**GEOCOST: A COMPUTER PROGRAM FOR
GEOTHERMAL COST ANALYSIS**

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SUMMARY

The GEOCOST computer program is a simulation model which calculates the cost of generating electricity from geothermal energy. GEOCOST will simulate the production of electricity from most types of geothermal resources. It is composed of two principal parts: a reservoir model which simulates the exploration, development, and operation of a geothermal reservoir, and a powerplant model which simulates the design, construction, and operation of the powerplant. Five different powerplant types can be simulated: flashed steam, binary fluid cycle, a hybrid combined flashed steam-binary fluid cycle, total flow, and geopressured reservoirs.

Sensitivity analysis can be performed, using the reservoir and powerplant models, to determine the relative effect of different economic parameters, assumptions, and uncertainties on the cost of generating electricity. The GEOCOST program can be used to:

- determine the economic incentives for specific geothermal research and development programs and projects,
- determine potential economic impacts of uncertainties in technology,
- identify major cost components of geothermal energy, and
- provide a systematic method for assessing the economic potential for each type of geothermal resource and power cycle.

Combined with resource assessment information, GEOCOST can be used to define the potential supply curve (price/quantity relationship) for geothermal energy. This supply curve forms the basis for: 1) assessing the potential role of geothermal energy in competition with other sources of energy, and 2) estimating potential economic incentives for new research and development programs.

GEOCOST can simulate nearly any financial and tax structure through varying the rates of return on equity and debt, the debt-equity ratios, and tax rates. The reservoir model and the powerplant model may have the same or separate financial structures and costs of capital. The plant and reservoir life can be varied over a long period, currently up to 50 years.

The GEOCOST program calculates the cost of energy based on the principle that the present worth of the revenues will be equal to the present worth of the expenses including investment return over the economic life of the plant and/or reservoir. The present worth factor is determined by the capital structure and rates of return on invested capital for the enterprise.

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GEOCOST: A COMPUTER PROGRAM FOR GEOTHERMAL COST ANALYSIS

INTRODUCTION

Geothermal energy, a potentially extensive and inexhaustible power source, may eventually be produced from several different types of resources whose characteristics and locations vary widely. Currently, only a few geothermal resources, consisting of dry steam or high temperature water capable of flashing to steam, are used to produce commercial electric power. The economic production of electricity from lower temperature water resources, high brine resources, geopressed resources, and hot, water-deficient resources will require the development of advanced power production technologies. Extensive government and industrial programs are currently underway to develop new resources and demonstrate potential economic power production using advanced technology.

In addition to the resource characteristics and the power recovery technology, the economics of geothermal power is affected by many other factors, such as geophysical and geological exploration and assessment techniques, drilling technology, fluid transmission technology, reservoir development and operation methods, plant operating conditions, tax rates and structure, financial conditions, and rates of return on invested capital.

A computer program, called GEOCOST, has been developed to rapidly and systematically calculate the potential costs of geothermal power. The GEOCOST program incorporates significant economic factors into one systematic framework and provides the flexibility to evaluate their individual economic impacts. This program will be expanded to include nonelectric uses and by-product values. This report describes the scope, capabilities, and flexibility of this computer program. A more detailed report documenting the program and a user's manual will be issued later.

GEOCOST CAPABILITIES

The GEOCOST program consists of deterministic cost models which simulate the production of electricity from each type of geothermal resource and powerplant design. These models relate the characteristics of geothermal reservoirs, powerplant designs, and economic factors to the cost of generating electricity. The input data are the wellhead conditions of the geothermal fluid, the powerplant design and capacity, and the design of the wells and well field. GEOCOST also includes an economic data file containing cost and tax data which are updated periodically. The code user may use the built-in data or specify any desired changes to the existing data file.

The flow diagram for GEOCOST is shown in Figure 1. The two main elements of the program are the reservoir and the powerplant models. Linkage between these two models is provided by the fluid transmission and the powerplant system submodels. The powerplant systems submodel calculates the total fluid flow requirements from the reservoir at the wellhead conditions. From this total flow the fluid transmission submodel calculates the number of wells required, pipe lengths and diameters, pumping requirements, and the temperature and pressure drop between the reservoir and the powerplant. The program iterates between the powerplant systems submodel, which calculates the additional flow required under the degraded fluid conditions, and the fluid transmission submodel, which provides the additional flow requirements by adding wells and determines the new temperature and pressure drop. Iteration continues until the flow to the powerplant converges within preset criteria.

After the required total fluid flow is established, the cash flow associated with the exploration, development, and operation of the reservoir from the beginning of exploration through the life of the powerplant is determined. From the cash flow, the required revenue from energy sales and the unit cost of energy from the reservoir are determined. The GEOCOST program solves for the unit cost of energy by equating the present worth of the revenues and expenses over the useful life of the powerplant.

Revenues are the product of net energy output and the unit cost. The net annual energy output and annual expenses are derived from the input data. The GEOCOST program provides for specifying any debt-equity ratio, any rate of return on equity, and any rate of interest on bonds. Bond interest expense is, of course, treated as a tax deductible expense. The program provides for incurring debt and equity at the specified ratio when expenses exceed revenues and repaying debt and equity in the same ratio when revenues exceed expenses. At the end of each project, debt and equity are exactly repaid and the project exactly earns the specified rate of return.

FIGURE 1. Economic Model for Geothermal Power Systems

The revenue to the reservoir is a cost to the powerplant. In the powerplant model, this cost is combined with the other powerplant capital and operating costs to generate the cash flow for constructing and operating the powerplant throughout its useful life. From the powerplant cash flow, the required revenue and unit cost of electricity are determined.

The major elements of the reservoir and powerplant model are discussed in more detail in later sections. An example case showing typical input and output from the program is described in Appendix A.

THE RESERVOIR MODEL

The reservoir model simulates a firm which explores for, discovers, develops, and operates a geothermal reservoir. The components of the energy costs supplied by the reservoir to the powerplant are computed and shown separately from the powerplant. This permits independent parametric analyses for the reservoir. The reservoir model includes submodels for simulating exploration and development costs, fluid transmission and disposal costs, drilling costs, and reservoir operating expenses. These submodels are described below:

EXPLORATION AND DEVELOPMENT

The exploration submodel* simulates the process by which a geothermal resource would be identified and evaluated. The approach used in the exploration model is to reduce the process to a series of discrete steps which have costs and success ratios assigned to them. These steps are: 1) identification of target areas, 2) preliminary land check, 3) preliminary geologic reconnaissance, 4) detailed land check and geologic reconnaissance, 5) identification of drillable sites, 6) exploratory drilling, 7) identification of the producible resource and 8) development.

Each of these eight major areas has a task description, time function, associated costs, decision points, and success ratios (finding rates). The reference cost values and finding rates are assigned on the basis of industry estimates. However, these values and rates are variable and sensitivity analyses can be performed to evaluate their relative importance.

On page A.3 of Appendix A, the sample case of the exploration and development costs is given. The desired result is one favorable site to be developed into a producing reservoir. This is indicated by the 1.00 final entry in the Favorable Sites Column. The number of favorable sites listed earlier in the column and associated with the discrete steps is

* Part of the input for this submodel has been taken from the works of R. Greider and M. J. Reed. (1,2)

determined by the assigned finding rates, page A.2 of Appendix A. With the exception of the drilling costs which are expensed differently, the Capitalized Costs column represents the unit cost for the associated task for one favorable site. These unit cost figures are input and can be varied.

In the present submodel the discrete steps occur sequentially in time with some specified time overlap. Each one of the steps may contain several sub-steps which occur parallel in time; e.g., Step 5, Identification of Drillable Sites, contains five geophysical exploration techniques which are being applied almost simultaneously. At the present time this is fixed in the submodel.

A purpose of the submodel is to permit the evaluation of different exploration strategies on costs, i.e. to change the time functions and task descriptions and finding rates. The most difficult values to estimate which affect costs are the finding rates because of the limited experience of geothermal exploration data. The model contains a provision to specify the total capacity of the reservoir and the fraction of the reservoir exploration cost which is to be allocated to an individual powerplant. In the example case, the reservoir capacity is 275 MWe and the powerplant size is 55 MWe; therefore, 20% of the exploration costs were allocated to this powerplant. (See footnote p. A.3).

All reservoir exploration costs are initially capitalized. As the sites are classified unfavorable through the success ratios, the costs which pertained to those sites are written-off as capital losses. The remaining capitalized costs for the favorable site are recovered through a cost depletion account (analogous to straight line depreciation) throughout the producing life of the powerplant.

The development submodel simulates the field development of the proven geothermal reservoir which was identified by the exploration submodel. This submodel accumulates all costs associated with reservoir development. These costs are calculated separately by the drilling, fluid transmission, and fluid disposal submodels. The development submodel includes provision for specifying the percentage of nonproducing

wells, capacity of injection wells, geometry of the well field, and the fraction of excess producing wells. Input data are shown on page A.3., Appendix A.

Reservoir development costs include only those costs required to develop and provide the energy supply to the specified powerplant; if the reservoir could support several powerplants, the costs of providing the energy supply to other powerplants would be treated separately. Reservoir development costs for the sample case are shown on p. A.3 under the heading, Field Development.

DRILLING

A submodel was developed for calculating drilling costs for geothermal wells as a function of the well depth, size of the well at the well bottom, the fraction of the well cased, and the hardness of the material being drilled. The component cost breakdown splits costs into tangible and intangible parts because tax regulations may treat these costs differently.

The GEOCOST program treats producing, nonproducing (dry), and injection wells differently. The tangible part of the producing wells is capitalized and expensed through a depreciation account. The intangible part is expensed immediately. However, the submodel would also permit all drilling costs for producing wells to be capitalized to test the sensitivity of power costs to the differential tax treatment. Non-producing wells are expensed. All costs, both the tangible and intangible, for injection wells are capitalized; these costs are recovered through the depreciation account.

Output of the drilling submodel is the total drilling cost, the tangible and intangible fractions, and the detailed distribution of the drilling costs. The elements of the cost distribution (Table 1) are taken from a 1969 industry cost study.⁽³⁾ Input data required for the drilling cost calculation are the depth, bottom hole diameter, fraction cased, and average rock hardness.

Tests of the submodel generally show good agreement between calculations and actual drilling costs. Expansion of the submodel to include functional variations like well temperature, well pressures, detailed casing structures, detailed hole-size steps, and regional effects is planned. Periodic updating of the model with price indexes is also planned to maintain good agreement between the calculated and the reported drilling costs. This submodel can also be used with a function tabulating and plotting routine⁽⁴⁾ already available to generate tables and plots of drilling cost in a stand-alone fashion.

TABLE 1. Example Drilling Cost Distribution
(Values rounded to nearest \$1000 or percent)

	<u>\$(Thousands)</u>	<u>% of Total</u>
Payments to Drilling Contractors	86	36
Road and Site Preparation	5	2
Transportation	2	1
Fuel	1	-
Drilling Mud & Additives	22	9
Well Site Logging and Monitoring	3	1
All Other Physical Tests	2	1
Logs & Wireline Evaluation Services	9	4
Directional Drilling Service	1	-
Perforate	1	-
Formation Treating	2	1
Cement & Cementing Service	11	5
Casing, Tubing, & Hardware	61	26
Special Tool Rentals	7	3
Drill Bits & Reamers	4	2
Wellhead Equipment	2	1
Other Equipment & Supplies	4	2
Plugging	1	-
Supervision & Overhead	5	2
All Other Expenditures	<u>8</u>	<u>3</u>
Total	238	100

RESERVOIR OPERATION

The operation submodel simulates the operation of the required reservoir capacity throughout the life of the powerplant. It is composed of several annual costs, e.g. royalty payments, injection costs, taxes, overhead and management, and well maintenance, which can be varied to examine their effect on the unit cost of power. Additionally, the operations submodel includes operating costs for the transmission and disposal systems as well as replacement well drilling and redrilling costs. All of the operating costs are assumed to be constant each year throughout the life of the powerplant. As with reservoir development costs, operating costs refer only to a single powerplant. All annual operating costs are expensed except for interim capital replacements. These are capitalized and recovered through the depreciation account. The tangible part of replacement producing wells is treated analogously to interim capital replacements. The intangible part of replacement producing wells is treated as an operating expense.

FLUID TRANSMISSION AND DISPOSAL

The fluid transmission submodel simulates the conduction of the geothermal fluid, either water or steam, from the wellhead to the powerplant. This submodel calculates the pipeline diameter, length, number of producing wells required, the well field layout, pumping requirements, and the costs of the transmission piping system, pumps, and associated equipment. It also calculates the fluid temperature, pressure, viscosity, density, and enthalpy on a node-by-node basis during transport from the wellhead to the plant. This submodel has been used to produce an economic description of a steam transmission system which correlates well with practice at The Geysers field.

The disposal submodel is analogous to the transmission submodel and simulates the conduction of water effluent from the wellheads and the powerplant to the injection well field. It calculates the effluent pipeline diameter and length, number of injection wells, injection well field layout, and the costs of the disposal piping system and associated equipment. Because of their similarity, only the transmission submodel is described in detail.

The cost of the fluid transmission and disposal systems establish the optimum powerplant size for a given geothermal resource. In general, powerplant costs show economies of scale and, therefore, decreased unit energy costs with increased plant size. However, because more wells are required which extends the distance of fluid transmission, pipeline and pumping costs increase very rapidly with plant size. The optimum plant size occurs when the marginal gain resulting from lower unit cost for larger powerplants is exactly offset by the marginal loss resulting from increasing unit costs for transmission and disposal.

Cost expressions for pipe, insulation, and appropriate pipeline components have been formulated for single phase flow conditions with water and steam. Pipeline costs are based on 1974 building construction cost data. Material, fitting and installation costs are expressed as a function of the pipe diameter and a scaling exponent. To reduce the influence of the transmission and disposal system on overall plant costs and performance, an optimization subroutine was developed to select optimum pipe diameters. Optimum pipe diameters are determined from economic trade-offs between pipeline cost, the value of friction energy lost in the pipeline, pump and drive motor capital costs, and the cost of power consumed in operating the pumps and motors.

The reservoir is described by a matrix of wellhead sites which are the nodes of the pipeline simulation. The wellheads are connected with pipe runs parallel to equilateral triangular coordinate axes. Pipeline diameters are sized and pipe scheduled on a node-by-node basis. Initially the economic optimization criteria identify the smallest practical diameters. An iterative routine changes the pipe diameter to avoid unacceptable fluid quality and correlates the pipeline design with fluid and thermodynamic conditions along its length. Pipe runs between nodes are sized by fluid mass flow rate, density, and viscosity. Multiple wellhead flashing is accommodated by up to four separate transmission lines for each quality of steam or hot water.

An insulation cost submodel was derived for the fluid transmission system. Vendor cost and heat conduction data were correlated to produce generalized cost and heat loss expressions. Of particular interest was the demonstration that an expression of the form,

$$h = \frac{a D^b T^c}{t^d}$$

where h is heat loss
D is pipe diameter
T is pipe temperature
t is insulation thickness

and a, b, c, and d are constants,

summarizes a vast amount of vendor-supplied engineering data which are usually available only in tabular form. Cost expressions for peripheral equipment such as flashers, separators, valves, pumps, motors and instrumentation were developed separately for inclusion with the transmission and disposal submodels.

The initial costs for the transmission and disposal systems are capitalized. Cost recovery is through the depreciation account using the sum-of-the-year's digit method.

Typical input to the transmission and disposal submodels is shown for a 55 MW_e isobutane cycle binary plant in Table 2. The corresponding output is shown in Table 3.

TABLE 2. Typical Input to Transmission and Disposal
Submodels for 55 MW_e Binary Plant

<u>Input Required for All Geothermal Plant Types^(a)</u>	
Geothermal plant type (1 = binary, 2 = steam, 3 = hybrid)	1
Average well flow rate (lb _m /sec)	119.4
Well spacing (acres)	11.2
Wellhead fluid temperature (°F)	392
Wellhead fluid pressure (psia)	256.7
Well life (yrs)	20
Fraction nonproducing wells	0.2
Fraction excess producing wells	.2
Total flow rate required by plant (lb _m /hr)	6154802
Maximum number of rows in well layout matrix	25
Maximum number of columns in well layout matrix	25
Transmission maintenance factor	0.05
Disposal maintenance factor	0.05
Fraction of pipe that can be salvaged	0.10
Plant net heat rate for fluid transmission line(s) (kW _t /kW _e)	14.28
Annualized cost factor	0.11
Plant Availability (hrs/yr) (85%)	7452
Value of output electric energy (\$/kW _e -hr)	0.02
Optional injection wells using well water effluent (0 = no, 1 = yes)	0
Optional injection wells using plant water effluent (0 = no, 1 = yes)	1
Ratio of injection/production well flow rate	2
Distance from well field to injection wells (m)	1000
Distance from plant to injection wells (m)	1000
Plant water effluent temperature (°F)	173.6
Plant water effluent pressure (psia)	160
Plant water effluent flow rate (lb _m /sec)	1709.7

Additional Input Required for Steam and Hybrid Plants

Location of flashers (0 = wellhead, 1 = plant)	
Number of flashing stages (NFLASH)	
Number of steam lines into powerplant (NFLOW)	
Steam flow rate required by plant in each steam line (lb _m /hr, I=1, NFLOW)	
Flashed steam temperatures (°F, I = 1, NFLASH)	
Flashed steam pressure (psia, I = 1, NFLASH)	
Effluent water temperature after final flashing (°F)	
Effluent water pressure after final flashing (psia)	

^aAlso includes built-in data base for computing well layout design, pipe schedule, pipe cost, insulation cost, cost of valves, gauges, separators, flashers, electric motors, and booster pumps; also data base for computing nodal temperature drop, nodal pressure drop, and electrical power required by booster pumps.

**TABLE 3. Typical Output from Transmission and Disposal
Submodels for 55 MW_e Binary Plant**

Number of fluid transmission lines to plant	1
Number of producing wells	18
Number of nonproducing wells	4
Throttled average well flow rate (lb _m /sec)	95
Pipe length between nodes (m)	250.6
Total transmission line and component costs (\$)	1405253
Pipe	793471
Insulation	303490
Wellhead valves	90000
Pressure gauges	18000
Rock separators	90000
Cyclone separator	35000
Wellhead flashers	0
Wellhead steam separators	0
Transmission booster pumps for water line	75292
Transmission maintenance cost (\$/yr)	70263
Transmission capital replacement rate (annual)	0.045
Final fluid conditions in transmission line at plant inlet	
Flow rate (lb _m /hr)	6154802
Temperature (°F)	391.7
Pressure (psia)	234.7
Number of fluid injection lines from plant to injection wells	1
Number of injection wells	8
Total injection line cost (\$)	678188
Injection maintenance cost (\$/yr)	33909
Injection capital replacement rate (annual)	0.045

Node-by-node matrices, illustrated here by showing the inlet properties at the first node and the exit properties from the last node prior to plant inlet^(a)

	First Node	Last Node
Well field design matrix numbering the wells	1	18
Matrix of number of wells upstream from each node	1	18
Matrices of well head fluid conditions		
Temperature (°F)	392	392
Pressure (psia)	256.65	256.65
Viscosity (lb/ft-sec)	10.18E-5	10.18E-5
Density (lb/ft ³)	54.15	54.15
Matrices of nodal fluid conditions		
Temperature (°F)	392	391.7
Pressure (psia)	256.65	236.4
Viscosity (lb/ft-sec)	9.00E-5	10.18E-5
Density (lb/ft ³)	54.15	54
Matrix of nodal internal pipe diameters (in)	7.1	26.7
Matrix of nodal pipe insulation thicknesses (in)	5	6

(a) Output for each plant cycle-transmission iteration and for each transmission line from well field to plant. Output results shown are for transmission line to plant. For the final plant cycle-transmission iteration satisfying the convergence criterion, analogous results are output for the injection line(s) and injection wells.

(b) The model operates on the assumption that all wells in the reservoir have the same average properties. However, variable well properties could be accommodated with minor code modification.

THE POWERPLANT SYSTEMS MODEL

The powerplant systems model simulates a firm which designs, constructs, and operates an electric generating plant. In this simulation, the firm purchases the energy supply from the firm which operates the geothermal reservoir. The powerplant systems model includes (1) submodels which simulate different power cycles and determine the fluid flow rates, thermodynamic properties, and the internal plant electrical consumption; and (2) functions for estimating major equipment and construction costs, operating and maintenance costs, water treatment costs, and outage rates. The major elements of this model are described below.

The geothermal powerplant systems model simulates the generation of electricity from several different types of power cycles. Based on the thermodynamic state of the geothermal fluid as it leaves the fluid transmission lines, this model predicts the mass flow rate of the geothermal fluid required for a specified electrical output. In addition to the fluid mass flow rate, the model also determines the physical and thermodynamic properties of numerous working fluids, the state points in the thermodynamic cycle being used, the size of various powerplant components, and the design performance of the powerplant.

Five different powerplant types can be simulated: flashed steam, binary fluid cycle, hybrid (flashed steam/binary fluid cycle), total flow and geopressured reservoirs. These powerplants are discussed in the following paragraphs.

STEAM PLANTS

The flashed steam submodel simulates electrical power generation from relatively high temperature reservoirs. The steam for this powerplant is generated by flashing hot geothermal water down to a reduced pressure. This flashed steam is subsequently expanded through a steam turbine which is coupled to an electrical generator. As an option, the submodel will also handle steam which is extracted directly from a geothermal well, similar to The Geysers area in California. After the steam is expanded through

the turbine, it is condensed in a barometric, contact-type condenser which is supplied with cooling water from a forced-draft, wet cooling tower. Noncondensable gases contained in the exhaust steam are removed from the condenser with a two-stage steam jet ejector. Excess water remaining after cooling tower evaporation is reinjected into the geothermal reservoir. The electrical consumption is calculated for internal power usage for cooling tower fans, cooling water pumps, and pumps for the geothermal fluid. This internal consumption is subtracted from the gross electrical output to yield the net electrical output. The flashed steam powerplant is illustrated in Figure 2. Typical input of this model is shown in Table 4.

FIGURE 2. Flash Steam Plant

TABLE 4. Typical Input to Flashed Steam Model

Gross Kilowatt Output (kW)	110000
Steam Temperature at Turbine Inlet (°F)	241
Absolute Steam Pressure at Turbine Inlet (psia)	25.44
Turbine Exhaust Pressure (psia)	2
Weight Fraction of Noncondensable Gases	0.01
Wet Bulb Air Temperature (°F)	65
Dry Bulb Air Temperature (°F)	80
Barometric Pressure (in. of Hg)	29.92
Humidity Ratio	0.40
Cooling Water Inlet Temperature (°F)	80
Intercondenser Exit Cooling Water Temperature (°F)	110
Aftercondenser Exit Cooling Water Temperature (°F)	120
Main Condenser Exit Cooling Water Temperature (°F)	120
Oil Cooler Exit Cooling Water Temperature (°F)	100
Hydrogen Cooler Exit Cooling Water Temperature (°F)	100
Dissolved Solids in Steam (%)	3

Typical output from the flashed steam model using the above input is listed in Table 5.

TABLE 5. Typical Output from Flashed Steam Model

Cooling Water Flow Rates

Intercondenser Flow (lb/hr)	2,305,000
Aftercondenser Flow (lb/hr)	1,960,000
Turbine Oil Cooler (lb/hr)	93,760
Hydrogen Generator Cooler (lb/hr)	356,300
Condenser Flow (lb/hr)	69,300,000
Temperature of Cooling Water into Tower (°F)	120

Internal Losses

KW Required for Fans (kW)	2,435
Condensate Pumps to Cooling Tower (kW)	1,539
Cooling Water Pumps (kW)	3,024
Cooling Tower Reinjection Pump (kW)	119
Flash Reinjection Pumps (kW)	3,558
KW Required for Vacuum Pump on Condenser (kW)	0
KW Required for Scrubber Pump (kW)	0
KW Required for Water Pressurizing Booster Pumps (kW)	0

TABLE 5. (Cont'd)

Overall Results

Actual Gross Steam Rate (lb/kW-hr)	27.9
Actual Gross Heat Rate (Btu/kW-hr)	32,440
Actual Net Steam Rate (lb/kW-hr)	32.3
Actual Net Heat Rate (Btu/kW-hr)	37,440
Average Net Steam Rate (lb/kW-hr)	32.3
Average Net Heat Rate (Btu/kW-hr)	37,450
Steam Flow to Turbine (lb/hr)	3,073,000
Total Steam Flow (lb/hr)	3,211,000
Total Wellhead Flow (lb/hr)	25,770,000
Total Cooling Water Requirements (lb/hr)	74,020,000
Cooling Tower Air Flow Rate (cfm)	16,810,000
Cooling Tower Evaporation Rate (lb/hr)	2,458,000
Heat Load of Cooling Tower (Btu/hr)	30,010,000 x 10 ²
Reinjection Rate-Blowdown (lb/hr)	752,600
Flash Reinjection Rate (lb/hr)	22,550,000
Internal Power Consumption (kW)	10,670
Net Power Output (kW)	99,330

BINARY FLUID CYCLE PLANT

In the binary fluid cycle plant, the geothermal fluid extracted from the reservoir is maintained as a liquid and is passed through a series of heat exchangers. Thermal energy is transferred from the hot water to a working fluid. The working fluid is vaporized and superheated and then expanded through a turbine. The cooled geothermal fluid is reinjected into the reservoir after passing through the heat exchangers. A schematic of this powerplant is shown in Figure 3. Both subcritical and supercritical binary cycles are available in this submodel. The input to the binary plant submodel is similar to that of the flashed steam, apart from the additional input of working fluid type and maximum working fluid temperature. Output of the binary plant submodel includes the same type of information as shown in Table 5, with the addition of data on the water-working fluid heat exchangers. Table 6 shows typical data from a 10 MW binary plant using geothermal water at an initial temperature of 392°F and isobutane as a working fluid.

FIGURE 3. Sub-Critical Binary Fluid Cycle Power Plant

This type of powerplant is frequently suggested when the geothermal fluid is highly saline, contains large quantities of noncondensable gases, or is at too low a temperature to justify flashing to steam.

HYBRID PLANT

The hybrid plant submodel is a combination of the flashed steam and the binary fluid cycle plant submodels, where the flashed steam section serves as the primary power generator, and the binary section is used as a bottoming cycle. Output of the hybrid plant model is similar to that of the flashed steam and binary cycle plant models.

TABLE 6. Heat Exchanger Summary

	<u>Preheater</u>	<u>Vaporizer</u>	<u>Super Heater</u>
Inside Heat Transfer Coefficient (Btu/hr-ft ² -°F)	2572	3097	3012
Tube Inside Diameter (ft)	0.1	0.1	0.1
Tube Outside Diameter (ft)	0.11	0.1	0.1
Number of Tubes	83	87	87
Equivalent Outside Diameter (ft)	0.05	0.05	0.05
Outside Heat Transfer Coefficient (Btu/hr-ft ² -°F)	2461	7848	2576
Overall Heat Transfer Coefficient (Btu/hr-ft ² -°F)	929.8	--	1005
Heat Transfer Area (ft ²)	2573	--	1222
Heat Transfer Length (ft)	89.4	15.2	40.5
Working Fluid			
Inlet Temperature (°F)	89.4	262.7	262.7
Inlet Pressure (psia)	476.2	476.2	476.2
Inlet Enthalpy (Btu/lb)	-792.5	-656.3	-612.5
Outlet Temperature (°F)	262.7	262.7	350
Outlet Pressure (psia)	476.2	476.2	476.2
Outlet Enthalpy (Btu/lb)	-656.3	-612.5	-544
Water			
Inlet Temperature (°F)	292.7	331.5	392
Inlet Pressure (psia)	305.5	280.5	255.5
Outlet Temperature (°F)	172.4	292.7	331.5
Outlet Pressure (psia)	280.5	255.5	230.5

TOTAL FLOW PLANT

The total flow submodel is based on work currently underway at the Lawrence Livermore Laboratories.⁽⁵⁾ The thermal energy contained in a two-phase mixture of geothermal fluid is converted to kinetic energy by expansion through a converging-diverging nozzle. This kinetic energy

drives a modified impulse turbine which is coupled to a generator. The total flow powerplant provides output similar to the other powerplant submodels.

GEOPRESSURED PLANTS

The geopressured plant submodel is specifically designed to extract energy from highly pressurized, relatively low temperature, geothermal reservoirs. These reservoirs are commonly called geopressured regions. Two unique aspects of the geopressured submodel are the potential utilization of the kinetic energy and methane, which are contained in the geopressure fluid. The geopressured plant can be simulated as either a binary fluid cycle plant or total flow plant. The submodel permits methane to be either sold or used to superheat the working fluid for the binary fluid cycle.

WORKING FLUID PROPERTIES

Numerous fluid properties are required in order to operate the five different powerplants discussed in the preceding paragraphs. A major portion of the powerplant systems model consists of the calculation of thermodynamic and physical properties of working fluids. Working fluids which are now available for use in the model include water, R-11, R-12, R-21, R-22, R-113, R-114, isobutane and n-butane. The capability exists for the addition of other working fluids such as ammonia, propylene, ethylene, and numerous fluorocarbons. Physical properties for these working fluids are stored in the model as functions of phase and temperature. Properties available from the data matrix include specific heat, thermal conductivity, density, viscosity, critical pressure, critical temperature, surface tension, and molecular weight.

Thermodynamic properties of the working fluids are calculated using two equations of state, not tabulated data. The Martin-Hou equation of state was used for the fluorocarbons and the Benedict-Webb-Rubin (BWR) equation of state was used for hydrocarbons.^(6,7) Properties which can

be calculated using these equations of state include pressure (psia), temperature ($^{\circ}\text{R}$), enthalpy (Btu/lb), entropy (Btu/lb/ $^{\circ}\text{R}$), and specific volume (ft^3/lb). These properties are used in the model to formulate the thermodynamic power cycle from various state points. The predicted thermodynamic properties agree well with tabular data. With the capability of determining properties of various working fluids, the powerplant systems model is able to evaluate various geothermal powerplant systems with varying source and sink temperatures for numerous working fluids.

POWERPLANT CAPITAL COSTS

The capital cost submodel generates capital cost data for geothermal powerplants. Capital costs as a function of power level and/or geothermal fluid or other process conditions are computed specifically for the powerplant, heat rejection system, and the switchyard. Equipment cost data were gathered from two primary sources: industry vendors and utility operators of geothermal powerplants. Binary plant costs were developed by analyses of the several cost proposals, estimates, and papers for these plants. The major component data were also checked with potential vendors. Much of the published cost data were pre-1974 and these were updated with indices to 1974 costs.

Total powerplant and installed equipment cost correlations (in 1974 dollars) were prepared by analyzing cost data for major plant components. Plant costs were correlated primarily as a function of power level and/or steam or working fluid flow rates. Costs for established dry steam and flash plants are shown in Figure 4. Estimates for total steam plant costs under similar temperature and flow conditions as generated from the individual cost equations correlated well with these data. The dependence of plant component costs as a function of steam and/or working fluid mass flow rates provides the sensitivity of total plant costs to geothermal fluid conditions. The cost routines are now operable for the flash, binary, and hybrid plants.

FIGURE 4. Installed Flash Plant Cost (w/o Field or Transmission) versus Plant Power, MWe

The flash plant uses the geothermal energy in the following modes which are reflected in the options built into the flash plant and reservoir cost routines: (1) steam flashed and separated (single flash cycle) or dry steam at the wellhead, (2) water transmitted to the plant and flashed and separated (single flash cycle) at the plant site, and (3) multiple flash combinations of options 1 and 2. The binary plant uses the geothermal fluid as a heat source for the binary working fluid. The hybrid plant uses both flashed steam as a working fluid and the flash effluent (bottoms) of a heat source for a binary cycle. Major component costs are set up in a decimal indexing system specific to each plant type. Cost data are correlated to the simple equation:

$$\text{Installed cost} = a + b(x)^S,$$

where

a reflects fixed costs and

b reflects materials, equipment, and installation dependent costs,

s is a size scale factor, and

x is the independent variable such as geothermal fluid flow rate,
plant power, working fluid flow rate or other process flow
rate.

Table 7, from the GEOCOST printout, illustrates the typical output for the plant cost model. A 350°F geothermal fluid binary plant is shown in this example. The different account categories treat the major plant components and costs. The decimal break-down within these categories provides the economic detail for specific equipment and/or cost items. Table 8 presents the same data for a 390°F geothermal fluid flash plant. The high cost of this plant is primarily due to the small plant size and low enthalpy of the flashed steam and the resultant high steam flow requirements.

TABLE 7. Installed Plant Cost - 10 MWe Binary
Isobutane Plant 350°F Geothermal Fluid
(500,000 lb/hr/well;
isobutane = 0.98E6 lb/hr;
total geothermal F.R. = 1.45E6 lb/hr)

<u>Account</u>		<u>Costs</u> <u>(\$1000)</u>
1.0	<u>Powerplant</u>	
1.1	Piping, Insulation, & Pumps	135
1.2	Crane	98
1.3	Turbo Generator	545
1.5	Vapor Generator (Boiler)	262
1.7	Auxiliary Heat Exchanger	115
1.9	Misc. Process Support Equip.	26
1.10	Instrumentation and Controllers	101
1.12	Electrical Support and Equip.	119
1.16	Condenser	171
1.17	Installation Testing	16
1.18	Buildings, Foundations, and Support Equipment	<u>190</u>
1.99	Total 1.0	1778

TABLE 7. Cont'd

2.0	<u>Heat Rejection System (Cooling Towers)</u>	
2.1	Cooling Tower System	<u>604</u>
2.99	Total 2.0	604
3.0	<u>Switch Yard</u>	
3.99	Total 3.0	200
5.0	<u>Other Costs</u>	
5.1	Engineering and Design	258
5.2	Administration and Indirect Costs	<u>207</u>
5.99	Total 5.0	465
	Total Powerplant Cost	3047

TABLE 8. Installed Plant Cost

10 MWe Flash Plant
390°F Geothermal Fluid (all water basis)

<u>Account</u>		<u>Costs (\$1000)</u>
1.0	<u>Powerplant</u>	
1.1	Piping, Insulation, & Pumps	89
1.2	Crane	134
1.3	Turbo Generator	1500
1.6	Flashers (Plant Located Units)	208
1.9	Misc. Process Support Equip.	26
1.10	Instrumentation and Controllers	134
1.12	Electrical Support and Equip.	119
1.16	Condenser	447
1.17	Installation Testing	29
1.18	Buildings, Foundations, and Support Equipment	212
1.19	Gas Ejectors (Steam Driven)	<u>111</u>
1.99	Total 1.0	3009
2.0	<u>Heat Rejection System (Cooling Towers)</u>	
2.1	Cooling Tower System	<u>652</u>
2.99	Total 2.0	652
3.0	<u>Switch Yard</u>	
3.99	Total 3.0	200
5.0	<u>Other Costs</u>	
5.1	Engineering and Design	386
5.2	Administration and Indirect Costs	<u>309</u>
5.99	Total 5.0	695
	Total Powerplant Cost	4556

ANNUAL POWERPLANT EXPENSES AND TAXES

Annual powerplant expenses include four items: operating costs, maintenance costs, interim capital replacements, and property insurance. In addition, the program provides for revenue taxes, property taxes, and state and Federal income taxes. The expression for annual operating costs is a function of plant size and was derived from utility statistics: $\text{operating cost} = 1455 (\text{MW}_e)^{0.9}$. The annual maintenance costs are a function of plant capital cost: $\text{maintenance cost} = 0.004 (\text{plant capital cost})$. Interim capital replacements are a function of plant capital cost: $\text{interim capital replacement} = K (\text{plant capital cost})$. The rate, K , is a variable specified by input. Property taxes and property insurance are similarly functions of plant capital cost and each rate is also variable.

The program provides for a gross revenue tax at a rate specified by input. The program also provides for both state and Federal income taxes, each rate specified through input. The program treats state income taxes as deductible expenses for Federal income taxes; but Federal income taxes are not deductible for state income taxes.

Plant capital costs, including interim capital replacements, are recovered through the depreciation account. Accounting for depreciation is based on sum-of-the-year's digit method.

CHEMISTRY

The chemistry submodel treats the effects of geothermal fluid temperature, steam/water ratio, pH, silica, H_2S , salinity, CO_2 , and calcite ($CaCO_3$). Material selection, costs, and lifetimes, as well as process and maintenance costs options, are produced by the submodel for cost effectiveness comparison and evaluation.

The chemistry submodel analytically describes the various components of plant construction, operating expenses, and cost increments which are affected by the geothermal fluid chemistry. These include: (1) reservoir well casings, piping, pumps, steam separators, and associated equipment; (2) plant piping, heat exchangers, scrubbers, etc.; (3) reinjection systems, including wells, piping, and pumps; (4) equipment lifetimes and maintenance requirements for the reservoir, plant, and reinjection systems; and (5) processes for modifying the chemistry of the fluid, including gas removal, pH and other chemical shimming, as well as filtering and settling particulates in the plant effluents.

A study of the effects of geothermal fluid chemistry on plant operations and component costs is presented in a report prepared for this program.⁽⁸⁾ This report, along with chemical industry data, provides the basis for estimating the cost effects of geothermal fluid chemistry.

The chemistry submodel computes process costs, process equipment capital costs, chemical disposal costs, and equipment capital, maintenance, and replacement costs as affected by system chemistry. Process requirements are treated as additional cost items in the plant capital and operating expenses. Plant and system equipment costs which are affected by fluid chemistry are treated as incremental costs over the base costs. Economic trade-offs exist for these items among initial investment, maintenance, and replacement lifetimes. The submodel, for instance, will analyze the trade-off between reinjection formation plugging, avoidance maintenance (such as hydrofracturing), and effluent filtration and treatment.

At present the GEOCOST chemistry submodel is limited to the materials selection subroutines for reservoir and powerplant components described below. A similar set of models are under development for maintenance procedures, costs, and fluid treatment options; these are not yet sufficiently refined to describe in this report.

MATERIAL SELECTION FOR FIELD PIPING, WELL CASINGS, AND FIELD EQUIPMENT

The material requirements for field piping, well casings, and field equipment are based primarily on the pH. Other contaminants may have secondary effects on material selection, mainly in the maintenance category, and are treated in other portions of the chemistry submodel. Table 9 provides data for field equipment material selection.

TABLE 9. Material Selection for Geothermal Field Equipment

Fluid	Temp. °F	pH	Material	Cost Factor	Years Service Life
Steam	All	NA	Carbon Steel ^(a)	1.0	30
Water	200-400	7+	Carbon Steel ^(a)	1.0	30
Water	200-400	6-7	Lined Steel or Similar Clad Material ^(a)	2.0	10
Water	200-400	4-6	Lined Steel or Similar Clad Material ^(a)	2.0	5
Water	200-400	<4	Hastelloy C or Similar Alloy	10	30
<u>Condensate and ReInjection Water</u>					
Water	<200	<4	Carbon Steel	1.0	2
Water	<200	All pH Cl Free ^(b)	316 Stainless Steel	2.0	30
Water	<200	<4	Hastelloy C or Similar Alloy	10	30
Water	<200	4-6	Carbon Steel	1.0	5
Water	<200	4-6	Lined Carbon Steel	2.0	15
Water	<200	5-6	Carbon Steel	1.0	15
Water	<200	7+	Carbon Steel	1.0	30+

(a) Process equipment such as valves, flashers, and pumps are assumed to be constructed of materials with corrosion resistance superior to the base pipe material.

(b) Cl <50 ppm.

MATERIAL SELECTION FOR POWERPLANT COMPONENTS

The material selection subroutine for the plant is based on the following:

- (1) Flash Plant - All process plant components are exposed to flashed steam or steam condensate with the exception of plant-located flashers (if used). Plant-located flashers will have the same requirements as the vapor generator cited in (2) below.
- (2) Binary Plant - Only the vapor generator (boiler) and other process auxiliary heat exchangers are exposed to the geothermal fluid.

Table 10 provides material selection data for the geothermal powerplant. As in the case of field equipment, pH considerations generally dominate the selection of the appropriate material.

TABLE 10. Geothermal Powerplant Material Selection

<u>Fluid</u>	<u>Contami- nants</u>	<u>Temp. (°F)</u>	<u>Components</u>	<u>Material</u>	<u>Cost^(a) Factor</u>	<u>Years Service Life</u>
Water	pH>7	All	Vapor Gen. & Aux. Ht. Ex.	Carbon Steel	0.5	30
Water	pH<7	All	Vapor Gen. & Aux. Ht. Ex.	Ti or Hastelloy C	5	30
Steam	H ₂ S	All	Turbine	Special Blade Material	1.0	30
Condensate and Steam	All ^(b)	All	Plant Piping Condensor, Process Equip.	Stainless Steel, except Condenser may use Cu Alloy	1.5	30
Condensate, Steam and Water	All	All	Gas Ejectors	Lined Cast Iron	1.0	30

(a) Cost factors are multipliers of the basic cost equations for the individual components. The cost factor often appears inconsistent because the basic cost equation already reflects use of corrosion resistant material(s) of construction.

(b) It is unlikely that steam and condensate will have a pH>7 due to CO₂ carryover.

COMPUTER PROGRAM DESCRIPTION

The GEOCOST computer program is written in FORTRAN IV extended for the Control Data CYBER 70 series computer system. The program currently requires 35,000 decimal words of computer memory and one disk file for storage of summary printout when executing consecutive cases. In addition to the standard FORTRAN library functions, a user generated steam library of subroutines on disk or tape is required to calculate a wide class of thermodynamic properties of water and steam. Typical execution time for one case is less than 10 seconds on the CYBER 74-18 computer with SCOPE 3.4.2 operating system.

The relatively low computer memory requirement was achieved by designing the program in modular fashion, with currently over 100 technical and economic subroutines and an additional 63 thermodynamic subroutines from the steam library. The modular design enables the user to select only those subroutines required to simulate the type of geothermal plant in which he is interested: dry steam, flashed steam, separated steam, binary, hybrid, or total flow. The subroutines selected by the user are then loaded into memory in six main parts called segments. The segmented loading enables certain parts of the program to reside in the same area of computer memory at different times to achieve the reduced memory requirement.

The segmented loading of the program is accomplished via the following tree structure:

where

- A = Root segment
- B = Executive driver for powerplant systems and fluid transmission
- B1 = Powerplant systems
- B2 = Fluid transmission and disposal
- C = Reservoir
- D = Powerplant

Representative values for the input data are initialized in a BLOCK DATA subroutine. These default values can be overridden for any simulation case by entering data through NAMELIST. Consecutive cases can be executed using the standard NAMELIST feature in which only those input data changing from the preceding simulation case require redefinition. As an alternative option, consecutive cases can also be generated internally in the program as combinations of selected parameters for parametric studies.

Printout options provide the following output: (1) comprehensive powerplant systems, fluid transmission, reservoir, and plant economic results, (2) powerplant systems and fluid transmission results only, or (3) reservoir and plant economic results only. Additionally, a summary of the final geothermal energy cost and its breakdown into reservoir and plant component costs is provided for each case when executing consecutive cases.

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APPENDIX A

EXAMPLE PRINTOUT FROM GEOCOST

EXAMPLE PRINTOUT FROM GEOCOST

An example summary printout from the GEOCOST code for a plant-located, two-stage, steam flashing cycle is shown in the following pages. More detailed printout is available at the user's option for the fluid transmission and powerplant systems as described earlier. The first page lists the characteristics of the reservoir and wells. All values are input except: MWt/Well, MWe/Well, producing wells on line, and total flow rate. The direct expenses associated with reservoir exploration, reservoir development, and reservoir operation are shown on page A.3. Other significant input economic factors for the reservoir and case identification information are listed on page A.4. Annual cash flow data for the major reservoir expenses are shown on page A.5. Summary accounts of deductible expenses are contained on page A.6. A simplified income statement is shown on page A.7 and the net cash flow and investment position is shown on page A.8. Page A.9 contains a summary of the costs of energy for the reservoir. In the right-hand column labeled distribution of energy costs, the taxes, royalty payments, and bond interest have been reallocated to the direct cost components for the reservoir. The rate of return on investment is included in the distributed energy cost for each component. The deductible nature of bond interest causes this expense to be partially included in the rate of return (the part which is included in the present worth factor) and the remainder to be accounted for separately. This completes the reservoir model.

Costs associated with the powerplant model begin on page A.10 with the powerplant capital costs. Pages A.11-A.15 contain the same economic and accounting information for the powerplant as pages A.4-A.8 for the reservoir. A summary of the total costs for the powerplant are shown on page A.16. All costs from the reservoir are included in the energy supply cost item. The energy supply costs are derived from the energy cost account shown on page A.12. This energy cost account is identical to the total power sales from the reservoir. The capacity penalty accounts for the portion of the cost associated with the in-house consumption of electricity. The difference between the unit cost for energy supply at the plant and the unit cost of energy from the reservoir is caused by the in-house consumption of electricity. As for the reservoir cost distribution, the taxes and bond interest have been reallocated to the primary cost components in the right-hand columns of the cost distribution.

ECONOMIC ANALYSIS FOR GEOTHERMAL POWER
HIGH TEMPERATURE-LOW SALINITY RESERVOIR

RESERVOIR CHARACTERISTICS

AVERAGE DEPTH	2800.0	M
AVERAGE TEMPERATURE	180.0	C
PRODUCING CAPACITY	275.0	MW(E)

FLUID COMPOSITION

CACO3	0.00	%	
NaCl	3.00	%	
SiO2	.03	%	272. PPM
OTHER	0.00	%	
TOTAL DISSOLVED SOLIDS	3.03	%	

WELL DESIGN (AVERAGE)

DEPTH	2800.0	M
BOTTOM DIAMETER	22.225	CM
FRACTION Cased	1.00	

NONCONDENSIBLE GASES

H2S	.030	%
CO2	.970	%
OTHER	0.000	%
TOTAL NONCONDENSIBLE GASES	1.000	%

WELL PROPERTIES (AVERAGE)

MW(TH)/WELL	76.9	
MW(E) /WELL	3.2	
MAXIMUM FLOW RATE/WELL	800000.0	#/HR
WELL LIFE	10.0	YEARS
PRODUCING WELLS ON LINE	17.0	
DRY WELLS	3.0	
INJECTION WELLS	7.0	
WELL SPACING	20.0	ACRES
ACTUAL FLOW RATE/WELL	634595.7	#/HR
TOTAL FLOW RATE	10788126.5	#/HR
WELL HEAD ORIGINAL PRESSURE	145.4	PSIA
WELL HEAD OVER PRESSURE	166.8	PSIA
FRACTION STEAM (WELLHEAD)	0.00	
STEAM SEPARATION (WELLHEAD)	1	
STEAM/FLASH MIX OPTION	0	
WELLHEAD PRESSURE FACTOR	2.000	
REDUCED PRESSURE FACTOR	1.147	

STRATIGRAPHY

ROCK TYPE	DEPTH(M)
HARD	2800.0

RESERVOIR ECONOMIC DEVELOPMENT FACTORS

FAVORABLE TARGET FRACTION	.500
FAVORABLE SITE FRACTION	.500
FRACTION OF SITES TO EVALUATE	.667
FRACTION OF SITES TO DRILL	.750
FRACTION OF WELLS TO CASE	.250
FRACTION OF SITES TO DEVELOP	.250
PERCENT NONPRODUCING WELLS	20.0
INJECTION/PRODUCTION WELL FLOW RATE	2.000
FRACTION EXCESS PRODUCING WELLS	.20

RESERVOIR EXPLORATION COSTS

	TOTAL (DOLLARS)	CAPITALIZED (DOLLARS)	EXPENSED (DOLLARS)	FAVORABLE SITES	BEGINNING MONTH/YEAR	ENDING MONTH/YEAR
IDENTIFICATION OF TARGETS						
LITERATURE SEARCH	2560.	20.0	2540.0	128.	MAY/1970	OCT/1970
PRELIMINARY LAND CHECK	6400.	50.0	6350.0	128.	MAY/1970	OCT/1970
PRELIMINARY RECONNAISSANCE						
LITERATURE SEARCH	8960.	140.0	8820.0	64.	JUN/1970	DEC/1970
GEOLOGICAL RECONNAISSANCE	12800.	230.0	12600.0	64.	JUN/1970	DEC/1970
DETAILED LAND CHECK	15360.	240.0	15120.0	64.	JUN/1970	DEC/1970
DETAILED RECONNAISSANCE						
LEASE COST	384000.	12000.0	372000.0	32.	JUL/1970	MAY/1971
FIELD GEOLOGY	21000.	1000.0	20000.0	21.	SEP/1970	JUN/1971
GEOCHEMICAL EXAMINATION	25200.	1200.0	24000.0	21.	SEP/1970	JUN/1971
GEOPHYSICAL EXAMINATION	105000.	5000.0	100000.0	21.	SEP/1970	JUN/1971
IDENTIFICATION OF DRILLABLE SITES						
HEAT FLOW	38400.	2400.0	36000.0	16.	APR/1971	MAR/1973
TEMPERATURE GRADIENT	40000.	2500.0	37500.0	16.	APR/1971	MAR/1973
ELECTRICAL RESISTIVITY	11200.	700.0	10500.0	16.	APR/1971	MAR/1973
MICROSEISMIC	16000.	1000.0	15000.0	16.	APR/1971	MAR/1973
DETAILED GEOCHEMISTRY	24000.	1500.0	22500.0	16.	APR/1971	MAR/1973
EXPLORATION DRILLING						
COST OF DRILLING	255363.	13888.2	241474.8	4.	APR/1972	MAR/1974
WELL TESTING	8600.	2000.0	6600.0	4.	APR/1974	APR/1974
TOTAL EXPLORATION COST *	974243.	43838.2	930404.8	1.00		
FIELD DEVELOPMENT		TANGIBLE	INTANGIBLE			
PRODUCING WELLS	2458231.	534772.9	1923458.4		APR/1974	SEP/1977
NONPRODUCING WELLS	433806.	0.0	433805.5		APR/1974	SEP/1977
INJECTION WELLS	1012213.	1012212.9	0.0		OCT/1977	DEC/1979
TRANSMISSION SYSTEM	3042659.	3042658.8	0.0		OCT/1977	DEC/1979
DISPOSAL SYSTEM	2014150.	2014149.9	0.0		OCT/1977	DEC/1979
TOTAL FIELD DEVELOPMENT COST	8961058.					
FIELD OPERATION						
REPLACEMENT WELL COST	245823.	53477.3	192345.8		JAN/1980	DEC/2008
NONPRODUCING WELL DRILLING COST	49165.	0.0	0.0		JAN/1980	DEC/2008
ABANDONMENT	17000.	0.0	0.0		JAN/1980	DEC/2009
WELL MAINTENANCE	24000.	0.0	0.0		JAN/1980	DEC/2009
OVERHEAD AND MANAGEMENT	161092.	0.0	0.0		JAN/1980	DEC/2009
WELL REGRILLING COST	85000.	0.0	0.0		JAN/1980	DEC/2009
INJECTION COST	40987.	0.0	0.0		JAN/1980	DEC/2009
INJECTION WELL COST	0.	0.0	0.0		JAN/1980	DEC/2009
TRANSMISSION SYSTEM MTE.	152133.	0.0	0.0		JAN/1980	DEC/2009
DISPOSAL SYSTEM MTE.	100707.	0.0	0.0		JAN/1980	DEC/2009
TOTAL FIELD OPERATION COST	875907.					

* TOTAL EXPLORATION COST ALLOCATED TO THIS 55. MWE POWER PLANT IS .2000 OF TOTAL EXPLORATION COST FOR THIS 275. MWE RESERVOIR PRODUCING CAPACITY

INPUT DATA

BOND REPAYMENT PROPORTIONAL		
SUM OF YEARS DIGITS DEPRECIATION		
CAPITAL INVESTMENT, \$M	6.6476	(INITIAL FINANCING)
PROJECT LIFE, YEARS	40.0000	
WORKING CAPITAL, \$M	0.0000	(INITIAL FINANCING)
FRACTION OF INITIAL INVESTMENT IN BONDS	.4200	
BOND INTEREST RATE	.0800	
EQUITY EARNING RATE (AFTER TAXES)	.1500	
FEDERAL INCOME TAX RATE	.4800	
POWER PLANT SIZE (MWE)	55.0000	
DEPRECIABLE LIFE OF WELLS, YRS.	10.0000	
VARIABLE OPERATING COST, \$M/YR	0.0000	(AT 100% PLANT FACTOR)
FIRST YEAR OF OPERATION	1980.	
STATE INCOME TAX RATE	.0700	
STATE GROSS REVENUE TAX RATE	0.0000	
PROPERTY TAX RATE	.0250	
DISPOSAL SYSTEM REPLACEMENT RATE	.0900	
TRANSMISSION SYSTEM REPLACEMENT RATE	.0900	
PROPERTY INSURANCE RATE	.0012	
ROYALTY PAYMENT, %	10.00	
RECOVERABLE COST OF LAND, \$M	0.0000	(INITIAL FINANCING)
NET SALVAGE VALUE OF PLANT, \$M	0.0000	
PLANT OPERATING LIFE	30.0000	
TRANSMISSION SYSTEM MTE. RATE	.0500	
DISPOSAL SYSTEM MTE. RATE	.0500	
EVALUATE	.020000	.010000
GEOTHERMAL PLANT TYPE	2	
NUMBER OF FLASHING STAGES	2	
LOCATION OF FLASHERS	1	
WELL REINJECTION OPTION	0	
DISTANCE(M) WELLS TO INJECTION FIELD	1000.0000	
PLANT REINJECTION OPTION	1	
DISTANCE(M) PLANT TO INJECTION FIELD	1000.0000	
STEAM SCRUBBER OPTION	1	
GAS EJECTION OPTION	1	
CASE GENERATION OPTION	0	
PLANT REINJECTION PUMP OPTION	0	

ANNUAL CASH FLOW DATA, EXPENSES IN \$M/YR

YEAR	LOAD FACTOR	FIELD IDENT.	FIELD EXPLOR.	FIELD DEVELOPMENT	RESERVOIR OPERATION	PROPERTY TAXES AND INSURANCE	INTERIM PLANT CAP. REPLACEMENT	TOTAL
1 1970	0.00000	.00896	.30705	0.00000	0.00000	.00026	0.00000	.31628
2 1971	0.00000	0.00000	.31387	0.00000	0.00000	.00060	0.00000	.31447
3 1972	0.00000	0.00000	.16056	0.00000	0.00000	.00084	0.00000	.16140
4 1973	0.00000	0.00000	.14388	0.00000	0.00000	.00105	0.00000	.14493
5 1974	0.00000	0.00000	.03992	.61972	0.00000	.00415	0.00000	.66379
6 1975	0.00000	0.00000	0.00000	.82630	0.00000	.00815	0.00000	.83445
7 1976	0.00000	0.00000	0.00000	.82630	0.00000	.01216	0.00000	.83845
8 1977	0.00000	0.00000	0.00000	1.29406	0.00000	.03283	0.00000	1.32689
9 1978	0.00000	0.00000	0.00000	2.69734	0.00000	.10350	0.00000	2.80084
10 1979	0.00000	0.00000	0.00000	2.69734	0.00000	.17417	0.00000	2.87151
11 1980	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
12 1981	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
13 1982	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
14 1983	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
15 1984	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
16 1985	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
17 1986	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
18 1987	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
19 1988	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
20 1989	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
21 1990	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
22 1991	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
23 1992	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
24 1993	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
25 1994	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
26 1995	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
27 1996	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
28 1997	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
29 1998	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
30 1999	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
31 2000	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
32 2001	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
33 2002	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
34 2003	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
35 2004	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
36 2005	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
37 2006	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
38 2007	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
39 2008	.85000	0.00000	0.00000	0.00000	.87591	.17417	.54621	1.59629
40 2009	.85000	0.00000	0.00000	0.00000	.58092	.17417	0.00000	.75509

ANNUAL DEDUCTIBLE EXPENSES, \$M

YEAR	10.325 PCT PRESENT WORTH FACTOR	FIELD OPERATING EXPENSES	BOND INTEREST	WELL DEPRECIATION	RESERVOIR DEPLETION AND DEPRECIATION	TOTAL DEDUCTIBLE OPER. EXP.	STATE INCOME TAXES
1 1970	.95206	.60474	0.00000	0.00000	0.00000	.60474	-.00033
2 1971	.86296	.16055	.01054	0.00000	0.00000	.17109	-.01198
3 1972	.78220	.03140	.01941	0.00000	0.00000	.11081	-.00776
4 1973	.70899	.22104	.02526	0.00000	0.00000	.24629	-.01724
5 1974	.64264	.96471	.02890	0.00000	0.00000	.99361	-.06955
6 1975	.58250	.68166	.03745	0.00000	0.00000	.71910	-.05034
7 1976	.52799	.68566	.05752	0.00000	0.00000	.74318	-.05202
8 1977	.47857	.53796	.07974	0.00000	0.00000	.61769	-.04324
9 1978	.43379	.10350	.12322	0.00000	0.00000	.22672	-.01587
10 1979	.39319	.17417	.22825	0.00000	0.00000	.40242	-.02617
11 1980	.35639	.99660	.34528	.09723	.39301	1.83212	.13427
12 1981	.32304	.99660	.34783	.13223	.89211	2.36877	.09670
13 1982	.29281	.99660	.34138	.11571	.84734	2.30102	.10144
14 1983	.26540	.99660	.33532	.10112	.80492	2.23796	.10586
15 1984	.24057	.99660	.32963	.08848	.76485	2.17956	.10995
16 1985	.21805	.99660	.32426	.07779	.72713	2.12578	.11371
17 1986	.19765	.99660	.31918	.06903	.69176	2.07657	.11716
18 1987	.17915	.99660	.31434	.06223	.65874	2.03191	.12028
19 1988	.16238	.99660	.30969	.05737	.62807	1.99173	.12309
20 1989	.14719	.99660	.30518	.05445	.59975	1.95598	.12560
21 1990	.13341	.99660	.30074	.05348	.57378	1.92459	.12779
22 1991	.12093	.99660	.29632	.05348	.55015	1.89654	.12976
23 1992	.10961	.99660	.29184	.05348	.52888	1.87080	.13156
24 1993	.09935	.99660	.28728	.05348	.50995	1.84731	.13320
25 1994	.09005	.99660	.28257	.05348	.49338	1.82602	.13469
26 1995	.08163	.99660	.27766	.05348	.47915	1.80689	.13603
27 1996	.07399	.99660	.27249	.05348	.46727	1.78984	.13723
28 1997	.06706	.99660	.26700	.05348	.45775	1.77482	.13828
29 1998	.06079	.99660	.26110	.05348	.45057	1.76175	.13919
30 1999	.05510	.99660	.25472	.05348	.44574	1.75054	.13998
31 2000	.04994	.99660	.24777	.05348	.44326	1.74110	.14064
32 2001	.04527	.99660	.24013	.05348	.44313	1.73334	.14118
33 2002	.04103	.99660	.23172	.05348	.44535	1.72714	.14162
34 2003	.03719	.99660	.22239	.05348	.44992	1.72238	.14195
35 2004	.03371	.99660	.21203	.05348	.45683	1.71893	.14219
36 2005	.03056	.99660	.20047	.05348	.46610	1.71664	.14235
37 2006	.02770	.99660	.18756	.05348	.47772	1.71535	.14244
38 2007	.02510	.99660	.17311	.05348	.49168	1.71487	.14247
39 2008	.02275	.99660	.15693	.05348	.50800	1.71500	.14247
40 2009	.02063	.75509	.13880	.21391	5.80671	6.91451	-.22150
TOTALS=				2.08561	21.95381		

ANNUAL INCOME STATEMENT, \$M

YEAR	POWER UNITS (M MWH)	TOTAL POWER SALES	REVENUE TAXES	ROYALTY PAYMENTS EXPENSES	TOTAL TAX DEDUCTIBLE EXPENSES	TAXABLE INCOME (FEDERAL)	FEDERAL INCOME TAX
1 1970	0.00000	0.00000	0.00000	0.00000	.00441	-.00441	-.00212
2 1971	0.00000	0.00000	0.00000	0.00000	.15912	-.15912	-.07638
3 1972	0.00000	0.00000	0.00000	0.00000	.10305	-.10305	-.04947
4 1973	0.00000	0.00000	0.00000	0.00000	.22905	-.22905	-.10995
5 1974	0.00000	0.00000	0.00000	0.00000	.92406	-.92406	-.44355
6 1975	0.00000	0.00000	0.00000	0.00000	.66877	-.66877	-.32101
7 1976	0.00000	0.00000	0.00000	0.00000	.69116	-.69116	-.33176
8 1977	0.00000	0.00000	0.00000	0.00000	.57445	-.57445	-.27574
9 1978	0.00000	0.00000	0.00000	0.00000	.21085	-.21085	-.10121
10 1979	0.00000	0.00000	0.00000	0.00000	.37425	-.37425	-.17964
11 1980	.40987	4.16691	0.00000	.41669	1.96639	1.78383	.85624
12 1981	.40987	4.16691	0.00000	.41669	2.46547	1.28475	.61668
13 1982	.40987	4.16691	0.00000	.41669	2.40246	1.34776	.64692
14 1983	.40987	4.16691	0.00000	.41669	2.34382	1.40640	.67507
15 1984	.40987	4.16691	0.00000	.41669	2.28950	1.46072	.70114
16 1985	.40987	4.16691	0.00000	.41669	2.23949	1.51073	.72515
17 1986	.40987	4.16691	0.00000	.41669	2.19373	1.55649	.74712
18 1987	.40987	4.16691	0.00000	.41669	2.15219	1.59883	.76785
19 1988	.40987	4.16691	0.00000	.41669	2.11482	1.63548	.78499
20 1989	.40987	4.16691	0.00000	.41669	2.08157	1.66865	.80095
21 1990	.40987	4.16691	0.00000	.41669	2.05239	1.69783	.81496
22 1991	.40987	4.16691	0.00000	.41669	2.02630	1.72392	.82748
23 1992	.40987	4.16691	0.00000	.41669	2.00236	1.74786	.83897
24 1993	.40987	4.16691	0.00000	.41669	1.98051	1.76971	.84946
25 1994	.40987	4.16691	0.00000	.41669	1.96072	1.78950	.85896
26 1995	.40987	4.16691	0.00000	.41669	1.94292	1.80730	.86750
27 1996	.40987	4.16691	0.00000	.41669	1.92707	1.82315	.87511
28 1997	.40987	4.16691	0.00000	.41669	1.91310	1.83712	.88182
29 1998	.40987	4.16691	0.00000	.41669	1.90094	1.84928	.88765
30 1999	.40987	4.16691	0.00000	.41669	1.89051	1.85971	.89266
31 2000	.40987	4.16691	0.00000	.41669	1.88174	1.86848	.89687
32 2001	.40987	4.16691	0.00000	.41669	1.87452	1.87570	.90034
33 2002	.40987	4.16691	0.00000	.41669	1.86876	1.88146	.90310
34 2003	.40987	4.16691	0.00000	.41669	1.86433	1.88589	.90523
35 2004	.40987	4.16691	0.00000	.41669	1.86112	1.88909	.90677
36 2005	.40987	4.16691	0.00000	.41669	1.85899	1.89122	.90779
37 2006	.40987	4.16691	0.00000	.41669	1.85779	1.89243	.90837
38 2007	.40987	4.16691	0.00000	.41669	1.85734	1.89288	.90858
39 2008	.40987	4.16691	0.00000	.41669	1.85747	1.89275	.90852
40 2009	.40987	4.16691	0.00000	.41669	6.69381	-2.94279	-1.41254

PAYOUT OF INVESTMENTS, \$M

YEAR	NET CASH FLOW	OUTSTANDING BONDS	EQUITY CAPITAL NOT RECOVERED	BOND INTEREST	EARNINGS ON UNRECOVERED EQUITY	BONDS REPAID	RECOVERY OF EQUITY
1 1970	-.31383	0.00000	0.00000	0.00000	0.00000	-.13181	-.18202
2 1971	-.26396	.13181	.18202	.01054	.02730	-.11086	-.15310
3 1972	-.17386	.24267	.33512	.01941	.05027	-.07302	-.10984
4 1973	-.10840	.31569	.43596	.02526	.06539	-.04553	-.06287
5 1974	-.25441	.36122	.49883	.02890	.07482	-.10685	-.14756
6 1975	-.59751	.46807	.64639	.03745	.09696	-.25095	-.34656
7 1976	-.66114	.71903	.99294	.05752	.14894	-.27768	-.38346
8 1977	-1.29411	.99671	1.37640	.07974	.20646	-.54352	-.75058
9 1978	-3.12603	1.54023	2.12698	.12322	.31905	-1.31293	-1.81310
10 1979	-3.48297	2.85316	3.94008	.22825	.59101	-1.46285	-2.02012
11 1980	-.07588	4.31601	5.96020	.34528	.89403	-.03187	-.04401
12 1981	.19209	4.34788	6.00421	.34783	.90063	.08068	.11141
13 1982	.18027	4.26720	5.89280	.34138	.88392	.07571	.10456
14 1983	.16945	4.19149	5.78825	.33532	.86824	.07117	.09828
15 1984	.15972	4.12032	5.68997	.32963	.85350	.06708	.09264
16 1985	.15121	4.05324	5.59733	.32426	.83960	.06351	.08770
17 1986	.14404	3.98973	5.50963	.31918	.82644	.06050	.08354
18 1987	.13834	3.92923	5.42609	.31434	.81391	.05810	.08024
19 1988	.13428	3.87113	5.34585	.30969	.80188	.05640	.07788
20 1989	.13201	3.81473	5.26796	.30518	.79019	.05544	.07657
21 1990	.13173	3.75929	5.19140	.30074	.77871	.05533	.07640
22 1991	.13313	3.70396	5.11499	.29632	.76725	.05591	.07721
23 1992	.13589	3.64805	5.03778	.29184	.75567	.05707	.07882
24 1993	.14015	3.59097	4.95896	.28728	.74384	.05886	.08128
25 1994	.14606	3.53211	4.87768	.28257	.73165	.06134	.08471
26 1995	.15379	3.47077	4.79297	.27766	.71895	.06459	.08920
27 1996	.16354	3.40618	4.70377	.27249	.70557	.06868	.09485
28 1997	.17550	3.33749	4.60892	.26700	.69134	.07371	.10179
29 1998	.18991	3.26378	4.50713	.26110	.67607	.07976	.11015
30 1999	.20703	3.18402	4.39698	.25472	.65955	.08695	.12008
31 2000	.22712	3.09707	4.27690	.24777	.64154	.09539	.13173
32 2001	.25051	3.00168	4.14517	.24013	.62178	.10521	.14529
33 2002	.27752	2.89646	3.99988	.23172	.59998	.11656	.16096
34 2003	.30853	2.77991	3.83892	.22239	.57584	.12958	.17495
35 2004	.34395	2.65033	3.65998	.21203	.54900	.14446	.19549
36 2005	.38425	2.50587	3.46048	.20047	.51907	.16139	.22287
37 2006	.42993	2.34448	3.23761	.18756	.48564	.18057	.24936
38 2007	.48153	2.16391	2.98826	.17311	.44824	.20224	.27929
39 2008	.53967	1.96167	2.70897	.15693	.40635	.22666	.31301
40 2009	4.13097	1.73501	2.39597	.13880	.35939	1.73501	2.39597

POWER COST, MILLS/KWHE

10.1665

	DETAILED CASH FLOW		DISTRIBUTION OF ENERGY COSTS	
	MILLS PER KWHE	ANNUAL (\$ MILLIONS)	MILLS PER KWHE	ANNUAL (\$ MILLIONS)
C O S T O F P O W E R	10.16650	1.50762		
FIELD IDENTIFICATION AND EXPLORATION	.55780	.08272	.74647	.11070

FIELD DEVELOPMENT (TOTAL)	2.81669	.41769	4.46992	.66286

PRODUCING WELLS	.92671	.13742	1.15182	.17081
TRANSMISSION SYSTEM	.86554	.12835	1.57240	.23318
DISPOSAL SYSTEM	.86091	.12767	1.56398	.23193
NONPRODUCING WELLS	.16354	.02425	.18171	.02695
FIELD OPERATING COSTS (TOTAL)	3.98102	.59636	4.95012	.73407

- DISPOSAL COSTS	1.00645	.14925	1.36077	.20179
PRODUCING WELLS	.90375	.13402	1.04464	.15491
TRANSMISSION COSTS	1.03548	.15355	1.39432	.20677
OTHER OPERATING COSTS	1.03535	.15353	1.15039	.17059
REVENUE TAXES	0.00000	0.00000		
STATE INCOME TAXES	.17668	.02620		
ROYALTY PAYMENTS	1.01665	.15076		
FEDERAL INCOME TAXES	1.12669	.16708		
BOND INTEREST	.49096	.07281		
TOTALS	10.16650	1.50762	10.16650	1.50762

POWER PLANT CAPITAL COSTS

ACCOUNT

1.0	POWER PLANT		
1.1	PIPING, INSULATION, & PUMPS	564.	\$K
1.2	CRANE	154.	\$K
1.3	TURBO GENERATOR	5100.	\$K
1.6	FLASHERS (PLANT LOCATED UNITS)	1372.	\$K
1.9	MISC. PROCESS SUPPORT EQUIP.	112.	\$K
1.10	INSTRUMENTATION AND CONTROLLERS	855.	\$K
1.12	ELECTRICAL SUPPORT AND EQUIP.	582.	\$K
1.16	CONDENSER	1180.	\$K
1.17	INSTALLATION TESTING	142.	\$K
1.18	BUILDINGS, FOUNDATIONS, AND SUPPORT EQUIPMENT	1170.	\$K
1.19	GAS EJECTORS (STEAM DRIVEN)	206.	\$K
1.99	TOTAL 1.0	11437.	\$K

ACCOUNT

2.0	HEAT REJECTION SYSTEM (COOLING TOWERS)		
2.1	COOLING TOWER SYSTEM	1420.	\$K
2.99	TOTAL 2.0	1420.	\$K

ACCOUNT

3.0	SWITCH YARD		
3.99	TOTAL 3.0	561.	\$K

ACCOUNT

5.0	OTHER COSTS		
5.1	ENGINEERING AND DESIGN	1340.	\$K
5.2	ADMINISTRATION AND INDIRECT COSTS	1070.	\$K
5.99	TOTAL 5.0	2410.	\$K

TOTAL POWER PLANT COST	15828.	\$K
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ESTIMATED COST -

BASIS IS EXISTING PLANTS
(FLASH STEAM PLANTS ONLY)

9340.	\$K
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INPUT DATA

BOND REPAYMENT PROPORTIONAL
SUM OF YEARS DIGITS DEPRECIATION

PLANT INVESTMENT, \$M	15.8280	(INITIAL FINANCING)
PROJECT LIFE, YEARS	33.0000	
NONFUEL WORKING CAPITAL, \$M	0.0000	(INITIAL FINANCING)
FRACTION OF INITIAL INVESTMENT IN BONDS	.5900	
BOND INTEREST RATE	.0800	
EQUITY EARNING RATE (AFTER TAXES)	.1200	
FEDERAL INCOME TAX RATE	.4800	
POWER PLANT SIZE (MWE)	55.0000	
DEPRECIABLE LIFE OF PLANT, YRS.	30.0000	
PLANT CONSTRUCTION AND LICENSING, YRS.	3.0000	
VARIABLE OPERATING COST, \$M/YR	0.0880	(AT 100% PLANT FACTOR)
FIRST YEAR OF OPERATION	1988	
STATE INCOME TAX RATE	.0700	
STATE GROSS REVENUE TAX RATE	.0400	
PROPERTY TAX RATE	.0250	
INTERIM CAPITAL REPLACEMENTS, RATE/YR	.0035	
PROPERTY INSURANCE RATE	.0012	
ROYALTY PAYMENT, %	0.0000	
RECOVERABLE COST OF LAND, \$M	0.0000	(INITIAL FINANCING)
NET SALVAGE VALUE OF PLANT, \$M	0.0000	
PLANT OPERATING LIFE	30.0000	

CASH FLOW TABLE POWER PLANT, \$ MILLIONS

YEAR	LOAD FACTOR	CAPITAL COSTS	ENERGY COSTS	PLANT OPERATING COSTS	INTERIM CAPITAL REPLACEMENT	PROPERTY TAXES INSURANCE	TOTAL COSTS
1 1977	0.00000	1.58280	0.00000	0.00000	0.00000	0.00000	1.58280
2 1978	0.00000	4.74840	0.00000	0.00000	0.00000	.04147	4.78987
3 1979	0.00000	9.49680	0.00000	0.00000	0.00000	.16588	9.66268
4 1980	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
5 1981	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
6 1982	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
7 1983	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
8 1984	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
9 1985	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
10 1986	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
11 1987	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
12 1988	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
13 1989	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
14 1990	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
15 1991	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
16 1992	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
17 1993	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
18 1994	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
19 1995	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
20 1996	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
21 1997	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
22 1998	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
23 1999	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
24 2000	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
25 2001	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
26 2002	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
27 2003	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
28 2004	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
29 2005	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
30 2006	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
31 2007	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
32 2008	.85000	0.00000	4.16691	.11692	.05540	.41469	4.75392
33 2009	.85000	0.00000	4.16691	.11692	0.00000	.41469	4.69852

ANNUAL TAX DEDUCTIBLE EXPENSES, \$ MILLIONS

YEAR	7.203 PCT PRESENT MORTG FACTOR	OPERATING EXPENSES	BOND INTEREST	DEPRECIATION	TOTAL DEDUCTIBLE OPERATING EXPENSES	STATE INCOME TAX
1 1977	.96582	8.00000	0.00000	0.00000	0.00000	0.00000
2 1978	.90093	.04147	.07471	0.00000	.11618	-.00813
3 1979	.84040	.16588	.38516	0.00000	.47104	-.03297
4 1980	.78394	4.69852	.77917	1.02116	6.49886	.02356
5 1981	.73127	4.69852	.76424	1.03907	6.50183	.02335
6 1982	.68214	4.69852	.74780	1.00181	6.44813	.02711
7 1983	.63631	4.69852	.73108	.96479	6.39440	.03087
8 1984	.59355	4.69852	.71486	.92801	6.34060	.03464
9 1985	.55368	4.69852	.69671	.89147	6.28671	.03841
10 1986	.51648	4.69852	.67900	.85517	6.23270	.04219
11 1987	.48178	4.69852	.66091	.81911	6.17853	.04598
12 1988	.44941	4.69852	.64238	.78328	6.12418	.04979
13 1989	.41921	4.69852	.62340	.74769	6.06961	.05361
14 1990	.39105	4.69852	.60391	.71235	6.01477	.05744
15 1991	.36477	4.69852	.58388	.67723	5.95964	.06130
16 1992	.34027	4.69852	.56327	.64236	5.90415	.06519
17 1993	.31749	4.69852	.54202	.60773	5.84827	.06910
18 1994	.29608	4.69852	.52009	.57333	5.79194	.07304
19 1995	.27619	4.69852	.49741	.53917	5.73510	.07702
20 1996	.25763	4.69852	.47393	.50525	5.67771	.08104
21 1997	.24032	4.69852	.44959	.47157	5.61968	.08510
22 1998	.22417	4.69852	.42432	.43813	5.56097	.08921
23 1999	.20911	4.69852	.39804	.40492	5.50149	.09337
24 2000	.19506	4.69852	.37068	.37196	5.44116	.09760
25 2001	.18196	4.69852	.34215	.33923	5.37990	.10188
26 2002	.16973	4.69852	.31237	.30674	5.31762	.10624
27 2003	.15833	4.69852	.28123	.27449	5.25423	.11068
28 2004	.14769	4.69852	.24863	.24247	5.18962	.11520
29 2005	.13777	4.69852	.21447	.21070	5.12368	.11982
30 2006	.12651	4.69852	.17862	.17916	5.05630	.12454
31 2007	.11988	4.69852	.14095	.14786	4.98734	.12936
32 2008	.11182	4.69852	.10134	.11680	4.91666	.13431
33 2009	.10431	4.69852	.05963	.62150	5.37964	.10190

DEPRECIATION SUM = 17.4345

ANNUAL INCOME STATEMENT, \$ MILLIONS

YEAR	POWER UNITS (M MWH)	TOTAL POWER SALES	REVENUE TAXES	TOTAL TAX DEDUCTIBLE EXPENSES	TAXABLE INCOME (FEDERAL)	FEDERAL INCOME TAX
1 1977	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
2 1978	0.00000	0.00000	0.00000	.10805	-.10805	-.05186
3 1979	0.00000	0.00000	0.00000	.43806	-.43806	-.21027
4 1980	.38090	7.12020	.28481	6.52241	.31298	.15023
5 1981	.38090	7.12020	.28481	6.52518	.31022	.14890
6 1982	.38090	7.12020	.28481	6.47524	.36016	.17288
7 1983	.38090	7.12020	.28481	6.42527	.41013	.19686
8 1984	.38090	7.12020	.28481	6.37523	.46016	.22088
9 1985	.38090	7.12020	.28481	6.32511	.51028	.24494
10 1986	.38090	7.12020	.28481	6.27488	.56051	.26905
11 1987	.38090	7.12020	.28481	6.22451	.61088	.29322
12 1988	.38090	7.12020	.28481	6.17397	.66143	.31749
13 1989	.38090	7.12020	.28481	6.12321	.71218	.34185
14 1990	.38090	7.12020	.28481	6.07222	.76318	.36633
15 1991	.38090	7.12020	.28481	6.02094	.81446	.39094
16 1992	.38090	7.12020	.28481	5.96934	.86606	.41571
17 1993	.38090	7.12020	.28481	5.91737	.91803	.44065
18 1994	.38090	7.12020	.28481	5.86498	.97042	.46580
19 1995	.38090	7.12020	.28481	5.81212	1.02327	.49117
20 1996	.38090	7.12020	.28481	5.75875	1.07665	.51679
21 1997	.38090	7.12020	.28481	5.70478	1.13061	.54269
22 1998	.38090	7.12020	.28481	5.65018	1.18522	.56890
23 1999	.38090	7.12020	.28481	5.59486	1.24054	.59546
24 2000	.38090	7.12020	.28481	5.53875	1.29664	.62239
25 2001	.38090	7.12020	.28481	5.48178	1.35361	.64973
26 2002	.38090	7.12020	.28481	5.42387	1.41153	.67753
27 2003	.38090	7.12020	.28481	5.36491	1.47048	.70583
28 2004	.38090	7.12020	.28481	5.30483	1.53057	.73467
29 2005	.38090	7.12020	.28481	5.24350	1.59189	.76411
30 2006	.38090	7.12020	.28481	5.18083	1.65456	.79419
31 2007	.38090	7.12020	.28481	5.11670	1.71870	.82497
32 2008	.38090	7.12020	.28481	5.05097	1.78442	.85652
33 2009	.38090	7.12020	.28481	5.48155	1.35385	.64985

PAYOUT OF INVESTMENTS, \$ MILLIONS

YEAR	NET CASH FLOW	OUTSTANDING BONDS	EQUITY CAPITAL NOT RECOVERED	BOND INTEREST	EARNINGS ON UNRECOVERED EQUITY	BONDS REPAID	RECOVERY OF EQUITY
1 1977	-1.58283	0.00000	0.00000	0.00000	0.00000	-.93385	-.64895
2 1978	-4.88246	.93385	.64895	.07471	.07787	-2.88265	-2.00181
3 1979	-10.64268	3.81450	2.65076	.30516	.31809	-5.92518	-4.11750
4 1980	.31632	9.73969	6.76826	.77917	.81219	.18663	.12969
5 1981	.34835	9.55305	6.63356	.76424	.73663	.20553	.14282
6 1982	.35421	9.34753	6.49574	.74780	.77949	.20898	.14522
7 1983	.36060	9.13854	6.35051	.73108	.76296	.21275	.14785
8 1984	.36758	8.92579	6.20267	.71406	.74432	.21687	.15071
9 1985	.37519	8.70892	6.05196	.69671	.72624	.22136	.15383
10 1986	.38346	8.48756	5.89813	.67900	.70778	.22624	.15722
11 1987	.39246	8.26131	5.74091	.66091	.68891	.23155	.16091
12 1988	.40223	8.02976	5.58000	.64238	.66960	.23731	.16491
13 1989	.41282	7.79245	5.41503	.62340	.64981	.24356	.16926
14 1990	.42430	7.54888	5.24583	.60391	.62950	.25034	.17396
15 1991	.43673	7.29855	5.07187	.58388	.60862	.25767	.17906
16 1992	.45018	7.04088	4.89281	.56327	.58714	.26560	.18457
17 1993	.46472	6.77527	4.70824	.54202	.56499	.27418	.19053
18 1994	.48043	6.50109	4.51771	.52069	.54212	.28345	.19697
19 1995	.49739	6.21764	4.32073	.49741	.51849	.29346	.20393
20 1996	.51570	5.92418	4.11680	.47393	.49402	.30426	.21144
21 1997	.53545	5.61992	3.90537	.44959	.46864	.31591	.21953
22 1998	.55674	5.30400	3.68583	.42432	.44230	.32848	.22827
23 1999	.57970	4.97552	3.45757	.39804	.41491	.34202	.23768
24 2000	.60443	4.63350	3.21989	.37068	.38639	.35661	.24782
25 2001	.63106	4.27689	2.97208	.34215	.35665	.37233	.25873
26 2002	.65974	3.90456	2.71334	.31237	.32560	.38924	.27049
27 2003	.69060	3.51532	2.44285	.28123	.29314	.40745	.28315
28 2004	.72381	3.10787	2.15973	.24863	.25916	.42705	.29676
29 2005	.75953	2.68082	1.86294	.21447	.22355	.44812	.31141
30 2006	.79795	2.23270	1.55153	.17862	.18618	.47079	.32716
31 2007	.83926	1.76190	1.22437	.14095	.14692	.49517	.34410
32 2008	.88367	1.26674	.88028	.10134	.10563	.52137	.36231
33 2009	1.26334	.74537	.51797	.05963	.06216	.74537	.51797

INSTALLED COST	287.78182	\$ PER KWE		
	DETAILED CASH FLOW MILLS PER KWHR	ANNUAL (\$ MILLIONS)	EQUIVALENT CASH FLOW MILLS PER KWHR	ANNUAL (\$ MILLIONS)
COST OF POWER	18.69309	5.62910	18.69309	5.62910
COST DISTRIBUTION				
INITIAL PLANT	3.54194	1.06659	5.60475	1.68777
INTERIM CAPITAL REPLACEMENTS	.14396	.04335	.19177	.05775
ENERGY SUPPLY	10.93963	3.29428	11.39545	3.43154
OPERATING EXPENSES	.30694	.09243	.31973	.09628
PROPERTY TAXES AND INSURANCE	1.13413	.34152	1.18138	.35575
STATE REVENUE TAX	.74772	.22516		
STATE INCOME TAX	.14020	.04222		
FEDERAL INCOME TAX	.89407	.26923		
BOND INTEREST	.84443	.25430		
TOTAL	18.69309	5.62910	18.69309	5.62910
INTERNAL POWER CONSUMPTION	1.32108	.39782		

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