AN ANALYSIS OF ELECTRICITY PRODUCTION COSTS
FROM THE GEOPRESSURED GEOTHERMAL RESOURCE

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SUMMARY

This study for the Energy Research and Development Administration's Division of Geothermal Energy assesses the economics of the geopressured geothermal resource along the northern coast of the Gulf of Mexico. Geopressured waters are nearly under twice the normal hydrostatic pressure and believed to be saturated with methane. We estimate the costs of generating electricity from this resource based on the description and conceptual development plans provided by the United States Geological Survey (USGS).

Methane content and selling prices are the most important factors affecting the commercial potential of geopressured resources - so it is important that electrical generation be viewed as a by-product of methane production. Without methane revenues to offset high well-drilling costs, estimated electrical generation costs from the thermal energy in the hot water far exceed current generation costs from conventional energy sources. However, if the thermal energy is available "free" as a by-product of methane production, then the incremental costs of electricity generation from the thermal energy in many geopressured reservoirs approaches generation costs from conventional energy sources.

On the same incremental cost basis, the cost of electricity generated from the geohydraulic energy is potentially competitive with conventional energy sources. This would require development of a small commercial high pressure, hydraulic turbine to extract geohydraulic energy at the wellhead in plants of about 3 MW capacity. Transmission of high pressured fluids from several wells to a central geohydraulic power plant would not be practical. The upper cost target for geohydraulic plants would be about \$800/kW.

Price/quantity relationships are developed for electricity generation from geopressured resources for each of three development plans proposed by USGS. The identified energy potential could supply up to 200 GW - roughly half the current installed generating capacity in the U.S. If methane revenues offset all water production and disposal costs, the incremental production costs for electricity as a by-product are estimated to range from competitive to triple the current generating costs from conventional sources.

The large distances required between wells results in significant costs for fluid transmission from the wellhead to a central power plant. In most cases fluid transmission is the largest expense of electricity generation from thermal energy. If electricity generation costs from thermal energy conversion are to become competitive, fluid transmission costs will have to be reduced by developing cheaper piping systems, reducing well spacing, and reducing power plant size.

Our studies, based on field constructed plants, indicated an optimum power plant size in the range of 20 to 60 MWe, depending on water temperature. However, if standardized thermal conversion power plants could be factory produced in the 6 MWe range competitively with larger field constructed plants, then the optimum plant size might be reduced to single wellhead units. Wellhead units would completely eliminate fluid transmission costs, but would probably incur higher costs for heat rejection, power plant operation, and electrical transmission. The upper cost target for competitive wellhead plants would be on the order of \$800/kW in 1975 dollars.

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AN ANALYSIS OF ELECTRICITY PRODUCTION COSTS FROM THE GEOPRESSURED GEOTHERMAL RESOURCE

INTRODUCTION

Geothermal waters along the northern coast of the Gulf of Mexico are under nearly twice the normal hydrostatic pressures and are expected to be saturated with methane. The thermal energy of the hot water, the hydraulic energy of water under pressure, and the methane content constitute a large energy potential. Our purpose in this report is to provide an economic assessment of this geopressured geothermal resource. We focus primarily on the cost estimates of generating electricity from the thermal and kinetic energy of the geopressured water.

The economic assessment in this report relies heavily on the description of the geopressured resource found in the United States Geological Survey Circular 726.⁽¹⁾ Although it is the most comprehensive description of the resource available, its estimates are based on relatively few sources and several assumptions. Consequently, both the extent and physical characteristics of this resource are uncertain. We use sensitivity analyses to assess the potential impact of major uncertainties on generation costs and price/quantity relationships.

The United States Geological Survey (USGS) has three conceptual development plans for the geopressured resource. We use these plans to define the conditions necessary for commercial viability, to provide insights into the more significant production cost relationships, and to evaluate the potential impact of uncertainties. This information may provide a basis for deriving improved development plans and for framing research and development programs with reduced costs and uncertainties.

We begin this analysis with descriptions of the methodology, the resource, and energy recovery systems. We analyze the electricity production costs by considering the impact of methane content and prices on the economics of resource recovery and by treating the methane resource separately as the primary product. With this approach, we treat electricity

production from the thermal and geohydraulic energy as potential by-products of methane production. Thus, production costs include only those incremental expenses directly related to electricity generation. We then combine these production costs with estimates of resource quantity to develop price/quantity relationships for several different production scenarios.

The USGS classified the resource into 21 different subareas which are described in Appendix A. Appendix B deals with the cost of generating electricity from the geopressed subareas and Appendix C lists the recoverable energy under the three development plans for each subarea. Price/quantity relationships are derived for each production scenario in Appendix D, and Appendix E gives the cost distribution and capital cost estimates from the GEOCOST model.⁽²⁾

METHODOLOGY

Our cost estimates of generating electricity from this geopressured geothermal resource are based on the particular reservoir's suitability for electricity production rather than on its methane content and its selling price. To do this, we treat the hot water and overpressured water as by-products of a methane production operation and calculate the cost of generating electricity from them accordingly.^(a) Under this approach, the cost of production and disposal wells are charged to the methane producer since these costs must be incurred to produce methane. Only the added costs for electricity generation (those for fluid transmission and the power plant) are charged to the electricity production.

The estimates for the cost of generating electricity from the hot water are made using the GEOCOST computer model.⁽²⁾ This model is used to estimate the generation cost for each of the 21 idealized reservoirs.⁽³⁾ Each reservoir is evaluated for the three development plans⁽⁴⁾ and three thermal-to-electric conversion technologies. In addition, several important parameters are varied to assess the sensitivity of generation cost to such changes.

In the GEOCOST model the production cost of electricity generation at the bus bar is calculated. The model is based on discounted cash flow analysis and life cycle costing at the power plant. The GEOCOST model provides systematic cost estimates of capital and operating costs for the power plant and water gathering systems based on the resource characteristics. Estimates of the distribution of generation costs and capital costs for several representative power plants are tabulated in Appendix E. The cost

^(a) This approach is taken because the uncertainties surrounding methane revenue and well cost tend to obscure the analysis of generation costs. As will be shown later, the range for either the methane content or its selling price (neither of which is a settled matter) can shift the geopressured geothermal resource from a highly attractive to a marginal resource. What clouds the analysis is that this fluctuation is independent of the particular resource's suitability for electricity production.

estimates refer to a general site and are intended to provide comparisons of the differential costs related to resource characteristics and power cycle technology. The basis for the cost estimates is described in previous reports.^(5,6) December 1975 is the reference point for the cost estimates in this report.

For comparison, we are assuming that the "bus bar" cost of electricity generated from new base-loaded coal and nuclear power plants will be 20 mills/kWh in 1975 prices. Obviously, if costs for nuclear and coal power plants escalate more rapidly than costs for geothermal power plants, geothermal plants would become more competitive. Relative escalation rates are outside the scope of this report. We have assumed constant 1975 dollars.

In the analysis of electricity production costs, we make the following assumptions: A large investor-owned utility operates the power plant and a large oil company provides the water production; financial structures, costs of financing, and tax rates historically typical for these firms apply (Appendix E); and the power plant has an 80% annual load factor. Unless otherwise stated, assumptions are identical in all analyses.

The generation costs calculated in this report are combined with the USGS estimates for resource availability to create supply curves. Circular 726⁽¹⁾ provides estimates for energy content for each ideal reservoir. From this and the restrictions of each of three proposed development plans described in the next section, the amount of electricity available under each plan is calculated. Price/quantity relationships for the electricity from the hot water are derived for three different conversion technologies for all of the development plans. In addition, for Plans 1 and 3, supply curves for electricity generated from the geohydraulic energy are derived.

THE GEOPRESSURED GEOTHERMAL RESOURCE

The energy potential of the known geopressured geothermal resource, which lies in a 200 to 300 mile strip along the northern shoreline of the Gulf of Mexico, is enormous. In their assessment of the most promising onshore areas in Mississippi, Louisiana and Texas, USGS estimated the electrical potential, excluding the energy equivalent of the stored methane, to be 9,000 to 35,000 MW-centuries (46,000 to 172,000 MW for 20 years), depending upon the development plan. This is 3 to 10 times their estimate for the total hydrothermal potential in all the western states. The USGS further speculates that the potential of the unassessed part of the resource is likely to equal if not exceed the assessed portion. This electrical potential, coupled with the methane and the likely nonelectrical uses of the resources, encompasses a significant potential contribution to U.S. energy needs.

The geopressured resource is characterized by water at a moderate temperature (140 to 180°C), at a depth of 5,000 to 15,000 ft (1500 to 4500 m), under abnormally high pressures (up to 6,000 to 8,000 lb/in² or 400 to 550 bar above hydrostatic) and believed to be saturated with methane. Its origin is associated with the sedimentary activity of large river systems which have poured enormous quantities of sand and clay onto the northern Gulf shoreline since early geologic time. This differs from the hydrothermal resources of the West, which are generally associated with relatively recent volcanism.

The exact structure of the reservoirs is not known. Many believe that the water is trapped in sandstone which is bordered on top and bottom by shale, but do not know whether the sandstone is continuous over large areas or segmented in small unconnected deposits. The USGS classified the resource into 21 idealized "conceptual reservoirs" in which the properties of the resource, derived from a few measurements, were assumed to be continuous over the whole reservoir.

Because a development plan involves complex environmental and economic issues, the USGS suggested three different plans for the subareas to

provide "order-of-magnitude" type assessments. Plan 1 provides for use of a relatively high level of mechanical energy from the overpressured water throughout the production life. This is done by placing a lower bound of $2,000 \text{ lb/in}^2$ (140 bar) on the wellhead pressure. This restriction is removed in Plan 2 to achieve the maximum thermal delivery from each reservoir. Plan 3 considers the very real possibility of subsidence. In this plan the lower bound on wellhead pressure is established so that the average subsidence in each subarea does not exceed 1 m.

The restrictions imposed by the development plans cause the well spacing and the number of wells within each subarea to vary. Since each well is assumed to produce at the same rate, $0.15 \text{ m}^3/\text{sec}$, the recoverable energy varies from one plan to the next. The well spacings under each development plan are tabulated in Appendix A. In Appendix C the recoverable energy under the three plans is listed for each subarea.

ELECTRICITY CONVERSION SYSTEMS

For converting the hot water to electricity, three conversion technologies are analyzed. The first is a binary system where the heat of the geopressured fluid is exchanged with the isobutane working fluid. The next system is a conventional flashed steam system. The third is the total flow concept modeled after the work of Austin, et al.⁽⁴⁾ For converting the geohydraulic energy to electricity, we base the analysis on the reverse centrifugal pump reported by Dow Chemical Company.⁽³⁾

BINARY SYSTEM

In this system the geothermal fluid is delivered to the plant as compressed liquid. At the plant the fluid passes through a three-stage (subcritical cycle), counterflow, tube and shell heat exchanger. Here the thermal energy is transferred to an isobutane working fluid. The vaporized isobutane drives a turbine in a closed loop Rankine cycle. After the turbine, the fluid is condensed in a tube and shell condenser where water from a cooling tower absorbs the rejected heat. The isobutane is then pumped up to the appropriate pressure and reheated by more geothermal fluid.

STEAM CYCLE

The steam cycle uses two flashing stages at the power plant. The compressed liquid is delivered to the plant and sent to the first flasher. Most of the steam produced enters the turbine. Some is used to drive off noncondensable gases. The effluent liquid travels to the second flashing stage. Here all of the steam produced goes to the turbine. The effluent from the second stage is mixed with the cooling tower blowdown and reinjected. After the turbine, the steam is condensed and mixed into the cooling water.

TOTAL FLOW SYSTEM

The total flow system is a new technology. There is no commercially operating system. The model of the physical plant is based on the preliminary paper by Austin, et al., at the Lawrence Livermore Laboratory.⁽⁴⁾ However, recent tests of the concept have yielded optimistic results which tend to confirm the predictions of the paper.⁽⁷⁾ At the total flow plant the geothermal water is delivered to the plant as it comes out of the well (except for some degradation in the transmission line). The water is sent through nozzles which are aimed at the blades of a two-phase expander which drives the generator. It is condensed in a barometric condenser and then disposed of by reinjection. The noncondensable gases are removed at the condenser with a steam ejector. The steam for this process is separated from the geothermal fluid ahead of the turbine.

GEOHYDRAULIC CONVERSION

To convert the geohydraulic energy to electricity we will use the device and costs of the Dow report cited earlier.⁽³⁾ They proposed that a barrel pump (centrifugal) operate in reverse to drive the generator. Several devices have been proposed by Lawrence Livermore Laboratory's total flow program. They include: a radial in-flow turbine (like the reverse centrifugal pump above);⁽⁴⁾ a Pelton wheel;⁽⁸⁾ and a Helical-rotor expander.⁽⁹⁾ However, since cost figures are only available for the device in the Dow report, it is used as the example.

Since high pressure turbines capable of operating under geopressured conditions have not been developed and tested, estimates of their performance and costs are uncertain.

ANALYSIS OF ELECTRICITY PRODUCTION COSTS

We analyze the costs of producing electricity under two conditions: first, where electricity is the primary product and methane is the salable by-product; and second, where methane is the primary product, and electricity is the salable by-product. The difference is that the water production costs are allocated only to the primary product - electricity in one case and methane in the other. The water production costs comprise mainly the cost of the production wells, disposal wells, and reinjection equipment. The cost of producing the by-product then includes only the incremental costs associated with its recovery.

A third alternative is to consider methane and electricity as co-products. Then the water production costs would be allocated to each according to some formula. This alternative has limited utility.

SIGNIFICANCE OF METHANE

Methane is expected to be dissolved in the geopressured water and many people expect the water to be saturated with methane.⁽¹⁰⁾ When we assume that the primary product is electricity and use the revenues from methane sales to offset electricity production costs, the production costs for electricity vary widely depending on the concentration and selling price for methane. The value of the resource appears to depend more on its methane content than on its value for electricity production. Therefore, if current conceptions of the geopressured resource are correct, its economic viability will probably be tied to methane production; i.e., the primary product will be methane, and electricity generation, if any, will be a by-product.

To illustrate this point, let us analyze the cost of producing electricity from the geopressured resource represented by USGS Subcategory AT1. This is the highest quality resource of the 21 USGS categories. The primary product is assumed to be electricity and methane is the by-product. We use the following reference conditions: the resource is saturated with

methane (about 0.7% by weight), the methane is sold for \$2 per 1,000 scf^(a) and the well cost is \$1 million.^(b) The cost of generating electricity for these conditions under Development Plan 1 (excluding the mechanical energy content) is -20.63 mills/kWh (Figure 1).^(c) The negative sign tells us that, even if we gave the electricity away, the revenue generated from the methane sales would more than cover expenses (which include return on the investment).

The sensitivity of generating costs to other potential methane contents and selling prices is also shown in Figure 1. For instance, if the methane content is one-half the saturation level, the cost of generation is 5 mills/kWh. If no methane is present, the cost is 31 mills/kWh. If the selling price of the methane is cut in half to \$1 per 1,000 scf, the effect is the same as reducing the content by one-half: the generation cost is 5 mills/kWh. If the selling price is increased to \$3, the generation cost is cut to -46 mills/kWh.

In this illustration, methane is a by-product of the electricity production and used to offset electricity production costs. When the by-product revenue exceeded the costs, the generation costs became negative.

Two points stand out in the analysis above: First, the methane revenue is potentially the dominant factor in the analysis.^(d) Under certain

(a) scf = standard cubic feet = one cubic foot ($.028 \text{ m}^3$) at standard temperature and pressure.

(b) Estimates of well costs generally range upwards from \$1 million.^(11, p.24) Higher well drilling costs would tend to increase the dependence on methane revenues to achieve commercial viability.

(c) The cost calculations did not include additional equipment for methane recovery. However, inclusion of this type of equipment would not increase costs significantly.

(d) Others have reached similar conclusions. For instance in the studies by House, et al., projected natural gas revenues exceeded electricity revenues by 150 to 400%.⁽⁸⁾

FIGURE 1. Impact of Methane Content and Selling Price

assumptions, this revenue exceeds all the expenses at the reservoir and the power plant. Second, the geopressed geothermal resource development will not likely proceed very far without significant methane revenues. The cost of electricity generation without the methane is 31 mills/kWh for the subcategory with the most favorable characteristics. This is about equivalent to electricity generation with oil at $\$12/\text{bbl}$ (about 8¢/liter) and is nearly twice the current generation costs with coal or nuclear. Since the resource characteristics in other geopressed subareas are worse, their cost of generation will be even higher. From this we conclude that if geopressed resources are developed according to the USGS plans, methane will most likely be the primary product and electricity will be a by-product.

COST OF BY-PRODUCT ELECTRICITY GENERATION

We have shown that methane is a significant factor in the cost analysis. In subsequent analyses, we view it as the primary product. We further assume that methane revenues cover all water production costs. We then treat the hot water as a "free" commodity available for electricity generation. Under this approach the cost of generating electricity from the hot water and the overpressured water is based only on the incremental equipment and facilities required to generate the electricity. These include the collection system and power plant for the hot water and the turbine and supporting facilities for the overpressured water. Since the wells and methane separators are necessary for methane production, their costs are not charged to electricity generation.

If, in reality, methane revenue does not cover all water production costs, then the revenues from electricity generation would have to absorb the uncovered portion. This is the co-product case mentioned previously. This would increase the cost of electricity generation over the "free" commodity approach described above. We show that under current competitive conditions, only the geohydraulic energy can absorb some of the water production costs and remain competitive with conventional power plants. The thermal energy generation could not absorb significant production costs and be competitive under the three development plans. Thus, the geopressure resource as described by the USGS will be developed only if the production costs can be substantially offset by methane revenues.

Hot Water Generation Costs

Using the "free" hot water approach, we analyzed the cost of generating electricity from each of the 21 USGS categories, under the three development plans, and for three power cycles. Table 1 is an example of the results of this analysis. Complete results are listed in Appendix B. Table 1 shows the cost of generation for each of the subareas under Development Plan 1 when the binary conversion cycle is used. Appendix B has the results for Development Plans 2 and 3 for the binary conversion cycle and also lists the generation costs for the total flow and the steam cycles under all three development plans. These data are used in a later section dealing with the price/quantity relationships for the resource.

**TABLE 1. Distribution of Generation Cost Under
Development Plan 1: Binary Conversion Cycle**

Category	Wellhead Temperature (°C)	Well Spacing		Fluid Transmission (mills/kWh)	Power Plant (mills/kWh)	Total (mills/kWh)
		(acres)	(km ²)			
AT1	186	2050	(8.2)	9.9	12.3	22.2
ATL2	156	2050	(8.2)	17.9	15.1	33.0
BT1	170	3240	(13.1)	19.4	12.9	32.3
BT2	150	2610	(10.6)	24.8	15.6	40.4
CT1	172	1440	(5.8)	11.7	12.6	24.3
DT1	172	1230	(5.0)	10.9	12.6	23.5
DT2	169	2180	(8.8)	16.3	13.0	29.3
DT3	153	2610	(10.6)	22.9	15.3	38.2
DTL4	141	2920	(11.8)	32.6	16.9	49.5
DL5	164	1790	(7.2)	16.6	13.5	30.1
DL6	160	1330	(5.4)	14.2	14.2	28.4
ET1	168	1230	(5.0)	12.7	13.1	25.8
ET2	166	2180	(8.8)	17.9	13.4	31.3
ET3	146	2180	(8.8)	25.6	16.5	42.1
ETL4	140	2610	(10.6)	33.4	17.1	50.5
EL5	165	1550	(6.3)	15.5	13.5	29.0
EL6	159	1440	(5.8)	14.8	14.4	29.2
EL7	145	1130	(4.6)	18.8	16.5	35.3
FT1	171	1550	(6.3)	13.6	12.8	26.4
FL2	148	1330	(5.4)	18.4	16.3	34.7
FL3	151	1330	(5.4)	17.9	15.5	33.4

The cost of generating electricity from the hot water can be divided into two categories: power plant costs and fluid transmission costs. Nearly all of the power plant costs are associated with the original construction of the plant. Only a small percentage is required to operate the plant. The distribution of fluid transmission costs is also capital intensive, similar to power plant costs.

In the three USGS development plans, the distances between wells (well spacings) are extremely large, which leads to high fluid transmission costs. Fluid transmission cost varies with fluid temperature and well spacing (Table 1). These factors are examined in greater detail later through sensitivity analyses. Fluid transmission costs exceed power plant costs in most of the 21 USGS resource categories.

If we compare the generation cost estimates for the three conversion cycles presented in Appendix B - binary, total flow, and flashed steam - we find that total flow costs are lower than the other two under all three development plans. A binary cycle, which is a nearer term conversion technology than total flow, costs slightly more. The steam cycle results in the highest generation cost, primarily due to the relatively low temperatures of the geopressed resources. We found in earlier analyses comparing only the steam and binary cycles that the steam cycle is slightly more cost effective at higher temperatures but the binary cycle is more cost effective at lower temperatures.⁽⁶⁾

The cost estimates for the total flow system assume successful development of this concept. The uncertainties in total flow estimates are mainly associated with cost and performance of the turbine. Of particular importance is the achievement of conversion efficiencies, on-line reliability, and turbine lifetime in line with the conceptual projections and commercial requirements. The other major components of the power plant are common to other power cycles. Our cost estimates are derived by analogy from steam plant data. The total flow cycle with its higher conversion efficiency would appear significantly more favorable than the binary cycle except for our assumption that the water is a free commodity. Higher conversion efficiencies generally reduce unit costs throughout the system.

Effect of Plant Size

All of the foregoing results are based on a plant size of 55 MW. To examine the effect of plant size, we varied the plant size for three different water temperatures. The relationship between generation cost and plant size forms a curve which is relatively flat (Figure 2). The generation cost is composed of two components--power plant costs and fluid transmission costs. Power plant costs decrease with plant size through economies of scale. Transmission costs increase with plant size because the average length of transmission from the wellhead to the power plant increases. The minimum cost occurs near 20 MW at the lower temperature and near 50 MW at the higher temperature. However, the variation is small throughout the entire range and probably within the range of uncertainties in the cost estimates. Only the extremely small plant sizes at the higher temperatures resulted in significantly higher generation costs.

FIGURE 2. Impact of Plant Size on Generation Cost

There have been suggestions that the appropriate plant size is equal to the output of one well, or a plant size in the 6 MW range. The above results show that a plant this size would cost more than a larger, centrally

located plant. However, these results do not consider the extra benefit from earlier revenue generation that would be possible if power plant operation began shortly after each of the production wells were drilled. Nor do they consider the possibility that small standardized plants might be mass produced in factories for less unit cost than field constructed plants.

Recent estimates by Barber⁽¹²⁾ of the installed costs for small Rankine cycle units in production quantities appear potentially attractive for this application. At 1 MW power output, the installed cost was estimated at only \$400/kW, excluding heat rejection equipment. On an incremental cost basis the upper total installed cost target for a commercial 6 MW unit would be about \$800/kW - achievable according to the above estimates.

The smaller plants, of course, would incur problems that the larger plants avoid. For example, connecting and dispatching from many small generating sources within a large utility electrical grid would probably cost more than from fewer larger sources. Also, the larger centrally located plant could use one large heat rejection unit. The small plants would each have one of their own which could result in a greater cost. The full evaluation of the potential wellhead power plants is left for later work. A good description of a small geothermal plant design has been provided by Rogers Engineering.⁽¹³⁾

Sensitivity Analysis of Other Parameters

The costs associated with producing electricity from hydrothermal geothermal resources are affected by many parameters. We examined the impact of the most important parameters - wellhead temperature, flow rate, and well cost - in an earlier publication.⁽⁶⁾ Here we will focus on the parameters which are most significant for geopressured resources: well spacing, fluid temperature, and well flow rate. These three parameters largely determine the cost of generating electricity from any one geopressured resource. To examine their individual impacts, we vary each parameter while holding the others constant.

Well Spacing

Well spacing in the geopressured resource is large compared to the hydrothermal resources of the West, and this increase production costs. The Geysers in California has well spacings of approximately 20 to 40 acres. The geopressured resource, according to the USGS development plans, will have well spacings on the order of several thousand acres or a distance between the wells of several kilometers. Figure 3 shows the increase in generation costs with increased well spacing. This increase is more pronounced as the temperature decreases.

FIGURE 3. Impact of Well Spacing on Generation Cost

The fluid transmission costs cause these large increases in generation cost. Figure 4 shows how the distribution of the total cost changes with well spacing. The cost of the transmission system is smaller than that for

FIGURE 4. Impact of Well Spacing on Generation Cost Distribution

the power plant at the lower end of the range of well spacings, but rapidly begins to dominate as well spacing increases. Power plant costs are not significantly affected by changes in well spacing. At the large well spacings in the USGS development plans, fluid transmission costs would have to be significantly reduced in most subareas for central power plants to become competitive.

Temperature

Temperature is important in the cost of generating electricity from geothermal resources for two reasons. First, there is less thermal energy available in each pound of fluid at lower temperatures. Second, the potential thermodynamic efficiency at lower temperatures is much smaller. The combination of these two rapidly increases the cost of generation as temperature of the resource decreases (Figure 5). At the lower temperatures and at the lower flow rates, small changes in temperature have a large impact on generation costs. At higher temperatures and higher flow rates, the impact is much smaller.

FIGURE 5. Impact of Water Temperature on Generation Cost

Well Flow Rate

The thermal energy available from geothermal wells is directly proportional to the mass flow rate of those wells. For a given power plant of a certain size and thermal conversion efficiency, the number of geothermal wells required is proportional to the inverse of the mass flow rate. Thus, a higher flow rate means fewer wells and lower generation costs. Figure 6 demonstrates this relationship for several of the subarea temperatures. The USGS assumes that the mass flow rate of the geopressed wells will be approximately $0.15 \text{ m}^3/\text{sec}$. This translates into about $1.1 \times 10^6 \text{ lb/hr/well}$, depending on fluid density. If the actual flow rate is very much lower than this figure, the cost of generating electricity from geopressed resources will be much higher.

FIGURE 6. Impact of Flow Rate on Generation Cost

Geohydraulic Generation Costs

The cost of generating electricity from the geohydraulic energy will be comprised of the capital and operating costs for only the turbo-generator set and its associated controls and instrumentation. This equipment will be located after the high pressure methane separation near the well to avoid surface transmission of high pressure fluids. (3,p.8;9,p.9) Thus, there are no significant fluid transmission costs associated with this operation.

The capital costs for the conversion system described by Dow will total \$1,548,000 installed (Table 2). (3) The University of Texas group itemized all the installed costs and came up with a slightly higher total (Table 3). (14) The conversion system will produce 5.61 MWe in the 25 MWe double-flashed steam system proposed by Dow (14,p.35) and 7.13 MWe in the single-flashed

steam system^(14,p.37) with proportionately higher costs. The result is approximately \$257/kW installed in both systems using Dow figures and \$286/kW using University of Texas calculations. These costs would be very favorable and should probably be viewed as target values.

TABLE 2. Dow Figures for Geohydraulic Capital Costs
Source: Wilson, 1976 (Ref. 3)

<u>Item</u>	<u>Installed Cost (\$1000)</u>
Hydraulic Turbine	1100
Generator	448
TOTAL INSTALLED COST	\$1548

TABLE 3. Installed Costs for Geohydraulic Power
Plant as Itemized by the University of Texas
Source: Underhill, et al., 1976 (Ref. 14)

<u>Item</u>	<u>Installed Cost (\$1000)</u>
Generator	168
Instruments	145
Cable	14
Turbine	380
Controls	180
Lube Oil System	90
Foundations	630
TOTAL INSTALLED COSTS	\$1607

Under USGS Development Plan 1, the wells in each of the subarea categories would produce from 2.6 to 3.4 MW/well. Using a 6/10 factor for the economies of scale and the low costs for the 5.6 MW turbine, the unit cost for 3 MW wellhead units would increase to about \$340/kW.

To calculate unit generating costs for geohydraulic energy, we used a fixed annual charge rate on capital investment. The fixed annual charge

rate is the annual cost schedule which is equivalent to all costs related to capital investment. It includes provisions for return to equity and bond interest as well as a sinking fund to retire both equity and debt. It also includes property insurance and taxes and other federal, state and local taxes. The fixed charge rate equivalent to the preceding analyses, which were based on GEOCOST calculations, is about 18% for a 20-year plant life. Additional costs for operation and maintenance are assumed to be 1 mill/kWh.

When these factors are applied to the capital cost of \$340/kW for well-head units, the total unit generation cost is 10 mills/kWh. This bus bar cost for generating electricity from the geohydraulic energy available from geopressured waters is much lower than conventional generation costs. It is important to keep in mind, however, that the turbine proposed is a conceptual device (the technology for the generator is well established^(3,p34)) and, as such, there are large uncertainties in its cost. Also, in this analysis we have assumed that the geopressured water is available at the wellhead as a free commodity. Under these assumptions the cost of the geohydraulic power plant could be double the Dow estimates and still be competitive with current conventional power plants.

The calculated cost of 10 mills/kWh will be used in the next section dealing with cost/quantity relationships. However, the potential adverse impact of uncertainties in turbine cost and performance and electrical transmission costs should be kept in mind.

GEOPRESSURED ELECTRICAL SUPPLY

In this section the generation cost results (summarized in Appendix B) are combined with resource availability assessments (Appendix C) to derive cost/quantity relationships. Separate calculations are made for each production scenario and are presented in Appendix D. The relationship for Plan 2 has only one component: the supply of electricity from the thermal energy of the hot water from each of the subareas. Plans 1 and 3 have two components: the supply of electricity from the geohydraulic energy and the thermal energy. One of each type is derived here to demonstrate the method.

These cost/quantity relationships are developed by tabulating the subareas in order of ascending generation cost. In Table 4 this is done for the case using a binary thermal conversion cycle under Development Plan 1, which also includes geohydraulic energy. The combined geohydraulic energy from all areas is listed first because the estimated generation cost for this contribution is uniform and lower than all others. The quantity of available energy is taken from Table C-1, Appendix C.

This same reordering for the case using binary conversion cycle under Development Plan 2 is listed in Table 5. Under Development Plan 2 there is no geohydraulic contribution to supply. The cost figures are taken from Table B-2A, Appendix B, and the resource quantity data are from Table C-2, Appendix C.

The difference made by the geohydraulic contribution is more apparent when we approximate the data from Tables 4 and 5 with curves (Figure 7). The solid line with a break in it depicts the supply curve under Development Plan 1. The dashed line is the supply under Development Plan 2. If the cost estimates for geohydraulic electricity generation are correct, the potential impact of this energy source would be large and immediate.

The contribution from conversion of the thermal energy in the hot water is greater but more expensive than the geohydraulic energy. Under Development Plan 1 the thermal energy available is less than under Plan 2. This is caused by the greater well spacing which comes from the restriction

TABLE 4. Geopressured Geothermal Energy Supply Assuming Development Plan 1 and a Binary Thermal Conversion Cycle

<u>Subarea</u>	<u>Available Energy^a (1,000 MWe)</u>	<u>Total Generation Cost (Mills/kWh)</u>
Total for all Geohydraulic	49.9	10
AT1	7.4	22.2
DT1	6.3	23.5
CT1	9.0	24.3
ET1	6.9	25.8
FT1	2.3	26.4
DL6	4.2	28.4
EL5	8.4	29.0
EL6	9.5	29.2
DT2	3.7	29.3
DL5	6.1	30.1
ET2	1.4	31.3
BT1	6.6	32.3
ATL2	14.8	33.0
FL3	6.6	33.4
FL2	5.1	34.7
EL7	7.6	35.3
DT3	4.0	38.2
BT2	3.0	40.4
ET3	4.7	42.1
DTL4	2.3	49.5
ETL4	1.8	50.5

^aEquivalent electrical capacity assuming a 20 year operating life.

TABLE 5. Geopressured Geothermal Supply Assuming Development Plan 2 and a Binary Thermal Conversion Cycles

<u>Subarea</u>	<u>Available Energy^a (1,000 MWe)</u>	<u>Total Generation Cost (Mills/kWh)</u>
AT1	12.4	20.3
DT1	10.6	21.3
CT1	12.7	22.7
ET1	11.0	23.4
FT1	3.6	23.9
EL6	17.8	25.6
DL6	6.0	26.4
EL5	12.7	26.4
DT2	5.6	26.5
DL5	9.4	27.2
-BT1	5.1	27.2
ET2	2.4	27.2
ATL2	26.9	28.7
FL3	9.4	30.8
FL2	7.6	31.6
EL7	11.1	32.3
DT3	6.8	33.3
-BT2	12.9	35.1
ET3	6.1	39.1
DTL4	3.9	42.4
ETL4	3.0	43.2

^aEquivalent electrical capacity assuming a 20 year operating life.

FIGURE 7. Geopressured Geothermal Energy Supply

placed on wellhead pressure (see Appendix C for further explanation). This greater well spacing leads to fewer wells. Since each well produces at the same rate, the thermal production is less under Plan 1.

The greater well spacing under Plan 1 increases generation costs about 10% over Plan 2 due to larger temperature losses in the fluid collection system and longer pipe lines. The effect can best be seen by comparing Tables 4 and 5. In Table 4 each subarea has slightly higher generation costs than in Table 5. The generation costs under Development Plan 3 would be even higher because the well spacing in Plan 3 is greatest.

These cost/quantity relationships are based on 1975 cost estimates for geothermal power plants. New nuclear and coal power plants coming on line in that year would generate electricity for less than 20 mills/kWh. A new oil-fired plant would generate electricity at about 30 mills/kWh (\$12/bbl oil).

Thus, under the incremental cost only assumptions in this analysis, the geohydraulic energy would be competitive with other forms of energy. The geopressed thermal energy would not be competitive with nuclear or coal, but substantial quantities could be produced for less than 30 mills/kWh in competition with new oil plants.

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APPENDIX A

SUBAREA CHARACTERISTICS

APPENDIX A

SUBAREA CHARACTERISTICS

In its most recent geothermal resource assessment, USGS Circular 726,⁽¹⁾ the USGS has divided the geopressed geothermal resource into 21 idealized conceptual reservoirs. Each of these subareas is presumed to have a separate set of characteristics which are constant over the entire subarea.

The USGS also outlined three development plans which allow for more or less production based on the mechanical energy used and the level of subsidence allowed. Under these plans the flow rate per well is held constant. To obtain greater production from a subarea, more wells are put into the same area and thus the well spacing is reduced.

The characteristics for each of the subareas are provided in Table A-1. The well spacings listed were obtained by the methods outlined below. The other characteristics were taken from the tables in the Circular.

The well spacing for all subareas under Plan 1 is provided in Table 25, page 137 of Circular 726. The well spacing for Plan 2, under which the entire formation head is used during the 20-year production life, can be obtained by referring to Figure 16, pp. 134-135, in the Circular. To use this figure one needs to divide the well flow rate of $0.15 \text{ m}^3/\text{sec}$ by the "Hydraulic Head" number for the subarea from Table 23. The calculation yields the number on the vertical axis of Figure 16. With this number and the curve for the subarea, the well spacing can be read from the horizontal axis. For example, the hydraulic head for AT1 is 4750. If this is divided into the flow rate of $0.15 \text{ m}^3/\text{sec}$, the answer is:

$$\frac{0.15}{4750} = 3.16 \times 10^{-5} \text{ m}^3/\text{sec}/\text{meter drawdown during a 20-year production life.}$$

Using this number and the curve for the AT1 resource, the well spacing can be read from the horizontal axis as 2.4 km.

To obtain the well spacing for the subarea under Plan 3, a few more calculations are required. One must begin from the primary restriction of

Development Plan 3 which is that the average subsidence cannot exceed one meter during the 20-year production life. To estimate the volume of water that can be produced, the USGS offers the simplifying assumptions that the water contributed from storage in the shale beds will result in an equal compaction of the shale and that this will be transmitted to the surface without loss. Thus, the volume is equal to the area of the subarea times 1 m. Using this method (which employs the formulae on p. 145 of the Circular) and the volume of water produced by one well flowing at $0.15 \text{ m}^3/\text{sec}$ for 20 years, one can calculate the well spacings for Plan 3.

TABLE A-1. Characteristics of Geopressured Geothermal Subareas

Subarea	Average Temperature (°C)	Hydraulic Head (m)	Well Spacing ^(a)		
			Plan 1 (km)	Plan 2 (km)	Plan 3 (km)
AT1	186	4,750	3.1	2.4	6.3
ATL2	156	4,060	3.1	2.3	5.5
BT1	170	4,010	3.9	2.8	6.6
BT2	150	4,310	3.5	2.7	6.6
CT1	172	4,450	2.6	2.2	5.2
DT1	172	4,920	2.4	1.9	6.3
DT2	169	4,740	3.2	2.6	6.6
DT3	153	4,210	3.5	2.7	6.6
DTL4	141	4,220	3.7	2.9	7.1
DL5	164	5,360	2.9	2.4	6.6
DL6	160	5,590	2.5	2.1	6.0
ET1	168	4,300	2.4	1.9	4.7
ET2	166	4,560	3.2	2.4	6.4
ET3	146	4,170	3.2	2.8	6.1
ETL4	140	4,550	3.5	2.7	7.1
EL5	165	5,340	2.7	2.2	6.4
EL6	159	5,340	2.6	1.9	6.0
EL7	145	5,330	2.3	1.9	5.4
FT1	171	4,590	2.7	2.2	5.6
FL2	148	5,040	2.5	2.1	5.6
FL3	151	5,830	2.5	2.1	6.2

(a) If hexagonal packing of the wells is presumed, as is the case in GEOCOST, well spacing in acres is equal to $213 \times \text{km}^2$. For example, Plan 3 well spacing for subarea AT1 is equal to about 8500 acres.

APPENDIX B

COST OF GENERATING ELECTRICITY FROM THE GEOPRESSURED SUBAREAS

TABLE B-1A. Distribution of Generation Cost Under
Development Plan 1: Binary Conversion Cycle

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Power Plant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	9.9	12.3	22.2
ATL2	17.9	15.1	33.0
BT1	19.4	12.9	32.3
BT2	24.8	15.6	40.4
CT1	11.7	12.6	24.3
DT1	10.9	12.6	23.5
DT2	16.3	13.0	29.3
DT3	22.9	15.3	38.2
DTL4	32.6	16.9	49.5
DL5	16.6	13.5	30.1
DL6	14.2	14.2	28.4
ET1	12.7	13.10	25.8
ET2	17.9	13.4	31.3
ET3	25.6	16.5	42.1
ETL4	33.4	17.1	50.5
EL5	15.5	13.5	29.0
EL6	14.8	14.4	29.2
EL7	18.8	16.5	35.3
FT1	13.6	12.8	26.4
FL2	18.4	16.3	34.7
FL3	17.9	15.5	33.4

**TABLE B-1B. Distribution of Generation Cost Under Development Plan 1:
Total Flow**

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	7.8	14.5	22.3
ATL2	12.5	18.8	31.3
BT1	12.4	16.5	28.9
BT2	16.4	20.1	36.5
CT1	8.0	16.2	24.2
DT1	7.4	16.2	23.6
DT2	10.4	16.7	27.1
DT3	15.0	19.4	34.4
DTL4	20.7	22.3	43.0
DL5	10.3	17.4	27.7
DL6	9.3	18.1	27.4
ET1	8.2	16.7	24.9
ET2	10.5	17.1	27.6
ET3	15.7	20.9	36.6
ETL4	20.9	22.5	43.4
EL5	9.1	17.2	26.3
EL6	9.7	18.2	27.9
EL7	11.6	20.8	32.4
FT1	8.8	16.4	25.2
FL2	12.3	20.4	32.7
FL3	11.2	19.8	31.0

**TABLE B-1C. Distribution of Generation Cost Under Development Plan 1:
Flashed Steam**

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	13.4	12.7	26.1
ATL2	23.7	15.0	38.7
BT1	21.6	13.9	35.5
BT2	31.8	15.8	47.6
CT1	14.7	13.4	28.1
DT1	13.7	13.4	27.1
DT2	18.3	13.7	32.0
DT3	29.6	15.4	45.0
DTL4	42.8	17.1	59.9
DL5	18.9	14.1	33.0
DL6	17.9	14.5	32.4
ET1	14.2	13.7	27.9
ET2	19.7	13.9	33.6
ET3	32.2	16.3	48.5
ETL4	41.0	17.3	58.3
EL5	17.0	14.0	31.0
EL6	18.7	14.6	33.3
EL7	23.6	16.2	39.8
FT1	15.4	13.5	28.9
FL2	24.2	15.9	40.1
FL3	22.0	15.5	37.5

TABLE B-2A. Distribution of Generation Cost Under
Development Plan 2: Binary Conversion Cycle

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	7.9	12.4	20.3
ATL2	13.7	15.0	28.7
BT1	19.5	15.6	35.1
CT1	10.1	12.6	22.7
DT1	8.7	12.6	21.3
DT2	13.5	13.0	26.5
DT3	18.0	15.3	33.3
DTL4	25.5	16.9	42.4
DL5	13.8	13.4	27.2
DL6	12.2	14.2	26.4
ET1	10.3	13.1	23.4
ET2	13.8	13.4	27.2
ET3	22.7	16.4	39.1
ETL4	26.2	17.0	43.2
EL5	12.9	13.5	26.4
EL6	11.2	14.4	25.6
EL7	15.9	16.4	32.3
FT1	11.1	12.8	23.9
FL2	15.4	16.2	31.6
FL3	15.3	15.5	30.8

TABLE B-2B. Distribution of Generation Cost Under
Development Plan 2: Total Flow Conversion Cycle

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	5.7	14.5	20.2
ATL2	9.6	18.7	28.3
BT1	9.2	16.5	25.7
BT2	13.0	19.9	32.9
CT1	6.9	16.2	23.1
DT1	6.0	16.1	22.1
DT2	8.7	16.6	25.3
DT3	11.9	19.3	31.2
DTL4	16.3	22.2	38.5
DL5	8.6	17.3	25.9
DL6	8.0	18.0	26.0
ET1	6.7	16.7	23.4
ET2	8.2	17.1	25.3
ET3	13.9	20.9	34.8
ETL4	16.4	22.4	38.8
EL5	7.6	17.2	24.8
EL6	7.4	18.2	25.6
EL7	9.8	20.8	30.6
FT1	7.3	16.3	23.6
FL2	10.3	20.4	30.7
FL3	9.6	19.8	29.4

TABLE B-2C. Distribution of Generation Cost Under
Development Plan 2: Steam Conversion Cycle

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	10.6	12.4	23.0
ATL2	18.0	15.0	33.0
BT1	16.1	13.6	29.7
BT2	25.0	15.6	40.6
CT1	12.7	13.4	26.1
DT1	10.9	13.4	24.3
DT2	15.2	13.6	28.8
DT3	23.2	15.3	38.5
DTL4	33.3	17.1	50.4
DL5	15.6	14.1	29.7
DL6	15.3	14.4	29.7
ET1	11.5	13.7	25.2
ET2	15.2	13.9	29.1
ET3	28.5	16.2	44.7
ETL4	32.0	17.3	49.3
EL5	14.1	14.0	28.1
EL6	14.1	14.6	28.7
EL7	19.8	16.2	36.0
FT1	12.5	13.5	26.0
FL2	20.1	16.0	36.1
FL3	18.8	15.5	34.3

**TABLE B-3A. Distribution of Generation Cost Under
Development Plan 3: Binary Conversion Cycle**

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	19.0	12.4	31.4
ATL2	31.0	15.1	46.1
BT1	32.1	13.0	45.1
BT2	45.9	15.8	61.7
CT1	22.1	12.7	34.8
DT1	26.8	12.7	39.5
DT2	32.5	13.1	45.6
DT3	42.3	15.5	57.8
DTL4	65.9	17.1	83.0
DL5	31.9	13.7	45.6
DL6	32.3	14.4	46.7
ET1	23.4	12.9	36.3
ET2	34.6	13.5	48.1
ET3	47.6	16.6	64.2
ETL4	66.7	17.3	84.0
EL5	35.3	13.7	49.0
EL6	32.6	14.4	47.0
EL7	42.4	16.6	59.0
FT1	26.9	12.8	39.7
FL2	39.9	16.4	56.3
FL3	42.8	15.7	58.5

**TABLE B-3B. Distribution of Generation Cost Under
Development Plan 3: Total Flow Conversion Cycle**

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	14.9	14.6	29.5
ATL2	21.5	18.9	40.4
BT1	20.3	16.6	36.9
BT2	30.3	20.1	50.4
CT1	14.9	16.3	31.2
DT1	18.0	16.4	34.4
DT2	20.4	16.8	37.2
DT3	27.6	19.5	47.1
DTL4	40.9	22.5	63.4
DL5	22.3	17.6	39.9
DL6	21.0	18.1	39.1
ET1	14.8	16.8	31.6
ET2	20.2	17.2	37.4
ET3	28.8	21.2	50.0
ETL4	41.3	22.8	64.1
EL5	20.5	17.3	37.8
EL6	21.1	18.4	39.5
EL7	25.7	21.1	46.8
FT1	17.2	16.5	33.7
FL2	26.3	20.7	47.0
FL3	26.5	20.0	46.5

**TABLE B-3C. Distribution of Generation Cost Under
Development Plan 3: Steam Conversion Cycle**

<u>Category</u>	<u>Fluid Transmission (mills/kWh)</u>	<u>Powerplant (mills/kWh)</u>	<u>Total (mills/kWh)</u>
AT1	25.9	12.5	38.4
ATL2	41.2	15.1	56.3
BT1	36.4	13.7	50.1
BT2	59.4	15.9	75.3
CT1	28.2	13.5	41.7
DT1	34.2	13.5	47.7
DT2	36.7	13.8	50.5
DT3	55.1	15.6	70.7
DTL4	81.3	17.4	98.7
DL5	41.7	14.2	55.9
DL6	41.1	14.6	55.7
ET1	26.4	13.8	40.2
ET2	38.5	14.0	52.5
ET3	60.3	16.5	76.8
ETL4	82.3	17.6	99.9
EL5	39.0	14.2	53.2
EL6	41.5	14.7	56.2
EL7	53.7	16.4	70.1
FT1	30.5	13.6	44.1
FL2	53.0	16.1	69.1
FL3	53.1	15.7	68.8

APPENDIX C

THE GEOPRESSURED SUBAREAS UNDER THREE DEVELOPMENT PLANS

APPENDIX C

ASSESSMENT OF THE ENERGY RECOVERABLE FROM THE GEOPRESSURED SUBAREAS UNDER THREE DEVELOPMENT PLAN

Estimates of the energy recoverable from the hot water and the overpressured water are provided in the tables in this appendix. Table C-1 corresponds to the Development Plan 1 outline in the USGS Circular 726. Tables C-2 and C-3 correspond to Plans 2 and 3 of that Circular, respectively.

Data for Plan 1 were taken from Table 25 in the Circular. The thermal energy is that energy recoverable from the hot water. The mechanical energy is that energy recoverable from the overpressured water. The columns labeled "Equivalent Electrical Capacity for 20 Years" were not provided in Table 25 of the Circular, but can be calculated. To obtain the equivalent electrical capacity for 20 years for thermal energy, we apply an 8% thermal-to-electrical conversion efficiency factor^(a) to the total recoverable energy listed, then multiply resultant recoverable energy in joules times 0.316×10^{-15} MW-century/joule. This results in the number of MW-centuries that energy represents. Since each of the power plants will be operating for only 20 years, the equivalent electrical capacity for that time is 5 times the MW-century number. To obtain the equivalent electrical capacity for the mechanical energy, we apply an 80% mechanical-to-electrical conversion efficiency factor and then the same conversion of factors.

Under Plan 2 there is no mechanical energy recoverable because there is no restriction placed on wellhead pressure. The entire initial head of the wells is used up during the production life. Thus, we need only calculate the thermal energy recoverable and its electrical equivalent under this development plan. To accomplish this we take the well spacing as calculated in Appendix B, square it, and divide it into the subarea from Table 21 of the Circular. This gives us the number of wells in each

(a) For simplicity, we used a uniform 8% factor to apply to all temperatures and all conversion technologies. Uncertainty in the resource assessment data outweighs any refinement in the individual conversion efficiency.

subarea under this development plan. Each of these wells produces the same volume of water over the 20-year production life. To obtain this value, we multiply the flow rate $0.15 \text{ m}^3/\text{sec} \times 3.16 \times 10^7 \text{ sec/yr} \times 20 \text{ yr}$; this yields $9.48 \times 10^7 \text{ m}^3/\text{well}/20 \text{ yrs}$. We multiply the number of wells times the volume of water produced by one well over the 20-year production life and this yields the total volume of water produced in the subarea. To obtain the recoverable energy represented by this volume of water we need the subarea fluid density at the surface from Table 23 of the Circular and the average specific heat used by the USGS which is $4350 \text{ J/kg/}^\circ\text{C}$, and the subarea temperature. We subtract 15°C from the subarea temperature and multiply the result by the average specific heat, the surface density, and the total water volume produced in 20 years. The result is recoverable energy in joules. This recoverable energy is then multiplied by the 8% conversion efficiency factor and the other conversion factors used in the above paragraphs for Development Plan 1. The result is the equivalent electrical capacity for 20 years recoverable under Development Plan 2.

To calculate the thermal energy recoverable and its electrical equivalent under Development Plan 3, the process is the same as for Development Plan 2. These figures are listed in Table C-3. It is not necessary to calculate the mechanical energy recoverable and its electrical equivalent for each of the subareas under this development plan. Since we are calculating the recoverable mechanical energy to construct a supply curve, and since each of the wells will produce electricity from the mechanical energy at the same cost, we only need to obtain total mechanical energy available for all subareas under this development plan. The total thermal equivalent of the mechanical energy, 3.3×10^{18} calories, can be obtained from the data on page 138 of the Circular. The electrical equivalents of this mechanical energy can be obtained from page 139. The total equivalent capacity for 20 years of this mechanical energy is equal to 17,800 MW. These figures are also provided in Table C-3 of this appendix.

TABLE C-1. Recoverable Energy Under Development Plan 1

Subarea	Well Spacing (km)	Number of Wells	Water Produced (10^{10}m^3)	Thermal Energy (10^{18}J)	Thermal Energy Equiv. Elec. Capacity for 20 Yr (a) (GWe)	Mech. Energy (10^{18}J)	Mech. Energy Equiv. Elec. Capacity for 20 Yr (b) (GWe)
AT ₁	3.1	930	8.80	58.5	7.4	2.1	2.7
ATL ₂	3.1	2,180	20.64	117.1	14.8	4.5	5.7
BT ₁	3.9	890	8.43	52.2	6.6	1.8	2.3
BT ₂	3.5	450	4.20	23.6	3.0	1.0	1.3
CT ₁	2.6	1,210	11.46	71.5	9.0	2.6	3.3
DT ₁	2.4	840	7.95	49.6	6.3	1.9	2.4
DT ₂	3.2	500	4.73	29.3	3.7	1.1	1.4
DT ₃	3.5	600	5.68	31.9	4.0	1.3	1.6
DTL ₄	3.7	370	3.50	18.4	2.3	0.8	1.0
DL ₅	2.9	830	7.86	48.4	6.1	2.1	2.7
DL ₆	2.5	590	5.59	33.3	4.2	1.5	1.9
ET ₁	2.4	930	8.80	54.2	6.9	2.0	2.5
ET ₂	3.2	190	1.80	10.8	1.4	0.4	.5
ET ₃	3.2	730	6.91	37.0	4.7	1.5	1.9
ETL ₄	3.5	280	2.65	13.9	1.8	0.6	.8
EL ₅	2.7	1,110	10.51	66.2	8.4	2.8	3.5
EL ₆	2.6	1,310	12.40	75.1	9.5	3.3	4.2
EL ₇	2.3	1,180	11.17	59.8	7.6	2.9	3.7
FT ₁	2.7	310	2.93	18.1	2.3	0.7	.9
FL ₂	2.5	750	7.10	40.1	5.1	1.8	2.3
FL ₃	2.5	980	9.28	52.0	6.6	2.6	3.3
TOTALS					121.7		49.9

(a) 8% Thermal-to-electrical conversion efficiency assumed.

(b) 80% Mechanical-to-electrical conversion efficiency assumed.

TABLE C-2. Recoverable Energy Under Development Plan 2

<u>Subarea</u>	<u>Well Spacing (km)</u>	<u>Number of Wells</u>	<u>Water Produced (10^{10}m^3)</u>	<u>Thermal Energy (10^{18}J)</u>	<u>Equiv. Elec. Capacity^(a) for 20 Yr (GWe)</u>
AT ₁	2.4	1,553	14.7	97.8	12.4
ATL ₂	2.3	3,962	37.6	213.1	26.9
BT ₁	2.8	1,733	16.4	101.9	12.9
BT ₂	2.7	767	7.3	40.3	5.1
CT ₁	2.2	1,700	16.1	100.5	12.7
DT ₁	1.9	1,420	13.5	84.0	10.6
DT ₂	2.6	762	7.2	44.7	5.6
DT ₃	2.7	1,018	9.7	54.1	6.8
DTL ₄	2.8	628	6.0	31.2	3.9
DL ₅	2.3	1,270	12.1	74.1	9.4
DL ₆	2.1	845	8.0	47.8	6.0
ET ₁	1.9	1,495	14.2	87.3	11.0
ET ₂	2.4	336	3.2	19.1	2.4
ET ₃	2.8	952	9.0	48.4	6.1
ETL ₄	2.7	474	4.5	23.5	3.0
EL ₅	2.2	1,682	15.0	100.3	12.7
EL ₆	1.9	2,451	23.2	140.5	17.8
EL ₇	1.9	1,730	16.4	87.8	11.1
FT ₁	2.2	490	4.7	28.7	3.6
FL ₂	2.0	1,120	10.6	59.9	7.6
FL ₃	2.1	1,392	13.2	74.0	9.4
TOTAL					<u>197.0</u>

^(a) 8% Thermal-to-electrical conversion assumed

TABLE C-3. Recoverable Energy Under Development Plan 3

<u>Subarea</u>	<u>Well Spacing (km)</u>	<u>Number of Wells</u>	<u>Water Produced ($10^{10}m^3$)</u>	<u>Thermal Energy ($10^{18}J$)</u>	<u>Equiv. Elec. Capacity for 20 Yr^(a) (GWe)</u>
AT ₁	6.31	224	2.1	14.1	1.8
ATL ₂	5.5	692	6.6	37.3	4.7
BT ₁	6.6	311	3.0	18.3	2.3
BT ₂	6.6	128	1.2	6.7	.9
CT ₁	5.2	308	2.9	18.2	2.3
DT ₁	6.3	122	1.2	7.2	.9
DT ₂	6.6	118	1.1	6.9	.9
DT ₃	6.6	170	1.6	9.1	1.1
DTL ₄	7.1	102	1.0	5.1	.6
DL ₅	6.6	160	1.5	9.4	1.2
DL ₆	6.0	104	1.0	5.9	.7
ET ₁	4.7	249	7.4	14.6	1.8
ET ₂	6.4	47	.4	2.7	.3
ET ₃	6.1	204	1.9	10.4	1.3
ETL ₄	7.1	69	.7	3.4	.4
EL ₅	6.4	196	1.9	11.7	1.5
EL ₆	6.0	247	2.3	14.2	1.8
EL ₇	5.4	215	2.0	10.9	1.4
FT ₁	5.6	73	.7	4.3	.5
FL ₂	5.6	148	1.4	8.0	1.0
FL ₃	6.2	158	1.5	8.4	1.1

TOTAL Electrical Equivalent to Thermal Energy: 28,500 MWe^(a)

TOTAL Electrical Equivalent to Mechanical Energy: 17,800 MWe^(b)

(a) 8% Thermal-to-electrical conversion efficiency assumed

(b) 80% Mechanical-to-electrical conversion efficiency assumed

APPENDIX D

GEOPRESSURED GEOTHERMAL SUPPLY FOR ALL PRODUCTION SCENARIOS

TABLE D-1A. Geopressured Geothermal Supply Assuming Development Plan 1 and a Binary Thermal Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	49.9	10.0
AT1	7.4	22.2
DT1	6.3	23.5
CT1	9.0	24.3
ET1	6.9	25.8
FT1	2.3	26.4
DL6	4.2	28.4
EL5	8.4	29.0
EL6	9.5	29.2
DT2	3.7	29.3
DL5	6.1	30.1
ET2	1.4	31.3
BT1	6.6	32.3
ATL2	14.8	33.0
FL3	6.6	33.4
FL2	5.1	34.7
EL7	7.6	35.3
DT3	4.0	38.2
BT2	3.0	40.4
ET3	4.7	42.1
DTL4	2.3	49.5
ETL4	1.8	50.5

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-1B. Geopressured Geothermal Supply Assuming Development Plan 1 and a Total Flow Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	49.9	10.0
AT1	7.4	22.3
DT1	6.3	23.6
CT1	9.0	24.2
ET1	6.9	24.9
FT1	2.3	25.2
EL5	8.4	26.3
DT2	3.7	27.1
DL6	4.2	27.4
ET2	1.4	27.6
DL5	6.1	27.7
EL6	9.5	27.9
BT1	6.6	28.9
FL3	6.6	31.0
ATL2	14.8	31.3
EL7	7.6	32.4
FL2	5.1	32.7
DT3	4.0	34.4
BT2	3.0	36.5
ET3	4.7	36.6
DTL4	2.3	43.0
ETL4	1.8	43.4

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-1C. Geopressured Geothermal Supply Assuming Development Plan 1 and a Steam Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	49.9	10.0
AT1	7.4	26.1
DT1	6.3	27.1
ET1	6.9	27.9
CT1	9.0	28.1
FT1	2.3	28.9
EL5	8.4	31.0
DT2	3.7	32.0
DL6	4.2	32.4
DL5	6.1	33.0
EL6	9.5	33.3
ET2	1.4	33.6
BT1	6.6	35.5
FL3	6.6	37.5
ATL2	14.8	38.7
EL7	7.6	39.8
FL2	5.1	40.1
DT3	4.0	45.0
BT2	3.0	47.6
ET3	4.7	48.5
ETL4	1.8	58.3
DTL4	2.3	59.9

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-2A. Geopressured Geothermal Supply Assuming Development Plan 2 and a Binary Thermal Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
AT1	12.4	20.3
DT1	10.6	21.3
CT1	12.7	22.7
ET1	11.0	23.4
FT1	3.6	23.9
EL6	17.8	25.6
DL6	6.0	26.4
EL5	12.7	26.4
DT2	5.6	26.5
DL5	9.4	27.2
BT1	5.1	27.2
ET2	2.4	27.2
ATL2	26.9	28.7
FL3	9.4	30.8
FL2	7.6	31.6
EL7	11.1	32.3
DT3	6.8	33.3
BT2	12.9	35.1
ET3	6.1	39.1
DTL4	3.9	42.4
ETL4	3.0	43.2

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-2B. Geopressured Geothermal Supply Assuming Development Plan 1 and a Total Flow Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
AT1	12.4	20.2
DT1	10.6	22.1
CT1	12.7	23.1
ET1	11.0	23.4
FT1	3.6	23.6
EL5	12.7	24.8
DT2	5.6	25.3
ET2	2.4	25.3
EL6	17.8	25.6
BT1	12.9	25.7
DL5	9.4	25.9
DL6	6.0	26.0
ATL2	26.9	28.3
FL3	9.4	29.4
EL7	11.1	30.6
FL2	7.6	30.7
DT3	6.8	31.2
BT2	5.1	32.9
ET3	6.1	34.8
DTL4	3.9	38.5
ETL4	3.0	38.8

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-2C. Geopressured Geothermal Supply Assuming Development Plan 2 and a Steam Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
AT1	12.4	23.0
DT1	10.6	24.3
ET1	11.0	25.2
FT1	3.6	26.0
CT1	12.7	26.1
EL5	12.7	28.1
EL6	17.8	28.7
DT2	5.6	28.8
ET2	2.4	29.1
BT1	12.9	29.7
DL5	9.4	29.7
DL6	6.0	29.7
ATL2	26.9	33.0
FL3	9.4	34.3
EL7	11.1	36.0
FL2	7.6	36.1
DT3	6.8	38.5
BT2	5.1	40.6
ET3	6.1	44.7
DTL4	3.9	50.4
ETL4	3.0	49.3

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-3A. Geopressured Geothermal Supply Assuming Development Plan 3 and a Binary Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10⁵ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	17.8	10.0
AT1	1.8	31.4
CT1	2.3	34.8
ET1	1.8	36.3
DT1	.9	39.5
FT1	.5	39.7
BT1	2.3	45.1
DT2	.9	45.6
DL5	1.2	45.6
ATL2	4.7	46.1
DL6	.7	46.7
EL6	1.8	47.0
ET2	.3	48.1
EL5	1.5	49.0
FL2	1.0	56.3
DT3	1.1	57.8
FL3	1.1	58.5
EL7	1.4	59.0
BT2	.9	61.7
ET3	1.3	64.2
DTL4	.6	83.0
ETL4	.4	84.0

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-3B. Geopressured Geothermal Supply Assuming Development Plan 3 and a Total Flow Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	17.8	10.0
AT1	1.8	29.5
CT1	2.3	31.2
ET1	1.8	31.6
FT1	.5	33.7
DT1	.9	34.4
BT1	2.3	36.9
DT2	.9	37.2
ET2	.3	37.4
EL5	1.5	37.8
DL6	.7	39.1
EL6	1.8	39.5
DL5	1.2	39.9
ATL2	4.7	40.4
FL3	1.1	46.5
EL7	1.4	46.8
FL2	1.0	47.0
DT3	1.1	47.1
ET3	1.3	50.0
BT2	.9	50.4
DTL4	.6	63.4
ETL4	.4	64.1

^(a) Equivalent electrical capacity assuming a 20-year operating life.

TABLE D-3C. Geopressured Geothermal Supply Assuming Development Plan 3 and a Steam Conversion Cycle

<u>Subarea</u>	<u>Available Energy^(a) (10³ MWe)</u>	<u>Total Generation Cost (mills/kWh)</u>
Total Geohydraulic	17.8	10.0
AT1	1.8	38.4
ET1	1.8	40.2
CT1	2.3	41.7
FT1	.5	44.1
DT1	.9	47.7
BT1	2.3	50.1
DT2	.9	50.5
ET2	.3	52.5
EL5	1.5	53.2
DL6	.7	55.7
DL5	1.2	55.9
EL6	1.8	56.2
ATL2	4.7	56.3
FL3	1.1	68.8
FL2	1.0	69.1
EL7	1.4	70.1
DT3	1.1	70.7
BT2	.9	75.3
ET3	1.3	76.8
DTL4	.6	98.7
ETL4	.4	99.9

^(a) Equivalent electrical capacity assuming a 20-year operating life.

APPENDIX E

COST DISTRIBUTION AND CAPITAL COST
ESTIMATES FROM GEOCOST MODEL

APPENDIX E

COST DISTRIBUTION AND CAPITAL COST ESTIMATES FROM GEOCOST MODEL

FINANCING AND TAX ASSUMPTIONS

	<u>Water Production (%)</u>	<u>Power Plant and Water Collection System (%)</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

POWER PLANT CAPITAL COSTS

Subarea: AT1

Brine Temperature: 186°C

Power Cycle: Binary

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation & tanks	1798
1.2 Crane	224
1.3 Turbo generator	2643
1.5 Vapor generator (boiler)	1725
1.7 Auxiliary heat exchangers	0
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	879
1.12 Electrical support equipment	467
1.16 Condenser	1281
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1343
1.20 Binary fluid pumps	4312
1.99 SUBTOTAL 1.0	15027
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	732
2.99 SUBTOTAL 2.0	732
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	1667
5.2 Administration and indirect costs	1334
5.99 SUBTOTAL 5.0	3001
Total Power Plant Cost	19,675
Installed Cost	\$358/kWe (gross) \$453/kWe (net)
Internal Power Consumption	11.6 MWe
Net Power Output	43.4
Gross Power Output	55.0

POWER PLANT CAPITAL COSTS

Subarea: DL5
Brine Temperature: 164°C
Power Cycle: Binary

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation, & tanks	5984
1.2 Crane	224
1.3 Turbo generator	2930
1.5 Vapor generator (boiler)	1852
1.7 Auxiliary heat exchangers	0
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	823
1.12 Electrical support equipment	370
1.16 Condenser	1420
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1343
1.20 Binary fluid pumps	2426
1.99 SUBTOTAL 1.0	17727
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	735
2.99 SUBTOTAL 2.0	735
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	1938
5.2 Administration and indirect costs	1550
5.99 SUBTOTAL 5.0	3488
Total Power Plant Cost	22,865
Installed Cost	\$416/kWe (gross) 496/kWe (net)
Internal Power Consumption	8.9 MWe
Net Power Output	46.1 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: ET3

Brine Temperature: 164°C

Power Cycle: Binary

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation, & tanks	9262
1.2 Crane	224
1.3 Turbo generator	3369
1.5 Vapor generator (boiler)	2281
1.7 Auxiliary heat exchangers	0
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	922
1.12 Electrical support equipment	379
1.16 Condenser	1623
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1343
1.20 Binary fluid pumps	2181
1.99 SUBTOTAL 1.0	21939
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	737
2.99 SUBTOTAL 2.0	737
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	2359
5.2 Administration & indirect costs	1887
5.99 SUBTOTAL 5.0	4246
Total Power Plant Cost	27,837
Installed Cost	\$506/kWe (gross) \$608/kWe (net)
Internal Power Consumption	9.2 MWe
Net Power Output	45.8 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: AT1
Brine Temperature: 186°C
Power Cycle: Flashed Steam

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation & tanks	1814
1.2 Crane	224
1.3 Turbo generator	7548
1.6 Flashers (plant located units)	2576
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	718
1.12 Electrical support equipment	485
1.16 Condenser	1566
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	238
1.20 Cooling water pump	161
1.99 SUBTOTAL 1.0	17520
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	1897
2.99 SUBTOTAL 2.0	1897
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	2033
5.2 Administration & indirect costs	1627
5.99 SUBTOTAL 5.0	3660
Total Power Plant Cost	23,992
Installed Cost	\$436/kWe (gross) \$469/kWe (net)
Internal Power Consumption	3.8 MWe
Net Power Output	51.2 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: DL5
Brine Temperature: 164°C
Power Cycle: Flashed Steam

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation, & tanks	2473
1.2 Crane	224
1.3 Turbo generator	8235
1.6 Flashers (plant located units)	2808
1.9 Misc. process support equipment	157
1.10 Instrumentation & controllers	775
1.12 Electrical support equipment	520
1.16 Condenser	1728
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	270
1.20 Cooling water pump	175
1.99 SUBTOTAL 1.0	19398
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	2055
2.99 SUBTOTAL 2.0	2055
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering & design	2237
5.2 Administration and indirect costs	1789
5.99 SUBTOTAL 5.0	4026
Total Power Plant Cost	26,394
Installed Cost	\$480/kWe (gross) \$526/kWe (net)
Internal Power Consumption	4.8 MWe
Net Power Output	50.2 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: ET 3
Brine Temperature: 146°C
Power Cycle: Flashed Steam

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation & tanks	3526
1.2 Crane	224
1.3 Turbo generator	9146
1.6 Flashers (plant located units)	3171
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	858
1.12 Electrical support equipment	572
1.16 Condenser	1954
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	312
1.20 Cooling water pump	195
1.99 SUBTOTAL 1.0	22148
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	2274
2.99 SUBTOTAL 2.0	2274
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	2534
5.2 Administration and indirect costs	2027
5.99 SUBTOTAL 5.0	4561
Total Power Plant Cost	29,898
Installed Cost	\$544/kWe (gross) \$610/kWe (net)
Internal Power Consumption	6.0 MWe
Net Power Output	49.0 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: AT1
Brine Temperature: 186°C
Power Cycle: Total Flow

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation & tanks	210
1.2 Crane	224
1.3 Turbo generator	17384
1.9 Misc. process support equipment	157
1.10 Instrumentation & controllers	373
1.12 Electrical support equipment	225
1.16 Condenser	1238
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	199
1.20 Pumps	130
1.99 SUBTOTAL 1.0	22173
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	1579
2.99 SUBTOTAL 2.0	1579
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	2467
5.2 Administration and indirect costs	1973
5.99 SUBTOTAL 5.0	4440
Total Power Plant Cost	29,107
Installed Cost	\$529/kWe (gross) \$537/kWe (net)
Internal Power Consumption	.8 MWe
Net Power Output	54.2 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: DL5
Brine Temperature: 164°C
Power Cycle: Total Flow

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation & tanks	213
1.2 Crane	224
1.3 Turbo generator	21806
1.9 Misc. process support equipment	157
1.10 Instrumentation and controllers	405
1.12 Electrical support equipment	239
1.16 Condenser	1398
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	223
1.20 Pumps	146
1.99 SUBTOTAL 1.0	26844
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	1735
2.99 SUBTOTAL 3.0	1735
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering and design	2949
5.2 Administration and indirect costs	2360
5.99 SUBTOTAL 5.0	5309
Total Power Plant Cost	34,803
Installed Cost	\$633/kWe (gross) \$643/kWe (net)
Internal Power Consumption	.9 MWe
Net Power Output	54.1 MWe
Gross Power Output	55.0 MWe

POWER PLANT CAPITAL COSTS

Subarea: ET 3
Brine Temperature: 146°C
Power Cycle: Total Flow

<u>Account</u>	<u>(\$ 1000)</u>
1.0 Power plant	
1.1 Piping, insulation, & tanks	217
1.2 Crane	224
1.3 Turbo generator	27250
1.9 Misc. process support equipment	157
1.10 Instrumentation & controllers	441
1.12 Electrical Support Equipment	255
1.16 Condenser	1584
1.17 Installation testing	198
1.18 Buildings, foundations, & support equipment	1835
1.19 Gas ejectors (steam driven)	252
1.20 Pumps	163
1.99 SUBTOTAL 1.0	32576
2.0 Heat rejection system (cooling towers)	
2.1 Cooling tower system (forced draft wet)	1915
2.99 SUBTOTAL 2.0	1915
3.0 Switch yard	
3.99 SUBTOTAL 3.0	915
5.0 Other costs	
5.1 Engineering & design	3541
5.2 Administration and indirect costs	2832
5.99 SUBTOTAL 5.0	6373
Total Power Plant Cost	41,779
Installed Cost	\$760/kWe (gross) \$774/kWe (net)
Internal Power Consumption	1.0 MWe
Net Power Output	54.0 MWe
Gross Power Output	55.0 MWe

COST DISTRIBUTION

Subarea AT1
Binary Cycle
55 MWe Power Plant

	<u>mills/kWh</u>
Cost of Power	20.26
Initial Plant	6.52
Interim Capital Replacements	0.22
Energy Supply(a)	7.62
Operating Expenses	0.43
Property Taxes & Insurance	1.81
State Revenue Tax	0.81
State Income Tax	0.21
Federal Income Tax	1.37
Bond Interest	1.24
Total	20.26

(a) Primarily for brine collection system; assumes "free" brine.

COST DISTRIBUTION

Subarea DL5
Binary Cycle
55 MWe Power Plant

	<u>mills/kWh</u>
Cost of Power	27.21
Initial Plant	7.14
Interim Capital Replacements	0.24
Energy Supply(a)	13.20
Operating Expenses	0.44
Property Taxes & Insurance	1.98
State Revenue Tax	1.08
State Income Tax	0.23
Federal Income Tax	1.50
Bond Interest	1.36
Total	27.21

(a) Primarily for brine collection system; assumes "free" brine.

COST DISTRIBUTION

Subarea ET 3
Binary Cycle
55 MWe Power Plant

	<u>mills/kWh</u>
Cost of Power	39.10
Initial Plant	8.74
Interim Capital Replacements	.29
Energy Supply(a)	21.75
Operating Expenses	.51
Property Taxes & Insurance	2.43
State Revenue Tax	1.56
State Income Tax	.28
Federal Income Tax	1.83
Bond Interest	1.67
Total	39.10

(a) Primarily for brine collection system; assumes "free" brine.

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