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**GEOHERMAL WELL FIELD AND POWER PLANT
INVESTMENT DECISION ANALYSIS**

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ABSTRACT

As part of its on-going program for accelerating the development of geothermal resources, the U.S. Department of Energy/Division of Geothermal Energy sponsored this analysis of investment decisions pertaining to hydrothermal well fields and electric power plants. This investment behavior reflects a degree of sensitivity to: (a) public policy alternatives concerning taxation and regulation of the resource and its energy conversion facilities; and (b) federally funded research, development and demonstration. The purpose of the current analysis is twofold. First, it provides a realistic and statistically sound means for estimating the impacts of policy and program alternatives on likely industry investment decisions. Second, it provides a reliable instrument for assessing the commercially viable hydrothermal energy potential in the United States.

In approaching the expressed objectives, Technecon has developed geothermal investment decision models which, when coupled to a site-specific stochastic cash flow model, estimate the conditional probability of a positive decision to invest in the development of geothermal resource areas. Quantitative decision models have been developed for each major category of investor currently involved in the hydrothermal projects. These categories include: large, diversified energy resource corporations; independently operating resource firms; investor-owned electric utilities; municipal electric utilities; state-run resource agencies; and private third-party power plant investors.

This report describes the geothermal cash flow, the investment decision analysis, and an example of model application for assessing the likely development of geothermal resource areas. The sensitivity of this investment behavior to federal incentives and research goals is also analyzed and discussed.

PREFACE

In October 1979, Technecon published a report, Geothermal Investment and Policy Analysis With Evaluation of California and Utah Resource Areas, which provided an account of research into the investment practices of geothermal resource developers. The report described a quantitative decision model which estimates the numerical likelihood of well field investments for developing specified hydrothermal resource discoveries. Underlying the decision model was a qualified assumption that an electric utility would construct a hydrothermal power plant and purchase steam from the well field if this steam was priced such that electric power produced from it was economically competitive with conventional baseload generation.

This report carries our geothermal investment analysis a step further. It provides an account of research into the investment practices of electric utilities and specifically addresses the earlier assumption of a utility's generation choice. This report describes a quantitative decision model which estimates the numerical likelihood of hydrothermal power plant investments at specified resource discoveries. Coupled with the above mentioned resource developers' decision model from our earlier work, the product is an instrument for program and policy analysis that estimates the joint likelihood of well field investment by a resource developer and power plant investment by an electric utility.

This report may be viewed as an updated and expanded second edition of the October 1979 report. We have revised much of the cost and performance data in the earlier cash flow discussions and we have added sections pertaining to the power plant investment decisions. Sections pertaining to the well field investment decisions remain intact, with some updating, from the first edition. The report is organized as follows:

- o Chapter One summarizes the project, its methods, results and on-going investigations.

- o Chapter Two discusses the development of a stochastic cash flow model which accounts for probabilistic resource and plant performance data in its evaluation of the financial attributes and risks of a geothermal venture. Methods for competitively pricing a geothermal resource are also discussed.
- o Chapter Three discusses the concerns of decision makers within the resource industry and the methodology for incorporating these concerns into a model which estimates the likelihood of favorable well field investment decisions. Decisions by diversified energy corporations and by independently operated firms are modeled separately.
- o Chapter Four discusses the concerns of decision makers within the electric power industry and the methodology for incorporating these concerns into a model which estimates the likelihood of favorable power plant investment decisions. Decisions by investor-owned electric utilities, tax-exempt bond financed electric utilities, and third party financiers are modeled separately.
- o Chapter Five discusses the concerns of potential third party investors.
- o Chapter Six addresses the issue of joint investment decision modeling of both resource developer and power plant owner/operator.
- o Chapter Seven presents an application of the investment models for site-specific resource assessment and for evaluation of federal program and policy alternatives.

Throughout these investigations, a generous degree of cooperation and participation by the resource and electric power industries has been received. Many hours of management interviews and a high response rate to quantitative surveys were contributed during the course of this work. The decision models which evolved from analysis of the industry's responses take the form of weighted functions of multiple investment criteria. Some of these criteria were explicitly discussed in management interviews while others were implicit but, nonetheless, found to be important variables for explaining industry investment behavior.

The decision models represent a new approach to investment analysis; however, their components and the collective influence of these components upon company decisions should be familiar and apparent to individuals within industry. Of primary importance are the models' abilities to reproduce or estimate industry investment decisions at acceptable levels of confidence. This capability is of significant value, particularly to program and policy analysts involved in the

structuring of responsible incentive and research strategies for supporting the development of geothermal resources.

This work is sponsored and managed by Dr. Fred Abel of the U.S. Department of Energy, Division of Geothermal Energy. Throughout the project, Dr. Abel, Mr. Randall Stephens and Dr. John Salisbury provided valuable support and constructive comments. Personal interviews and information were provided by no fewer than eighty individuals during the course of this work. These industry participants -- who are too numerous to acknowledge here -- represented twenty resource firms, thirteen electric utilities, and several banks, investment firms and government agencies. Their contributions of both time and effort are largely responsible for the results provided in this report. Last, though by no means least, the authors acknowledge Mrs. Norma Crouse and Gloria Phelan for their patient and very capable assistance in the production of this report.

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Chapter One

INTRODUCTION AND SUMMARY

1.1 BACKGROUND AND PURPOSE

In the mid-1950's, the pioneering efforts of B.C. McCabe and his partners in Magma Power Company produced the first commercial steam well at The Geysers in northern California. Today -- following joint development by energy resource companies and electric utilities (see Figure 1-1) -- natural steam from the Geysers supports the world's largest geothermal power complex. Geothermal electric power currently supplies a significant fraction of the generation load in northern California at costs which are competitive with any fossil-fueled or nuclear alternative.

The technological and economic success at The Geysers, coupled with today's domestic concern for energy alternatives, have contributed to a rapidly expanding and active national interest in geothermal energy. A hydrothermal¹ resource base capable of supporting several thousands of megawatts of generation capacity has been identified in the United States and its development is progressing, albeit cautiously, at many areas. The rate and extent to which this resource base is developed will depend upon the rate and extent to which industry will invest capital into hydrothermal well field development and power plant

¹Geothermal resources, as the name implies, originate from heat within the earth. When a geologic anomaly brings this heat to within a few miles of the earth's surface, it may be tapped by present well drilling technology. This report deals with one type of geothermal resource, namely hydrothermal energy, which occurs when such an anomaly and a natural aquifer coexist--the result being a subterranean reservoir of steam and/or hot water. Other types of geothermal resources, which are not as near term commercially as the hydrothermal resources, include geopressed reservoirs in which the water in deep, high pressure hydrothermal reservoirs is saturated with methane gas, and hot dry rock resources which, as the name implies, have no aquifer. See Muffler (1979).

Figure 1-1. DEVELOPMENT AT THE GEYSERS GEOTHERMAL AREA

construction. The understanding and estimation of this investment behavior, and of incentives which will prompt positive industry response, are the topics of this report.

The purposes of this work are twofold:

- o To provide a means for making probabilistic estimates of the commercial potential and rate of development of hydrothermal power in the United States.
- o To provide a means for evaluating the comparative effectiveness of alternative Federal policies and program strategies in a rational and objective manner.

These objectives are met by quantitative decision models that forecast capital investments in specified hydrothermal ventures. These decision models estimate the likelihood of a positive investment decision as a function of a few key attributes of the investment opportunity. The attributes (e.g. rate of return, cost of energy, risk of loss, etc.) were selected by modern econometric techniques for their ability to efficiently explain industrial investment behavior. Statistical soundness has been demonstrated by: (a) standard tests of significance applied to the econometric regression analysis; (b) correlation of model estimates with historical data on hydrothermal power development in the United States; and (c) comparison of model estimates with forecasts published by industry organizations.

Modeling efficiency is crucial to achieving the purposes of this work. Resource assessment and policy analysis on a national level require the processing of a great number of known and projected resource sites through the decision model. Therefore the selection of a limited number of investment attributes, and the structuring of efficient computer models to both estimate and act upon these attributes, are important concerns for providing a cost-effective analytic instrument.

In this regard, the objective here is to efficiently estimate the outcome of an industrial investment decision based upon an investment analysis that is considerably less rigorous than that employed in the actual industrial decision process. Whereas the industrial

decision-maker considers a multitude of attributes when weighing the risks and returns of an investment opportunity, it is possible to predict the numerical likelihood of a positive decision --within an acceptable confidence interval -- by employing econometric methods that require significantly fewer investment attributes in a somewhat less rigorous analysis.

1.2 OVERVIEW

The large scale commercialization of geothermal electric power depends upon joint positive investment decisions by (a) resource companies to develop well fields and (b) electric utilities to construct on-site power plants and transmission facilities. Figure 1-2 illustrates the model structure for estimating the likelihood of these joint investment decisions. Following is a summary of the model which discusses the sequence of computerized operations progressing from left to right through the schematic diagram.

Resource characteristics are provided exogenously to two detailed cash flow programs. One program simulates the life of a well field project while the other program simulates the life of a hydrothermal power plant. The two cash flow programs are executed probabilistically to account for uncertainties and risk perceptions which are inherent to many geothermal ventures. Eight stochastic variables within the cash flow (i.e. distributions of resource temperature, well flow, well cost, well life, dry well fraction, reservoir size, reservoir life and plant availability) vary over time as a function of on-site production experience, number of wells drilled and acreage in production.

Results from the well field and power plant cash flow simulations are then provided to the respective decision models of the resource developer and of the electric utility. The decision models analytically compare the geothermal investments to alternative investment opportunities available to each type of firm. From the resource developers' point of view, comparisons are made in terms of rate of return, duration of investment exposure, project size, amount of capital

Figure 1-2. HYDROTHERMAL POWER FORECAST MODEL

at risk, and the probability of project failure. From the electric utilities' point of view, comparisons are made in terms of: electric energy production cost (mills/kWh) delivered to a main transmission corridor, plant availability, net plant output, and risk to corporate or municipal bond rating.

Using decision modeling techniques which integrate multiattribute utility analysis and logit choice estimation, the two decision models provide estimates of the numerical likelihood of investment in a specified hydrothermal opportunity by resource developers and by electric utilities, respectively. These models reproduce investment preferences as expressed by the respective firms in executive interviews and in demonstrated field practice.

Resource selling price is the negotiable variable which couples the well field cash flow and the power plant cash flow. A high price improves investment returns to the resource developer and generally increases his likelihood of investment. Meanwhile, this high price raises the production cost (mills/kWh) of hydrothermal electric energy and generally decreases the electric utility's likelihood of investment. Technecon's computer-based simulation of resource price negotiation uses an iterative technique to converge on a price which maximizes the joint likelihood of investment ($P_D \cdot P_U$ in Figure 1-2) by both parties.

Although the investment analysis methodology discussed in this report is necessarily abbreviated from that used in the actual industrial decision process, many elements of analysis are common to both approaches. In particular, the cash flow elements for both the well field and the power plant have been developed in considerable detail from industry sources and empirical field data. The accounting methods incorporated into the cash flow analyses are likewise derived from accepted practices in the resource and electric utility industries.

To accommodate uncertainties in several key resource and power plant parameters, the parameters are introduced to the cash flow in the form of site-specific probability distributions. These distributions are time dependent in the model to reflect increased knowledge gained by

production experience at each resource site. Characteristics of the distributions and of their respective time dependencies were estimated from both empirical data and consultation with hydrothermal geologists, hydrologists and reservoir engineers.

The stochastic cash flow models for well field and power plant projects provide probabilistic estimates of the selected investment attributes required by the decision models. Acting upon these selected attributes, the decision models in turn provide an estimate of the joint likelihood of positive investment decisions for the well field and the power plant. Modern techniques of "multiattribute utility analysis" and "logit analysis of probabilistic choice" are employed in the decision models. The decision models are based upon systematic regressions of data obtained from two years of extensive interviews and surveys of decision-makers within the resource industry, electric utility industry, and financial community. Investment decisions may be separately evaluated for: major diversified resource corporations; independently operating resource companies; investor-owned electric utilities; tax-exempt bond financed electric utilities, cooperatives and agencies; and third party power plant financiers.

The likely effects of alternative policies and R&D programs are evaluated by adjusting the cash flow models to accommodate estimated changes in tax, cost, performance and other impacted parameters. Known and projected hydrothermal resource sites² are then sequentially processed through the model and the effects of these adjustments are evaluated for their influence on joint well field/power plant investment decisions at the several sites. The product is a rational and objective analysis of alternative program and policy strategies.

²On-going work at Technicon as this report is being published is developing a hydrothermal exploration model which will include the capability to stochastically estimate the timing and quality of hydrothermal resource discoveries. At present, discovery projections are performed exogenously.

1.3 APPLICATIONS AND RESULTS

The quantitative methods discussed in this report have, to date, been applied in the following analyses:

- o Assessment of nine Known Geothermal Resource Areas (KGRA's) in California and Utah³;
- o Evaluation of the likely effect of the National Energy Act of 1978, the Geothermal Loan Guarantee Program and proposed incentives including³:
 - Maintaining 22% depletion allowances
 - Additional investment tax credits
 - Energy production tax credits;
- o Evaluation of investment tax credits for both well field and power plant capital and of forgivable loans for exploratory drilling⁴;
- o Analysis of the incentive to resource developers offered by district heating and industrial process heat ventures⁵;
- o Estimation of the rate of development of hydrothermal electric power in the United States with and without federal support⁶.

Results from the last analysis listed above are summarized in this section following a brief summary of Chapter 7 which provides a study of two KGRA's: Roosevelt Hot Springs in Utah and East Mesa in southern California.

1.3.1 Developmental Estimates: Roosevelt Hot Springs and East Mesa

Roosevelt Hot Springs in southwestern Utah and East Mesa in southern California are two dissimilar Known Geothermal Resource Areas offering different levels of investment incentive. Both are confirmed hydrothermal resources and both are in the early stages of commercial development. A 20 MWe power plant is scheduled to be on-line at Roosevelt in 1982. An 11 MWe pilot plant is presently installed at East

³see Cassel, et al. (1979)

⁴see Cassel (1979)

⁵see Cassel and Amundsen (1980)

⁶see U.S. Department of Energy (1980)

Mesa. The USGS estimates the electric power potential at Roosevelt to be 970 MWe and that at East Mesa to be 360 MWe (see Muffler, 1979).

Both resources are relatively "clean" in terms of dissolved solids content; however, in terms of reservoir temperature and well flow rate -- two parameters which greatly influence resource economics -- the two sites are significantly dissimilar. Available data indicates that Roosevelt is a high quality resource with both high reservoir temperatures and high well flow rates. Resources of this quality are rare occurrences. In contrast, East Mesa is more typical of the known resources which have electric power producing potential. The resource temperature at East Mesa is about 100F lower than that at Roosevelt and well flow rates are reportedly about half those at Roosevelt.

As described in Chapter 7, the joint investment behavior of resource developers and investor-owned electric utilities was forecasted at Roosevelt Hot Springs and East Mesa. The investment decision models were executed twice for each resource: first, with continuing Federal support (at or above FY 1980 levels) through policy incentives and R&D program benefits and, second, without these policy and program benefits. Figures 1-3 and 1-4 illustrate the resulting power development estimates at Roosevelt Hot Springs with and without Federal support, respectively. Figures 1-5 and 1-6 illustrate these respective estimates for the hydrothermal resource at East Mesa.

As illustrated in Figures 1-3 and 1-4, estimated development at the high (and rare) quality Roosevelt resource is likely to be only slightly affected by Federal support beyond that already provided in the National Energy Act of 1978.⁷ With diligent development, about 500 MWe are likely to be on-line by the year 2000 with or without Federal support. There is some, albeit low, likelihood that 600 MWe could be on-line by 2000. With active Federal support, this likelihood of 600 MWe increases significantly.

⁷i.e. depletion allowance, expensing of intangible well costs, and energy investment tax credits.

FIGURE 1-3. HYDROTHERMAL ELECTRIC POWER ESTIMATE:
ROOSEVELT HOT SPRINGS - (WITHOUT FEDERAL SUPPORT)

FIGURE 1-4. HYDROTHERMAL ELECTRIC POWER ESTIMATE:
ROOSEVELT HOT SPRINGS - (WITH FEDERAL SUPPORT)

FIGURE 1-5. HYDROTHERMAL ELECTRIC POWER ESTIMATE:
EAST MESA - (WITHOUT FEDERAL SUPPORT)

FIGURE 1-6. HYDROTHERMAL ELECTRIC POWER ESTIMATE:
EAST MESA - (WITH FEDERAL SUPPORT)

In contrast to Roosevelt, the effect of Federal support is likely to be very significant at the more prevalent East Mesa-type resource (see Figures 1-5 and 1-6). With benefits of active Federal R&D programs -- particularly in areas of well stimulation, downhole pump development and power plant performance improvement -- it is probable that diligent efforts will put 500 MWe on-line within the next 20 years at East Mesa. Without these benefits of Federal support, the likelihood of large scale development at East Mesa is much less certain. Within the next 20 years, the extent of any development falls from 500 MWe with Federal support to 200-300 MWe without this support.

1.3.2 National Hydrothermal Electric Power Forecast

The Earth Science Laboratory of the University of Utah Research Institute (UURI/ESL) has postulated that, by the year 2000, with active Federal support there could be 134 confirmations of hydrothermal resources of greater than 300F temperature. 53 of these resources are known, though perhaps not confirmed, today (ref. Muffler, 1979 -- USGS Circular 790). Figure 1-7 illustrates the distribution by temperature of these postulated estimates. Without active Federal support in terms of policy incentives and R&D programs, the number of potential resources postulated by UURI/ESL drops to 101.

As part of a Task Force effort (see U.S.DOE, 1980), Technecon processed UURI/ESL's postulated resources through the investment decision models discussed in this report. The likelihood of joint investment decisions by resource developers and electric utilities was estimated at each resource site. The resulting estimates provide the electric power potential and rate of commercial development of the hydrothermal resource base in the United States. Much of the cost and performance data used in these national estimates are provided in Chapter 2 of this report. Other regional data are listed in Table 1-1.

Figure 1-7. DISTRIBUTION OF POTENTIAL CONFIRMATIONS
WITH RESOURCE TEMPERATURE

TABLE 1-1

REGIONAL ECONOMIC DATA

	Regions ¹				
	1,2	4,5,7,8	3	6	9
State Corporate Income Tax Rate	9%	5%	7%	10.5%	5%
Local Ad Valorem Tax Rate ²	1%	1.3%	2%	1%	0.7%
Competing Baseload Generation	Coal	Coal	Coal	Nuclear	Coal
Capital Cost (1980 \$/kWe) ³	935	935	935	1255	935
Fuel Cost (1980 Mills/kWh) ⁴	17.1	11.8	14.5	8.1	15.8
Fuel Escalation Rate ⁵	8%	8%	8%	8%	8%
Recurrent Cost Fraction ⁶	6.2%	6.2%	6.2%	3%	6.2%
Recurrent Cost Escalation Rate ⁵	7.5%	7.5%	7.5%	7.5%	7.5%

¹Regions defined as follows:

1,2: CA (No. and So.)

4,5,7,8: NV,UT,ID,MT,WY,CO

3: OR,WA

6: AZ

9: NM

²On full cash value; i.e. includes assessment rate and tax on assessed value.

³Capital Cost of competing baseload plant including transmission.

⁴Fuel cost of competing baseload generation.

⁵Annual rate for 20-Yr outlook.

⁶Includes annual operating, maintenance, administrative, general and insurance expense for competing baseload generation; expressed as fraction of 1980 capital cost of plant.

The electric power potential of hydrothermal resources which are expected to be confirmed in the United States by the year 2000 is provided in Table 1-2. Power potential is estimated with regard for the economic decision criteria expressed by resource companies and electric utilities. Figures 1-8 and 1-9 illustrate the estimated rate of development of this hydrothermal electric power within the next 20

years, with and without active Federal support respectively. These illustrated results are provided by the investment decision models discussed in this report. Figure 1-10 illustrates how these estimates correlate with estimates prepared by the Electric Power Research Institute from a survey of the announced plans of electric utilities (see Kruger, 1980).

TABLE 1-2

ESTIMATED ECONOMIC ELECTRIC POWER CAPACITY
OF HYDROTHERMAL RESOURCES FOR WHICH
CONFIRMATION IS PREDICTED BY 2000

(Net Gigawatts)

LIKELIHOOD	NO FEDERAL PROGRAM	WITH FEDERAL PROGRAM
>90%	11.7	29.7
>50%	16.3	39.8
> 5%	23.0	54.0

FIGURE 1-8

FIGURE 1-9

Figure 1-10. DOE TASK FORCE HYDROTHERMAL ELECTRIC POWER ESTIMATES VERSUS EPRI SURVEY

The national estimates indicate that the potential for economic hydrothermal electric power in the United States is on the order of thirty to fifty thousand megawatts. By the year 2000, eleven to seventeen thousand megawatts are estimated to be commercially installed and on-line. In light of attractive alternative investment opportunities (particularly in oil and gas for the resource companies and in coal-fired generation for electric utilities) a strong measure of Federal support will be required to achieve these estimated development levels. The majority of known and projected hydrothermal resources are marginal investment opportunities today, and their development is sensitive to Federal policies and to the expected benefits of Federal R&D programs. Without such Federal support, forecasted development of hydrothermal power in the United States drops to less than half of that given above.

1.4 CONCLUSIONS

With extensive support from resource companies, electric utilities and financial institutions over the past 2 years, Technecon has developed quantitative industrial decision models to provide estimates of the likelihood of positive investment decisions for hydrothermal electric power projects. Estimates provided by these models correlate well with both historical investment behavior to date and investment decisions announced by the geothermal industry. The computerized investment decision models offer a cost-effective instrument for both hydrothermal resource assessment and rational, objective analysis of national policies and programs.

Evaluations performed by the decision models to date indicate that, in light of alternative investment opportunities currently available to companies and investors having geothermal interests, the majority of known and projected hydrothermal resources offer marginal risk/return qualities. However, with active Federal support via both policy incentives and R&D program benefits, a very significant number of otherwise unattractive and marginal hydrothermal investment

opportunities will be pursued within the next 20 years. The estimated potential for economic electric power production from hydrothermal resources in the United States is large, and an aggressive Federal program is expected to more than double the extent of its development by the year 2000.

1.5 RECOMMENDATIONS

Three recommendations are offered with respect to the work discussed in this report:

- o Utilize the cost-effective decision modeling instrument developed in this work for objective analysis of federal and/or state policies and programs. A rational strategy is required that will effectively select the appropriate federal activities. The instrument provided here can assist policy analysts by forecasting the likely effect of alternative strategies.
- o Develop a hydrothermal resource exploration model that will be capable of forecasting the rate of discovery and quality of resources within statistically acceptable confidence intervals. Technicon is presently working with the University of Utah Research Institute, Cascadia Exploration Corp. and USGS to develop such a model. The work discussed in this report will process discovery projections from the recommended exploration model and forecast site-specific power development.
- o Continually update the investment decision models to reflect: new resource data from field operations; new economic data on competing energy costs and inflation rates; observed investment behavior in hydrothermal projects; and current cost and performance data.

Chapter Two

PROJECT CASH FLOW REQUIREMENTS

The purpose of Chapter Two is to present the stochastic discounted cash flow models used to assess hydrothermal investment opportunities from the perspective of both the resource producer and electric utility. Section 2.1 discusses the hydrothermal well field analysis model. Included in the discussion are preproduction and production cash flow components based on industry supplied data and accounting practices. The electric utility cash flow analysis model is developed in Section 2.2. Resource pricing considerations are addressed in Section 2.3. As discussed in Chapter One, the resource selling price is the critical link between resource producer and electric utility cash flows in this investment analysis.

2.1 HYDROTHERMAL WELL FIELD FINANCIAL ANALYSIS

A stochastic discounted cash flow model is used to analyze hydrothermal well field investment opportunities. This model accounts for a time-series of capital investments, expenses, taxes, royalties and revenues incurred in the exploration, confirmation, development and production of hydrothermal resources for electric power generation.

With the cash flow model, probabilistic outcomes of a positive investment decision may be analyzed for each investment opportunity. For the hydrothermal well field projects being studied at present, the model provides probabilistic estimates of: (a) the rate of return on invested capital, (b) the investment payback time, and (c) the net present value of profits. The model also provides probabilistic estimates of (d) the amount of investment at risk and, based upon site-specific mappings of confidence levels prepared by consulting geothermal geologists, the model estimates the likelihood that such loss will be incurred.

2.1.1 Stochastic Variables

Uncertainties in each hydrothermal investment opportunity are accommodated through probability distributions attached to eight key elements of the cash flow model. Power plant capacity factor, well cost, dry well frequency, resource temperature, well flow rate, well life, surface piping cost, and power plant cost are uncertain to significant degrees and are, therefore, provided to the model in the form of site-specific density functions. Using iterative Monte Carlo simulation techniques, random variates are drawn from these density functions and are processed by the model. The Monte Carlo iterations produce probabilistic estimates of the four investment attributes (a thru d, above) which, together with the above mentioned likelihood of loss estimate, are necessary ingredients for investment decision analysis as discussed in Chapter 3.

As new and more substantial empirical data become available from hydrothermal development projects, the uncertainties associated with stochastic elements of the current model will be reduced. These new data will permit redefinition of the distribution functions associated with each variable and will refine the model's accuracy. Until such time as substantial new data are provided, significant uncertainty and investment risk will be characteristic of hydrothermal ventures.

2.1.2 Pre-Production Cash Flow

The investment decision being modeled in this analysis is assumed to follow resource discovery and concerns capital expenditures required for post-discovery resource development and production. As such, all expenditures incurred prior to reservoir confirmation are treated as sunk costs in this model. Such costs include expenditures for reconnaissance, exploration and land acquisition, representative values for which are provided in Table 2-1. This assumption is based on generally accepted oil and gas industry capital budgeting procedures. For consistent decision modeling evaluation, hydrothermal investment opportunities will be compared against alternative investment opportunities exclusive of similar magnitudes of the aforementioned sunk costs (see section 3.2.2).

TABLE 2-1
PRE-PRODUCTION COST ESTIMATE
FOR ONE PRODUCIBLE HYDROTHERMAL DISCOVERY

YEAR	PROCEDURES	AREAS ¹	CAPITALIZED COST	EXPENSED COST ²
1	RECONNAISSANCE - Literature search & analysis - Photography, imagery & photogeology	62	\$0	\$40,000
	PRE-LEASE SURFACE EXPLORATION - Permits & Notice of Intent - Geology, geochemistry & thermal gradients	35	50,000	1,700,000
2 & 3	LAND ACQUISITION - Application & environmental studies (if req'd) - Competitive bonus bid (if req'd)	18	Site-specific ³	1,400,000 ⁴
	POST-LEASE SURFACE EXPLORATION - Geophysical & electrical - Market assessment & financing	18	15,000	250,000
4	SHALLOW SUB-SURFACE EXPLORATION - Drill & log thermal gradient wells - Permits, drill & test shallow wells - Conceptual models	13	40,000	480,000
5	DETAILED EXPLORATION - Geology, geophysics & geochemistry	5	75,000	300,000
	DEEP EXPLORATORY WELLS - Permits, mobilize rig & drill deep well - Test & evaluate	5 ⁵	Site-specific ⁶	1,800,000 ⁷
	CONFIRMATION - Permits, 2 step-out wells ⁸ & injection wells - Sustained flow test	1	Site-specific ⁶	0
6	MODELING & ENVIRONMENTAL STUDIES - Fault pattern definition - Environmental assessments - Consumer evaluations & negotiations	1	800,000	0
7	WELL FIELD ENGINEERING - Permits & development plan - Engineer surface facilities	1	125,000	0
8 & 9	CONSTRUCT SURFACE FACILITIES - Permits & procurement - Construct roads & buildings	1	225,000	0
	WELL FIELD DEVELOPMENT - Mobilize drilling rig - Drill & case producer & injector wells - Construct surface piping	1	Site-specific ^{6,9}	Site-specific ¹⁰

¹One Area = 7500 acres.

²Expenses will also include annual land rental, ad valorem taxes, and (for tax purposes) the intangible portion of capitalized well costs. The cash flow will also be credited with income tax refunds afforded by investment tax credits on installed wellfield capital and by deducting capital depreciation and expenses from unrelated taxable income. Refer to text.

³Based upon site-specific lease bonus (a cash flow model input parameter) on ultimately productive acreage.

⁴Equivalent to an average lease bonus of \$11/acre on 17 unretained acres @ 7500 acres/area.

⁵Estimated success ratios for deep exploration wells vary from 1:15 (Ref. University of Utah, 1978, p.58) to 5:15 (Ref. Ward, 1977). The 1:5 estimate used

here represents a compromise between these estimates and is consistent with the 21% success rate for exploratory wells outside well-known areas per University of Utah (1978) p.51.

⁶Site-specific deep well cost is a function of reservoir depth and geology. Refer to text.

⁷Assumes 3 failures @ \$350,000 and 1 failure with casing run @ \$750,000.

⁸Industry responses to the question of the number of deep wells required for confirmation varied from two to more than five with three (i.e. one successful exploratory well plus two step-out wells) being the mean response.

⁹Includes active and spare producer wells and injector wells plus additional redrill costs. Refer to text.

¹⁰Includes dry wells encountered in field development. Refer to text.

The stochastic post-confirmation cash flow components are discussed below. Treatment of the several cost items, as to whether each is expensed as incurred or capitalized and subsequently amortized over a specified depreciable life, follows the suggestions of Greider (1974) and Porter (1965). Expensed items include unsuccessful well costs and expenditures required to maintain commercial operations including rentals, royalties, taxes and operating and maintenance costs. Capitalized items include lease bonuses, and capital costs for all surface facilities. For tax purposes, the intangible portion⁸ of successful well costs is expensed and the tangible portion is capitalized. For book purposes, the total cost of a successful well is capitalized.

Rentals. Following acquisition, annual rental is paid on leased land until commercial production commences or until the land is relinquished (Porter, 1965). Annual rentals on public lands are typically \$1 per acre, except on Federal KGRA land where the rent is \$2 per acre. Rental rates on public lands may escalate by \$1 per acre per year if diligent development has not progressed after five years from acquisition (U.S.B.L.M., 1978). Rental payments on private lands may be considerably higher until commercial production.

Ad Valorem Taxes. Ad valorem tax liabilities vary from county to county in both rate and computational methodology. Lindsey and Supton (1976), Porter (1965), Sacarto (1977) and Wagner (1977) discuss ad valorem tax levies in considerable detail. For Utah resources in the Roosevelt/Cove Fort-Sulphurdale region, for example, annual ad valorem taxes are levied at a rate of 5 percent of 25 percent of the book value of installed well field capital prior to commercial production and at 5 percent of gross revenues less expenses, resource depletion and capital depreciation during commercial production. On the other hand, for California resources in the Geysers area, ad valorem taxes prior to reservoir confirmation are levied at a rate of 4 percent of 25 percent of the lease cost. Once the reservoir is confirmed, taxes are levied on the estimated before-tax net present value of the resource.

⁸50% (Ref. Sacarto, 1977) to 75% (Ref. EPRI, 1978) of a well's cost may be considered intangible and expensed as such for tax purposes.

Deep Well Requirements. The required number of active producing wells is dependent upon the site-specific temperature of the resource, the flow rate per well and the capacity and performance of the power plant being supported by the well field. Resource temperature and well flow rate are treated stochastically in the investment model as discussed earlier in this chapter.

Power plant performance may be expressed in terms of net specific energy (watt hours generated per pound of hydrothermal fluid) as a function of the resource temperature. Figure 2-1 illustrates the relationship between net specific energy and resource temperature for liquid-dominated reservoirs as supplied by EG&G Idaho. As shown, the net brine effectiveness is a function of resource salinity and the heat recovery system used (i.e., flash or binary). For investment modeling purposes, regression analysis was used to estimate the relationship between net specific energy and these causal variables. Equation 2.1 defines this relationship:

$$n_s = -16.90 + .0615 (\text{TEMP}) + 2.344 (\text{TYPE}) - .534 (\text{BCI}) \quad (2.1)$$

(64.76) (14.2) (10.00)

$$R^2 = .985$$

$$F = 1078$$

where: n_s = net specific energy (W hr/lb fluid)
TEMP = resource temperature ($^{\circ}\text{F}$)
TYPE = 1 if binary; 0 if flash
BCI = brine contamination index
(0=low salinity to 3=high salinity)

As indicated by the "t-statistics" in parentheses, all coefficients are significant at the 99 percent level of confidence. The coefficient of determination (R^2) and the F-statistic given above also indicate acceptable levels of goodness of fit.

Figure 2-1. ENERGY CONVERSION EFFICIENCY
OF LIQUID-DOMINATED HYDROTHERMAL POWER PLANTS

For investment modeling purposes, the active producing well requirement is estimated by the relation:

$$NACT = [kW \div n_s(T)] \div WF \quad (2.2)$$

where kW represents the generation capacity being supported (kilowatts), n_s is the net specific energy at resource temperature T, and WF is the flow rate per active producer well (1000 lbs/hr).

Resource temperature and well flow rates may decline with time thereby increasing well requirements during production years. This resource drawdown phenomenon has been experienced at the Broadlands field in New Zealand (ref. Hitchcock and Bixley, 1976) and has been theoretically estimated for the Heber field in California (ref. Bechtel, 1977). It has been experienced to a small degree at The Geysers. Drawdown effects may be controlled somewhat by reservoir management techniques and enhanced recovery methods. Blair and Cassel (1978) and Blair et al. (1979) discuss the economic consequences of hydrothermal resource decline in considerable detail; however, because of its largely speculative nature at present, this phenomenon is not included in the present application of this model.

In addition to the active producer wells drilled during field development, injector wells and spare producer wells are also required, the former to reinject spent geothermal fluid into the aquifer upon discharge from the power plant and the latter to provide a reasonable standby margin of reserve production capacity. The ratio of active producer to injector wells (PIR) is generally 2:1 according to industry data while the spare well fraction (SWF), i.e. fraction of total producing wells which represents spare capacity, varies from 0.25 to 0.10. Total deep well requirements for field development are therefore:

$$DRL = \left[1 + \frac{1}{PIR} + \frac{SWF}{1-SWF} \right] \times NACT \quad (2.3)$$

Deep Well Costs. For investment modeling purposes, deep well costs were found to increase in proportion to the square of well depth when fit by least squares regression to available well cost data⁹. The resulting cost curves (shown in Figure 2-2) are:

$$\text{Sedimentary Geology: } WC = .283 + .005d^2 \quad R^2 = .83 \quad (2.4)$$

$$\text{Igneous Geology: } WC = .437 + .024d^2 \quad R^2 = .72 \quad (2.5)$$

⁹Cost data in Figure 2-2 were provided by EG&G Idaho.

with d expressed in thousands of feet and WC in millions of dollars for well, well head, and casing. Both d and WC are treated as site-specific variables.

Figure 2-2. HYDROTHERMAL DEEP WELL COSTS

A fraction (IRD) of deep producer wells, typically about 30 percent based upon industry-supplied data, may be expected to require redrilling initially during field development to improve fluid flow. The cost of redrilling a well is estimated to be about 35 percent (RDC) of WC . The average cost during development of active and spare producer wells is therefore: $[1 + (IRD \times RDC)] \times WC$.

During field development, a fraction (DWF) of the total number of wells drilled as producers are expected to be unsuccessful dry wells. This dry well fraction is treated as a site-specific stochastic variable. The expected number of dry wells is therefore:

$$\text{DRY} = \left[\frac{\text{DWF}}{1-\text{DWF}} \right] \times \left[1 + \frac{\text{SWF}}{1-\text{SWF}} \right] \times \text{NACT} \quad (2.6)$$

Unsuccessful wells are not fully cased and, therefore, are estimated to cost 90 percent (DWC) of the cost (WC) of a successful deep well.

Well Field Surface Equipment Costs. Published cost estimates for surface piping between the well heads and power plant are a function of the type of heat recovery system employed, as well as resource quality. Figure 2-3 show the variation in well field surface equipment capital cost at resources of different temperature and salinity for flash and binary systems⁹. Figure 2-4 illustrates the same relationship if downhole pumping is required. Regression analysis was used to develop the following equations used to estimate well field surface equipment capital costs for flash and binary systems (WFS_F and WFS_B):

$$\text{WFS}_F = \exp \left[\underset{(45.54)}{9.245} - \underset{(34.17)}{.008}(\text{TEMP}) - \underset{(6.21)}{1.207}(\text{WF}) + \underset{(5.91)}{.055}(\text{BCI}) \right] \quad (2.7)$$

$R^2 = .96$
 $F = 826$

$$\text{WFS}_{F\text{-PUMPED}} = \exp \left[\underset{(34.85)}{9.806} - \underset{(36.45)}{.0105}(\text{TEMP}) - \underset{(5.91)}{1.337}(\text{WF}) + \underset{(5.91)}{.064}(\text{BCI}) \right] \quad (2.8)$$

$R^2 = .97$
 $F = 652$

$$\text{WFS}_B = \exp \left[\underset{(14.8)}{9.506} - \underset{(20.9)}{.0109}(\text{TEMP}) - \underset{(3.8)}{1.347}(\text{WF}) + \underset{(3.8)}{.071}(\text{BCI}) \right] \quad (2.9)$$

$R^2 = .97$
 $F = 252$

$$\text{WFS}_{B\text{-PUMPED}} = \exp \left[\underset{(16.24)}{8.137} - \underset{(18.08)}{.0063}(\text{TEMP}) - \underset{(3.69)}{1.152}(\text{WF}) + \underset{(3.69)}{.066}(\text{BCI}) \right] \quad (2.10)$$

$R^2 = .926$
 $F = 208$

⁹Cost data in Figure 2-2 were provided by EG&G Idaho.

Figure 2-3. WELL FIELD SURFACE EQUIPMENT COST:
SINGLE FLASH SYSTEM

Figure 2-4. WELL FIELD SURFACE EQUIPMENT COSTS:
DUAL FLASH SYSTEM

All coefficients are significant at the 99 percent confidence level.

In addition to surface piping costs, other expenses relating to site development are also incurred. In the first year following reservoir confirmation, well field engineering and reservoir modeling expenses are required. These expenses are estimated to amount to \$95,000. The costs of environmental testing and permitting are treated as expenses, estimated to be \$150,000, and are incurred in the second year following confirmation. Finally, capital costs associated with ancillary surface facilities must be included. These items include access roads, fencing, maintenance sheds, administrative headquarters, and related expenditures. These capital expenditures are made in the third year following confirmation, and are estimated to be \$270,000.

Downhole Well Pump Costs. The installation of downhole well pumps is, in many cases, a cost-effective means of improving the likelihood of resource development. Without Federal support, projected pumping technologies are expected to limit applications to those resources with temperatures under 370°F. A continuation of current Federal research and development programs is expected to promote the development of pumps capable of operating at temperatures up to 400°F by 1985. Based on computer simulations, it was determined that provision of downhole pumping capability was cost-effective at all resources with an unpumped well flow rate of less than 400,000 lbs/hr, and a temperature of less than 370°F (or 400°F for post-1985 developments if Federal support is maintained). Pump capital costs (\$/lb/hr), based on data provided by EG&G Idaho, are estimated as follows:

$$\text{PUMP CAPITAL COST} = \exp [-.607 + .995 \times \text{WF}] \quad (2.11)$$

Income Tax Deductions and Credits. Pre-production expenses, ad valorem taxes, interest on the borrowed portion of invested capital, intangible well costs and capital depreciation are assumed to be deductible from unrelated income for tax purposes. Subject to at-risk

limitations, certain reductions in income tax liability attributable to these deductions plus investment tax credits on installed well field capital combine to provide a positive credit to the resource producer's pre-production cash flow.

2.1.3 Cash Flow During Commercial Production

The following discussion outlines the resource producer cash flow during commercial production. Revenue accruing from the sale of hydrothermal fluid is addressed, as well as capital costs and expenses needed to maintain commercial operation. Such expenditures include capital replacements, well field operation and maintenance expenses, royalties, ad valorem taxes, and income tax payments.

Revenue Cash Flow. The sale price of the hydrothermal fluid is determined jointly by the resource producer and power plant owner/operator. Both parties have clearly conflicting objectives when entering into a resource sales contract agreement. The resource producer seeks to maximize revenues by obtaining a high purchase price for the resource, while the power plant owner attempts to keep fluid purchase costs to a minimum. Thus the ultimately negotiated pricing contract is dependent upon the minimally acceptable criteria which resource producer and power plant decision makers require of investment opportunities (e.g., rate of return, levelized busbar cost, etc.), as well as the relative bargaining strength of each party.

A two-step procedure is used to simulate this negotiation process. First, a resource pricing algorithm is used to determine the resource selling price ($P_{h,b}$) which would equate the levelized busbar cost of geothermal power with the cost of the electric utility's preferred conventional base load alternative. This marginally competitive resource pricing algorithm is discussed in section 2.3. At this resource sale price ($P_{h,b}$ in mills/kWh), gross revenue cash flow in years of commercial operation may be estimated as:

$$GR_y = P_{h,b} \times CAP \times 8.76 \times KW_y \times (1 + g_F)^{y-y_b} \quad (2.12)$$

where the gross revenues, GR_y , are expressed in dollars of the current year y , KW_y represents the total installed kilowatt capacity in year y , CAP represents the power plant capacity factor, g_F represents the "fuel" cost escalation rate, and y_b is the resource pricing base year.

To maximize the joint likelihood of investment, cash flow and investment decision simulations are conducted at resource selling prices both above and below this marginally competitive price.

Capital Replacements. Estimates of the expected useful and economic life of hydrothermal wells are somewhat shorter than the expected 30 year life of the power generation facilities they will support. Depending on the fluid composition being produced, plugging and corrosion mechanisms may limit well life times to maximum expected values of 10-15 years. In the current investment model, capital replacements for active and spare producer wells and injector wells are simulated at site-specific lifetime intervals. This well life interval is a stochastic variable selected at random from a site-specific probability distribution. A given fraction (RRD) of the replacement wells are modeled as reworked existing wells and the balance (1-RRD) are modeled as new wells. Typically, industry data indicates that the rework fraction, RRD, is about 1/3.

Well Field Operation and Maintenance Expense. The costs associated with well field operation and maintenance were found to be a function of the number production wells required, the quality of the resource (expressed in terms of the Brine Contamination Index), and the capital cost of well field surface capital equipment. Operation and maintenance costs (in thousands of dollars per year) are estimated according to the following relation (Source: EG&G, Idaho):

$$OME = 320 + 110.2 (1+BCI) NACT + .01 (BCI^2 - BCI + 2) WF \quad (2.13)$$

These costs include field staff expenses, costs incurred in the acidizing, surveying, hydrofracturing, and abandonment of production wells, and the stimulation, surveying, hydrofracturing, and abandonment of injection wells. If downhole well pumping is required, additional well pumping operation and maintenance expenses are also incurred. These costs (in \$1000 per year) are estimated as follows (EG&G Idaho):

$$\text{PUMP O\&M COST} = 56.3 + 24.5 \times \ln (\text{WF}) \quad (2.14)$$

Royalties. Royalty payments to the land lessor are typically one-tenth to one-eighth of gross revenues free and clear from all production expense.

Ad Valorem Taxes. Local ad valorem taxes paid during resource production vary from state to state and county to county. These taxes are discussed earlier in section 2.1.2.

Income Taxes. State and Corporate income tax liabilities are based on taxable income net of expenses, local taxes, royalties, accelerated capital depreciation, interest payments on borrowed capital, and percentage depletion. The depletion deduction was held as legally permissible by the Reich case, (see Peterson and Seo, 1975) for the vapor-dominated hydrothermal resource at The Geysers. Depletion allowances for liquid dominated resources became legally permissible with the passage of the National Energy Act in 1978. According to the NEA, a 22% depletion allowance may be claimed through 1980, 20% may be claimed in 1981, 18% in 1982, 16% in 1983, and 15% may be claimed thereafter.

Other incentives offered by the NEA include: (a) the option to claim the intangible fraction (50-75%) of a well's cost as a deductible expense, and (b) an additional investment tax credit of 10% above the currently permissible 10% for "alternative" or "specially-defined energy property". Geothermal well field capital, in many instances, qualifies as such property.

2.1.4 Investment Risk

Capital Risk. Industry interviews indicate that hydrothermal power plant technology is relatively well developed and is, for practical purposes, free of investment risk. Risks associated with reservoir confirmation and performance are of primary concern and pose significant barriers to rapid, large scale commercial development.

As discussed in section 2.1.2, hydrothermal resources may suffer degradation in the form of temperature and well flow decline as fluid is extracted over time. However, this phenomenon is not well understood at present and may be controllable by prudent reservoir management. For these reasons, and because of the lack of data (empirical or otherwise) upon which to estimate the likelihood and/or extent of such time-wise degradation, the post-confirmation investment risk associated with premature and unexpected resource degradation is excluded from present consideration.

For modeling purposes, investment risk is confined to capital outlays following confirmation of a producible hydrothermal resource. Limited field experience to date indicates that once successful step-out wells have defined a resource and sustained flow tests have verified its producibility, there remains little risk to capital investments for well field development for commercial production. The risk incorporated into the present investment model is that of losing well field confirmation capital including expenditures required for three deep step-out wells. Some of this loss is assumed to be recouped via income tax deductions from unrelated income. The unrecouped balance of the loss is modeled as the investment risk for a particular well field venture.

Likelihood of Loss. The probability of losing well field confirmation investments is estimated from site-specific mappings of confidence provided by consulting geothermal geologists¹⁰. Figure 2-5 provides an

¹⁰Confidence maps were provided by Eugene Ciancanelli of Cascadia Exploration Corp., Escondido, CA for California KGRA's outside of the Imperial Valley, and by Dr. Bill Smith of Republic Geothermal, Inc. for KGRA's within the Imperial Valley and in the State of Utah.

example of such a mapping for a specific resource area. These mappings represent the levels of confidence attached to currently available information at each resource site.

Figure 2-5. LEVELS OF CONFIDENCE
AT ROOSEVELT HOT SPRINGS KGRA (MID-1979)

The probability of loss, P_L , at a particular level of well field development, i.e. kW in kilowatts, is estimated as follows:

(a) A level of confidence is estimated for each well space in the resource area by using an iterative interpolation method¹¹, based upon the geologists' confidence contours as illustrated in Figure 2-5, to assign a level of confidence to each well space within the area. Well spacing, defined as an input parameter (WSPACE), is typically 40 acres per well. Thus, this method would estimate a level of confidence for each 40 acre square in a grid covering the resource area.

(b) The number of well spaces required to achieve a development level, kW, is estimated by the relation:

$$NW = \left[1 + \frac{DWF}{1-DWF} \right] \times \left[1 + \frac{SWF}{1-SWF} \right] \times NACT \quad (2.15)$$

where NACT represents the required number of active producing wells and is a function of kW as given in (2.1), and DWF and SWF are dry well fractions and spare well fractions, respectively, as defined in section 2.1.2¹².

(c) A drilling sequence (WSEQ) of well spaces is ordered such that development progresses from the well spaces of highest confidence outward to the spaces of lower confidence. The probability of loss at development level kW is estimated as one minus the confidence level of the NW-th sequential well space.

2.1.5 Financial Attributes

The attributes of an investment opportunity which are required to perform the decision analysis discussed in Chapter 3 are: (a) the rate of return on invested capital, (b) the investment payback time, (c) the

¹¹The method used is the Gauss-Seidel method for approximating a Laplacian operator.

¹²Note that injection wells are assumed to be located outside the production area and, therefore, do not affect the well space requirement in equation (2.15).

net present value of profits and (d) the amount of capital at risk and the probability of incurring this loss. Computational methodologies and assumptions pertaining to the first three attributes (a,b,c) as incorporated into the financial analysis model, are summarized below. The fourth attribute (d) has been discussed above.

Rate of Return on Invested Capital. Rate of return is an investment attribute which is of primary concern to energy resource firms as a measure of the efficiency of investment capital. Theoretically, investment opportunities to a given firm should be ranked according to the rate of return projected for each and investments should be made to the point where the marginal rate of return on the last dollar invested is equal to the marginal cost of that last dollar. This theory is illustrated in Figure 2-6 where the marginal efficiency of investment (meI) represents the ranking of opportunities according to the rate of return projected for each, and where the marginal cost of funds (mcf) represents the increasing marginal cost of capital to the firm. The meI/mcf intersect represents the theoretically optimum level of investment.

Realistic application of this investment theory requires consideration of profit goals set by the investing firms which, in effect, increase the desired minimum return. In the major diversified firms, investment opportunities are routinely measured against a corporate minimum acceptable rate of return. This threshold reflects the rate of return realized by the firm's diversified operations and its current investment alternatives.

For the relatively small, non-diversified independent operators, the minimum acceptable rate of return reflects their marginal cost of capital plus a profit margin. With limited access to capital markets, the relatively expensive equity financing of the independents generally results in a higher threshold return than that of the major firms.

Figure 2-6. MARGINAL EFFICIENCY OF INVESTMENT
AND THEORETICALLY OPTIMAL INVESTMENT LEVEL (I^*)

Internal Rate of Return. The method by which rate of return is estimated is an important consideration in investment analyses. The internal rate of return, IRR, concept (also referred to as the marginal efficiency of capital) was published by Keynes (1936) as a method for ranking investment opportunities. IRR is that rate of discount which equates the present worth of an opportunity's revenue stream to the present worth of its expense and investment stream, i.e., that discount rate (i) at which the net present value (NPV) of an opportunity reduces to zero...

$$NPV = \sum_{t=0}^n \frac{NR_t - I_t}{(1+i)^t} \quad (2.16)$$

where, NR_t and I_t are revenues net of expenses and investments, respectively, during period t and n represents the expected economic life of the opportunity.

It is important to note that, as demonstrated by Alchian (1955) and Hirshleifer (1958), Keynes' IRR method will correctly and realistically rank investment opportunities when: (1) net receipts may be immediately and indefinitely reinvested at the IRR, and (b) when NPV (i) curves do not intersect as illustrated in Figure 2-7.

Figure 2-7. NET PRESENT VALUE - vs - DISCOUNT RATE
FOR HYPOTHETICAL INVESTMENT OPPORTUNITY

The IRR reinvestment criteria may be satisfied by independent operators whose business concentrations are in similar hydrothermal opportunities. However, hydrothermal opportunities represent a relatively small fraction of the operations of major resource corporations and their impact on corporate reinvestment rates are unlikely to be significant. For this reason, when assessing

hydrothermal opportunities of the major corporate producers, the IRR method is discarded in favor of the financial management rate of return, FMRR, method. With the FMRR method, discussed below, the reinvestment rate may be externally specified.

Financial Management Rate of Return. Financial management rate of return (FMRR) is a method for ranking investment opportunities recently discussed by Messner and Findley (1975). The FMRR method discounts all preproduction negative cash flows to an equivalent single initial investment and estimates the interest rate required to equate this investment to a single end-of-life return. The end-of-life return is the sum of all net production revenues compounded forward at a realistic reinvestment rate.

FMRR avoids the problems of unrealistic reinvestment rates of the IRR and is proposed and used herein as the proper rate of return for ranking hydrothermal investment opportunities of major resource corporations.

Investment Payback Time. Unlike petroleum ventures where a single well is capable of producing revenue when complete, it takes a field of completed wells and an on-site power plant to create revenues in a geothermal electric power venture. This period from prospect discovery to revenue can extend several years and is highly dependent on uncertain institutional, logistical and technical barriers likely to be encountered along the way. Inherent in such an uncertain and long developmental time frame are investment risks associated with long range capital commitments, uncertain costs and uncertain revenues.

Payback time estimates are a second primary concern of resource firms and indicate the length of time an investment will be subject to the above mentioned risks before it is recovered by project receipts. As a rule, longer payback requirements involve higher costs of capital because of the associated risk premiums. Independently operating resource firms are particularly sensitive to long payback times because of the limited availability of private venture capital for long term

financing. The larger resource corporations appear less concerned with payback time as exemplified by recent activities by many of these firms in outer continental shelf oil production where payback estimates typically run 8-10 years.

As discussed in the beginning of this chapter, a series of capital investments extending over several years are required to confirm and develop a hydrothermal well field. Individual discounted investments are assumed to be paid back, in order of occurrence, from discounted net revenues. A weighted average discounted payback time is employed in this analysis to estimate a single measure of payback time for the investment stream.

Net Present Value of Profits. The estimated net present value (NPV) of an investment opportunity is a third primary concern of resource firms. It provides an indicator of the magnitude of profit expected of a venture and allows a firm to determine if the proposed venture is compatible with its scale of operations. NPV is the projected stream of net revenues and capital expenditures of an opportunity reduced to a single value at an appropriate discount rate (recall equation 2.16). As discussed at some length by Weston and Brigham (1978) and Phung (1977), a proper discount rate for NPV analyses is the firm's weighted average after-tax cost of capital¹³.

2.2 POWER PLANT FINANCIAL ANALYSIS

To analyze hydrothermal investment opportunities from the perspective of an investor owned or municipal utility, a stochastic discounted cash flow model is used. This model provides estimates of the year by year revenue requirements associated with the investment. Included in the model are provisions for capital repayment and return,

¹³Estimation of realistic values for a firm's cost of capital is not a trivial task - see Weston and Brigham (1978), Chapter 19.

tax liabilities, operating expenses, and all other relevant cash flows related to the investment. This model will be used to derive probabilistic estimates of positive investment decisions on the part of electric utilities for the hydrothermal investment opportunities discussed in this report. For investment modeling purposes, the model provides probabilistic estimates of: (a) the ratio of hydrothermal levelized busbar cost to the levelized cost of the otherwise preferred conventional baseload alternative, (b) the capacity factor of the hydrothermal unit, (c) the investment's impact on the financial health of the utility (expressed in terms of the probabilistic change in the times interest earned ratio), and (d) the ultimate reservoir capacity. These investment attributes will be shown in Chapter Four to be critical elements for explaining the overall electric utility decision making process.

The cash flow model is unique in its ability to determine how capital costs and expenses would be altered in the event of a premature forced closing of the hydrothermal plant. This modeling capability is required due to the uncertainty involved in estimating reservoir life. Discussions with consulting geologists and reservoir engineers suggest that there exists some probability, albeit small, that reservoir output may become insufficient to support the hydrothermal facility at some time prior to the end of its design life (see Chapter Six). Such an occurrence could have important ramifications on the electric utility's financial well being.

2.2.1 Stochastic Variables

Uncertainties in hydrothermal plant investment opportunities are accommodated through probability distributions attached to four critical elements in the cash flow. These stochastic variables include power plant capacity factor, reservoir life, ultimate reservoir capacity, and power plant capital cost. Using Monte Carlo simulation techniques discussed in section 2.1.1, random variates are drawn from the probability density functions for each stochastic variable. This procedure enables probabilistic estimates of the aforementioned investment attributes to be obtained.

2.2.2 Hydrothermal Plant Capital Costs

Hydrothermal power plant capital cost data were provided by EG&G, Idaho. As shown in Figure 2-8, capital cost is a function of resource temperature and quality, as well as the heat recovery system used. Equations 2.17 and 2.18 express the capital costs of the hydrothermal plant (\$/KW) in terms of temperature and brine contamination index:

$$\text{CAP (FLASH)} = \exp \left[\underset{(13.7)}{3.040} - \underset{(7.09)}{.00261} \times (\text{TEMP}) + .069 \times (\text{BCI}) \right] \quad (2.17)$$
$$R^2 = .86$$
$$F = 89.7$$

$$\text{CAP (BINARY)} = \exp \left[\underset{(14.38)}{2.508} - .0014 \times (\text{TEMP}) \right] \quad (2.18)$$
$$R^2 = .86$$
$$F = 90$$

These estimates compare favorably with other published estimates (see Bechtel 1977; Greider, 1977; EPRI, 1976).

2.2.3 Capital Cost Carrying Charge Components

The following discussion outlines the procedure used to develop year by year revenue requirements for a proposed hydrothermal power plant. The model is primarily based on the American Telephone and Telegraph Engineering Economy report. The ATT study outlines the different capital cost requirements associated with new investments of regulated utilities. Additional refinements to the normalization/flow through accounting procedures were suggested by the Philadelphia Electric Company. These refinements are incorporated in the treatment of deferred tax liabilities.

Figure 2-8. CAPITAL COST OF LIQUID-DOMINATED
HYDROTHERMAL POWER PLANTS

The capital costs associated with an investment can be split into three basic categories:

- (1) depreciation (or return of capital),
- (2) return (or return on capital),
- (3) income taxes associated with the investment.

Each of these items will be discussed in the following analysis. These carrying charge components will be derived in the detail necessary to project the year by year revenue requirements of the project.

Depreciation. An annual stream of revenues is required to recover the initial capital cost of the facility. Book depreciation is the mechanism used to generate the needed funds for this carrying charge component. Book depreciation in year i ($DPRB_i$) is defined as follows:

$$DPRB_i = CI_0 \div N \quad \begin{array}{l} CI_0 = \text{total capital cost} \\ \text{of the facility} \\ N = \text{book life of the facility} \end{array} \quad (2.19)$$

Hydrothermal plant capital cost estimates have been provided in Section 2.2.2. A book life of 30 years is commonly assumed.

Return on Capital. The utility is also required to earn a return on the invested capital. The required rate of return (k) can be expressed as a weighted cost of capital:

$$k = k_c f_c + k_d f_d + k_p f_p \quad (2.20)$$

Estimates of common debt/equity fractions and costs for investor-owned utilities are provided below:

	<u>Parameter</u>	<u>Variable</u>	<u>Value</u>
Cost of:			
Debt Issues (%)		k_d	8.0
Common Stock Issues (%)		k_c	13.5
Preferred Stock Issues (%)		k_p	8.5
Fraction of Investment Funded by:			
Debt (%)		f_d	50.0
Common Stock (%)		f_c	35.0
Preferred Stock (%)		f_p	15.0

The return on capital can be found by multiplying the required rate of return (k) by the remaining undepreciated book value of the facility:

$$\text{RETURN}_i = [\text{CI}_0 - (i-1) \times \text{DPRB}] \times k \quad (2.21)$$

Income Tax. The third component of capital cost carrying charges is the income tax liability associated with the project. This component will include both state and federal income taxes. The composite tax rate (t) is a weighted combination of the state tax rate (t_s) and federal tax rate (t_f):

$$t = t_s + t_f (1-t_s) \quad (2.22)$$

The federal corporate tax rate is assumed to be 46 percent. State corporate income tax rates are treated as site-specific variables.

The tax liability can be determined by multiplying the taxable income by the composite tax rate. Taxable income is found by deducting debt interest and tax depreciation (DPRT) from the revenues received:

$$\text{TAX}_i = t \times (\text{taxable income}_i) \quad (2.23)$$

$$\text{TAX}_i = t \times (\text{DPRB}_i + \text{RETURN}_i + \text{TAX}_i - \text{debt interest}_i - \text{DPRT}_i) \quad (2.24)$$

To accommodate the tax ramifications of different tax depreciation practices, Equation 2.24 can be written:

$$\text{TAX}_i = t(\text{RETURN}_i + \text{TAX}_i - \text{DEBT INTEREST}_i) + t(\text{DPRB}_i - \text{DPRT}_i) \quad (2.25)$$

$$\text{TAX}_i = \frac{t}{(1-t)} (\text{RETURN}_i - \text{DEBT INTEREST}_i) + \frac{t}{(1-t)} (\text{DPRB}_i - \text{DPRT}_i) \quad (2.26)$$

To simplify later computations, it will be useful to express debt interest as a function of the return on capital. This can be done in the following manner:

$$\text{RETURN} = k \times (\text{capital}) \quad (2.27)$$

$$\text{DEBT INTEREST} = k_d f_d \times (\text{capital}) \quad (2.28)$$

$$\text{DEBT INTEREST} = \frac{k_d f_d \times (\text{RETURN})}{k} \quad (2.29)$$

Combining Equations (2.26) and (2.29) yields an expression for the total tax liability (TAX):

$$\text{TAX}_i = \frac{t}{1-t} \times \left[\text{RETURN}_i - \frac{k_d f_d \times \text{RETURN}_i}{K} \right] + \frac{t}{1-t} \times (\text{DPRB}_i - \text{DPRT}_i) \quad (2.30)$$

$$\text{TAX}_i = \frac{t}{1-t} \times \left[1 - \frac{k_d f_d}{k} \right] \times \text{RETURN}_i + \frac{t}{1-t} \times (\text{DPRB}_i - \text{DPRT}_i) \quad (2.31)$$

$$\text{TAX}_i = \text{BTL}_i + \Delta \text{TAX}_i \quad (2.32)$$

$$\text{BTL}_i = \frac{t}{1-t} \times \left[1 - \frac{k_d f_d}{k} \right] \times \text{RETURN} \quad (2.33)$$

$$\Delta \text{TAX}_i = \frac{t}{1-t} \times (\text{DPRB}_i - \text{DPRT}_i) \quad (2.34)$$

Equation (2.32) represents the total tax liability of the firm.

If all the tax benefits associated with accelerated depreciation are flowed through on the income statement, tax liabilities are reduced in the early years of operation. It is assumed that the maximum potential tax savings are achieved with sum-of-years-digits depreciation over Asset Depreciation Range life ($\text{DPRT}_{\text{SOYD-ADR}}$). The effects of flow through accounting of accelerated depreciation are summarized in Equation (2.35):

$$\Delta \text{TAX}_{i,\text{max}} = \frac{t}{1-t} \times (\text{DPRB}_i - \text{DPRT}_{i,\text{SOYD-ADR}}) \quad (2.35)$$

Based on discussions with representatives of a major electric utility company, current accounting practices dictate that only a portion of the total accelerated depreciation tax savings ($\Delta \text{TAX}_{i,\text{MAX}}$) be flowed through. For new generating units:

- (a) the differences between the use of accelerated depreciation at ADR life ($\text{DPRT}_{i,\text{SOYD-ADR}}$) and straight line depreciation at guideline life ($\text{DPRT}_{i,\text{SL-GL}}$) is normalized.

(b) the difference between the use of straight line depreciation at guideline life ($DPRT_{i,SL-GL}$) and book depreciation ($DPRB$) is flowed through.

This normalization/flow through accounting procedure has two impacts. First, a portion of the maximum flow-through benefits ($\Delta TAX_{i,MAX}$) are deferred, represented by Equation (2.36):

$$\Delta TAX_{i,def} = \frac{t}{1-t} \times (DPRT_{i,SOYD-ADR} - DPRT_{i,SL-GL}) \quad (2.36)$$

Secondly, this procedure provides the firm with a source of internally generated funds, as represented by the accumulated deferred tax balance ($CUMDEFT$). These funds act to reduce the return on capital portion of the year-by-year carrying charges of the facility. The deferred taxes in year i ($DEFT_i$) are equal to the income which would have been generated by using accelerated depreciation over ADR life instead of straight line depreciation at guideline life, multiplied by the tax rate:

$$DEFT_i = t(DPRT_{i,SOYD-ADR} - DPRT_{i,SL-GL}) \quad (2.37)$$

The accumulated deferred tax balance reduces the return component of the total capital cost carrying charge:

$$CUMDEFT_i = \sum_{j=1}^{i-1} DEFT_j \quad (2.38)$$

$$RETURN_i = k[CI_0 - (i - 1)DPRB - CUMDEFT] \quad (2.39)$$

Finally, it is necessary to consider the impact of any available investment tax credits. It is assumed that the tax credit is amortized over the book life of the facility in equal annual installments. Recalling Equation (2.25), and adding the effect of the amortized investment tax credits (ATC):

$$TAX_i = t(RETURN_i + TAX_i - DEBT INTEREST_i) + t(DPRB_i - DPRT_i) - ATC \quad (2.40)$$

$$TAX_i = \frac{t}{(1-t)} (RETURN_i - DEBT INTEREST_i) + \frac{t}{(1-t)} (DPRB_i - DPRT_i) - \frac{ATC}{1-t} \quad (2.41)$$

The final term in Equation (2.41) represents the reduction in the total tax liability attributable to the investment tax credit:

$$ATC = \frac{CI_0 \times a}{NB} \quad a = \text{investment tax credit rate} \quad (2.42)$$

Summary. The following equations summarize the components of the year-by-year capital cost carrying charge model:

$$TOTAL \text{ CAPITAL COST CARRYING CHARGE}_i = RETURN_i + DPRB_i + TAX_i \quad (2.43)$$

$$RETURN_i = (CI_0 - DPRB_i - CUMDEFT_i) \times k \quad (2.44)$$

$$DPRB_i = CI_0 \div NB \quad (2.45)$$

$$CUMDEFT_i = \sum_{j=1}^{i-1} DEFT_j \quad (2.46)$$

$$TAX_i = BTL_i + \Delta TAX_{i,max} + \Delta TAX_{i,def} - ITC$$

$$BTL_i = \frac{t}{1-t} \times \left[1 - \frac{K_d f_d}{K} \right] \times RETURN \quad (2.48)$$

$$\Delta TAX_{i,max} = \frac{t}{1-t} \times (DPRB_i - DPRT_{i,SOYD-ADR}) \quad (2.49)$$

$$\Delta TAX_{i,def} = \frac{t}{1-t} \times (DPRT_{i,SOYD-ARD} - DPRT_{i,SL-GL}) \quad (2.50)$$

2.2.4 Operating Expenses

Costs for fuel purchases, operation and maintenance expense, other taxes and insurance, and administration and general expenses must also be included. Fuel costs are represented by Equation (2.51):

$$\text{Fuel Cost} = P_{h,b} \times 8.76 \times KW_y \times (1 + g_F)^{y-y_b} \quad (2.51)$$

The fuel cost is initially set at the marginally competitive resource selling price (see Section 2.1.3). This price is later allowed to vary in order to maximize the joint probability of investment. This "Fibonacci search" procedure is described in detail in Chapter Six.

The remaining costs items are expressed as a fraction of the initial capital cost, escalated at an annual rate (g_C). Annual recurrent costs for ad valorem taxes, operation and maintenance, administrative and general expense, and insurance may be estimated by the relation:

$$O \& M = \beta \times CI_0 \times (1 + g_C)^{y-y_b} \quad (2.52)$$

where the recurrent cost fraction, is:

$$\beta = \beta_{OM} + \beta_{AG} + \beta_I + \beta_{AV} \quad (2.53)$$

with: β_{OM} being the annual operating and maintenance expense expressed as a fraction of the initial capital cost, CI_b ; β_{AG} being the annual administrative and general expense fraction; β_I being the annual insurance premium fraction of CI_b ; and β_{AV} being the annual ad valorem tax fraction.

Data for estimating the annual operating and maintenance capital cost fraction (β_{OM}) were provided by EG&G. Annual operating and maintenance costs for binary plants can be estimated as follows:

$$O \& M \text{ (Binary)} = 548.5 + .02 \times CI_0 \quad (2.54)$$

Based on an average capital cost of \$700/KW (see section 2.2.2), this is approximately equal to 3.6 percent of the total capital cost. Annual operating and maintenance costs for flash systems is represented by the following equation:

$$O\&M \text{ FLASH} = 509.5 + (.02 \times CI_0) + BCI(BCI-1)[92.88 \frac{MW}{n_s} + 112] \quad (2.55)$$

To express cost as a function of capital cost, equation (2.55) can be rewritten as:

$$O\&M \text{ (FLASH)} = \frac{509.5 + (.02 \times CI_0) + BCI \times (BCI-1) \times [46.44 \times MW + 56]}{CI_0} \quad (2.56)$$

These costs include staff wages and salaries, equipment maintenance, scale removal (where necessary), cooling water treatment, clarifier costs, and other miscellaneous expenses. β_{AG} is estimated by FPC (1971) to be 25% of β_{OM} or 0.5%. β_I is a nominal 0.1% of initial capital cost based on utility information. β_{AV} depends on local tax rates and assessments and is generally between 1% and 2% for the remote locations of usual hydrothermal resource sites.

2.2.5 Effect of Plant Closure on Electric Utility Cash Flow

There exists the possibility that, because of reservoir failure, the actual plant life may fall short of its design life. The possible occurrence of such a reservoir failure is addressed in Chapter Six. If such a situation should occur, significant changes in the utility's power production cash flow may be likely. These changes can be summarized as follows:

- o The public utility commission may, at its discretion, disallow expenses relating to the further book depreciation of the asset.
- o The public utility commission may elect to prohibit the utility from earning the regulated rate of return on the remaining undepreciated book value of the asset.
- o The utility would incur additional operating expenses in the form of replacement power costs. With the loss of geothermal capacity, replacement capacity would be required either from less economic dispatch of existing capacity, or energy purchases from neighboring utilities.

The treatment of these issues is addressed in the following section.

Book Depreciation Allowances. Based on discussions with electric utility representatives, it appears unlikely that the public utility commission would choose to disallow the continuation of book depreciation expenses associated with the investment. It has frequently been suggested that a more likely ruling would be to allow the utility to write off the asset over a specified period of time (presumably shorter than the remaining book life). This practice has been followed

in a number of related cases.¹⁴ For investment modeling purposes, it is assumed that a 3 to 5 year write off period is granted, over which time the remaining undepreciated book value of the asset is recovered in equal annual installments.

Return on Capital Allowances. Current public utility commission practices dictate that the allowed rate of return be granted only on assets that are providing needed service to its customers. This "used and useful" philosophy would indicate that, with the premature closure of a hydrothermal generating plant, the utility would be prohibited from earning the regulated rate of return on the remaining undepreciated book value of the facility. A number of previous precedents indicates that this treatment would be the most likely scenario¹⁵.

Replacement Power Allowances. The additional cost incurred in providing power to replace the output lost due to the shut down of the hydrothermal unit must also be considered. The replacement power, obtained via grid purchase or rescheduling of existing capacity, represents an added cost burden to the utility and its customers. The public utility commission may, at its discretion, pass all (or some fraction) of these costs on to the consumers. In similar previous

¹⁴Amortization permitted: e.g., Re Newport Gas Light Co. (RI 1970) PUR3d 257, 260, 261; Re Consolidated Edison Co. of New York (NY 1964) 56 PUR3d 337, 371; Re Jacksonville Gas Corp. (Fla 1961) PUR3d 372, 374, 375; and Re Pacific Gas E. Co. (Cal 1933) 1 PURNS 1, 20. Amortization denied: e.g., Pacific Gas and E. Co. v California R. Commission (1938) 26 PUR NS 1, 26 F Supp 507, 522. See also Re Boston Edison Co. (Mass 1976) 16 PUR4th 1, 5; Re Eastern Massachusetts Street R. Co. (Mass 1952) 95 PUR NS 33, 35-37 (Investors bear risk of technological obsolescence); City of Grand Forks, Red River Power Co. (ND Dist Ct 1936) 12 PUR NS 353, 368; and Re Northwestern Electric Co. (Or 1934) 3 PUR NS 1, 11-13. (See Avery, 1979).

¹⁵See, e.g., Boston Gas Co. Mass. Dept. of Public Utilities (Mass Sup Jud 1975) 13 PUR 4th 147, and Re Brooklyn Union Gas Co. (NY 1973) 100 PUR3d 345, 350, 351.

cases, commission rulings have dictated a wide range of treatments¹⁶. For investment modeling purposes, in this report, it is assumed that 85 percent of the replacement power cost is allowed to enter the rate-making process. The remaining 15 percent of the cost represents a reduction in income available for return. This is currently the allowed replacement power cost fraction granted to Metropolitan Edison following the closure of the Three Mile Island Generating Station.

2.2.6 Electric Utility Investment Attributes

As discussed in Chapter Four, the investment attributes which are required to perform investment decision analysis include: (a) the ratio of the levelized busbar cost of hydrothermal power to the levelized busbar cost of the preferred conventional base load alternative, (b) the average annual capacity factor, (c) the impact of the hydrothermal plant cash flow on the firm's Times Interest Earned Ratio, and (d) the ultimate reservoir capacity potential. The following discussion outlines the computational procedure and assumptions used in the derivation of the four attributes cited above.

Levelized Busbar Cost Ratio. The levelized busbar costing procedure is a commonly used methodology to assess the relative economic attractiveness of alternative capacity additions. Typically included in the busbar cost computations are all cost items associated with the plant investment and operation, including any transmission capital costs or expenses needed to deliver the power to a main transmission corridor. The levelized busbar cost of a single capacity addition represents an annual payment which, if collected yearly over the book life of the plant, would be adequate to meet all capital expenses, operation and maintenance expenses, and all debt and equity financial obligations. The levelized busbar cost ratio is simply a measure of the economic attractiveness of the hydrothermal plant vis a vis the conventional base load alternative.

¹⁶See Avery, 1979.

The general busbar cost computational procedure is well defined and universally accepted by electric utility planners. The annual busbar cost is defined as:

$$\text{BUSBAR COST} = \frac{\text{NET PRESENT VALUE OF CAPITAL COSTS} + \text{EXPENSES}}{\text{NET PRESENT VALUE OF ENERGY GENERATED}}$$

The year by year revenue requirements model could have been used to generate the estimated levelized busbar cost of the hydrothermal facility (exclusive of the transmission related cost component). However, most conventional busbar cost models assume that the benefits of tax preference items are either entirely flowed through or normalized -- not both, (see section 2.2.3). For this reason, an alternative procedure was used to derive busbar costs for hydrothermal and alternative capacity additions.

For investment modeling purposes, the Electric Power Research Institute's recommended busbar cost accounting procedure was adopted (see EPRI, 1979). This methodology is exactly equivalent to the levelized annual cost of electric energy computation discussed in Section 2.3.1 of this report. When the resource selling price is set at the marginally competitive level, the busbar cost ratio is equal to 1.0. To maximize the joint probability of positive investment decisions by both resource producers and electric utilities, the resource selling price is allowed to diverge from the marginally competitive level. This optimization procedure is discussed in Chapter Six.

Average Annual Capacity Factor. The average annual capacity factor is an indicator of overall plant reliability. To effectively compete with conventional baseload alternatives, the hydrothermal capacity must provide power with a minimum number of both forced and planned outages. Plant reliability is an especially important concern of electric utility system planners because of the decline in the annual capacity factors of new coal fired units (to 70-72 percent) due primarily to maintenance problems related to newly mandated pollution control equipment (see EPRI 1979). Capacity factors for hydrothermal plant additions are modeled stochastically. A triangular probability distribution is assumed, with minimum, mode, and maximum values required as data inputs. The capacity factor probability distributions assumed for investment modeling purposes are discussed in Chapter Seven.

Impact on Times Interest Earned Ratio. The Times Interest Earned Ratio is a critical indicator of the electric utility's financial health. This ratio is defined by Equation 2.57:

$$\text{Pretax coverage ratio} = \frac{\text{Net Income before Taxes and Interest Expenses}}{\text{Interest Expenses}} \quad (2.57)$$

If either ratio declines significantly, the firm will find it increasingly difficult to meet debt and equity financial obligations. The response of capital markets will be to demand higher risk premiums for new capital acquisition. This will raise the overall cost of capital to the firm. These issues are discussed more thoroughly in Chapter Four.

Premature closure of the hydrothermal plant addition may have an adverse impact on the electric utility's TIER. The impacts of such an occurrence (due to reservoir failure) are addressed in Chapter Four. To derive a quantitative assessment of the change in the TIER, the after-tax net income and debt interest expenses of the hydrothermal plant are determined, and then incorporated into the balance of the electric utility's income statement. The maximum reduction in the TIER attributable to the hydrothermal plant addition can then be assessed.

Reservoir Capacity. The estimated ultimate hydrothermal electric power development level which the reservoir is capable of supporting is shown in Chapter Four to be a major element in the electric utility's investment decision. Faced with increasing load requirements (see section 4.2.1), electric utilities must be able to bring new capacity on-line in a timely and efficient manner, and in magnitudes sufficient to match load growth profiles. Investment in specific hydrothermal resource areas may be precluded if it appears that the resource is not capable of contributing a significant share of projected new generation requirements.

The estimated reservoir capacity is a function of the areal extent of the resource, the net specific energy of the resource, the temperature and flow rates of producing wells, and the level of

confidence attached to each production well (recall 2.1.4). Combining (2.2) and (2.15) yields the following expression for expected reservoir capacity:

$$\text{RESERVOIR CAPACITY} = \sum_i^j P_i \times \frac{WF \times n_s(T)}{\left[1 + \frac{DWF}{1-DWF}\right] \times \left[1 + \frac{SWF}{1-SWF}\right]} \quad (2.58)$$

where P_i represents the level of confidence attached to the i^{th} well, and j represents the maximum number of wells available for drilling given area and well spacing requirements.

2.3 RESOURCE PRICING CONSIDERATIONS

There is considerable literature concerning pricing mechanisms for hydrothermal fluid, e.g. EPRI (1978), Finn (1975), Greider (1977), and Lindsey and Supton (1976). Legislative concern over so-called "windfall profits" to producers is exemplified by the California Senate Concurrent Resolution No. 37 of 1976 which initiated a study of regulatory policy alternatives for hydrothermal steam. From this study, the California Energy Commission concluded that price regulation was neither warranted nor desirable from the perspective of promoting resource development.

In the absence of regulation, it is up to the resource producer (i.e. the seller) and the electric power producer (i.e. the buyer) to negotiate a mutually acceptable resource price. From the power producer's view, the cost-competitiveness of hydrothermal electric energy may be determined at the point where it reaches a main transmission corridor. At this point, its total cost - including "fuel" cost, power production costs, and apportioned transmission cost - competes with such costs of alternative forms of baseload generation, e.g. coal and nuclear generation. Responses of nine western electric utilities to questions of concern for electric energy cost indicate that, for favorable consideration, hydrothermal electric energy must be roughly competitive in cost to that of the least expensive alternative form of baseload generation. Thus considered, the least expensive baseload alternative dictates the cost of hydrothermal power at the margin of acceptability.

Alternative types of generation technology may be ranked in terms of the electric utility's "utility" for each, where utility is a numerical measure of preference. Figure 2-9 illustrates the mean utility of hydrothermal power, as a function of busbar cost¹⁷, as regressed from interview responses from nine western utilities. A slight bias in favor of hydrothermal generation is illustrated at the point in Figure 2-9 where the hydrothermal busbar cost is equivalent to the least expensive alternative. A rapidly increasing aversion to hydrothermal generation is apparent when its busbar cost exceeds that of the least costly alternative by more than about 2 1/2%. If the busbar cost of the least costly alternative is exceeded by about 18%, a maximum disutility is perceived and the hydrothermal option would, most likely, be precluded from consideration.

Figure 2-9. ELECTRIC UTILITIES' "UTILITY" FOR GEOTHERMAL POWER - vs - DELIVERED COST OF ELECTRIC ENERGY

¹⁷Busbar cost of electricity is but one of several items which comprise an electric utility's "total utility" for an alternative type of generation. Other items may include anticipated permitting delays, capital cost, outlook for fuel prices, plant reliability, etc.

Competitive Resource Pricing. The above illustration supports the assumption that an acceptable pricing mechanism for hydrothermal "fuel" from the electric utilities' perspective is one which satisfies the relation:

$$\underbrace{(\bar{P}_{h,b} \times Q) + \bar{C}_{h,b}}_{\text{Level Annual Cost of Hydrothermal Electric Energy}} = \underbrace{(\bar{P}_{i,b} \times Q) + \bar{C}_{i,b}}_{\text{Level Annual Cost of Alternative Electric Energy}} \quad (2.59)$$

where: $\bar{P}_{h,b}$ and $\bar{P}_{i,b}$ represent the levelized price per kilowatt-hour of hydrothermal and alternative fuel, respectively in some common base year (y_b) dollars; Q represents the quantity of electric energy produced annually expressed in kilowatt-hours; and $\bar{C}_{h,b}$ and $\bar{C}_{i,b}$ represent level annual production costs, exclusive of fuel costs, for hydrothermal and alternative plants, respectively, in base year dollars. This equation can be rewritten:

$$\bar{P}_{h,b} = \bar{P}_{i,b} + \frac{\bar{C}_{i,b} - \bar{C}_{h,b}}{Q} \quad (2.60)$$

which expresses the marginally competitive levelized price for the hydrothermal resource.

Included in the annual non-fuel production cost are costs associated with: (1) recovering the power plant and apportioned transmission capital investment at the electric utilities' regulated rate of return, (b) meeting liabilities for state and federal corporate income and local ad valorem taxes, and (c) covering maintenance and operating expenses, administrative and general expenses, and insurance premiums. These cost items may be expressed as a function of the original capital investment as discussed below.

Fixed Power Production Costs. Level annual fixed costs for capital recovery and corporate income taxes may be estimated by the relation suggested by Doane (1976):

$$C_F = CRF_{K,N} \times \left[\frac{1 - (\tau \times DPF) - \alpha}{1 - \alpha} \right] \times CI_b \quad (2.61)$$

where the capital recovery factor, $CRF_{K,N}$ is:

$$CRF_{K,N} = \frac{K}{1 - (1 + K)^{-N}} \quad (2.62)$$

the weighted average after-tax cost of capital, K , of the utility is:

$$K = (1 - \tau)K_d f_d + K_c f_c + K_p f_p \quad (2.63)$$

the effective corporate income tax rate, τ , is:

$$\tau = \tau_s + (1 - \tau_s)\tau_f \quad (2.64)$$

the accelerated tax depreciation factor (based on sum of years digits method), DPF , is:

$$DPF = \frac{2(n - CRF_{K,n})}{n(n + 1)K} \quad (2.65)$$

the present value of invested capital, CI_b , in base year dollar value, is:

$$CI_b = CI_o \left[\frac{1 + g_c}{1 + g} \right]^{y_o - y_b} \quad (2.66)$$

and other terms are defined as follows:

CI_o : capital invested at year y_o , in base year (y_b) dollar value, inclusive of short term interest charges incurred during construction

f_c : common stock fraction of utility's capital structure

f_d : long term debt fraction of utility's capital structure

f_p : preferred stock fraction of utility's capital structure

g : general inflation rate

g_c : plant cost escalation rate

K_c : annual cost of utility's common stock

K_d : annual cost of utility's long term debt

K_p : annual cost of utility's preferred stock

N : book life of facility

n : tax life of facility

y_b : base year of analysis and pricing

y_o : initial year of commercial operation

τ : investment tax credit fraction

τ_s : state corporate income tax rate

τ_f : federal corporate income tax rate

Recurring Power Production Costs. Level annual recurrent costs for ad valorem taxes, operation and maintenance, administrative and general expense, and insurance may be estimated by the relation:

$$\bar{C}_R = CRF_{K,N} \times \beta \times CI_b \times \left[\frac{1 + g_R}{K - g_R} \right] \left[1 - \left(\frac{1 + g_R}{1 + K} \right)^N \right] \quad (2.67)$$

where the recurrent cost fraction, β , is:

$$\beta = \beta_{OM} + \beta_{AG} + \beta_I + \beta_{AV} \quad (2.68)$$

with: β_{OM} being the annual operating and maintenance expense in year y_0 expressed as a fraction of the capital cost, CI_b ; β_{AG} being the annual administrative and general expense fraction of CI_b ; β_I being the annual insurance premium fraction of CI_b . Terms to the right of CI_b above represent the expression for determining the present value of a stream of uniform payments of $\beta \times CI_b$ initial value escalating at rate, g_R . Data for estimating the annual operating and maintenance capital cost fraction (β_{OM}) were provided by EG&G. (See section 2.2.4).

Resource Pricing Formula. For a given type of plant, the total level annual non-fuel production cost, in base year (y_b) dollars, is comprised of fixed ($\bar{C}_F$) and recurring ($\bar{C}_R$) components. Thus, the levelized resource pricing formula can be expressed:

$$\bar{P}_{h,b} = \bar{P}_{i,b} + \frac{(\bar{C}_F + \bar{C}_R)_{i,b} - (\bar{C}_F + \bar{C}_R)_{h,b}}{Q} \quad (2.69)$$

By defining:

$$\gamma \equiv \left[\frac{1 - (\tau \times \text{DPF}) - \alpha}{1 - \tau} \right] + \beta \left[\frac{1 + g_R}{K - g_R} \right] \left[1 - \left(\frac{1 + g_R}{1 + K} \right)^N \right] \quad (2.70)$$

the levelized pricing formula can be rewritten:

$$\bar{P}_{h,b} = P_{i,b} + \frac{\text{CRF}_{K,N} \times \gamma \times (CI_{i,o} - CI_{h,o}) \left[\frac{1+g_C}{1+g} \right]^{y_o - y_b}}{Q} \quad (2.71)$$

where $CI_{i,o}$ and $CI_{h,o}$ are capital investments in alternative and hydrothermal plants, respectively, at base year (y_b) cost levels for plants coming on-line in year y_o .

Assuming that fuel prices, including the hydrothermal fluid price, will escalate at an annual rate g_F , the level annual price for a fuel at base year y_b can be written:

$$P. \bar{P}_{.,b} = \text{CRF}_{K,N} \times P_{.,b} \times \left[\frac{1+g_F}{1+g} \right]^{y_o - y_b} \left[\frac{1+g_F}{K-g_F} \right] \left[1 - \left(\frac{1+g_F}{1+K} \right)^N \right] \quad (2.72)$$

where $P_{.,b}$ is the fuel price (not levelized) at the base year of the analysis (y_b). By substitution, a non-levelized resource pricing formula can now be written:

$$P_{h,b} = P_{i,b} + \frac{\gamma \times (CI_{i,o} - CI_{h,o}) \left[\frac{1+g_C}{1+g} \right]^{y_o - y_b}}{Q \times \left[\frac{1+g_F}{1+g} \right]^{y_o - y_b} \left[\frac{1+g_F}{K-g_F} \right] \left[1 - \left(\frac{1+g_F}{1+K} \right)^N \right]} \quad (2.73)$$

The quantity of electric energy produced annually, expressed in kilowatt-hours, is:

$$Q = \text{CAP} \times 8760 \times \text{KW} \quad (2.74)$$

where the capacity factor, CAP, is the fraction of a year that the plant actually produces power (a stochastic variable), 8760 are the hours in a

year, and KW is the rated plant capacity in kilowatts. By defining:

$$\epsilon \equiv \text{CAP} \times 8.760 \times \left[\frac{1+g_F}{K-g_F} \right] \left[1 - \left(\frac{1+g_F}{1+K} \right)^N \right] \quad (2.75)$$

the resource pricing formula can be written:

$$P_{h,b} = P_{i,b} + \frac{\gamma \times (CI_{i,o}^* - CI_{h,o}^*) \left[\frac{1+g_C}{1+g} \right]^{y_o - y_b}}{\epsilon \times \left[\frac{1+g_F}{1+g} \right]^{y_o - y_b}} \quad (2.76)$$

which provides the marginally competitive resource price in mills per kilowatt-hour at base year (y_b) price levels and dollar value. Note that $CI_{i,o}$ and $CI_{h,o}$ denote plant capital costs per rated kilowatt of capacity.

To estimate the hydrothermal fluid price when multiple plants are concerned, each commencing commercial operation in separate years, the pricing formula becomes:

$$P_{h,b} = P_{i,b} + \frac{\gamma \sum_j \left[\frac{1+g_C}{1+g} \right]^{y_{o,j} - y_b} (CI_{i,o_j}^* - CI_{h,o_j}^*)}{\epsilon \sum_j \left[\frac{1+g_F}{1+g} \right]^{y_{o,j} - y_b}} \quad (2.77)$$

Hydrothermal and Alternative Power Plant Capital Costs. Hydrothermal power plant capital cost data were provided by EG&G Idaho, Inc. as shown in Figure 2-8. The capital cost and fuel cost for the competing alternative power generation plant (i.e. $CI^*_{i,0}$ and $P_{i,b}$ in the resource pricing equations 2.75 and 2.76 above) varies from one locality to the next. For California and Utah areas, for example, coal-fired generation appears to be the least costly alternative to hydrothermal generation at this time; therefore, the busbar cost of coal-fired generation will determine the marginally competitive busbar price of hydrothermal power in these areas.

Recent coal plant cost estimates indicate that, at mid-1980 price levels, plants with flue gas desulfurization (FGD) equipment cost \$867/KW_e. Coal fuel prices at 1980 price levels in the Utah region are 10.7 mills/kWh based on system average costs supplied by Utah Power and Light Company (1978). In the California region coal prices are significantly higher (i.e. in the 15.0 to 17.0 mills/kWh range) because of the absence of long term purchase contracts and transportation expense.¹⁸

Transmission Line Capital Costs. Estimating capital costs for electric transmission is a complex task entailing numerous interrelated factors including total power being transported, system voltage, design of towers and foundations, size of conductors, span between towers, and costs of obtaining corridor Right of Ways and land for substations. For the present investment model applications the following assumptions pertaining to transmission costs are made.¹⁹

¹⁸California coal prices determined from estimates provided by the California Energy Commission and Pacific Gas and Electric Company.

¹⁹Transmission line cost in this study obtained from Utah Power and Light Co., Philadelphia Electric Co., Pacific Gas and Electric Co., Southern California Edison Company, San Diego Gas and Electric Company, and WESTEC Services, Inc.

At each resource site, transmission requirements needed to deliver hydrothermal power to load centers was determined. For power development levels below a 200 MW_e threshold, it is assumed that power will be transmitted to local substations. The cost of transmission feeder lines and substation tie-ins is estimated to be \$50/KW_e. For developments above this threshold, far more extensive transmission facilities will be required. Power will have to be routed greater distances and at high voltages to regional substations. This cost is estimated to be \$27,000,000 in mid 1980 dollars.

Chapter Three

WELL FIELD INVESTMENT DECISION ANALYSIS

A multiobjective decision model is used to estimate the likelihood that a resource developer will elect to invest in a hydrothermal well field opportunity. Each opportunity is defined in terms of the four attributes discussed in the previous chapter, namely: (a) rate of return on invested capital, (b) discounted investment payback time, (c) net present value of profits, and (d) the amount of capital at risk and the probability of incurring this loss.

The decision model provides a new and statistically sound integration of recent advances in both multiobjective decision analysis and applied theories of probabilistic choice as developed and discussed by Cassel (1979) and Cassel, et al. (1979b). The model is based upon interview responses from management representatives of twenty energy resource firms. Its predictive capabilities are substantiated by industry investment behavior as realized to date.

3.1 HYDROTHERMAL RESOURCE DEVELOPERS

The commercial potential of hydrothermal electric power is realized in the United States today largely due to the pioneering efforts of B.C. McCabe and his partners in Magma Power Company. In the mid-1950's, Magma drilled the first commercial steam well at The Geysers. Subsequent joint development by Magma, Thermal Power Company, and Pacific Gas and Electric Company produced the western hemisphere's first commercial geothermal electric power in 1960. In 1967, Union Oil Company of California joined the developers and, with its ample supply of capital, significantly advanced The Geysers rate of growth as illustrated in Figure 3-1. With more than 900,000 kilowatts of generation capacity installed today, The Geysers is the world's largest source of geothermal electric power.

Figure 3-1. DEVELOPMENT AT THE GEYSERS GEOTHERMAL AREA

Today the commercial feasibility of hydrothermal electric power attracts active investment and development interests of a large number and wide variety of resource producing firms. Major integrated petroleum and mining corporations and small independent operators alike are actively involved in exploring for, acquiring and developing hydrothermal resources. Table 3-1 provides a listing of current and proposed hydrothermal electric power projects and illustrates the types of firms participating in these ventures (Source: U.S.DOE, 1980 (2)).

For the purposes of this study, the resource developers are classified as follows:

- o Major Corporations. Large diversified corporations, usually integrated petroleum or mining companies, with assets typically in excess of one billion dollars and substantial income from non-geothermal operations. Annual capital investments and exploration expenditures are typically in the order of hundreds of millions of dollars. 20-30% of capital structure is long term debt. Weighted averaged after-tax cost of new capital is about 10-15%.
- o Independent Operators. Non-diversified, independently operating firms with annual investment and exploration budgets typically in the order of hundreds of thousands to millions of dollars. Financing is usually through sale of equity, frequently in the form of limited partnership interests. Minimum cost of new capital to the firm is about 15-20% to attract investors. Government loan guaranties may provide access to debt financing for these firms.

TABLE 3-1. CURRENT AND PROPOSED
GEOTHERMAL ELECTRIC POWER PROJECTS

STATE	AREA	DEVELOPER	UTILITY	NET OUTPUT MWZ	YEAR ON LINE	NOTES
CA	Brawley	Union Oil	SCE	10	1980	1
CA	East Mesa	Magma Power	SDG&E	10	1980	2,3
CA	Geysers	Union-Magma-Thermal	PG&E	11	1960	4
CA	Geysers	Union-Magma-Thermal	PG&E	13	1963	4
CA	Geysers	Union-Magma-Thermal	PG&E	27	1967	4
CA	Geysers	Union-Magma-Thermal	PG&E	27	1968	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1971	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1971	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1972	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1972	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1972	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1973	4
CA	Geysers	Union-Magma-Thermal	PG&E	53	1973	4
CA	Geysers	Union-Magma-Thermal	PG&E	106	1975	4
CA	Geysers	Union-Magma-Thermal	PG&E	106	1979	4
CA	Geysers	Thermogenics	PG&E	55	1979	4
CA	Geysers	Aminoil USA	PG&E	129	1980	4,5
CA	Brawley	CU-I Venture	CDWR	45	1984	6
CA	Brawley	Union Oil	SCSE			1,7
CA	Coso	California Energy	US Navy	20	1984	8,9
CA	Coso	California Energy	US Navy	55	1989	8,9
CA	East Mesa	Republic Geothermal	SDG&E	50	1982	3,10
CA	Geysers	MCR Geothermal	CDWR	55	1984	6,11
CA	Geysers	Geothermal Kinetics	CDWR	55	1985	6,12
CA	Geysers		CDWR	55	1986	6
CA	Geysers	Resources Funding	NCFA	66		13,14
CA	Geysers	Shell Oil	NCFA	110	1982	14
CA	Geysers	Union-Magma-Thermal	PG&E	110	1980	4
CA	Geysers	Union-Magma-Thermal	PG&E	110	1982	4
CA	Geysers	Union-Magma-Thermal	PG&E	110	1982	4
CA	Geysers	Aminoil USA	PG&E	110	1983	4,5
CA	Geysers	Union-Magma-Thermal	PG&E	110	1984	4
CA	Geysers	Aminoil USA	PG&E	55	1986	4,5
CA	Geysers	Union-Magma-Thermal	PG&E	110	1986	4
CA	Geysers		PG&E	110	1987	4
CA	Geysers		PG&E	110	1988	4
CA	Geysers		PG&E	110	1988	4
CA	Geysers	Aminoil USA	SMUD	55	1984	5,15
CA	Geysers		SMUD	55	1985	15
CA	Geysers		SMUD	55	1986	15
CA	Heber	Chevron	SCE	50	1982	1
CA	Heber	Chevron	SCE	100	1986	1
CA	Heber	Chevron	SDG&E	45	1984	3
CA	Mono-Long Valley	Magma Power	SCE	20	1985	1,2
CA	Niland	Union Oil	SCE			1,7
CA	Niland	Union Oil	SCE	10	1982	1
CA	Niland	Magma Power	SDG&E	24	1983	2,3
CA	Niland	Magma Power	SDG&E	49	1985	2,3
CA	Wendel-Amedef	Geoproducs	CDWR	50	1984	6,16
CA	Westmorland	Republic Geothermal		48	1985	10,17,18
HI	Puna	State of Hawaii	HELCO	3	1981	19
ID	Raft River	INEL/EG&C		5	1980	20
NM	Valles Caldera	Union Oil	PNM	45	1983	21
NV	Desert Peak	Phillips Petroleum	SPFC	10	1982	22,23
NV	Desert Peak	Phillips Petroleum	SPFC	50	1984	22,23
UT	Roosevelt N.S.	Phillips Petroleum	UP&L			24,25
UT	Roosevelt N.S.	Phillips Petroleum	UP&L	20	1983	25

- Notes:
1	8/1/80	Southern California Edison	15	8/19/80	Sacramento Municipal Utility District
2	8/7/80	Magma Power Inc.	16	8/7/80	Geoproducs Inc.
3	8/7/80	San Diego Gas & Electric	17	8/14/80	Department of Energy/San Francisco
4	8/6/80	Pacific Gas & Electric	18	8/18/80	MAPCO Inc.
5	8/15/80	Aminoil USA	19	8/11/80	Hawaii Department of Planning & Economic Development
6	7/31/80	California Department of Water Resources	20	8/12/80	Idaho National Engineering Laboratory
7	SCE has	contract with Union Oil for 450 MWZ steam supply	21	8/8/80	Department of Energy/Baca
8	8/6/80	California Energy Company	22	8/14/80	Sierra Pacific Power Company
9	8/6/80	US Navy	23		Desert Peak is a tentative area
10	8/15/80	Republic Geothermal Inc.	24		UP&L negotiating with Phillips for 200 to 300 MWZ steam supply
11	7/31/80	MCR Geothermal Inc.	25	8/11/80	Utah Power & Light
12	8/5/80	Geothermal Kinetics Inc.			
13		Developer reported to be in receivership			
14	8/7/80	Northern California Power Authority			

3.2 DECISION OBJECTIVES AND PREFERENCES

3.2.1 Investment Objectives

Interviews with management representatives of the twenty firms participating in this analysis indicate that four objectives are of primary concern to investment decision-makers of the energy resource industry. These investment objectives are to:

- o maximize the efficiency of invested capital (as assessed in terms of the anticipated net after-tax rate of return).
- o minimize the length of time during which invested capital is at risk (as assessed in terms of the anticipated investment payback time).
- o undertake projects which are compatible with the firm's scale of operations (as assessed in terms of the anticipated net present value of the profit stream).
- o avoid financial ruin (as assessed in terms of the amount of invested capital at risk).

Qualitatively the four investment objectives are similar for both large and small types of resource firms as defined above. Quantitatively, however, significant differences exist in the utility, i.e. numerical value of preference or aversion, that each type of firm attaches to given levels of the attributes: rate of return, payback time, present value of profits, and capital loss. These differences, as perceived by the major corporations and smaller independent operators are demonstrated in the following paragraphs.

3.2.2 Investment Attributes and Utilities

For predictive decision modeling purposes, the quality of a hydrothermal opportunity is assessed by the four investment attributes given above. The degree to which each of these attributes meets the firms' investment objectives may be expressed in terms of "numerical

utility". A minimum utility of zero implies "no investment incentive" and a maximum utility of one implies "highest positive incentive".

Utility functions, which translate attribute values into corresponding numerical utilities, were estimated from industry-supplied data for the two classes of resource developers: major diversified energy corporations and smaller non-diversified independent operators. After testing the industry responses for statistical heteroskedasticity, i.e. non-equality of variances across sample observations, the data was regressed either by simple least squares techniques, weighted least squares techniques, or non-linear multiple regression methods. The results of this statistical analysis, as illustrated in Figures 3-2, 3-3, 3-4 and 3-5 are utility functions of rate of return $U_R(r)$, payback time $U_P(p)$, present value of profits $U_V(v)$ and capital loss $U_L(v)$, respectively. These functions represent both the maximum likelihood estimates (MLE) and best linear unbiased estimates (BLUE) of the industry responses.

Figure 3-2. RESOURCE PRODUCERS' UTILITY FOR RATE OF RETURN ON INVESTED CAPITAL

Figure 3-3. RESOURCE PRODUCERS' UTILITY FOR INVESTMENT PAYBACK PERIOD

Figure 3-4. RESOURCE PRODUCERS' UTILITY FOR FINANCIAL GAIN

Figure 3-5. RESOURCE PRODUCERS' DISUTILITY OF FINANCIAL LOSS

Rate of Return. It may be noted that, in Figure 3-2, a minimum acceptable rate of return exists which is consistent with the discussion of threshold return as expressed in industry interviews. Furthermore, the curves in Figure 3-2 are monotonic increasing with r which is consistent with the industry responses of increasing preference for increasing return. Figure 3-2 also exhibits decreasing marginal utility in the direction of increasing preference which would indicate that preference asymptotically approaches an upper bound at high levels of return, i.e. at sufficiently high returns negligible additional investment incentive is provided by increasing the return.²⁰

As noted in Section 2.1.2, all costs incurred prior to resource confirmation (i.e. reconnaissance, exploration and land acquisition expenditures) are considered to be "sunk costs" in the well field cash flow model. These costs represent the up-front risk of a geothermal venture. The rate of return preferences implied by the utility curves in Figure 3-2 reflect a risk-adjustment which is sufficient to both recover sunk costs and earn a satisfactory return on post-discovery capital investments for well field development.

Payback Time. Figure 3-3 illustrates the utility functions for payback time, $U_p(p)$, which were produced from this assessment. It may be noted that the curves in Figure 3-3 are everywhere monotonic decreasing with increasing payback time which is consistent with decreasing industry preferences for long paybacks. Figure 3-3 also exhibits decreasing marginal utility as payback times get very short, indicating that at sufficiently short payback times, there is negligible additional investment incentive provided by further reduction in payback time.

It is also interesting to note that payback times in line with those of 8-10 years, as estimated for outer continental shelf oil ventures, are just above neutral preference, i.e. $U = 0.5$, for major corporations. This same payback period is below neutral preference for

²⁰t-statistics for the regression parameters of the corporate producers curve are at the 90% and 99% level of confidence; for the independent producer curve they are at the 80% and 99% level. Coefficients of determination (R^2) are 0.48 and 0.73 for the two curves, respectively.

the smaller firms, one of which indicated in a personal interview that available venture capital requires, at most, a 7 year payback²¹.

Present Value of Profits. Figure 3-4 illustrates the utility functions for net present value of profits, $U_V(v)$, which were produced from this analysis. From Figure 3-4 it is interesting to note that the utility curve for the small firm is reasonably consistent with that found by Grayson (1960) for a small operator. Grayson's curve appears to asymptotically approach a maximum preference at monetary gains in excess of \$1 million. The value today of \$1 million in 1958 (the time of Grayson's work) is \$2-3 million which is consistent with the lower limit of values in Figure 3-4 which approach maximum preference.

It is also interesting to note that the utility curve for the major corporations demonstrates neutral preference, i.e., $U=0.5$, at monetary gains of \$5-10 million and near maximum preference at about \$50 million. According to Greider (1978), a 5-10 million barrel onshore oil field is an average discovery which has a net present value of \$6-10 million. A 40 million barrel discovery is highly attractive, but rare, and has an estimated N.P.V. of \$43 million. These estimates for "average" and "attractive" N.P.V.'s are consistent with the "neutral" and "high" preference values shown in Figure 3-4²².

Capital Loss. The utility -- or more appropriately the disutility or aversion -- associated with various levels of monetary loss is estimated by the following method:

Industry decision makers are presented with sixteen hypothetical lotteries in which two outcomes are possible: there is possibility, P_j , that a monetary loss, L_j , will be incurred and probability $(1-P_j)$ that a monetary gain will be received. The gain is defined as the "maximum realistic gain" possible from a venture. Preferences for the sixteen combinations of four values of P_j and four values of L_j are provided by the decision maker on a 12-point scale.

²¹t-statistics for the corporate producer curve and for the independent producer curve are at the 99% level of confidence; coefficients of determination (R^2) for the two curves are 0.86 and 0.90, respectively.

²²t-statistics for the corporate producer curve are at the 80% to 99% level of confidence; those for the independent producer curve are all at the 99% level. Coefficients of determination (R^2) for the two curves are 0.70 and 0.85, respectively.

The preference scale is normalized from zero at the least preferable combination(s) of P_j and L_i , to one at the most preferable combination(s). Industry responses are interpreted as being the expected utility of each lottery which is:

$$EU_{ij} = P_j U(L_i) + (1-P_j) U(G) \quad (3.1)$$

The utility of the "maximum realistic gain", $U(G)$, is defined at the maximum value of one. It follows that:

$$U(L_i) = 1 - \frac{1 - EU_{ij}}{P_j} \quad (3.2)$$

After testing the industry data for heteroskedasticity, as discussed earlier, simple or weighted least squares regression techniques were employed to derive the utility functions for monetary loss, $U_L(v)$, as illustrated in Figure 3-5. It is interesting to note that, according to Figure 3-5, a major corporation shows fairly strong aversion to risks in the hundreds of millions of dollars while a smaller firm shows the same aversion to losses in the millions of dollars. Recent reports of exploratory oil drilling activities by major firms on the outer continental shelf indicate investment losses of \$60-\$150 million prior to abandonment. These reports are consistent with Figure 3-5. The risk aversion levels of the smaller firms represent a major fraction of their total assets which is not unexpected for independent, "wildcatting" operators.²³

3.2.3 Multiattribute Decision Analysis

When assessing an opportunity having uncertain, probabilistic outcomes, a resource developer is concerned with three attributes if an outcome represents a monetary gain:

- o rate of return on investment (r),
- o investment payback time (p), and
- o net present value of profits ($v > 0$).

²³t-statistics for the corporate producer curve and for the independent producer curve are at the 99% level of confidence. Coefficients of determination (R^2) are 0.31 and 0.62 for the two curves, respectively.

If an outcome represents a probabilistic monetary loss, the firm is concerned with one attribute:

o net present value of investment at risk ($v < 0$).

Conditional preferences for these four attributes are expressed in terms of the univariate utility functions -- U_R , U_P , U_V and U_L respectively -- as discussed above.

Multiobjective preferences for the positive outcomes, i.e. outcomes representing a monetary gain, are expressed in terms of a multiattribute utility function which is a nested function of the three conditional univariate utility functions:

$$U = f [U_R(r), U_P(p), U_V(v)] \text{ if } v > 0. \quad (3.3)$$

Aversions to a monetary loss are expressed in terms of the univariate utility function:

$$U = U_L(v) \quad \text{if } v \leq 0 \quad (3.4)$$

To estimate the functional form of the multiattribute utility function, f , in equation (3.3), industry decision responses were observed at 80 combinations of the three attributes. After statistically testing for properties of utility independence (see Cassel, 1979), step-wise multiple regression analysis was employed to converge on the most efficient multilinear form of f . Separate regression analyses were performed for the major corporate firms and for the independently operating firms.

For the major corporate firms, the resulting functional form of multiattribute utility is²⁴:

$$U = \begin{cases} .419U_R(r) + .133U_V(v) + .448U_R(r)U_P(p) & \text{for } v > 0 \\ (9.7) \quad (3.8) \quad (10.8) & R^2=.86 \\ & F=158 \end{cases} \quad (3.5)$$

and for the independently operating firms the resulting functional form is:

$$U = \begin{cases} .168U_V(v) + .345U_R(r)U_V(v) + .487U_R(r)U_P(p)U_V(v) & \text{for } v > 0 \\ (2.9) \quad (7.5) \quad (9.4) & R^2=.83 \\ & F=129 \end{cases} \quad (3.6)$$

An explanation of investment behavior by potential geothermal resource producers is provided by inspection of the multiattribute utility functions given in equations (3.5) and (3.6). Decisions by major resource corporations appear heavily weighted by the unconditional rate of return offered by an investment opportunity. This is consistent with both investment theory and the industry interviews discussed earlier. Anticipated payback time enters into the decision process only conditional upon a satisfactory rate of return; however, the combined influence of rate of return and payback time is strong. The influence of unconditional net present value of profits offered by an opportunity is appreciable but carries only a fraction of the weight of the rate of return criterion.

Decisions by the independent operators appear very heavily influenced by the conditional net present value of profits offered by an investment opportunity. The rate of return criterion is conditional upon

²⁴t-statistics for all "k" coefficients in both equation (3.5) and (3.6) are at the 99% level of confidence as are the F-statistics which test the joint confidence of the three additive terms. Coefficients of determination (R^2) for the two equations are 0.86 and 0.83, respectively.

satisfactory N.P.V. of profits and the payback time criterion is conditional upon both satisfactory rate of return and satisfactory N.P.V. of profits. The joint influence of rate of return and N.P.V. of profits is strong, as is the joint influence of rate of return, N.P.V. of profits and payback time. The unconditional influence of N.P.V. of profits is appreciable but not strong if the other two criteria are not satisfactory.

3.3 ESTIMATION OF PROBABILISTIC CHOICE

When choosing among alternatives with uncertain outcomes (i.e. opportunities characterized by probabilistic gains and losses) rational decision makers behave as maximizers of "expected utility"; that is, they will select opportunities offering the highest expected utility, EU:

$$EU = \sum U_i \Pi_i \quad (3.7)$$

where U_i is the utility of outcome i and Π_i is its probability of occurrence. Expected utility, EU, is the explanatory variable for rational decision behavior under conditions of uncertainty.

Theoretic literature on probabilistic models of binary choice (see Cassel, 1979) presents several models for making estimates of individual decision behavior--i.e., the probability that one will choose rather than reject opportunity A--as a function of one's utility for A. One particular model, the "logit" model, is selected for application here on the basis of conceptual propriety and analytical simplicity compared to alternative linear and "probit" models.

The logit model employed in this analysis is of the form:

$$P(A|EU_A) = \frac{1}{1 + e^{\alpha - \beta \cdot EU_A}} \quad (3.8)$$

which represents the probability of selecting opportunity A conditional upon the expected utility of A, EU_A . Figure 3-6 illustrates the general form of the logit model. The logit model was estimated separately for the major corporate firms and the independently operating firms by applying least squares regression techniques to the industry-supplied investment decision responses.²⁵

Figure 3-6. THE LOGIT MODEL OF PROBABILISTIC CHOICE

²⁵See Cassel (1979).

Chapter Four

POWER PLANT INVESTMENT ANALYSIS

As summarized earlier in this report, the numerical likelihood of electric power development at specified resource sites may be estimated by quantitative decision analysis methods. Specifically, the likelihood of well field development by resource developers, and the likelihood of power plant construction by electric utilities or third parties, are estimated by methods which integrate multiattribute utility techniques and logit regression techniques. Decision modeling of the resource developers is discussed in Chapter Three. The electric utility power plant investment decision model is discussed in this Chapter. Modeling of power plant investment decisions on the part of third parties is presented in Chapter Five.

4.1 THE ELECTRIC UTILITIES' ROLE IN HYDROTHERMAL DEVELOPMENT

Recalling Table 3-1 of the previous Chapter, the role of electric utilities in hydrothermal power plant financing is evident. Of the 48 commercial hydrothermal units currently on line or proposed, 38 have been or are to be financed by investor-owned electric utilities and 10 have been or are to be financed by tax-exempt municipal or state operated electric utilities. These figures demonstrate that hydrothermal electric power development in the United States primarily depends upon the dual decisions of (a) resource companies to invest in well field development, and (b) electric utilities -- investor-owned or municipal -- to invest in power plant construction.

Third party financing, which will be discussed in Chapter Five, provides an alternative source of power plant capital; however, this financing vehicle has not been instrumental in large scale hydrothermal power development to date and does not appear as a significant factor in currently planned large scale hydrothermal development. This report, therefore, views electric utility financing as the most likely source of hydrothermal power plant capital.

4.2 GENERATION PLANNING

The Federal Power Act of 1935 established an electric utility's fundamental responsibility as providing a reliable source of power to its customers at the lowest possible cost. The utility attempts to meet this responsibility while at the same time maintaining access to capital markets and satisfying all environmental and institutional constraints. Hence, a decision to introduce hydrothermal capacity will be made only if it is at least as responsive to these objectives as alternative base load technologies.

The development of an optimal generation expansion plan involves the work of system planners, corporate executives, financial market analysts, and public utility commission officials. As shown in Figure 4-1, future expansions are determined by first estimating capacity needs, and then developing a program to satisfy the expected needs at the lowest cost, subject to important financial and institutional considerations. In the following analysis, each of the steps in the development of an optimal expansion plan will be discussed, particularly as they apply to a hydrothermal power plant investment decision.

Figure 4-1. GENERATION EXPANSION PLANNING

4.2.1 Load Growth Projections.

Recent load growth projections for electric utilities in the Western System Coordinating Council (WSCC, see Figure 4-2) indicate that electric power demands are expected to grow at an annual rate of 4.4 percent over the next 10 years for the western system as a whole (WSCC, 1979). To meet these demands, utilities in the WSCC have announced a net increase in installed generation capacity of 59,000 megawatts by 1990. Of this planned increase, 90 percent is baseload capacity including some 15,000 megawatts of nuclear additions, 9,700 megawatts of conventional hydro additions, 27,000 megawatts of coal-fired additions and 1,800 megawatts of geothermal additions.

Although only 3 percent of the planned increase is presently slated as geothermal power, the baseload qualities of geothermal generation render it a suitable candidate for a much greater fraction of the 59,000 megawatt increase. If economically feasible, geothermal generation could, for example, supplant some of the planned nuclear and coal-fired additions. This may be desirable because, as noted in the WSCC reliability study, "nuclear and coal-fired baseload units are highly susceptible to delays...and substantial or sustained delays in these installations can be expected to have serious consequences on the adequacy of the region's bulk power supply". The relatively short construction lead times and minimal environmental impact of geothermal plants offer an attractive planning option.

Two recent and independent assessments of geothermal electric power potential concur that, at best, about 5,000 megawatts of economic geothermal generation could be installed by 1990 at known and projected resource discoveries (Kruger and Roberts, 1980, and U.S.D.O.E., 1980.1). This upside potential is less than 10 percent of the baseload additions required by western electric utilities within the same time frame. These figures demonstrate that optimistic geothermal supply projections are significantly less than baseload demand projections in western regions.

Figure 4-2. WESTERN SYSTEMS
COORDINATING COUNCIL

These paragraphs strongly support an underlying assumption to the work presented in this report; that is, within the foreseeable future, there will be no constraint on geothermal power demand attributable to utility system capacity requirements. There are likely to be constraints attributable to geothermal resource supply, relative generation economics and technical feasibility. However, if these criteria are satisfied, a demand for geothermal power does, and will, exist.

4.2.2 System Reliability

The electric utilities' mandate to supply reliable power dictates that adequate reserve margins be maintained as a buffer between installed generation capacity and peak system power demands. To accommodate risks attributable to delays in construction lead-times for new generation, unscheduled outage of installed generation equipment and uncertain system demand forecasts, electric utility planners use Loss of Load Probability (LOLP) estimates as a measure of expected system reliability (see EPRI, 1978; Lee et al, 1978; Masud, 1977). The LOLP represents the probability that available capacity will be inadequate to meet system demands over a specified time interval (normally one year), expressed as an expected value of the number of days per year in which capacity will be deficient. LOLP provides a useful measure of the need to install new or more reliable generation capacity. For most utilities, a LOLP of 0.1 days per year is generally indicative of adequate reserve margins. As LOLP begins to exceed this threshold, the ability of the system to meet expected demands comes into question and introduction of new or more reliable capacity is indicated.

Hydrothermal power plants offer both advantages and disadvantages when compared to conventional nuclear and fossil-fired baseload plants in terms of system reliability and LOLP. Hydrothermal advantages include the following:

- o Short Construction Lead Time. Compared to the excessive and uncertain construction and permitting lead times of coal and nuclear plants, the demonstrated two to three year lead time of hydrothermal plants contributes to sound generation planning and improved system reliability.

- o Small Unit Size. Economic unit sizes of hydrothermal plants are in the order of 10 to 100 megawatts (versus several hundred megawatts for coal and nuclear units). These smaller unit increments permit electric utilities, particularly smaller electric utilities, to closely follow capacity expansion profiles without creating excessive reserve margins. The relatively low unit cost of hydrothermal power plants is an advantage in that a resource may be progressively developed as production experience accumulates and site-specific uncertainties diminish. By the time capital of equivalent coal, oil or nuclear power plants is committed, perceived risks will have been significantly reduced through site-specific experience.

Hydrothermal disadvantages in terms of system reliability include:

- o Reservoir and Technology Performance Risk. Hydrothermal power plants carry a degree of performance uncertainty which is not common to nuclear and fossil-fired baseload plants. With the conventional plants, reliable operation is generally assured throughout the facilities' economic life barring prolonged disruption by regulatory shutdowns or by labor strikes or embargoes related to fuel supply. With hydrothermal plants, though, there remains some uncertainty about both the equipment technology (particularly at low temperature and/or highly saline resources) and the longterm production capability of the resource.²⁶ These uncertainties are ameliorated with time as production experience is gained at a specific resource. At The Geysers, for example, after 20 years of production experience Pacific Gas & Electric's power plants are providing availability factors at the same level as conventional fossil-fired plants (see Matthew, 1975). Nonetheless, each resource is unique and until two to five years (ref. Sanyal, 1980) of production experience is accumulated at each site, there are risks due to the uncertainties of: plant equipment performance; scaling and corrosion; producer and injector well flow; reservoir drawdown effects; differential land surface subsidence; and induced seismicity.

4.2.3 Generation Economics

As a regulated public industry, electric utilities have a mandate to minimize the cost of electric energy delivered to their customers. Once a need for capacity expansion has been identified, system planners must determine how the required capacity can be supplied most economically. This decision rests not only on the operating characteristics of units available for future installation, but also on the characteristics of the existing available capacity. Future expansion programs must be selected on the basis of which combination of new units (size and fuel

²⁶See EPRI (1978) for discussions of risks and uncertainties in geothermal power plant ventures.

type), when integrated into the existing system, will result in the lowest overall operating costs. Among the considerations which must be incorporated into this analysis are projected capital and fuel costs, operation and maintenance expenses, future escalation rates and individual generating unit reliabilities.²⁷

Levelized Energy Cost Analysis. Given that there is currently a demonstrated utilization potential for hydrothermal power by utilities in the WSCC (recall section 4.2.1), the economic viability of hydrothermal power becomes a critical focal point in the decision to install hydrothermal capacity. To evaluate the economic costs of hydrothermal power, a levelized energy cost model is used which incorporates all relevant cost considerations. The rationale for selecting the levelized energy cost methodology to evaluate the economic attractiveness of hydrothermal power vis a vis alternative coal or nuclear generation, rather than the more comprehensive system-wide linear or dynamic programming techniques discussed above, rests on several key judgements. Hydrothermal power effectively competes only with baseload power sources. Thus any new hydrothermal power would supplant alternative new baseload capacity. Major revisions in generation dispatch would not result from small (less than 300 MW) additions of hydrothermal capacity. If the levelized energy cost analysis shows hydrothermal power to be competitive with nuclear or fossil fuel plants on a mills per kWh basis, the addition of hydrothermal power into the system will not materially change the optimal 20-30 year generation plan derived through programming techniques.

²⁷To minimize total system costs, system planners must evaluate the tradeoff between the installation of high capital/low operating cost baseload units versus peaking units of low capital but high operating costs. A number of generation expansion planning models have been developed to assist system planners in evaluating this tradeoff. Commonly used analytical techniques involve the use of linear, dynamic or integer programming routines (for overviews of such, see Anderson, 1972; Lee et al., 1978). Examples of models commonly used by electric utilities include: Westinghouse Generation Expansion Optimization Program; Optimized Generation Planning, (General Electric Corporation); Wien Automatic System Planning Package, (Oak Ridge National Laboratory); Economic Environmental System Planning Package, (Massachusetts Institute of Technology); Planning of Unconventional Power Sources, (Systems Control Inc.).

Equally important is the fact that as a relatively new technology, risk averse utilities are apt to adopt hydrothermal power only after corporate decision makers have analyzed the proposed single unit addition. The uncertainties involved in adoption of new technologies can be more easily captured and focused upon in a levelized energy cost analysis than in the linear programming framework of analysis. These estimations can provide "bottom-line" comparisons between competing generation units which are especially useful to utility corporate executives and members of public utility commissions in the assessment of proposed capacity expansions. Examples of studies utilizing levelized energy costs as the primary focus for economic comparisons of alternative capacity additions include ERDA, 1976; Stover, 1976; Mitre, 1978, and Wimer, 1977. The levelized busbar cost methodology used in this analysis is discussed in Sections 2.2 and 2.3.

4.2.4 Financial Considerations

The financial conditions of an electric utility can play an important role in the capacity expansion decision. Because of the capital-intensive nature of the industry, utilities need to maintain ready access to capital markets at interest rates that are not excessive. The generation expansion planning process must be careful to incorporate any financial limitations of the utility, and the general conditions of the current financial market. Failure to include these financial parameters in the ultimate decision may result in a high cost of capital or, in the extreme case, a total inability to raise needed capital in the financial market.

Financial constraints have played an increasingly important role in recent years. Capital availability has been severely strained as escalating capital costs and regulatory lag have resulted in lower debt coverage ratios and lower stock prices. As shown in Table 4-1, the financial conditions became especially severe during 1973-1975. It is estimated that almost 200,000 MW of new fossil or nuclear generating capacity were either cancelled or delayed because of the deterioration of the utilities' financial situation (Business Week, 1975).

TABLE 4-1. FINANCIAL OVERVIEW OF ELECTRIC UTILITIES, 1952-1975

Characteristic	"Golden Age" (1952-1966)	Transition (1966-1973)	"Hard Times" (1973-1975)
Ratio of internally generated funds to capital expenditures	.8	.5	.3
Coverage ratio	>5.0	3.0	2.0
Interest rate (%)	<4.6	5-7	>8.14
Inflation rate (%)	1.25	4.5	9.5
Stock price (% of book)	250	150	<100
Construction	Average	Heavy	Cutbacks
Consumer rates	Decreasing	Steadily increasing	Accelerating

Source: Rand Corporation, 1977.

Capacity additions may be financed with debt issues, equity issues, and internally generated funds. Because of the increasing capital expenditure requirements of the industry, primary reliance is placed on debt issues and equity issues (both common and preferred stock). Debt issues and preferred stock are the least expensive source of capital available to the utility. Expansion programs cannot be financed exclusively by low cost debt issues however. Utilities have optimal capital structures which determine the proportion of long term debt, preferred stock and common stock which will minimize overall capital cost. Recently, the optimal capital structure is approximately 50 percent long term debt, 10 percent preferred stock, and 40 percent common stock. In the following discussion, the role which each capital source plays in the capacity expansion decision-making process is assessed.

Debt Issues. The ability of a utility to finance a proposed capacity addition and the cost of this financing is tied to the bond ratings assigned to its debt issues. Although the rating agencies qualitatively define what each rating represents, they do not specify explicitly how they arrive at the ratings. The rating agencies do indicate the electric utility characteristics, (see Table 4-2), that they consider in determining ratings. Table 4-3 contains a glossary of terms for the financial ratios in Table 4-2. From Table 4-2, it can be seen that the evaluation process includes general considerations about the overall market and power system of the utility, takes into account existing construction plans, the regulatory climate, and existing outstanding debt obligations, and estimates of a set of key financial ratios that relate the ability of the utility to repay its debt obligations. These financial ratios provide a reasonably accurate explanatory variable for bond rating decisions (Rand, 1977; Standard and Poor's, 1976 and 1978). These include the pretax and after-tax coverage ratios, defined by:

$$\text{After-Tax Coverage Ratio} = \frac{\text{After Tax Net Income Before Interest Expense}}{\text{Interest Expenses}}$$

$$\text{Pretax Coverage Ratio} = \frac{\text{Net Income Before Tax and Interest Expenses}}{\text{Interest Expenses}}$$

TABLE 4-2. ELEMENTS CONSIDERED IN THE RATING PROCESS

Economic Analysis of Service Territory

Population
Wealth
Employment
Size of service area and outlook
Historic and estimated load growth customers

Type of System

Self generation
Distribution
Combination
Wholesale and bulk power

Facilities

Fuel mix; cost, availability and price
Capacity and reserves
Operating cost
Environmental concerns

Capital Improvement Plans

Realistic construction cost estimates
Alternatives to own construction

Rate Structure

Likely regulatory climate
Comparative rates
Ability to adjust

Bond Security

Revenues
Debt service reserve
Contingency fund
Capitalized interest
Rate covenant
Additional bonds covenant
Power contracts

Key Ratios

Operating ratio
Net take-down
Interest coverage
Debt service coverage
Debt service safety margin
Debt ratio
Interest safety margin

TABLE 4-3. GLOSSARY FOR FINANCIAL RATIOS

- 1) Operating ratio: operating and maintenance expenses (excluding depreciation) divided by total operating revenues.
- 2) Net take-down: net revenues (gross revenues less operating and maintenance expenses) divided by system gross revenues.
- 3) Interest coverage: interest for year divided into net revenues available for debt service.
- 4) Debt service coverage: principal plus interest requirements for year divided into net revenues available for debt service.
- 5) Debt service safety margin: system gross revenues less operating and maintenance expenses and less current debt service divided by system gross revenues.
- 6) Debt ratio: net debt (gross debt as shown on balance sheet less bond principal reserve) divided by sum of net utility plant plus net working capital.
- 7) Interest safety margin: gross revenues less operating and maintenance expenses and less current interest for year divided by system gross revenue.

Standard and Poor's Corporation suggests the following general relationship between pretax coverage, bond rating, and cost of capital (Standard and Poor's, 1976):

Coverage Ratio	Bond Rating	Average Yield
3.0 - 3.5	AA	11.0%
2.5 - 2.75	A	11.3%
< 2.0	BBB	12.1%

Capacity expansion programs must therefore be carefully structured to avoid lowering the debt service coverage ratios below the threshold levels cited above. Should a new debt issue have to be derated, interest charges can be expected to rise accordingly. Further, the ability to finance additional future construction projects may be effectively eliminated if a utility finds itself with minimum coverage ratios, as specified in the utility's bond covenant requirements.

Hydrothermal plant additions may have one of two effects on the critical debt service coverage ratios of the utility. Recent capital cost estimates for hydrothermal power plants appear lower, per kilowatt of capacity, than those of alternative coal²⁸ or nuclear plants. This is of particular advantage to utilities in tight capital situations and, if the plant provides a reliable source of power over its 20-30 year service life, the utility would increase its debt service ratios by replacing more capital intensive conventional base load units with geothermal capacity. Further, if hydrothermal power proved to have lower variable costs per kWh, the earnings or net income of the utility would be enhanced. Both these factors would leave the utility in a more secure capital position over the conventional base load option, with a lower overall cost of capital.

²⁸With flue gas desulfurization equipment.

Potentially adverse financial consequences, however, could result from a major failure of the hydrothermal plant. Loss of any hydrothermal unit would force the utility to purchase more expensive power, causing a reduction in net income if rates were not immediately increased. In the case of a privately-owned utility, the remaining undepreciated value of the plant could be removed from the rate base at the discretion of the public utility commission. The utility would no longer be able to earn the regulated rate of return on the hydrothermal plant, further compounding the utility's financial dilemma. The impacts that such potential plant or reservoir failures may have on debt coverage ratios and bond rating must be carefully analyzed. Hydrothermal investment may be deferred or effectively eliminated if the probability of plant failure and its subsequent financial impacts is thought to seriously jeopardize the utility's access to capital markets.

Two vehicles presently exist for mitigating much of the risk associated with geothermal project failure. One is the U.S. government's Geothermal Loan Guaranty Program (GLGP) which is a temporary scheme (due to expire in 1989) that guarantees up to 75% of a project's cost (up to 90% for municipal and co-operative utilities). The second is commercially available geothermal reservoir insurance which will insure project capital against resource failure. There are costs attached to both vehicles which may affect the competitive economics of a geothermal project; however, the protection offered by these vehicles significantly reduces financial risk.

Interviews with executives of Wall Street investment brokerages, who are responsible for bond ratings, indicate that well conceived hydrothermal projects could serve to enhance a utility's rating. Several factors will contribute to this possible enhancement:

- o Given the current uncertainties pertaining to international oil supply, nuclear safety, and the environmental and labor aspects of coal, there is a degree of desirability for fuel source diversification through the use of domestic alternatives such as hydrothermal energy.

- o If an issue is structured such that the hydrothermal capital is but a small percentage of the total issue -- i.e. that a major portion of the issue is for "conventional" non-hydrothermal construction -- then any perceived risks associated with hydrothermal generation could be effectively sheltered by the non-hydrothermal generation.
- o Sequential plant development for a hydrothermal field may keep capital requirements small until the riskiness of development has been reduced. Hence the small geothermal project size tends to counteract perceived riskiness of such projects.
- o Much of the rating impact of a hydrothermal project will depend upon the anticipated or realized actions of public utility commissions. As mentioned earlier, if a commission will grant adequate and timely rate relief and/or accelerated write-off in the event of a hydrothermal failure, it is unlikely that the financial position of the utility would be adversely affected. If the management of the utility can justify its attempt to develop new power sources, a priori and ex post evaluations by the capital markets and regulatory authorities may be supportive.
- o Finally, if the projects' economics can absorb the attendant costs of implementing the U.S. Department of Energy's Geothermal Loan Guaranty or commercial reservoir insurance, much of the perceived financial risk can be mitigated and favorable response can be anticipated from the capital market.

Equity Issues. As discussed earlier, equity capital can be expected to make up approximately 50 percent of a utility's capital structure. Like bond issues however, capital acquisition by the sale of stock is subject to important market limitations. If the total equity base increases more slowly than the total number of shares outstanding, total earnings per share will decrease unless offset by an increase in the regulated rate of return. Such dilution of an investor's equity share will depress market value of the stock and deter stock purchases.

As market performance of a utility's stocks degrades, equity capital becomes more difficult and expensive to raise. As shown in Table 4-1, market prices fell from 250 to less than 100 percent of book

value during the period from 1960-1975. This is attributed to the lack of growth in earnings, a regulated rate of return which was not competitive with alternative investments, increased fears of further stock dilution, and increased risk due to declining interest coverage (Flesher, 1976). To maintain the quality of an electric utility's equity, capacity expansions must not have an adverse impact on utility earnings, while at the same time adding to the stockholders' total equity base.

Internally Generated Funds. Internally generated funds include revenues from retained earnings, depreciation, deferred taxes, and tax credits. Because of the large capital demands of utilities, internally generated funds do not represent a major source of funding for capacity expansions. As shown in Table 4-1, capital expenditures were 3 times the volume of internally generated funds during the period from 1973-1975. The importance of a proposed capacity expansion's impact on internally generated funds rests on what subsequent impacts will be felt on interest coverage ratios and stock values. As discussed above, a utility's ability to issue debt and equity capital is closely linked to the volume of internally generated funds.

A large utility may elect to classify the first hydrothermal unit at a reservoir as a research, development and demonstration (RD&D) facility. The relatively low cost of the initial unit (i.e. about \$10-20 million for a 10-20 megawatt unit in 1980) may permit this to be expensed as an RD&D item and to be financed entirely from internal funds. Given that the first unit at a reservoir, in the absence of any production experience, is the most risky investment, this method of financing the first unit may be particularly attractive. Subsequent commercial units at the reservoir would be financed with debt/equity issues as normally used for capacity expansion.

4.2.5 Institutional Factors

Any generation expansion plan must be formulated with a clear understanding of the relevant environmental and regulatory issues which may act as constraints on the development of the program. Such obstacles increase both the uncertainty associated with plant construction costs and the date of project completion. More restrictive environmental standards and licensing procedures can increase capital costs of new units by requiring more expensive abatement equipment and delaying project completion, thereby adding to interest charges. Two types of institutional considerations are identified as major elements in the capacity expansion plan: 1) adherence to all state and federal environmental and land use statutes, and 2) in the case of a regulated utility, public utility commission approval.

Environmental Acceptability. Environmental and land use restrictions currently play an important role in the development of an optimal generation expansion plan. As shown in Figure 4-3, any new capacity addition must comply with federal, state, and local environmental statutes. The most important standards influencing generation technology choice include (ERDA, 1976):

- o Emission limitations for sulfur oxides, nitrogen oxides, and suspended particles;
- o Thermal discharge limitations;
- o Criteria for siting, design construction, and operation;
- o Discharge limitations in effluent water;
- o Controls on resource exploitation;
- o Air and water quality standards applicable to facilities integrated with the power plant;
- o Limitations on development of naturally occurring sites.

Institutional Considerations	Local Zoning Regulations	Uncertainty of Length or Results of Hearings for Sites and Rights-of-Way
	State Regulations	Public Service Commission Hearings
		State Environmental Laws
		Legal Actions by Those For and Against Plan
		Uncertainty of Governmental Policy
	Federal Regulations	Federal Power Commission FEA Regulations
		Environmental Protection Laws
		National Defense Considerations
		Energy Policy for Better Utilization of National Resources
		Uncertainty of Governmental Policies

Source: Masud, 1976.

**Figure 4-3. INSTITUTIONAL CONSIDERATIONS IN
GENERATION EXPANSION PLANNING**

Public Utility Commission Approval. A regulated utility must have any new generating unit approved by the state public utility commission if it is to be allowed a return on the capital invested in that unit. The public utility commission, by granting a Certification of Public Necessity, allows the utility to add the invested capital to its rate base and thereby earn the regulated rate of return on that capital. The CPN is generally granted only after the unit is on-line, and after it has been shown to be a wise and prudent investment. This assessment is generally based on the following considerations:

- o Is there a proven need for the power;
- o Can the utility properly finance the facility;
- o Does the project minimize the rate-payers burden;
- o Other public policy considerations (e.g. conservation of non-renewable resources, diversification of fuel supplies, etc).

The public utility commissions may, at their discretion, actively promote technologies which they consider especially desirable. This can be done by revising current standards for construction work in progress, depreciation allowances, write-off provisions in the event of unit failure, and by adjusting rate of return on specific units to reflect risk premiums.

For purposes of choosing between hydrothermal and conventional baseload units, institutional factors may be subsumed under the energy cost and financial considerations outlined above. Environmental factors are to be embodied in the capital cost, operating cost and performance of new units. Included in the capital cost are whatever pollution abatement technologies are needed to make the unit satisfy all state and federal environmental statutes. Special tax-exempt and/or low interest bonds may be available for pollution control capital and this will impact financial considerations. The impact of unexpected plant licensing and construction delays on total capital cost is included in the energy cost by representing the generating unit's lead time stochastically.

4.3 MODELING THE ELECTRIC UTILITIES' DECISION

4.3.1 Investment Objectives and Project Attributes

Over the past two years, Technecon has surveyed eighteen investor-owned and municipal electric utilities to develop an efficient modeling approach for forecasting hydrothermal power plant investments. As a regulated and capital intensive industry, the utilities' investment objectives are understandably different from those of the unregulated and profit-oriented resource developers discussed in Chapter 3. Four investment objectives were found to be of primary concern for modeling the behavior of decision makers within the electric utility industry.

These objectives are to:

- o minimize ratepayers' burden (as modeled here in terms of the ratio of the cost--in mills/kWh--of alternative baseload generation delivered to a main transmission corridor to that of the hydrothermal generation);
- o maintain desirable margins of generation reserve by matching baseload growth profiles (as modeled here in terms of the megawatt capacity of the hydrothermal reservoir);
- o maximize generation system reliability (as modeled here in terms of the anticipated capacity factor of the hydrothermal power plant);
- o minimize adverse effects on the availability and cost of construction capital (as modeled here in terms of the impact upon the "times interest earned ratio" -- TIER, a measure of bond health -- of a probabilistic hydrothermal failure).

For decision modeling purposes, the quality of a hydrothermal power plant project is assessed by the four attributes given in parentheses above, i.e. electric energy cost ratio, reservoir capacity, plant capacity factor and TIER impact. It will be demonstrated that these four attributes are statistically acceptable explanatory variables for the predictive modeling of electric utilities' hydrothermal investment decisions. As discussed in Section 4.2, however, the actual generation planning process in the electric utility industry is considerably more complex than the procedure outlined below for stochastic predictions.

4.3.2 Preference Rankings

The degree to which each of the four attributes meets the electric utilities' investment objectives may be expressed in terms of "numerical utility".²⁹ As defined earlier in Section 3.2.2, a minimum utility of zero implies "no investment incentive" and a maximum utility of one implies "highest positive incentive".

Utility functions were estimated for the four power plant attributes by applying the same statistical procedures outlined in Section 3.2.2 to industry-supplied decision data. The results of this analysis, as illustrated in Figures 4-4, 4-5, 4-6 and 4-7, are utility functions of electric energy cost ratio $U_C(c)$, reservoir capacity $U_M(m)$, plant capacity factor $U_F(f)$, and TIER impact $U_T(t)$, respectively.³⁰

²⁹To avoid confusion between electric "utilities" (companies) and numerical "utilities" (preferences), the former will always be prefaced with "electric".

³⁰In Figures 4-4 through 4-7 the term "preference level" has been introduced in place of "utility". The terms may be considered synonymous for the purposes of this report.

Figure 4-4. ELECTRIC UTILITIES' PREFERENCE:
BUSBAR COST RATIO

Figure 4-5. ELECTRIC UTILITIES' PREFERENCE:
RESERVOIR CAPACITY

Figure 4-7. ELECTRIC UTILITIES' PREFERENCE:
TIMES INTEREST EARNED RATIO DECREASE

Figure 4-6. ELECTRIC UTILITIES' PREFERENCE:
PLANT CAPACITY FACTOR

Discussions of each of the four power plant attributes and their corresponding utility functions follow below. In section 4.3.3 a multiattribute utility function is presented which combines and "weights" the four univariate utilities, based upon regressions of electric utility industry data, into a single measure of multiobjective preference. In section 4.3.4 the methodology is presented for relating the multiattribute utility of section 4.3.3 to the numerical likelihood of a positive electric utility investment decision.

Electric Energy Cost Ratio. As a regulated public industry, electric utilities have a mandate to minimize the cost of electric energy delivered to their customers. Interviews with management representatives of electric utilities indicate that cost minimization is a major objective in investment decisions.

The cost-competitiveness of electric energy may be determined at the point where this energy reaches a main transmission line corridor. At this point, the total energy cost - including fuel cost, power production costs, and apportioned transmission cost - competes with those costs of alternative forms of baseload generation, e.g. coal, nuclear, and oil-fired generation. Responses of western electric utilities to questions of concern for electric energy cost indicate that for favorable consideration, hydrothermal electric energy must be roughly competitive in cost to that of the least expensive alternative form of baseload generation.

As indicated in Figure 4-4, electric utilities express no desire to use hydrothermal generation if an alternative type of baseload generation is available at less than 65% of the hydrothermal cost. The electric utilities' utility for hydrothermal power increases steadily from this 65% value and approaches a maximum level of preference when the alternative generation is about 50% more costly than hydrothermal. Hydrothermal utility is marginally diminishing at high cost ratios and approaches an asymptote which indicates that a level of sufficiently favorable economics exists beyond which there is little additional incentive to be gained by reducing hydrothermal costs.³¹

³¹t-statistics for the regression parameters of the electric utilities' cost ratio curve are at the 99% level of confidence; the curve's coefficient of determination is 0.75.

Reservoir Capacity. Industry responses to questions of preference for hydrothermal generation as a function of the megawatt capacity of a resource varied, understandably, according to the size of an electric utility's system demand. As shown in Figure 4-5, small municipal and rural electric utilities expressed a fairly high preference for generation sources of 20 to 50 megawatts. Larger electric utility systems, on the other hand, expressed the same high level of preference for generation sources of 200 to 300 megawatts. Disaggregation of industry responses into two groups depending on system baseload demand provided the statistically-sound regression results shown in Figure 4-5.³²

Plant Capacity Factor. Capacity factor is the fraction of the hours in a year during which a power plant is in commercial operation. It provides a measure of outage due to forced and scheduled maintenance as well as discretionary down-time due to lack of system demand and economic dispatch considerations. Hydrothermal generation is viewed throughout the electric utility industry as baseload generation because of the technical desirability of maintaining producer well flow and, therefore, of avoiding plant cycling. Baseload generation typically has a reliable capacity factor in the range of 0.65 to 0.85. Figure 4-6 was developed from industry responses and is consistent with capacity factor expectations as published in electric power literature.³³

TIER Impact. Because of their capital-intensive nature, electric utilities must maintain access to capital markets at interest rates which are not excessive. The ability of an electric utility to finance needed capacity additions, and the cost of this financing, is closely related to bond ratings assigned to a company's debt issues. Bond

³²t-statistics and F-statistics for the regression parameters of the reservoir capacity curves are at the 99% level of confidence; the curves' coefficient of determination is 0.63.

³³t-statistics for the regression parameters of the capacity factor curve are at the 99% level of confidence; the curve's coefficient of determination is 0.82.

ratings are determined by investment firms based upon a review of several characteristics of the company pertaining to its financial health. Of these several characteristics, certain key financial ratios describing the electric utility's ability to repay debt issues are closely correlated with rating decisions. Pre-tax and after-tax coverage ratios (TIER) are often suggested as the most accurate predictor of corporate bond ratings.

Figure 4-7 illustrates the utility function for TIER impact which was developed by a regression analysis of industry survey responses.³⁴ As discussed in Section 2, three consulting geothermal reservoir engineers and geologists were retained by Technecon to assess the numerical probabilities of premature reservoir failure over the 30 year book life of a hydrothermal power plant. These assessments are coupled with the power plant cash flow model to estimate probabilistic impacts on an electric utility's TIER.

4.3.3 Multiobjective Decision Analysis

Conditional preferences for the four primary attributes of a power plant investment (i.e., electric energy cost ratio, c ; plant size, m ; unit capacity factor, f ; and TIER impact, t) are expressed by the four univariate utility functions (U_C , U_M , U_F and U_T , respectively) as discussed above. These univariate functions are combined into a single multiattribute measure of multiobjective preference by statistical regression of industry-supplied data as discussed in section 3.2.3. The resulting functional form of a multiattribute utility for electric utilities is³⁵:

$$U = .467U_C(c)U_F(f) + .203U_C(c)U_M(m) + .330U_C(c)U_T(t) \quad \begin{matrix} R^2=.77 \\ F=258 \\ (4.1) \end{matrix}$$

(10.08) (3.63) (8.33)

³⁴t-statistics for the regression parameters of the TIER curve are at the 99% level of confidence; the curve's coefficient of determination is 0.93.

³⁵t-statistics and F-statistics for equation (4.1) are all at the 99% level of confidence; the coefficient of determination (corrected for degrees of freedom) is 0.74.

Inspection of equation 4.1 indicates that an electric utility's decision to invest in a hydrothermal project is heavily influenced by the economics of hydrothermal generation relative to alternative forms of conventional baseload generation. The electricity cost ratio utility $U_C(c)$ enters into every term of the equation. All other attributes (i.e., capacity factor f , reservoir capacity m , and TIER impact t) enter into the decision process conditional upon economic considerations.

To account for the uncertainties associated with hydrothermal projects, probability distributions are associated with each of four project attributes. This produces a probabilistic measure of multiattribute utility (U in equation 4.1) such that a numerical probability Π_i is associated with each multiattribute utility U_i . As discussed earlier in section 3.3, rational decision makers select opportunities having the highest "expected utility" EU , where:

$$EU = \sum U_i \Pi_i \quad (4.2)$$

Estimates of the numerical likelihood that an electric utility will respond positively to a hydrothermal opportunity are provided by a logit model (as discussed earlier) of the form:

$$P = \frac{1}{1 + e^{\alpha - \beta EU}} \quad (4.3)$$

which is determined by regression analysis of decision data provided by the electric utility industry.

The logit decision models of both the hydrothermal resource developing industry and the electric utility industry are statistically-strong. Furthermore, results of the models applications to date are well supported by the actual investment behavior of these industries.

Chapter Five

POWER PLANT INVESTMENT DECISIONS BY THIRD PARTIES

5.1 POWER PLANT LEASING

5.1.1 Leasing Arrangements in the Electric Utility Industry

Based upon the history of hydrothermal power plant financing as realized and planned to date (recall Table 3-1), this report views the most likely source of capital for hydrothermal power plant construction projects to be electric utilities. Never the less, project financing by a third party, i.e. a party other than a resource developer or an electric utility, has been recommended as a vehicle for expediting the construction of hydrothermal power plant facilities (see Beim, 1978; Panawek, 1978; and Rodzianko, 1978 and 1979). Under such an arrangement, a third party finances and holds title to the power plant which is leased and operated by a regional electric utility. The advantages of this type of financing are:

- o it avoids investment in hydrothermal projects by a risk averse electric utility which is frequently in tight capital situations;
- o in areas where a utility is unwilling to finance a geothermal plant, it eliminates the need for a resource developer to do so and, thereby, to invest more capital than that already invested in well field development;
- o it prevents classification of the resource developer as a regulated public utility which is a concern if the developer were to finance and operate a power plant;
- o it allows private investors to receive a fair rate of return which is commensurate with the degree of risk in a geothermal venture, i.e. a higher return than that permitted for regulated electric utility investments.

Plant leasing arrangements are not uncommon to the electric utility industry. In the recent past, increased requirements for generating capacity have forced many utilities into heavy construction programs

which, in several cases, have exceeded their limits to accessible capital. Leasing arrangements have provided a means for utilities in such a capital squeeze to add needed plant capacity without committing additional capital of their own.

5.1.2 Hydrothermal Risk Perception and Minimization

Consortiums of banks and traditional institutional investors such as insurance companies and pension funds have been willing to finance and lease electric power plants largely because of the essentially low risk nature of these projects. Hydrothermal power plants, however, carry a degree of risk which is not common to previous hydro, nuclear or fossil-fired plants³⁶. With the previous plants, reliable operation could be assured throughout the facilities' economic life barring prolonged disruption by labor strikes, embargoes or regulatory shutdowns. With the hydrothermal plant, though, there remains some uncertainty about both the equipment technology and the longterm production capability of the subsurface resource. These hydrothermal uncertainties are likely to be perceived as unacceptable investment risks by the banks and traditional financial institutions unless some form of indemnification against loss can be provided.

Two means of indemnification against investment loss are presently available to investors in hydrothermal projects. These are the U.S. government-backed Geothermal Loan Guaranty Program (GLGP) and commercially available geothermal resource insurance.

Geothermal Loan Guaranty Program. The GLGP will back, with the full faith and credit of the U.S. government, up to 75% of the cost of a qualifying geothermal venture (see Woods, 1978). For municipal and cooperative projects, the GLGP will guaranty up to 90% of the projects' cost. The remaining 10% or 25% at-risk portion is provided in some form of equity investment and may include previously sunk capital such as well field confirmation and development investments. Despite the

³⁶See EPRI (1978) for discussions of risks and uncertainties in geothermal power plant ventures.

application and servicing paperwork required for the GLGP, and an additional one percent servicing fee added to the cost of the GLGP-backed funds, the program has been successful in securing loans from risk averse banks and financial institutions. The GLGP is a temporary incentive scheme which is presently due to expire in 1989.

Geothermal Resource Insurance. Geothermal resource insurance has been recommended for indemnifying investors against the risks of unexpected reservoir failure (see EPRI, 1978). Insurance of this type recently became commercially available³⁷ and provides a means for the geothermal industry to secure investment capital without continued government support. The ability of a venture to absorb the premiums for such insurance will depend upon site-specific project economics. Recent evaluation of investment opportunities at several hydrothermal areas (see Cassel, et al., 1979) indicates that it is likely the costs of these premiums can be absorbed while maintaining attractive investment returns.

Geothermal resource insurance offers to mitigate the investment risks to which electric utilities have been highly averse in the past. In doing so, this insurance eliminates one reason for third party financing in hydrothermal power plant projects. However, a second reason for third party financing -- that being the shortage of available capital to many utilities -- remains as an important reason for this type of project financing.

5.1.3 Structuring the Tax Leveraged Lease

Banks and institutional investors are likely to provide funds for third party financing of geothermal power plants if resource insurance is structured such that risks to invested capital are effectively eliminated. With the availability of this debt capital, an attractive arrangement for third party financing is through a "tax leveraged lease". Tax leveraged leasing involves a lessor, who finances plant

³⁷Geothermal resource insurance has been initiated by Corroon & Black of Pennsylvania, Inc., Philadelphia.

construction with substantial amounts of borrowed capital and a minimum³⁸ amount of equity, and a lessee, who operates the plant, sells the electricity, and pays rental to the lessor plus all operating expenses and taxes. The rentals and investment tax benefits fully amortize the lessors investment while providing investors an attractive rate of return.

Tax Benefits. A particular advantage of the tax leveraged lease lies in its tax benefits, i.e. investment tax credits, accelerated capital depreciation, and deductible interest on borrowed funds. Electric utilities are frequently unable to use these benefits because of previous investments in heavy construction programs which have amassed a backlog of tax credits and deductions to legal limits. With third party financing via the tax leveraged lease, the lessor may be able to claim tax benefits on the full project cost while his actual equity investment is only a small fraction of this cost. These benefits are, in turn, passed on to the lessee, i.e. the electric utility, in the form of reduced rental payments.

When financing a leveraged lease, it may be necessary to provide the lender of borrowed capital with recourse to the lessor. In the absence of such recourse, many of the lessor's tax benefits may be limited by "at risk limitations" to the percentage of equity investment in the project. The potential consequences of IRS "at risk limitations" should be carefully assessed for their applicability to the particular circumstances of each project.

Equity investors should also assess potential consequences of IRS "preference income" provisions. For example, the difference between accelerated depreciation and straight line depreciation may be classified as preference income and be subject to minimum tax liabilities. This will depend upon the financial characteristics and tax brackets of individual investors and, depending on personal circumstances, may or may not be of significant concern.

³⁸Minimum equity requirements in tax leveraged leasing arrangements are 20% of project cost according to IRS Revenue Ruling 7521.

Public Utility Regulation. A concern of third party financiers is that, as owners of an operating power plant, they not be classified as a public utility subject to regulated investment returns. It appears that such classification can be avoided according to the Securities and Exchange Commission's adoption of Rule 7(d) under the Public Utility Holding Company Act of 1935. It also appears that such classification can be avoided under the Federal Power Commission's ruling of March 24, 1977 in the case of Ford Motor Credit Company, et al. Docket No. E-9580. However, the FPC (predecessor to the present Federal Energy Regulatory Commission, FERC) ruling will have to be tested for the specific circumstances of each leasing arrangement and may not be universally applicable.

5.2 PLANT OWNERSHIP --THE PUBLIC UTILITY REGULATORY POLICY ACT

The Public Utility Regulatory Policy Act (PURPA) exempts qualifying small power production facilities from certain provisions of the Federal Power Act, from all provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from state laws regulating electric utility rates and financial organization (Federal Register, 1980). As amended in 1980, PURPA explicitly includes hydrothermal power plants of 80 megawatts capacity or less in the category of qualifying small power production facilities. Multiple hydrothermal generation units at a single resource are also explicitly included in the qualifying category, provided their combined capacity does not exceed 140 megawatts (U.S.DOE 1980).

Under PURPA, electric utilities are required to purchase electric energy from qualifying hydrothermal power plants at a price equivalent to the electric utilities' "avoided cost". To enable small power producers to estimate this avoided cost: (a) the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems; and (b) the rules formulate the procedure for determining avoided cost from such data. The rules permit a small power producer to earn an unregulated return on a qualifying

hydrothermal power plant investment, provided the producer's selling price for electric energy lies within the avoided cost stipulation.

Under PURPA, qualifying hydrothermal power plants are also eligible for system interconnection and wheeling through electric utilities' transmission facilities. Discriminatory hook-up charges and interconnection charges are explicitly prohibited.

These regulatory dispensations make possible third party ownership of hydrothermal power plants. Prior to PURPA enactment, such ownership was infeasible because of public utility regulatory restrictions. This may promote the early development of hydrothermal resources if the return which a third party is able to realize on its power plant investment is commensurate with the risk perceived during the early, and uncertain, years of production at each new resource. The 140 megawatt limitation for qualifying hydrothermal generation capacity at a site will, however, require that large scale resource development (i.e. development beyond the initial 140 megawatts) be accomplished without third party plant ownership. Therefore, third party/electric utility plant leasing arrangements or, more likely, electric utility capital investment are the methods of power plant financing which appear most probable for large scale hydrothermal resource development.

5.3 THIRD PARTY INVESTMENT DECISIONS

5.3.1 Investment Objectives

An investor's decision to finance a hydrothermal power plant will depend upon the risks and returns which are estimated for the proposed venture and upon the availability of investment capital. The latter concern, capital availability, is of primary importance on a micro level, i.e. from the perspective of an individual investor; however, on a macro level, i.e. viewing the population of potential third party investors, it can be assumed that capital will be available if estimated investment returns are sufficient to compensate both the investor's cost of capital and the inherent risks of the venture.

With this assumption pertaining to the availability of capital, investment decisions can be explained in terms of the venture's risks and returns. Potential third party investors indicate that their investment decisions are motivated by certain objectives which are to:

- o maximize the efficiency of invested capital (as assessed in terms of its after-tax rate of return);
- o minimize the length of time during which invested capital is exposed to risk (as assessed in terms of discounted payback time); and
- o minimize the risk to which invested capital is exposed (as assessed in terms of the amount and probability of investment loss).

Individual investors -- be they persons, partnerships or corporations -- are also concerned with the magnitude of an investment opportunity as assessed in terms of both (a) the amount of invested capital which will be at risk and (b) the present value of cumulative profits from the investment. The level of this concern depends upon the investor's available capital and upon the scale of the investor's usual business activities. For the purposes of this study, it is assumed that the third party investor is, by definition, a person, partnership or corporation with both (a) sufficient available capital to meet the requirements of a hydrothermal power plant project and (b) usual business dealings which are consistent with the scope and scale of such a project. Investment decisions by a third party can, therefore, be explained in terms of the attributes discussed above, namely:

- o the estimated rate of return on invested capital;
- o the estimated discounted payback time for invested capital; and
- o the estimated probability and amount of investment loss.

Each of these attributes of the hydrothermal venture is discussed below.

5.3.2 Project Attributes

Rate of Return. As discussed in Section 2.1.5, the method by which rate of return is estimated is an important consideration in investment analyses. The internal rate of return, IRR, method will correctly and realistically rank investment opportunities only when net receipts may

be immediately and indefinitely reinvested at the IRR. For this reason, the IRR method is discarded in favor of the financial management rate of return, FMRR, method. With the FMRR method, the reinvestment rate may be externally specified.

When applying the FMRR method to a tax leveraged lease arrangement, gross project revenues will include fixed lease rental payments plus tax benefits which can be applied against unrelated taxable income of the third party investor. Net project revenues are estimated by subtracting from this gross income the expenses associated with administering the lease, insuring the power plant and repaying the principal and interest on borrowed capital. In a "net" lease arrangement, as this is assumed to be, the plant lessee pays the operating expenses and taxes associated with the power plant.

Preproduction negative cash flows for FMRR applications are assumed to be the investment requirements of the third party investor. For the leveraged lease arrangement, these investment requirements are limited to the investor's equity only and exclude borrowed capital.

FMRR represents a realistic measure of the rate of return on investor's equity. When evaluating the merit of a hydrothermal venture, its FMRR should be compared against those of alternative investment opportunities. If the hydrothermal project provides an attractive return, and if its payback and risks are acceptable, it is assumed that the rational investor will choose to finance the venture.

Investment Payback Time. Payback time estimates are a second primary concern of third party investors and indicate the length of time an investment will be subject to risks and economic uncertainties before it is recovered by project receipts. As a rule, longer payback requirements involve higher costs of capital because of the associated risk premiums. A series of capital investments extending over several years are required to engineer and construct a hydrothermal power plant. Individual discounted investments are assumed to be paid back, in order of occurrence, from discounted net revenues including tax

benefits applied to unrelated income. A weighted average discounted payback time is recommended in this study to estimate a single measure of payback time for the investment stream.

Risk of Loss. As mentioned earlier in this report there is a degree of uncertainty pertaining to both the performance of hydrothermal power plant technology and, more so, the production capabilities of a hydrothermal reservoir over the 20 to 30 year life of a power plant. These uncertainties translate into investment risks which, in the extreme, could conceivably cause a premature and complete loss of revenues to the hydrothermal venture.

It should be emphasized that, to date, such loss has not been experienced with commercial hydrothermal power equipment. Never the less, risks are perceived, especially in the early developmental stages of new resource areas, and this risk of loss will weigh on the investment decisions of third party investors.

As discussed in section 5.1.2, vehicles do exist for insuring against unexpected resource failure. If the economics of a proposed venture can absorb the cost of premiums for such insurance while maintaining attractive investment returns, much of the investment risk in a hydrothermal power plant venture can be effectively mitigated.

Uninsured risks may be subjectively evaluated by making judgemental estimates of the likelihood and timing of plant failures. Experienced geothermal geologists, reservoir engineers, and plant engineering specialists are best qualified to provide such probabilistic estimates. By examining the time-wise probability of loss estimates together with a discounted cash flow schedule, the third party investor can assess the probabilistic risk of losing time-wise decreasing amounts of unrecovered invested capital.

5.3.3 Third Party Investment Decision Model

There is insufficient empirical evidence to suggest that third party financing of hydrothermal power plants will play a significant role in the development of hydrothermal electric power in the United States. To date, electric utilities have chosen to finance the

construction of commercial hydrothermal plants as summarized in Table 3-1. The regulatory changes introduced by PURPA (refer to section 5.2) may have some influence on the participation of third party investors in the future, however, and for this reason an investment decision model has been included in this study for this class of potential power plant investors.

Univariate Utility Functions. The investment utility functions of the class of investors who finance the independently operating resource developers (recall Chapter 3) are viewed here as likely preference functions for the third party equity investors in hydrothermal power plant ventures. The univariate utility functions from section 3.2.2 corresponding to the investment attributes of rate of return, payback time, and capital loss for these investors, are illustrated in Figures 5-1, 5-2 and 5-3 respectively. As defined earlier, a minimum utility of zero implies "no investment incentive" while a maximum utility of one implies "highest investment incentive". The statistical parameters for these three functions indicate meaningful levels of confidence as footnoted in section 3.2.2.

Figure 5-1. THIRD-PARTY INVESTOR UTILITY
FOR RATE OF RETURN ON INVESTED CAPITAL

Figure 5-2. THIRD-PARTY INVESTOR UTILITY
FOR INVESTMENT PAYBACK PERIOD

Figure 5-3 THIRD PARTY INVESTOR DISUTILITY
FOR INVESTMENT LOSS

Multiattribute Utility. When evaluating a hydrothermal opportunity having uncertain outcomes, the third party equity investor (as defined in section 5.3.1) is concerned with two project attributes for probabilistic outcomes representing a monetary gain:

- o after-tax rate of return (r)

- o discounted payback time (p)

and one attribute for probabilistic outcomes representing a monetary loss:

- o present value of capital at risk (v).

Conditional preferences for these three attributes are expressed by the univariate utility functions U_R , U_p and U_L , respectively, as discussed above.

Multiattribute utility for the third party investor is expressed by the functional form:

$$U = \begin{cases} .168 + .345U_R(r) + .487U_R(r)U_p(p) & \text{for gains} \\ (2.9) \quad (7.5) \quad (9.4) & \\ U_L(v) & \text{for losses} \end{cases} \quad \begin{matrix} R^2=.83 \\ F=129 \end{matrix} \quad (5.1)$$

This function is derived from equation (3.6) with the univariate utility for present value of profits (i.e. U_v in 3.6) set to one.

Probabilistic Choice. As discussed in section 3.3, when choosing among alternatives with uncertain outcomes (i.e. opportunities characterized by probabilistic gains and losses) rational decision makers behave as maximizers of "expected utility" (EU); that is, they will select from several candidate opportunities that opportunity which offers the highest expected utility:

$$EU = \sum U_i \Pi_i \quad (5.2)$$

where U_i is the utility of outcome i and Π_i is its probability of occurrence.

As before, a logit model is used in this analysis to estimate the numerical likelihood that a third party equity investor will choose, rather than reject, an opportunity as a function of the opportunity's expected utility (EU). The logit model is expressed as:

$$P(A|EU_A) = \frac{1}{1 + e^{-a - b EU_A}} \quad (5.3)$$

which represents the probability of selecting opportunity "A" conditional upon its expected utility, EU_A .

Chapter Six

JOINT INVESTMENT DECISIONS FOR WELL FIELD AND POWER PLANT

Hydrothermal power development at a resource discovery is dependent upon joint investment decisions to (a) develop the well field and (b) construct power plant and transmission facilities. In the preceding three chapters, investment decisions of resource developers, electric utilities and third party investors were discussed independently. In this chapter, joint investment behavior is discussed for two financing arrangements:

- o The most likely arrangement of well field investment by a resource developer and power plant investment by an electric utility; and
- o Well field investment by a resource developer and power plant investment by a third party who, in turn, either leases the plant or sells electric energy to an electric utility.

6.1 RESOURCE SALES CONTRACT

6.1.1 Terms and Conditions

Joint investment decisions pertaining to hydrothermal well fields and power plants are mutually dependent upon the terms and conditions of a resource sales contract which is negotiated between the resource developer (seller) and the power plant owner/operator (buyer). Resource sales contracts typically address the topics listed in Table 6-1. In addition to defining the mechanism for resource pricing over the term of the agreement, the sales contract delineates the risk exposure, responsibilities and indemnities of the contracting parties.

TABLE 6.1

HYDROTHERMAL RESOURCE SALES CONTRACT TOPICS

Definition of Terms	Resource Price
Location of Lands	Pricing Basis
Land Rights	Price Escalation
Land Taxes	Payment
Resource Title	Taxes
Title Insurance	Royalties
Plant Site	Accounting Methods
Development Plans	Penalties
Construction Plans	Environmental Control
Description of Facilities	Environmental Surveillance
Resource Quantity	Compliance with Laws
Resource Quality	Indemnities
Minimum Performance	Force Majeure
Measurement and Testing	Assignment
Rights to Data	Term of Agreement
Seller's Operations	Renegotiation
Buyer's Operations	Termination
Notices Required	Arbitration
Conditions Precedent	Power of Attorney

6.1.2 Modeling Sales Contract Influences

For the purposes of this analysis, influences of the resource sales contract upon joint investment decisions are modeled by: (a) adjusting the resource price which couples the well field and power plant cash flow simulations; (b) defining investment and expense responsibilities of the resource producer and of the power plant owner/operator; and (c) assigning financial risks and indemnities among the contracting parties. The resource price adjustment is performed by Technecon's computer model with an iterative technique that converges on a price which maximizes the joint likelihood of positive investment decisions by both parties. As the resource price increases, the power plant incurs increasing "fuel" expense and the logit estimation of power plant investment likelihood, P_U , decreases. Simultaneously, the resource developer is realizing increasing revenues and the logit estimation of well field investment likelihood, P_D , increases. Using a Fibonacci search technique (see Kiefer 1953 and Johnson 1956), the simulation converges on the optimal resource price which maximizes the joint likelihood, $P_U \times P_D$, of investment by the two parties.

The Fibonacci search locates the optimal value of a unimodal function over a given interval with a theoretically minimal number of iterative functional evaluations. The numerical likelihoods of positive investment decisions by the well field investor and power plant investor are monotonic increasing and decreasing, respectively, with resource price. Hence, the joint probability of positive decisions is a unimodal function of resource price which can be efficiently optimized by the Fibonacci method.

6.2 JOINT INVESTMENT DECISION MODEL I: RESOURCE DEVELOPER AND ELECTRIC UTILITY

The decision models developed in the course of this study examine the qualities of a specified hydrothermal resource discovery and estimate the numerical likelihood of positive investment decisions to commercially develop this resource for electric power production. Progressive development at each resource is evaluated by analyzing

successive generating unit additions until the capacity of the resource is fully utilized. The joint likelihood of positive investment decisions for each sequential generating unit and its attendant well field facility is estimated separately.

Figure 6-1 illustrates the structure of the hydrothermal electric power decision model for the expected case of electric utility financing of the power plant. Following is a summary of the model which discusses the sequence of computerized operations progressing from left to right through the schematic diagram.

The hydrothermal power market estimates are prepared on a site-by-site basis. Resource discovery characteristics are provided to two detailed cash flow programs. One program simulates the life of a well field project while the other program simulates the life of a hydrothermal power plant. The economically optimum combination of pumped versus unpumped wells and binary versus flash plant design is selected at each site. Well field and power plant performance and cost data from Chapter 2 is used in these computerized cash flow programs. Table 6-2 lists the several input data parameters which are provided to the cash flow analyses.

Figure 6-1. HYDROTHERMAL POWER FORECAST MODEL

Table 6-2a. RESOURCE PARAMETERS

BRIE CONTAMINATION INDEX	REDRILL FRACTION
CONFIRMATION WELLS REQUIRED	REWORK COST
DEVELOPMENT COMMITMENTS TO DATE	REWORK FRACTION
DRY WELL COST	ROYALTY RATE
DRY WELL FRACTION	SPARE WELL FRACTION
FINDING COST CAPITALIZED	SURFACE FACILITY COST
FINDING COST EXPENSED	SURFACE PIPING COST
FIRMS IN JOINT VENTURE	TEMPERATURE OF RESOURCE
FLOW TEST AND MODELING COST	TYPE OF RESOURCE DEVELOPER
LAND RENT	WELL COST
LEASE BONUS	WELL FLOW, FREE
OPERATION AND MAINTENANCE EXPENSE	WELL FLOW, PUMPED
PERMITTING EXPENSE	WELL LIFE
PRODUCER/INJECTOR RATIO	WELL PUMP THRESHOLD
PRODUCIBLE ACREAGE AT 50% CONFIDENCE	WELL SPACING
PRODUCIBLE ACREAGE AT 99% CONFIDENCE	YEAR OF DISCOVERY
REDRILL COST	

Table 6-2b. POWER PLANT PARAMETERS

BOOK LIFE OF ALTERNATIVE PLANT	RECURRING ANNUAL COST OF ALTERNATIVE PLANT
BOOK LIFE OF HYDROTHERMAL PLANT	RECURRING ANNUAL COST OF HYDROTHERMAL PLANT
CAPACITY FACTOR OF ALTERNATIVE PLANT	REPLACEMENT POWER COST
CAPACITY FACTOR OF HYDROTHERMAL PLANT	REPLACEMENT POWER COST ALLOWABLE
CAPITAL COST OF ALTERNATIVE PLANT	SIZE OF HYDROTHERMAL PLANT
CAPITAL COST OF HYDROTHERMAL PLANT	TIME FROM DECISION TO PLANT ON-LINE
CAPITAL COST OF TRANSMISSION	TIME INTERVAL BETWEEN PLANTS
EFFICIENCY OF HYDROTHERMAL PLANT	TYPE OF PLANT (FLASH/BINARY)
FUEL PRICE OF ALTERNATIVE PLANT	TYPE OF UTILITY
INSURANCE PREMIUMS	WRITE-OFF PERIOD ALLOWABLE
LAST YEAR OF PROJECT OPERATION	

Table 6-2c. ECONOMIC & FINANCIAL PARAMETERS

ALTERNATIVE PLANT COMMON STOCK COST	HYDROTHERMAL PLANT LONG TERM DEBT FRACTION
ALTERNATIVE PLANT COMMON STOCK FRACTION	HYDROTHERMAL PLANT PREFERRED STOCK COST
ALTERNATIVE PLANT LONG TERM DEBT COST	HYDROTHERMAL PLANT PREFERRED STOCK FRACTION
ALTERNATIVE PLANT LONG TERM DEBT FRACTION	INFLATION RATE FOR GOODS AND SERVICES
ALTERNATIVE PLANT PREFERRED STOCK COST	INFLATION RATE FOR POWER PLANT CONSTRUCTION
ALTERNATIVE PLANT PREFERRED STOCK FRACTION	INFLATION RATE FOR POWER PLANT FUEL (REGIONAL)
ELECTRIC UTILITY DEBT OBLIGATIONS	RESOURCE DEVELOPER'S DISCOUNT RATE
ELECTRIC UTILITY GROWTH RATE	THIRD PARTY'S DEBT INTEREST RATE
ELECTRIC UTILITY NET INCOME	THIRD PARTY'S DISCOUNT RATE
HYDROTHERMAL PLANT COMMON STOCK COST	THIRD PARTY'S EQUITY FRACTION
HYDROTHERMAL PLANT COMMON STOCK FRACTION	THIRD PARTY'S RETURN ON EQUITY
HYDROTHERMAL PLANT LONG TERM DEBT COST	

Table 6-2d. TAX PARAMETERS

FEDERAL TAX RATE FOR RESOURCE DEVELOPER	MINIMUM TAX RATE ON PREFERENCE ITEMS
FEDERAL TAX RATE FOR ELECTRIC UTILITY ALTERNATIVE	PERCENTAGE DEPLETION ALLOWANCE SCHEDULE
FEDERAL TAX RATE FOR ELECTRIC UTILITY HYDROTHERMAL	STATE TAX RATE FOR ELECTRIC UTILITY ALTERNATIVE
FEDERAL TAX RATE FOR THIRD PARTY	STATE TAX RATE FOR ELECTRIC UTILITY HYDROTHERMAL
INTANGIBLE FRACTION OF WELL COST	STATE TAX RATE FOR RESOURCE DEVELOPER
INVESTMENT TAX CREDIT FOR NON-UTILITY HYDROTHERMAL	STATE TAX RATE FOR THIRD PARTY
INVESTMENT TAX CREDIT FOR ELECTRIC UTILITY ALTERNATIVE	TAX LIFE FOR ALTERNATIVE PLANT
INVESTMENT TAX CREDIT FOR ELECTRIC UTILITY HYDROTHERMAL	TAX LIFE FOR HYDROTHERMAL PLANT
LOCAL TAX RATES	TAX LIFE FOR WELL FIELD CAPITAL

The two cash flow programs are executed probabilistically to account for uncertainties and risk perceptions which are inherent to many geothermal ventures. Eight stochastic variables within the cash flow (i.e. resource temperature, well flow, well cost, well life, dry well fraction, reservoir size, reservoir life and plant availability) vary over time as a function of on-site production experience, number of wells drilled and acreage in production³⁹. Figure 6-2 presents the several stochastic parameters, the probability profile associated with each, and the independent variables which influence time-wise changes in the probability profiles.

Results from the well field and power plant cash flow simulations are then provided to the respective decision models of the resource developer and of the electric utility. The decision models analytically compare the geothermal investments to alternative investment opportunities available to each type of firm. From the resource developers' point of view, comparisons are made in terms of rate of return, duration of investment exposure, project size, amount of capital at risk, and the probability of project failure. From the electric utilities' point of view, comparisons are made in terms of: electric energy production cost (mills/kWh) delivered to a main transmission corridor, plant capacity factor, net plant output, and risk to corporate or municipal bond rating. The resource developers' decision model is described in Chapter 3 of this report and the electric utilities' decision model is described in Chapter 4.

The computer models are flexible and may be readily adapted to estimate the likely investment behavior of either large diversified corporations or independently operating firms on the resource developers' side, and either investor-owned companies or tax-exempt municipal or state agencies on the electric utilities' side. These adaptations are performed by: (a) adjusting federal, state and local tax rates and liabilities; (b) adjusting capital structure and cost; and (c) adjusting the utility functions and logit models to reflect the preferences of the respective type of company as discussed in Chapters 3 and 4.

³⁹Reservoir risk perceptions and time-wise variances are based upon the recommendations of 3 consultants: Dr. S. Sanyal of Stanford University, D. Goldman of E G & G Idaho, Inc. and E. Ciancanelli of Cascadia Exploration Corp., San Diego.

UNCERTAIN PARAMETER	DISTRIBUTION	FACTORS AFFECTING VARIANCE
<ul style="list-style-type: none"> • POWER PLANT CAPACITY FACTOR • WELL LIFE, INJECTORS • WELL LIFE, PRODUCERS • RESERVOIR TEMPERATURE • WELL FLOW RATE • WELL COST • DRY WELL FRACTION		<ul style="list-style-type: none"> • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME • ON-SITE PRODUCTION TIME; ABSOLUTE TIME; WELLS DRILLED • ON-SITE PRODUCTION TIME; ABSOLUTE TIME; WELLS DRILLED • ABSOLUTE TIME; WELLS DRILLED • ABSOLUTE TIME; WELLS DRILLED
<ul style="list-style-type: none"> • PRODUCIBLE ACREAGE		<ul style="list-style-type: none"> • ACREAGE IN PRODUCTION
<ul style="list-style-type: none"> • ECONOMIC RESERVOIR LIFE		<ul style="list-style-type: none"> • ON-SITE PRODUCTION TIME; ABSOLUTE TIME

Figure 6-2. HYDROTHERMAL POWER
PROJECT UNCERTAINTIES

— : Initial Perception
- - - : Less Uncertainty

The two decision models provide estimates of the numerical likelihood of investment in a specified hydrothermal opportunity by resource developers and by electric utilities, respectively. These models are statistically-strong in their ability to reproduce investment preferences as expressed by the respective firms in executive interviews and in demonstrated field practice. Statistical indicators of confidence include a high coefficients of determination (corrected for degrees of freedom) and meaningful F-statistics and t-statistics as discussed in Chapters 3 and 4.

Resource selling price is the negotiable variable which couples the well field cash flow and the power plant cash flow. A high price improves investment returns to the resource developer and generally increases his likelihood of investment. Meanwhile, a low price lowers the production cost (mills/kWh) of hydrothermal electric energy and generally increases the electric utility's likelihood of investment. Technecon's computer-based simulation of resource price negotiation uses an iterative Fibonacci technique to converge on a price which maximizes the joint likelihood of investment($P_D \cdot P_U$ in Figure 6-1) by both parties.

When estimating the time-wise development of a specified resource discovery, each plant addition is evaluated separately. This evaluation is repeated in successive time periods until either a pre-specified time horizon is reached or the likelihood of the joint well field/plant investment approaches 100 percent. Subsequent plant additions at the specified resource are evaluated in the same manner and continue until the resource is fully utilized or until the pre-specified time horizon is reached.

6.3 JOINT INVESTMENT DECISION MODEL II: RESOURCE DEVELOPER AND THIRD PARTY POWER PLANT INVESTOR

Figure 6-3 illustrates the structure of the hydrothermal electric power decision model for the case of third party financing of the power plant. As discussed in section 4.1, this method of financing is unlikely compared to electric utility financing. With recent PURPA regulations, however, third party financing may, to a limited extent, become more commonplace in the future (see section 5.2).

The model, as structured for third party financing, is identical to that for electric utility financing (see section 6.2 above) except in the submodels of power plant project simulation and power plant investment decision estimation. As shown in Figure 6-3, the cash flow component of the project simulation submodel includes revenues to the third party from either lease payments or electric energy sales under PURPA. The third party decision submodel is structured according to the discussion of section 5.3.3.

Figure 6-3. HYDROTHERMAL POWER FORECAST MODEL
(THIRD PARTY FINANCING)

Chapter Seven

INVESTMENT DECISION MODELING EXAMPLES:

ROOSEVELT HOT SPRINGS, UTAH, AND

EAST MESA, CALIFORNIA

This chapter demonstrates the use of investment decision models to evaluate the likely commercial development at specified hydrothermal resources and the effect upon this development of Federal policies and R&D programs. Other recent applications of this methodology for rational and objective policy analysis are summarized in Chapter One, the introduction to this report.

7.1 BACKGROUND AND SUMMARY

In the examples that follow the assumed investment decision makers are resource developers for well field financing and investor-owned electric utilities for power plant financing. Third party financing is not considered in these examples. Based upon advice from electric utilities in the regions of interest, the hydrothermal power plant investment decisions in both examples hinge upon competition with the economics and performance of baseload coal-fired generation. Two resources, Roosevelt Hot Springs in southwestern Utah and East Mesa in southern California (see map, Figure 7-1), are analyzed in the following examples.

Figure 7-1. LOCATIONS OF SELECTED KNOWN GEOTHERMAL RESOURCE AREAS

7.1.1 Roosevelt Hot Springs, Utah

Located in Beaver County, Utah, Roosevelt Hot Springs has been actively explored, confirmed and evaluated. Both Phillips Petroleum Company and Thermal Power Company have conducted successful well flow tests. An agreement with Utah Power and Light Company was signed in 1980 for a 20 megawatt power plant, planned to be on-line in 1982.

Tables 7-1 through 7-4 summarize the physical and economic characteristics at Roosevelt which were obtained from published data. Figure 7-2 maps levels of confidence over the resource area as it is understood today. The high resource temperature, high well flow rates and low salinity (brine contamination index of 1 for modeling purposes) of this resource make it well suited for development. Power from Roosevelt will likely be transmitted to the substation at Sigurd Cove Fort, a total distance of 62 miles.

Figure 7-2. LEVELS OF CONFIDENCE
AT ROOSEVELT HOT SPRINGS KGRA (MID-1979)

TABLE 7-1. ECONOMIC DATA (1980-2000)

Parameter	Model Code	Value
GNP Deflator	G	0.075
Nominal Cost Inflation	GC	0.075

TABLE 7-2. RESOURCE CHARACTERISTICS

Parameter	Model Code	Roosevelt	East Mesa
Ratio of producer to injector wells	PIR	2	2
Dry well cost (fraction of producer well cost)	DWC	0.9	0.9
Intangible fraction of producer well cost	IF	0.75	0.75
Fraction of new wells requiring redrilling	IRD	0.3	0.3
Redrilling cost (fraction of initial cost)	RDC	0.35	0.35
Fraction of wells reworked at end of well life	RWF	0.33	0.33
Rework cost (fraction of initial cost)	RWC	0.35	0.35
Spare well fraction	SWF	0.2	0.2
Producer well spacing (acres/well)	WSPACE	40	40
Book life of project (years)	PLFH	30	30
Tax life of well field capital (years)	PTLF	11	11
Royalty (fraction of gross revenues)	RLF	0.10	0.10
Ad valorem tax rate (on full cash value)	ADV	0.013	0.010
State corporate income tax rate	TS2	0.05	0.09
Federal corporate income tax rate	TF2	0.46	0.46
Land rental until production (\$/acre)	RNT	2	2
Brine contamination index ¹	BCI	1	1
Number of firms in well field venture	NF	1	1
Year of resource confirmation	TDSC	1976	1975
Investment tax credit through 1985	ITC2	0.25	0.25
Investment tax credit after 1985	ITC2	0.10	0.10

Notes:

1) 0: Low Salinity < 2,000 ppm; 1: Moderate Salinity 2,000 - 10,000 ppm; 2: High Salinity >10,000 ppm.

TABLE 7-3. POWER PLANT CHARACTERISTICS

Parameter	Model Code	Roosevelt	East Mesa
Common stock fraction	FC	0.35	0.35
Preferred stock fraction	FP	0.15	0.15
Long term debt fraction	FD	0.50	0.50
Cost of common stock	KC	0.135	0.135
Cost of preferred stock	KP	0.085	0.085
Cost of long term debt	KD	0.08	0.08
Book life of hydrothermal plant	PLFH	30	30
Book life of competing plant	PLFA	30	30
Tax life of hydrothermal plant	TLFH	22	22
Capacity factor - competing plant	CAPA	0.75	0.75
Competing plant type	—	Coal	Coal
Capital cost-competing plant (\$/kWE) ^{1 2}	CALT	935	935
Fuel cost-competing plant (mills/kWh) ¹	PALT	11.8	17.1
Recurrent cost fraction (non-fuel) ³	BETAA	0.062	0.062
Fuel escalation rate, nominal ⁴	GF	0.08	0.08
Replacement power cost (mills/kWh) ¹	RPWR	50	50
Ad valorem tax rate (on full cash value)	ADV	0.013	0.010
State corporate income tax rate	TS	0.05	0.09
Federal corporate income tax rate	TF	0.46	0.46
Investment tax credit on plant	ITC	0.10	0.10
Electric utility annual debt service (\$1000) ¹	DEBT	84300	309100
Electric utility annual net revenues (\$1000) ¹	NETY	194000	758000
Nominal electric utility economic inflation	GU	0.08	0.08

NOTES:

- 1) 1980 Dollar Value
- 2) For units on line in 1980: includes apportioned transmission to a main corridor.
- 3) Annual cost of operation, maintenance, insurance, and administrative expense as a fraction of capital cost, CALT.
- 4) Average annual estimate for 1980 - 2000 time frame (coal).

TABLE 7-4. STOCHASTIC PARAMETERS¹

Parameters	Model Code	Roosevelt			East Mesa		
		MIN	MODE	MAX	MIN	MODE	MAX
Capacity-hydrothermal plant	CAPH	0.60	0.85	0.90	0.60	0.85	0.90
Well-head resource temperature (F) ²	WT	335	475	520	265	375	415
Producer well cost (\$1000) ³	WC	375	750	1900	375	750	1900
Dry well fraction during development	DWF	0.1	0.15	0.351	0.1	0.15	0.35
Well flow unpumped (1000 lb/hr) ²	WF	350	700	840	150	300	360
Well flow pumped (1000 lb/hr) ²	WF	N/A	N/A	N/A	250	500	600
Well life (years)	WLF	1	10	13	1	10	13
Producible acreage (see maps 7-2, 7-3)	A	--	--	--	--	--	--

NOTES:

- 1) Initial perceived variances in absence of production experience.
- 2) Mean life-time values including drawdown effects.
- 3) Early 1980 dollar value.

Based upon available data for Roosevelt, the investment decision model estimates a high likelihood that 500 megawatts of electric power will be developed at this resource within the next 20 years. Policy incentives beyond those already provided by the National Energy Act of 1978⁴⁰ have little effect upon the estimated high likelihood of development at Roosevelt.

7.1.2 East Mesa, California

Located in Imperial County, California, the East Mesa KGRA is being actively explored and developed by both the Magma Power Company and Republic Geothermal Company. Magma has constructed an 11 MWe pilot plant primarily for research and development purposes. Republic Geothermal is also considering development of a 50 MWe plant at East Mesa. San Diego Gas and Electric, in conjunction with its resource company, New Albion Resources, is also actively investigating the commercial potential of the KGRA. Figure 7-3 illustrates levels of confidence over the KGRA as it is presently understood.

⁴⁰The NEA provided a package of tax incentives for hydrothermal resource developers including: the option to expense intangible drilling costs, additional tax credits, and a percentage depletion allowance.

**Figure 7-3. LEVELS OF CONFIDENCE
AT EAST MESA KGRA (MID-1979)**

In contrast to Roosevelt Hot Springs, East Mesa is a somewhat marginal resource according to the available data presented in Tables 7-1 through 7-4. Without additional policy incentives and without the benefits of technological research and development programs, the investment decision model estimates a low to moderate likelihood that 300 megawatts will be developed at East Mesa within the next 20 years. However, with additional incentives and a successful Federal research program, the model estimates a high likelihood that up to 500 megawatts would be developed within the next 20 years.

7.2 MODELING PARAMETERS AND ASSUMPTIONS

7.2.1 Project and Financial Data

Site-specific and general data used in the Roosevelt and East Mesa examples are provided in Tables 7-1, 7-2, 7-3 and 7-4. Table 7-1 lists general economic data as derived from the Wharton Annual Econometric Model for the 1980-2000 time frame. Tables 7-2 and 7-3 lists data pertaining to the well-field and power plant respectively. These data were derived from regional electric utilities, local tax assessors, University of Utah Research Institute (1980) and Cassel et al. (1979).

Table 7-4 lists the characteristics of triangular probability distributions for the several stochastic variables used in the analyses. These values were derived from the University of Utah Research Institute (1980) and from three consultants in hydrothermal risk perceptions⁴¹. Figures 7-2 and 7-3 accompany the stochastic data presented in Table 7-4 and provides geographic mappings of the numerical level of confidence in producible acreage at Roosevelt and East Mesa, respectively (from Cassel et al., 1979).

The stochastic parameters presented in Table 7-4 represent initial perceptions prior to any commercial production experience. The uncertainties evident in the variance between minimums and maximums in

⁴¹Three consultants hired by Technicon to assess hydrothermal resource risk perceptions are: Dr. S. Sanyal, Reservoir Engineer, Stanford University; D. Goldman, Hydraulic Engineer, EG&G Idaho, Inc.; and E. Ciancanelli, Geologist, Cascadia Exploration Co..

the probability distributions will diminish with time as: (a) production experience is gained; (b) additional wells are drilled; and (c) additional acreage is put into production. The rate and extent to which variances in the stochastic distributions will diminish was estimated by the hydrothermal reservoir engineering consultants employed by Technecon for this analysis (recall footnote 9).

Performance, capital cost and recurrent cost data for the hydrothermal well field and power plant are estimated within the cash flow model as a function of the stochastic resource data provided in Table 7-4. The functional relationships for performing these estimates are discussed in Chapter 2 of this report. Both binary and flash power plant designs are evaluated in the analysis and the better performing of the two is selected within resource temperature constraints.

7.2.2 Rate of Development

Table 7-5 indicates that, based upon historical data at eight hydrothermal resource areas, five years may be expected to lapse between the year in which a resource is confirmed and the year in which electric power is first put on line. This is time required for reservoir testing and modeling, permitting, environmental studies, steam sales contract negotiations and the design and construction of initial well field and power generation and transmission facilities. The initial generating unit at a site may range in capacity from 5 to 50 megawatts. As indicated in Table 7-5, 20 megawatts is an average size of this first unit.

TABLE 7-5. HYDROTHERMAL RESOURCE DEVELOPMENT HISTORIES

Resource Area	Year of Confirmation	1st Generating Unit		Years to 1st Plant
		Size (MWe)	Year On-line	
Geysers (CA)	1955	11	1960	5
East Mesa (CA)	1975	11	1980	5
Brawley (CA)	1975	10	1980	5
Raft River (ID)	1975	5	1980	5
Heber (CA)	1975	41	1982	7
Salton Sea (CA)	1976	10	1982	6
Roosevelt (UT)	1976	20	1982	6
Valles Caldera (NM)	1977	50	1982	5
Average		20		5

From: Anderson (1980)

As illustrated at the Geysers (recall Figure 3-1), a few years of experience and successful demonstration of electric power production are desired at each new resource site prior to the acceleration of large scale commercial development. Electric utilities and hydrothermal reservoir engineers surveyed by Technecon over the past two years indicate that 2 to 5 years of commercial resource production are needed to understand the long-term production characteristics of a resource. This "learning curve" is illustrated in Figure 7-4 which was derived by a regression analysis of survey responses from eighteen western electric utilities.

Based upon the above information, the project simulation model developed from this analysis assumes that: (a) the minimum interval between the first and second generating unit at a site will be 3 years; (b) the minimum interval between the second and third unit will be 2 years; and (c) successive units after the third will come on-line at one year intervals. In the absence of existing or committed generating units at a site, the simulation model assumes the first unit will be 20 megawatts in size, the second and third units will be 50 megawatts each, and subsequent units will be 100 megawatts each. These development assumptions may be overridden by the specification of the year and size of existing or planned units at a site when executing the simulation model.

Figure 7-4. ELECTRIC UTILITIES' "LEARNING CURVE"

7.2.3 Timing of Investment Decision

The decision being analyzed in this work is that of investing capital into (a) a specific generating unit and (b) its supporting well field at a given hydrothermal resource area. Because of the risk perceptions and cost escalation which vary with time, an important consideration is the point in time when a particular decision is being made. For the purpose of this analysis, the investment decisions are assumed to be made three years prior to the time when the particular generating unit is scheduled to be put on line. This allows a year for permitting, engineering and financing and two years for procurement, construction, check-out and startup.

The conditions for favorable investment decisions generally improve with time as: (a) technological advances occur; (b) experience causes risk perceptions at a given resource to be minimized; and (c) escalating competing energy costs (e.g. coal, oil, nuclear) improve the competitive economics of hydrothermal power. Therefore, an investment decision that appears unfavorable or marginal in terms of risks and returns at one point in time may very well be viewed as an attractive opportunity some years later. To accommodate this time-wise dependency of investment likelihood, the decision model is structured to "re-try" investment decisions at specified time intervals until either: (a) a pre-set time limit is reached, or (b) a high numerical likelihood (i.e. greater than 90%) of a positive decision is estimated.

7.2.4 Premature Plant Failure

As discussed in Chapter 2, the power plant cash flow model stochastically evaluates the premature failure of a hydrothermal unit and the consequential impact upon electric utility system economics and financial health. Public utility commission decisions are extremely significant in such an event, particularly as they apply to the treatment of unrecovered plant costs and replacement power costs. For the purposes of examples being discussed here, two assumptions are made pertaining to such a PUC reaction: (1) the entire replacement power cost of 50 mills/kWh (early 1980 dollar value) is allowed to be passed through into the company's rate base; and (2) the unrecovered book value of the plant is allowed to be amortized in three years.

In the absence of any empirical data on premature hydrothermal plant failure, it is difficult to estimate probabilistic values for the production life of a plant under failure conditions. For this analysis, three hydrothermal consultants were employed to address this issue (recall footnote 39).

7.3 RESULTS

Based upon the data and modeling assumptions given earlier in this chapter, the joint likelihood of positive investment decisions on the part of resource companies and electric utilities was estimated for the progressive development of the Roosevelt and East Mesa resource areas. The resulting estimates are presented below, both with and without the benefits of new Federal policy incentives and research and development programs.

7.3.1 Results Without New Policy Incentives and R&D Benefits

Figures 7-5 and 7-6 illustrate the joint investment decision modeling results for the hydrothermal resources at Roosevelt Hot Springs and East Mesa, respectively. These results assume no new Federal policy incentives or research and development benefits. The distinct differences in resource quality are evident in these results.

The East Mesa results indicate that, on the basis of available data:

- o There is a low likelihood that about 300 MWe will be commercially developed within the next 10 years;
- o There is a moderate likelihood (i.e. greater than 50%) that about 200 MWe will be commercially developed within the next 10 years;
- o There is no commercial development, beyond the existing 11 MWe pilot plant, that can be predicted with a high degree of confidence (i.e. likelihood greater than 90%).

The magnitude of the development capacities estimated above for East Mesa is consistent with the 360 MWe figure published by USGS in Circular 790 (see Muffler, 1979).

The Roosevelt results are considerably more optimistic than those at East Mesa. On the basis of available data:

- o There is some, albeit small, likelihood that about 600 MWe will be commercially developed by the early 1990's;
- o There is a high likelihood that between 400 and 500 MWe will be commercially developed by the early to mid 1990's.

FIGURE 7-5: HYDROTHERMAL ELECTRIC POWER ESTIMATE:
ROOSEVELT HOT SPRINGS - (WITHOUT FEDERAL SUPPORT)

FIGURE 7-6: HYDROTHERMAL ELECTRIC POWER ESTIMATE:
EAST MESA - (WITHOUT FEDERAL SUPPORT)

The magnitude of developmental capacity estimated by USGS for Roosevelt, i.e. 970 MWe, appears somewhat optimistic for the 1980-2000 time frame in view of the above results (see Muffler, 1979).

7.3.2 Assumed Federal Policy and Program Benefits

Several Federal policy incentives and R&D programs are evaluated for their synergistic effect upon the predicted hydrothermal investment decisions at Roosevelt Hot Springs and East Mesa. The benefits of these Federal policies and programs were modeled as follows (ref. U.S.DOE, 1980):

- o Downhole Pump Program. After 1985, well pumps are assumed to be available for 400 F resources -- a 30F increase above the 370 F temperature limit assumed without continuation of DOE's pump program. No cost reduction is attributed to this program because of more expensive materials and designs required to increase the temperature threshold.
- o Drilling Technology Program. After 1983, well drilling and completion costs are reduced by 15% because of the anticipated benefit of DOE's hydrothermal well program. After 1985 the well cost reduction is 25%.
- o Well Stimulation Program. After 1985, DOE's scaling control and stimulation program for hydrothermal wells is assumed to increase well life by 28%. This prolongs well service life prior to redrilling or major reworking.
- o Fluid Transmission Program. After 1985, DOE-funded R&D to reduce scaling and corrosion in brine piping is assumed to reduce surface piping operating and maintenance costs by 10% and surface piping capital costs by 4% for flash plant lines and 8% for binary plant lines.
- o Power Plant Technology Program. After 1985, DOE's R&D programs dealing with materials and equipment for hydrothermal power plants are assumed to: (i) increase plant availability by 5%; (ii) decrease flash plant capital cost by 1% and binary plant cost by 2%; (iii) decrease flash plant operating and maintenance cost by 8% but increase binary plant O&M by 3%; (iv) increase plant performance, i.e. "brine effectiveness" in watt-hours per pound of fluid, by 9% for both flash and binary technologies.

As described in section 7.3.3 below, and as demonstrated in the national hydrothermal power forecasts prepared by Technecon as part of a Task Force effort in 1980 (see Introduction), Federal policies and programs are expected to have a significant impact upon both the rate and extent of development of resources that today are considered marginal opportunities.

7.3.3 Estimates With Federal Program Benefits.

Figures 7-7 and 7-8 illustrate the joint investment decision modeling results for Roosevelt Hot Springs and East Mesa, respectively, including the benefits of the Federal programs described in 7.3.2, above. The significantly favorable impact of the Federal programs on the rate and extent of development at East Mesa is seen by comparing Figures 7-6 and 7-8.

FIGURE 7-7: HYDROTHERMAL ELECTRIC POWER ESTIMATE:
ROOSEVELT HOT SPRINGS - (WITH FEDERAL SUPPORT)

FIGURE 7-8: HYDROTHERMAL ELECTRIC POWER ESTIMATE:
EAST MESA - (WITH FEDERAL SUPPORT)

With the Federal programs, the East Mesa results indicate that:

- o There is some, albeit small, likelihood that about 300 MWe will be commercially developed within the next 10 years and about 500 MWe within the next 15 years;
- o There is moderate (i.e. greater than 50%) likelihood that about 200 MWe will be commercially developed within the next 10 years and 500 MWe within the next 15 years;
- o There is a high likelihood (i.e. greater than 90% level of confidence) that about 100 MWe will be commercially developed within the next 10 years and 500 MWe within the next 15 years.

By comparing the developmental estimates for East Mesa with and without Federal program benefits (Figures 7-8 and 7-6), the favorable significance of the program upon marginal resource estimates can be seen. The DOE program increases both the likelihood and extent of development at the East Mesa site.

In contrast to the pronounced improvement at East Mesa, the Federal program has minor impact upon the developmental estimates at the high quality resource at Roosevelt Hot Springs. At Roosevelt, the program may permit an additional 100 megawatts to be developed by the year 2000 (i.e. the increment from about 500 to 600 MWe) because of more efficient utilization of the resource.

From a national perspective, the great majority of hydrothermal resources fall into the category of marginal resources, such as East Mesa, rather than that of the high quality type of resource at Roosevelt Hot Springs. This is illustrated in the resource frequency diagram presented in Figure 7-9 (from University of Utah Research Institute, 1980). As demonstrated above, the Federal DOE program is expected to significantly improve the extent and likelihood of development of marginal resources over the next 20 years. Therefore, continuation of DOE's hydrothermal program is expected to have a pronounced effect upon the development of hydrothermal electric power in the United States between now and the year 2000.

Figure 7-9. DISTRIBUTION OF POTENTIAL CONFIRMATIONS
WITH RESOURCE TEMPERATURE

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