much faster pace than the general inflation in response to both an increased demand for drilling

services and increased costs. (4) Because of the anticipated wide variability in geothermal well costs, we have treated well costs parametrically and independently of resource characteristics.

5.4 WELL SPACING

Power costs vary directly with well spacing (Figure 9). The increase in power cost with increased well spacing is caused by increased fluid transmission costs which result from three factors:

- (1) More piping is needed to transmit the fluid from the field to the plant, resulting in higher capital and maintenance costs.
- (2) Increased heat loss through the longer pipe runs results in less usable energy delivered to the powerplant.
- (3) Increased pressure drops over the increased distances so that either pumping costs or pipe diameters must be increased.

FIGURE 9. Effect of Well Spacing on Power Costs

In this analysis, the wells were located on a triangular lattice. The well spacing is directly related to the lattice area. It was assumed that the well spacing of the producing wells and reinjection wells was identical.

5.5 WELL REPLACEMENT RATE

Power costs increase with the well replacement rate (Figure 10). The well replacement rate is the annual rate at which new producing wells are added to augment declining flow caused by production. For depreciation cost accounting, well life is the inverse of the well replacement rate. It was assumed that no replacement wells would be required in the final year of powerplant operation.

FIGURE 10. Effect of Well Replacement Rate on Power Cost

5.6 POWER CYCLE

These analyses considered two power cycles, the binary cycle and flashed steam. The binary cycle is based on isobutane as the working fluid. The flashed steam cycle is based on a double flash at the plant. Under the specified conditions, the isobutane binary cycle appears more economic than the steam cycle below about 225°C (see Figure 5). Powerplants using the steam cycle, however, are closely competitive, running about 10% higher in total power costs at 200°C and 20% higher at 150°C. The breakeven temperature and comparative advantage of either cycle could vary over a wide range depending on the relative costs of the energy supply and powerplant, the noncondensable gas content, scaling rates, and other factors.

However, because of the lack of experience with binary cycle powerplants, there is considerable uncertainty in their capital and operating costs and their performance. The sensitivity of power costs to these uncertainties is as follows: A 50% increase in our capital cost estimates for binary plants would shift the breakeven temperature, at which the power costs for the steam and binary cycles are equal, down to about 200°C, but this 50% increase in plant cost would only increase the total power cost by 4.5 mills/kW-hr for the 150°C resource and even less for higher temperature resources. A decrease in capital cost would have the opposite effect. Improvements might be more rapid in the new binary cycle technology relative to the well-developed steam technology, and thus the binary cycle capital costs might become more competitive with time.

Part of the uncertainty in capital costs is related to uncertainties in the rate of scale or "crud" formation in the heat exchangers. Scale formation reduces the heat transfer coefficient. If frequent cleaning for scale removal is impractical, then a lower design heat transfer coefficient is required. Lower heat transfer coefficients require larger heat exchangers, increasing the capital cost. The effect of the heat transfer coefficient on power costs is treated later. Uncertainties in the scaling rate could also lead to higher capital costs for spare heat exchangers which might be employed to avoid excessive downtime for scale removal.

Uncertainties in powerplant operating costs, which are small, would in general, not have a significant impact on power costs - except for uncertainties in the cost of scale removal. Excessive scaling rates could lead to incurring prohibitive operating costs for scale removal. Scaling rates, resulting from silica deposition, would tend to increase with temperature because of the higher silica solubility and greater ΔT across the heat exchanger. Scaling rates might become excessive for brines over 250°C. However, if the noncondensable gas content is low, the steam cycle will probably be preferred to the binary cycle at these temperatures. In some brines excessive scaling from either silica or calcite deposition might also be encountered at lower temperatures.

Uncertainties in the performance of the binary cycle, whether caused by scaling or other factors, might be manifested by a reduction in load factor. The effect of the load factor on power costs is significant and is discussed later.

5.7 STEAM CONTENT

The steam content at the wellhead has a significant effect, like wellhead temperature, on power cost (Figure 11). The steam content is expressed as the weight percent of saturated steam in the geothermal brine at the wellhead. With no steam, water only is conducted to the plant. With both steam and water, a two-phase mixture is conducted to the plant. In these cases the fluid is flashed as required at the powerplant. With 100% steam, steam only is conducted to the plant; no flashing is required.

The enthalpy of the brine increases rapidly with the steam content. If the temperature and flow remain constant, the power output per well increases rapidly with steam content. Steam content and brine temperature are both related through the common factor, enthalpy.

In many practical instances, where the steam cycle is to be used, the wellhead pressure may be deliberately reduced to induce a greater well flow. The reduced pressure may lead to flashing and, consequently,

FIGURE 11. Effect of Steam Content on Power Costs

lower temperatures, whereas suppressing the steam formation would maintain the temperature of the fluid; but the enthalpy of the brine is the same under both conditions.

Increasing the steam content tends to increase the diameter of the fluid conductors, leading to an increased unit cost of transmissions. As illustrated in section 5.9, increasing steam content at the wellhead might tend to decrease the optimum powerplant size.

5.8 STEAM TEMPERATURE

As expected, the cost of power declines with increasing steam temperature (Figure 12). However, the sensitivity to steam temperature is not great for the relatively favorable well conditions in this illustration. The well flow is assumed to be 100% steam.

FIGURE 12. Effect of Steam Temperature at the Wellhead on Power Costs

5.9 POWERPLANT CAPACITY

The effect of plant capacity on the cost of power is shown in Figure 13. Costs decrease rapidly to about 50 MW. Over 50 MW, power costs gradually decline for high quality resources (e.g. Cases A and B). For low quality resources (e.g. Case C), a minimum power cost is reached in the 50-100 MWe range. The minimum is much more apparent for Case B, when a steam cycle with flashing in the field is used. Here the larger, more costly, steam transmission lines lead to a well-defined optimum powerplant capacity near 50 MW. Plant capacity is expressed as the net generating capacity in MWe; the net capacity is equal to the gross capacity less the internal power consumption.

The optimum powerplant capacity represents an economic tradeoff between the cost of the fluid transmission system, including energy losses in transmission, and the economies of scale achieved with powerplant size. The optimum plant capacity, therefore, tends to increase with

FIGURE 13. Effect of Powerplant Capacity on Power Costs

increasing fluid quality and all other factors which tend to reduce the cost of the energy supply, such as higher temperature, higher flow rate, lower well spacing, and lower drilling cost.

Because power costs decrease only gradually above 50 MW, new geothermal plants will probably be in the 50-100 MW range. Even though power costs may continue to decline above 100 MW, the incremental savings achieved with larger plants will probably be outweighed by the risks related to reservoir and powerplant reliability. As confidence in the reliability increases with experience and technology, powerplant capacities should tend to increase, but individual geothermal plants will probably rarely exceed 200 MW.

The variation in powerplant capital costs with capacity (Figure 14) can be represented by the equation:

FIGURE 14. Economies of Scale for Geothermal Powerplants

$$C = aT^x$$

where

C = powerplant unit capital cost (\$/kWe net)

T = powerplant capacity (MWe net)

x = scaling exponent

a = constant

This expression for the total unit powerplant cost is derived from the composite of individual powerplant components. Cost relationships for individual components are described in another report.⁽⁵⁾ The approximate values for a and x for steam and binary plants for two different geothermal resources are:

Powerplant Technology	a	x	Brine Temperature °C
Steam	1450	-.29	150
Steam	1050	-.30	250
Binary	1000	-.23	150
Binary	880	-.23	250

5.10 NONCONDENSIBLE GASES

Increases in the content of noncondensable gases in the geothermal fluid increase power costs dramatically for the steam cycle (Figure 15). In the reference design for the steam plant, a steam ejector is used to evacuate the noncondensable gases from the condenser. As the noncondensibles increase, more steam flow is required for the ejector and, consequently, less is available percentagewise for power production. For the 200°C resource shown in Figure 15 net power production drops to zero when the noncondensibles reach 3.4%. The impact of the noncondensibles is much worse for lower temperature resources; for flashed steam cycle with a 150°C water resource, all of the steam would be required for the steam ejector when the noncondensable gas content reaches 2.2% and no power would be produced. Obviously, under these conditions, an alternative method of gas removal or power generation would be required.

FIGURE 15. Effect of Noncondensable Gases on the Cost of Power and Net Power Output of a Well

Plant design alternatives to the steam ejectors are vacuum pumps, turbine discharge to atmosphere, and the binary cycle. Vacuum pumps, however, would increase the internal electrical consumption. Discharge of the turbine to the atmosphere would eliminate the condenser but decrease the recovery of energy from the steam. The binary cycle, which is not greatly affected by the noncondensable gas content, would be preferred over the steam cycle for geothermal resources in which the noncondensable gas content was high, provided the scaling rates were manageable.

5.11 PLANT EFFICIENCY

The plant thermal-to-electric conversion efficiency is directly related to the amount and, therefore, the cost of geothermal fluid required by the powerplant. An increase in conversion efficiency would reduce the quantity of geothermal fluid required in direct proportion. Increases in efficiency might be achieved through reduced losses or greater energy recovery, such as multistage flashing, higher temperature drops across the heat exchanger, or the "total flow" cycle.⁽⁶⁾ An optimum efficiency occurs when the reduced costs of the energy supply are exactly offset by the increased costs of the energy recovery system.

Because the cost of the energy supply makes up a greater proportion of the total cost of power from low quality resources, increases in plant efficiency would contribute proportionally more to the commercial viability of the less high quality geothermal resources.

5.12 LOAD FACTOR

Since a large fraction of the costs associated with geothermal power are fixed, the cost of power increases rapidly as the load factor decreases (Figure 16). In the preceding analyses the load factor was assumed to be constant at 80%.

FIGURE 16. Effect of Load Factor on Power Costs

The average annual load factor is the effective percent of the year that the plant operates at full power. For instance, a 50% load factor would be achieved by operating at half power all year, full power for only half the year, or any equivalent combination of time and power level. In this analysis, the annual well replacement rate was assumed to vary directly with the load factor; for example, the annual well replacement rate would be cut in half when the load factor is reduced from 80% to 40%. In effect, this assumes that each well will deliver a constant amount of energy. In most instances, wells would probably deliver more energy at lower withdrawal rates since the amount of recharge would be higher.

The distribution of fixed and variable costs is an important criterion in determining the specific application for a powerplant. Base-loaded plants usually have the lowest variable operating costs, whereas load-following plants usually have lower fixed costs and higher variable costs. Geothermal plants, in general, have a low proportion of variable to fixed

costs (Table 11). The variable costs, however, increase as the quality of the resource decreases. Resource conditions were specifically selected to yield the distribution of power costs shown in Table 11; the well replacement rate and well cost, which are the principle determinants of the variable costs, were identical for each resource condition. Geothermal plants utilizing high quality resources will also have comparatively low fixed costs. Thus, future geothermal plants will probably be used for both base load and load-following applications.

TABLE 11. Fixed and Variable Costs for
Geothermal Power Generation
(Mills/kW-hr)

<u>Resource Conditions</u>	<u>Power Cost Total (a)</u>	<u>Fixed Cost</u>	<u>Variable Cost</u>	<u>% Variable Cost</u>
1	13.3	11.6	1.6	12
2	14.8	12.4	2.4	16
3	17.5	14.4	3.1	18
4	21.5	16.8	4.7	22
5	23.2	18.0	5.2	22
6	25.7	19.7	6.0	23
7	29.8	22.6	7.2	24
8	31.3	24.1	7.3	23
9	34.8	26.5	8.3	24
10	38.9	29.4	9.5	24

(a) For 80% uniform load factor

5.13 HEAT TRANSFER COEFFICIENT

One of the critical factors to the success of binary cycle technology will be the performance of the heat exchangers. The effects of variable heat exchanger performance are illustrated for four geothermal binary cycle cases (Table 12).

TABLE 12. Effects of Variable Heat Exchanger Performance

<u>Case No.</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>
Gross Power (MW)	55	55	55	64
Well Flow (lb/hr)	430,000	1,020,000	215,000	250,000
Temperature (°C)	200	150	200	180
Working Fluid	Isobutane	Isobutane	Isobutane	Isobutane

The cost of power is a weak function (Figure 17) of the overall heat transfer coefficient in normal ranges but the cost increases rapidly for sub-normal coefficients; i.e., little is gained by maintaining a heat transfer coefficient above 200 Btu/hr/ft²/°F, but much is lost if it slips below 100. The overall heat transfer coefficient is defined as the numerical average of the heat transfer coefficients for the superheater, vaporizer and preheater. The design heat transfer coefficient is directly related to the required heat transfer area and thus to the cost of the heat exchangers. The relationship between power cost and heat transfer coefficient is similar in all four cases, even though the cost of power for each case is different. Similar cost trends should apply in other cases over all cost of power ranges. Only when the heat exchangers are extremely costly, i.e. made from expensive materials such as titanium, would the heat transfer coefficient have a much greater effect on the cost of power.

FIGURE 17. Cost of Power as a Function of Heat Transfer Coefficient

The power costs vary linearly with the inverse of the heat transfer coefficients (Figure 18). This relation can be expressed by the equation:

$$\text{COST} = m(1/\bar{u}) + b$$

where

COST = cost of power (mills/kW-hr)

$\bar{u}$ = average overall heat transfer coefficient (Btu/hr/ft²/°F)

m, b = constants for each reference case.

The numerical values of m obtained from this study are shown below.

The magnitude of m is roughly a function of the geothermal fluid temper-

FIGURE 18. Cost of Power as a Function of Inverse Heat Coefficient

ature and the unit cost of the heat exchangers. The value of b , the intercept for a hypothetical infinite heat transfer coefficient, depends on other factors not related to the heat transfer coefficient.

<u>Case</u>	<u>m</u>
1	335
2	572
3	332
4	547

5.14 ISOCOSTS FOR LOW SALINITY HYDROTHERMAL RESOURCES

From parametric analyses on a wide range of low salinity hydrothermal resources the relative importance of each factor to the cost of power was determined. The dominant factors which determined geothermal power costs for low salinity, hydrothermal resources were (1) the wellhead temperature, (2) the well flow rate, and (3) the cost of the wells. These three factors tend to establish the economic value of a resource. Figures 19-21 relate these factors in terms of isocosts - lines of equal power cost - for each of three different well costs: \$150,000, \$300,000, and \$500,000. Combined, these three factors are analogous to the installed unit capital cost of a powerplant. The temperature and flow rate form a measure of the power capacity from a well and the well cost is equivalent to a capital cost. Thus, for instance, a well producing 5000 kW and costing \$500,000 would be analogous to an installed capital cost of \$100/kW. Differences in timing, tax treatment, financing, and useful life do not permit identical translations between powerplant capital costs and well costs into equivalent energy costs. As an illustration of the dominant impact of well costs on the energy costs from low quality geothermal resources, if the same \$500,000 well produced only 1000 kW, then the equivalent capital cost would be \$500/kW.

To illustrate some uses of the isocost figures:

- Refer to the 20 mill/kW-hr curve on the \$300,000 per well figure (Figure 20). This curve depicts all combinations of temperature and flow rate which would yield a 20 mill/kW-hr power cost. Thus, for example, a 200°C resource with a 500,000 lb/hr average well flow rate would be equivalent to a 175°C resource with an 800,000 lb/hr flow rate; similar comparison can be made using other isocosts.
- The effect of an increase in well drilling costs can be estimated. For instance, at \$150,000 per well (Figure 19), a 200°C, 500,000 lb/hr resource would result in a power cost of about 17 mills/kW-hr while the same resource at \$500,000 per well (Figure 21) would result in a power cost of 27 mills/kW-hr, an increase of 10 mills/kW-hr attributable to well costs.

FIGURE 19. Isocosts for Hydrothermal Resources at a Well Cost of \$150,000

FIGURE 20. Isocosts for Hydrothermal Resources at a Well Cost of \$300,000

FIGURE 21. Isocosts for Hydrothermal Resources at a Well Cost of \$500,000

- The effect of flow stimulation can be estimated. For instance, at \$500,000 per well, an increase in the average flow rate from 500,000 to 600,000 lb/hr for the 200°C resource would decrease the cost of power about 3 mills/kW-hr (i.e., from 27 mills/kW-hr to 24 mills/kW-hr). On the other hand, the same increase in flow rate for a 150°C resource would decrease the cost of power about 8 mills/kW-hr (i.e., from 50 mills/kW-hr to 42 mills/kW-hr).

In general, the lower quality resources would always benefit more than higher quality resources from proportional increases in flow rate or decreases in well costs because a much higher fraction of their costs are associated with the wells.

Although these three factors will probably determine the relative economic value of most hydrothermal resources, many other factors will also affect geothermal power costs to a lesser extent. Of these, well replacement rate, well spacing, and fluid composition are probably the most important. The fluid composition, particularly the highly acidic brines, could have a very large impact on power costs. Thus, the value of specific geothermal resources must be determined on an individual basis. The isocost curves illustrate systematic relationships and assume that all other factors are constant. The assumed values for the more important factors were: annual well replacement rate, 0.1; well spacing, 20 acres; pH, 7; and 0.1% noncondensable gases. The isocost figures are derived from both binary (below 250°C) and flashed steam plants (above 250°C). The financing and tax assumptions are the same as used in the previous analysis, which would be typical of a large oil company operating the reservoir, an investor-owned utility operating the power-plant, and a composite tax rate typical of the western states.

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