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INTEGRATION OF HYDROTHERMAL ENERGY
ECONOMICS RELATED QUANTITATIVE STUDIES

ENGINEERING & ECONOMICS RESEARCH, INC.

MASTER

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OCTOBER, 1982

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1.0 INTRODUCTION

1.1 Purpose

Several Federally-sponsored studies in recent years have sought to examine the economic feasibility of hydrothermal energy for electric and direct heat applications. These studies, which focus primarily on the estimation of cost of energy, have employed methodologies and assumptions which differ significantly, and consequently there is considerable divergence in their estimates of the economic viability of hydrothermal energy projects. Even though regular revisions of the major studies, such as those of the Jet Propulsion Laboratories, Pacific Northwest Laboratory, Brookhaven National Laboratory and the MITRE Corporation and new studies are underway, the economic feasibility and energy price projections continue to vary widely.

The development of a procedure or methodology for projecting the cost of energy from hydrothermal resources is a common element among the studies reviewed in this paper. The approach to the estimation of cost of energy ranges from simple financial cash flow models to more complicated engineering models that attempt to develop optimization procedures to achieve the minimum cost (production) for a given set of resource and economic conditions. Some of these models estimate the cost of energy and cash flows from a detailed set of financial data (e.g., capital and annual O&M costs), while others estimate project costs (total as well as component capital costs) and cash flows from a limited set of resource and financial data.

Much of the work to date has been at the theoretical level. The estimates presented in the various studies cannot be compared directly due to variations in the data used for specific resource charac-

teristics and economic variables. In order to clearly understand the differences in findings, often conflicting and contradictory, there is a need to examine the focus of the study methods and assumptions involved in the energy costing models. As more empirical data become available and the understanding of the technology improves, it will become feasible to develop a standard set of assumptions and there is reason to believe that the energy price estimates will become reliable and the differences among studies will be narrowed.

The major purpose of this paper is to provide an evaluation of the existing hydrothermal energy economics related quantitative studies. The objective is to present the similarities and differences in methodology and assumptions, and explain the impact of these differences on the energy price estimates. The approach to this effort consists of a comparison of general methodology, and technical/economic assumptions, and an analysis of the effects of the major assumptions on cost estimates.

In order to determine the impacts of the technical and economic assumptions on cost estimates, this analysis develops a measure of relative sensitivity or elasticity of prices to uncertain resource and economic variables. This measure is used to indicate the relative importance of the several parameters in price determination, and to explain the differences or uncertainties in the estimates provided by various studies. Further, they can be used as a guide to establish an integrated set of major technical and economic assumptions that are essential for a study to yield credible estimates of the cost of hydrothermal energy.

For the purpose of this paper, Engineering and Economics Research, Inc. selected for evaluation the following ten major

studies performed for the Department of Energy by various organizations: APL/JHU, GRITS¹; PNL, GEOCOST²; PNL, GEOCITY³; MITRE, GELCOM⁴; MITRE, CGFM⁵; DuPont, VENVAL⁶; JPL, GPCM⁷; PSL/NMEI, BTHERM⁸; TECHNECON, GIPA⁹; and BNL, GMDH¹⁰.

In Section 2.0, a brief summary of the study categories, economic evaluation methodology, technical and economic assumptions and major outputs of the studies is presented. Section 3.0 discusses the relative importance and the likely effects of the most important technical and economic factors on the cost of energy. The sensitivity analysis results provided in Section 3.0 are useful in judging the credibility as well as the relative weaknesses and strengths of the various cost of energy estimation studies. The major conclusions of the evaluation and the recommendations for future research are presented in Section 4.0.

2.0 OVERVIEW AND COMPARISON OF STUDIES

A preliminary review of the relevant literature on the cost of energy studies and the follow-up of lengthy discussions with the DGE/DOE project officer resulted in the decision to analyze and compare ten studies in greater detail as to their focus, methodologies, assumptions, outputs and general usefulness in developing energy price forecasts. These studies are:

- o Barrow, W. and Knoll, P., "GRITS: A Computer Program for the Economic Evaluation of Direct-Use Applications of Geothermal Energy, GEMS-008, Applied Physics Laboratory, Johns Hopkins University, June 1980.
- o Bloomster, C.H., GEOCOST: A Computer Program for Geothermal Cost Analysis, Battelle, Pacific Northwest Laboratories, Feb 1975.
- o Huber, H.D., et.al., User Manual for GEOCITY: A Computer Model for Geothermal District Heating Cost Analysis, Battelle, Pacific Northwest Laboratories, Oct 1978.
- o Gupta, J.N. and Leigh, J.G., GELCOM: A Geothermal Levelized Busbar Cost Model: Description and User's Guide, MITRE Corporation, Jan 1978.
- o Keimig, M.A., Rosenberg, J.I. and Entingh, D.J., Geothermal Loan Guaranty Cash Flow Model: Description and User's Guide, MITRE Corporation, Nov 1980.
- o Synfuel Program Analysis, Volume II: VENVAL Users Manual, Dupont, Inc., (JPL), Feb 1981.
- o Orren, L.H., et.al., Geothermal Probabilistic Cost Model, Jet Propulsion Laboratory, Feb 1981.
- o Cunniff, R.A., Glazner, G. and Houldsworth, M., Geothermal Energy for Residential, Commercial, and Industrial Users: A Computer Simulation Model, B THERM; and Geothermal Potential Direct Use, Rocky Mountain Basin and Range, Physical Science Laboratory, New Mexico Energy Institute, April 1980.
- o Cassel, T.A.V., et.al., Geothermal Investment and Policy Analysis with Evaluation of California and Utah Resource Areas, Technicon Analytic Research, Inc., Oct 1979.
- o Reisman, A., A Generic Model for District Heating: A Geothermal Application, Brookhaven National Laboratory, Nov 1980.

A brief description of each of these studies is presented in Appendix A. In order to understand the main features of the ten studies and to facilitate comparison among them, five matrices of information - general information, technical parameters, economic parameters, methodology, and major outputs - are provided in Tables 2 through 6 of this section. The matrices have been carefully developed after a detailed review of the studies. Since there is no ideal or comprehensive model to suit the particular needs of a variety of decision makers, applications and the site specific nature of the hydrothermal energy utilization, the matrices for technical and economic assumptions contain only those significant parameters or factors which are relevant and important for estimating the cost of energy. Table 1 presents the important parameters that were selected for comparison purposes.

An overview of the ten studies in terms of study categories as well as economic evaluation methodologies is presented below.

2.1 Study Categories

A review of the purposes and methodologies of the cost of energy projection studies indicates that these studies fit into two general categories: (1) financial (or economic) feasibility models, and (2) engineering (or optimization) feasibility models.

(1) Financial Feasibility Models are accounting models which primarily examine the impacts of changes in specific geothermal resource and economic parameter values on economic accounting (e.g., GRITS¹, GCFM⁵, GELCOM⁴, VENVAL⁶, GPCM⁷, BTHERM⁸, and GIPA⁹). While some of these financial feasibility models may contain important engineering relationships to determine the size and operational characteristics for major capital components, the results provided by such models are influenced by simplifying assumptions, (e.g., GRITS¹, GCFM⁵, GELCOM⁴, BTHERM⁸, and GIPA⁹); others (e.g., VENVAL⁶ and GPCM⁷

TABLE 1

TECHNICAL AND ECONOMIC PARAMETERS
FOR COMPARISON OF STUDIES

TECHNICAL PARAMETERS	ECONOMIC PARAMETERS
<p>Wellhead temperature ($^{\circ}\text{F}$)</p> <p>Well flow rate (lbs/hr)</p> <p>Well depth (ft)</p> <p>Rock type (soft, hard)</p> <p>Salinity (PPM)</p> <p>Producing capacity (MW)</p> <p>Capacity factor</p> <p>Well life (yrs)</p> <p>Project life (yrs)</p> <p>Peak energy demand (MMBTU/hr)</p> <p>Plant type (binary, flash, hybrid)</p> <p>Length of distribution system (ft)</p> <p>Well spacing (acres)</p>	<p>Debt fraction</p> <p>Equity fraction</p> <p>Bond rate</p> <p>Return on equity</p> <p>Discount rate</p> <p>Federal income tax</p> <p>State income tax</p> <p>State gross revenue tax</p> <p>Property tax</p> <p>Insurance fee</p> <p>Depletion allowance</p> <p>Royalty</p> <p>Depreciation</p> <p>ITC</p> <p> - capital cost - O&M cost - energy prices </p> <p>Escalation Rate</p> <p>O&M costs</p> <p>Energy prices</p> <p>Inflation</p> <p>Salvage value</p> <p>Plant operating life</p> <p>Intangible drilling cost</p>

TABLE 2

GENERAL INFORMATION MATRIX

STUDIES TOPICS	GRITS (APL)	GEOCOST (PNL)	GEOCITY (PNL)	GCFH (MITRE)	GELCON (MITRE)	VENVAL (JPL)	GPCM (JPL)	BTHRM (NMEI)	GIPA (TECH)	GMDH (DNL)
Focus of Study	<ul style="list-style-type: none"> Estimate cost of energy Determine economic feasibility Policy impact analysis 	<ul style="list-style-type: none"> Estimate cost of energy Optimization of plant design Cash flow analysis 	<ul style="list-style-type: none"> Estimate cost of district heating Optimization Cash flow analysis 	<ul style="list-style-type: none"> Estimate cost of energy Estimate field and electric plant costs Optimization 	<ul style="list-style-type: none"> Estimate cost of energy Estimate field and electric plant costs Estimate Impacts of R&D 	<ul style="list-style-type: none"> Estimate cost of energy 	<ul style="list-style-type: none"> Estimate cost of energy Provide probability distribution of NPV 	<ul style="list-style-type: none"> Estimate cost of energy Determine economic feasibility and market potential 	<ul style="list-style-type: none"> Estimate marginal competitive resource price Determine commercialization potential 	<ul style="list-style-type: none"> Optimization of design Market potential for district heating
Applications	Direct Uses	Electric	Direct Uses	Electric	Electric	Electric & direct uses	Electric	Direct Uses	Electric	Direct uses
Market Sectors	<ul style="list-style-type: none"> IPH Community heating for R/C 	<ul style="list-style-type: none"> Utility Developer 	<ul style="list-style-type: none"> District heating 	<ul style="list-style-type: none"> Utility Developer 	<ul style="list-style-type: none"> Utility Developer 	<ul style="list-style-type: none"> Utility Developer District heating Process heating 	<ul style="list-style-type: none"> Developer 	<ul style="list-style-type: none"> District heating IPH R/C water heating 	<ul style="list-style-type: none"> Developer 	<ul style="list-style-type: none"> District heating

TABLE 3

TECHNICAL PARAMETERS FOR COMPARISON OF STUDIES

TECHNICAL PARAMETERS	GRITS (APL)	GEOCOST (PML)	GEOCITY (PML)	GELCON (NITRE)	GCFH (NITRE)	VENVAL (JPL)	GPCM (JPL)	OTHERM (MITI)	GIPA (TECH)	CHMI (PML)
Wellhead temperature ($^{\circ}$ F)	X	X	X	X	X	X	X	X	X	X
Well flow rate (lbs/hr)	X	X	X	X	X	X	X	X	X	X
Well depth (ft)	X	X	X	X	X	X	X	X	X	X
Rock type (S,N)		X	X	X	X	X	X		X	X
Salinity (PPM)		X	X	X	X					X
Producing capacity (MM)		X		X	X	X	X		X	X
Capacity factor		X	X	X	X	X	X			X
Well life (yrs)	X	X	X	X	X	X	X			X
Project life (yrs)	X	X	X	X	X	X	X	X	X	X
Peak energy demand (MMBTU/hr)	X	X	X		X	X		X		X
Plant type (b,f,h)		X		X	X				X	
Length of distribution system (ft)	X		X	NA	NA	X	NA	X	NA	X
Well spacing (acres)		X	X							
APPLICATIONS	D	E	D	E	E	D,E	E	D	E	D

NA - Not Applicable

D - Direct Heat

E - Electric

TABLE 4

ECONOMIC PARAMETERS FOR COMPARISON OF STUDIES

ECONOMIC PARAMETERS	GRITS (APL)	GEOCOST (PNL)		GEOCITY (PNL)		GCFH (MITRE)		GELCON (MITRE)		VENVAL (JPL)	GPCM (JPL)	BTHERM (MWET)	GIPA (TECN)	GIMM (BNI:)
		R	U	R	P	R	R	PR	U		R	RU	R	
Debt fraction	X	X	X	X	X	X	X	X	X	X	X	X	X	
Equity fraction		X	X	X	X	X	X	X	X	X	X	X	X	
Bond rate	X	X	X	X	X	X	X	X	X	X	X	X	X	
Return on equity		X	X	X	X	X	X	X	X	X	X	X	X	
Discount rate	X	X	X	X	X	X	X	X	X	X	X	X	X	
Federal income tax	NA	X	X	X	X	X	X	X	X	X	X	X	X	
State income tax	NA	X	X	X	X	X	X	X	X	X	X	X	X	
State gross revenue tax	NA	X	X	X	X	X	X					X	X	
Property tax	NA	X	X	X	X	X	X	X	X	X	X	X	X	
Insurance fee	NA	X	X	X	X	X	X						X	
Depletion allowance		X	NA	X	X	X	X	X		X	X	X	X	
Royalty		X	NA	X	NA	X	NA	X	NA	X	X	X	X	
Depreciation		X	X	X	X	X	X	X	X	X	X	X	X	
ITC		X	X	X	X	X	X	X	X	X	X	X	X	
- capital cost - O&M cost - energy prices	X					X	X	X	X	X	X		X	
						X	X	X	X	X	X		X	
						X	X	X	X	X	X	X	X	
O&M costs	X	X	X			X	X	X	X	X	X	X	X	
Energy prices	X					X	X	X	X	X	X	X	X	
Inflation	X					X	X	X	X	X	X		X	
Salvage value	X	X	X	X	X	X		X	X		X			
Plant operating life	X	X		X	X	X	X	X	X	X	X		X	
Intangible drilling cost		X	NA	X	NA	X	NA	X	NA	X	X	X	X	
APPLICATIONS	D	D,E		D		E		E		D,E	E	D	E	D

NA - Not Applicable

D - Direct Heat Applications

E - Electric Uses

U - Utility

R - Resource Developer

P - Utilization Plant

TABLE 5
STUDY METHODOLOGY MATRIX

STUDIES TOPICS	GRITS (APL)	GEOCOST (PNL)	GEOCITY (PNL)	GCFM (MITRE)	GELCON (MITRE)	VENVAL (JPL)	GPCM (JPL)	BTHERM (NREL)	GIPA (TECN)	CHNH (BNL)
Methodology	<ul style="list-style-type: none"> • Economic cost model • User provides resource and financial parametric values • Uses user's discount rate • Uses DCF technique • Includes engineering simulation to analyze resource characteristics on cash flows • calculates nominal/real price 	<ul style="list-style-type: none"> • Engineering design/cost model • Optimizes plant design • Estimates costs for reservoir and power plant • Uses DCF analysis • Simulation financial and tax structures • "Revenue to reservoir" is "energy cost" to power plant • Combined reservoir and power plant models form total system 	<ul style="list-style-type: none"> • Engineering design/cost model • Optimizes system design • Estimates costs of reservoir and distribution • Uses DCF analysis • Revenue to reservoir" is cost to distribution system 	<ul style="list-style-type: none"> • Economic cost model • Estimates costs of field, plant and components • Performs year-by-year calculations • Calculate levelized busbar cost • Uses GEOCOST estimating equations for plant costing • Uses GELCON for field costs and life cycle costing 	<ul style="list-style-type: none"> • Economic cost model • Estimates capital and operating for production field and plant • Uses RR approach • Computes RR for field and plant • Computes levelized busbar electricity cost • Estimates impact of R&D 	<ul style="list-style-type: none"> • Economic cost model • Requires a complete set of cost data and probability density functions for physical and time variables • Uses year-by-year cash flow method • Uses monte carlo techniques to generate probability statistics 	<ul style="list-style-type: none"> • Economic cost model • Requires a complete set of cost data and probability density functions for physical and time variables • Uses RR approach 	<ul style="list-style-type: none"> • Economic cost model • Uses DCF technique • Incentive analysis • Includes engineering design and cost equations 	<ul style="list-style-type: none"> • Economic cost model • Estimates probabilistic cash flows • Restricted to resource producer 	<ul style="list-style-type: none"> • Engineering design/cost model • Optimizes system design • Estimates heat load • Calculates levelized cost of heat

TABLE 6
MAJOR OUTPUTS MATRIX

<div style="text-align: center;">STUDIES</div> <div style="text-align: center;">TOPICS</div>	GRITS (APL)	GEOCOST (PNL)	GEOCITY (PNL)	GCFH (MITRE)	GELCOM (MITRE)	VENVAL (JPL)	GFCM (JPL)	BTHERM (NMEI)	GIPA (TECH)	GHHI (BNL)
Major Outputs	<ul style="list-style-type: none"> • Discounted average cost • NPV • Annual cash flows • Breakeven year • Initial capital cost 	<ul style="list-style-type: none"> • Levelized cost of power • Annual RR cash flow for field and plant • Electric plant design 	<ul style="list-style-type: none"> • Levelized cost of heat • Annual cash flows • Detailed system design 	<ul style="list-style-type: none"> • Levelized breakeven price of fluid and electricity to meet RR • Internal rate of return • year-by-year cash flow for field and plant • generates requisite cost accounts 	<ul style="list-style-type: none"> • Levelized breakeven price for fluid and electricity to meet RR • sensitivity analysis results • capital and operating cost estimates for field and plant • Impacts of R&D on busbar cost of electricity 	<ul style="list-style-type: none"> • Levelized energy cost • Probability distribution of NPV of expected profit and standard deviations • Internal rate of return • Annual cash flows 	<ul style="list-style-type: none"> • Levelized energy cost for different scenarios to meet RR • Net present value of profit • Probability distribution of NPV of profit 	<ul style="list-style-type: none"> • Levelized price • Discounted payback • NPV • Potential geothermal energy on-line, 1981-90 • Required Federal outlays for development 	<ul style="list-style-type: none"> • Marginal competitive price for geothermal resource • Payback • Probabilistic estimates of NPV of profits • Capital exposed to risk 	

require a complete set of cost accounts together with a schedule for their occurrence and a complete set of financial parameters applicable to a particular venture. Some of these programs include enough engineering simulation to provide preliminary economic assessment, so as to allow the user to analyze the impact of changes in technical and economic parameters on cost of energy, moreover they can be run at a minimum cost. The major differences among the financial feasibility studies are to be found in their treatment of conventional energy prices and their escalation rates, inflation, discount rate, investment tax credit, and debt payment and depreciation procedure in constant and current dollar analysis.

(2) Engineering Feasibility Models. The primary purpose of these models is to determine the minimum engineering cost for a particular application. These models include elaborate internal thermodynamic cycle optimization routines for designing subsections of the utilization system (e.g., GEOCOST2, GEOCITY3, and GMDH10). They estimate capital and operating costs of energy production based on a systematic relationship between the plant design and geothermal resource characteristics. These internally derived estimates are used in the economic analysis model to calculate the unit cost of energy and the associated cash flows.

Engineering feasibility models also determine the number of production and injection wells, heat exchanger design, supplementary system requirement, fluid flow rates, costs of wells, fluid distribution system heat exchanger and supplementary system.

Three types of input data are needed for engineering feasibility models: a) energy demand data - peak energy demand, utilization factor, process temperature and allowable working fluid temperature drop in the process, fuel cost and energy plant cost for supplementary system, and specific heat of the working fluid; b) resource characteristics data - wellhead temperature, well depth for production and injection wells, type of rock, well flow rate and salinity index; and c) energy utilization plant data - energy utilization in the brine (direct or indirect), restrictions on injection temperature of brine and length of distribution system.

Since the engineering feasibility models operate on a limited set of physical, resource, climatic, engineering and financial data,

they are useful for estimating the economic characteristics of a proposed geothermal energy system even before the field is explored. However, in the absence of a standard or empirically acceptable methodology for estimating the capital and operating costs of geothermal energy development, the cost estimates generated by these models could vary significantly. These variations are influenced by the particular conceptual design of a plant adopted in thermodynamic optimization procedures as well as the differences in the treatment of individual technical parameters or input data identified above. A discussion of the impact of the important technical variables on cost estimates is presented in Section 3.0.

2.2 Economic Evaluation Methodology

The studies reviewed in this paper have employed one of the two following economic evaluation methodologies: discounted cash flow rate of return (DCFROR) or revenue requirements (RR). The salient features of these two techniques are that they account for the timing of costs and revenues, system life and the time value of money. Further, both of them equate the present value of receipts to the present value of costs of the project. DCFROR method determines the internal rate of return (IRR) or the opportunity cost of money invested in the project. To calculate IRR, cash flows for each year of the life of the project are computed or known beforehand. The revenue requirement (RR) method determines the minimum revenue or price required to earn a prespecified rate of return on investment after covering all expenses - capital costs, annual operating costs, taxes and depreciation.

The cost per unit of energy (mills/kwh or \$/106 Btu) estimated in these studies is a levelized energy cost (LEC), which is computed as the quotient of total annualized system cost divided by expected annual energy output, and can be expressed in either constant (real) or current (nominal) dollars. Constant dollar levelized costs are easier to compare with current operating costs of a given expenditure, and are also more representative of the actual costs because they are more likely to remain constant in constant year dollars than in current year dollars. However, for some financial analyses, current dollar calculations may be more meaningful; for example, current regulations do not allow for adjustment of depreciation charges for inflation, and similarly, annual debt payments are contracted in current dollars. In such cases, constant dollar analysis results in underestimation of the energy price and the revenue stream.

2.3 Comparison Matrices

The comparison of ten studies revealed that the methodology, applications and assumptions considered by these studies varied considerably. Even where the economic evaluation methodologies were similar, there were significant differences in the treatment of economic parameters and the data used to reflect the economic conditions. Also, the studies were not all performed under the same economic climate. Since the economic conditions have changed considerably during the last ten years, the range of values assumed for important economic parameters (e.g., inflation, discount rate, competitive energy price levels and their escalation rates, etc.) to reflect the current economic conditions exhibits wide differences.

For example, studies which were performed during 1975-77 period used energy prices, escalation rates, inflation and discount rates which appear unrealistically low compared with the studies that were performed more recently. Therefore, the data as well as the estimates of cost of energy generated thereof cannot be compared meaningfully.

Moreover, the geothermal resource characteristics data employed in these studies are either hypothetical or site-specific, and in some cases their results cannot be directly compared and generalized. For example, the cost estimates for well development exhibit differences by as much as a factor of two, the equations not only differ from one another, but also lack empirical basis. A further discussion of the relationship between well cost and energy prices is presented in Section 3.0 and Appendix B.

However, an examination of these studies is both instructive and useful with regard to the methodologies and assumptions. This is so because the formulation of technical relationships and assumptions clearly indicates the views of the analyst or study about the future. It becomes abundantly clear from the evaluation of the studies and sensitivity analysis (Section 3.0) that the differences in assumptions about economic and technical parameters lead to differences in cost of energy estimates. For instance, higher temperature, softer rock and shallower wells result in lower unit cost. Likewise, lower capital cost, higher capacity factor and longer plant lives tend to reduce costs.

The sensitivity analysis and the relative importance of individual technical and economic factors in the cost of energy are examined briefly in Section 3.0. In view of the uncertainty surrounding geo-

thermal resource characteristics, such an examination is useful because it will enable the user of a particular model to judge the credibility of the output, as well as its strengths and weaknesses in terms of the important parameters.

3.0 SENSITIVITY ANALYSIS OF HYDROTHERMAL ENERGY COST DETERMINANTS

3.1 Uncertainty and Relative Importance of Energy Cost Determinants

A review of the literature on hydrothermal energy cost determination reveals that besides a host of technical and economic factors that influence the level of unit cost of energy, there is also a considerable degree of uncertainty as to the range of values attributable to the various factors. As such, the cost of energy estimates are not only influenced by the number of important factors considered in the analysis but also the specific values used for them. It will become clear from the following sensitivity analysis that the energy price behavior varies considerably over the range of values assigned to a particular technical or economic parameter of importance. Perhaps some of the important sources of differences in various cost estimates may be traced to the treatment of individual technical and economic factors.

3.2 Elasticity: A Measure of Relative Sensitivity

In order to develop credible estimates of energy prices from hydrothermal resources, it is necessary to understand the relative importance of the most significant factors that determine the cost of energy. The relative importance of various factors can be analyzed by measuring the sensitivity of energy prices to changes in factor values over the ranges for parameters in question. The sensitivity measure utilized in this paper is the average elasticity of the price of energy (E) which describes the relative impact of a determinant on the energy price. The average elasticity of price of energy is defined as the ratio of percentage change in the price of energy for a given percentage change in the value of a technical or economic

variable that affects the cost of energy production. The following equation is used to compute elasticity coefficients:

$$E = \frac{Y_1 - Y_2}{Y_1 + Y_2} \quad \frac{X_1 - X_2}{X_1 + X_2} \quad \text{or} \quad \frac{\% \Delta Y}{\% \Delta X}$$

where E = coefficient of elasticity of energy price

Y = price of energy

X = value of a technical or economic variable

Subscripts 1 and 2 denote reference values for comparison.

In the above equation, the sign of the elasticity coefficient indicates the direction of the effect on prices resulting from a given change in the determinant, whereas the value of the coefficient denotes the relative magnitude of the impact of that determinant. As a first approximation, the elasticity coefficients can be used for two purposes: (1) to prioritize the several technical and economic factors in terms of the magnitude of their impact on hydrothermal energy price*; and (2) to indicate the uncertainty (band) of price estimates over a range of values for a technical or economic variable.

The relative importance of a parameter in energy cost determination should be determined through an analysis in which all the relevant parameters/variables are considered together. Such a determination calls for a multiple regression analysis which is beyond the scope of this paper.

* The elasticity measures developed in this paper should be used only to indicate the magnitude of the impact of a variable when all other factors are held constant.

The most important factors - technical and economic parameters - determining hydrothermal energy economics were identified through a literature survey and are presented in Tables 3 and 4 in Section 2.0. The parameters chosen for prioritization analysis include: wellhead temperature, well flow rate, well depth, rock type, producing capacity (plant size), capacity factor, well life, well spacing, discount rate, inflation rate, prices for conventional fuel, escalation rates for capital costs, O&M costs, and conventional fuel prices, and investment tax credit. Even though some other economic factors listed in Table 4 do influence the cost of energy, e.g., taxes, depreciation, royalty, depletion, etc., they have not been included in the following sensitivity analysis for prioritization because their values are ordinarily fixed from the point of view of an individual investment decision maker.

Using the measure of elasticity as defined above, this section discusses the importance of several technical and economic variables in the hydrothermal energy price estimation process in two steps. First, the importance of individual technical factors will be analyzed followed by economic factor elasticity measures. Second, based on these elasticity measures, prioritization of technical and economic variables in hydrothermal energy price determination will be presented.

3.3 Values of Technical Factors and Elasticity of Hydrothermal Energy Price

A review of the ten studies indicates that the most important technical determinants of the unit cost of hydrothermal energy are: the wellhead temperature, well flow rate, and the well cost. Some of

the less important technical factors are capacity factor, energy conversion cycles, well spacing, well life, fluid composition, and replacement schedules for field and power plant components. The cost of wells, including drilling and extraction, is a function of well depth, well size at the bottom, fraction cased and rock hardness. Wellhead temperature and well flow rate determine the power capacity of a well. The ratio of the total cost of a production well to its estimated power capacity is analogous to the installed unit capital cost of the hydrothermal energy plant.

The relationship between wellhead temperature, well flow rate, well costs and cost of energy is illustrated by isocost curves in Figures 1, 2 and 3. Unless otherwise stated, the elasticity measures for various technical factors presented in this section are derived from these curves and the numerical examples provided in Pacific Northwest Laboratory (PNL) study.* The economic assumptions and technical conditions for generating electricity from low salinity geothermal resources used in the cited PNL study are presented in Table 7.

3.3.1 Wellhead Temperature

Resource temperature is an important determinant of the cost of electricity generated from hydrothermal resources. For example, higher temperatures along with higher flow rates and lower well costs will result in lower unit cost of energy. Table 8 illustrates the relationship between the cost of energy and resource temperatures for

*C. H. Bloomster, An Economic Analysis of Geothermal Energy Costs, Battelle, Pacific Northwest Laboratories, BNWL-5A-5596, 1975.

SOURCE: Battelle

FIGURE 1

ISOCOSTS FOR HYDROTHERMAL RESOURCES
AT A WELL COST OF \$150,000

SOURCE: Battelle

FIGURE 2

ISOCOSTS FOR HYDROTHERMAL RESOURCES
AT A WELL COST OF \$300,000

SOURCE: BATTELLE

FIGURE 3

ISOCOSTS FOR HYDROTHERMAL RESOURCES
AT A WELL COST OF \$500,000

Table 7 - Resource Conditions and Economic Assumptions

(a) RESOURCE CONDITIONS

Resource Conditions:	
Temperature	200°C
Average Flow Rate Per Well	430,000 lb/hr
Average Well Spacing	11.2 acres
Average Well Life	15 years
Powerplant Capacity	55 MWe
Power Cycle	Isobutane
Annual Plant Capacity Factor	85%

(b) ECONOMIC ASSUMPTIONS

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

TABLE 8

RELATIONSHIP BETWEEN RESOURCE TEMPERATURES AND
COST OF ENERGY IN ELECTRIC APPLICATIONS

Case	Resource Temper- ature (°C)	Cost of Energy in Mills/Kwhr when the Well Flow Rate (in 10 ³ Lbs/Hour) Per Well is [▲]			Elasticity when the Well Flow Rate (in 10 ³ Lbs/Hour) per Well is*		
		400	600	800	400	600	800
Case A**	150	38.50	29.00	26.50	1.983	1.923	2.274
	200	21.50	16.50	13.50	1.602	1.607	1.760
	250	15.00	11.50	9.00	(1.757)***	(1.728)	(1.971)
Case B	150	45.00	35.00	29.00	1.999	2.116	1.826
	200	25.00	18.75	17.00	2.250	1.629	1.552
	250	15.00	13.00	12.00	(2.000)	(1.833)	(1.658)
Case C	150	60.00	45.00	37.00	2.333	2.130	2.088
	200	30.00	24.00	20.00	1.693	1.667	1.588
	250	20.50	16.50	14.00	(1.962)	(1.853)	(1.803)

▲ The cost of energy and well cost estimates are in 1974 dollars.

* The signs of the elasticity coefficients are negative.

** Cases A, B, and C refer to well cost of \$150,000, \$300,000 and \$500,000 per well respectively (1976 dollars).

*** The figures in parentheses represent the average elasticity for specific well flow rates over the entire temperature range.

different levels of well costs and flow rates. The effect of resource temperature changes on the cost of electricity is presented in terms of absolute impact (mills/kwh) as well as relative impact (elasticity), as defined earlier.

It is clear from Table 8 that the cost of energy is highly sensitive to the resource temperature. The elasticity is as high as 2.233 (absolute value) for a resource temperature of 150°C, a flow rate (400,000 lbs/hr) and a well cost of \$500,000. The lowest value of elasticity is 1.552 (absolute value) for case B, with 200°C resource temperature and a well flow rate of 800,000 lbs per hour.

The magnitude and wide range of elasticity of energy price and changes in resource temperature make it obvious that the determination of economic feasibility and estimates of energy prices from hydrothermal resources are subject to a large margin of error, unless the resource temperature is ascertained with a lot of confidence.

It is not possible to draw any definite conclusion about the relationship between resource temperature and cost of energy for direct heat applications. Even though this paper has not made any attempt to examine the engineering design and cost estimation techniques used by various simulation models, a quick analysis of the published data as to the sensitivity of prices to changes in temperature levels for district heating applications showed dramatic differences in the price trend as well as its sensitivity.

The results of two studies* are presented in Tables 9 and 10 for

* "Residential Heating Costs - A Comparison of Geothermal, Solar, and Conventional Resources" (PNL) and "Geothermal Energy for Residential, Commercial, Industrial Users: A Computer Simulation Model BTHERM" (NMEI).

TABLE 9

RELATIONSHIP BETWEEN TEMPERATURE AND COST
COST OF ENERGY IN DIRECT HEAT APPLICATIONS

Temperature (°C)	Cost of Energy (\$/MMBtu, 1979 \$)* when the Well Flow Rate (in 10 ³ lbs/hr.) is				Elasticity of Cost of Energy** when the Well Flow Rate (in 10 ³ lbs/hr.) is			
	150	200	300	400	150	200	300	400
60	7.69	6.31	4.62	4.00	2.093	2.117	2.136	2.211
80	4.15	3.38	2.46	2.08	1.921	1.711	1.468	1.576
100	2.69	2.30	1.77	1.46	1.238	1.389	1.390	1.320
150	1.62	1.30	1.00	0.85	(1.521)***	(1.536)	(1.503)	(1.515)

Assumptions:

- Private financing
- 30-year well life
- \$400,000 well cost
- Downhole pumps at 400 feet

* The cost of energy data was derived from the cost curves in Figure 6.11 presented in Pacific Northwest Laboratory study, Residential Heating Costs - A Comparison of Geothermal, Solar, and Conventional Resources, August, 1980.

** The sign of the elasticity coefficients is negative.

* The figures in parantheses are overall average elasticity coefficients.

TABLE 10

RELATIONSHIP BETWEEN WELLHEAD TEMPERATURE, DISTANCE
AND COST OF ENERGY FOR A DISTRICT HEATING SYSTEM

Temperature (°C)	Cost of Energy* (\$ MMBTU) For Distance Case			Elasticity of Cost With Regard To Temperature for the Distance Case		
	A**	B**	C**	A**	B**	C**
70	3.281	3.716	4.248	-	-	-
	(0.093)*** (0.200)			0.018	-0.036	-0.125
80	3,289	3.698	4.178	-	-	-
	(0.878) (0.183)			0.075	0.025	0.107
90	3.318	3.709	4.231	-	-	-
	(0.083) (0.197)			-0.147	-0.212	-0.352
100	3,267	3,267	4.077	-	-	-
	(0.078) (0.175)			0.232	0.135	0.072
110	3.340	3.674	4.105	-	-	-
	(0.071) (0.166)					

* The data for cost of energy is taken from New Mexico Energy Institute Study, Geothermal Energy for Residential, Commercial, Industrial Users: A Computer Simulation Model BTHERM.

** A, B, and C refer to distances of 1, 5, and 10 miles for location of geothermal resource area to the end-use applications.

*** Figures in parantheses are elasticity of price with reference to distance.

illustration. In the PNL study, the relationship between energy prices and temperature levels for direct heat applications is direct and stable, and the elasticity of prices is significantly high as in the case of electric applications. In the NMEI15 BTHERM study, however, not only is the elasticity of cost of energy with respect to variations in resource temperature for district heat applications close to zero, but there is no uniform or predictable relationship between the cost of energy and temperature levels. In fact, the unit cost of energy in the BTHERM study can be expected to vary very little over different temperature levels for a given distance of the geothermal resource area to the end-user center.

Such disparate results between two studies indicate that the variances are largely due to differences in thermodynamic design methods and components cost estimation procedures. The inherent differences between the cost of energy models for electric, and direct heat projects are emphasized by the observations pertaining to analysis of "cost of energy" elasticity with respect to the fluid temperature. It is possible that the results of the "energy cost elasticity" analysis for the BTHERM model will be replicated by other hydrothermal direct heat applications cost of energy models. A number of repeated applications of various models with a carefully chosen set of input data would be needed for quantitative characterization of the sensitivity of the results yielded by different models to changes in the values of some key input variables and/or model parameters. Such a detailed comparison is beyond the scope of this study.

3.3.2 Well Flow Rate

For a given well cost the unit cost of energy is inversely related to the average well flow rate. That is, the price per unit of energy declines with an increase in well flow rate. Figure 4 and Table 11 illustrate the relationships between well flow rates and cost of energy.

The coefficient of elasticity indicates that on an average, the unit cost of energy declines by one-half of one percent for every one percent increase in the flow rate. However, the individual elasticity of energy price lies in the range of -0.36 and -0.52. Figure 4 also shows that the most favorable effect of increasing flow rate on energy price is to be found for binary/isobutane plants as compared with binary/freon and flash plants. The results shown in this figure are based on the GEOCOST model.

Table 12 illustrates the sensitivity of cost of energy to well flow rates at different resource temperatures and well costs. The results clearly indicate that higher flow rates bring about considerable reduction in energy price; however, the magnitude of reduction in energy costs as well as the elasticity of energy cost with respect to well flow rates vary widely at different resource temperature and well costs combinations; the individual elasticities range from 0.254 to 2.690 while the overall average elasticities lie in the range of 0.334 to 0.750.

A careful reading of the behavior of energy costs and elasticity coefficients in Table 12 reveals that there is a consistent relationship (inverse) between well flow rate and prices (measured in absolute levels), while there is no such unique relationship between well flow rate and prices in terms of elasticity. For example, under

FIGURE 4
BUSBAR COST OF ELECTRICITY VS. WELL FLOW RATE

Source: Battelle (PNL)

TABLE 11

RELATIONSHIP BETWEEN WELL FLOW RATE AND COST OF ELECTRICITY
(FOR BINARY/ISOBUTANE PLANTS)

Average well flow rate (10 ³ lbs/hr/well)	Cost of electricity (mills/kwh)	Elasti- city (percent)
430.0	18	-0.36
215.0	23	-0.52
017.5	33	(-0.49)*

* Figure in parantheses is elasticity over the entire range of well flow rate.

TABLE 12

RELATIONSHIP BETWEEN WELL FLOW RATE AND COST OF ENERGY
AT DIFFERENT LEVELS OF RESOURCE TEMPERATURE AND WELL COSTS

Well Costs ⁺	Well Flow Rate (10 ³ lbs/ hr/well)	Cost of Energy in mills/kwh when the resource temperature is			Elasticity* of Cost of Energy when the resource temperature is		
		150°C	200°C	250°C	150°C	200°C	250°C
Case A**	400	38.50	21.50	15.00	0.703	0.657	0.350
	600	29.00	16.50	13.50	0.575	0.838	1.061
	700	27.50	14.50	11.00	0.277	0.536	1.500
	800	26.50	13.50	9.00	(0.554)***	(0.686)	(0.750)
Case B	600	45.00	25.00	15.00	0.625	0.714	0.357
	600	35.00	18.75	13.50	0.582	0.356	0.254
	700	32.00	17.75	12.50	0.738	0.324	0.306
	800	29.00	17.00	12.00	(0.649)	(0.571)	(0.333)
Case C	400	60.00	30.00	21.50	0.714	0.555	0.657
	600	45.00	24.00	16.50	0.965	0.565	0.629
	700	40.00	22.00	15.00	0.585	0.714	0.517
	800	37.00	20.00	14.00	(0.711)	(0.600)	(0.634)

+ All costs are in 1974 Dollars.

* The signs for all the elasticity coefficients in this table are negative.

** Cases A, B and C refer to well costs of \$150,000, \$300,000, and \$500,000 per well, respectively

*** The figures in the parentheses are the estimated elasticities over the entire range of well flow rates.

case A, when well flow rates increase in the range of 400,000 lbs/hr - 800,000 lbs/hr the prices decline at each of the levels of well flow rate for 200°C resource temperature conditions; however, the coefficient of elasticity rises from 0.657 to 0.838 and then declines to 0.536. Similar results can be found for other cases in the table. This observation suggests that the elasticity measures provided in the table with reference to flow rates must be used with caution by taking into account the levels of flow rate as well as well costs and resource temperature.

In general, for a constant temperature, increases in flow rate raise energy production potential, requiring fewer production wells, thus reducing production cost; however, this does not affect transmission and distribution costs. Because of the relatively smaller proportion of the total field cost attributable to the production wells at higher fluid temperatures, the relative effect of well flow rate on cost of energy production is smaller at higher temperatures.

3.3.3 Plant Size and Power Cycles

Figure 4 shows the differential energy price effects of flow rates in conjunction with different power cycles. The size of the power plant has a significant impact on the busbar cost of energy for a given set of resource characteristics and energy conversion cycle. The relationship between the busbar cost of energy and the plant size for a number of energy conversion cycles is displayed in Figure 5.

Among the power cycles suitable for exploiting a resource with a wellhead temperature of 200°C, the binary cycle using isobutane is the most economical, while the steam cycle with flashing at the wellhead is the most expensive in terms of the busbar cost of electri-

FIGURE 5

BUSBAR COST OF ELECTRICITY VS. PLANT SIZE
(GEOTHERMAL PLANTS)

Source: Battelle

flashing at the wellhead.

Up to a point the cost of energy declines with an increase in plant size. However, the effect of plant size on the cost of energy is negligible beyond 50 MWe capacity except for the field flash steam cycle. In the latter instance, the unit costs rise due to higher steam transmission cost and higher steam degradation over the longer pipe runs.

3.3.4 Well Cost

The importance of well cost in determining the cost of energy from hydrothermal resources is emphasized in all the studies. Well cost is a function of the well depth, rock hardness, well size at the bottom and fraction cased. Table 13 presents the predicted energy cost per unit at the busbar for well costs ranging from three levels of temperature - 150°C, 200°C and 250°C. The flow rate is fixed at 500,000 lbs/hr/well. The elasticity of price measures are also provided in the table.

The price of energy varies directly with the well cost: the greater the well cost, the greater the level of energy prices and vice versa. This relationship is true for all resource temperature conditions. The elasticity varies from 0.184 to 0.500 for costs ranging from \$150,000/well to \$500,000/well at different well temperatures. The overall average elasticity values fall in the range of 0.331 - 0.401.

3.3.5 Well Cost Estimating Equations

All studies acknowledge that well costs are a major factor in the economic feasibility of hydrothermal energy resources. However, because of the lack of baseline data on well costs, the estimates are

TABLE 13

RELATIONSHIP BETWEEN WELL COST AND COST OF ENERGY

Well Cost 10^3 \$/well (1974 \$)	Cost of Energy at Busbar* (mills/kwh - 1974 \$) when the Resource Temperature is			Elasticity of Busbar Cost when the Resource Temperature is **		
	150°C	200°C	250°C	150°C	200°C	250°C
150	29.0	16.5	11.5	0.281	0.195	0.184
300	35.0	18.7	13.0	0.500	0.496	0.474
500	45.0	24.0	16.5	(0.401)***	(0.344)	(0.331)

* The cost estimates are based on the Isocost curves generated by utilizing the results produced by the GEOCOST Model. The cost figures correspond to a well flow rate of 500,000 lbs/hr.

** The sign for the elasticity coefficients is positive.

*** Figures in parentheses are overall average elasticities.

based on equations which differ among studies. The result is that the cost estimates provided by these studies as well as the elasticity of well costs (as a function of depth and type of rock) vary widely, thus adding to the uncertainty in their cost of energy projections.

The three commonly used equations to estimate the well costs are given below for illustration purposes.* They are:

1. $C_w = 10K + (D/17140)$ (APL/JHU)

where,

C_w = well cost per foot in 1976 dollars

K = 1.6 for hard rock, 1.2 for soft rock

D = depth in feet

2. $C_w = 0.245 + 0.0044d^2$ (soft rock) (Technecon)
 $0.378 + 0.0211d^2$ (igneous rock)

where,

C_w = cost of well in million \$ (1978 dollars)

d = well depth in thousands of feet.

3. $C = 2.887 D^{1.496}$ (Hard rock) (EG&G)
 $102.8 D^{1.035}$ (Soft rock)

where,

C = cost of well (1980 \$)

D = depth in feet

* These expressions can be utilized for estimating the cost of standard 9 5/8 in. bore wells.

Figure 6 shows the estimated well costs for a range of well depths. It can be observed that the normalized cost estimates (normalized to 1980 dollars) generated by the three well cost expressions differ significantly. Since the cost of production wells is an important element of the capital cost of the geothermal field development, large changes in this cost will inevitably lead to substantial variance in the cost of energy estimates generated by different models. The problem is further compounded by the fact that during the last few years the rate of increase in the cost of geothermal wells has been significantly higher than the general rate of inflation and the normalization of well costs based on the rate of inflation is bound to yield low estimates of the busbar cost of energy. It is interesting to observe that equation number 1 yields a higher well cost estimate for a soft rock formation than for a well of identical depth in a hard rock formation. Equation numbers 2 and 3 produce a higher well cost estimate for hard rock formations as compared with soft rock formations.

The elasticity measures for well costs as a function of depth and rock type presented in Table 14 clearly indicate the complete variance in the estimates provided by the three equations.

3.3.6 Plant Capacity Factor

A high proportion of geothermal power plant costs is fixed and does not vary with plant output. Therefore, the unit cost of energy is highly sensitive to the average plant capacity factor. The inverse relationship between the capacity factor and the cost of energy as well as the relative sensitivity (elasticity) of cost of energy to changes in capacity factor is displayed in Figure 7 and in

FIGURE 6
COST OF WELL VS. WELL DEPTH

TABLE 14

WELL COST ESTIMATION EQUATIONS
AND ELASTICITY OF WELL COST

Equation Number: 1				
		Well Cost (1976 \$)		Elasticity of Well Cost
Depth (ft.) (X)	Hard Rock (igneous) (Y)	Soft Rock (sedimentary) (Y)	Hard Rock	Soft Rock
1,000	18,127	45,534	1.17498	1.17421
2,000	41,468	104,102	1.31762	1.31900
3,000	71,144	178,707	1.45555	1.45552
4,000	108,498	272,534	1.59172	1.59172
5,000	155,121	389,646	1.72719	1.72719
6,000	212,908	534,800	1.86222	1.86224
7,000	284,104	713,638	1.99674	1.99672
8,000	371,356	932,803	2.13208	2.13209
9,000	477,862	1,200,335	2.26524	2.26625
10,000	607,295	1,525,457	—	—
Equation Number: 2				
		Well Cost (1978 \$)		Elasticity of Well Cost
Depth (ft.) (X)	Hard Rock (igneous) (Y)	Soft Rock (sedimentary) (Y)	Hard Rock	Soft Rock
1,000	399,100	249,400	0.22043	0.07734
2,000	462,400	262,600	0.51199	0.20102
3,000	567,900	284,600	0.80022	0.35933
4,000	714,500	315,400	1.06111	0.53162
5,000	905,500	355,000	1.24962	0.70200
6,000	1,137,600	403,400	1.39867	0.86065
7,000	1,411,900	460,600	1.51180	1.00284
8,000	1,728,400	526,600	1.59819	1.12730
9,000	2,087,100	601,400	1.66490	1.23476
10,000	2,488,000	685,000	—	—
Equation Number: 3				
		Well Cost (1980 \$)		Elasticity of Well Cost
Depth (ft.) (X)	Hard Rock (igneous) (Y)	Soft Rock (sedimentary) (Y)	Hard Rock	Soft Rock
1,000	88,807	130,916	1.42956	1.03222
2,000	250,488	268,262	1.47160	1.03401
3,000	459,431	408,144	1.48348	1.03450
4,000	706,527	549,699	1.48840	1.03470
5,000	986,520	692,512	1.49091	1.03480
6,000	1,295,869	836,335	1.49235	1.03484
7,000	1,631,975	981,001	1.49326	1.03490
8,000	1,992,826	1,126,397	1.49387	1.03491
9,000	2,376,805	1,272,431	1.49429	1.03494
10,000	2,782,574	1,419,036	—	—

SOURCE: BATTELLE

FIGURE 7
COST OF ELECTRICITY VS. PLANT CAPACITY FACTOR

Table 15.

In Figure 7, the cost of energy declines from 21.50 mills/KWh to 17.00 mills/KWh when the average capacity factor increases from 60% to 85%. The elasticity coefficients vary from 0.510 to 0.712. The sensitivity of the busbar cost of energy to changes in the value of capacity factor depends on the fraction of total costs which does not depend on the energy output of the power plant.

Capacity factor determines both the price of energy and the profits through its effects on output sold and gross revenues. An increase in the capacity factor reduces the energy cost per unit but at the same time raises the gross revenue. Since the rates of return on investment and the net present value of a project are important determinants of the attractiveness of a geothermal energy project, it is very desirable to have the plant capacity factor as an input variable for a geothermal cost of energy model.

3.3.7 Well Life

For a given set of resource and economic conditions, the length of the life of a well has an important influence on the energy price level. An increase in the average well life results in a decrease in the price of energy, and vice versa.* This inverse relationship between well life and cost of energy for two sets of resource conditions (Case A and Case B) is illustrated in Table 16.

The elasticity of energy prices to changes in well life is lower than for many other resource factors considered in the sensitivity

* It is assumed that an adequate well flow rate is maintained during the extended well life time.

Table 15

Relationship Between Capacity Factor and
Cost of Energy

Plant Capacity Factor (percent)	Cost of Energy (mills/kwh)	Elasticity (percent)
60	21.50	0.802
70	19.00	0.510
80	17.75	0.712
85	17.00	(0.678)*

* Elasticity of cost of energy over the given range of capacity factor values.

Table 16

Relationship Between Well Life and Cost of Energy*

Well Head Transportation and Flow Rate	Well Life (years)	Cost of Energy (mills/kwh in 1974 \$)	Elasticity+
Case A (250°C, 750,000 lbs/hr)	10	20.00	0.218
	15	18.33	0.162
	20	17.50	(0.200) ^Δ
Case B (200°C, 500,000 lbs/hr)	10	28.50	0.213
	15	26.17	0.160
	20	25.00	(0.197) ^Δ

* The cost of energy figures in this table were computed by using the Battelle GEOCOST Model and are based on an assumed well cost of \$500,000, and gross plant size 55 MWe. In both cases, the power cycle is binary with isobutane working fluid.

+ The sign for elasticity coefficients is negative.

Δ The figures in parentheses represent the elasticity of cost over the entire range of well life times.

analysis. However, it is important to note that the relative responsiveness of cost of energy to changes in well life is higher at shorter end of well lives. The individual elasticity coefficients vary between -0.162 and -0.218 whereas the overall average elasticity is about -0.200.

Although the levelized busbar cost of electricity is not very sensitive to the life times for production wells, the capital cost associated with the replacement of wells is an important element of the cash flow for the producer. Therefore, a model whose outputs are to be utilized as a basis for estimating the cash flow for a geothermal energy project must provide for variable well life time as an input.

3.3.8 Well Spacing

A decrease in the well spacing (acres) reduces the cost of energy and vice versa. The reduction in cost of energy is mainly due to lower capital and O&M costs of the fluid transport system, and reduced heat loss and pressure drop resulting from more dense well spacing. However, the possibility of reduced well flow rate must be considered when a decision about production well spacing is made.

As shown in Table 17, the elasticity of the cost of energy as a function of production/injection well spacing is relatively low, nevertheless, a good "cost of geothermal energy" model should have the capability of computing the capital and O&M costs of the fluid transport system and the heat loss and fluid pressure drop if the well spacing is provided as an input variable.

Table 17

Relationship Between Well Spacing and Cost of Energy*

Resource Characteristics	Well Spacing (acres)	Cost of Energy (mills/kWh in 1976 \$)	Elasticity
Case A*	20	20.00	-
	30	21.00	0.122
	40	22.00	0.163
Case B*	20	29.00	-
	30	30.00	0.085
	40	31.00	0.114

* Case A - Wellhead temperature 250°C, well flow rate 750,000 lbs/hour, binary (isobutane) cycle - 55 MWe gross plant.

Case B - Wellhead temperature 200°C, well flow rate 500,000 lbs/hour, binary (isobutane) cycle - 55 MWe gross plant size.

The cost estimates were yielded by the GEOCOST Model.

3.4 Trade-off Analysis of Technical Factor Vis-a-Vis Cost of Energy

Of the several technical or resource factors that have important influence in determining the cost of energy from hydrothermal resources, the three dominant factors are resource temperature, flow rate and well costs. From a reading of the isocost curves in Figures 1, 2 and 3, it is easy to see that there are several combinations of these three factors that result in the same cost of energy. Table 18 combines data derived from Figures 1, 2, and 3 to permit trade-off analysis among well cost, resource temperature and flow rate as they jointly tend to determine the price of energy.

Cases A, B, and C illustrate the trade-off between well cost and flow rate for a given temperature condition. As the well cost increases to higher levels from \$150,000 to \$500,000, a proportionately greater increase in the well flow rate is needed for maintaining the same energy price per unit. A one percent increase in the well cost (in the range of \$150,000 - \$300,000) for 200°C wellhead temperature condition requires a 0.18 percent increase in well flow rate for keeping the busbar cost of electricity unchanged. In the well cost range \$300,000 to \$500,000, a one percent increase in the well cost requires a 0.85 percent increase in the well flow rate for keeping the busbar cost of energy constant. Similar behavioral relationship holds true for 225°C and 250°C temperature conditions.

Cases D, E, and F depict the trade-off relationship between well flow rate and well head temperature for a given cost per well. As the wellhead temperature increases to higher levels, from 200°C to

Table 18

**Trade-off Relationship Between Wellhead Temperature,
Well Flow Rate, Well Cost and Cost of Energy**

Well cost (10 ³ \$/well)	Wellhead temperature (C°)	Flow Rate (10 ³ lbs/hr/well)	Cost of Energy (mills/kWh)
Case A*			
150	200	440	20
300	200	500	20
500	200	770	20
Case B*			
150	225	310	20
300	225	360	20
500	225	530	20
Case C*			
150	250	230	20
300	250	267	20
500	250	370	20
Case D**			
150	200	440	20
150	225	310	20
150	250	230	20
Case E**			
300	200	500	20
300	225	360	20
300	250	310	20
Case F**			
500	200	770	20
500	225	530	20
500	250	370	20
Case G⁺			
150	170	500	20
300	200	500	20
500	225	500	20
Case H^Δ			
150	200	440	20
300	225	360	20
500	250	370	20

*Cases A, B, and C illustrate trade-off between well cost and flow rate for different temperature conditions.

**Cases D, E, and F illustrate trade-off between well flow rate and wellhead temperature for different well costs.

+ Case G illustrates trade-off between well cost and wellhead temperature for a given flow rate condition.

Δ Case H illustrates trade-off among well cost, wellhead temperature and flow rate.

250°C, a proportionately small reduction in well flow rate is required for the busbar cost of electricity to remain on the isocost curve. A one percent increase in resource temperature (in the range of 200°C - 225°C) requires 2.95% reduction in well flow rate whereas the corresponding required reduction in well flow rate is only 2.81% in the temperature range of 225°C - 250°C. Similar behavioral relationship exists for well costs cases of \$300,000 and \$500,000. Case G represents a trade-off relationship between resource temperature and well cost for a given well flow rate. As the well cost increases, it requires higher resource temperatures to achieve the same unit cost of energy. A one percent increase in well cost, on an average, requires 0.243 to 0.235% increase in resource temperature. Finally, Case H is an illustration of all three factors - wellhead temperature, well cost and flow rates - varying simultaneously. It shows that a combination of low well costs, low resource temperature, and a high flow rate can yield the same unit cost of energy as a combination of high well costs, high resource temperature, and a low well flow rate.

3.5 Prioritization of Technical Parameters in Hydrothermal Energy Price Determination

The elasticity measures computed through the analysis of the contribution of several technical parameters can be used to determine their hierarchy. Table 19 is a summary of the results of sensitivity analysis. The technical factors, their range of values and the associated elasticity coefficients are presented in terms of their relative importance or priority in influencing the price of energy. The overriding importance of temperature, flow rate, capacity factor

Table 19

Prioritization of Technical Parameters in Hydrothermal
Price Determination

Technical parameters	Units	Range of values*	Elasticity of energy price +
Temperature	(°C)	150 - 250	(-1.552) (-2.333)
Flow rate	(10 ³ lbs/hr)	400 - 800	(-0.277) (-1.500)
Capacity factor	(%)	60 - 85	(-0.510) (-0.802)
Well Cost	(10 ³ \$/well) (1974\$)	150 - 500	(-0.196) (-0.500)
Well life	(years)	5 - 30	(-0.160) (-0.218)
Well spacing	(acres)	20 - 40	(0.025) (-0.163)

* The ranges of values for the technical parameters were drawn from the isocost curves for hydrothermal electrical generation presented in PNL study, An Economic Analysis of Geothermal Energy Costs by C.H. Boomster. The study is an application of PNL GEOCOST model.

+ The elasticity of energy price is a measure of the relative impact a change in the technical parameter on the cost of energy; the relative impact is defined as the percentage change in energy price for a given percentage change in the value of a technical parameter.

and well cost becomes obvious from an examination of the elasticity measures. While most of the studies recognize the importance of three factors, i.e., temperature, flow rate and well cost, and do not pay enough attention to the capacity factor, the surprising result of the analysis in terms of elasticity is that the capacity factor appears to be more important than the well cost in hydrothermal energy economics. It is appropriate to point out the fact that the assumptions and engineering/economic logic associated with different cost of energy models may produce technical parameter rankings which are different from those shown in Table 19. However, plant capacity factor will always be one of the most important determinants of the cost of geothermal energy.

3.6 Values of Economic Parameters and Elasticity of The Cost of Hydrothermal Energy Price

Several important economic factors that determine the price of energy from hydrothermal resources have been identified in Table 1, Section 2.0. Some of the most important sources of differences in cost estimates are to be found in the treatment of economic factors such as, capital and O&M cost escalation rates, inflation, discount rate, debt payment and depreciation in current and constant dollar analysis, and capital plant replacement schedules, etc. The effect of each of these economic variables on cost of energy is uncertain and varies considerably over a range of values assigned to them. The sensitivity of hydrothermal energy prices to several economic parameters such as, conventional energy price levels and their escalation rate, discount rate, general inflation and investment tax credit is analyzed below. The quantitative measures (elasticity) of the

relationship between the various economic parameters and hydrothermal energy prices are derived from the numerical examples provided in a recent Jet Propulsion Laboratory (JPL) study.* The economic analysis results presented in the JPL study was with reference to a geothermal reservoir at Heber, California. The reservoir characteristics are: net power production (45 MWe), well depth (4,000-10,000 ft), well flow rate (1,380-1,600 gpm), wellhead temperature (180°C), capacity factor (70%) and well life (15 years).

Table 20 provides a summary of the quantitative relationship between the major economic variables, cost of energy and profits. The relationship between each of these economic variables and the cost of energy and profits** is briefly discussed below in order to highlight the wide divergence that can occur in energy price estimates due to differences in sensitivity of energy price to large variations in the economic variables.

3.6.1 Conventional Energy Price Level

The competitive price received by the resource developer and utility for the electricity supplied affects the present value of profits, total costs of production and the levelized energy price

* Jet Propulsion Laboratory, Geothermal Probabilistic Cost Model, July 1981.

** The cost of energy is the levelized cost of energy (mills/kwh) expressed in 1980 dollars; and, profits are net present value of profits, also expressed in 1980 dollars.

TABLE 20

RELATIONSHIP BETWEEN ECONOMIC PARAMETERS,
COST OF ENERGY AND PROFITS

Economic Parameters	Range of Values	Cost of Energy* (mills/kwh)	Present Value Profits (millions 1980 \$)	Elasticity (percent)	
				Cost of Energy	Profits
Energy Price Escalation Rate (%)	9.0	16.91	2.04	-	-
	10.0	15.68	7.64	-0.717	10.992
	11.0	14.63	14.55	-0.727	6.539
				(-0.723) ⁺	(7.541) ⁺
Competitive Energy Price Level (mills/kwh)	15.0	14.28	3.02	0.607	5.634
	17.5	15.68	7.64	0.636	3.477
	20.0	17.07	12.25	0.703	2.148
				(0.681)	(2.460)
General Inflation Rate (%)	8.0	14.95	10.67	0.405	-2.813
	9.0	15.68	7.64	0.507	-5.899
	10.0	16.54	4.02	(0.454)	(4.074)
Capacity Factor (%)	60.0	16.78	2.54	-0.447	8.355
	70.0	16.10	5.09	-0.432	5.408
	80.0	15.68	7.64	(-0.441)	(6.513)
Discount Rate (%)	15.0	15.68	7.64	0.361	-6.298
	16.0	16.05	5.06	0.463	-11.062
	20.0	17.79	-0.52	(0.441)	(-8.022)
ITC (%)	10.0	15.68	7.64	-0.021	0.167
	25.0	15.40	8.82	(-0.021)	(0.167)
Well Life (years)	10.0	16.40	4.62	-0.112	1.232
	15.0	15.68	7.64	-0.064	0.455
	30.0	15.02	10.36	(-0.088)	(0.767)

* Cost of energy is the levelized cost of energy expressed in 1980 dollars.

+ Figures in parentheses represent the average elasticity of the cost of energy or profits over the entire range of the values of the parameter(s) involved.

required to render the net present value of the project equal to zero. The present value of profits increases with the level of competitive price, and vice versa; however, the costs of production also increase because a higher competitive price by raising the gross revenues leads to increased royalty payments and taxes which are treated as production costs. The result is an increase in the levelized energy cost. In the range of 15 mills/kwh to 30 mills/kwh for competitive energy price, the individual elasticities of hydrothermal energy price lie between 0.607 and 0.703, and the overall average elasticity is 0.681; on the other hand, the overall average elasticity of profits is significantly larger (2.46) over the same range of competitive energy price levels. However, the sensitivity of hydrothermal energy cost increases at higher levels of conventional energy prices whereas the sensitivity of profits declines from 5.634 to 2.148 when the competitive price level rises from 15 mills/kwh to 30 mills/kwh.

3.6.2 Energy Price Escalation

The escalation rate for competitive energy prices significantly raises profits and lowers the levelized hydrothermal energy price. Consequently, if the escalation rate value increases from 9% to 11%, the levelized hydrothermal energy price declines to 14.63 mills/kwh from 16.91 mills/kwh; for the same condition, the level of profits increases significantly from \$2.04 million to \$14.55 million. It is clear from the results in Table 20 that, because the effect on profits is cumulative through the life of the project, the elasticity of profits to a change in the escalation rate of energy prices is much greater (7.541) than the hydrothermal energy price (-0.723).

The elasticity of price is much more stable (varying between 0.717 and 0.727), as compared to the elasticity of profits which vary widely, ranging from 10.992 to 6.539.

The uncertainty surrounding the sensitivity of price and profits to energy escalation rates and the importance of the latter on energy price formation requires that due attention be given to energy escalation rates in the economic feasibility and cost of energy projection studies.

3.6.3 Inflation

Unlike energy price escalation rates, an increase in the inflation rate tends to reduce the present value of profits while raising the hydrothermal energy price level. Within the range of 8% - 10% rate of inflation, hydrothermal energy price increases from 14.95 mills/kwh to 16.54 mills/kwh whereas profits decline from \$10.67 million to \$4.02 million. However, as in the case of energy price escalation rate, the sensitivity of profits is significantly larger (-4.074) than the sensitivity of hydrothermal energy prices (0.454). The numerical illustration clearly points out that the choice of values for inflation rate will have significant impact on the estimated profitability of a venture.

3.6.4 Discount Rate

Discount rate changes (after tax cost of capital) are directly related to energy prices, but have an inverse relationship with profits. For instance, when the discount rate is raised from 15 to 20 percent, the levelized cost of energy increases from 15.68 mills/kwh to 17.79 mills/kwh and profits decline from \$7.64 million

to a negative value (loss) of \$0.52 million. But, even though profits are extremely sensitive (8.022) to discount rates whereas energy prices are less elastic (0.441), the effect of discount rate on energy prices cannot be ignored because for every one percent increase in discount rate there will be a 0.44% increase in energy price.

Further, the after-tax discount rate not only results in lower levelized cost of energy compared with the before tax discount rate, but also yields a higher present value of net cash flow for the project. The model documentation should state explicitly whether the discount rate used was a before-tax or after-tax rate.

3.6.5 Investment Tax Credit (ITC)

ITC is a credit against the tax bill and not a deduction from taxable income such as depreciation, and it does not affect the depreciation basis of an asset. Compared with the contribution of several other economic parameters, ITC has the least effect on hydrothermal energy prices (0.21), although profits (0.167) are more sensitive to it. Undoubtedly, the provision of additional energy credit for investments in renewable energy technologies should prove beneficial to the economics of hydrothermal energy resource development. In addition, by making the capital investment a larger proportion of the total cost, and by capitalizing rather than expensing a greater fraction of drilling cost, the ITC impact can be further increased.

The relative contribution of the five economic variables (in decreasing order of importance) to hydrothermal energy economics is as follows: energy price escalation (0.723), competitive energy

price level (0.681), general inflation (0.454), discount rate (0.441) and investment tax credit (0.021). Some earlier studies (e.g., GEOCOST, GEOCITY, BTHERM) have not considered the energy escalation rates and inflation rates in their energy price projections. However, the higher cost elasticity values for these two variables (0.723 for energy price escalation rate and 0.454 for inflation rate) indicate significant sensitivity of hydrothermal energy prices. Further, in view of the relatively high values of these parameters during the last few years, the results produced by cost of energy models which ignore these parameters are not quite valid. A decision maker involved in estimating the cost of geothermal electricity should utilize the recently developed models (e.g., GCFM, GELCOM, VENUAL) if he wants to account for the impact of inflation and escalation of energy prices.

3.7 Prioritization of Technical and Economic Factors in Hydrothermal Energy Price Formation

The energy cost elasticity estimates produced by the foregoing separate sensitivity analyses of technical and economic parameters/variables can be used to rank the relative importance of the several variables in the energy price determination. Table 21 provides a prioritized list of the technical and economic variables (in their descending order of importance) and the associated elasticity of hydrothermal energy price coefficients.

To sum up, although the overriding importance of key technical factors (wellhead temperature, flow rate, capacity factor and well cost) becomes abundantly clear, factors such as energy price escalation, competitive energy price level and inflation rates are no less

Table 21

**Sensitivity of Hydrothermal Energy Price:
Prioritization of Technical and Economic Factors**

Technical and Economic Factors	Units	Range of Values	Elasticity of Price
Wellhead temperature	(C°)	150 - 250	(-1.552)-(-2.333)
Flow rate	(103 lbs/hr)	400 - 800	(-0.277)-(-1.500)
Capacity factor	(%)	60 - 85	(-0.510)-(-0.802)
Energy price escalation	(%)	9 - 11	(-0.717)-(-0.727)
Energy price	(mills/kwh)	15 - 30	(0.607 - (0.703)
General inflation	(%)	8 - 10	0.405 - 0.507
Well cost	(103 \$/well 1974 \$)	150 - 500	(0.196)-(-0.500)
Discount rate	(%)	15 - 20	0.361 - 0.463
Well life	(years)	5 - 30	(-0.160)-(-0.218)
Well spacing	(acres)	5 - 30	(0.085)-(-0.168)
Investment tax credit	(%)	10 - 25	(-0.021)

important in determining hydrothermal energy economics. Ignoring escalation rate for energy prices, capital costs, and O&M costs will not only seriously underestimate the revenues and project profitability, but will result in serious errors in the calculation of various cash flows, including taxes, royalty, depreciation, and depletion.

It needs to be pointed out that the sensitivity analyses discussed in this section were somewhat limited due to the non-availability of the computer software for many of the models covered by this study. Consequently, a selected subset of models was utilized for carrying out computations leading to the estimation of energy cost elasticity coefficients. Given more abundant resources for analysis and better access to the computer models, a more comprehensive comparison of the cost of hydrothermal energy models can be conducted.

4.0 CONCLUSIONS AND RECOMMENDATIONS

The evaluation of the major studies on hydrothermal energy economics makes it abundantly clear that the predictions or results of the studies based on the uncertain and wide range of values for technical economic factors and a variety of assumptions can confuse the decisionmaker because two models can yield significantly different cost of energy estimates despite the utilization of identical input data for both of them. Therefore, it would be desirable to develop normalization factors which neutralize the impact of uncommon assumptions and extreme values of parameters associated with some models.

Based on the review of the studies and the sensitivity analysis of cost of energy in relation to technical and economic parameters, significant factors, resource temperature, well flow rate, capacity factor, energy price escalation, competitive energy price level, well cost, general inflation, discount rate, well life, well spacing and investment tax credit (in descending order of importance), were identified as variables/parameters whose values must be determined or estimated with a lot of precision. However, the range of values for these variables as well as their relative impact on energy prices vary considerably. Further, their impact on cost of energy appears to depend considerably on the end use (i.e., whether it is for generating electricity or for direct heat applications).

One of the difficulties in evaluating the studies reviewed in this paper was the lack of baseline data against which to judge the reliability of their estimates. For example, at least three different equations, completely at variance with one another, are used in the studies to determine the well cost, and in the absence of avail-

able baseline data, it is difficult to judge which one of these provides a close approximation to actual cost. Since the well costs are an important determinant of the final cost of energy, the utilization of an invalid function for estimating the well cost can introduce a large error in the estimated cost of energy.

Moreover, differing purposes, technical and economic assumptions and methodologies involved in their estimation processes, in addition to widely varying and site-specific values used for resource characteristics, make the comparison of these studies really difficult. Thus, in order to compare these results in a meaningful way, it is necessary to run the models for a standard set of data for technical and economic assumptions. This type of analysis is beyond the scope of this study.

Clearly there is a great need for a uniform methodology which yields consistent results. There are a number of areas requiring further work so that the existing studies can be made more useful for the investment decision makers, for policy making and program evaluation. The first and most important step in this direction is to develop an integrated set of technical and economic assumptions to be used in energy costing models. Based on an analysis of very limited data, a preliminary set of such factors as well as their relative impact on cost of energy estimates has been identified here, but more systematic analysis of these factors based on detailed data is urgently called for. The need for collecting more and better baseline data to test the validity of assumptions specified in the studies cannot be over emphasized.

In order to provide a common frame for comparing the results of different cost of hydrothermal energy models, a data base of resource

characteristics, engineering parameters and economic factors should be developed. A consensus concerning this data base and the validity of a set of standard assumptions can be reached at a workshop attended by the researchers who have developed the models discussed in this study. Pending the development of a consensus, it would be desirable to come up with a set of normalization factors which make it possible to transform the output of each model so that it may be comparable with the output of another model. If such an effort were to deal with all the existing models, the number of such pairs can be very large and it would be impossible to develop the necessary normalization factors.

In view of these observations, it is recommended that DOE should select a set of no more than three hydrothermal electricity cost models and two direct heat applications cost models for more detailed comparisons. This exercise should lead to the development of normalization factors discussed above. On the basis of the analysis documented in this report, GCFM, VENVAL and GIPA models appear to be good candidates for inclusion in the set of electric cost models. Among the direct heat cost models, GEOCITY and BTHERM possess most of the desirable attributes of a good cost-of-energy model.

5.0 LIST OF STUDIES

Hydrothermal Energy Economics Related Quantitative Studies

1. Barron, W. and Knoll, P., GRITS: A Computer Program for the Economic Evaluation of Direct-Use Applications of Geothermal Energy, GEMS-008, Applied Physics Laboratory, Johns Hopkins University, June 1980.
2. Bloomster, C.H., GEOCOST: A Computer Program for Geothermal Cost Analysis, Battelle, Pacific Northwest Laboratories, Feb 1975.
3. Huber, H.D., et.al., User Manual for GEOCITY: A Computer Model for Geothermal District Heating Cost Analysis, Battelle, Pacific Northwest Laboratories, Oct 1978.
4. Gupta, J.M. and Leigh, J.G., GELCOM: A Geothermal Levelized Busbar Cost Model: Description and User's Guide, MITRE Corporation, Jan 1978.
5. Keimig, M.A., Rosenberg, J.I. and Entingh, D.J., Geothermal Loan Guaranty Cash Flow Model: Description and User's Guide, MITRE Corporation, Nov 1980
6. Synfuel Program Analysis, Volume II: VENVAL Users Manual, Dupont, Inc., (JPL), July 1980
7. Orren, L.H., et.al., Geothermal Probabilistic Cost Model, Jet Propulsion Laboratory, Feb 1981.
8. Cunniff, R.A., Glazner, G. and Houldsworth, M., Geothermal Energy for Residential, Commercial, and Industrial Users: A Computer Simulation Model, B THERM; and Geothermal Potential Direct Use, Rocky Mountain Basin and Range, Physical Science Laboratory, New Mexico Energy Institute, Apr 1980.
9. Cassel, T.A.V., et.al., Geothermal Investment and Policy Analysis with Evaluation of California and Utah Resource Areas, Technicon Analytic Research, Inc., Oct 1979.
10. Reisman, A., A Generic Model for District Heating: A Geothermal Application, Brookhaven National Laboratory, Nov 1980.

APPENDIX A

**DESCRIPTION OF COST OF GEOTHERMAL
ELECTRIC ENERGY MODELS**

GRITS MODEL

GRITS: A Computer Program for the Economic Evaluation of Direct-use Applications of Geothermal Energy. Barron, W., and Kroll, P., the Johns Hopkins University, Applied Physics Lab., GEMS-008, QM-80-077, June, 1980, pp. 78.

Geothermal Resource Interactive Temporal Simulation (GRITS) is a computer model for the economic evaluation of direct-use applications of how to moderate temperature geothermal energy. It is primarily an accounting model designed to study the impacts of changes in specific resource and economic parameter values on economic accounting. Although it uses relatively detailed engineering formulas to determine the size and operational characteristics of major capital components, it does not include internal optimization routines for designing subsections of the utilization system to determine the minimum cost engineering solution for a particular application.

The GRITS model provides preliminary economic assessment of geothermal resources for direct-use in terms of several economic measures, including the discounted average cost, net present value, and annual cost and revenue streams. The model includes engineering simulation to allow the user to track the impact on the cost and revenue streams of changes in reservoir characteristics or the type of end-use. The user of the model defines a project by specifying values for a wide range of resource conditions (e.g., number of production and injection wells, well depth, fluid temperature, pumping requirements, maximum flow rate, demand conditions (e.g., user type, local weather conditions, rate of market penetration), and financial conditions (e.g., interest rate, inflation rate, project lifetime, cost of purchased energy).

The model contains two separate routines, one each for industrial process heating and community heating for residential/

commercial purposes. GRITS provides several economic measures, including the discounted average cost per million BTU's, the net present value of the system at the end of the project evaluation period (project lifetime), the year in which break-even occurs, the total capital cost of the system and others.

The total capital costs in the GRITS model are defined as the sum of the amortized outlays for initial system components, exclusive of replacement costs. Prices in the GRITS model may be specified in real (constant) or nominal dollars terms. The model uses a real discount rate (default value, or specified by the user) to reflect time preference, opportunity cost, risk, or a combination of these, rather than an after-tax weighted average cost of capital. Although GRITS includes internal cost formulas for major system components, the actual cost is calculated on the basis of user-specified values for size and design of each component.

The study concludes that its cost estimates of energy delivered by the system under default conditions are conservative. The model permits the user to specify values of parameters to reflect optimistic resource and operating conditions. The study concludes further that even under its conservative scenario, geothermal energy can be cost competitive with conventional fuels for a wide variety of conditions, especially for industrial users.

The GRITS program provides flexibility while keeping its operation simple and inexpensive. It may be accessed by using interactive terminals through the DEC-10 computer system. The user can specify a large number of parameter values or can utilize the default values to conduct extensive sensitivity analysis. The results of model runs can be displayed on a CRT terminal and also produced as a hard copy

output. Figure A-1 shows the structure and computation flow for the GRITS model. The input/output options available to the users of the GRITS model are shown in Exhibit A-1.

EXHIBIT A-1

INPUT/OUTPUT OPTIONS AVAILABLE TO THE USER OF GRITS

Option No.	Parameter
H	TYPES OUT THIS LIST OF POSSIBLE INPUTS
1	TYPES OUT THE CURRENT SCENARIO PARAMETERS
2	NAME OF FILE TO RECEIVE OUTPUT OF GRITS. THE FILE NAME MUST FOLLOW STANDARD DEC-1) CONVENTIONS.
3	RETURN TO THE DEFAULT SCENARIO
4	TYPE IN RUN NAME (up to 80 characters)
5	SELECT WHETHER THE MODEL IS FOR RESIDENTIAL-COMMERCIAL OR INDUSTRIAL SALES (residential-commercial is default)
6	RETYPE RESULTS OF MOST RECENT SCENARIO RUN
7	RUN THE CURRENT SCENARIO
8	GENERATE DATA FILE FOR TABULATION OR LATER PLOT GENERATION
9	END EXECUTION OF GRITS
10	AREA UNDER CONSIDERATION
	1 - ATLANTIC CITY, NJ
	2 - SALISBURY, MD
	3 - NORFOLK, VA
	4 - AREA CHOSEN BY USER (hourly weater data must then be input)
11	WATER TEMPERATURE AT WELLHEAD (°F)
12	AVERAGE DEPTH OF UPWELL (ft)
13	HOUSING TYPE, EITHER
	1 - SINGLE FAMILY SUBURBAN
	2 - SINGLE FAMILY DENSE
	3 - TOWNHOUSES
	4 - GARDEN APARTMENTS
	5 - HIGH-RISE MULTIFAMILY HOUSING
	6 - MIXED HOUSING
14	DESIGN TEMPERATURE OF SYSTEM (°F)
15	CAPITAL EQUIPMENT LIFE FOR:
	0 - ALL EQUIPMENT
	1 - WELLS
	2 - DISTRIBUTION SYSTEM
	3 - HEAT EXCHANGER
	4 - HOOKUP COSTS
	5 - IN-WELL PUMPS
	6 - PEAKING SYSTEM BOILER (fossil fuel)
16	ADJUSTMENT FACTOR FOR COST OF AVERAGE WELL
17	ADJUSTMENT FACTOR FOR COST OF HEAT EXCHANGER
18	COST PER HOOKUP (\$)
19	PERCENTAGE OF ULTIMATE NUMBER OF HOUSEHOLDS ON SYSTEM
20	PRICE OF ELECRTICITY (/kWh)
21	REJECT TEMPERATURE (°F)
22	PIPE COSTS FOR DISTRIBUTION SYSTEM (thousands of dollars/mile)
Option No.	Parameter
23	DEPTH OF AVERAGE REINJECTION WELL (ft)
24	STORAGE TANK CAPACITY (hours of flow)
25	INFLATION RATE---AVE. ANNUAL RATE FOR LIFE OF PROJECT (%)

- 26 WELL DRAWDOWN (%)
- 27 INTEREST RATE (%)
- 28 MINIMUM AMBIENT TEMPERATURE (°F)
- 29 FOSSIL FUEL PRICE (\$/million Btu)
- 30 BOILER COST (%/hundred thousand Btu/hour)
- 31 INDUSTRIAL UTILIZATION FACTOR (%)
- 32 MAXIMUM FLOW RATE OF WATER FROM AWUIFIER (gal/min)
- 33 LENGTH OF STUDY PERIOD* AND INTERVAL FOR COST CALCULATIONS (years)
- 34 ULTIMATE DENSITY OF HOUSEHOLDS ON GEOTHERMAL SYSTEM (%)
- 35 PERCENTAGE OF DISTRIBUTION SYSTEM INSTALLED EACH YEAR
- 36 SELLING PRICE OF SYSTEM ENERGY (\$/million Btu)
- 37 DISCOUNT RATE—TIME PREFERENCE ONLY (%)
- 38 TRANSPORT DISTANCE (miles)
- 39 TAXES
- 40 ECONOMIC ACCOUNTING METHOD
- 41 RESOURCE ASSESSMENT PERIOD AND COST
- 42 NUMBER OF PRODUCTION WELLS
- 43 NUMBER OF REINJECTION WELLS
- 44 OPERATION AND MAINTENANCE COSTS (% of capital equipment costs)
- 45 CHARACTERISTICS OF COMMERCIAL BUILDINGS
- 46 FLOOR AREA OF COMMERCIAL BUILDING TYPES (ft²/building)
- 47 HEAT REQUIREMENTS OF COMMERCIAL BLDG TYPES
 - 1 - SPACE HEAT (Btu/°F/ft²/day)
 - 2 - HOT WATER HEAT (Btu/ft²/day)
- 48 NUMBER OF COMMERCIAL BUILDINGS OF EACH TYPE
- 49 HOOKUP COST FOR COMMERCIAL BUILDINGS (\$/ hookup)
- 50 LENGTH OF DISTRIBUTION SYSTEM FOR COMMERCIAL BUILDINGS (miles)
- 51 RATE OF COMMERCIAL MARKET PENETRATION (%)

FIGURE A-1
MODEL STRUCTURE AND FLOW DIAGRAM FOR
GRITS MODEL

GEOCOST MODEL

GEOCOST is primarily an engineering feasibility model designed to determine the thermodynamic and engineering parameters of plant design. GEOCOST combines technical and economic factors into one systematic framework and has the flexibility to individually or collectively evaluate their economic impacts. It simulates production of electricity from most types of geothermal resources, and is composed of two major submodels: a reservoir model that simulates the costs associated with the discovery, development and operation of a geothermal resource; and a power plant model that calculates the costs associated with the design, construction and operation of the power plant.

The model is usable for electrical applications only. The model creates plan design and field development scenario and the associated cost accounts based on engineering, resource and financial assumptions. The important technical and economic parameters included in the determination of the cost of energy are wellhead temperature, well flow rate, capacity factor, well cost, plant size, well life and spacing, and discount rate. Competitive energy price levels and their escalation rates and inflation are not considered. The consequence of ignoring these important economic parameters is either underestimation or overestimation of the cost of energy. For example, failure to consider inflation could result in underestimating the price of energy by as much as 4.56%, whereas ignoring energy price escalation rate could lead to overestimating the price of energy by 7.12%.

Wellhead conditions of the geothermal fluid, power plant design and capacity, design or cost of the wells, and well field layout are input requirements of the program. The reservoir and the power plant models are linked through the fluid transmission and the power plant system submodels. These two submodels calculate total fluid flow requirements from the reservoir, number of wells required, pipe lengths and diameters, pumping requirements, the temperature and pressure drop between the reservoir and the power plant.

After determining total fluid flow, the cash flow for the reservoir, including the capital and operating costs of the power plant from exploration through the life of the plant is determined. The revenue to the reservoir is the energy supply expense to the power plant. The unit cost of energy is calculated based on the cash flow and energy supplied. The cash flow for the power plant consists of energy supply expense of the reservoir and capital and operating costs of the plant. From the power plant and cash flow, the required revenue and the unit cost of energy are determined which, on a present worth basis exactly offset all costs and expenses.

In the GEOCOST model, financial and tax structures are simulated by varying the rates of debt-equity ratios, rates of return on equity and debt, and tax rates. The cost of energy is calculated by using the discounted cash flow analysis which equates the present worth of the revenues and expenses over the economic life of the plant or reservoir. The program provides for incurring as well as retiring debt and equity in the same ratios. At the end of the project life, debt and equity are exactly repaid and the project earns a specified rate of return. Calculations are performed in constant dollars.

The study discusses the relative effects of different average well drilling costs, plant size, power cycles, wellhead temperature, well flow rate, capacity factor and others on generating cost of electricity.

Based on parametric analysis, the study concludes that the three principal determinants of geothermal energy costs for low salinity hydrothermal resources are: the wellhead temperature, the well flow rate, and the cost of wells (drilling and extraction). Other lesser important factors affecting geothermal power costs are replacement rate, well spacing and fluid composition.

The economic assumptions employed in the model are typical of a large oil company operating the reservoir and an investor-owned utility operating the power plant, and a composite state tax rate typical of Western States. The predicted cost expressed in 1974 dollars is 18.69 mills/kw hr.

The GEOCOST program provides the following outputs: comprehensive power plant systems, fluid transmission, reservoir and plant economic results; and a summary of the final geothermal energy cost and its breakdown into reservoir and plant component costs, including annual cash flow data for major expenses.

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

on the CYBER 74-18 computer with SCOPE 3.4.2 operating system. Figure A-2 shows the structure of the GEOCOST model.

The program contains default values for the input data which can be overridden by the user. It permits sensitivity analysis of parameters. Further, the program is designed in a modular fashion to enable the user to select only those subroutines required to simulate the type of geothermal plant in which he is interested: dry steam, flashed steam, separated steam, binary hybrid, or total flow.

The model is applicable only for electrical applications because the technical and economic data file of the GEOCOST program does not contain parameters that are pertinent to direct use applications. However, the model has the capability to create a plant design and field development scenario and the associated cost accounts based on engineering, resource characteristics and financial assumptions. Thus, even in the absence of detailed cost account data the model can provide an initial economic assessment of a proposed geothermal power plant.

The serious shortcoming of the GEOCOST model is that it fails to include competitive energy prices and their escalation rates, and inflation rate in its economic analysis, considering that profits are highly sensitive to these two factors. It can be seen from the sensitivity analysis of economic factors (presented earlier) that ignoring the rapidly increasing inflation will underestimate the levelized price of electricity; similarly, neglecting energy price escalation rate will overestimate the levelized price. In addition, calculations of cash flow items such as depreciation, taxes, depletion, debt

FIGURE A-2
STRUCTURE AND FLOW DIAGRAM FOR
GEOCOST MODEL

services, royalty and others will be in serious error when the economic analysis does not incorporate energy price escalation and inflation rates.

GEOCITY MODEL

Pacific Northwest Laboratories, (1) User Manual for GEOCITY: A Computer Model for District Heating, October 1978; and (2) The GEOCITY Model: Description and Application, June 1977.

The GEOCITY model is similar to GEOCOST model except that it is primarily designed for determining the engineering and economic feasibility of district heating using geothermal energy. It calculates the cost of district heating based on a limited amount of resource, engineering, population, heat demand of the city and financial data. The model optimizes system component designs, and calculates the capital and operating costs for the entire system, including production, distribution and disposal of the geothermal water.

The GEOCITY program includes an economic and technical data file consisting of design parameters, and economic and tax data. The user can utilize the default values or supply any desired changes in resource and economic parameters to analyze the sensitivity of the cost of energy. GEOCITY can simulate various financial and tax structures as well as private enterprise and municipal utility systems. Using discounted cash flow analysis, it calculates the required revenue and the unit cost of energy.

GEOCITY considers the important resource and economic factors, including wellhead temperature, flow rate, well cost, capacity factor, well life and spacing and discount rate. However, it ignores inflation, competitive energy prices and their escalation rates. The consequences of ignoring these economic parameters are overestimation or underestimation of the unit cost of energy and the expected profitability of a proposed project. For example, given the current rates of inflation and price escalation, the cost of energy projections provided by the model could be underestimated by as much

as 4.56% due to inflation and overestimated by as much as 7.12% due to energy price escalation. Further, expected profits as well as other cash flow items such as depreciation, depletion allowance, taxes, debt services and others will be in error, due to the fact that inflation and energy price escalation rates are not considered in the economic analysis.

GEOCITY is an offshoot of the GEOCOST model (described earlier) which calculates the cost of generating electricity from geothermal resources. GEOCITY consists of two major submodels: the reservoir model and the distribution system model. The reservoir model in GEOCITY is taken directly from GEOCOST. The reservoir model calculates the cost of energy by simulating the exploration, development and operation of a hydrothermal reservoir and the distribution of this energy to a distribution center. The distribution system model calculates the cost of heat by simulating the design, construction, and operation of the district heating distribution system. The distribution system model can simulate many designs of hot water heating systems, including various configurations of heat pumps and/or heat exchangers, different piping system design practices, and the use of different materials for pipe, insulation, and casing. The distribution model uses the climatic parameters to determine the distribution of the demand, peak demand, average demand, the load factor, and supplemental heat requirements.

Linkage between the reservoir and distribution system model is provided by the fluid transmission and distribution system demand submodels. These two submodels compute total fluid demand at wellhead conditions, number of wells required, pipe lengths and

diameters, pumping requirements, and the temperature and pressure loss between the reservoir and the distribution system.

Using discounted cash flow analysis, GEOCITY calculates the required revenue and the unit cost of energy by equating the present worth of the revenues to the present worth of all expenses including investment return over the economic life of the distribution system. The present worth factor is determined by the capital structure and rates of return on invested capital. GEOCITY can simulate various financial and tax structure (through varying the rates of return on debt and equity, debt-equity ratios, and tax rates) as well as private enterprise and municipal utility systems. Further, the financial structure and costs of capital can be the same or different in the reservoir and distribution system submodels.

The debt-equity ratios are held constant throughout the life of the project. The after-tax discount rate used in the analysis is determined from the capital structure, bond interest rate and the rate of return on equity. Plant capital costs, including capital replacements are recovered through the depreciation account. The model calculates the annual operating expenses for the reservoir, including royalty payments, taxes, overhead and management, well maintenance, maintenance costs for the transmission and disposal systems, and well redrilling costs. Each operating expense is assumed to be constant each year throughout the life of the facility.

GEOCITY is programmed in Fortran IV and is operational on the control Data Cyber 73 computer with Scope 3.4.4 Operating System. The source code of GEOCITY and the 1967 ASME Steam Tables used to calculate thermodynamic and physical properties of water are available from the Argonne Code Center on one reel of magnetic tape.

The tape recording mode is optional: 7-track, 556 BPI, even parity, and EBDIC code. It requires 16 seconds of CPU time for executing a case.

The GEOCITY Program includes an economic and technical data file consisting of design parameters and economic and tax data. The user can utilize the default values or supply any desired changes. It is designed only for distinct heating, and cannot be used for an analysis of geothermal electric applications. Also the model is capable of producing a whole design based on very limited engineering, resource and economic data. The structure and logic flow for the GEOCITY model is shown in Figure A-3.

FIGURE A-3
STRUCTURE AND FLOW DIAGRAM FOR
GEOCITY MODEL

GELCOM MODEL

The MITRE Corporation - GELCOM - A Geothermal Levelized Busbar Cost Model - January 1978.

GELCOM is an engineering/economic model designed to project costs of electricity from hydrothermal resources. It estimates the first-order capital and operating costs for the production field and electrical generating plant based on resource characteristics, engineering design and financial parameters. Using revenue requirement approach, it calculates the levelized busbar energy cost for geothermal power plants. The model computes the revenues required by the producer and the utility to cover all their costs and to make a reasonable profit. The interactive mode of the model makes provision for overriding the default value for parameters at the discretion of the user. The levelized price can be expressed in constant or current dollars.

The engineering/plant design segment of the model starts with resource characteristics data (e.g., temperature, well flow rate, well depth, etc.), and estimates the capital and operating costs for the production field and the power plant. Different resource temperatures, fluid activities and energy conversion cycles are combined into twelve generic plant designs grouped into two major categories, namely flash cycle steam plants and binary cycle plants. Estimates of well depth and rock hardness are the basis for computing the well cost.

The capital and operating cost data are used as input to the financial segment of the model. In conjunction with other financial data (e.g., depth equity ratio, cost of capital, tax rates, etc.), the capital and O&M costs are processed through the financial segment to compute the levelized busbar cost of electricity.

The calculations of the busbar cost of electricity take into account the effect of inflation and escalation of costs. The busbar cost estimate is based on conventional life cycle costing for the entire project.

The GELCOM model is capable of assessing the impact of reductions in capital and O&M costs (due to R&D and/or learning experience). The effect of changes in the economic/financial parameters can also be evaluated by exercising certain special features of this model. Since this model can be operated in the interactive mode, sensitivity analyses involving the busbar cost of geothermal electricity can be carried out very expeditiously.

Figure A-4 shows the structure and logic flow for the GELCOM model.

FIGURE A-4
STRUCTURE AND FLOW DIAGRAM FOR
GELCOM MODEL

GCF MODEL

The MITRE Corporation: Geothermal Loan Guaranty Cash Flow Model
(GCFM) - 1981

GCFM is a cash flow model designed to estimate geothermal production field and power plant costs, year-by-year cash flow patterns, and levelized breakeven prices for either geothermal fluid or electricity. It can also estimate the detailed costs of components for either the field development or geothermal electrical plant or both during construction and operation. It does not contain provisions for estimating the costs of geothermal direct heat applications.

GCFM has three major segments: power plant, field, and financial modules. The power plant and field modules are cost estimation routines designed to determine investment and operating costs based on several sets of data such as: resource characteristics, engineering design, operation criteria, and required expenditure schedules. By utilizing these cost estimates, the financial modules perform calculations to determine the year-by-year cash flow as well as a levelized busbar cost of electricity or a levelized price for geothermal fluid. The model makes provisions inside the costing routines to supply many default values where critical values are not provided by the user. Figure A-5 shows the linkages between various modules.

An auxiliary program called the Power Plant Cycle Design Routine is an integral part of the power plant module. It calculates the reservoir flow requirements and provides the first-order capital cost estimates for the plant and replacement components. Four different generic power plant designs - dry steam, single stage flash, dual

FIGURE A-5

STRUCTURE AND FLOW DIAGRAM FOR
GCFM MODEL

stage flash, and Isobutane/Brine Binary - are handled by the cycle design routine. The model uses the GEOCOST estimating equations (Battelle, PNL) to calculate the power plant equipment costs.

However, the field module calculates default values for costs, well flows, and other parameters - directly from the resource characteristics - based on MITRE's GELCOM model.

The financial module performs life cycle costing calculations based on the series of capital expenditures and operating costs created by either the power plant module or the field design module. It combines several financial parameters - cost of borrowed money, taxes, required return on equity, escalation rates, investment tax credit, depletion allowances, etc. - to estimate the levelized price of electricity necessary to meet the revenue requirements of the project. It also calculates net present value and the internal rate of return (profit) for the project. The model also calculates the profitability of a project by generating the revenue stream from a given market price.

The distinction between the power plant and field modules made in the model makes it easier to use the results of the model in evaluating a loan guaranty proposal submitted for either a geothermal field or plant development.

The model does not require a complete set of cost accounts for the plant and field. An abbreviated set of data is the only requirement. In fact, even where the plant cost data are not available, the model generates requisite cost accounts based on resource data. The model includes storage capacity for 10 plant designs, 10 field designs and 15 financial cases. This flexibility permits the model to analyze multiple projects against a set of financial cases. One

of the most important features of the model is the provision of default values for important variables used in project design and/or costing. The estimates of the default values are based on existing or reference data available in the literature concerning geothermal electric projects. It provides for the option of determining levelized prices in either constant or current dollars.

GCFM is a FORTRAN code which designs and costs geothermal field and electric power plants. It is a fully interactive model which allows the user to estimate costs and perform life-cycle costing on selected geothermal projects. The interactive capability allows the user to display or change data in any of a number of power plant projects, field projects, or financial cases and enables the user to utilize the program for checking the sensitivity of cash flow patterns and the cost of energy to changes in various parameters.

GCFM requires a real or virtual core memory size of 750,000 words. It contains options to produce output of many values of intermediate calculations. The model has been tested and refined to insure the least error frequency in operating the computer program. The model can be run on an IBM 370 VMS system, or on a Hewlett-Packard 3000 series 3.

VENVAL MODEL

VENVAL is a financial cash flow tool aimed at the evaluation of proposed private sector business investments. It requires a complete set of cost accounts together with a schedule of their occurrence and a complete set of parameters applicable to a specific venture for exercising the model.

VENVAL looks at a year-by-year cash flow: it calculates revenues and derives depreciation, depletion allowance, taxes and tax credits. It provides figures of merit for project evaluation, including net cash flow, net present value and internal rate of return. Its capabilities include sensitivity and risk analyses.

VENVAL is easily usable for evaluating ventures involving geothermal reservoirs, electrical power plants, and direct heat applications. It does consider all the important financial variables identified in our analysis.

The greatest shortcoming of VENVAL is that in the absence of detailed cost account data, it would not be usable. It does not have the capability to generate a system design or cost accounts from a limited set of resource and cost data.

Since VENVAL is a proprietary model, it is not possible to provide a detailed description of its important features. A logic flow diagram from the model is presented in Figure A-6.

FIGURE A-6
STRUCTURE AND FLOW DIAGRAM FOR
VENVAL

GCP MODEL

Orren, L. H., et. al. - The Geothermal Probabilistic Cost Model (GPCM) - Jet Propulsion Laboratory, Feb. 1981.

GPCM evaluates the economics of geothermal projects whose costs are affected by uncertainties in project duration and physical parameters. The model is applicable to any venture provided a complete set of cost data and probability density functions for the uncertain physical and time variables are available. Further, there is need to have the engineering scaling equations to adjust the cost accounts for different values of the uncertain physical variables.

The cash flow model uses a revenue required approach to derive the project costs and all costs are aggregated into a net present value figure. It does not show yearly cash flows. It presents the probability distributions of the net present value of expected profit. It solves for the internal rate of return for the project.

The model contains five sets of data: financial variables, technical description, costs by stage of development, revenue and probabilistic assumptions. Financial variables include energy price, energy price escalation, general inflation, discount rate, the required after tax rate of return on capital invested, royalty rate, federal tax rate, state tax rate, local tax rate, ITC, depletion allowance, and depreciation method.

Technical description data include: the number of production and injection wells, well depth, diameter, flow per well, total flow to plant, well lifetime, cost estimate of wells, capacity factor, power production (gross and net).

Cost accounts are divided into 4 stages of reservoir development: resource proving, permit process, developing the resource, and operating the reservoir.

Revenue to the reservoir is based on the gross output of the generating plant during stage IV (operating the reservoir). Probabilistic assumptions include probability distributions for uncertain time and physical variables, e.g., length of stages, well flow rate, etc.

The model presents expected profits (in 1980 \$) and its standard deviation. It permits sensitivity analysis on the base case set of data such as energy price, discount rate, capacity factor, investment tax credit, energy price escalation, general price escalation, and well life.

The model can be applied to the development of the reservoir for the production of steam as well as the construction of a power plant for the generation of electricity.

The model estimates that 60% of the cost of electricity from a geothermal facility is attributable to the production of steam, 30% is due to the initial power plant cost and 10% is accounted for by the annual expenses related to the power plant.

GPCM was used to evaluate the economics of a geothermal reservoir at Heber, California which was to provide geothermal fluid to power a 45 MW (net) binary-cycle electric generating plant. The study concludes that the reservoir portion of the Heber Geothermal Project does appear to be economically profitable though the degree of profitability is very sensitive to certain key parameters.

The study presents results for a Base Case Scenario and Reference Scenario and all other scenarios. The Reference Scenario is the most likely developmental pattern or the baseline case from which all the scenarios are derived. Cost accounts are input into the program for only this Reference Scenario. For all other scenarios, only

their stage times, physical parameters (e.g., well flow rates, reservoir depth, fluid temperatures, permitting and construction times), and the associated probabilities are input; their cost accounts are derived within the program by modifying the appropriate reference scenario cost accounts for any differences in the length of the stages or for any differences in the values of the physical parameters.

The flow of logic and data in the GPC model is shown in Figure A-7.

FIGURE A-7
STRUCTURE AND FLOW DIAGRAM FOR
GEOTHERMAL PROBABILISTIC COST MODEL

BTHERM MODEL

New Mexico Energy Institute, Geothermal Energy for Residential,
Commercial Industrial Users: A Computer Simulation Model
BTHERM, 12/79; and Geothermal Potential Direct Use: Rocky
Mountain Basin Range, 4/80.

BTHERM is an engineering/economic model designed to evaluate the economic feasibility of low to moderate temperature geothermal resources for direct applications - district space heating, domestic and commercial water heating, and industrial process heat. It provides a framework for assessing the effects of policy and economic variables on geothermal direct-use development. The model determines whether or not a geothermal application is/or potentially could be economic, and if so, when (what year) the geothermal energy could be price competitive for a specific application.

The major input requirements of the model are: heat demand at a specific location, engineering parameters and costs required to meet heating needs, geophysical characteristics of the geothermal anomaly, and financial and policy variables. The model possesses the ability to analyze the economic impacts of changes a variety of these engineering, geological, and financial parametric inputs. (The model is capable of considering the impact of the price and price growth rate of conventional energy.)

The model's primary output is the estimated levelized price per MMBTU of delivered energy for a given resource and application. Additional outputs include: nominal or discounted investment necessary for obtaining the levelized geothermal price; cost-benefit analysis of federal and state taxes and royalties, consumer savings in comparison with the cost of conventional energy; breakeven year for the project; and estimated costs by investment categories.

BETHERM uses a discounted cash flow analysis to evaluate the cost of heat energy required for a specific application, the investments and operating expenses required to supply that heat, and the revenues required for the developer to meet his cost of capital and a guaranteed rate of return for each year of the investment life of a geothermal anomaly. The model calculates the price of geothermal energy which equates the present worth of net revenues to the present worth of the investment.

The model contains separate routines for (1) a private developer of an existing development, (2) a private developer for only new development, and (3) a city-owned utility, which can examine existing energy consumers, or new growth. The model can estimate cost or price differential to show the effects of state, federal, or other grants. BETHERM permits sensitivity analysis for examining the possible price deviation over some range of a single variable such as flow rate, rate of return, temperature, etc. The price elasticity can also be analyzed when two separate variables are varied simultaneously. Figure A-8 shows the flow of data and sequence of computations through the BETHERM model.

The Rocky Mountain Basin and Range report presents the preliminary findings of the geothermal direct use potential for high intensity energy users in the ten Intermountain states. According to the analysis, a total of 399 potential users could provide as much as 0.27 quads per year of geothermal energy on-line by the year 1990 in price competition with the lowest cost form of alternative available to these users. It provides the results of four policy cases to illustrate the effect of governmental initiatives on the acceleration or slow down of geothermal development.

FIGURE A-8
STRUCTURE AND FLOW DIAGRAM FOR
BTHERM SIMULATION MODEL

The B THERM computer simulation model is in daily use performing parametric analysis of policy variables for specific sites in ten Intermountain States. Unlike the elaborate engineering feasibility models for district space heating, such as the GEOCITY³ and the Generic District Heating Model,¹⁰ the B THERM is a more funtional model which considers a broad spectrum of potential district heat applications (residential, commercial, and industrial process heat, singly or in combination).

GIPA MODEL

Technecon Analytic Research, Inc., Geothermal Investment and Policy Analysis with Evaluation of California and Utah Resource Areas.

The focus of this study is to stimulate the investment behavior of resource producers or well field developers at specific hydrothermal resource areas, and to evaluate resource commercialization potential for nine known geothermal resource areas in California and Utah. A hydrothermal financial analysis model called TCW2000 is used to estimate four financial attributes: rate of return, payback period, net present value of profits, and the amount of capital exposed to risk. The model uses site-specific parameters to simulate well field development and all cash flows associated with well field exploration, confirmation, development and production of geothermal fluid for electric power generation.

To accommodate uncertainties in available resource data, nine site variables (wellhead temperature, well flow rate, dry well fraction, well life, resource depth, well cost, plant capacity factor, plant cost and piping cost) are either supplied to the model or estimated by the model, in the form of site-specific probability distributions.

The financial analysis model requires as many as 75 input variables to define the geologic, economic and financial parameters of a well field development opportunity. The model simulates the requirements for active producing wells, spare wells, injection wells, redrilled wells and dry wells over the life of a project. It generates cash flows for book and tax capital, book and tax expenses, royalties, depreciation, revenues, depletion, ad valorem taxes, and income taxes. The cash flow analysis is performed probabilistically

and provides estimates for: internal rate of return on invested capital, net present value of profits, discounted payback period and the amount of capital exposed to risk. The computation flow through the GIPA model is depicted in Figure A-9.

The study estimates a marginally competitive geothermal resource price by subtracting the costs associated with a geothermal power plant and transmission facilities from the delivered electric energy cost of the competing alternative. This competitive geothermal price is used as the basis for estimating well field revenues. It does not consider electric utilities' decision to include geothermal power in their generation mix. The marginally competitive resource prices vary significantly depending on geographic location and resource quality. The study presents site by site estimates of the marginally competitive price for Utah and California regions.

The model's analytic capabilities include sensitivity analysis of the effects of joint venture arrangements, resource pricing variations, tax deductible intangible expenses, investment tax and energy tax credits, depletion allowance, and loan guarantees. To determine the sensitivity of the investment decision to the resource price, investment probabilities are estimated for a selling price equivalent to 80, 100 and 120 percent of the marginally competitive resource price.

For each KGRA in Utah and California states (economic, financial, tax, and resource), the study presents site specific input parameters, model results, a summary of geothermal development to date, and the confidence levels in available data. The model's financial results including rate of return, payback period, net

A-47

FIGURE A-9
STRUCTURE AND FLOW DIAGRAM FOR
GIPA MODEL

present value and loss of investment probability in each KGRA are presented separately for Corporate producers and independently operating producers.

BNL-DH MODEL

Reisman, A., and Karkheck, J., District Heating Model: An Overview. Brookhaven National Laboratory, December, 1980 (U.S. DOE Contract Number DE-AC02-76Ch00016).

The District Heating Model (DHM) developed by the Brookhaven National Laboratory is designed to assess the economic feasibility of district heating for any community in the U.S. DHM can provide estimates of the potential for district heating and the cost of district heating at the national as well as individual community levels by using built-in site-specific data bases (census data, county level data, engineering data and geothermal resource data). The model encompasses life cycle costing and includes an overall optimization of system design.

DHM consists of four submodels - Heat Demand, Heat Source, District Heating System and Market Analysis - each of which serves a distinct function in the analysis of district heating. The linkages between these submodels are shown in Figure A-10.

The Heat Demand submodel, using existing U.S. census data bases, estimates the heat load and fuel use for residential and/or commercial buildings at the geographic level of disaggregation of the census tract or minor civil divisions. The Heat Source submodel characterizes and estimates the cost of the equipment which provides hot water (geothermal low to medium temperature) to the district heating transmission and delivery system; it calculates the optimal fraction of the total heat to be supplied by the geothermal fluid as well as the rest of the peaking heat demand to be provided by the (back-up) oil-fired boilers. The optimization is achieved by minimizing total production and heat delivery costs. The average heat production cost is obtained as a weighted average of the costs for the

FIGURE A-10

STRUCTURE AND FLOW DIAGRAM FOR
BNL DISTRICT HEATING MODEL

geothermal resource produced heat and boiler produced heat. The optimum system size (minimum average cost) is determined as a function of conventional fuel prices, retrofit costs, the level of taxes on district heat, and the price structure of district heat across various customer classes.

The District Heating System submodel optimizes the district heating transmission and distribution piping system; it specifies the optimal flow velocity of hot water for the system peak heating demand by providing an inventory of pipe diameters and lengths for each heating zone based on the least cost system configuration.

The Market Analysis submodel uses life cycle costing techniques to calculate a levelized cost (MMBTU) for providing district heat. The model can be run under a variety of user assumptions with respect to market conditions and economic parameters.

By utilizing the built-in data bases, the DEM model can provide quick estimates of important parameters including disaggregated residential load, commercial heat load, a pipe inventory at various diameters and associated cost, the power requirements and capital and O&M costs for the primary heat source (geothermal water) and for peakers, the optimal number of geothermal wells and the estimated field lifetime. The model also provides estimates of best, worst, and expected cases by varying key input parameters. It permits sensitivity analysis of the cost of district heat to a number of key parameters, such as alternate heat sources, pipe materials, retrofit options, ownership, construction schedules, financing schemes, etc.

Based on an economic analysis of district heating systems for Salt Lake city, Utah, the study concludes that geothermal district heating could not compete with the December, 1978, residential

natural gas price \$1.71 per million BTU; however, with the expected increase (real) in the price of natural gas, district heating will be competitive in 1990. The breakdown of the sales price for district heat in terms of system costs is as follows: distribution and convection liner (41%), well development (22%), peaker fuel and electricity (14%), transmission line (10%), peaking and storage facilities (8%), and administration and maintenance (5%).

According to the study, the factors which would improve the economic attractiveness of geothermal district heating, in decreasing order of importance are: location of system in areas currently using oil or electricity; higher price of natural gas; larger heat demand density; lower geothermal production cost; optimal scheduling of construction; use of interruptable gas for peakers; tax relief to consumers; and fast write-off of wells. On the other hand, those factors which would reduce the attractiveness of geothermal district heating are, in roughly decreasing order of importance: continuation of low price for natural gas; higher interest rates; higher building retrofit costs; and shorter payback periods.

APPENDIX B

WELL COST ESTIMATION EQUATION

WELL COST ESTIMATION EQUATION

Equation 1

$$C = 10^{K+D/17140*}$$

C = well cost in 1976 \$/ft

K = 1.6 for hard rock
1.2 for soft rock

$$C_s = C_H \times .3981 \quad (S = \text{soft rock})$$

$$C_H = C_s \times 2.5118 \quad (H = \text{hard rock})$$

DEPTH (ST)	WELL COST (1976 \$)		ELASTICITY OF WELL COST		
	HARD ROCK (igneous)	SOFT ROCK (sedimentary)	$\frac{\% \Delta Y}{\% \Delta X}$		
X	Y	Y	Z	Z	Z
1000	45,534.	18,127	2.288	1.176	1.186
2000	104,162	41,468	2.288	1.176	
3000	178,707	71,144	1.716	1.318	
4000	272,534	108,498	1.525	1.339	
5000	389,646	155,121	1.430	1.592	
6000	534,800	212,908	1.373	1.727	1.779
7000	713,638	284,104	1.334	1.862	
8000	932,803	371,356	1.307	1.997	
9000	1,200,335	477,862	1.287	2.132	
10,000	1,525,457	607,295	1.271	2.266	
					1.514

* This equation is taken from Milora, S.L., and Tesker, J.W. Geothermal Energy as a Source of Electric Power: Thermodynamic and Economic Design Criteria, MIT Press, 1976.

Equation 2

$$CW = .245 + .0044d^2$$

$$.378 + .0211d^2$$

Soft Rock

Igneous Rock

d = 1,000 ft.

c = cost of well in millions of \$

Well Depth (ft)	Well Cost (\$) 1980		Elasticity of well cost	
	Hard rock	Soft rock	Hard rock	Soft rock
1,000	399,100	249,400	.220	.077
2,000	462,400	262,600	.512	.201
3,000	567,900	284,600	.806	.359
4,000	715,600	315,400	1.054	.532
5,000	905,500	355,000	1.250	.702
6,000	1,136,600	403,400	1.399	.861
7,000	1,411,900	460,600	1.512	1.003
8,000	1,728,400	526,600	1.598	1.127
9,000	2,087,100	601,400	1.665	1.123
10,000	2,488,000	685,000		

Technecon

Equation 3

$$C_H = 2.887 D^{1.496}$$

D = depth in ft.

Geef

$$C_S = 102.8 D^{1.035}$$

C = cost in \$

Depth Ft.	Cost of well in 1980 \$		Elasticity of well cost	
	Hard rock	Soft rock	Hard rock	Soft rock
10,000	88,807	130,916	1.430	1.032
2,000	250,488	268,262	1.472	1.034
3,000	459,431	408,144	1.483	1.035
6,000	706,527	549,699	1.488	1.035
5,000	986,520	692,512	1.491	1.035
6,000	1,295,869	836,335	1.492	1.035
7,000	1,631,975	981,001	1.493	1.035
8,000	1,992,826	1,126,397	1.494	1.035
9,000	2,376,805	1,272,431	1,495	1.035
10,000	2,782,574	1,419,036		

The cost of well increases by 2.82059 time and 2.049115 time for every doubling of the depth in feet for hard rock and soft rock respectively.