DOE/ID/12174--T1

DE83 007301

DOE/ID/12174--T1

G E E F

* * * * * * *

A GEOTHERMAL ENGINEERING AND ECONOMIC FEASIBILITY MODEL

DESCRIPTION AND USER'S MANUAL

PREPARED FOR:

DIVISION OF GEOTHERMAL ENERGY
U.S. DEPARTMENT OF ENERGY
UNDER CONTRACT NO. DE-AC-07-80-ID 12174

MS. SUSAN PRESTWICH, PROGRAM OFFICER
DOE/IDAHO OPERATIONS

PREPARED BY:

ENGINEERING AND ECONOMICS RESEARCH, INC.
1951 KIDWELL DRIVE
VIENNA, VIRGINIA 22180

SEPTEMBER 1982

DISCLAIMER

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DOE/ID/12174--T1

TABLE OF CONTENTS

LIST OF ILLUSTRATIONS

LIST OF TABLES

1.0 INTRODUCTION

The objective of the modeling effort described in this paper is to provide a uniform engineering and economic evaluation methodology for analyzing the economic feasibility of geothermal resource utilization for direct heat applications. The model is designed to enable decision makers to compare the economics of geothermal projects with the economics of alternative energy systems at an early stage in the decision process. The geothermal engineering and economic feasibility computer model (GEEF) is written in FORTRAN IV language and can be run on a mainframe or a mini-computer system. An abbreviated version of the model is being developed for usage in conjunction with a programmable desk calculator. The GEEF model has two main segments, namely (i) the engineering design/cost segment and (ii) the economic analysis segment. In the engineering segment, the model determines the numbers of production and injection wells, heat exchanger design, operating parameters for the system, requirement of supplementary system (to augment the working fluid temperature if the resource temperature is not sufficiently high), and the fluid flow rates. The model can handle single stage systems as well as two stage cascaded systems in which the second stage may involve a space heating application after a process heat application in the first stage.

The financial segment of the model carries out life cycle cost analysis of the proposed geothermal system. The output of the model includes estimated levelized cost of energy (ALCE), net present value of the project (NPV), discounted cash flow rate of return (DCFROR) and discounted payback period (DPP). The NPV, DCFROR, and DPP computations are based on the estimated cost of required energy from the least cost energy source. The model also generates the year-by-year cash flow tables for the geothermal project being evaluated.

The input data requirements of the model are consistent with the expected capability of model users to provide the information. The user has to specify the process temperature, allowable temperature drop in the process, the peak energy demand (millions of Btu's per hour) and the utilization factor. If a two stage system is to be utilized, this information will be needed for both the stages. The required resource data include the well head temperature, well depth, type of rock, salinity, and estimated well flow rate. If an injection well is to be utilized, the depth of this well has to be specified.

The model user is expected to provide financial inputs including debt/equity ratio, interest on debt, inflation and real cost escalation rates, capital and O&M costs (whenever available) of major plant components, costs of energy from alternative sources (gas, oil, and electricity) and data concerning tax rates. Although the model is designed to generate most of the cost estimates internally, (given the required information about sizes and operating parameters), the user is encouraged to input the best available plant and field cost estimates, and override the computer generated costs.

Figure 1 shows the model structure and input/output characteristics. It is appropriate to emphasize that this model is designed to

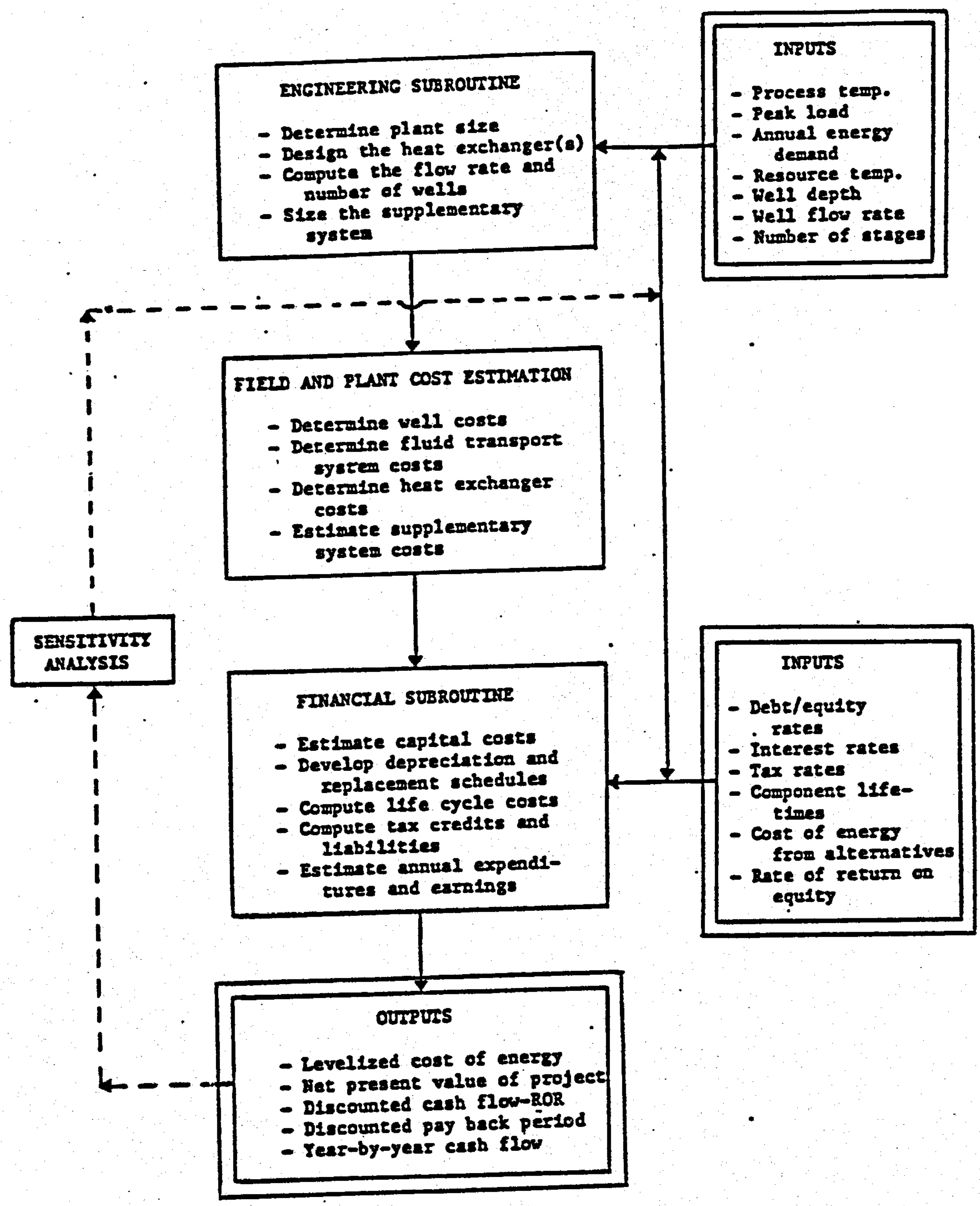


FIGURE 1

MODEL STRUCTURE AND INPUT/OUTPUT CHARACTERISTICS provide quantitative outputs on the basis of which a potential user can make an <u>initial</u> determination of the technical and economic feasibility of utilizing hydrothermal energy for satisfying the energy requirements of a proposed project. Since the model is likely to be used when a lot of input data (particularly resource data) is not known with any certainty, the model is designed to allow the user to perturb values of some critical variables (e.g., resource temperature, well flow rate, alternative fuel price escalation rates, etc.) to determine the sensitivity of the model outputs to changes in the values of these variables.

Although the model may appear to have a considerable amount of detail built into it, the model users should not utilize the model for designing the plant once a decision to proceed with the project has been made. Some of the assumptions and short cuts incorporated in this model will not be acceptable when a detailed plant design is to be developed. The GEEF model is designed strictly for making a preliminary determination of the economic feasibility of using hydrothermal energy for a particular application.

2.0 STRUCTURE OF GEOTHERMAL ENGINEERING AND ECONOMIC FEASIBILITY (GEEF) MODEL

2.1 The Engineering/Cost Subroutine

The engineering/cost subroutine is designed to carry out a preliminary size determination of the heat exchanger, and the supplementary system (if needed). In addition, this subroutine computes the numbers of production and injection wells. The approximate costs of the wells, the fluid distribution system, the heat exchanger and supplementary system are also estimated by the engineering/cost subroutine. The level of detail in this subroutine is consistent with the ability of an average model user to supply the inputs pertaining to energy demand, resource characteristics, and the operating parameters for the system. Some users may already have computed many of the engineering/cost parameters needed for carrying out the financial analysis. These users can by-pass some of the sections of this subroutine and may also override many default values embedded in the model.

In order to make the input data requirements as simple as possible, a number of assumptions are built into the model. Most of these assumptions are explained in the description of different components of the model. Although the engineering design and cost estimation computations could be made more precise, the benefit of this precision would be diluted by the fact that these computations will generally be made on the basis of resource characteristics data about which the model users are not very confident. The emphasis has been placed on developing a simple engineering/cost subroutine which can be used a number of times to assess the sensitivity of the model output to errors in the estimated values of certain critical resource parameters and financial parameters.

A brief explanation of the input data requirements, sequence of steps, and the outputs of the engineering/cost subroutine follows.

2.1.1 Input Data Requirements

Recognizing that most users will not have very reliable data concerning the resource characteristics and operating parameters of the system, the input data requirements have been kept relatively simple. The inputs needed by the engineering/cost subroutine of the model fall into three categories, namely (i) energy demand data, (ii) resource characteristics data and (iii) energy utilization plant data.

(i) Energy Demand Data

- The user will be required to specify the nature and magnitude of the energy demand which the geothermal system is expected to satisfy. The user has to specify the process temperature and the allowable working fluid temperature drop in the process. If the process allowable temperature drop is not known, the user can specify a value around 20°F. Since the model can handle a two stage cascaded usage system, the user is expected to supply the above mentioned information for each stage (if two stages are involved). The peak load has to be specified in terms of Btu's per hour. A safety margin of 10% to 20% is recommended.

- The estimated annual energy demand (Btu's per year) should be specified for each stage. If necessary, the user can specify the annual utilization factor, and the model will compute the annual energy usage on the basis of the factor and the peak demand for each stage. It is anticipated that the utilization factors of the two stages of a cascaded system will be different in most cases.

- The user will be expected to specify the fuel cost and the energy plant cost for the most economical energy supply system which can be considered as a supplementation system to the geothermal energy system. The choice of the supplementary fuels is restricted to natural gas, oil, and electricity. The user has to provide values concerning the energy plant capital cost for supplementation purposes. Supplemental system is used to elevate the temperature of the circulating water and not as a backup system.

(ii) Resource Characteristics Data

In most cases, the resource characteristics data provided by the users will represent their best judgement. The following resource characteristics will have to be specified by the user.

- The well head temperature in °F is an essential input. If there is uncertainty about the well head temperature, three values i.e., the "lowest" estimate, the "most likely" estimate, and the "highest" estimate should be given. The first model run will utilize the "most likely" well head temperature. The other two values can be utilized during the sensitivity analysis.

- The well depths (for production and injection wells) and types of rock (hard or soft) have to be specified. Three values of the well depth (in ft.) can be provided. The model will utilize the most likely value to estimate the cost of the wells. If the depth of production well is different from the depth of injection wells, two separate sets of estimates should be given.

- The well flow rate in lbs/hour has to be specified for the production wells. It is appropriate to observe that the estimate may have to be made prior to flow testing of the well. Therefore, the user should use all available information and technical expertise before making an estimate of the well flow rate. In this case also, it would be desirable to give three estimates including the "most likely" value. The production and injection well costs will generally amount to a large fraction of the total geothermal energy plant cost, and the need for making reasonably good estimates of well depth and well flow rate cannot be over-emphasized.

- An estimate of the salinity characteristics of the brine is necessary for determining the fluid flow rate and the cost of heat exchanger. For the purpose of this model, the salinity can be characterized as "high" or "low."

(iii) Energy Utilization Plant Data

The information falling in this category is utilized for setting the values of the plant operation parameters in the process of determining the fluid flow rate and the design of the heat exchanger.

- The user is expected to specify whether the utilization of the energy in the brine will be direct or indirect (i.e., via a heat exchager and secondary working fluid).

- If there are any restrictions on the re-injection temperature of the brine, the lowest allowable brine injection must be specified.

- Since the type of application has considerable impact on the fluid transport and distribution system costs, the user should specify a longer distribution system for a district heating system than for a system to be utilized by a single energy consumer.

2.1.2 The Engineering Design Process

The engineering design segment of the GEEF model carries out a rough computation of the required fluid flow rates through the heat exchanger, and the peak demand for energy from the supplementation system (if needed). To keep this part of the model routine relatively simple, two standard indirect system (involving a heat exchanger) configurations were adopted for the engineering design process. The model can handle one direct energy system also. A brief description of the system configurations and the procedure for establishing design operating parameters and the energy plant component sizes is provided below.

(i) <u>Standard System Configuration</u>

Figure 2 shows the schematic diagram for a one stage indirect system in which thermal energy is transferred from the geothermal brine to a working fluid in a shell and tube heat exchanger*. The model user can specify the brine temperature at the heat exchanger inlet, and the terminal temperature differences at the two ends of the heat exchanger. If these values are not provided, the model assumes a 5°F brine temperature drop between the well head and the inlet to the heat exchanger. The default values for the heat exchanger terminal temperature difference are 20°F at the brine inlet side and 10°F at the brine outlet side. The supplementary system is utilized only when the working fluid temperature needs to be augmented to raise it to the level of the required process temperature.

Figure 3 shows the schematic diagram for a cascaded two stage system with separate heat exchangers for the high temperature stage and the low temperature stage. In this case, the temperature supplementation can be provided in the high temperature stage only. The system operating parameters for the cascaded system are established in the same manner as for the single stage system. The method for determining these parameters is explained later.

The schematic diagram for a direct system, in which the brine is injected into the utilization system, is shown in Figure 4. In this

---

* It is possible that in some cases plate heat exchangers will be used. This model does not have the capability for designing and costing a plate heat exchanger. However, the user can compute the heat exchanger cost outside the model and use it as an input.

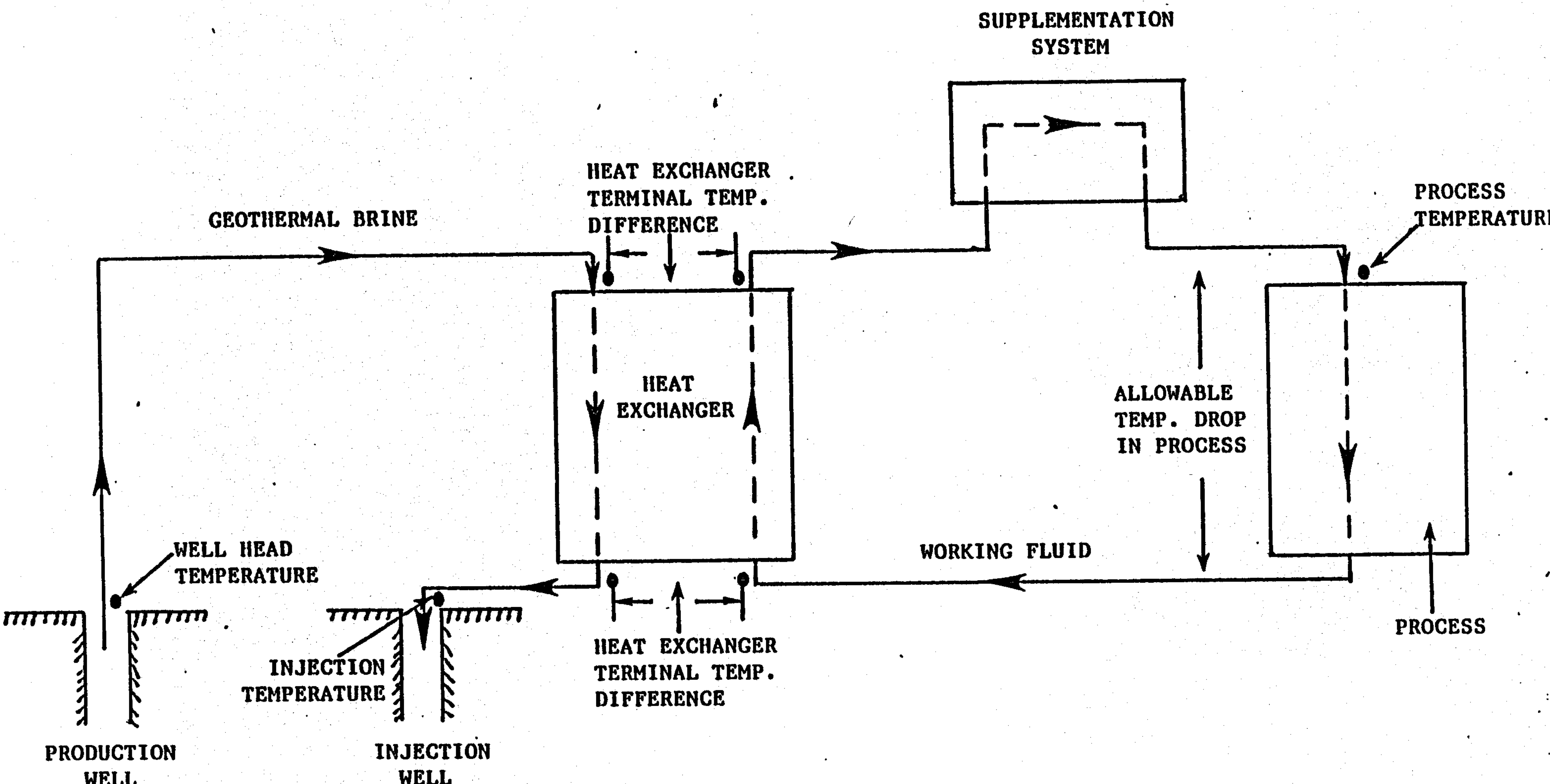


FIGURE 2

SCHEMATIC DIAGRAM FOR A ONE-STAGE INDIRECT SYSTEM

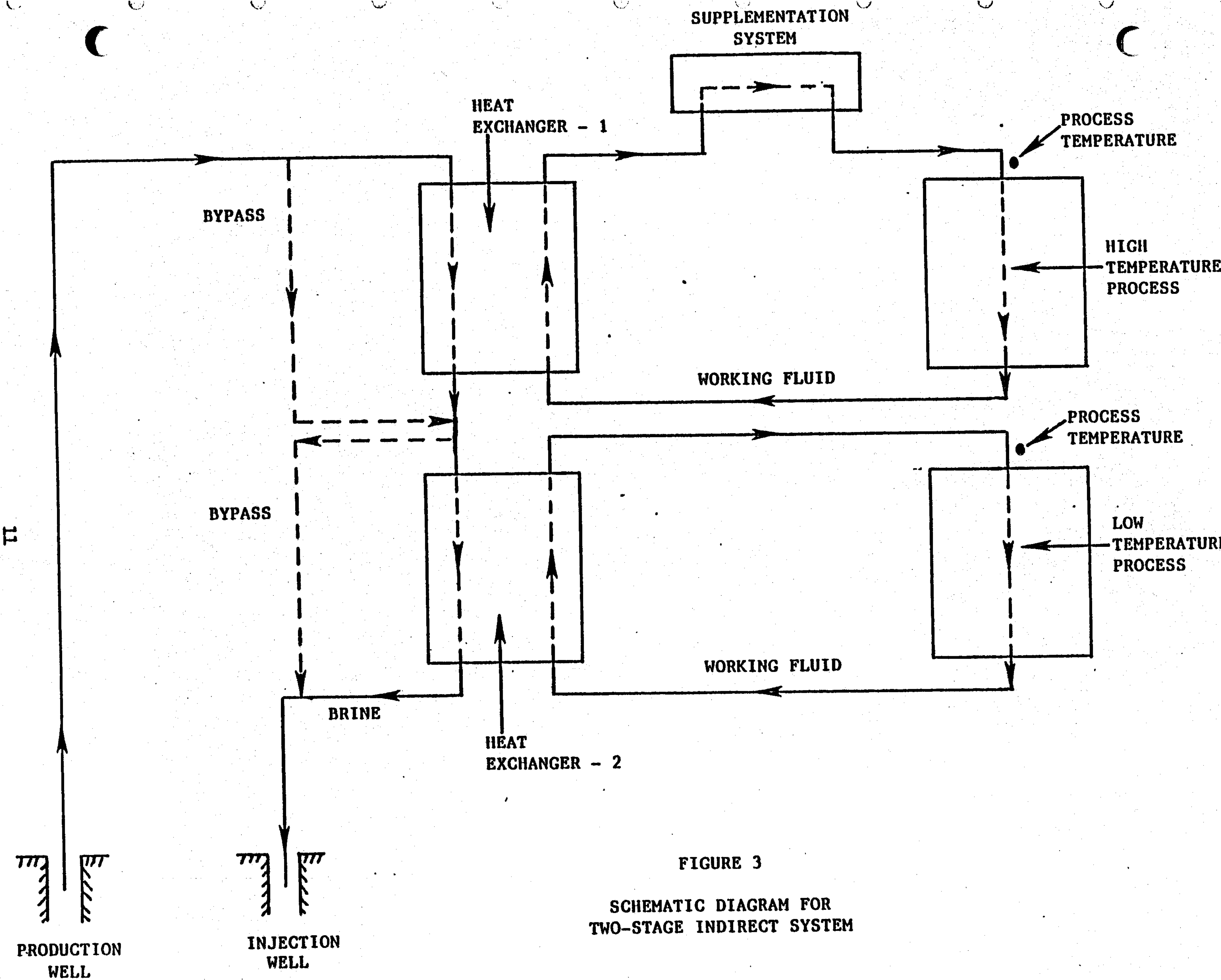


FIGURE 3

SCHEMATIC DIAGRAM FOR
TWO-STAGE INDIRECT SYSTEM

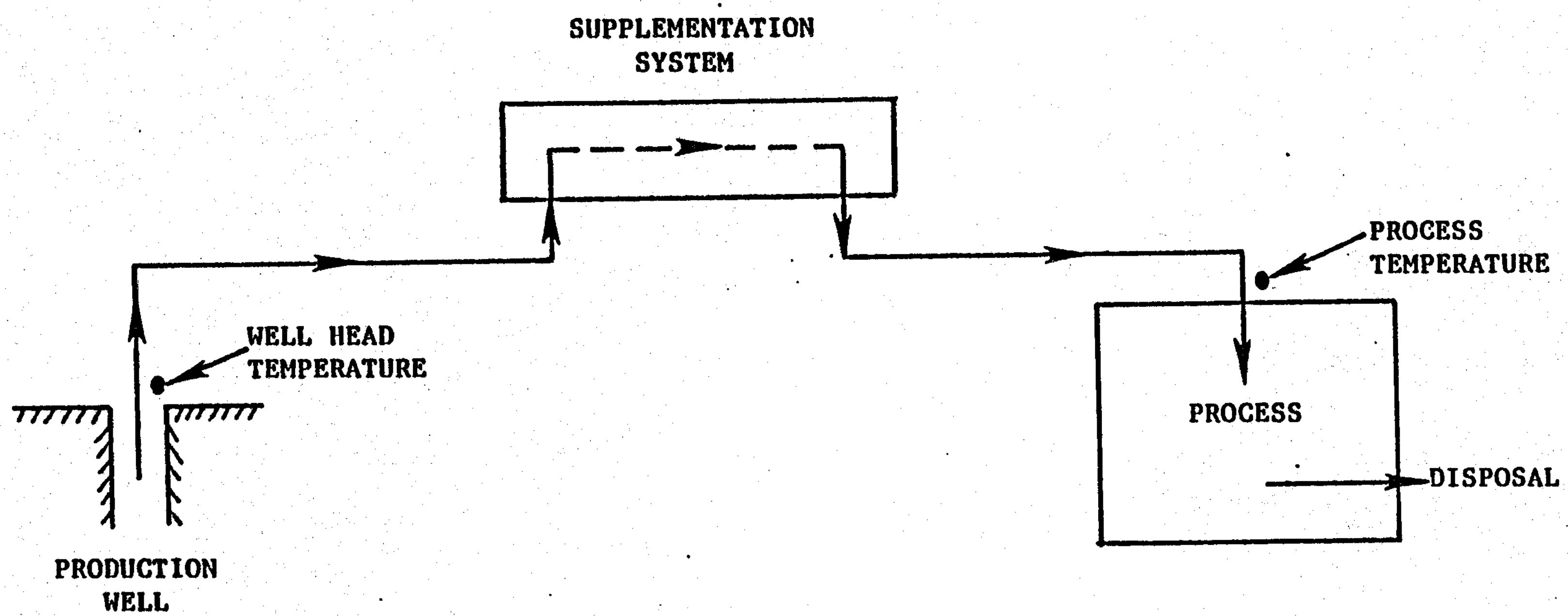


FIGURE 4

SCHEMATIC DIAGRAM FOR A DIRECT BRINE UTILIZATION SYSTEM case also, temperature supplementation can be effected if the brine temperature at plant inlet is lower than the required process temperature. It is appropriate to point out that practicality of utilizing a direct system is likely to be limited to a few sites due to the salinity and dissolved gases in the brine and local environmental regulations.

It is recognized that many other system configurations can be considered to meet the special needs of specific applications. Modifications of the system configurations associated with GEEF model could enhance the efficiency of utilization of geothermal energy. Additional configurations and modifications of the three configurations described in this section are considered to be beyond the scope of this model. Nevertheless, model users with special requirements can modify the computer routine to handle non-standard system configurations.

(ii) <u>System Design and Sizing</u>

The system design component of the model is capable of establishing the operating parameters and determining the heat exchanger size if the model user provides the input data specified in Section 2.1.1. It is emphasized that the system design sections of the GEEF model are not meant for sophisticated designing or optimization of the system. The primary objective is to determine:

(i) the brine flow rate requirements and the numbers of production and injection wells.

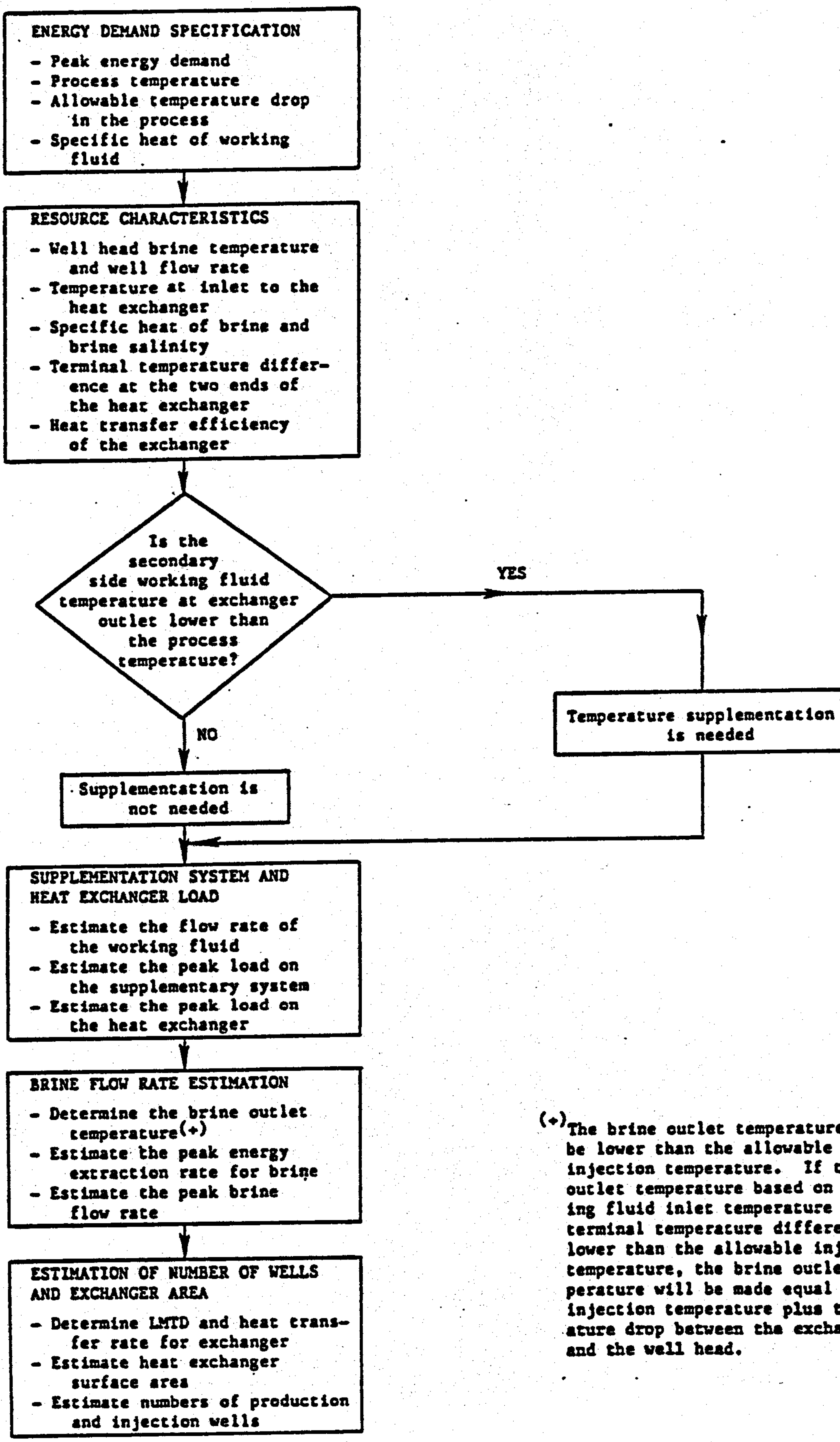
(ii) the need for temperature augmentation of the working fluid, and the size of the supplementation system; and

(iii) the size(s) of the heat exchanger(s).

Since all the system characteristics/component sizes mentioned above depend on the characteristics of the resource which are not likely to be known with a high degree of confidence when this model is used, greater detail in system design and sizing will be unproductive. The user must remember that GEEF model is a tool for a quick check of the technical and economic feasibility of using hydrothermal energy for a given project, and detailed design and costing will have to be carried out if a decision to utilize the geothermal option is made.

Figure 5 shows the sequence of steps involved in determining the heat exchanger size, the numbers of production/injection wells, and the size of the supplementary system. This explanation is relevant to a single stage system. The first step in this procedure involves the determination of the requirement of a supplementation system. To accomplish this, the heat exchanger inlet and outlet temperatures of the working fluid have to be determined on the basis of the process temperature, the allowable temperature drop for the working fluid in the process, the brine temperature at the heat exchanger inlet, and the terminal temperature differences at the two ends of the heat exchanger. If the working fluid temperature at the heat exchanger outlet is lower than the process temperature, the augmentation of the working fluid temperature through a gas, oil or electricity fueled supplementation system is estimated by determining the peak working fluid flow rate and the required temperature augmentation.

The brine temperature at the heat exchanger outlet cannot be lower than the allowable brine injection temperature (the environmental



(+) The brine outlet temperature cannot be lower than the allowable brine injection temperature. If the brine outlet temperature based on the working fluid inlet temperature and the terminal temperature difference is lower than the allowable injection temperature, the brine outlet temperature will be made equal to the injection temperature plus the temperature drop between the exchanger outlet and the well head.

FIGURE 5

STEPS IN DESIGNING A SINGLE STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM and/or injection well scale formation considerations may limit the temperature of the brine at the injection wellhead). Before setting the brine temperature at the heat exchanger outlet, it is necessary to compare the desirable temperature (this is equal to the working fluid inlet temperature plus the terminal temperature difference) with the lowest allowable brine injection temperature.+ The design brine outlet temperature will be equivalent to the higher of the two temperatures.

Once the peak load for the heat exchanger and the brine inlet and outlet temperatures have been determined, the peak brine flow rate can be computed. Using the value of the estimated production well flow rate, the model determines the number of production wells needed to yield the required peak brine flow rate. It has been assumed that there will be at least one production well and one injecion well. When there is a requirement of two or more production wells, the number of injection wells will be approximately one half the number of production wells.

The heat exchanger design process starts with the computation of the log-mean temperature difference. The heat exchanger surface area is estimated by utilizing either the data provided by the model user or the default value of the heat transfer rate in Btu/hr °F sq.ft. The default values for the heat exchanger design are based on the assumption that the heat transfer is liquid to liquid. If the heat

+ The lowest allowable temperature at the heat exchanger outlet will be equal to the sum of the temperature at the injection wellhead and the brine temperature drop between the exchanger outlet and the wellhead.

transfer is liquid to vapor, or liquid to gas, the user can override the default values for the heat transfer coefficient by inputting the appropriate value. The model is designed to make adjustments for the impact of fouling due to high brine salinity (the heat transfer coefficient decreases due to the fouling on the shell side as well as the tube side).

The determination of the operating parameters, brine flow rate, and the heat exchanger design for a two stage system is more complicated. In this case, the second stage is designed first because the brine outlet temperature from the first stage heat exchanger has to match the brine inlet temperature for the second stage heat exchanger. It is assumed that there will be no temperature supplementation in the low temperature (second) stage. The heat exchanger operating parameters, and the peak working fluid and brine flow rates through the second stage heat exchanger are determined by following the procedure explained for a single stage system. The first stage heat exchanger and the supplementation system (if needed) are designed next. The peak brine flow rate through the first stage heat exchanger is estimated on the basis of the peak energy load and the brine inlet and outlet temperatures. It is anticipated that in most cases the brine flow rate for the first stage will be different from the brine flow rate for the second stage. The higher of these peak flow rates is adopted as a figure for estimating the numbers of production and injection wells. The surplus brine for either stage bypasses the heat exchanger as shown in Figure 3*.

In the case of the direct system, the need for temperature supplementation will depend on the differences between the process temperature and the brine temperature at the inlet to the plant. The peak brine flow rate will depend on the allowable temperature drop in the process. There may be a need to design a fluid disposal system involving an option other than fluid injection. The model user is expected to provide the cost data for such a system.

It is appropriate to reiterate that the plant and field design subroutine in the GEEF model is very utilitarian and is not a substitute for a detailed design activity which must be gone through if the geothermal system is to be built. There are numerous shortcuts and assumptions in the plant design segment of the model, and no attempt was made to optimize the utilization of the resource. Most of the assumptions tend to make the plant design and cost estimates very conservative. Therefore, the resultant geothermal energy cost estimates generated by the GEEF model are likely to be higher than the revised cost estimates based on more detailed and sophisticated designs. This

---

* It is apparent that a temperature distortion will occur at the inlet to the second stage heat exchanger when some brine bypasses the first stage. This distortion is ignored by the model because this approach will result in a more conservative design, eventually yielding a higher cost estimate for the geothermal system.

approach is consistent with the need to guard against undue optimism about the geothermal system on the basis of data about which the model users are not very confident.

2.1.3 <u>Field and Plant Cost Estimation</u>

Following the completion of the field and plant design and sizing phase, the GEEF model initiates the field and plant cost estimation phase. In recongition of the lack of precision in the designing of the field and plant, the cost estimates are somewhat aggregated. The model users are also alerted to the fact that all field costs are very site-specific and they should utilize the default values in the model only when they have no cost estimates for the project site.

The cost estimates for the geothermal field and plant are grouped into five categories. These are:

(1) The Field Exploration Costs
(2) Production and Injection Well(s) Costs
(3) Fluid Transport and Distribution System Costs
(4) Heat Exchanger(s) Costs
(5) Supplementation System Costs.

The field exploration costs which include the expenses associated with all activities leading to a decision to drill production wells are site dependent and will vary as a function of the size of the project. These activities include reconnaisance, geophysical surveys, exploratory drilling, test well drilling (for most small projects, the test well will eventually become a production or injection well), and any other costs associated with the confirmation of the resource. The model has assumed a value of 5% of the development expenses as a default value for this cost, but it is recommended that the model users should override this value whenever they have a reasonably good estimate for their projects.

The production and injection well costs depend on the depth of the well, the type of rock (hard or soft), the size of the well and the well completion requirements. The GEEF model uses exponential functions for estimating the costs of standard (9 5/8" dia) wells as a function of the depth. If a pump is to be provided in conjunction with the production well, the pump costs are included in the production well cost estimates. Since the well costs are also site dependent, it would be desirable for the users to provide their own estimates of the production and injection well costs.

The fluid transport and distribution system costs can vary over a wide range depending on the distance between the wells (production and injection) and the point of utilization. The type of application has a significant impact on the fluid distribution cost. The fluid distribution costs for a single process heat application may be insignificant, but the distribution costs for a district heating system may be a very big fraction of the total system costs. The fluid transport and distribution costs include the pipeline and valves costs, as well as the costs of circulating pumps. The model computes the fluid transport and distribution costs on the basis of pipeline length and diameter data provided by the model user. However, the model user can override the computer generated costs if he has better estimates.

The heat exchanger cost estimate is based on the surface area, the material, brine salinity, and operating parameters served as flow rate, pressure and temperature. The model incorporates procedures for estimating the capital costs of shell and tube heat exchanger.

The supplementary system cost depends on the estimated peak load on the system. The plant capital cost will depend on the types of fuel used. The user is encouraged to determine the locally applicable plant capital cost for the supplementation system. The major cost for the supplementation system is the annual fuel cost, which will depend on the estimated energy supplied by the system per year and the cost per million Btu's of energy in the fuel. The efficiency of utilization of the fuel will also be a factor. The GEEF model has default values for energy utilization efficiencies, current prices of fuels and the real fuel cost escalation rates. In this case also, the model user is advised to provide the site-specific cost estimates.

It is important to recognize that the relative attractiveness of a geothermal system will depend on the costs of alternative energies/ fuels. Therefore, the users should be careful in estimating the costs of alternative fuels over the lifetime of the project.

The GEEF model will utilize the internally generated or user provided field and plant size/cost estimates to carry out an economic comparison between a geothermal system and alternatives. The validity of this comparison will be dependent on the soundness of the cost estimates and the realism of values of the financial parameters utilized in the economic analysis. A detailed explanation of the economic analysis subroutines is presented in the next section.

2.2 Financial Subroutine

2.2.1 Economic Analysis

The economic analysis segment in the GEEF model consists of a financial subroutine. It involves a step by step economic evaluation of the geothermal energy system for direct uses. It includes (1) a determination of preproduction costs (exploration, confirmation, environmental studies and development) and of energy production costs, replacement costs, alternative plant cost for supplementation, annual fuel, operation and maintenance costs and the associated rates of escalation* (2) a consideration of the various fiscal parameters, such as, depreciation, depletion allowance, tax credits (investment and energy), and, (3) a consistent financial methodology that appropriately treats the capital structure of the venture, tax status of the owner, system lifetime, etc.

The three basic input data requirements of the proposed integrated economic model are: (1) geothermal energy system data (GESD): a description of the geothermal energy system for direct applications to meet a specific quantity of energy demanded in district heating, industrial processing or space heating; (2) system owner's financial

---

* The various costs estimated in the engineering/cost subroutine are inputs into the financial model.

data (SOFD): the financial characteristics of the resource developer or owner of the system: and, (3) economic conditions data (ECD): a set of assumptions on the general economic climate for the period of analysis. Specific items belonging to each of these basic input data requirements are presented in Table 1 and 2.

The basic approach of the financial subroutine is to derive an estimate of the owner or developer's total system lifetime cost on an annual basis for producing a specific amount of annual energy output that will satisfy the user's stated or expected annual energy demand in direct application. The ratio of annual costs (when suitably discounted for by the "time value of money") to the expected annual energy output produced by the system is the cost of energy expressed in constant dollars per MMbtu. This derived price of energy will yield revenues to the investor which will cover all the costs incurred during system life, including a desired rate of return. The price per unit of energy calculated by the GEEF model is the levelized cost of energy (ALCE) which represents an average of the distribution of varying charges.

<u>Treatment of Costs for Financial Analysis</u>

Even though in the final analysis all costs - capital, replacement, operation and maintenance, and fuel costs - are considered together to derive the cost of energy, each of these cost categories has to be reported separately because they are influenced by different

Table 1

Economic Feasibility Model Assumptions:
Geothermal Energy System Data

Data Descriptive Term	Symbol
I. Geothermal Energy System Data (GESD)	
A. Energy required:	
peak energy requirement	IPKRE
utilization factor	
B. Resource Characteristics:	
wellhead temperature	ITWHP
well flow rate	IFPW
well depth	WDEP
salinity index	ISAL
temperature drop	ITDRP
annual utilization factor	UFSUP
C. System and Components Life:	
project	N1
D. Capital costs:	IC
production well	IPWC
transmission	DISSC
heat exchanger	PHIX
injection well/disposal system	IIWDSC
supplementation	SUPCST

Table 2

Economic Feasibility Model Assumptions:
System Owner's Financial Data

System Owner's Financial Data (SOFD)	Symbol
Debt fraction	D
Equity fraction	E
- common stock	E_c
- preferred stock	E_p
Interest rate on debt	A_{kd}
Rate of return on:	
- common stock	A_{kc}
- preferred stock	A_{kp}
Federal income tax rate	T_f
State income tax rate	T_s
Property tax/insurance rate	B1
Royalty rate	B2
Investment tax credit	A1
Depletion allowance	B3
Economic Condition Data (ECD)	
General inflation rate	g
Capital cost escalation rate*	gc
Operation and maintenance cost escalation rate	g_{om}
Fuel cost escalation rate	g_f

* Escalation rates are expressed in real terms over and above the general rate of inflation.

Table 2 (Concluded)

Economic Feasibility Model Assumptions:
System Owner's Financial Data

Time Parameters	Symbol
System economic life	N1
Depreciation life for tax purposes	N2
Start-up or commercial operation year (assumed to occur at the beginning of this year)	Iv
start expenditure year	Is
Base or price year for constant dollars	Ib
Intermediate Output Data (IOD)*	
Weighted average after-tax cost of capital**	A_k
Effective income tax rate	TR
Amortization capital recovery factor	CRFKN1
Depreciation capital recovery factor	CRFKN2
Annualized fixed charge rate	$\overline{FCR}$

* These are calculated or predetermined values in the model.

** A_k is treated as discount rate.

escalation rates, depreciation and tax treatment, all of which have significance for the cash flow analysis.

Major preproduction cost categories of geothermal resource development and distribution are exploration, confirmation, environmental studies, and development. Each of these categories consists of several cost elements which are presented in Table 3. For tax purposes, preproduction costs of hydrothermal energy system can be classified into capitalized and expensed costs. Capitalized costs are investment expenditures which are recovered through depreciation and depletion over a period of time longer than one year. Expensed costs can be recovered by "write-off" for tax purposes in the year they are incurred. If income does not exist from the project that generated expensed costs in the year in which they are incurred, these costs, can be written off for tax purposes against income from other sources. In the GEEF model, preproduction costs are capitalized and deducted over a period of time as depreciation on the assumption that the project does not generate income in the year expensed costs are incurred.

Sensitivity Analysis

Geothermal energy cost depends on the particular financial and economic assumptions considered in the model. Changes in the values of the input parameters can be expected to affect cost and cash flows. The GEEF model has the capability for conducting sensitivity or scenario analysis on any or all measures of economic feasibility that are included in the model. The user can specify one or more possible

TABLE 3

PREPRODUCTION CAPITALIZED AND EXPENSED COST ITEMS

Preproduction Cost Factors	Capitalized	Expensed
Exploration -		
Reconnaissance		x
Pre-lease exploration	x	x
Land acquisition	x	x
Post-lease surface exploration	x	x
Shallow subsurface exploration	x	x
Detailed exploration	x	x
Deep exploratory wells	x	x
Confirmation -		
Injection wells	x	
Flow test	x	
Environmental Studies	x	
Development -		
Well field engineering	x	
Surface facility construction	x	
Well field development (drilling rig, surface piping, etc.)	x	x

* Technecon Analytic Research, Inc. Geothermal Investment and Policy Analysis With Evaluation of California and Utah Resource Areas, October, 1979. Chapter 2, pp. 3.5.

scenarios consisting of a set of system resource characteristics (wellhead temperature, well depth, rock type, etc.) finance data (debt/equity ratio, interest rate, income tax rate, etc.) and economic parameters (inflation rate, cost escalation rates, selling price of energy, etc.).

A baseline has been specified that describes default values for a typical geothermal energy facility for direct application purposes. It also provides default values for a given set of general economic conditions that are commonly utilized in the financial analysis. If the user incorporates the decriptions of the GES and the default values for the general economic conditions provided in the baseline, some of the model intermediate outputs such as the weighted after-tax cost of capital (A_k), capital recovery factor (CRF) and fixed charge rate (FCR), are predetermined. Incorporation of these intermediate outputs considerably simplifies the use of model. However, specifying different values for parameters other than the default values, will require fresh calculations of intermediate results according to equations (2) for A_k, (3) and (4) for CRFKN1 and CRFKN2, and (9) for FCR in Section 2.2.3.

2.2.2 Procedures for Calculating Economic Feasibility Measures

This subsection presents the stepwise procedures and equations necessary for the calculation of following economic feasibility measures: levelized cost of energy (ALCE), year-by-year cash flows

(YCF), net present value (NPV), discounted cash flow rate of return (DCFROR), and discounted payback (DPP).

2.2.3 Method for Calculating Levelized Cost of Energy (ALCE)

All the system lifetime capital charges are consolidated into a single number, the annualized fixed charge rate, $\overline{FCR}$. The product of $\overline{FCR}$ and the present value of the capital investment (AICPV) results in the contribution of initial capital investment, replacement costs, initial plant costs due to supplementation, income and property taxes, tax credit and depreciation to the annualized system resultant capital cost (ACC). $\overline{FCR}$ includes the effects of ownership of the system, capital structure, project as well as component lifetime, and the cost of capital in determining the cost of energy calculation. $\overline{FCR}$ interacts with the rest of the model in determining the levelized cost of energy (ALCE).

To the present value of capital charges are added the present values of the cost streams arising from operating, maintenance and fuel costs, again adjusted for inflation and relevant escalation rates. Two additional adjustments to arrive at the present value of all the costs associated with the project are the appropriate depletion allowance and royalty payments. The levelized cost of energy in the start-up year is determined by equating the present value of total project costs to the present value of the revenue stream.

The following equations are used for computing the levelized cost of energy (ALCE).

1. <u>Compute Effective Marginal Income Tax Rate (TR)</u>

$$TR = T_f + T_s - (T_f \cdot T_s) \qquad (1)$$

where T_f and T_s are Federal and State marginal income tax rates.

2. <u>Compute Weighted Average After-Tax Cost of Capital or Discounted Rate (A_k)</u>

$$A_k = (1 - TR)\, A_{kd} \cdot AD + A_{kc} \cdot E_c + A_{kp} \cdot E_p \qquad (2)$$

where A_{kd} is the interest rate on debt, AD is debt fraction, A_{kc} and A_{kp} are rates of return on common (E_c) and preferred equity (E_p) financial instruments. The tax deductibility of interest rate is denoted by (1-TR). The weighted average after-tax cost of capital A_k is used to calculate capital recovery factor, present values of cash flows, and discounted payback.

3. <u>Compute Amortization Capital Recovery Factor (CRFKN1)</u>

$$CRFKN1 = \frac{A_k}{1 - (1 + A_k)^{-N1}} \qquad (3)$$

where N1 is the system lifetime. Capital recovery factor refers to the fraction of original capital that is to be paid in uniform annual payments so as to fully amortize the loan over a specified period of time, N1.

4. <u>Compute Depreciation Capital Recovery Factor (CRFKN2)</u>

$$CRFKN2 = \frac{A_k}{1 - (1 + A_k)^{-N2}} \qquad (4)$$

where N2 is depreciation life for tax purposes. It is expected that geothermal system capital components have a shorter life than the project life and therefore need replacements. An average depreciation life of 10 years is assumed for capital replacement. CRFKN2 is used in calculating the present value of depreciation.

5. Compute Depreciation Factor (DPFSD)

$$\text{DPFSD} = \frac{2\left(\text{N2} - \dfrac{1}{\text{CRFKN2}}\right)}{\text{N2 (N2 + 1)} \; A_k} \qquad (5)$$

where DPFSD is the sum of year-digits depreciation factor. $\frac{1}{\text{CRFKN2}}$ represents the present value of the depreciation of an original asset over N2 years. Sum of the year-digits depreciation method provides for acceleration of yearly depreciation charges in the earlier years and they decline at the end of accounting lifetime.

6. Compute Annualized Fixed Charge Rate ($\overline{\text{FCRN1}}$)

$$\overline{\text{FCRN1}} = \text{CRFKN1}\left[\frac{1 - \text{TR (DPFSD)} - \text{A1}}{1 - \text{TR}}\right] \qquad (6)$$

7. Compute Amortized Replacement Fixed Charge Rate ($\overline{\text{FCRN2}}$)

$$\overline{\text{FCRN2}} = \text{CRFKN2}\left[\frac{1 - \text{TR (DPFSD)} - \text{A1}}{1 - \text{TR}}\right]$$

8. <u>Compute Weighted Replacement Fixed Charge Rate ($\overline{FCRRN1}$)</u>

$$\overline{FCRRN1} = \frac{CRFKN1}{CRFKN2}\left[\overline{FCRN2} + \left(\frac{1 + g}{1 + A_k}\right)^{N2} \cdot \overline{FCRN2}\right] \qquad (8)$$

where g is the general rate of inflation.

9. <u>Compute Weighted Annualized Fixed Charge Rate ($\overline{FCR}$)</u>

$$\overline{FCR} = [(A_{11} \cdot \overline{FCRN1})] + [(1 - A_{11} \cdot \overline{FCRRN1}] + B1 \qquad (9)$$

where A_{11} = fraction of initial AICPV not to be replaced,

B_1 = property tax and insurance rates

10. <u>Compute Present Value of Capital Investment (AICPV)</u>

$$AICPV = (1+g)^{Ib-Iv} \sum_{I=Is}^{Iv+N1} IC_I \, (1 + g + g_c)^{I-Ib} \, (1 + A_k)^{Iv-I} \qquad (10)$$

where AICPV = present value of investment capital at the start-up year Iv.
g_c = capital cost escalation rate (real)
Ib = base year
I = year of cash flow
Iv = start-up year
Is = start expenditure year

AICPV is the present value of all capital investment in the energy system brought to the beginning of the start-up year Iv, expressed in base year dollars. IC_I is the capital investment in year I expressed in Ib dollars. IC_I can occur prior to start-up year as well as during the economic lifetime of the commercial operation of the project for capital replacement purposes. This is especially true in geothermal energy system where the lives of wells may be only 10 years and the project life may be

20 or 30 years. Reinvestments have to be treated as part of the capital investment stream IC_I. A summation is performed for all years in which IC_I is not zero. This formula is used under the assumption that the capital cost escalation rates for all subcategories of IC are constant in real terms for all years. If capital cost escalation rates among components vary, each component has to be evaluated separately and obtain the sum of the present values. Interest during construction years as well as plant cost of the supplementation system are included in AICPV.

11. Compute Fuel Cost Present Value Factor (DESCF)

$$DESCF = \left(\frac{1 + g + g_f}{1 + g}\right)^{Iv-Ib} \left\{ \frac{1 - \left(\frac{1 + g + g_f}{1 + A_k}\right)^{N1}}{A_k - g - g_f} \right\} \quad \text{if } g+g_f \neq A_k \qquad (11)$$

$$DESCF = \left(\frac{1 + g + g_f}{1 + g}\right)^{Iv-Ib} \cdot N1 \qquad \text{if } g+g_f = A_k$$

where g_f is real escalation rate for fuel costs. The fuel costs enter the GEEF model in the case of a hybrid system where supplementation by a conventional energy system is necessary to provide the balance of required energy that is not met by the geothermal plant.

12. Compute Operation and Maintenance Present Value Factor (DESCOM)

$$DESCOM = \left(\frac{1 + g + g_{om}}{1 + g}\right)^{Iv-Ib} \left\{ \frac{1 - \left(\frac{1 + g + g_{om}}{1 + A_k}\right)^{N1}}{A_k - g - g_{om}} \right\} \text{if } g+g_{om} \neq A_k \quad (12)$$

$$DESCOM = \left(\frac{1 + g + g_{om}}{1 + g}\right)^{Iv-Ib} \qquad \text{if } g+g_{om} = A_k \quad (12)$$

where g_{om} is real escalation rate for operation and maintenance costs. In equations (11) and (12) escalation factors are calculated to convert the future recurrent cost streams into their present values at the beginning of start-up year expressed in base year dollars.

13. Compute Annualized Fuel Cost Multiplier (AFF)

$$AFF = DESCF \cdot AFCF \qquad (13)$$

where AFCF is the fuel cost recovery factor and it is set equal to CRFKN1.

14. Compute Annualized Operation and Maintenance Cost Multiplier (AFOM)

$$AFOM = DESCOM \cdot AOMCF \qquad (14)$$

where AOMCF is the O&M cost recovery factor and it is set equal to CRFKN1.

15. Compute Total Annualized Cost of Energy (TACE)

$$ACC = \text{annualized capital cost} = AICPV \cdot \overline{FCR} \qquad (15)$$
$$AFC = \text{annualized fuel cost*} = FC \cdot AFF \qquad (16)$$
$$AOMC = \text{annualized O\&M cost**} = O\&M \cdot AFOM \qquad (17)$$
$$TACE = ACC + AFC + AOMC \qquad (18)$$

Each of the annualized costs in equation 15, 16 and 17 represents the present values of distinct sums of a series of

---

* The annual fuel cost (FC) in the start-up year is expressed in base year dollars.

** The annual cost for operation and maintenance (O&M) in the start-up year is assumed to be 5 percent of the present value of capital cost until the start-up year only, exclusive of the replacement capital cost in later years.

constant annual payments towards the total annualized cost of the energy project TACE in equation (18). They are expressed in base year dollars per year. If the system resultant cost TACE is collected each year as revenues, it will be equal to the sum of the present values of all separate and distinct cost distributions of ACC, AFC and AOMC.

16. Compute Levelized Cost of Energy (ALCE)

$$ALCE = \frac{TACE}{ERA} = \$/MMbtu \qquad (19)$$

where ERA is expected annual energy output expressed in MMbtu's. ERA is an exogenous input into the financial model supplied by the user. The levelized cost of energy, ALCE (in equation 19) is a measure of the cost per unit of energy, expressed in constant \$/MMbtu in base year dollars. As such it represents constant real value, growing in nominal value at the general inflation rate. ALCE also results in zero net present value by equating the present value of revenue stream to the present value of life cycle cost of the system.

17. Compute Levelized Cost of Energy with Depletion Allowance and Royalty (ALCEDR)

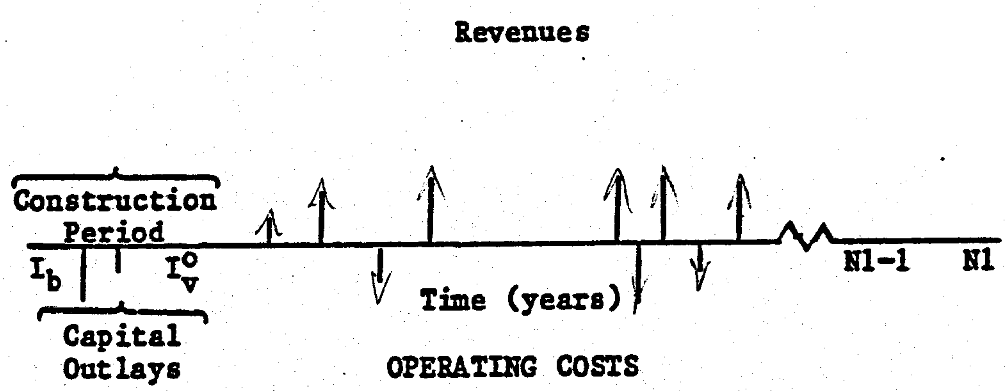
Where the effect of depletion allowance and royalty on the system ALCE is to be considered, ALCE in equation 19 becomes ALCEDR as in equation 20.

$$ALCEDR = ALCE * \frac{1 - TR}{1 - TR + B_3 \cdot TR - B_2 + B_2 \cdot TR} \qquad (20)$$

where B3 = depletion allowance as a fraction of gross revenue in equation 21 or TACE in equation 18.

B2 = royalty payments as a fraction of gross revenue in equation 21 or TACE in equation 18.

Figure 6 illustrates the cash flows associated with the geothermal energy system throughout its economic lifetime. Cash outflows or negative cash flows can be shown below the line whereas cash flow or revenues can be shown above the line. The GEEF model computes the levelized cost of energy (ALCE) for which the sum of the present values of the cash flows (negative and positive) occurring at different points of time is equal to zero.



System Cash Flows

Figure 6

Ib = base year
Iv = start-up year or first year of commercial operation
N1 = project lifetime

2.2.4 Year-by-Year Cash Flow Analysis

Year-by-year cash flow analysis in the GEEF model estimates gross revenue, royalty payments, operating costs, depreciation charges, depletion allowance, tax payments, interest payments, investment and energy tax credits. It derives net income before and after taxes, and yearly net cash flows (ANCF) to determine the net present values (NPV), discounted cash flow rate of return (DCFROR), and discounted payback period (DPP).

Geothermal costs vary according to the financial and economic assumptions considered in the analysis. It will become clear from cash flow analysis that the discounted payback period and discounted cash flow rate of return are sensitive to changes in capital investment, debt/equity ratio, return on debt and equity instruments, cost escalation rates and selling price.

For the purposes of estimating annual gross revenue from a geothermal project, the levelized price of delivered energy from the least-cost alternative energy system is calculated. If the derived or estimated levelized cost of energy (ALCE) for the geothermal system is less than the levelized price of delivered energy from the least cost alternative, then the geothermal cost of energy is used in estimating the annual gross revenue streams for the geothermal project. The financial and economic assumptions presented in Table 2 are used in determining the year-by-year cash flow.

The model will compute year-by-year net cash flows for a given set of system resource characteristics, financial and economic scenario.

In its capsule form, the following stepwise procedure (equation 21) is involved in deriving annual net cash flows:

$$\begin{aligned} GY(I) &= ALCE * ERA \\ ANYBT(I) &= GY(I) - BT(I) - OMT(I) - FCT(I) - RODT(I) - DEP(I) - \\ &\quad DPLT(I) \\ ANPT(I) &= ANYBT(I) - TYT(I) \\ ANCF(I) &= ANPT(I) + DEP(I) + DPLT(I) + ITCY(I) - ROE(I) \end{aligned} \tag{21}$$

where

I = year of cash flow
GY = gross income
ALCE = levelized cost of energy
ERA = annual energy output
ANYBT = net income before taxes
BT = royalty payments
OMT = operation and maintenance costs
FCT = fuel costs
RODT = return on debt
DEP = depreciation charges
DPLT = depletion allowance
ANPT = net income after tax
TYT = income tax
ANCF = net cash flow
ITCY = investment and energy tax credits
ROE = dividend payments

2.2.5 Methodology for Computing Net Present Value (NPV)

Net present value (NPV) is one of the most commonly used criterion for the selection of a project. NPV is the sum of the discounted revenue and cost streams. The after-tax net cash flows (ANCF) are discounted back to the base year to determine the present values of ANCF. The discount rate used to determine NPV in this finance model is the weighted average after-tax cost of capital, A_k. NPV is given by equation 22:

$$NPV = \sum_{I=1}^{N1} \frac{ANCF(I)}{(1 + A_k)^I} - AICPV \tag{22}$$

where

AICPV = capital investment for the project
ANCF = annual net cash flow
A_k = present value discount factor
N1 = life of the project in years

The project is deemed economically attractive if NPV is positive. If the user specifies the levelized price of delivered energy that is greater than the one calculated by GEEF model for the geothermal energy system, the net present value will be positive.

2.2.6 Discounted Cash Flow Rate of Return Methodology

Discounted cash flow rate of return (DCFROR) is the rate of return that makes the net present value (NPV) of a project equal to zero. NPV is equal to the difference between a project's cash inflow including after-tax salvage value and the present worth of after-tax investment calculated at the minimum rate of return. DCFROR is an overall measure of project profitability where year-by-year cash flows are weighted differently. DCFROR in the GEEF model is based on annual net cash flows (ANCF), the money that is available to pay out the capital invested after paying the investor a guaranteed dividend return to equity. DCFROR is compared, to the minimum discount rate, A_k, or the weighted average after-tax cost of capital, in order to determine if a particular project is satisfactory.

DCFROR is calculated by solving for r in equation 23:

$$AICPV = \sum_{I=1}^{N1} \frac{ANCF(I)}{(1 + r)^{I}} \qquad (23)$$

where

ANCF = annual net cash flows
N1 = project life in years
AICPV = total capital investment expressed in base year dollars
r = discounted cash flow rate of return
I = year of cash flow

2.2.7 Discounted Payback Period Calculations

Discounted payback period (DPP) is the number of years required for annual net cash flows (ANCF) to recover initial capital investment at the weighted average after-tax cost of capital or the discount rate, A_k. DPP is calculated by solving for h in the following equation:

$$AICPV1 = \sum_{I=1}^{h} \frac{ANCF(I)}{(1 + A_k)^I} \tag{24}$$

where

AICPV1 = initial capital investment expressed in base year dollars
ANCF = annual net cash flows
A_k = weighted average after-tax cost of capital or discount rate
h = discounted payback period in years

2.2.8. Determination of Economic Feasibility

The financial subroutine of the GEEF model is designed primarily to determine the ALCE of a geothermal energy system (GES) for direct applications. However, in order to determine the economic feasibility of a GES, it is necessary to compare the levelized cost of energy (ALCE) of GES with the ALCE of alternative conventional energy system. The GEEF model's financial methodology can be used to determine the

ALCE of a competing conventional energy system. The ALCE of the least-cost alternative conventional energy system is easily determined by using annualized fuel cost multiplier AFF in equation 13 of the GEEF model. The product of the delivered price of the least-cost competitive conventional fuel (expressed in $/MMbtu) and AFF will give the ALCE for the alternative for the comparable lifetime of GES considered in the analysis.

Once the ALCEs of the GES and the conventional system are computed, an appropriate determination of the economic feasibility of the GES can be made. For example, a lower ALCE for GES than the ALCE for the alternative system demonstrates the economic attractiveness of GES and provides evidence of GES competitiveness on a lifecycle costing basis. However, the alternative energy system will prove to be more economical if ALCE for GES is greater than the ALCE for the conventional system.

APPENDICES

APPENDIX A

A.0 THE GEEF MODEL: USER'S MANUAL

A.1 Introduction

The Geothermal Engineering and Economic Feasibility (GEEF) model is designed to provide a uniform engineering and economic evaluation methodology for determining the economic feasibility of geothermal resource utilization for direct heat applications. The GEEF model outputs will enable the decision makers to compare the economics of geothermal energy projects with the economics of alternative or conventional energy systems at an early stage in the decision process.

The GEEF model has two main segments: the engineering design/cost segment and the economic analysis segment. The engineering design/cost segment of the model determines the number of production and injection wells, heat exchanger design, operating parameters for the system, requirements of supplementary system and the fluid rates. Both the single stage system and the two stage cascade systems in which the second stage may involve a space heating application after a process heat application in the first stage can be easily handled by the model. The financial segment of the model carries out life cycle cost analysis of the proposed geothermal energy system and yields the following outputs: the levelized cost of energy (ALCE), net present value (NPV), discounted cash flow rate of return (DCFROR) and discounted payback period (DPP). If the proposed geothermal energy system (GES) is deemed economically feasible when compared with the alternative or conventional energy system (CES) based on the life cycle cost criterion, the model also generates year-by-year cash flows for the geothermal energy project being evaluated.

The structure and input/output characteristics of the GEEF model are provided in Figure 7. The quantitative outputs of the GEEF model are designed strictly to enable the potential user for making an initial determination of the technical and economic feasibility of utilizing hydrothermal energy for direct heat applications.

A.2 A Guide to the GEEF Model Users

A detailed description of the GEEF model's methodology for determining the economic feasibility of geothermal energy system for direct heat applications is presented in Section 2. This section provides a user's guide to the GEEF model. The GEEF model is coded in Fortran IV computer language and has been tested on IBM 370/148 using Fortran H compiler. The program does not require any changes or modifications for compilation by either Fortran G or Fortran H compiler. A complete listing of the program is given in Appendix C.

The GEEF model displays pre-tax and after-tax cash flow projections and calculates the following four outputs for investment decisions: levelized cost of energy (ALCE), net present value (NPV), discounted cash flow rate of return (DCFROR) and discounted payback period (DPP).

The GEEF computer model accepts Geothermal Energy System Data, System Owner's Financial Data and Economic Condition Data items listed in Table 2 (Section 2.2.1) as inputs and computes the total system lifetime cost on an annual basis for the expected annual energy output (ERA). The model computes ERA based on the peak energy demand and the

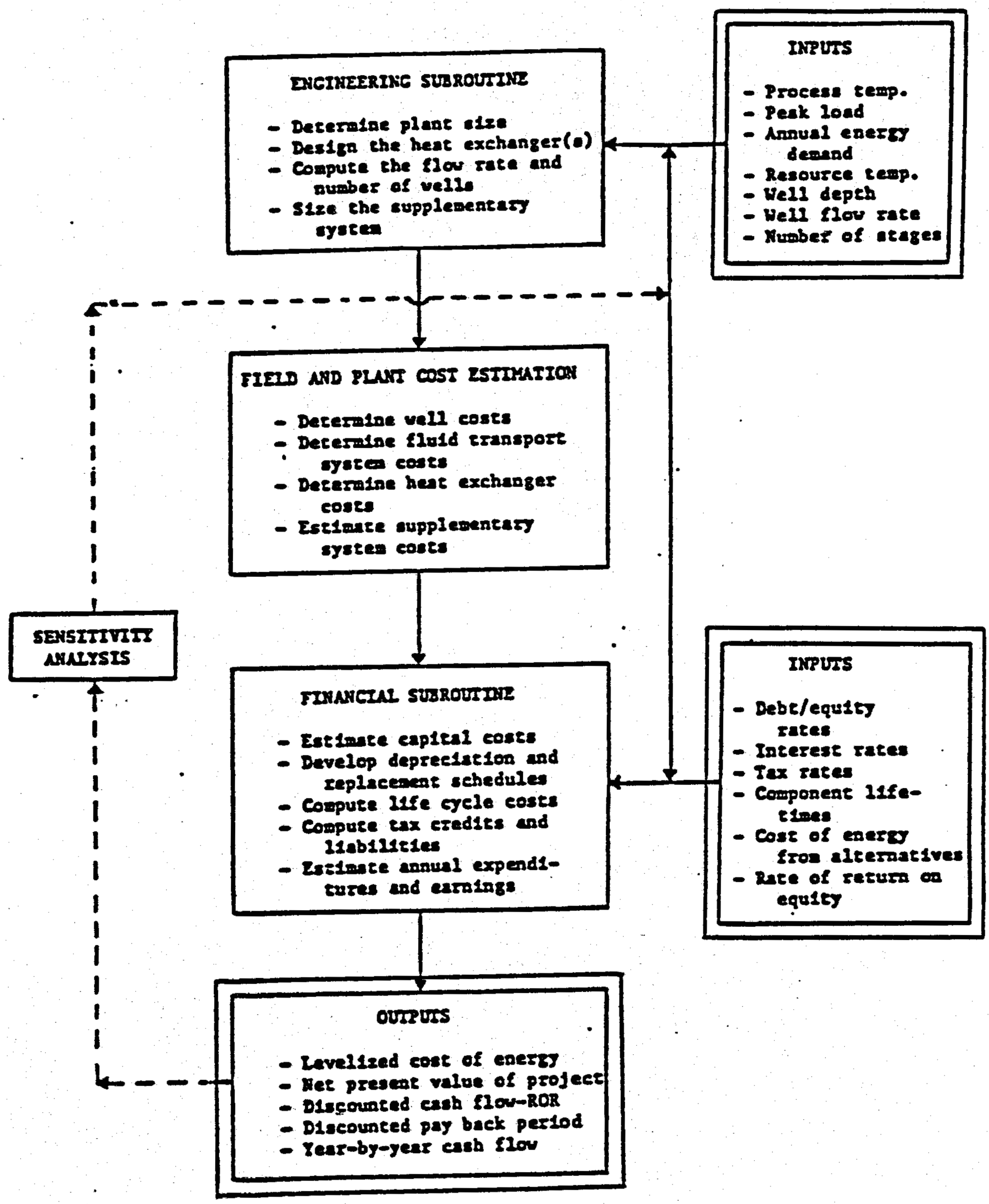


FIGURE 7

Structure and Input/Output Characteristics of GEEF Model utilization factor specified by the user. For the purpose of determining the levelized cost of energy (ALCE), the GEEF model computations are divided into two sections: engineering cost determination section and economic analysis section.

By utilizing the Geothermal Energy System Data, the engineering cost determination section estimates the following elements: total well flow rate, number of required production and injection wells, production well cost, injection well cost, base capital cost of heat exchangers (if any required), base capital cost for distribution system, and average annual fuel cost where supplementary system is considered.

These engineering cost estimates along with the System Owner's Financial Data and Economic Conditions Data described earlier (Section 2, Table 2) are used in the economic analysis section of the model to compute internally the following intermediate outputs: effective income tax rate, weighted average after-tax cost of capital, capital recovery factor, fixed charge rate, present value of capital investment, present value factors and annualized multipliers for fuel cost as well as operation and maintenance costs.

The model allows for capital construction and replacement schedule. In view of the overlapping of activities in the preproduction process, the total construction period is assumed to be three years. The model assumes zero salvage value at the end of the project economic life. Depreciation charges are calculated based on sum of the year-digits method. The levelized cost of energy is computed for both the geothermal energy system (GES) and the least-cost competing conventional energy system (CES). The annual net cash flows (ANCF) are discounted to determine NPV, DCFROR and DPP.

After the completion of a first run based on GEEF model's baseline or the default values for input data, the user can modify or perturb any of these values in the input data base and rerun the model. The sensitivity analysis for ALCE, NPV, DCFROR and DPP may be performed by varying cost escalation rates, debt/equity ratio, investment tax credit rate, etc. Input data can be easily modified or altered by making appropriate changes in the input data base.

A.3 The GEEF Model Input Data Base: ECODAT File

Only one data file, ECODAT, is maintained in the input data base. The data in ECODAT may be changed by the user of the GEEF model both to obtain Geothermal Energy costs and its related cash flows, and to perform sensitivity analysis. However, a specified data format has to be followed.

ECODAT contains variable number of records depending upon the type of geothermal energy system. The number of records varies between a minimum of 8 and a maximum of 10. For direct system (0 heat exchanger), the number of records will be 8, whereas, for 1 and 2 stage indirect systems, the number of records required will be 9 and 10 respectively. The input data requirements including the variable/parameter name and description, their default values and formats corresponding to the direct system, 1 stage indirect system and 2 stage indirect system are presented in Tables 4,5 and 6 respectively.

A.4 Accessing GEEF

After the user has logged on computer, he must create ECODAT file. The ECODAT file is developed by following the formats described in the previous subsection. Once the ECODAT file is generated, the user should create and save a Job Control Language (JCL) file, ECOEXC, consisting of the following control statements:

```
// JOB CARD (Accounting Information and User ID)
//A EXEC FORTHCLG or FORTGCLG
//FORT.SYSIN DD DSN=WYL.USERID.GEEF,DISP=SHR
//GO.FT08F001 DD DSN=WYL.USERID.ECODAT,DISP=SHR
```

It must be noted that standard IBM data set naming conventions have been followed in creating the above JCL file.

When both ECODAT and ECOEXC files have been created, the user is ready to execute GEEF by issuing a command: RUN FETCH ERT=1. ERT represents the estimated job run time in minutes. The output can now be fetched online or printed offline.

A.5 Sample Inputs and Outputs of the GEEF Model

For illustration sake, three test cases are presented in this subsection. The inputs for these cases are illustrated in Tables 7-9 and the corresponding outputs are given in Tables 10-12.

TABLE 4

Input Data Format for Direct Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
1	1-3	Numbers of Heat Exchangers	IHEXC[+]	-	-	0 - for direct system. 1 or 2 for one or two stage indirect systems, respectively.	I3
	4-6	Type of Supplementary System	ITSUP	-	-	1 - oil, 2 - gas, 3 - electrical.	I3
	7-9	Salinity Index	ISAL	-	-	0 - low (up to 1000 ppm T.D.S.), 1 - high (above 1000 ppm T.D.S.).	I3
	10-17	Heat Transfer Coefficient	HTCOEF	BTU/Ft^2 °F hr.	120	In the case of high salinity, the exchanger surface area is increased by 20%. Liquid-to-liquid heat transfer is assumed.	F8.2
2	1-5	Production Wellhead Temperature	ITWHP	°F	-	This temperature must be specified by the user.	I5
	6-10	Temp. Drop Between Wellhead and Plant Inlet	ITDRP	°F	5		I5
	11-15	Process Temperature	ITPR[+]	°F	-	This is the working fluid temperature at the process inlet.	I5
	16-20	Allowable Temperature Drop in the Process	IATD[+]	°F	-	This will depend on the lowest working fluid temperature in the process.	I5
	21-28	Peak Energy Requirement for Process	IPKRE	MMBTU/hr	-	The peak demand is based on one hour.	I8
	29-36	Well Flow Rate	IFPW[+]	lbs/hr	-	The user can specify three values (lowest, most likely, and highest).	I8
	37-41	Specific Heat for Brine	SHB	BTU/lb/°F	1.0		F5.2
	42-46	Process Utilization Factor	UFSUP	Fraction	0.6	This utilization factor is based on annual utilization.	F5.2
3	1-8	Supplementary System Fuel Cost	SUPCST	$/Unit	-	Electric - $ per KWHR; gas - $ per 1000 SCF; oil - $ per barrel.	F8.2
	9-16	Supplementary System Efficiency Factor for Converting Chemical Energy into Thermal Energy	EFFY	-	-		F8.2

TABLE 4 (Continued)

Input Data Format for Direct Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
3 (Cont)	17-24	Supplementary System Capital Cost	ISSC	$	0	This value is internally computed if the user uses default value 0.	I8
	25-32	Exploration Cost	IEXPC	$	0	This value is internally computed if the user uses default value 0.	I8
	33-40	Base Capital Cost for Distribution System	IDSC	$	0	This value is internally computed if the user uses default value 0.	I8
4	1-8	Length of Distribution System	LEN	Feet	2000	For individual users 2000 ft. is appropriate. For district heating systems, this value will be much larger.	I8
	9-16	Type of Rock	IROCK*	-	-	1 - soft rock; 2 - hard rock.	I8
	17-24	Production Well Depth	IPWDEP*	Feet	-		I8
	25-32	Injection Well Depth	IIWDEP	Feet	-	This value must be specified as the brine disposal system cost is not given.	I8
	33-37	Distribution System Pipe Diameter	DIAP	Inches	4		F5.2
	38-42	Distribution System Pipe Insulation Diameter	DIAINS	Inches	6		F5.2
5	1-8	Production Well Cost (Per Well)	IPWC*	Dollars			I8
	9-16	Total Injection Well and Disposal System Cost	IIWDSC	Dollars		If the disposal system cost is not specified, the cost of an injection well will be utilized.	I8
6	1-5	Federal Income Tax Rate	TF	Fraction	0.46		F5.2
	6-10	State Income Tax Rate	TS	Fraction	0.04		F5.2
	11-15	Annual Interest Rate on Debt	AKD	Fraction	0.15	The values for these vary based on user's financial status and expectations. They can be specified by the user to conduct sensitivity analyses.	F5.2
	16-20	Debt Fraction	AD	Fraction	0.60		F5.2

TABLE 4 (Concluded)

Input Data Format for Direct Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
6 (Cont)	21-25	Rate of Return on Common Equity	AKC	Fraction	0.20		F5.2
	26-30	Common Stock Fraction	EC	Fraction	0.30		F5.2
	31-35	Rate of Return on Preferred Stock	AKP	Fraction	0.15		F5.2
	36-40	Preferred Stock Fraction	EP	Fraction	0.10		F5.2
7	1-5	Tax Credit Rate	A1	Fraction	0.25	It includes investment and energy tax credits.	F5.2
	6-10	Property Tax and Insurance Rate	B1[+]	Fraction	0.00		F5.2
	11-15	Initial Investment Capial Not to be Replaced	A11	Fraction	0.40		F5.2
	16-20	Royalty Payment as a Fraction of Gross Revenues	B2	Fraction	0.10		F5.2
	21-25	Depletion Allowance Rate	B3	Fraction	0.15		F5.2
	26-30	Inflation Rate	G	Fraction	0.09	This value is based on DRI, Inc. fore-cast for 1980-2000 period.	F5.2
	31-35	Escalation Rate for Capital Costs	GC	Fraction	0.00		F5.2
	36-40	Escalation Rate for Fuel Costs	GF	Fraction	0.03		F5.2
	41-45	Escalation Rate for O&M Costs	GOM	Fraction	0.01		F5.2
8	1-5	Project Life Span	N1	Years	20		I5
	6-10	Depreciation Life for Tax	N2	Years	10	The value for N2 has to be less than the value for N1.	I5
	11-15	Project Base Year	IB	Year Name	1980		I5
	16-20	Project Vintage Year	IV	Year Name	1983		I5
	21-25	Start Expenditure Year	IS	Year Name	-		I5

TABLE 5

Input Data Format for One Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
1	1-3	Numbers of Heat Exchangers	INEXC+	-	-	0 - for direct system. 1 or 2 for one or two stage indirect systems, respectively.	I3
	4-6	Type of Supplementary System	ITSUP	-	-	1 - oil, 2 - gas, 3 - electrical.	I3
	7-9	Salinity Index	ISAL	-	-	0 - low (up to 1000 ppm T.D.S.), 1 - high (above 1000 ppm T.D.S.).	I3
	10-17	Heat Transfer Coefficient	HTCOEF	BTU/Ft^2 °F hr.	120	In the case of high salinity, the exchanger surface area is increased by 20%. Liquid-to-liquid heat transfer is assumed.	F8.2
2	1-5	Production Wellhead Temperature	ITWHP	°F	-	This temperature must be specified by the user.	I5
	6-10	Temp. Drop Between Wellhead and Heat Exchanger	ITDRP	°F	5		I5
	11-15	Process Temperature	ITPR+	°F	-	This is the working fluid temperature at the process inlet.	I5
	16-20	Allowable Temperature Drop in Process	IATD+	°F	-	This will depend on the lowest working fluid temperature in the process.	I5
	21-28	Peak Energy Requirement for Process	IPKRE	MMBTU/hr	-	The peak demand is based on one hour.	I8
	29-36	Well Flow Rate	IFPW+	lbs/hr	-	The user can specify three values (lowest, most likely, and highest).	I8
	37-41	Specific Heat for Brine	SHB	BTU/lb/°F	1.0		F5.2
	42-46	Process Utilization Factor	UFSUP	Fraction	0.6	This utilization factor is based on annual utilization.	F5.2
3	1-5	Terminal Temperature Difference at Inlet of Exchanger	NGTTD1	°F	10		I5
	6-10	Terminal Temperature Difference at Outlet of Exchanger	NGTTD2	°F	5		I5

TABLE 5 (Continued)

Input Data Format for One Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
3 (Cont)	11-15	Injection Wellhead Temperature	ITWHI	°F	90	Environmental or scale formation considerations may put a lower bound on this parameter.	I5
	16-20	Temperature Difference Between Injection Wellhead and Exchanger Outlet	ITDRI	°F	5		I5
	21-28	Heat Exchanger Surface Area	IAREA1	Sq. Ft.	-	It the model user has an externally computed figure, that figure should be used.	I8
	29-33	Specific Heat for Working Fluid	SHW	BTU/lb/°F	1.0	The actual value will generally be smaller then 1.0.	F5.2
	34-38	Heat Exchanger Efficiency	ETA1	Fraction	0.6	This utilization factor is based on annual utilization.	F5.2
4	1-8	Supplementary System Fuel Cost	SUPCST	$/Unit	-	Electric - $ per KWHR; gas - $ per 1000 SCF; oil - $ per barrel.	F8.2
	9-16	Supplementary System Efficiency Factor for Converting Chemical Energy into Thermal Energy	EFFY	-	-		F8.2
	17-24	Supplementary System Capital Cost	ISSC	$	0	This value is internally computed if the user uses default value 0.	I8
	25-32	Exploration Cost	IEXPC	$	0	This value is internally computed if the user uses default value 0.	I8
	33-40	Base Capital Cost for Distribution System	IDSC	$	0	This value is internally computed if the user uses default value 0.	I8
5	1-8	Length of Distribution System	LEN	Feet	2000	For individual users 2000 ft. is appropriate. For district heating systems, this value will be much larger.	I8
	9-16	Type of Rock	IROCK*	-	-	1 - soft rock; 2 - hard rock.	I8
	17-24	Production Well Depth	IPWDEP*	Feet	-		I8

TABLE 5 (Continued)

Input Data Format for One Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
5 (Cont)	25-32	Injection Well Depth	IIWDEP	Feet	-	This value must be specified as the brine disposal system cost is not given.	I8
	33-37	Distribution System Pipe Diameter	DIAP	Inches	4		F5.2
	38-42	Distribution System Pipe Insulation Diameter	DIAINS	Inches	6		F5.2
6	1-8	Production Well Cost (Per Well)	IPWC*	Dollars			I8
	9-16	Total Injection Well and Disposal System Cost	IIWDSC	Dollars		If the disposal system cost is not specified, the cost of an injection well will be utilized.	I8
7	1-5	Federal Income Tax Rate	TF	Fraction	0.46		F5.2
	6-10	State Income Tax Rate	TS	Fraction	0.04		F5.2
	11-15	Annual Interest Rate on Debt	AKD	Fraction	0.15	The values for these vary based on user's financial status and expectations. They can be specified by the user to conduct sensitivity analyses.	F5.2
	16-20	Debt Fraction	AD	Fraction	0.60		F5.2
	21-25	Rate of Return on Common Equity	AKC	Fraction	0.20		F5.2
	26-30	Common Stock Fraction	EC	Fraction	0.30		F5.2
	31-35	Rate of Return on Preferred Stock	AKP	Fraction	0.15		F5.2
	36-40	Preferred Stock Fraction	EP	Fraction	0.10		F5.2
8	1-5	Tax Credit Rate	A1	Fraction	0.25	It includes investment and energy tax credits.	F5.2
	6-10	Property Tax and Insurance Rate	B1+	Fraction	0.00		F5.2
	11-15	Initial Investment Capital Not to be Replaced	All	Fraction	0.40		F5.2
	16-20	Royalty Payment as a Fraction of Gross Revenues	B2	Fraction	0.10		F5.2

TABLE 5 (Concluded)

Input Data Format for One Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
8 (Cont)	21-25	Depletion Allowance Rate	B3	Fraction	0.15		F5.2
	26-30	Inflation Rate	G	Fraction	0.09	This value is based on DRI, Inc. forecast for 1980-2000 period.	F5.2
	31-35	Escalation Rate for Capital Costs	GC	Fraction	0.00		F5.2
	36-40	Escalation Rate for Fuel Costs	GF	Fraction	0.03		F5.2
	41-45	Escalation Rate for O&M Costs	GOM	Fraction	0.01		F5.2
9	1-5	Project Life Span	N1	Years	20		I5
	6-10	Depreciation Life for Tax	N2	Years	10	The value for N2 has to be less than the value for N1.	I5
	11-15	Project Base Year	IB	Year Name	1980		I5
	16-20	Project Vintage Year	IV	Year Name	1983		I5
	21-25	Start Expenditure Year	IS	Year Name	-		I5

TABLE 6

Input Data Format for Two Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
1	1-3	Numbers of Heat Exchangers	INEXC*	-	-	0 - for direct system. 1 or 2 for one or two stage indirect systems, respectively.	I3
	4-6	Type of Supplementary System	ITSUP	-	-	1 - oil, 2 - gas, 3 - electrical.	I3
	7-9	Salinity Index	ISAL	-	-	0 - low (up to 1000 ppm T.D.S.), 1 - high (above 1000 ppm T.D.S.).	I3
	10-17	Heat Transfer Coefficient	HTCOEF	BTU/Ft^2 °F hr.	120	In the case of high salinity, the exchanger surface area is increased by 20%. Liquid-to-liquid heat transfer is assumed.	F8.2
2	1-5	Production Wellhead Temperature	ITWHP	°F	-	This temperature must be specified by the user.	I5
	6-10	Temp. Drop Between Wellhead and Heat Exchanger 1	ITDRP	°F	5		I5
	11-15	Process Temperature	ITPR*	°F	-	This is the working fluid temperature at the process inlet.	I5
	16-20	Allowable Temperature Drop in Process 1	IATD*	°F	-	This will depend on the lowest working fluid temperature in the process.	I5
	21-28	Peak Energy Requirement for Process 1	IPKRE	MMBTU/hr	-	The peak demand is based on one hour.	I8
	29-36	Well Flow Rate	IFPW*	lbs/hr	-	The user can specify three values (lowest, most likely, and highest).	I8
	37-41	Specific Heat for Brine	SHB	BTU/lb/°F	1.0		F5.2
	42-46	Process 1 Utilization Factor	UFSUP	Fraction	0.6	This utilization factor is based on annual utilization.	F5.2
3	1-5	Terminal Temperature Difference at Inlet of Exchanger 1	NGTTD1	°F	10		I5
	6-10	Terminal Temperature Difference at Outlet of Exchanger 1	NGTTD2	°F	5		I5

TABLE 6 (Continued)

Input Data Format for Two Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
3 (Cont)	11-15	Injection Wellhead Temperature	ITWHI	°F	90	Environmental or scale formation considerations may put a lower bound on this parameter.	I5
	16-20	Temperature Difference Between Injection Wellhead and Exchanger 1 Outlet	ITDRI	°F	5		I5
	21-28	Heat Exchanger 1 Surface Area	IAREA1	Sq. Ft.	-	It the model user has an externally computed figure, that figure should be used.	I8
	29-33	Specific Heat for Working Fluid	SHW	BTU/lb/°F	1.0	The actual value will generally be smaller then 1.0.	F5.2
	34-38	Heat Exchanger 1 Efficiency	ETA1	Fraction	0.6	This utilization factor is based on annual utilization.	F5.2
4	1-5	Process Temperature at Heat Exchanger 2	ITPR2⁺	°F	-	This is the working fluid temperature at the process inlet.	I5
	6-10	Allowable Temperature Drop Within Process 2	IATD2⁺	°F	-	This will depend on the lowest working fluid temperature in the process.	I5
	11-15	Terminal Temperature Difference at Inlet of Heat Exchanger 2	NGTTD3	°F	10		I5
	16-20	Terminal Temperature Difference at Outlet of Heat Exchanger 2	NGTTD4	°F	5		I5
	21-28	Heat Exchanger 2 Surface Area	IAREA2	Sq. Ft.	-	If the model user has an externally computed figure, that figure should be used.	I8
	29-36	Peak Energy Required for Process 2	IPKRE2⁺	MMBTU/hr	-	This peak is based on one hour.	I8
	37-41	Heat Exchanger 2 Efficiency	ETA2	Fraction	0.95		F5.2
	42-46	Utilization Factor for Process 2	UFSUP2	Fraction	0.40		F5.2

TABLE 6 (Continued)

Input Data Format for Two Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
5	1-8	Supplementary System Fuel Cost	SUPCST	$/Unit	-	Electric - $ per KWHR; gas - $ per 1000 SCF; oil - $ per barrel.	F8.2
	9-16	Supplementary System Efficiency Factor for Converting Chemical Energy into Thermal Energy	EFFY	-	-		F8.2
	17-24	Supplementary System Capital Cost	ISSC	$	0	This value is internally computed if the user uses default value 0.	I8
	25-32	Exploration Cost	IEXPC	$	0	This value is internally computed if the user uses default value 0.	I8
	33-40	Base Capital Cost for Distribution System	IDSC	$	0	This value is internally computed if the user uses default value 0.	I8
6	1-8	Length of Distribution System	LEN	Feet	2000	For individual users 2000 ft. is appropriate. For district heating systems, this value will be much larger.	I8
	9-16	Type of Rock	IROCK*	-	-	1 - soft rock; 2 - hard rock	I8
	17-24	Production Well Depth	IPWDEP*	Feet	-		I8
	25-32	Injection Well Depth	IIWDEP	Feet	-	This value must be specified as the brine disposal system cost is not given.	I8
	33-37	Distribution System Pipe Diameter	DIAP	Inches	4		F5.2
	38-42	Distribution System Pipe Insulation Diameter	DIAINS	Inches	6		F5.2
7	1-8	Production Well Cost (Per Well)	IPWC*	Dollars			I8
	9-16	Total Injection Well and Disposal System Cost	IIWDSC	Dollars		If the disposal system cost is not specified, the cost of an injection well will be utilized.	I8

TABLE 6 (Continued)

Input Data Format for Two Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
8	1-5	Federal Income Tax Rate	TF	Fraction	0.46		F5.2
	6-10	State Income Tax Rate	TS	Fraction	0.04		F5.2
	11-15	Annual Interest Rate on Debt	AKD	Fraction	0.15	The values for these vary based on user's financial status and expectations. They can be specified by the user to conduct sensitivity analyses.	F5.2
	16-20	Debt Fraction	AD	Fraction	0.60		F5.2
	21-25	Rate of Return on Common Equity	AKC	Fraction	0.20		F5.2
	26-30	Common Stock Fraction	EC	Fraction	0.30		F5.2
	31-35	Rate of Return on Preferred Stock	AKP	Fraction	0.15		F5.2
	36-40	Preferred Stock Fraction	EP	Fraction	0.10		F5.2
9	1-5	Tax Credit Rate	A1	Fraction	0.25	It includes investment and energy tax credits.	F5.2
	6-10	Property Tax and Insurance Rate	B1*	Fraction	0.00		F5.2
	11-15	Initial Investment Capial Not to be Replaced	A11	Fraction	0.40		F5.2
	16-20	Royalty Payment as a Fraction of Gross Revenues	B2	Fraction	0.10		F5.2
	21-25	Depletion Allowance Rate	B3	Fraction	0.15		F5.2
	26-30	Inflation Rate	G	Fraction	0.09	This value is based on DRI, Inc. forecast for 1980-2000 period.	F5.2
	31-35	Escalation Rate for Capital Costs	GC	Fraction	0.00		F5.2
	36-40	Escalation Rate for Fuel Costs	GF	Fraction	0.03		F5.2
	41-45	Escalation Rate for O&M Costs	GOM	Fraction	0.01		F5.2

TABLE 6 (Concluded)

Input Data Format for Two Stage Indirect Geothermal Energy System

Record No.	Column	Variable/Parameter Description	Symbol	Units	Default Value	Remarks	Format
10	1-5	Project Life Span	N1	Years	20		I5
	6-10	Depreciation Life for Tax	N2	Years	10	The value for N2 has to be less than the value for N1.	I5
	11-15	Project Base Year	IB	Year Name	1980		I5
	16-20	Project Vintage Year	IV	Year Name	1983		I5
	21-25	Start Expenditure Year	IS	Year Name	-		I5

TABLE 7

Input Data File For Direct Geothermal Energy System, Case I

```
 1.    0  2  1  120.00
 2.   220   10  210   40       10  250000 0.95 0.60
 3.     5.00    0.75   20000   00000   00000
 4.     2000       1    3300    2000 4.00 6.00
 5.        0       0
 6.  0.46 0.04 0.15 0.60 0.20 0.30 0.15 0.10
 7.  0.25 0.00 0.40 0.10 0.15 0.09 0.00 0.03 0.01
 8.    20    10 1980 1983 1980
```

TABLE 8

Input Data File For One Stage Indirect Geothermal Energy System, Case II

```
 1.    1  2  1  120.00
 2.   220   10  210   40       10  250000 0.95 0.60
 3.    10    5  100   10     5000 0.98 1.00
 4.     5.00    0.75   20000   00000   00000
 5.     2000       1    3300    2000 4.00 6.00
 6.        0       0
 7.  0.46 0.04 0.15 0.60 0.20 0.30 0.15 0.10
 8.  0.25 0.00 0.40 0.10 0.15 0.09 0.00 0.03 0.01
 9.    20    10 1980 1983 1980
```

TABLE 9

Input Data File For Two Stage Indirect Geothermal Energy System, Case III

```
 1.    2  2  1  120.00
 2.   220   10  210   40       10  250000 0.95 0.60
 3.    10    5  100   10     5000 0.98 1.00
 4.   150   20   20   10     5000         6 1.00 0.40
 5.     5.00    0.75   20000   00000   00000
 6.     2000       1    3300    2000 4.00 6.00
 7.        0       0
 8.  0.46 0.04 0.15 0.60 0.20 0.30 0.15 0.10
 9.  0.25 0.00 0.40 0.10 0.15 0.09 0.00 0.03 0.01
10.    20    10 1980 1983 1980
```

TABLE 10

GEEF MODEL OUTPUTS FOR DIRECT GEOTHERMAL ENERGY SYSTEM,

CASE I

NO. OF HEAT EXCHRS= .0	
PROD. WELLHD TEMP.(DEG. F)=	220
TEMP. DROP BET. PROD. WELLHD & PL. INLET(DEG F)=	10
PROCESS TEMP. (DEG F)=	210
ALLOW. TEMP. DROP IN THE PROCESS(DEG. F)=	40
PEAK ENERGY REQMT. FOR PROCESS(MMBTU/HR)=	10
WELL FLOW RATE (LBS./HR.)=	250000
SPECIFIC HEAT FOR BRINE(BTU/LB/DEG. F)=	0.95
UTILIZATION FACTOR FOR PROCESS=	0.60
DISTRB SYSTEM PIPELINE LENGTH(FEET)=	2000
DISTRB SYSTEM PIPELINE DIAMETER(INCHES)=	0.33
DISTRB SYSTEM PIPELINE INSUL. DIA.(INCHES)=	0.50
TYPE OF ROCK: SOFT	
SALINITY: HIGH	
PRODUCTION WELL DEPTH(FEET)=	3300
FLOW RATE REQUIRED(LBS/HR)=	263158
NUMBER OF PRODUCTION WELLS=	2
NUMBER OF INJECTION WELLS=	0
ANN. ENERGY REQD. FROM SUPPLM. SYS.(BTU)=	0.0
BASE CAPITAL COST FOR HEAT EXCHR(S)=	0.0
AVERAGE ANNUAL FUEL COST=	0.0
BASE CAPITAL COST FOR DIST. SYSTEM=	0.847E 05
PRODUCTION WELLS COST=	0.901E 06
INJECTION WELLS COST=	0.0
SUPPLEMENTRY SYSTEM CAPITAL COST	0
EXPLORATION COST=	45045

TABLE 10

GEEF MODEL OUTPUTS FOR DIRECT GEOTHERMAL ENERGY SYSTEM,

CASE I

(Continued)

FED INCOME TAX RATE(FRACTION):	0.46
STATE INCOME TAX RATE(FRACTION):	0.04
ANNUAL INTEREST RATE ON DEBT(FRACTION):	0.15
DEBT FRACTION:	0.60
RATE OF RETURN ON COMMON STOCK(FRACTION):	0.20
COMMON STOCK FRACTION:	0.30
RATE OF RETURN ON PREFERRED STOCK(FRACTION):	0.15
PREFERRED STOCK FRACTION:	0.10
TAX CREDIT RATE(FRACTION):	0.25
PROPERTY TAX AND INSURANCE RATE(FRACTION):	0.0
INIT. INVEST. CAP. NOT TO BE REPLACED(FRACTION):	0.40
ROYAL. PAYMT. AS FRACTION OF GROSS REVENUE:	0.10
DEPLETION ALLOWANCE(FRACTION):	0.15
INFLATION RATE(FRACTION):	0.09
ESCALATION FACT. FOR CAPITAL COSTS:	0.0
ESCALATION FACT. FOR FUEL COSTS:	0.03
ESCALATION FACT. FOR O & M COSTS:	0.01
PROJECT BASE YEAR:	1980
PROJECT VINTAGE YEAR:	1983
START EXPENDITURE YEAR:	1980
PROJECT LIFE SPAN (YEARS):	20
DEPRECIATION LIFE FOR TAX(YEARS):	10

TOTAL ANN. ENERGY REQD.(MMBTU)=	52559.98
TOTAL ANNLZD. COST OF GEOTHERMAL ENERGY($M)=	0.458
LEVEL. COST OF GEOTHERMAL ENERGY ($/MMBTU)=	8.71
LEVEL. COST OF ENERGY FROM ALTERNATE SYSTEM($/MMBTU)=	12.91

TABLE 10

GEEF MODEL OUTPUTS FOR DIRECT GEOTHERMAL ENERGY SYSTEM, CASE I

(Continued)

YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY

YEAR OF OPER.	GROSS REVENUE	ROYALTY AND OPER. COSTS	NET INCOME BEFORE TAXES	NET INCOME AFTER TAXES	NET CASH FLOW
1	0.4577E 06	0.2194E 06	0.1150E 05	0.5961E 04	0.1699E 06
2	0.4577E 06	0.2201E 06	0.2497E 05	0.1294E 05	0.1697E 06
3	0.4577E 06	0.2208E 06	0.3688E 05	0.1912E 05	0.1695E 06
4	0.4577E 06	0.2216E 06	0.4741E 05	0.2458E 05	0.1691E 06
5	0.4577E 06	0.2223E 06	0.5669E 05	0.2939E 05	0.1687E 06
6	0.4577E 06	0.2230E 06	0.6486E 05	0.3362E 05	0.1683E 06
7	0.4577E 06	0.2238E 06	0.7540E 05	0.3909E 05	0.1680E 06
8	0.4577E 06	0.2245E 06	0.8796E 05	0.4560E 05	0.1221E 06
9	0.4577E 06	0.2253E 06	0.9892E 05	0.5128E 05	0.1160E 06
10	0.4577E 06	0.2260E 06	0.1085E 06	0.5623E 05	0.1107E 06
11	0.4577E 06	0.2700E 06	0.7353E 05	0.3812E 05	0.5472E 05
12	0.4577E 06	0.2708E 06	0.8068E 05	0.4182E 05	0.5050E 05
13	0.4577E 06	0.2716E 06	0.8682E 05	0.4501E 05	0.4675E 05
14	0.4577E 06	0.2724E 06	0.9206E 05	0.4772E 05	0.4343E 05
15	0.4577E 06	0.2732E 06	0.9650E 05	0.5003E 05	0.4049E 05
16	0.4577E 06	0.2740E 06	0.1002E 06	0.5197E 05	0.3788E 05
17	0.4577E 06	0.2748E 06	0.1034E 06	0.5358E 05	0.3556E 05
18	0.4577E 06	0.2756E 06	0.1059E 06	0.5490E 05	0.3350E 05
19	0.4577E 06	0.2765E 06	0.1080E 06	0.5597E 05	0.3167E 05
20	0.4577E 06	0.2773E 06	0.1096E 06	0.5681E 05	0.3005E 05

NET PRESENT VALUE: -0.916E 06

TABLE 10

GEEF MODEL OUTPUTS FOR DIRECT GEOTHERMAL ENERGY SYSTEM,

CASE I

(Concluded)

YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY
AT ALTERNATE ENERGY LIFE CYCLE COST

YEAR OF OPER.	GROSS REVENUE	ROYALTY AND OPER. COSTS	NET INCOME BEFORE TAXES	NET INCOME AFTER TAXES	NET CASH FLOW
1	0.6783E 06	0.2415E 06	0.1199E 06	0.6214E 05	0.3726E 06
2	0.6783E 06	0.2422E 06	0.1468E 06	0.7611E 05	0.3728E 06
3	0.6783E 06	0.2429E 06	0.1706E 06	0.8846E 05	0.3730E 06
4	0.6783E 06	0.2436E 06	0.1917E 06	0.9938E 05	0.3731E 06
5	0.6783E 06	0.2444E 06	0.2103E 06	0.1090E 06	0.2909E 06
6	0.6783E 06	0.2451E 06	0.2266E 06	0.1175E 06	0.2554E 06
7	0.6783E 06	0.2458E 06	0.2409E 06	0.1249E 06	0.2478E 06
8	0.6783E 06	0.2466E 06	0.2535E 06	0.1314E 06	0.2410E 06
9	0.6783E 06	0.2473E 06	0.2644E 06	0.1371E 06	0.2349E 06
10	0.6783E 06	0.2481E 06	0.2740E 06	0.1420E 06	0.2296E 06
11	0.6783E 06	0.2921E 06	0.2391E 06	0.1239E 06	0.1736E 06
12	0.6783E 06	0.2929E 06	0.2462E 06	0.1276E 06	0.1694E 06
13	0.6783E 06	0.2936E 06	0.2523E 06	0.1308E 06	0.1657E 06
14	0.6783E 06	0.2944E 06	0.2576E 06	0.1335E 06	0.1623E 06
15	0.6783E 06	0.2952E 06	0.2620E 06	0.1358E 06	0.1594E 06
16	0.6783E 06	0.2961E 06	0.2658E 06	0.1378E 06	0.1568E 06
17	0.6783E 06	0.2969E 06	0.2689E 06	0.1394E 06	0.1545E 06
18	0.6783E 06	0.2977E 06	0.2714E 06	0.1407E 06	0.1524E 06
19	0.6783E 06	0.2985E 06	0.2735E 06	0.1418E 06	0.1506E 06
20	0.6783E 06	0.2994E 06	0.2751E 06	0.1426E 06	0.1490E 06

NET PRESENT VALUE: 0.321E 06
DISCNT. CASH FLOW RATE OF RET.(%): 15.74
DISCNT. PAYBACK PERIOD (YEARS): 5

TABLE 11

GEEF MODEL OUTPUTS FOR ONE STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE II

NO. OF HEAT EXCHRS= 1

PROD. WELLHD. TEMP.(DEG. F)=	220
TEMP.DROP BET. PROD WELLHD. & EXC.1 IN.(DEG F)=	10
PROCESS TEMP. AT EXCHR 1 (DEG. F)=	210
ALLOW. TEMP. DROP WITHIN THE PROCESS 1(DEG F)=	40
PEAK ENERGY REQMT. FOR PROCESS 1(MMBTU/HR)=	10
INJECTION WELLHD. TEMP.(DEG. F)=	100
TEMP.DROP BET. INJ. WELLHD. & EXC.1 OUT.(DEG. F)=	10
TERM. TEMP. DIFF. AT INLET OF EXCHR.1(DEG. F)=	10
TERM. TEMP. DIFF. AT OUTLET OF EXCHR. 1(DEG F)=	5
WELL FLOW RATE (LBS/HR)=	250000
SPECIFIC HEAT FOR BRINE(BTU/LB/DEG. F)=	0.95
SPECIFIC HEAT FOR WORK. FLD. (BTU/LB/HR)=	0.98
EFFICIENCY FOR HEAT EXCHR. 1=	1.00
UTILIZATION FACTOR FOR PROCESS 1=	0.60
DISTRB SYSTEM PIPELINE LENGTH(FEET)=	2000
DISTRB SYSTEM PIPELINE DIAMETER(INCHES)=	0.33
DISTRB SYSTEM PIPELINE INSUL. DIA.(INCHES)=	0.50
TYPE OF ROCK: SOFT	
SALINITY: HIGH	
PRODUCTION WELL DEPTH(FEET)=	3300
INJECTION WELL DEPTH(FEET)=	2000
FLOW RATE REQUIRED(LBS/HR)=	263158
NUMBER OF PRODUCTION WELLS=	2
NUMBER OF INJECTION WELLS=	1
ANN. ENERGY REQD. FROM SUPPLM. SYS.(BTU)=	0.131E 11
BASE CAPITAL COST FOR HEAT EXCHR(S)=	0.996E 05
AVERAGE ANNUAL FUEL COST=	0.876E 05
BASE CAPITAL COST FOR DIST. SYSTEM=	0.847E 05
PRODUCTION WELLS COST=	0.901E 06
INJECTION WELLS COST=	0.268E 06
SUPPLEMENTRY SYSTEM CAPITAL COST	20000
EXPLORATION COST=	63436

TABLE 11

GEEF MODEL OUTPUTS FOR ONE STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE II

(Concluded)

FED INCOME TAX RATE(FRACTION):	0.46
STATE INCOME TAX RATE(FRACTION):	0.04
ANNUAL INTEREST RATE ON DEBT(FRACTION):	0.15
DEBT FRACTION:	0.60
RATE OF RETURN ON COMMON STOCK(FRACTION):	0.20
COMMON STOCK FRACTION:	0.30
RATE OF RETURN ON PREFERRED STOCK(FRACTION):	0.15
PREFERRED STOCK FRACTION:	0.10
TAX CREDIT RATE(FRACTION):	0.25
PROPERTY TAX AND INSURANCE RATE(FRACTION):	0.0
INIT. INVEST. CAP. NOT TO BE REPLACED(FRACTION):	0.40
ROYAL. PAYMT. AS FRACTION OF GROSS REVENUE:	0.10
DEPLETION ALLOWANCE(FRACTION):	0.15
INFLATION RATE(FRACTION):	0.09
ESCALATION FACT. FOR CAPITAL COSTS:	0.0
ESCALATION FACT. FOR FUEL COSTS:	0.03
ESCALATION FACT. FOR O & M COSTS:	0.01
PROJECT BASE YEAR:	1980
PROJECT VINTAGE YEAR:	1983
START EXPENDITURE YEAR:	1980
PROJECT LIFE SPAN (YEARS):	20
DEPRECIATION LIFE FOR TAX(YEARS):	10

TOTAL ANN. ENERGY REQD.(MMBTU)=	52559.98
TOTAL ANNLZD. COST OF GEOTHERMAL ENERGY($M)=	0.853
LEVEL. COST OF GEOTHERMAL ENERGY ($/MMBTU)=	16.22
LEVEL. COST OF ENERGY FROM ALTERNATE SYSTEM($/MMBTU)=	12.91

TABLE 12

GEEF MODEL OUTPUTS FOR TWO STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE III

NO. OF HEAT EXCHRS= 2

PROD. WELLHD. TEMP.(DEG. F)=	220
TEMP.DROP BET. PROD WELLHD. & EXC.1 IN.(DEG F)=	10
PROCESS TEMP. AT EXCHR 1 (DEG. F)=	210
ALLOW. TEMP. DROP WITHIN THE PROCESS 1(DEG F)=	40
PEAK ENERGY REQMT. FOR PROCESS 1(MMBTU/HR)=	10
INJECTION WELLHD. TEMP.(DEG. F)=	100
TEMP.DROP BET. INJ. WELLHD. & EXC.1 OUT.(DEG. F)=	10
TERM. TEMP. DIFF. AT INLET OF EXCHR.1(DEG. F)=	10
TERM. TEMP. DIFF. AT OUTLET OF EXCHR. 1(DEG F)=	5
WELL FLOW RATE (LBS/HR)=	250000
SPECIFIC HEAT FOR BRINE(BTU/LB/DEG. F)=	0.95
SPECIFIC HEAT FOR WORK. FLD. (BTU/LB/HR)=	0.98
EFFICIENCY FOR HEAT EXCHR. 1=	1.00
UTILIZATION FACTOR FOR PROCESS 1=	0.60
PROCESS TEMP. AT EXCHR. 2 (DEG. F)=	150
ALLOW.TEMP. DROP WITHIN PROCESS 2(DEG. F)=	20
TERM. TEMP. DIFF AT INLET OF EXCHR.2(DEG. F)=	20
TERM. TEMP. DIFF. AT OUT. OF EXCHR.2(DEG. F)=	10
PEAK ENERGY REQMT. FOR PROCESS 2(MMBTU/HR)=	6
EFFICIENCY FOR HEAT EXCHR.2 =	1.00
UTILIZATION FACTOR FOR PROCESS 2=	0.40
DISTRB SYSTEM PIPELINE LENGTH(FEET)=	2000
DISTRB SYSTEM PIPELINE DIAMETER(INCHES)=	0.33
DISTRB SYSTEM PIPELINE INSUL. DIA.(INCHES)=	0.50
TYPE OF ROCK: SOFT	
SALINITY: HIGH	
PRODUCTION WELL DEPTH(FEET)=	3300
INJECTION WELL DEPTH(FEET)=	2000
FLOW RATE REQUIRED(LBS/HR)=	171428
NUMBER OF PRODUCTION WELLS=	1
NUMBER OF INJECTION WELLS=	1
ANN. ENERGY REQD. FROM SUPPLM. SYS.(BTU)=	0.131E 11
BASE CAPITAL COST FOR HEAT EXCHR(S)=	0.189E 06
AVERAGE ANNUAL FUEL COST=	0.876E 05
BASE CAPITAL COST FOR DIST. SYSTEM=	0.847E 05
PRODUCTION WELLS COST=	0.450E 06
INJECTION WELLS COST=	0.268E 06
SUPPLEMENTRY SYSTEM CAPITAL COST	20000
EXPLORATION COST=	45892

TABLE 12

GEEF MODEL OUTPUTS FOR TWO STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE III

(Continued)

FED INCOME TAX RATE(FRACTION):	0.46
STATE INCOME TAX RATE(FRACTION):	0.04
ANNUAL INTEREST RATE ON DEBT(FRACTION):	0.15
DEBT FRACTION:	0.60
RATE OF RETURN ON COMMON STOCK(FRACTION):	0.20
COMMON STOCK FRACTION:	0.30
RATE OF RETURN ON PREFERRED STOCK(FRACTION):	0.15
PREFERRED STOCK FRACTION:	0.10
TAX CREDIT RATE(FRACTION):	0.25
PROPERTY TAX AND INSURANCE RATE(FRACTION):	0.0
INIT. INVEST. CAP. NOT TO BE REPLACED(FRACTION):	0.40
ROYAL. PAYMT. AS FRACTION OF GROSS REVENUE:	0.10
DEPLETION ALLOWANCE(FRACTION):	0.15
INFLATION RATE(FRACTION):	0.09
ESCALATION FACT. FOR CAPITAL COSTS:	0.0
ESCALATION FACT. FOR FUEL COSTS:	0.03
ESCALATION FACT. FOR O & M COSTS:	0.01
PROJECT BASE YEAR:	1980
PROJECT VINTAGE YEAR:	1983
START EXPENDITURE YEAR:	1980
PROJECT LIFE SPAN (YEARS):	20
DEPRECIATION LIFE FOR TAX(YEARS):	10

TOTAL ANN. ENERGY REQD.(MMBTU)=	73583.94
TOTAL ANNLZD. COST OF GEOTHERMAL ENERGY($M)=	0.688
LEVEL. COST OF GEOTHERMAL ENERGY ($/MMBTU)=	9.35
LEVEL. COST OF ENERGY FROM ALTERNATE SYSTEM($/MMBTU)=	12.91

TABLE 12

GEEF MODEL OUTPUTS FOR TWO STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE III

(Continued)

YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY

YEAR OF OPER.	GROSS REVENUE	ROYALTY AND OPER. COSTS	NET INCOME BEFORE TAXES	NET INCOME AFTER TAXES	NET CASH FLOW
1	0.6880E 06	0.3354E 06	0.6684E 05	0.3465E 05	0.2842E 06
2	0.6880E 06	0.3387E 06	0.7922E 05	0.4107E 05	0.2813E 06
3	0.6880E 06	0.3422E 06	0.8998E 05	0.4665E 05	0.2783E 06
4	0.6880E 06	0.3457E 06	0.9929E 05	0.5147E 05	0.2751E 06
5	0.6880E 06	0.3493E 06	0.1114E 06	0.5774E 05	0.2719E 06
6	0.6880E 06	0.3531E 06	0.1250E 06	0.6481E 05	0.2687E 06
7	0.6880E 06	0.3569E 06	0.1366E 06	0.7079E 05	0.2620E 06
8	0.6880E 06	0.3608E 06	0.1462E 06	0.7578E 05	0.1860E 06
9	0.6880E 06	0.3648E 06	0.1541E 06	0.7988E 05	0.1782E 06
10	0.6880E 06	0.3689E 06	0.1605E 06	0.8318E 05	0.1710E 06
11	0.6880E 06	0.4171E 06	0.1215E 06	0.6298E 05	0.1123E 06
12	0.6880E 06	0.4214E 06	0.1252E 06	0.6491E 05	0.1062E 06
13	0.6880E 06	0.4259E 06	0.1278E 06	0.6625E 05	0.1005E 06
14	0.6880E 06	0.4304E 06	0.1294E 06	0.6707E 05	0.9515E 05
15	0.6880E 06	0.4351E 06	0.1300E 06	0.6741E 05	0.9015E 05
16	0.6880E 06	0.4399E 06	0.1298E 06	0.6731E 05	0.8542E 05
17	0.6880E 06	0.4449E 06	0.1289E 06	0.6682E 05	0.8094E 05
18	0.6880E 06	0.4499E 06	0.1273E 06	0.6598E 05	0.7665E 05
19	0.6880E 06	0.4551E 06	0.1250E 06	0.6481E 05	0.7253E 05
20	0.6880E 06	0.4605E 06	0.1222E 06	0.6334E 05	0.6855E 05

NET PRESENT VALUE: -0.250E 06

TABLE 12

GEEF MODEL OUTPUTS FOR TWO STAGE INDIRECT GEOTHERMAL ENERGY SYSTEM

CASE III

(Concluded)

YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY
AT ALTERNATE ENERGY LIFE CYCLE COST

YEAR OF OPER.	GROSS REVENUE	ROYALTY AND OPER. COSTS	NET INCOME BEFORE TAXES	NET INCOME AFTER TAXES	NET CASH FLOW
1	0.9497E 06	0.3616E 06	0.2267E 06	0.1175E 06	0.5257E 06
2	0.9497E 06	0.3649E 06	0.2515E 06	0.1304E 06	0.5232E 06
3	0.9497E 06	0.3684E 06	0.2730E 06	0.1415E 06	0.4949E 06
4	0.9497E 06	0.3719E 06	0.2917E 06	0.1512E 06	0.3665E 06
5	0.9497E 06	0.3755E 06	0.3077E 06	0.1595E 06	0.3552E 06
6	0.9497E 06	0.3792E 06	0.3213E 06	0.1666E 06	0.3449E 06
7	0.9497E 06	0.3830E 06	0.3328E 06	0.1725E 06	0.3356E 06
8	0.9497E 06	0.3869E 06	0.3424E 06	0.1775E 06	0.3270E 06
9	0.9497E 06	0.3910E 06	0.3504E 06	0.1816E 06	0.3192E 06
10	0.9497E 06	0.3951E 06	0.3567E 06	0.1849E 06	0.3120E 06
11	0.9497E 06	0.4432E 06	0.3178E 06	0.1647E 06	0.2533E 06
12	0.9497E 06	0.4476E 06	0.3215E 06	0.1667E 06	0.2472E 06
13	0.9497E 06	0.4520E 06	0.3241E 06	0.1680E 06	0.2415E 06
14	0.9497E 06	0.4566E 06	0.3256E 06	0.1688E 06	0.2361E 06
15	0.9497E 06	0.4613E 06	0.3263E 06	0.1692E 06	0.2311E 06
16	0.9497E 06	0.4661E 06	0.3261E 06	0.1691E 06	0.2264E 06
17	0.9497E 06	0.4710E 06	0.3252E 06	0.1686E 06	0.2219E 06
18	0.9497E 06	0.4761E 06	0.3235E 06	0.1677E 06	0.2177E 06
19	0.9497E 06	0.4813E 06	0.3213E 06	0.1666E 06	0.2135E 06
20	0.9497E 06	0.4866E 06	0.3185E 06	0.1651E 06	0.2096E 06

NET PRESENT VALUE:	0.103E 07
DISCNT. CASH FLOW RATE OF RET.(%):	20.64
DISCNT. PAYBACK PERIOD (YEARS):	4

B.0 A DISCUSSION OF THE GEEF MODEL RESULTS

B.1 Three Cases for Illustration

The Geothermal Engineering and Economic Feasibility methodology described in Section 2 was applied to three cases: Case I is a direct geothermal energy system; Case II and Case III are 1 stage and 2 stage indirect geothermal energy systems respectively. The following subsections illustrate the economic feasibility results for three cases presented in Appendix A (Tables 10-12) and indicate the policy implications for decision makers in using different investment decision outputs of the GEEF model.

B.1.1 Consistency in Economic Feasibility Determination

For a meaningful and consistent comparison of Geothermal Energy System (GES) with the least-cost competitive conventional energy system (CES), economic feasibility in each of the three cases is determined by comparing the levelized cost of energy (ALCE) for both GES and CES. This is a more reasonable approach to the determination of economic feasibility of GES than comparing the ALCE of GES with the current price of energy for CES at the start-up year of GES.

Consistency in comparing competing energy systems refers to a consideration of the timing of streams of benefits and capital and variable costs, their magnitude and the time value of money. Variable costs such as operation and maintenance costs can be expected to increase with inflation whereas fuel costs can escalate more rapidly than the inflation rate, depending on the energy demand and supply balance for a given period. The true levelized cost of conventional energy is the product of the price of energy times the annualized fuel cost multiplier (AFF) derived in equation 13. The multiplier is determined by a levelized value of an escalating cost stream expressed in constant dollars. The rate of energy price escalation for the conventioal fuel over the lifetime is also taken into account in computing the multiplier.

The levelized costs of energy for GES and CES are expressed in constant year dollars. This is achieved by defining the present worth of year-by-year cash requirements throughout the system life in terms of a capital recovery factor that is based on real or inflation-adjusted discount rate. The levelized cost of energy, expressed in constant dollars, is a better representative of the actual costs than if it were expressed in current dollars because the former can be expected to stay constant in constant dollars than in current dollars.

GES is deemed economically feasible if the ALCE of GES is equal to or less than the ALCE of GES. If GES is determined to be economically feasible based on this life-cycle costing criterion, the GEEF model will further compute these following outputs: net present value (NPV), discounted cash flow rate of return (DCFROR) and discounted payback period (DPP) for GES. Two separate values are calculated for each of these outputs, each evaluated at the ALCE of GES and the ALCE of CES.

B.2 Policy Implications for Decision Makers

The examples presented in this report are used strictly to illustrate the application of GEEF model and they are not meant to make generalizations about the economic feasibility of GES for direct heat application. Table 13 presents a summary of the results of the GEEF computer model computations for three cases described earlier. It contains a description of the GES for each of the three cases: their annual energy output, total annualized cost of energy, and levelized costs of energy for GES and CES. If the cases indicate economic feasibility, additional outputs of the model - NPV, DCFROR and DPP - are also presented in the table.

It is clear from the table that Case I and Case III are economically feasible based on life-cycle costing criterion, whereas Case II does not satisfy the economic feasibility test. Between the two economically feasible alternatives, Case I and Case III, Case I is more attractive than Case III purely in terms of pricing criterion, whereas Case III offers the decision makers better profitable opportunities than Case I because it provides greater NPV and DCFROR and requires shorter DPP than Case I.

The multiple outputs of the GEEF model presented in Table 13 are designed to assist different decision makers in meeting their particular business objectives in the utilization of geothermal energy for direct uses. The decision makers include both private and public sectors - resource developer, end-user, financial institutions and government policy makers.

The results dramatically illustrate the differing implications for different investment decision makers. For example, both Case I and

TABLE 13

Summary of GEEF Model Results for Three Cases

	Case I	Case II	Case III
Standard System	Direct (0)*	Indirect (1)*	Indirect (2)*
Annualized Energy Output (MMbtu)	52559.98	52559.98	73583.94
Total Annualized Energy Cost (Millon $)**	0.547	0.950	0.779
Levelized Cost of Energy (ALCE) for GES ($/MMbtu)	10.40***	18.08	10.58***
Levelized Cost of Energy (ALCE) for CES ($/MMbtu)****	12.91	12.91	12.91
Net Present Value (Million $):			
- at GES ALCE	2.52	-	3.48
- at CES ALCE	3.56	-	4.87
Discounted Cash Flow Rate of Return (%):			
- at GES ALCE	21.53	-	21.73
- at CES ALCE	21.81	-	22.04
Discounted Payback Period (Years):			
- at GES ALCE	5	-	4
- at CES ALCE	4	-	4

* Figures in parantheses refer to the number of heat exchangers.

** All dollar figures are expressed in 1980 dollars.

*** Indicates that GES is economically feasible.

**** Levelized cost of least-cost conventional fuel (oil) was derived by using the GEEF methodology.

Case III are economically feasible and Case I is economically more attractive than Case III based on life-cycle cost criterion; however, a financial institution may choose the project represented by Case III over Case I because the discounted payback period for Case III is shorter than for Case I.

APPENDIX C

C.0 GEEF MODEL: COMPUTER PROGRAM LISTING

```
      COMPILER OPTIONS - NAME=  MAIN,OPT=02,LINECNT=58,SIZE=1024K,
                         SOURCE,EBCDIC,NOLIST,NODECK,LOAD,MAP,NOEDIT,ID,NOXREF
ISN 0002              COMMON/MAH/INEXC,IPKRE,IPKRE2,UFSUP,UFSUP2,SUPCST
ISN 0003              READ(8,9)INEXC,ITSUP,ISAL,HTCOEF
ISN 0004        9     FORMAT(3I3,2F8.2)
ISN 0005              WRITE(6,13)INEXC
ISN 0006       13     FORMAT(1H1,/////,5X,'NO. OF HEAT EXCHRS=',2X,I2)
ISN 0007              READ (8,180) ITWHP,ITDRP,ITPR,IATD,IPKRE,IFPW,SHB,UFSUP
ISN 0008      180     FORMAT(4I5,2I8,2F5.2)
ISN 0009              IF (INEXC .NE. 0) GO TO 182
ISN 0011              WRITE (6,181) ITWHP,ITDRP,ITPR,IATD,IPKRE,IFPW,SHB,UFSUP
ISN 0012      181     FORMAT(//,2X,'PROD. WELLHD TEMP.(DEG. F)=',T64,I5,
                     1/,2X,'TEMP. DROP BET. PROD. WELLHD & PL. INLET(DEG F)=',T64,I5,
                     2/,2X,'PROCESS TEMP. (DEG F)=',T64,I5,
                     3/,2X,'ALLOW. TEMP. DROP IN THE PROCESS(DEG. F)=',T64,I5,
                     4/,2X,'PEAK ENERGY REQMT. FOR PROCESS(MMBTU/HR)=',T64,I8,
                     5/,2X,'WELL FLOW RATE (LBS./HR.)=',T64,I8,
                     6/,2X,'SPECIFIC HEAT FOR BRINE(BTU/LB/DEG. F)=',T64,F5.2,
                     7/,2X,'UTILIZATION FACTOR FOR PROCESS=',T64,F5.2)
ISN 0013              IPKRE=IPKRE*1000000
ISN 0014              ITHI=ITWHP - ITDRP
ISN 0015              ERSS=0.
ISN 0016              IF(ITHI .GE. ITPR) GO TO 179
ISN 0018              ERSS=(ITPR-ITHI)*IPKRE/FLOAT(IATD)
ISN 0019      179     FPR=IPKRE/(IATD*SHB)
ISN 0020              IFPR=IFIX(FPR)
ISN 0021              NPW=FPR/IFPW + 1
ISN 0022              NIW=0
ISN 0023              GO TO 50
ISN 0024      182     READ(8,183) NGTTD1,NGTTD2,ITWHI,ITDRI,IAREA1,SHW,ETA1
ISN 0025      183     FORMAT(4I5,I8,2F5.2)
ISN 0026              WRITE (6,184) ITWHP,ITDRP,ITPR,IATD,IPKRE,ITWHI,ITDRI,NGTTD1,
                     1 NGTTD2,IFPW,SHB,SHW,ETA1,UFSUP
ISN 0027      184     FORMAT(//,2X,'PROD. WELLHD. TEMP.(DEG. F)=',T64,I5,
                     1/,2X,'TEMP.DROP BET. PROD WELLHD. & EXC.1 IN.(DEG F)=',T64,I5,
                     2/,2X,'PROCESS TEMP. AT EXCHR 1 (DEG. F)=',T64,I5,
                     3/,2X,'ALLOW. TEMP. DROP WITHIN THE PROCESS 1(DEG F)=',T64,I5,
                     4/,2X,'PEAK ENERGY REQMT. FOR PROCESS 1(MMBTU/HR)=',T64,I8,
                     5/,2X,'INJECTION WELLHD. TEMP.(DEG. F)=',T64,I5,
                     6/,2X,'TEMP.DROP BET. INJ. WELLHD. & EXC.1 OUT.(DEG. F)=',T64,I5,
                     7/,2X,'TERM. TEMP. DIFF. AT INLET OF EXCHR.1(DEG. F)=',T64,I5,
                     8/,2X,'TERM. TEMP. DIFF. AT OUTLET OF EXCHR. 1(DEG F)=',T64,I5,
                     9/,2X,'WELL FLOW RATE (LBS/HR)=',T64,I8,
                     1/,2X,'SPECIFIC HEAT FOR BRINE(BTU/LB/DEG. F)=',T64,F5.2,
                     2/,2X,'SPECIFIC HEAT FOR WORK. FLD. (BTU/LB/HR)=',T64,F5.2,
                     3/,2X,'EFFICIENCY FOR HEAT EXCHR. 1=',T64,F5.2,
                     4/,2X,'UTILIZATION FACTOR FOR PROCESS 1=',T64,F5.2)
ISN 0028              IF (INEXC .EQ. 2) GO TO 25
ISN 0030              IPKRE=IPKRE*1000000
ISN 0031              ITHI=ITWHP-ITDRP
ISN 0032              ITRE=ITWHI-ITDRI
ISN 0033              ITCI=ITPR-IATD
ISN 0034              FSEC=IPKRE/(IATD*SHW)
ISN 0035              ITHO=ITRE
ISN 0036              IF (ITCI+NGTTD2 .GE. ITRE) ITHO=ITCI+NGTTD1
ISN 0038              ITCO=ITHI - NGTTD1
```

```
ISN 0039           ERSS=0.
ISN 0040           IF (ITCO .GE. ITPR) GO TO 20
ISN 0042           ERSS=FSEC*(ITPR-ITCO)*SHW
ISN 0043     20    EPRW=(IPKRE-ERSS)/ETA1
ISN 0044           FPR=EPRW/((ITHI-ITHO)*SHB)
ISN 0045           IFPR=IFIX(FPR)
ISN 0046           NPW=FPR/IFPW + 1
ISN 0047           NIW=.5*NPW + .5
ISN 0048           GO TO 50
ISN 0049     25    READ (8,185) ITPR2,IATD2,NGTTD3,NGTTD4,IAREA2,IPKRE2,ETA2,UFSUP2
ISN 0050     185   FORMAT(4I5,2I8,2F5.2)
ISN 0051           WRITE (6,22) ITPR2,IATD2,NGTTD3,NGTTD4,IPKRE2,ETA2,UFSUP2
ISN 0052     22    FORMAT(2X,'PROCESS TEMP. AT EXCHR. 2 (DEG. F)='T64,I5,
                  1/,2X,'ALLOW.TEMP. DROP WITHIN PROCESS 2(DEG. F)=',T64,I5,
                  2/,2X,'TERM. TEMP. DIFF AT INLET OF EXCHR.2(DEG. F)=',T64,I5,
                  3/,2X,'TERM. TEMP. DIFF. AT OUT. OF EXCHR.2(DEG. F)=',T64,I5,
                  4/,2X,'PEAK ENERGY REQMT. FOR PROCESS 2(MMBTU/HR)=',T64,I8,
                  5/,2X,'EFFICIENCY FOR HEAT EXCHR.2 =',T64,F5.2,
                  6/,2X,'UTILIZATION FACTOR FOR PROCESS 2=',T64,F5.2)
ISN 0053           IPKRE=IPKRE*1000000
ISN 0054           IPKRE2=IPKRE2*1000000
ISN 0055           ITHI=ITWHP-ITDRP
ISN 0056           ITRE=ITWHI-ITDRI
ISN 0057           ITCI=ITPR-IATD
ISN 0058           ITCI2=ITPR2-IATD2
ISN 0059           ITHO2=ITRE
ISN 0060           IF (ITCI2 +NGTTD4 .GE. ITRE) ITHO2=ITCI2+NGTTD4
ISN 0062           ITHO=ITCI+NGTTD2
ISN 0063           ITCO2=ITPR2
ISN 0064           IF (ITHO .LT. ITCO2+NGTTD3) ITHO=ITCO2+NGTTD3
ISN 0066           ITHI2=ITHO
ISN 0067           ITCO=ITHI-NGTTD1
ISN 0068           FR22=IPKRE2/FLOAT(IATD2)
ISN 0069           FR21=IPKRE2/(ETA2*(ITHI2-ITHO2))
ISN 0070           FR12=IPKRE/((ITPR-ITCI)*SHW)
ISN 0071           HETR1=IPKRE-FR12*(ITCO-ITCI)*SHW
ISN 0072           HET1=HETR1/ETA1
ISN 0073           FR11=HET1/((ITHI-ITHO)*SHB)
ISN 0074           BFRT=FR11
ISN 0075           IF(FR21 .GT. FR11)BFRT=FR21
ISN 0077           ERSS=0
ISN 0078           IF(ITCO .GE. ITPR)GO TO 26
ISN 0080           ERSS=FR12*(ITPR-ITCO)*SHW
ISN 0081           IFPR=IFIX(BFRT)
ISN 0082     26    NPW=(BFRT/IFPW+1)
ISN 0083           NIW=0.5*NPW+0.5
ISN 0084     50    CONTINUE
ISN 0085           READ(8,188) SUPCST,EFFY,ISSC,IEXPC,IDSC
ISN 0086     188   FORMAT(2F8.2,3I8)
ISN 0087           READ(8,90) LEN,IROCK,IPWDEP,IIWDEP,DIAP,DIAINS
ISN 0088     90    FORMAT(4I8,2F5.2)
ISN 0089           READ(8,196) IPWC,IIWDSC
ISN 0090     196   FORMAT(2I8)
ISN 0091           FC=0.
ISN 0092           IF (ITSUP .EQ. 3) SUPCST=SUPCST*1000000./3415.
ISN 0094           IF (ITSUP .EQ. 1) SUPCST=SUPCST/6.
```

```
ISN 0096            IF (ERSS .EQ. O.) GO TO 60
ISN 0098            ERSS=ERSS*8760.*UFSUP
ISN 0099            IF (ITSUP .EQ. 1) GO TO 61
ISN 0101            IF (ITSUP .EQ. 2) GO TO 62
ISN 0103            FC=(ERSS/1000000.)*SUPCST
ISN 0104            GO TO 60
ISN 0105      61    FC=(ERSS/1000000.)*SUPCST/EFFY
ISN 0106            GO TO 60
ISN 0107      62    FC=ERSS*SUPCST/(1000000.*EFFY)
ISN 0108      60    CONTINUE
ISN 0109            PHIX=O.
ISN 0110            IF (INEXC .EQ. O) GO TO 200
ISN 0112            T1=ITHI-ITCO
ISN 0113            T2=ITHO-ITCI
ISN 0114            IF (T1 .EQ. T2) GO TO 70
ISN 0116            IF (T1 .GT. T2) GO TO 69
ISN 0118            T3=T2 - T1
ISN 0119            IF (X .LT. O.) X=-X
ISN 0121            X=T2/T1
ISN 0122            T4=ALOG(X)
ISN 0123            TEMP1=T3/T4
ISN 0124            GO TO 75
ISN 0125      69    T3=T1-T2
ISN 0126            X=T1/T2
ISN 0127            IF (X .LT. O.) X=-X
ISN 0129            T4=ALOG(X)
ISN 0130            TEMP1=T3/T4
ISN 0131            GO TO 75
ISN 0132      70    TEMP1=T1
ISN 0133      75    AA1=FPR/(HTCOEF*TEMP1)
ISN 0134            IF (AA1 .LE. IAREA1) AA1=IAREA1
ISN 0136            PHIX=3000.*(AA1/200.)**0.671
ISN 0137            IF (INEXC .NE. 2) GO TO 80
ISN 0139            T1=(ITHI2 - ITCO2)
ISN 0140            T2=(ITHO2 - ITCI2)
ISN 0141            IF (T1 .EQ. T2) GO TO 77
ISN 0143            IF ( T1 .GT. T2) GO TO 76
ISN 0145            T3=T2 - T1
ISN 0146            X=T2/T1
ISN 0147            IF (X .LT. O.) X=-X
ISN 0149            T4=ALOG(X)
ISN 0150            TEMP1=T3/T4
ISN 0151            GO TO 78
ISN 0152      76    T3=T1 - T2
ISN 0153            X=T1/T2
ISN 0154            IF (X .LT. O.) X=-X
ISN 0156            T4=ALOG(X)
ISN 0157            TEMP1=T3/T4
ISN 0158            GO TO 78
ISN 0159      77    TEMP1=T1
ISN 0160      78    AA2=FR21/(HTCOEF*TEMP1)
ISN 0161            IF (AA2 .LE. IAREA2) AA2=IAREA2
ISN 0163            PHIX2=3000.*(AA2/200.)**0.671
ISN 0164            PHIX=PHIX + PHIX2
ISN 0165      80    CONTINUE
ISN 0166     200    PHIX= PHIX*2.17*1.47
```

```
ISN 0167          IF (ISAL .EQ.1) PHIX=PHIX*1.2
ISN 0169          IF (IDSC.NE.O)GO TO 916
ISN 0171          DIAP=DIAP/12.
ISN 0172          DIAINS=DIAINS/12.
ISN 0173          PHIM=20.* LEN * (DIAP/2.)**.52
ISN 0174          PHIL=11.6*LEN*(DIAINS/2.)**.39
ISN 0175          PHII=3.14158*(-DIAP*DIAP + DIAINS*DIAINS)*LEN*32.5
ISN 0176          DISSC=(PHIM+PHIL+PHII)*1.4700000
ISN 0177          GO TO 917
ISN 0178    916   DISSC=IDSC
ISN 0179    917   IF (IROCK .EQ. 1) GO TO 95
ISN 0181          WC1=2.887*IPWDEP**1.496
ISN 0182          WC2=2.887*IIWDEP**1.496
ISN 0183          GO TO 96
ISN 0184    95    WC1=102.8*IPWDEP**1.035
ISN 0185          WC2=102.8*IIWDEP**1.035
ISN 0186    96    WCP=NPW*WC1
ISN 0187          WCI=NIW*WC2
ISN 0188          IF (IPWC .NE. O) WCP=IPWC*NPW
ISN 0190          IF (IIWDSC .NE. O) WCI=IIWDSC
ISN 0192          WRITE(6,91)   LEN,DIAP,DIAINS
ISN 0193    91    FORMAT( 5X,
                 1/,5X,'DISTRB SYSTEM PIPELINE LENGTH(FEET)=',T60,I8,
                 2/,5X,'DISTRB SYSTEM PIPELINE DIAMETER(INCHES)=',T60,F8.2,
                 3/,5X,'DISTRB SYSTEM PIPELINE INSUL. DIA.(INCHES)=',T60,F8.2)
ISN 0194          IF (IROCK .EQ. 1) WRITE(6,92)
ISN 0196    92    FORMAT(5X,'TYPE OF ROCK: SOFT')
ISN 0197          IF (IROCK .EQ. 2) WRITE(6,93)
ISN 0199    93    FORMAT(5X,'TYPE OF ROCK: HARD')
ISN 0200          IF (ISAL .EQ. 1) WRITE(6,220)
ISN 0202    220   FORMAT(5X,'SALINITY: HIGH')
ISN 0203          IF (ISAL .NE. 1) WRITE(6,221)
ISN 0205    221   FORMAT(5X,'SALINITY: LOW')
ISN 0206          IF (IPWC .EQ. O) WRITE (6,215) IPWDEP
ISN 0208    215   FORMAT(5X,'PRODUCTION WELL DEPTH(FEET)=',T60,I8)
ISN 0209          IF (IIWDSC .EQ. O .AND. INEXC .NE. O) WRITE (6,216) IIWDEP
ISN 0211    216   FORMAT(5X,'INJECTION WELL DEPTH(FEET)=',T60,I8)
ISN 0212          WRITE (6,51) IFPR,NPW,NIW,ERSS
ISN 0213          WRITE(6,81) PHIX,FC
ISN 0214    81    FORMAT(///,5X,'BASE CAPITAL COST FOR HEAT EXCHR(S)=',T60,E10.3,
                 1 /,5X,'AVERAGE ANNUAL FUEL COST=',T60,E10.3)
ISN 0215    51    FORMAT(/,5X,'FLOW RATE REQUIRED(LBS/HR)=',T60,I8,
                 1/,5X,'NUMBER OF PRODUCTION WELLS=',T60,I8,
                 1 /,5X,'NUMBER OF INJECTION WELLS=',T60,I8,
                 2 /,5X,'ANN. ENERGY REQD. FROM SUPPLM. SYS.(BTU)=',T60,E10.3)
ISN 0216          IF(FC.EQ.O)ISSC=O
ISN 0218          IF(IEXPC.EQ.O)IEXPC=O.05*(WCP+WCI+DISCC+PHIX)
ISN 0220          WRITE(6,97) DISSC,WCP,WCI,ISSC,IEXPC
ISN 0221    97    FORMAT(/,5X,'BASE CAPITAL COST FOR DIST. SYSTEM=',T60,E10.3,
                 1 /,5X,'PRODUCTION WELLS COST=',T60,E10.3,
                 2 /,5X,'INJECTION WELLS COST=',T60,E10.3,
                 3/,5X,'SUPPLEMENTRY SYSTEM CAPITAL COST',T60,I8,
                 4/,5X,'EXPLORATION COST=',T60,I8)
ISN 0222          IF (INEXC .NE. 2) IPKRE2=O
ISN 0224          CALL FINA(DISSC,WCP,WCI,FC,PHIX,ISSC,IEXPC)
ISN 0225          STOP
```

ISN 0226 END 00223000

NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.
X	SFA	R*4	000A10	FC	SFA	R*4	000A14	T1	SF	R*4	000A18	T2	SF	R*4	000A1C
T3	SF	R*4	000A20	T4	SF	R*4	000A24	AA1	SF	R*4	000A28	AA2	SF	R*4	000A2C
FPR	SFA	R*4	000A30	LEN	SF	I*4	000A34	NIW	SF	I*4	000A38	NPW	SF	I*4	000A3C
SHB	SF	R*4	000A40	SHW	SF	R*4	000A44	WCI	SFA	R*4	000A48	WCP	SFA	R*4	000A4C
WC1	SF	R*4	000A50	WC2	SF	R*4	000A54	BFRT	SFA	R*4	000A58	DIAP	SF	R*4	000A5C
EFFY	SF	R*4	000A60	EPRW	SF	R*4	000A64	ERSS	SF	R*4	000A68	ETA1	SF	R*4	000A6C
ETA2	SF	R*4	000A70	FINA	SF XF	R*4	000000	FR11	SF	R*4	000A74	FR12	SF	R*4	000A78
FR21	SF	R*4	000A7C	FR22	S	R*4	000A80	FSEC	SF	R*4	000A84	HET1	SF	R*4	000A88
IATD	SFA	I*4	000A8C	IDSC	SF	I*4	000A90	IFPR	SF	I*4	000A94	IFPW	SF	I*4	000A98
IPWC	SF	I*4	000A9C	ISAL	S	I*4	000AA0	ISSC	SFA	I*4	000AA4	ITCI	SF	I*4	000AA8
ITCO	SF	I*4	000AAC	ITHI	SF	I*4	000AB0	ITHO	SF	I*4	000AB4	ITPR	SF	I*4	000AB8
ITRE	SF	I*4	000ABC	PHII	SF	R*4	000AC0	PHIL	SF	R*4	000AC4	PHIM	SF	R*4	000AC8
PHIX	SFA	R*4	000ACC	DISCC	F	R*4	000AD0	DISSC	SFA	R*4	000AD4	HETR1	SF	R*4	000AD8
IATD2	SFA	I*4	000ADC	IEXPC	SFA	I*4	000AE0	INEXC	SF C	I*4	000000	IPKRE	SF C	I*4	000004
IROCK	S	I*4	000AE4	ITCI2	SF	I*4	000AE8	ITCO2	SF	I*4	000AEC	ITDRI	SF	I*4	000AF0
ITDRP	SF	I*4	000AF4	ITHI2	SF	I*4	000AF8	ITHO2	SF	I*4	000AFC	ITPR2	SF	I*4	000B00
ITSUP	S	I*4	000B04	ITWHI	SF	I*4	000B08	ITWHP	SF	I*4	000B0C	PHIX2	SF	R*4	000B10
TEMP1	SF	R*4	000B14	UFSUP	SF C	R*4	00000C	FRXPR#	XF	R*4	000000	ALOG	XF	R*4	000000
DIAINS	SF	R*4	000B18	HTCOEF	SF	R*4	000B1C	IAREA1	SF	I*4	000B20	IAREA2	SF	I*4	000B24
IBCOM#	F XF	R*4	000000	IIWDEP	SF	I*4	000B28	IIWDSC	SF	I*4	000B2C	IPKRE2	SF C	I*4	000008
IPWDEP	SF	I*4	000B30	NGTTD1	SF	I*4	000B34	NGTTD2	SF	I*4	000B38	NGTTD3	SF	I*4	000B3C
NGTTD4	SF	I*4	000B40	SUPCST	SF C	R*4	000014	UFSUP2	SF C	R*4	000010				

***** COMMON INFORMATION *****

NAME OF COMMON BLOCK * MAH* SIZE OF BLOCK 000018 HEXADECIMAL BYTES

VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.
INEXC	I*4	000000	IPKRE	I*4	000004	IPKRE2	I*4	000008	UFSUP	R*4	00000C
UFSUP2	R*4	000010	SUPCST	R*4	000014						

LABEL	ADDR	LABEL	ADDR	LABEL	ADDR	LABEL	ADDR
179	000D0C	182	000DD4	20	000F92	25	00107C
26	00136A	50	0013FC	61	00151A	62	001532
60	001548	69	001606	70	00164C	75	001654
76	00177E	77	0017C4	78	0017CC	80	001846
200	001846	916	00195A	917	001986	95	001A26
96	001ABA						

OPTIONS IN EFFECT   NAME= MAIN,OPT=02,LINECNT=58,SIZE=1024K,

OPTIONS IN EFFECT   SOURCE,EBCDIC,NOLIST,NODECK,LOAD,MAP,NOEDIT,ID,NOXREF

STATISTICS   SOURCE STATEMENTS =   225 ,PROGRAM SIZE =   7606

STATISTICS NO DIAGNOSTICS GENERATED

****** END OF COMPILATION ******   972K BYTES OF CORE NOT USED

```
        COMPILER OPTIONS - NAME=  MAIN,OPT=02,LINECNT=58,SIZE=1024K,
                           SOURCE,EBCDIC,NOLIST,NODECK,LOAD,MAP,NOEDIT,ID,NOXREF
ISN 0002            SUBROUTINE FINA(DISSC,WCP,WCI,FC,PHIX,ISSC,IEXPC)
ISN 0003            COMMON /MAH/INEXC,IPKRE,IPKRE2,UFSUP,UFSUP2,SUPCST
ISN 0004            DIMENSION ICT(30),GY(30),BT(30),YBT(30),OMT(30),FCT(30),
                   1WCKD(30),RODT(30),ANYBD(30),DEP(30),TYBDPL(30),
                   2TYADPL(30),TYT(30),ANPT(30),AITCY(30),ANCF(30),ROE(30),
                   3SCF(30),TA(2),ANYBT(30)
ISN 0005            DIMENSION ECE(30),ACSF(30),CCSF(30)
ISN 0006            READ (8,101) TF,TS,AKD,AD,AKC,EC,AKP,EP
ISN 0007      101   FORMAT(8F5.2)
ISN 0008            READ (8,102)  A1,B1,A11,B2,B3,G,GC,GF,GOM
ISN 0009      102   FORMAT(9F5.2)
ISN 0010            READ (8,103) N1,N2,IB,IV,IS
ISN 0011      103   FORMAT(5I5)
ISN 0012            WRITE (6,105) TF,TS,AKD,AD,AKC,EC,AKP,EP
ISN 0013      105   FORMAT(1H1,///,5X,'FED INCOME TAX RATE(FRACTION):',T60,F5.2,
                   1/,5X,'STATE INCOME TAX RATE(FRACTION):',T60,F5.2,
                   2/,5X,'ANNUAL INTEREST RATE ON DEBT(FRACTION):',T60,F5.2,
                   3/,5X,'DEBT FRACTION:',T60,F5.2,
                   4/,5X,'RATE OF RETURN ON COMMON STOCK(FRACTION):',T60,F5.2,
                   5/,5X,'COMMON STOCK FRACTION:',T60,F5.2,
                   6/,5X,'RATE OF RETURN ON PREFERRED STOCK(FRACTION):',T60,F5.2,
                   2/,5X,'PREFERRED STOCK FRACTION:',T60,F5.2)
ISN 0014            WRITE (6,106) A1,B1,A11,B2,B3,G,GC,GF,GOM
ISN 0015      106   FORMAT(5X,'TAX CREDIT RATE(FRACTION):',T60,F5.2,
                   1/,5X,'PROPERTY TAX AND INSURANCE RATE(FRACTION):',T60,F5.2,
                   2/,5X,'INIT. INVEST. CAP. NOT TO BE REPLACED(FRACTION):',T60,F5.2,
                   3/,5X,'ROYAL. PAYMT. AS FRACTION OF GROSS REVENUE:',T60,F5.2,
                   4/,5X,'DEPLETION ALLOWANCE(FRACTION):',T60,F5.2,
                   5/,5X,'INFLATION RATE(FRACTION):',T60,F5.2,
                   6/,5X,'ESCALATION FACT. FOR CAPITAL COSTS:',T60,F5.2,
                   7/,5X,'ESCALATION FACT. FOR FUEL COSTS:',T60,F5.2,
                   8/,5X,'ESCALATION FACT. FOR O & M COSTS:',T60,F5.2)
ISN 0016            WRITE (6,107) IB,IV,IS,N1,N2
ISN 0017      107   FORMAT(5X,'PROJECT BASE YEAR:',T60,I5,
                   1/,5X,'PROJECT VINTAGE YEAR:',T60,I5,
                   2/,5X,'START EXPENDITURE YEAR:',T60,I5,
                   3/,5X,'PROJECT LIFE SPAN (YEARS):',T60,I5,
                   4/,5X,'DEPRECIATION LIFE FOR TAX(YEARS):',T60,I5)
              C:
              C:    BEGIN FINANCIAL COMPUTATIONS*******
              C:
ISN 0018            TR=TF+TS-TF*TS
ISN 0019            AK=(1.-TR)*AKD*AD + AKC*EC + AKP*EP
ISN 0020            X1=(1+AK)**N1
ISN 0021            X1=1./X1
ISN 0022            CRFKN1=AK/(1.-X1)
ISN 0023            X2=(1.+AK)**N2
ISN 0024            X2=1./X2
ISN 0025            CRFKN2=AK/(1.-X2)
ISN 0026            DPFSD=2.*(N2 - 1./CRFKN2)/(N2*(N2+1)*AK)
ISN 0027            FCRN1 = CRFKN1*(1.-TR*DPFSD-A1)/(1.-TR)
ISN 0028            FCRN2 = CRFKN2*(1.-TR*DPFSD-A1)/(1.-TR)
ISN 0029            X3 = (1.+G)/(1+AK)
ISN 0030            X3 = X3**N2
```

```
ISN 0031          FCRRN1=(CRFKN1/CRFKN2)*(FCRN2+X3*FCRN2)
ISN 0032          J = IV+N1
ISN 0033          DO 110  I=IS,J
ISN 0034          ITEMP=I-IS+1
ISN 0035    110   ICT(ITEMP)=0
ISN 0036          ICT(1)=IEXPC
ISN 0037          ICT(2) = WCP+WCI
ISN 0038          ICT(3)=DISSC+PHIX+ISSC
ISN 0039          ITEMP=IV-IS+N2
ISN 0040          ICT(ITEMP) = 0.6*(WCP+WCI+DISSC+PHIX)
ISN 0041          J = IV+N1-1
ISN 0042          AICPV=0.
ISN 0043          DO 111  I = IS,J
ISN 0044          JJ = I-IB
ISN 0045          JJJ = IV-I
ISN 0046          AICPV = AICPV+ICT(I-IS+1)*((1.+G+GC)**JJ)*
                 1  ((1.+AK)**JJJ)
ISN 0047    111   CONTINUE
ISN 0048          ICT(ITEMP)=0
ISN 0049          AICPV1=0.
ISN 0050          DO 211 I=IS,J
ISN 0051          JJ=I-IB
ISN 0052          JJJ=IV-I
ISN 0053          AICPV1=AICPV1+ICT(I-IS+1)*(1.+G+GC)**JJ*((1.+AK)**JJJ)
ISN 0054    211   CONTINUE
ISN 0055          FCR = A11*FCRN1+(1.-A11)*FCRRN1+B1
ISN 0056          X1 = (1+G+GF)/(1+G)
ISN 0057          X2 = (1+G+GF)/(1+AK)
ISN 0058          GG=G+GF
ISN 0059          IF(GG.EQ.AK)GO TO 919
ISN 0061          X3 = (1.-X2**N1)/(AK-G-GF)
ISN 0062          DESCF=(X1**(IV-IB))*X3
ISN 0063          GO TO 920
ISN 0064    919   DESCF=(X1**(IV-IB))*N1
ISN 0065    920   X1=(1.+G+GOM)/(1.+G)
ISN 0066          X2=(1.+G+GOM)/(1.+AK)
ISN 0067          GG=G+GOM
ISN 0068          IF(GG.EQ.AK)GO TO 921
ISN 0070          X3=(1.-X2**N1)/(AK-G-GOM)
ISN 0071          DESCOM = (X1**(IV-IB))*X3
ISN 0072          GO TO 922
ISN 0073    921   DESCOM=(X1**(IV-IB))*N1
ISN 0074    922   AFF = DESCF*CRFKN1
ISN 0075          AFOM = DESCOM*CRFKN1
ISN 0076          ACC = AICPV*FCR
ISN 0077          AFC = FC*AFF
ISN 0078          AOMC= (.05*AICPV1)*AFOM
ISN 0079          TACE = ACC+AFC+AOMC
ISN 0080          ERA = IPKRE*UFSUP
ISN 0081          IF (INEXC.EQ.2) ERA = ERA+IPKRE2*UFSUP2
ISN 0083          ERA = (ERA/1000000)*8760
ISN 0084          ALCE = TACE/ERA
ISN 0085          ALCE=ALCE*(1-TR)/(1.-TR+B3*TR-B2+B2*TR)
ISN 0086          TACE=ALCE*ERA
ISN 0087          TACE1=TACE/1000000.
ISN 0088          SUPCST=SUPCST*AFF
```

```
ISN 0089           WRITE (6,112) ERA,TACE1,ALCE,SUPCST
ISN 0090      112  FORMAT(///,5X,'TOTAL ANN. ENERGY REQD.(MMBTU)=',T60,F8.2,
                  1/,5X,'TOTAL ANNLZD. COST OF GEOTHERMAL ENERGY($M)=',T60,F8.3,
                  2/,5X,'LEVEL. COST OF GEOTHERMAL ENERGY ($/MMBTU)=',T60,F8.2,
                  3/,5X,'LEVEL. COST OF ENERGY FROM ALTERNATE SYSTEM($/MMBTU)=',
                  4T60,F8.2)
ISN 0091           IF (SUPCST .LT. ALCE) GO TO 999
ISN 0093           TA(1)=TACE
ISN 0094           TA(2)=SUPCST*ERA
ISN 0095           DO 500 IJ=1,2
ISN 0096           TACE=TA(IJ)
ISN 0097           IF (IJ .EQ. 1) WRITE(6,351)
ISN 0099      351  FORMAT(1H1,//,14X,' YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY',
                  1///)
ISN 0100           IF (IJ .EQ. 2) WRITE (6,352)
ISN 0102      352  FORMAT(1H1,///,14X,'YEAR BY YEAR CASH FLOW FOR GEOTHERMAL ENERGY'
                  1,/,18X,'AT ALTERNATE ENERGY LIFE CYCLE COST',///)
ISN 0103           AICPV2=AICPV-AICPV1
ISN 0104           DO 450 I=1,N1
ISN 0105      450  ECE(I)=0.
ISN 0106           ECE(N2)=AICPV2
ISN 0107           DO 941 LM=1,N2
ISN 0108           RODT(LM)=AK*AD*AICPV1
ISN 0109      941  ROE (LM)=(1.-AD)*AK*AICPV1
ISN 0110           JM=N2+1
ISN 0111           DO 741 LM=JM,N1
ISN 0112           RODT(LM)=AK*AD*AICPV
ISN 0113      741  ROE(LM)=(1.-AD)*AK*AICPV
ISN 0114           SUM = 0.
ISN 0115           DO 171  J = 1,N2
ISN 0116      171  SUM =  SUM+J
ISN 0117           Z6 = A1*AICPV1
ISN 0118           Z7 = 0.
ISN 0119           Z8 = 0.
ISN 0120           DO 150  I = 1,N1
ISN 0121           GY(I)=TACE
ISN 0122           BT(I) = GY(I)*B2
ISN 0123           OMT(I)=((1.+GOM)**(I-1))*(0.05*AICPV1)
ISN 0124           FCT(I)=((1+GF)**(I-1))*FC
ISN 0125           ANYBD(I)=GY(I)-(BT(I)+OMT(I)+FCT(I)+RODT(I))
ISN 0126           DEP(I)=0.
ISN 0127           IF (I.GE.N2) GOTO 128
ISN 0129           DEP(I) = (N2-I+1)*AICPV1/SUM
ISN 0130      128  DEP(I)=(2*N2-I+1)*ECE(N2)/SUM
ISN 0131           DEP(I)=DEP(I)/(1.+G)**(I-1)
ISN 0132           TYBDPL(I)=ANYBD(I)-DEP(I)
ISN 0133           Z4 = B3*GY(I)
ISN 0134           DPLTT = Z4
ISN 0135           Z5 = 0.5*TYBDPL(I)
ISN 0136           IF (Z5.LE.Z4) DPLTT = Z5
ISN 0138           IF (Z5 .LT. 0.) DPLTT=0.
ISN 0140           ANYBT(I) = TYBDPL(I)-DPLTT
ISN 0141           TYT(I) = TR*ANYBT(I)
ISN 0142           ANPT(I) = ANYBT(I)-TYT(I)
ISN 0143           AITCY(I) = 0.
ISN 0144           IF (I.GT.7) GOTO 126
```

```
ISN 0146          IF (Z8.GE.Z6) GOTO 126
ISN 0148          IF (ANPT(I).LE.O) GOTO 126
ISN 0150          Z7 = Z7+ANPT(I)
ISN 0151          Z9 = Z6-Z8
ISN 0152          IF (Z7.GT.Z6) AITCY(I) = Z9
ISN 0154          IF (Z7.LE.Z6) AITCY(I) = ANPT(I)
ISN 0156          Z8 = Z8+ANPT(I)
ISN 0157    126   ANCF(I) = ANPT(I)+DEP(I)+DPLTT+AITCY(I)-ROE(I)
ISN 0158    150   CONTINUE
ISN 0159          WRITE (6,160)
ISN 0160    160   FORMAT(//,1X,'YEAR',T13,'GROSS',T26,'ROYALTY',T39,'NET',
                 1T52,'NET',T65,'NET',/
                 2,3X,'OF',T13,'REVENUE',T26,'AND',T39,'INCOME',T52,'INCOME'
                 3,T65,'CASH',/
                 4,1X,'OPER.',T26,'OPER. COSTS',T39,'BEFORE',T52,'AFTER',T65,
                 5'FLOW',/
                 6,T39,'TAXES',T52,'TAXES')
ISN 0161          DO 165 I = 1,N1
ISN 0162          ROPC=BT(I)+OMT(I)+FCT(I)+RODT(I)
ISN 0163           WRITE(6,166)I,GY(I),ROPC,ANYBT(I),ANPT(I),ANCF(I)
ISN 0164    166   FORMAT (2X,I2,5X,E12.4,1X,E12.4,1X,E12.4,1X,E12.4,1X,E12.4)
ISN 0165    165   CONTINUE
ISN 0166          SUM=O.
ISN 0167          DO 300 I=1,N1
ISN 0168          SUM=SUM+ANCF(I)/(1.+AK)**(I-1)
ISN 0169    300   CONTINUE
ISN 0170          ZNPV=SUM-AICPV
ISN 0171          WRITE(6,301)ZNPV
ISN 0172    301   FORMAT(///,5X,'NET PRESENT VALUE:',T55,E10.3)
ISN 0173          IF (SUM.EQ.AICPV)GO TO 306
ISN 0175          IF (SUM.LT.AICPV)GO TO 500
ISN 0177          AK12=AK+.010
ISN 0178          SUM2=O.
ISN 0179          DO 312 I=1,N1
ISN 0180          SUM2=SUM2+ANCF(I)/(1.+AK12)**(I-1)
ISN 0181    312   CONTINUE
ISN 0182          ZNPV1=SUM2-AICPV
ISN 0183          AK11=AK+.010*ZNPV/(ZNPV-ZNPV1)
ISN 0184          AK11=AK11*100.
ISN 0185          GO TO 316
ISN 0186    306   AK11=AK*100.
ISN 0187    316   WRITE(6,302) AK11
ISN 0188    302   FORMAT(5X,'DISCNT. CASH FLOW RATE OF RET.(%):',T55,F8.2)
ISN 0189           SUM3=O
ISN 0190          DO 307 I=1,N1
ISN 0191          SUM3=SUM3+ANCF(I)/(1.+AK)**(I-1)
ISN 0192          IF(SUM3.GE.AICPV1)GO TO 308
ISN 0194    307   CONTINUE
ISN 0195    308   WRITE(6,309) I
ISN 0196    309   FORMAT(5X,'DISCNT. PAYBACK PERIOD (YEARS):',T55,I4)
ISN 0197    500   CONTINUE
ISN 0198    999   RETURN
ISN 0199          END
```

NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.
G	SF	R*4	0007C0	I	SF	I*4	0007C4	J	SF	I*4	0007C8	AD	SF	R*4	0007CC
AK	SF	R*4	0007D0	A1	SF	R*4	0007D4	BT	SF	R*4	000900	B1	SF	R*4	0007D8
B2	SF	R*4	0007DC	B3	SF	R*4	0007E0	EC	SF	R*4	0007E4	EP	SF	R*4	0007E8
FC	F	R*4	0007EC	GC	SF	R*4	0007F0	GF	SF	R*4	0007F4	GG	S	R*4	0007F8
GY	SF	R*4	000978	IB	SF	I*4	0007FC	IJ	SF	I*4	000800	IS	SF	I*4	000804
IV	SF	I*4	000808	JJ	SF	I*4	00080C	JM	SF	I*4	000810	LM	SF	I*4	000814
N1	SF	I*4	000818	N2	SF	I*4	00081C	TA	SF	R*4	0009F0	TF	SF	R*4	000820
TR	SF	R*4	000824	TS	SF	R*4	000828	X1	SF	R*4	00082C	X2	SF	R*4	000830
X3	SF	R*4	000834	Z4	SF	R*4	000838	Z5	SF	R*4	00083C	Z6	SF	R*4	000840
Z7	SF	R*4	000844	Z8	SF	R*4	000848	Z9	SF	R*4	00084C	ACC	SF	R*4	000850
AFC	SF	R*4	000854	AFF	SF	R*4	000858	AKC	SF	R*4	00085C	AKD	SF	R*4	000860
AKP	SF	R*4	000864	A11	SF	R*4	000868	DEP	SF	R*4	0009F8	ECE	SF	R*4	000A70
ERA	SF	R*4	00086C	FCR	SF	R*4	000870	FCT	SF	R*4	000AE8	GOM	SF	R*4	000874
ICT	SF	I*4	000B60	JJJ	SF	I*4	000878	OMT	SF	R*4	000BD8	ROE	SF	R*4	000C50
SCF		R*4	N.R.	SUM	SF	R*4	00087C	TYT	SF	R*4	000CC8	WCI	F	R*4	000880
WCP	F	R*4	000884	YBT		R*4	N.R.	ACSF		R*4	N.R.	AFOM	SF	R*4	000888
AK11	SF	R*4	00088C	AK12	SF	R*4	000890	ALCE	SF	R*4	000894	ANCF	SF	R*4	000D40
ANPT	SF	R*4	000DB8	ADMC	SF	R*4	000898	CCSF		R*4	N.R.	FINA		R*4	00089C
ISSC	F	I*4	0008A0	PHIX	F	R*4	0008A4	RODT	SF	R*4	000E30	ROPC	SF	R*4	0008A8
SUM2	SF	R*4	0008AC	SUM3	SF	R*4	0008B0	TACE	SF	R*4	0008B4	WCKD		R*4	N.R.
ZNPV	SF	R*4	0008B8	AICPV	SF	R*4	0008BC	AITCY	SF	R*4	000EA8	ANYBD	SF	R*4	000F20
ANYBT	SF	R*4	000F98	DESCF	SF	R*4	0008C0	DISSC	F	R*4	0008C4	DPFSD	SF	R*4	0008C8
DPLTT	SF	R*4	0008CC	FCRN1	SF	R*4	0008D0	FCRN2	SF	R*4	0008D4	IEXPC	F	I*4	0008D8
INEXC	C	I*4	000000	IPKRE	F C	I*4	000004	ITEMP	SF	I*4	0008DC	TACE1	SF	R*4	0008E0
UFSUP	F C	R*4	00000C	ZNPV1	SF	R*4	0008E4	FRXPI#	XF	R*4	000000	AICPV1	SF	R*4	0008E8
AICPV2	SF	R*4	0008EC	CRFKN1	SF	R*4	0008F0	CRFKN2	SF	R*4	0008F4	DESCOM	SF	R*4	0008F8
FCRRN1	SF	R*4	0008FC	IBCOM#	F XF	I*4	000000	IPKRE2	F C	I*4	000008	SUPCST	SF C	R*4	000014
TYADPL		R*4	N.R.	TYBDPL	SF	R*4	001010	UFSUP2	F C	R*4	000010				

***** COMMON INFORMATION *****

NAME OF COMMON BLOCK * MAH* SIZE OF BLOCK 000018 HEXADECIMAL BYTES

VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.	VAR. NAME	TYPE	REL. ADDR.
INEXC	I*4	000000	IPKRE	I*4	000004	IPKRE2	I*4	000008	UFSUP	R*4	00000C
UFSUP2	R*4	000010	SUPCST	R*4	000014						

LABEL	ADDR	LABEL	ADDR	LABEL	ADDR	LABEL	ADDR
110	0014C6	111	001644	211	0016FA	919	0017A2
920	0017F0	921	001872	922	0018C0	450	001B74
941	001BAC	741	001BDA	171	001BF6	128	001D10
126	001E42	150	001E5A	165	001EDC	300	001F36
312	001FC2	306	001FF4	316	001FFC	307	002074
308	00207E	500	00209C	999	0020BC		

```
*OPTIONS IN EFFECT*      NAME=  MAIN,OPT=02,LINECNT=58,SIZE=1024K,

*OPTIONS IN EFFECT*      SOURCE,EBCDIC,NOLIST,NODECK,LOAD,MAP,NOEDIT,ID,NOXREF

*STATISTICS*     SOURCE STATEMENTS =     198 ,PROGRAM SIZE =     8484

*STATISTICS*  NO  DIAGNOSTICS GENERATED

****** END OF COMPILATION ******                                964K BYTES OF CORE NOT USED

*STATISTICS*  NO  DIAGNOSTICS THIS STEP
```

APPENDIX D

D.0 GLOSSARY OF TERMS USED IN THE GEEF METHODOLOGY

Alternative or Conventional Energy System (CES) is any energy system that is used to provide the energy necessary to meet the requirements of the intended end-use application, other than the proposed.

Amortization Capital Recovery Factor (CRFKN1) refers to the fraction of original capital that is paid in uniform annual payments so as to fully amortize the loan over a specified period of time.

Annual Capital Surplus Funds (ACSF) is the money that is available to pay out the initial equity capital after paying the investor a guaranteed minimum return on investment and retiring the debt capital. ACSF is used to compute the discounted cash flow rate of return (DCFROR).

Annualized Fixed Charge Rate (FCR) is a factor by which the present value of capital (AICPV) must be multiplied to obtain the contribution of capital investment to the annualized cost. FCR interacts with the rest of the model in determining the levelized cost of energy (ALCE).

Capacity is the maximum level of production or output.

Capital Expenditure is an expenditure on an asset, such as property, which benefits the operation beyond the current period. It is recovered through depreciation and depletion over a period of time.

Constant Dollar is a unit of measure of the value or purchasing power of money that is invariant with time.

Cumulative Capital Surplus Fund (CCSF) is the sum of annual capital surplus fund (ACSF) which earns an annual rate of return equal to the weighted average after-tax capital cost of equity capital. CCSF is used in deterining the net present value (NPV) and discounted payback period (DPP).

Current Dollars grow with time at the rate of inflation, given a fixed real value of money.

Depletion refers to the recovery of an owner's economic interest in mineral reserves through federal tax deductions related to the removal of the mineral over the economic life of the property.

Depletion Allowance (B3) refers to a fraction of each year's geothermal energy project gross revenue that can be used for tax deduction purposes; depletion allowance in any given year cannot exceed the limit of 50% of taxable income.

Depreciation is the allocation of costs of a replaceable tangible capital asset, such as building or equipment, less salvage value, over the expected useful life of the asset.

Depreciation Capital Recovery Factor (CRFKN2) is used in calculating the present value of depreciation. An average depreciation life of 10 years is assumed for both initial capital and replacement capital.

Depreciation Life (N2) is the asset lifetime used for the purpose of computing depreciation charges. It can be less than or equal to the system or project lifetime (N1).

Discount Rate (A_k) is a percentage rate which accounts for the time value of money in a given investment; the weighted average after-tax capital cost is used as the discount rate in computing present values.

Discounted Cash Flow Rate of Return (DCFROR) is the rate of return that makes the net present value (NPV) of a project equal to zero. DCFROR is an overall measure of project profitability where year-by-year capital surplus funds (ACSF) are weighted differently.

Discounted Payback Period (DPP) is the number of years required for cumulative capital surplus funds (CCSF) to recover initial equity capital at the discount rate, A_k.

Drawdown is the rate of depletion of a hydrothermal resource.

Drilling and Completion Costs are those costs which are incurred in the drilling of a well. These costs consist of capitalized drilling costs and intangible drilling costs.

End Use Application is the purpose for which the energy from the proposed system is being used. Examples of end use applications are industrial processes or space heating.

Energy Investment Tax Credit is equal to a 15% reduction in income tax liability for expenditures on energy saving or energy producing property.

Equity is the portion of the investment capital structure of a firm or property in which there is a risk interest or ownership right. The equity portion of the investment capital structure is equal to the combined value of preferred (E_p) and common stock (E_c).

Escalation refers to the percentage change in the real cost of a commodity or service; it is an increase over and above the general rate of inflation, g.

Expensed Costs are investment expenditures that can be recovered by "write-off" for tax purposes in the year they are incurred or during the years of operation. They include various preproduction costs.

Exploration refers to all activities involved in the determination of a resource's location and characteristics, prior to the drilling of a production well.

Fuel Cost (FC) is the recurred cost of fuel required to operate the (supplementary) system.

Fluid Chemistry is the parts per million of total suspended and dissolved solids in the hydrothermal brine.

Fluid Transportation System is that portion of the system which is used as a conduit for the fluids between components of the hydrothermal system. This system is comprised of a primary distribution transmission pipeline, the tunnel, and the secondary distribution pipeline.

Geothermal Energy System (GES) is the hydrothermal energy system plus any supplemental energy system.

Gross Revenues (GY) are equal to the product of the price of a unit of the plant's output and the quantity of production units sold.

Heat Exchanger is the component of the energy system which allows for the transfer of heat from the inlet brine to a form which is suitable for use in the end-use application.

Heat Transfer Surface Area (IAREA) is the size, in square feet, of the heat exchanger.

Heat Transfer Coefficient (HTCOEF) is the amount of heat loss which occurs due to phase change in the brine, as it is converted to boiling fluid at the exchanger inlet and outlet.

Inflation (g) is the percentage change in prices of goods and services over a given timeframe; it is a change in the general purchasing power of money.

Initial Investment is the base capital cost of an investment proposal.

Injection Well is used as a means of disposal of the waste hydrothermal fluids, by returning the fluid back into the reservoir via pumps on gravity.

Investment Tax Credit is a 10% reduction in income tax liability for expenditures for depreciable, tangible property, with an expected life of at least three years, that is used for manufacturing, production, or extraction, excluding buildings and structural components.

Labor, Operating, and Maintenance Costs are those expenses which are incurred in order to keep a system in good working order.

Levelized Cost of Energy (ALCE) is an annualized cost (TACE) divided by the expected annual energy output (ERA), resulting in a cost per unit of energy.

Life Cycle Cost is the present value, as of the year of start-up year or the year of commercial operation, Iv, of the sum of all system-resultant costs that are incurred over the lifetime of a project.

Marginal Tax Rate is the additional or incremented tax rate expressed in percent; it is a tax on each additional dollar of taxable income received.

Net Present Value Analysis (NPV) is a method for ranking investment proposals. The difference between the yearly cash inflows and outflows is discounted to its present value using the weighted average cost of capital as the discount rate. In the GEEF model, the after-tax cumulative capital surplus fund (CCSF) is discounted back to the base year to determine the NPV.

Peak Energy Requirement (IPKRE) is the maximum amount of energy that must be provided at a given time point in time to satisfy the energy demand of an end use application.

Percentage Depletion Allowance is a method of depleting a wasting asset in which the percentage difference of revenues from the sale of a mineral less royalties is less than 50% of after-tax income.

Present Value of Capital Investment (AICPV) refers to the capital investment for the energy system brought to the beginning of the start-up year expressed in base year dollars. Interest during construction years, replacement costs and supplementation costs are included in AICPV.

Production Wells are utilized to extract the hydrothermal fluid which can be used to provide energy to power end use applications.

Replacement Capital Cost (ECE) is the cost of replacing a capital asset which has worn out due to the fact that the useful life of that asset is less than the useful life of the total system.

Resource Characteristics are those features of a hydrothermal resource, such as temperature, fluid chemistry, well flow rate, and drawdown rate which define the ability of the resource to provide the level of energy necessary to meet the requirement of the intended end-use application.

Royalty Payment (B2) is a percentage payment to the owner of a mineral lease by the producers based on the annual sales from the plant.

Sum of Years Digits Depreciation (DPFSD) is an accelerated method of depreciation in which decreasing charges are made; these are determined by applying a series of fractions, each of a smaller value, to the depreciable value of an asset. These fractions are defined in terms of the sum of the asset life periods.

Supplemental Energy System (ITSUP) is the system which is used to augment, fracture and/or supplement a hydrothermal energy system in order to provide the additional energy necessary to meet the requirements of the intended end-use application which cannot be provided by the hydrothermal energy system.

Time Value of Money is the value of money held for future consumption, which is foregone if the money is used today.

Transmission Distance (LEN) refers to how far the brine must be transported through the fluid transportation system, from the production well to the plant where the end-use application occurs.

Utilization Factor (UFSUP) is the percentage of system capacity which is actually put into use.

Weighted Average Cost of Capital is the average of the after-tax rates-of return on each of the components of the investment capital structure, based on the relative proportion of these components to the total amount of capitalization. It is treated as the discount rate for the determination of economic feasibility or evaluation of projects.

Well Buildings are the facilities which house the circulation pumps and wellhead equipment.

Wellhead Equipment consists of all the components, such as electric motors, etc., that are necessary for the successful operation of the well.