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GEOTHERMAL POWER PLANT INVESTMENT DECISIONS

Interim Report, June 1—November 30, 1979

By
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MASTER

December 1979

Work Performed Under Contract No. AC02-79ET 27242

Technecon Analytic Research, Inc.
Philadelphia, Pennsylvania

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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- Interim Report -
for Period June 1, 1979 - November 30, 1979

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December 1979

Prepared for

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UNDER CONTRACT NO. DE-AC-02-79ET27242

ABSTRACT

Large scale commercialization of geothermal electric power will depend upon favorable investment decisions for both well field development and power plant construction. These investment decisions are the subject of on-going analysis being conducted at Technecon Analytic Research, Inc., Philadelphia, under contract to the U.S. Department of Energy. The purpose of this research is to achieve an understanding of pertinent investment objectives and, based upon this understanding, to recommend reasonable and effective policy incentives for accelerating the commercialization of geothermal power.

This interim project report discusses investment decisions for financing the construction of geothermal power plants. This work complements related projects at Technecon which concern the analysis of investment decisions for financing the development of geothermal well fields. Discussed in this report are the investment objectives of investor-owned electric utilities, municipal electric utilities, and potential third party financiers as determined from extensive reviews of literature, executive interviews and responses to mailed surveys. The contents of this report provide the framework for a computerized quantitative decision model currently being developed at Technecon for investment and policy analysis applications.

PREFACE

This interim project report is an account of on-going work being performed by Technecon Analytic Research, Inc. under contract to the U.S. Department of Energy (Contract No. DE-AC02-79ET27242; Dr. Fred Abel, D.O.E. Program Manager). The report discusses the objectives and decision criteria of firms concerned with the financing of geothermal electric power plants. It is based upon information obtained through current literature reviews, many hours of management interviews and responses to an industry survey mailing. A generous degree of cooperation and participation by both the electric power industry and the financial community has been received throughout these investigations. These contributions of both time and effort are largely responsible for the results provided in this report.

The purpose of this report is to present significant industry investment objectives and decision criteria which impact the timely commercialization of geothermal electric power. Findings from this work provide the framework for a computerized industry decision model -- currently being developed at Technecon -- which will be used to estimate the likely effects of alternative incentive schemes upon geothermal investments. This work complements recent Technecon accomplishments in the area of geothermal well field investment analysis (see, for example, Geothermal Investment and Policy Analysis with Evaluations of California and Utah Resource Areas, D.O.E. Document No. C00-4713-2, October 1979). Together, the two analyses provide a means for estimating the likely effects of policy alternatives upon joint investment decisions by geothermal well field developers and geothermal power plant financiers. The report is organized as follows:

- Chapter One summarizes the project, its purpose, methods, results and continuing investigations.
- Chapter Two reviews generation planning by electric utilities and identifies those factors which will be of significance in a utility's choice between geothermal or alternative capacity additions.
- Chapter Three discusses capital markets, bond ratings and

specific considerations for geothermal project financing including insurance and loan guarantee provisions.

- Chapter Four describes the role of third party financing for geothermal power plant projects.

The Department of Energy Program Manager for this project is Dr. Fred Abel who, together with Mr. Randall Stephens and Dr. Louis Werner, has provided valuable support and direction during the course of this work. Industry participants from thirteen electric utilities and several banks and investment firms -- who are too numerous to acknowledge individually -- are credited for their collective contributions of time and experience. Last, though by no means least, the authors acknowledge Mrs. Norma Crouse for her patient and very capable assistance in the production of this report.

Philadelphia

T.A.V.C., C.B.A., R.H.E., P.D.B.

CONTENTS

1. INTRODUCTION AND SUMMARY	1-1
1.1 Introduction	1-1
1.1.1 Background	1-1
1.1.2 Methods	1-1
1.1.3 On-Going Research	1-2
1.2 Executive Summary	1-2
1.2.1 Assumptions	1-2
1.2.2 Electric Utility Investment	1-4
1.2.3 Capital Markets	1-5
1.2.4 Third Party Investors	1-6
1.2.5 Decision Modeling	1-7
2. ELECTRIC UTILITY GENERATION PLANNING	2-1
2.1 Optimal Generation Expansion Planning	2-1
2.1.1 Identification of New Capacity Requirements	2-1
2.1.2 Economic Analysis	2-3
2.1.3 Financial Analysis	2-5
2.1.4 Institutional Considerations	2-8
2.2 Geothermal Decision Criteria	2-11
2.2.1 Identification of Need for Geothermal Capacity	2-12
2.2.2 Cost Analysis of Geothermal Capacity	2-15
2.2.3 Minimizing Rate Payer's Burden	2-16
2.2.4 Geothermal Financial Impacts	2-17
2.2.5 Institutional Issues in Geothermal Development	2-19
3. CAPITAL MARKETS	3-1
3.1 Electric Utility: Assumptions and General Considerations	3-1
3.2 Financial Structure	3-2
3.2.1 Equity	3-2
3.2.2 Debt	3-3
3.2.3 Capital Structure	3-4
3.3 The Cost of Capital	3-5
3.3.1 The Cost of Capital Equation	3-5
3.3.2 Capital Structure and the Cost of Capital	3-6
3.4 The Cost of Capital and Issue Ratings	3-8
3.5 Geothermal Project Financing	3-8
4. THIRD PARTY FINANCING	4-1
4.1 Plant Leasing Arrangements	4-1
4.2 Financing the Lease	4-1
4.3 Mitigating Geothermal Risks	4-2
4.3.1 Geothermal Loan Guaranty Program	4-2
4.3.2 Geothermal Resource Insurance	4-2

4.4 Tax Leveraged Leasing	4-3
4.4.1 Structuring the Lease	4-3
4.4.2 Tax Benefits	4-4
4.4.3 Public Utility Regulation	4-4
4.5 Investment Decision	4-5
4.5.1 Investment Decision Criteria	4-5
4.5.2 Rate of Return on Investment	4-6
4.5.3 Investment Payback Time	4-7
4.5.4 Risk of Loss	4-8

BIBLIOGRAPHY

LIST OF FIGURES

2-1 Generation Expansion Planning	2-2
2-2 Institutional Considerations in Generation Expansion Planning	2-10
2-3 Western Systems Coordinating Council	2-14
2-4 Electric Utilities' "Utility" for Geothermal Power - vs - Delivered Cost of Electric Energy	2-18
3-1 Relationship Between Debt Ratio and Average Cost of Capital	3-7

LIST OF TABLES

2-1 Financial Overview of Electric Utilities, 1952-1975	2-6
2-2 Peak System Demand: Western Systems Coordinating Council	2-12
2-3 Western Systems Coordinating Council Summary of Generation Additions	2-13
3-1 Elements Considered in the Rating Process	3-9
3-2 Glossary for Financial Ratios	3-10

Chapter One

INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

1.1.1 Background

The large scale commercialization of geothermal electric power depends upon joint positive decisions by (a) resource companies to develop well fields and (b) electric utilities to construct on-site power plants and transmission facilities. The rate and extent to which this largely untapped resource is developed will depend on the rate and extent to which these industries are willing to invest developmental capital. An understanding of this investment behavior is necessary to structure reasonable and effective federal programs and policies for accelerating the commercialization of geothermal power.

Investment decisions by resource companies are the topic of a recent analysis supported by the Department of Energy¹. To complement this recent work, D.O.E. is supporting current research² concerning the investment behavior of electric utilities and potential third party financiers having interests in geothermal power plant construction. Interim findings of this current analysis are presented in this report.

1.1.2 Methods

Extensive literature reviews, personal interviews with industry executives, and statistical analyses of responses to mailed surveys provide the data and information upon which this report is based. To date, over one hundred published articles, books and reports concerning electric utility and third party investment decisions have been reviewed and synthesized³. Interviews with management representatives of ten electric utilities, two commercial banks, two investment houses and two engineer-

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¹See "Geothermal Investment and Policy Analysis with Evaluations of California and Utah Resource Areas" by Technecon Analytic Research, Inc. (Philadelphia) under D.O.E. Contract ET-78-S-02-4713; October 1979.

²Work being performed under D.O.E. Contract No. DE-AC02-79ET27242; Dr. Fred Abel, D.O.E. Program Manager.

³See bibliography at the end of this report.

ing/construction firms have been conducted. Eleven⁴ investor-owned and municipal electric utilities responded to a mailed survey which questioned load growth projections, capital structure, financial health and relative impacts of ten decision criteria.

Findings, to date, from the literature, interviews and surveys are summarized in this interim project report. The purpose of this report is to identify the significant decision criteria and objectives of the involved industries which will influence the decision to construct geothermal, as opposed to alternative, baseload power plants.

1.1.3 On-Going Research

As this interim report is written, on-going research on this project is directed at incorporating industry decision methods and criteria into a computerized investment decision model. Using modeling techniques similar to those applied in the resource developers' model (see footnote 1), an instrument is being developed for estimating the likelihood of geothermal power plant investments.

When complete, the decision model will provide probabilistic estimates of progressive levels of development at specified geothermal resource areas. It is anticipated that these estimates will be provided at statistically sound levels of confidence. By modifying various elements within the model, the likely impacts of alternative federal programs and policies may be assessed. Recommendations for effective and reasonable government incentives will be offered pending the completion of these sensitivity evaluations.

1.2 EXECUTIVE SUMMARY

1.2.1 Assumptions

According to the Western System Coordinating Council, there is a significant requirement for baseload capacity expansion by utilities in the western regions where geothermal resources are prevalent. For the purposes of this report it is assumed, therefore, that a market for new geothermal generation exists if this technology satisfies the utilities'

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⁴An 85% response rate was achieved with the mailed surveys.

other selection criteria.

Given the market for geothermal electric power, concern is focused upon the economic, financial, environmental, institutional and reliability aspects of this technology. Economic and financial concerns are found to be of primary importance. Geothermal power will have to be economically competitive with alternative types of baseload generation, and the perceived risks associated with geothermal resources and technology must be accommodated without adverse effects on the utilities' financial health.

Environmental, institutional, and reliability concerns are, for the purposes of this report, assumed to be embodied in the economic and financial aspects given above. It is assumed that geothermal power plants will have to conform to all applicable environmental regulations and restrictions, and that the costs of conformance will be reflected in the competitive economics of geothermal power. Institutional concerns are primarily those of delays and costs associated with permitting, licensing, etc. These are also reflected in the competitive economics of geothermal power.

The reliability of geothermal generation is, to a degree, uncertain because of limited field experience. To date, geothermal power plants in Northern California, Mexico and overseas have proven themselves to be a reliable source of inexpensive electric energy. Geothermal power plant technology is reasonably well understood and presents minimal risk. However, each geothermal reservoir is distinct and, until several years of production have been realized, each reservoir presents uncertain risks concerning long term producibility, scaling and corrosion, land subsidence, induced seismicity, and drawdown over time.

Reliability concerns influence two areas of electric utility planning: (a) system stability and capability to meet demand, and (b) financial impacts if a plant investment fails to produce revenues. Geothermal power plants are of relatively small (50-100 MWe) unit size compared to conventional coal, oil or nuclear alternatives (>500 MWe, typically). Therefore, the unscheduled loss of a unit is unlikely to have a significant adverse impact upon the operational stability of a well designed utility system. The failure of a fully developed resource area, however,

could conceivably result in an unscheduled loss of several hundred megawatts of generation capacity. A loss of this magnitude is analogous to the failure of a large conventional plant, which utility systems are designed to accommodate. Additionally, it is likely that a major resource failure would occur gradually over time and would provide utility planners with sufficient advance warning to prevent a catastrophic loss of load.

For the purposes of this report, it is assumed that the perceived risks associated with geothermal reliability can be accommodated from the standpoint of utility system operations. However, from the standpoint of utility finances, the risk of revenue loss and disposition of an unproductive asset remain as significant decision criteria in considerations of geothermal power.

1.2.2 Electric Utility Investment

Given the above mentioned assumptions, an investor-owned or municipal electric utility's choice regarding geothermal power is based on two objectives. First, the generation and transmission cost (per kilowatt-hour) of geothermal electric energy must be competitive with that of alternative baseload generation. Second, the financial health of the utility must not be jeopardized by the addition of geothermal generating capacity.

The first of these objectives may be assessed by comparative estimates of the levelized cost (in mills per kilowatt-hour) of both geothermal electric energy and that of the least expensive alternative, both delivered to main transmission corridors. The ratio of these costs provides a means for measuring the economic feasibility of geothermal capacity additions.

The second objective, i.e. that of preserving financial health, may be assessed in terms of the utility's bond rating and the estimated impact which geothermal capacity additions might have on this rating. Commercial investment brokers take into account several key financial ratios when assigning ratings and these ratings, in turn, influence the cost and availability of capital to the utility. It is imperative that a utility faced with a large construction program maintain its access

to relatively low cost capital.

Probabilistic geothermal failures may be assessed by their probabilistic impact upon both electric energy costs and financial rating. Much of this impact will depend upon public utility commission rulings as to whether an unproductive investment and cost of replacement power are passed on to rate payers or to the utility's investors. In either case, there are potential consequences of increased rates or damaged financial position.

The relatively small unit size and cost of geothermal power plants is an advantage in that a resource area may be progressively developed in increments as production experience accumulates and uncertainties diminish. Thus, by the time the capital of equivalent coal, oil or nuclear power plants is committed, risks will have been significantly reduced through experience. Furthermore, recent capital cost estimates for geothermal power plants appear lower, per kilowatt of capacity, than those of alternative coal⁵ or nuclear plants. This is of particular advantage to utilities in tight capital situations.

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 1984) that guarantees up to 75% of a project's cost. 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 risks.

1.2.3 Capital Markets

Interviews with executives of Wall Street investment brokerages, who are responsible for bond ratings, indicate that well conceived geothermal projects could serve to enhance a utility's rating. Several factors will contribute to this possible enhancement: (a) Given the current uncertainties pertaining to international oil supply, nuclear

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⁵with flue gas desulfurization equipment.

safety, and the environmental and labor aspects of coal, there is a degree of desirability for domestic alternatives such as geothermal. (b) If an issue is structured such that the geothermal capital is but a small percentage of the total issue -- i.e. that a major portion of the issue is for "conventional" non-geothermal construction -- then any perceived risks associated with geothermal generation could be effectively sheltered by the non-geothermal generation. (c) Much of the rating impact of a geothermal project will depend upon the anticipated or realized actions of public utility commissions. As mentioned earlier, if a regional p.u.c. will grant adequate and timely rate relief and/or accelerated write-off in the event of a geothermal failure, it is unlikely that the financial position of the utility would be adversely affected. (d) Finally, if the project's economics can absorb the attendant costs of implementing the GLGP or commercial reservoir insurance, much of the perceived financial risk can be mitigated and favorable response can be anticipated from the capital market.

1.2.4 Third Party Investors

Geothermal power plant financing by a third party, i.e. a party other than an electric utility or a resource developer, provides a means for circumventing utility risk aversion or unavailability of utility construction capital. An attractive arrangement for third party participation is through a tax leveraged lease arrangement. In such an arrangement, a third party finances plant construction (using a large amount of borrowed capital) and then leases the plant to a utility for operation.

If the lease is structured as a "net" lease, i.e. the lessee assumes all operating expenses, then the lessor will likely be able to avoid p.u.c. regulation. If so, the lessor may be able to receive sufficient after-tax return on invested capital to make the lease arrangement an attractive investment. The potential tax benefits to the third party lessor are substantial but depend, to a great degree, upon IRS rulings pertaining to "at risk" limitations, tax credit availability, preference taxes and recapture rules.

Potential third party investors indicate that their investment decisions are motivated by certain objectives which are to:

- maximize the efficiency of invested capital (as assessed in terms of its rate of return);
- minimize the length of time during which invested capital is exposed to risk (as assessed in terms of discounted payback time); and
- minimize the risk to which invested capital is exposed (as assessed in terms of the 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 geothermal power plant project and (b) usual business dealings which are consistent with the scope and scale of such a project.

1.2.5 Decision Modeling

The findings presented in this report provide the framework for a quantitative decision model currently being developed by Technecon Analytic Research, Inc. to estimate the likelihood of favorable decisions to invest in specified geothermal power plant projects. This computerized model is designed to perform a comprehensive financial analysis of a proposed venture; and, based on the results of this analysis and on the several decision criteria summarized above, the model will estimate likely investment behavior. Analytic methods used in the model include an integration of "multiattribute utility analysis" and "logit analysis of probabilistic choice".

Investor-owned electric utilities, municipal electric utilities, and potential third party investors are all handled separately by this computerized decision analysis. When complete, the model will be applied to assess and recommend realistic and effective federal programs and policies for accelerating the commercialization of geothermal electric power.

Chapter Two

ELECTRIC UTILITY 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 geothermal capacity will be made only if it is at least as responsive to these objectives as alternative base load technologies.

The purpose of this chapter is to outline the economic, financial, and institutional factors which are evaluated in the design of an optimal generation expansion plan. This analysis will focus on key economic, financial, and institutional decision parameters which ultimately determine how future capacity needs are to be satisfied. These parameters are then used to evaluate the choice between geothermal and conventional base load capacity. It will be shown that the decision to install geothermal capacity is based on a subset of the decision parameters normally considered in the derivation of an optimal expansion plan. By focusing on this subset of decision criteria, the ability of geothermal capacity to satisfy future capacity needs can be efficiently determined.

2.1 OPTIMAL GENERATION EXPANSION PLANNING

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 2-1, 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.

2.1.1 Identification of New Capacity Requirements

An electric utility's decision to add new generating capacity is based on estimates of future customer demands and energy requirements,

Figure 2-1. GENERATION EXPANSION PLANNING

currently scheduled capacity additions and retirements, and designation of appropriate system reserve margins. Recommendations for capacity additions are made when, in the judgement of system planners, the ability of the utility to meet future demands comes into question. This planning process has become increasingly difficult in recent years; historical load growth has departed from the relatively uniform rate of 6-7 percent observed in the early 1970's and has shown erratic fluctuations since 1974. Despite the introduction and refinement of new analytical methods which estimate demand as a function of relevant explanatory variables⁶, projections of future consumption over a 10-20 year period remains subject to high levels of uncertainty. Escalating lead times for bringing new base load capacity on line have exacerbated the problem.

To incorporate such uncertainties into the generation expansion planning process, Loss of Load Probability (LOLP) estimates are often used (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 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 capacity is indicated.

2.1.2 Economic Analysis

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

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⁶Relevant explanatory variables include price of electricity, price of alternative energy substitutes, income, and climatic variables.

fuel 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.

Generation Planning Models. To minimize total system costs, system planners must evaluate the tradeoff between the installation of high capital/low operating cost base load 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). Such programming methods minimize total system costs subject to the demand and energy constraints placed on the system, based on unit capital and operating costs. Additional constraints such as capital availability or pollutant emission constraints can also be incorporated into this analysis (e.g., Rutz et al., n.d.). The results of this analysis provide the optimal new generation expansion program, including the size, type and on-line date of new capacity additions. Examples of such models commonly used by electric utilities include:

- Westinghouse Generation Expansion Optimization Program (W-GENOP): a linear mixed integer programming model developed by Westinghouse Electric Corporation
- Optimized Generation Planning (OGP): a model developed by General Electric Corporation which incorporates reliability criteria, systems operation, engineering economics, and financial simulations.
- Wien Automatic System Planning Package (WASP): a dynamic programming model developed by Oak Ridge National Laboratory.
- Economic Environmental System Planning Package: a mixed integer programming model developed at the Massachusetts Institute of Technology to explicitly consider the feasibility and cost of meeting environmental standards.
- Planning of Unconventional Power Sources (PUPS): a screening

model developed by Systems Control, Incorporated to evaluate unconventional generation technology.

Levelized Energy Cost Analysis. The total lifetime cost of individual generation units may be evaluated using a levelized energy cost (or required revenue) analysis. The levelized energy cost is defined as the constant charge per kilowatt-hour needed to yield an annual cash flow sufficient to cover all capital costs and expenses incurred through operation of the unit, while maintaining a sufficient rate of return on capital invested in the unit. Descriptions of analytic methods for computing levelized energy cost may be found in Doan et al., 1976 and Mitre, 1978. This costing technique can be especially useful in evaluating proposed capacity additions which represent only a small portion of total system capacity. The installation of such units would not significantly change the optimal generation dispatch schedule, thereby leaving all units operating at or near their planned capacity factors.

If there is a clearly identified need for additional baseload power, levelized energy cost analysis can be employed to evaluate different generating technologies which may be used to meet anticipated capacity requirements. 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.

2.1.3 Financial Analysis

The financial conditions of the 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 2-1, the financial conditions become 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 2-1. 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, having interest rates in the 9-10 percent range, while common stock costs are generally 13-15 percent. 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 is tied to the bond ratings assigned to its debt issues. The bond rating procedure involves the analysis of a wide variety of factors impacting the economic health of the utility, including:

- 1) economic analysis of service area
- 2) type of system
- 3) facilities
- 4) capital improvements plan
- 5) rate structure
- 6) bond security
- 7) key financial ratios

The most important of these criteria are the key financial ratios describing the utility's ability to repay debt issues (Rand, 1977; Standard and Poor's, 1976 and 1978). These include the pretax and after-tax coverage ratios, defined by:

$$\text{After-tax coverage ratio} = \frac{(\text{after taxes}) \text{ Net Income before Interest Expenses}}{\text{Interest Expenses}}$$

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

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.

Equity Issues. As discussed above, 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 2-1, 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 2-1, 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.

2.1.4 Institutional Considerations

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 2-2, any new capacity addition must comply with federal, state, and local environmental statutes. The most important standards influencing generation technology choice include (ERDA, 1976):

- Emission limitations for sulfur oxides, nitrogen oxides, and suspended particles from newly constructed fossil plants;
- Thermal discharge limitations for both fossil and nuclear plants;
- Criteria for siting, design construction, and operation of nuclear plants with an emphasis on minimizing the potential for release of radioactive materials into the atmosphere through accidents as well as normal operations;
- Discharge limitations governing release of selected trace radioactive isotopes (e.g., tritium) in effluent water from nuclear plants;
- Controls on mining of utility steam coals (especially surface-mined coals);
- Air and water quality standards applicable to coal preparation and conversion facilities integrated with the power plant;
- Limitations on development of naturally occurring sites for hydroelectric and pumped storage generation.

Public Utility Commission Approval. A regulated utility must have any

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 2-2. INSIITUTIONAL CONSIDERATIONS IN
GENERATION EXPANSION PLANNING

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:

- 1) is there a proven need for the power
- 2) can the utility properly finance the facility
- 3) does the project minimize the rate-payers burden
- 4) does the project involve excessive risks
- 5) 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 returns on specific units to reflect risk premiums.

2.2 GEOTHERMAL DECISION CRITERIA

The decision being evaluated in this report is the decision to install new geothermal power plant capacity. As a baseload technology, geothermal capacity must compete with large coal and nuclear plants. Geothermal plants have several important features which differentiate them from conventional baseload capacity, notably:

- small unit size - geothermal plants are added in 50-100 MW increments, in comparison to 600+ MW additions of coal or nuclear capacity
- little operating experience - hydrothermal plants at liquid-dominated reservoirs are new technologies, unlike coal and nuclear units.

These unique aspects of geothermal power have important ramifications on the factors involved in the decision of whether to add new geothermal power. In the following analysis, it will be shown that geothermal

capacity additions are based on a subset of the criteria outlined in Section 2.1.

2.2.1 Identification of Need for Geothermal Capacity

An analysis of projected future system demands for utilities in the Western System Coordinating Council (shown in Figure 2-3) indicate that peak demands are expected to grow at an annual rate of 4.4 percent over the next 8 years for the system as a whole. Peak demand forecasts for each of the WSCC's five subregions are shown in Table 2-2. To meet these demands, utilities in the WSCC have scheduled a net increase in generation capacity of 27,696 MW over the period from 1979-1983. As shown in Table 2-3, almost 90 percent of the planned capacity expansion is baseload.

TABLE 2-2. PEAK SYSTEM DEMAND:
WESTERN SYSTEMS COORDINATING COUNCIL

(1000 MW) Peak Demand	1979	1981	1983	1985	1987	Annual Growth Rate: 1979-1987
WSCC Region	75.6	83.1	90.4	98.4	106.9	4.4
Northwest Power Pool	30.2	33.3	37.0	40.1	43.6	4.7
Rocky Mtn " "	4.9	5.8	6.6	7.4	8.3	6.8
Ariz-N.Mex " "	8.3	9.6	10.8	12.3	13.7	6.5
So. Cal-Nev " "	20.8	22.4	23.8	25.6	27.5	3.6
No. Cal-Nev " "	16.5	17.7	18.9	20.3	21.9	3.6

Based on the magnitude of the planned baseload capacity expansion program, the ability of utilities to fully absorb large amounts of geothermal power is easily documented. Geothermal plants, built sequentially could supplant the need for either baseload nuclear or fossil fuel units. Further, the electric utilities in the WSCC could install geothermal capacity as a contingency to guard against unexpected delays in the completion of new nuclear or coal fired base load units. As noted in the WSCC reliability study "nuclear and coal fired base load 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" (WSCC, 1979). If geothermal power plants could be brought on line in a timely and cost effective manner, the demand for power would not be a binding limitation on

TABLE 2-3. WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF GENERATION ADDITIONS
1979--1988

(WINTER CAPABILITY - MW)

GENERATION TYPE	NORTHWEST POWER POOL AREA	ROCKY MTN. POWER AREA	ARIZONA- NEW MEXICO POWER AREA	SO. CALIF.- NEVADA POWER AREA	NO. CALIF.- NEVADA POWER AREA	WSCC TOTAL	PERCENT OF TOTAL
HYDRO	8654	8	0	329	420	9411	15.6%
HYDRO-PUMP STORAGE	200	200	600	0	1125	2125	3.5%
STEAM--COAL	4130	6003	4101	5500	3025	22759	37.7%
STEAM--GAS OR OIL	-7	-6	-95	103*	-276	-281	-.5%
NUCLEAR	9076	200	5080	2200	2190	18746	31.0%
COMBUSTION TURBINE	345	25	335	390	386	1481	2.5%
COMBINED CYCLE	0	0	0	1517	2215	3732	6.2%
GEOTHERMAL	0	0	210	108	1502	1820	3.0%
INTERNAL COMBUSTION	0	0	0	0	-2	-2	-.0%
OTHER	-10	0	0	346	273	609	1.0%
TOTAL	22388	6430	10231	10493	10858	60400	100.0%
PERCENT OF WSCC TOTAL	37.1%	10.6%	16.9%	17.4%	18.0%	100.0%	

* The increase in capability is due to rerating and converting an existing natural gas unit to oil burning capability.

Source: WSCC, 1979.

Figure 2-3. WESTERN SYSTEMS
COORDINATING COUNCIL

Source: (WSCC, 1979)

geothermal commercialization.

2.2.2 Cost Analysis of Geothermal Capacity

Given that there is currently a proven utilization potential for geothermal power by utilities in the WSCC, the economic viability of geothermal power becomes a critical focal point in the decision to install geothermal capacity. To evaluate the economic costs of geothermal power, a levelized energy cost model is being developed to fully incorporate all relevant cost considerations. The rationale for selecting the levelized energy cost methodology over alternative linear or dynamic programming techniques rests on several critical judgements. Geothermal power effectively competes only with alternative base load power sources. Thus any new geothermal power would supplant alternative new base load capacity. Major revisions in generation dispatch would not result from small (less than 300 MW) additions of geothermal capacity. If the levelized energy cost analysis shows geothermal power to be competitive with nuclear or fossil fuel plants on a mills per kWh basis, the addition of geothermal power into the system will not materially change the optimal 20-30 year generation plan derived through programming techniques.

Equally important is the fact that as a new technology, risk averse utilities are apt to adopt geothermal power only after high ranking corporate executives have analyzed the proposed capacity addition. These executives, ultimately responsible for introducing an unproven technology, will be more concerned with the single unit addition, rather than the 20-30 year impact on total system cost. 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.

It is important that, in the development of a levelized energy cost model, all relevant cost considerations be represented. In particular the cost evaluation should include:

- A capital recovery component to account for depreciation and the required return on investment.
- An income tax component to account for both federal and state taxes.

- Operation and maintenance expenses including fuel costs.
- Administrative and general expenses.
- Insurance premiums.
- Ad valorem property taxes.
- An allowance for working capital requirements.

The above components of the cost analysis are frequently expressed as an annual percentage of the required capital investment by electric utilities.

The model currently being developed at Technecon, as discussed in Section 1.2.5, will be stochastic thus incorporating the inherent uncertainty involved in estimating future geothermal capital and operation costs. The model will also provide for the uncertainty regarding future capital and fuel costs of conventional base load facilities. The basic economic assumptions of the levelized energy cost model will include:

- Capital costs of hydrothermal and conventional units will be represented by stochastic probability distributions.
- Conventional coal or nuclear fuel costs will be represented stochastically; hydrothermal "fuel" costs will be assigned such that the joint probability of investment by resource producer and electric utility is maximized.
- Hydrothermal plant life will be estimated stochastically, with provision made for unexpected loss of the geothermal plant. Such losses may stem from reservoir failure, temperature degradation of the reservoir, or major plant technology failure.

2.2.3 Minimizing Rate Payer's Burden

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 thirteen utilities indicate that cost minimization is a major criterion in investment decisions.

The cost-competitiveness of geothermal 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.

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 2-4 illustrates the mean utility of hydrothermal power as a function of energy cost, as regressed from interview responses from nine western utilities. A slight bias in favor of hydrothermal generation is illustrated at the point in Figure 2-4 where the hydrothermal energy cost is equivalent to the least expensive alternative. A rapidly increasing aversion to hydrothermal generation is apparent when its energy cost exceeds that of the least costly alternative by more than about 2½%. If the energy 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.

2.2.4 Geothermal Financial Impacts

The factors influencing the ability of the utility to finance a proposed capacity addition have been outlined in Section 2.1.3. It was shown that the major financial impacts are related to the magnitude of the capital requirements, and how the proposed addition will change earnings and rate base. The interaction between these factors determines in large part the firm's bond ratings and stock performance, and thus the overall cost of capital. Debt service coverage ratios may be used to identify how a utility's cost of capital may change as a result of a proposed capacity expansion.

Geothermal plant additions may have one of two effects on the critical debt service coverage ratios of the utility. If the plant provides a reliable source of power over its 20-30 year service life, the utility would increase in its debt service ratios by replacing more capital intensive conventional base load units with geothermal capacity. Further, if geothermal power proved to have lower variable costs per kWh, the

Figure 2-4. ELECTRIC UTILITIES' "UTILITY" FOR GEOTHERMAL POWER - vs - DELIVERED COST OF ELECTRIC ENERGY

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.

Potentially adverse financial consequences could result from a major failure of the geothermal plant however. Loss of any geothermal 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 geothermal 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. Geothermal 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.

2.2.5 Institutional Issues in Geothermal Development

The institutional factors influencing capacity expansion planning have been outlined in Section 2.1.4. For purposes of choosing between geothermal and conventional base load units, these factors may be subsumed under the busbar cost and financial analysis outlined above. Environmental factors are to be embodied in the capital cost 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. The impact of unexpected plant licensing and construction delays on total capital cost is included in the busbar cost by representing the generating units lead time stochastically. The cost analysis will also determine which alternative capacity addition is the least costly, thereby minimizing the impact on the rate payer. The financial analysis will examine the impact on the utility's financial status of early closure of the geothermal plant. The magnitude of this risk, and ability of the utility to withstand such a loss will provide an indication of the financial soundness of the investment.

Chapter Three

CAPITAL MARKETS

This chapter examines how alternative long-term financing methods for a geothermal electric power plant are likely to affect an electric utility's economic situation and its financial decision-making process. The analysis represents a synthesis of the precepts of corporate finance as well as field interviews with electric utilities, various financial institutions and capital market institutions. At the outset, it is important to understand that the long-term financing of any particular power plant, while generally accounting for a small portion of a typical utility's long run capital requirements, may affect its general financial status, and, therefore, should be evaluated in the context of the overall economic well-being of the utility.

The chapter is sub-divided into five sections. The first discusses general assumptions and considerations about an operating electric utility. The second section focuses on the financial structure of an electric utility and particularly, the choice of long-term debt/equity financing. In the third section, the interrelationship between the capital structure of the utility and its cost of capital is outlined. The fourth section discusses how alternative financing packages issued by electric utilities are evaluated by the financial market; the key part of this discussion relates to the rating of financial market instruments. The last section integrates the electric utility's concerns with project financing and its overall financial and performance objectives.

3.1 ELECTRIC UTILITY: ASSUMPTIONS AND GENERAL CONSIDERATIONS

An electric utility, on the one hand, has a mandate to provide acceptable, reliable, low-cost service to its customers, and, on the other hand, to generate sufficient revenues to meet its financial responsibilities and needs. In the case of municipal utilities, revenues should provide funds to meet solvency and liquidity requirements in order that the utility may conduct its current and future business. For an investor-owned electric utility, revenues should additionally provide for adequate or fair rates of returns to investors. In order to meet these objectives, an electric utility confronts a complex inter-related set of decisions

relating to its energy technology systems and financial management.

Subsequent analysis in this chapter assumes load growth, technology, and system stability and reliability problems can be resolved by the electric utility. The main concern for financing geothermal projects (or any other power project) in this context, therefore, is to assume that: (a) the project will provide power at an acceptable production cost; and (b) that the project will not interfere with the utility's future access to capital markets or increase its costs of future capital.

3.2 FINANCIAL STRUCTURE

Project financing for an electric utility is generally accomplished by some form of long-term debt and equity issues⁷. While it is possible to generate long-term financing for an electric utility through a sequence of short- or intermediate-term financing (such as term loans or lease financing) these means are generally not the methods employed by utilities for raising long-term capital and are, therefore, excluded from the scope of this chapter.

3.2.1 Equity

Equity financing has several advantages. Common stock does not entail either fixed charge obligations or fixed maturity at issue. If an electric utility generates earnings, it may elect to pay common stock dividends but it is not legally obligated to do so. Also, in contrast to bond financing, there is no legal obligation to repurchase the stock at the end of a certain pre-specified maturity term. In this manner, common stock provides a cushion against losses for creditors and the issuance of common stock increases the credit-worthiness of the utility.

However, these advantages must be compared with the disadvantages

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⁷There are many classes of fixed income securities: long-term and short-term, secured and unsecured, marketable and non-marketable, participating and non-participating, senior and junior, and so on. Also, preferred stock is a form of long-term fixed income security. For simplicity, we omit discussion about all the nuances of varied forms of debt and preferred stock issues.

of stock issuance. The sale of common stock extends voting rights and a measure of control of the utility to the new stockholders. This also gives the new stockholders the right to share in the income of the utility. Furthermore, the costs of underwriting and distributing new common stock usually are higher than those for underwriting and distributing preferred stock or debt. Flotation costs for selling common stock are characteristically higher because (1) cost of investigating an equity security investment are higher than investigating the feasibility of a comparable debt security, and (2) stocks are more risky which means equity holding must be diversified and which, in turn, means that a given dollar amount of new stock typically must be sold to a greater number of purchasers than the same amount of debt.

As shall be discussed below, if a utility has more equity, or less debt, than is called for in its optimal capital structure, the average cost of capital will be higher than necessary. Also, common stock dividends are not deductible as expenses for calculating the utility's tax liabilities (while bond interest is deductible); the impact of this factor is reflected in the relative after-tax cost of equity capital vis-a-vis debt capital.

3.2.2 Debt

Financial leverage through the use of debt can boost the ratio of return on net worth over the returns available on equity financed assets. In particular, whenever the risk-adjusted return on assets exceeds the cost of debt, leverage is favorable and the return on equity is raised by using it. However, if the returns on assets fall below the cost of debt, then leverage reduces the returns on equity. This reduction is proportional to the amount of leveraging a utility employs. Hence, increased leverage tends to increase economic risk.

When a number of alternative methods of long-term financing are under consideration, the following conditions favor the use of long-term debt:

- Expected future earnings (and sales of services) are relatively stable, or a substantial increase in expected load growth and earnings can provide a substantial benefit from the use of leverage.

- A significant rise in utility rates is anticipated in the future, making future fixed dollar obligations easy to repay.
- The existing debt is relatively small vis-a-vis other utilities.
- Management thinks that the price of common stock in relation to that of bonds is temporarily depressed.
- The sale of common stock would involve problems of maintaining the existing control patterns.

Decisions about the use of debt should also be considered in terms of its effect on the average cost of capital, as shall be discussed in the next section. Utilities have optimal capital structures and the average cost of capital is higher than it need be if the utility uses a sub-optimal amount of debt. The factors listed above all relate to an optimal debt ratio. Whenever the utility raises new outside capital and is choosing between debt and equity, it is implicitly making a judgement about its actual debt ratio in relation to the optimal ratio.

3.2.3 Capital Structure

Capital structure represents the permanent financing of the utility in terms of long-term debt, preferred stock, and common equity, but excluding all short-term credit. Leverage is a key element in a utility's financial and capital structure.

Four interrelated factors usually are considered the more important determinants of a utility's capital structure: (1) The future growth of peak load demand, coupled with technical reliability and energy mix issues, can be used to measure the extent to which the earnings per share of an electric utility are likely to be magnified by leverage. (2) Debt-servicing ability is dependent upon profitability as well as actual levels of sales. Hence, the stability of profit margins and the responsiveness of regulators to decreasing margins are crucial elements in determining debt issuance policies. (3) Asset structure influences the sources of financing in several ways. In the case of electric utilities, with long-lived fixed assets, especially when demand for their power output is relatively assured, the extensive use of long-term mortgage debt is appropriate. This is further influenced by the fact that, partly because of its regulatory environment, utility management tends to be

conservative, requiring relatively low risk - low return options. (4) Finally, regardless of management's analyses of proper leverage, the attitudes of the capital market and lenders of capital are important determinants of ultimate capital structure.

3.3 THE COST OF CAPITAL

The cost of capital to a utility is of great concern. First, capital budgeting decisions have a major impact upon the long run performance of the utility, and proper capital budgeting requires an estimate of the cost of capital. Second, a knowledge of the cost of capital, and how it is influenced by financial leverage, is useful in making capital structure decisions. Finally, the cost of capital is a function of the composition of the utility's capital structure.

3.3.1 The Cost of Capital Equation

A generalized equation can be used to calculate the weighted average after-tax cost of capital, K , of the utility:

$$K = (1 - \tau)K_d f_d + K_c f_c + K_p f_p \quad (3.1)$$

where the effective corporate income tax rate, τ , is:

$$\tau = \tau_s + (1 - \tau_s)\tau_f \quad (3.2)$$

and other terms are defined as follows:

- 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
- 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
- τ_s : state corporate income tax rate
- τ_f : federal corporate income tax rate

It would be possible to expand this equation to encompass short-term debt, convertibles, and so forth. However, one short-coming of this method is that it relates what is the *current* state of the utility, and perhaps neither its optimal long run position, nor what K has been or is going to be in the future. Furthermore, in the analysis of capital

budgeting projects, the analyst frequently should be concerned with the *marginal* cost of capital, not the *average* cost of capital. This latter consideration relates to the fact the cost of capital and the capital structure are inter-dependent, and therefore influenced by the extent of changes in financial leverage.

3.3.2 Capital Structure and the Cost of Capital

In the literature on corporate finance, neither theory nor empirical analysis has been able to specify precisely the optimal capital structure for a firm, or the precise cost of capital at any given capital structure. This inability to find consensus is not for lack of research efforts⁸. However, capital structure decisions remain largely matters of informal judgment. Current understandings and beliefs may be summarized as follows: the average cost of capital function as related to the debt-value ratio is saucer-shaped, with an optimum capital structure occurring where the average cost of capital is minimized (point A in Figure 3-1). Hence, financial managers must give careful consideration to a utility's capital structure; but the curve does not have a sharply defined minimum, so a utility can depart somewhat from the optimal debt structure without severe financial penalty. The exact shape of the average cost of capital curve is derived from the belief that the costs of both debt and equity rise with increased degrees of financial leverage⁹.

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⁸A classic article on the cost of capital is F. Modigliani and M. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investment, A.E.R. 48 (June 1958), 261-297. See, also, M. Miller and F. Modigliani, "Cost of Capital to the Electric Utility Industry" A.E.R. 56 (June 1966), 333-391. For different points of view about the cost of capital, see, for example, R. Reilly and W. Wecker, "On the Weighted Average Cost of Capital", JFQA 8 (January 1973), 123-126 or D. Scott, "A Theory of Optimal Capital Structure", Bell Journal of Economics 7 (Spring 1970), 33-54.

⁹This analysis does not take into account that changes in the economic environment over time should cause a utility's "optimal debt position" to change. For example, if capital market conditions undergo a pronounced, long-run change, making either debt or equity relatively more favorable, then the long-run optimal capital structure should change, too.

Figure 3-1. RELATIONSHIP BETWEEN DEBT
RATIO AND AVERAGE COST OF CAPITAL

3.4 THE COST OF CAPITAL AND ISSUE RATINGS

The effective interest rate a firm pays on its bonded debt and the effective cost of equity financing are closely correlated with the ratings such issues are given. Although the rating agencies define what each rating means, they do not specify explicitly how they arrive at the ratings. However, the rating agencies do indicate the elements of utility performance that they do consider in determining their ratings.

Table 3-1 suggests the elements that appear to be most important in the evaluation of, say, a specific bond issue. Table 3-2 contains a glossary of terms for the financial ratios in Table 3-1. From Table 3-1, it can be seen that the evaluation process commences with very 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 finally generates a set of key financial ratios that relate the ability of the utility to repay its new debt obligations. For the purposes of this report, the *key ratios* in Table 3-1 will provide the attributes to be used in the utility analysis.

3.5 GEOTHERMAL PROJECT FINANCING

A utility might argue that the undertaking of intrinsically risky new technologies and/or relatively untried power sources, such as those involved in a geothermal project, will increase the economic risks of their business. Ultimately, this may effect their credit ratings, and their access to and cost of capital. However, to examine this argument properly one must look at the avenues by which the credit ratings might be altered.

First, it is important to determine if the investment in a geothermal project will effect the key financial ratios relating to the utility's perceived credit worthiness. On the one hand, a geothermal project may be more risky; on the other hand, the geothermal project is likely to represent a very small part of the overall capital needs of a utility (or sequential plant development for a geothermal field may keep capital requirements small until the riskiness of development has been reduced).

TABLE 3-1. 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 3-2. 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.

Hence the small geothermal project size tends to counteract possible higher riskiness of such projects. Furthermore, 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. Actions by regulatory agencies are especially important because they affect the ability of the utility to alter its rate base if necessary to maintain its fiscal quality.

Second, and related to the argument that geothermal projects (at least initially) will tend to be small, the possibility of packaging, say, a utility's bonds may diversify risks of geothermal projects¹⁰. For instance, if geothermal plant capital requirements represent ten percent of all capital funds being raised in the market, a utility might offer *joint project* bonds, backed by the several projects or the general resources of the utility. If the utility is basically credit worthy and well managed, it is not likely that well-conceived geothermal projects must affect adversely either cost or availability of capital.

Finally, to the extent that other fuel sources are likely to become more expensive and/or less dependable (e.g., oil shortages, coal strikes, environmental regulations about levels of certain fuel uses, and so forth), geothermal projects may *reduce* overall performance and economic risks. If this is true, then it may be possible that in the longer-run, geothermal electric power plants will increase general access to and reduce overall costs of capital for the utility. This, in part, may result from geothermal electric power plants providing cheaper relative energy costs to customers as well as enhancing system reliability through fuel source diversification.

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¹⁰To bring geothermal powered plants to fruition, given their currently perceived prospective of experimental nature, may require new financing approaches, of which the D.O.E.'s geothermal loan guarantee program represents one potential avenue. Others, not discussed here, but worthy of future considerations may relate to "joint ventures" among utilities, resource companies, and third party financiers (see Chapter Four).

Chapter Four

THIRD PARTY FINANCING

4.1 PLANT LEASING ARRANGEMENTS

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 geothermal 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:

- that it avoids investment in a somewhat risky geothermal venture by a highly risk averse electric utility industry;
- that, 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;
- that it prevents classification of the resource developer as a regulated public utility which is likely if the developer were to finance and operate a power plant;
- that 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.

4.2 FINANCING THE LEASE

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. Geothermal power plants, however, carry a degree of risk which is not common in previous hydro, nuclear or fossil-fired plants¹¹. 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 geothermal plant, though, there remains some uncertainty about both the equipment technology and the longterm production capability of the subsurface resource. These geothermal uncertainties are perceived as unacceptable investment risks by the banks and traditional financial institutions unless some form of indemnification against loss can be provided.

4.3 MITIGATING GEOTHERMAL RISKS

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

4.3.1 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). The remaining 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 application and servicing paperwork required for the GLGP, and an additional one percent added to the cost of GLGP-backed funds, the program has been successful in securing loans from risk averse banks and financial institutions. The GLGP, however, is a temporary incentive scheme which is presently due to expire in 1984.

4.3.2 Geothermal Resource Insurance

Geothermal resource insurance has been recommended for indemnifying investors against the risks of unexpected reservoir failure (see EPRI,

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¹¹ See EPRI (1978) for discussions of risks and uncertainties in geothermal power plant ventures.

1978). Insurance of this type recently became commercially available¹² 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 geothermal 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 geothermal 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.

4.4 TAX LEVERAGED LEASING

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".

4.4.1 Structuring the Lease

Tax leveraged leasing involves a lessor, who finances plant construction with substantial amounts of borrowed capital and a minimum¹³ 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.

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¹²Geothermal resource insurance has been initiated by Corroon & Black of Pennsylvania, Inc., Philadelphia.

¹³Minimum equity requirements in tax leveraged leasing arrangements are 20% of project cost according to IRS Revenue Ruling 7521.

4.4.2 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 is 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, 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 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.

4.4.3 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 according to 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.

4.5 INVESTMENT DECISIONS

4.5.1 Investment Decision Criteria

For the purposes of this study it is assumed that tax leveraged leasing is the method used by third party investors for participating in geothermal power plant ventures. An investor's decision to finance such an arrangement will depend upon the risks and returns which are estimated for the proposed venture and upon the availability of investment capital. This 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:

- maximize the efficiency of invested capital (as assessed in terms of its rate of return);
- minimize the length of time during which invested capital is exposed to risk (as assessed in terms of discounted payback time); and
- minimize the risk to which invested capital is exposed (as assessed in terms of the 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 geothermal power plant project and (b) usual business dealings which are consistent with the scope and scale of such a project. Investment decisions by the third party investor, given this definition, can be explained in terms of the three criteria discussed above, namely:

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

Each of these criterion are influenced by several characteristics of the geothermal venture discussed below.

4.5.2 Rate of Return on Investment

The method by which rate of return is estimated is an important consideration in investment analyses. The internal rate of return, IRR, method (also referred to as the marginal efficiency of capital) was published by Keynes (1936) and is often used for evaluating 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...

$$NPV = \sum_{t=0}^n \frac{NR_t - I_t}{(1 + i)^t} \quad (4.1)$$

where, NR_t and I_t are net revenues 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 only when net receipts may be immediately and indefinitely reinvested at the IRR. Given the economic diversification and relatively limited number of attractive geothermal investment opportunities at present, it is unlikely that this reinvestment require-

ment can be met. 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. 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 project revenues compounded forward at a specified and realistic reinvestment rate.

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 geothermal venture, its FMRR should be compared against those of alternative investment opportunities. If the geothermal 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.

4.5.3 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 geothermal 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.

4.5.4 Risk of Loss

As mentioned earlier in section 4.2 there is a degree of uncertainty pertaining to both the performance of geothermal power plant technology and, more so, the production capabilities of a geothermal 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 geothermal venture.

It should be emphasized that, to date, such loss has not been experienced with commercial geothermal 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 4.3, 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 geothermal 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. Geologists and 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.

Technecon's on-going research is using quantitative decision analysis techniques to weigh the various investment criteria of the third party investor. Ultimately, these methods will permit estimates to be made of the likelihood of third party investments in specified geothermal ventures. By testing the sensitivity of these estimates to alternative federal programs and policies, recommendations will be provided for effective incentives.

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