Energy

GEOTHERMAL

366
1/30/84
(LB)

(2)

DR# 2083-4

DOE/CS/30674-2
(DE84003171)

GEOTHERMAL POWER PLANT R&D. AN ANALYSIS OF COST-PERFORMANCE TRADEOFFS AND THE HEBER BINARY-CYCLE DEMONSTRATION PROJECT

By
Thomas A. V. Cassel
Chris B. Amundsen
Peter D. Blair

June 30, 1983

Work Performed Under Contract No. AC02-81CS30674

Technecon Analytic Research, Inc.
Philadelphia, Pennsylvania

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AND THE
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Thomas A.V. Cassel, Ph.D., P.E.
Chris B. Amundsen
Peter D. Blair, Ph.D.

Technecon Analytic Research, Inc.
2400 Chestnut Street
Philadelphia, Pennsylvania 19103

Prepared for:

THE U.S. DEPARTMENT OF ENERGY
UNDER CONTRACT NO. DE-AC02-81CS30674

ABSTRACT

This 2-part report documents an analysis of Federal research and development (R&D) of technologies for producing electric power from 300-400° (Fahrenheit) geothermal resources. This work was performed in 1982 and early-1983 by Technecon Analytic Research, Inc. of Philadelphia for the U.S. Department of Energy. Part I of the report describes a study of advancements in power plant designs for use at geothermal resources in the low to moderate (300-400F) temperature range. In 3 case studies, the benefits of R&D to achieve these advancements are evaluated in terms of expected increases in installed geothermal generating capacity over the next 2 decades. In addition to these case studies, a parametric sensitivity study is discussed which analyzes differential power development for combinations of power plant efficiency and capital cost. This part of the report concludes that, while the potential for development at 300-350F resources is not substantial, the potential for development at 350-400F resources is in the order of several thousand megawatts of electric power by the end of this century. This power development is expected to be realized if R&D efforts can achieve modest improvements in geothermal power plant performance without substantial increases in plant capital costs. Affordable tradeoffs between plant performance and capital costs are illustrated in the report.

Part II of the report describes Technecon's independent review and analysis of the expected costs of construction, operation and maintenance of the Heber Binary Cycle Geothermal Power Demonstration Plant. This project is funded, to a large degree, by the Federal government to demonstrate power production from the 360F geothermal resource at Heber CA. Included in this assessment is an analysis of each of the major cost components of the project, including (1) construction cost, (2) well field development costs, (3) fluid purchase costs, and (4) well field and power plant operation and maintenance costs. The total cost of power generated from the Heber Plant (in terms of mills per kWh) is then compared to the cost of power from alternative fossil-fueled base load units. The report concludes that this binary cycle system will likely prove competitive with oil-fired generation once R&D-related costs are removed from subsequent mature, commercial designs. Also evaluated in Part II are the provisions of both: (a) the Cooperative Agreement between the Federal Government and San Diego Gas & Electric (SDG&E); and (b) the Geothermal Heat Sales Contract with Union Oil Company.

PREFACE

This report documents a study of Federally-funded research and development activities pertaining to geothermal power plants for use at resources in the 300-400° (Fahrenheit) range. This work was performed for the U.S. Department of Energy (DOE) in 1982 and early 1983 by Technecon Analytic Research, Inc., Philadelphia, under Contract DE-AC02-81CS30674. The study focuses on R&D for resources in the 300-400°F range because it is in this class of resources that we feel the government can realize the greatest payoff from high-risk, long-term research that is unlikely to be undertaken by private industry alone. Divided into two distinct parts, the report discusses both (1) planning for future R&D activities and (2) cost and contractual aspects of DOE's binary cycle Geothermal Demonstration Project at the 360°F resource at Heber, California.

Part I. The R&D planning analysis -- Part I of the report -- presents a study of tri-variate tradeoffs between goals for geothermal power plant performance, capital cost, and the differential amount of electric generating capacity that can be expected to be developed at geothermal resources in the United States. This analysis relies upon the geothermal power forecasting methodology that was developed by Technecon for DOE between 1978 and 1982 under Contracts ET-78SO2-4713 and DE-AC02-79ET27242.

Throughout these investigations, a generous degree of cooperation and participation by the geothermal resource and electric power industries has been received. More than 80 individuals representing some 20 resource companies, 13 electric utilities and a number of financial institutions contributed to this effort. Many hours of management interviews and a high response rate to quantitative surveys were contributed during the course of this work. The forecasting models which evolved from our analysis of industry responses take the form of weighted functions of multiple investment criteria. Many of the computer techniques used in this work are based upon those commonly used in oil and gas evaluations and are, for the first time, applied to geothermal cases. Of primary importance is the models' ability to simulate industry investment behavior at acceptable

levels of confidence. This capability is of significant value, particularly to program and policy analysts involved in the structuring of responsible incentives and research strategies for supporting the development of geothermal resources.

Part I of this report is organized as follows:

Chapter One presents the background and objectives of this study, summarizes the methods we used, and discusses the results and conclusions of the R&D planning analysis.

Chapter Two describes the details of the methodology and format of results. Details of geothermal well field and power plant cash flow analyses, including geothermal resource pricing, are presented in this Chapter.

Chapter Three describes both known and forecasted geothermal resources in the 300-400°F range that are targets for the R&D activities analyzed in this study. An overview of the resource forecasting methodology is provided.

Part II. A major objective of the Heber Binary Cycle Demonstration Project is to establish the binary cycle plant as a competitive alternative energy source for electric power generation and, thereby, stimulate geothermal power development in the United States. Confirming the technical viability of the project will not, in itself, be sufficient to ensure that this goal is met. In addition to meeting performance goals (net plant output, reliability, etc.), the plant must demonstrate an economically viable alternative to fossil-fueled base load generation. Widespread adoption of geothermal binary cycle power plant technology is expected to take place if the cost of power generated from these plants is competitive with the cost of power from other base load sources.

To assist DOE in their evaluation of Project economics, Technecon has prepared an analysis of the major cost components of the Heber Project. The purpose of this analysis is to assess the likelihood that the Heber Demonstration Project, and second-generation "mature" binary cycle plant designs, can achieve the competitive economic objectives. Included in this analysis is an independent review of construction costs, operation and maintenance costs, and contractual provisions pertaining to the geothermal fluid purchase agreement.

A summary of our economic evaluation is presented in Chapter One of Part II. The remainder of Part II contains a detailed assessment of project costs, and is organized as follows:

Chapter Two provides an independent review of the Project's construction cost estimate.

Chapter Three estimates well field development costs which are likely to be incurred before the Heber plant is brought on-line.

Chapter Four reviews the heat sales agreement, and estimates the return on investment that well field developers can expect to earn.

Chapter Five examines the provisions in the Cooperative Agreement under which revenue generated by operation of the plant would be shared among Project co-sponsors.

Chapter Six compares the cost of power generated from the Heber plant to the cost of power generated from newly constructed fossil-fueled base load power plants.

Chapter Seven provides an analysis of the extent to which the construction cost of second generation, technologically mature binary plants can be expected to differ from the cost of the Demonstration Project.

* * * *

The work described in Part I has been managed by Mr. Ray LaSala of DOE's geothermal division at its Washington headquarters. The Part II effort was managed by Mr. Denis Feck of the same office. Mr. LaSala, Mr. Feck, Mr. Martin Sheave, Dr. James C. Bresee, and Mr. Tony Aducci -- all of DOE -- provided very valuable support and constructive comments during the progress of this work. In addition, our research benefited from expertise provided by Mr. Eugene Ciancanelli of Cascadia Exploration Corp., San Diego, Mr. Jack Demuth of EG&G, Idaho, Inc., and United Engineers and Constructors, Inc. of Philadelphia. As Technecon's subcontractors, their respective analyses of geothermal resources and Heber Project construction costs provide an integral and valuable part of this work.

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.

Thomas A.V. Cassel

Chris B. Amundsen

Peter D. Blair

Technecon Analytic Research, Inc.
Philadelphia
June 30, 1983

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- PART I -

**GEOHERMAL POWER PLANT R&D PLANNING
COST/PERFORMANCE TRADEOFFS**

Chapter One

INTRODUCTION AND PRESENTATION OF RESULTS

1.1 INTRODUCTION

1.1.1 Objective

Geothermal resources in the western U.S. offer the potential of supplying a significant share of the region's new electric power requirements by the end of this century. Recent studies indicate that 10-15% of new generating capacity to be installed in western states between now and 2000 could be in the form of geothermal capacity (ref. Cassel, et al. 1983). Currently, geothermal plants provide more than 1000 megawatts of electric power -- primarily from The Geysers vapor-dominated resource area in northern California.

For technical and economic reasons, development of liquid-dominated geothermal resources outside The Geysers is presently targeted for higher temperature resources. Electric power can be efficiently and economically generated from these resources with existing geothermal technology. However, these higher temperature resources comprise a small fraction of the total U.S. resource base as illustrated in Figure 1-1. If the substantial potential of geothermal power is to be realized, active exploration and development must be pursued at the preponderance of technically-challenging liquid-dominated resources in the low and moderate temperature range (300-400F).

Technology improvements, from effective research and development (R&D) programs, are needed to improve the energy conversion efficiency and power production economics of liquid-dominated geothermal resources in the 300-400F range. The purpose of this study is to develop a method for evaluating the expected effectiveness of alternative R&D programs, and to demonstrate how this methodology can be applied to target specific geothermal program goals. Program effectiveness is evaluated in this study in terms of the expected levels of development (i.e., megawatts of electric power placed in service) achieved at U.S. geothermal resources under varying levels of technology improvements. Measured in this way, program effectiveness will reflect (1) the range of applications for the specific

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

Source: University of Utah (1980)

technology improvement (i.e., the number of compatible resource areas), (2) the likelihood that the private sector will adopt the improvement for commercial applications, and (3) the marginal increase in geothermal power development afforded by the R&D achievement.

1.1.2 Summary of Methods

A detailed description of the methods used in this study is provided in Chapter Two. A brief summary is provided here. To evaluate the expected effectiveness of alternative R&D program goals, a multi-step procedure is used.

First, the characteristics of current and forecasted geothermal resource discoveries are estimated. This forecast reflects the likely future impacts of (1) resource depletion, (2) anticipated investment returns for geothermal and oil investments, (3) the number and quality of past resource discoveries, and (4) regional considerations. Known and forecasted resources are characterized in terms of multiple variables including temperature, well flow rate, well costs, year of discovery, salinity and producible acreage estimates. Technecon worked closely with a number of highly qualified geothermal geologists and reservoir engineers to ensure that the U.S. resource base was adequately characterized with up-to-date data.

Once a characterization of the applicable resource base has been obtained, parallel procedures are employed to estimate (a) the technological potential for development at each resource and (b) the numerical likelihood that such development will take place. A detailed cash flow and investment analysis is performed as part of this procedure. Modern, statistically-sound techniques from the decision sciences (i.e., "multiattribute utility analysis" and "logit estimation of positive choice") are employed to evaluate the attractiveness of geothermal project investments relative to other investment opportunities. More than 80 individuals from the geothermal community -- including representatives from 20 resource firms, 13 electric utilities and several financial institutions and government agencies -- contributed to this part of the study to ensure that our geothermal investment decision models were soundly constructed.

The output from this methodology is the product of: (a) the potential extent of resource development (in megawatts of power) over time; and (b) the numerical likelihood that positive investment decisions will be made to pursue this development. This resulting product of potential and probability is known as "expected power".

To examine the effectiveness of alternative R&D programs, the cash flow analysis within our methodology is adjusted to reflect cost and performance changes that may be attributable to resulting technological improvements. From our methodology, both marginal and absolute estimates of expected power development are provided for various cases of technological performance and cost modifications.

1.1.3 Scope of Evaluations

For purposes of this analysis, and as explained in section 1.1.1 above, technology advances are confined to improvements in the energy conversion efficiency of power plants located at low and moderate temperature (300-400F) resources. Recent analyses by Technecon have shown that current state of the art technology provides sufficient investment returns to spur development at most higher temperature resources. Previous studies (see, for example, Cassel, et al. 1981 and Cassel, et al. 1982) have also examined the expected benefit of technological improvements associated with geosciences, well drilling, well maintenance and materials research.

Three specific test cases, designed by EG&G Idaho, Inc. are used to demonstrate the use and flexibility of this methodology for evaluating the effectiveness of R&D advancements. A sensitivity analysis is also presented describing the effectiveness of tradeoffs between higher energy conversion efficiencies and coincident increases in power plant capital costs.

1.2 DESCRIPTION OF R&D PROGRAM TEST CASES

To demonstrate the use of this methodology, EG&G Idaho, Inc. designed three representative R&D program initiatives. For each program, specific improvements in power plant "hardware" and operating conditions were

envisioned. EG&G then defined the ultimate net impact of such improvements on the capital cost and net brine effectiveness (net plant output, watt-hr/lb brine) of the power plant. Separate analyses were prepared for low (300-350F) and moderate (350-400F) temperature resources. A description of each R&D initiative is provided below.

1.2.1 Case I: "Heber-type" Binary Power Plant.

This case was established to represent a commercial version of the Heber 50 MWe geothermal demonstration binary power plant described in Part II of this report. Major plant features include:

- o 0.88 isobutane/0.12 isopentane working fluid mixture,
- o Supercritical cycle,
- o Co-current or pot condensing with a 10°F pinch point,
- o Plant outlet geofluid temperature of 160°F,
- o No regenerative preheating.

It is assumed that the conceptual design for this plant, and those described below, will be completed by 1985.

The brine effectiveness value for a 360F resource having negligible dissolved solids was obtained from cycle analyses conducted previously by EG&G. Capital costs were derived by updating cost estimates reported in Cassel, et al, 1982. Table 1-1 shows the estimated brine effectiveness and capital costs for a commercially available Heber type plant in relation to "Base Case" (i.e. current technology) assumptions.

1.2.2 Case II: Low Cost Advanced Binary Plant.

The Case II design achieves better performance than the Case I Heber design and at substantially lower cost. This case was selected to encompass several improvements relative to the Heber type plant described above. These improvements for a clean 360F resource encompass the following plant features:

- o 0.96 isobutane/0.04 heptane working fluid mixture,
- o Supercritical cycle,
- o Countercurrent condensing with a 10°F pinch point,

Table 1-1
GEOHERMAL POWER PLANT COST AND PERFORMANCE
CASE I: HEBER-TYPE BINARY SYSTEM

POWER PLANT CAPITAL COST (1983 \$/kW)

Temp. ²	BCI ¹	Base Case: Current Technology			Case I: Heber Type Plant		
		0	1	2	0	1	2
300 °F		1,340	1,440	1,541	1,522	1,635	1,750
325 °F		1,260	1,350	1,450	1,431	1,533	1,647
350 °F		1,180	1,270	1,360	1,340	1,442	1,544
375 °F		1,110	1,190	1,280	1,261	1,351	1,454
400 °F		1,040	1,120	1,200	1,181	1,272	1,363

NET BRINE EFFECTIVENESS (w hr/lb of fluid)

Temp. ²	BCI ¹	Base Case: Current Technology			Case I: Heber Type Plant		
		0	1	2	0	1	2
300 °F		3.89	3.36	2.82	4.06	3.50	2.94
325 °F		5.43	4.90	4.36	5.66	5.11	4.55
350 °F		6.97	6.44	5.90	7.27	6.72	6.15
375 °F		8.51	7.98	7.44	8.88	8.32	7.76
400 °F		10.04	9.51	8.97	10.47	9.92	9.31

NOTE:

- (1) Brine Contamination Index: 0 = < 2,000 ppm total dissolved solids (TDS)
 1 = 2,000 - 100,000 ppm TDS
 2 = > 100,000 ppm TDS
- (2) Temperature is down-hole resource temperature (°F).

- o Plant outlet geofluid temperature of 160°F,
- o Turbine exhaust recuperator used for partial working fluid preheating.

Cycle analyses for this advanced binary plant have been previously conducted for a 360°F resource with negligible dissolved solids (see EG&G, 1981b). The net brine effectiveness for this improved plant is predicted to be 20 percent higher than values of effectiveness anticipated for a Heber type plant throughout the range of resource temperatures and dissolved solids conditions.

Component sizes (heater, condenser, turbine, etc.) for the advanced binary plant were derived relative to the Heber-type plant described above. Capital costs were estimated by EG&G. The fractional change in capital cost (\$/kW) relative to the Heber plant was assumed to apply for all resource temperatures and dissolved solids conditions. Table 1-2 presents the estimated capital costs and brine effectiveness of this advanced binary system at resources of varying temperatures and salinities.

1.2.3 Case III: Advanced Binary Plant at Increased Capital Cost.

This case was selected to provide an assessment of the effect of a major increase in capital cost for an advanced binary plant. For this case, brine effectiveness values are assumed to be the same as for the advanced system described in Case II above. The plant capital cost was selected as \$2,000/kW (1983 dollars) for a 350° F. clean resource. The same scaling factors as those used in Case II were applied to estimate capital costs at resources of different temperature and salinity. Table 1-3 compares the capital cost and brine effectiveness values for this case against those of the Base Case.

1.3 TEST CASE RESULTS

For the current technology Base Case, and each of the three cases of technology improvements described above, comparative estimates of expected geothermal power development were evaluated. Separate analyses are presented for low (300-350°F) and moderate (350-400°F) temperature resources. Time-wise forecasts of "expected" power development, utilizing

POWER PLANT CAPITAL COST (1983 \$/kW)

Temp. ² BCI ¹	0	1	2	0	1	2
300 °F	1,340	1,440	1,541	1,388	1,491	1,596
325 °F	1,260	1,350	1,450	1,305	1,398	1,502
350 °F	1,180	1,270	1,360	1,222	1,315	1,408
375 °F	1,110	1,190	1,280	1,150	1,232	1,325
400 °F	1,040	1,120	1,200	1,077	1,160	1,243

Temp. ² BCI ¹	0	1	2	0	1	2
300 °F	3.89	3.36	2.82	4.87	4.20	3.53
325 °F	5.43	4.90	4.36	6.79	6.13	5.46
350 °F	6.97	6.44	5.90	8.72	8.06	7.38
375 °F	8.51	7.98	7.44	10.66	9.98	9.31
400 °F	10.04	9.51	8.97	12.56	11.90	11.24

(2) Temperature is down-hole resource temperature (°F).

Table 1-3
 GEOTHERMAL POWER PLANT COST AND PERFORMANCE
 CASE III: HIGH COST ADVANCED BINARY SYSTEM

POWER PLANT CAPITAL COST (1983 \$/kW)

Base Case: Case III:
 Current Technology High Cost Adv. Binary Sys.

Temp. ² BCI ¹	0	1	2	0	1	2
300 °F	1,340	1,440	1,541	2,271	2,441	2,612
325 °F	1,260	1,350	1,450	2,136	2,288	2,458
350 °F	1,180	1,270	1,360	2,000	2,153	2,305
375 °F	1,110	1,190	1,280	1,881	2,017	2,169
400 °F	1,040	1,120	1,200	1,763	1,898	2,034

NET BRINE EFFECTIVENESS (w hr/lb of fluid)

Base Case: Case III:
 Current Technology High Cost Adv. Binary Sys.

Temp. ² BCI ¹	0	1	2	0	1	2
300 °F	3.89	3.36	2.82	4.87	4.20	3.53
325 °F	5.43	4.90	4.36	6.79	6.13	5.46
350 °F	6.97	6.44	5.90	8.72	8.06	7.38
375 °F	8.51	7.98	7.44	10.66	9.98	9.31
400 °F	10.04	9.51	8.97	12.56	11.90	11.24

NOTE:

- (1) Brine Contamination Index: 0 = < 2,000 ppm TDS
 1 = 2,000 - 100,000 ppm TDS
 2 = > 100,000 ppm TDS

- (2) Temperature is down-hole resource temperature (°F).

the methodology described in Chapter 2, are provided below. This forecast is based upon the following set of important assumptions (each of which is addressed in greater detail in Chapters 2 and 3):

- o Of the currently discovered moderate temperature resources, only Heber and East Mesa are assumed to be confirmed. Expected power forecasts at the other discovered resources (Brady Hazen, Steamboat Springs, Sulfur Bank, and Clear Lake) reflect uncertain eventual confirmation (see Section 3.1).
- o A small number of new moderate temperature resources will be discovered over the next ten years.
- o Geothermal power plants are required to operate at costs competitive with coal-fired generation.
- o The geothermal exploration industry remains essentially status quo for the next fifteen years without appreciable increases or decreases in the rate of exploration activity.

1.3.1 Projected Development at Low Temperature Resources.

As noted in Table 1-4, development of power plant facilities at sub-350F resources is not expected to occur with either current technology or with the technological benefits of any of the three R&D programs (Cases I, II and III above). The anticipated investment returns are insufficient to offset the substantial well field capital expenditures required to support power plant operation even with a 20 percent improvement in energy conversion efficiencies (as in Case II). More dramatic R&D advancements will clearly be required if low temperature resources are to be developed by the end of the century. The magnitude of technological improvements and/or capital cost reductions needed to induce development at low temperature resources is addressed in Section 1.4.

1.3.2 Projected Development at Moderate Temperature Resources.

As observed in Table 1-5, expected power at moderate temperature resources (350-400F) is estimated to total 540 MWe by 2000 under Base Case assumptions. This 540 MWe represents approximately 10 percent of the hydrothermal capacity expected to be brought on line by the year 2000, the remaining capacity being located at resources having downhole temperatures in excess of 400°F. Table 1-6 provides site-specific expected

Table 1-4.

EXPECTED POWER FORECASTS FOR R&D TEST CASE PROGRAMS

- LOW TEMPERATURE RESOURCE BASE (300-350° F.) -

Research and Development Initiative	Expected Power Forecast (MWe)	
	by 1990	by 2000
Base Case: Current Technology	0	0
Case I: Commercially Available Heber-type Binary Plant	0	0
Case II: "Low-Cost" Advanced Binary Plant	0	0
Case III: "High-Cost" Advanced Binary Plant	0	0

Table 1-5.

EXPECTED POWER FORECASTS FOR R&D TEST CASE PROGRAMS
- MODERATE TEMPERATURE RESOURCE BASE (350-400° F.) -

Research and Development Initiative	Expected Power Forecast (MWe)	
	by 1990	by 2000
Base Case: Current Technology	330	540
Case I: Commercially Available Heber-type Binary Plant	310	540
Case II: "Low-Cost" Advanced Binary Plant	610	1,280
Case III: "High-Cost" Advanced Binary Plant	60	180

Table 1-6.
SITE-SPECIFIC EXPECTED POWER* FORECASTS
FOR THE YEAR 2000 FOR R&D TEST CASE PROGRAMS
(Megawatts)

	BASE CASE: <u>Current Technology</u>	CASE I: <u>Commercially Available Heber-Type Plant</u>	CASE II: <u>Low Cost Advanced Binary Plant</u>	CASE III: <u>High Cost Advanced Binary Plant</u>
Soda Lake, NY	0	0	0	0
Heber, CA	10	45	300	10
East Mesa, CA	45	90	300	45
Brady Hazen, NV	20	20	45	0
Steamboat H.S., NV	50	45	90	0
Clear Lake, CA	150	160	220	125
Sulfur Bank, CA	30	30	45	0
	<u>305</u>	<u>390</u>	<u>1000</u>	<u>180</u>
Future Resource Discoveries	235	150	280	0
TOTAL	540	540	1280	180

*"Expected power" is the amount of power multiplied by the numerical probability that this power will be brought on line.

development levels for those resources discovered to date, as well as forecasted development at future resource discoveries.

Projected development under Case I remains essentially unchanged from the Base Case forecast. The 4 percent increase in brine effectiveness is achieved at the expense of a 14 percent increase in power plant capital cost. These impacts effectively offset each other, leaving development incentives unchanged.

The impact of the technology improvement brought about by Case II (a 25 percent increase in brine effectiveness, with only a 3.5 percent power plant capital cost increase) is substantial. An expected 1280 MWe of capacity is forecast by 2000 if the technology goals of this R&D program could be met. This is an 80 percent increase over the Base Case.

The importance of attaining the plant performance increase without substantial cost increases is noted in Case III. Development levels are reduced to only 180 MWe under this scenario, as the 70 percent increase in power plant capital cost reduces the marginally competitive resource price to below 15 mills/kWh. The revenues generated from fluid sales at these prices are insufficient to adequately compensate the resource developer for well field development expenditures.

1.3.3 Sensitivity to Probabilistic Confirmation of Known Resources

As discussed above, these projections incorporate uncertainties surrounding the eventual confirmation of the resources at Brady Hazen, Steamboat Springs, Sulfur Bank, and Clear Lake. Expected development profiles at each resource are multiplied by the probability that each would be confirmed. These probabilities were assigned by consulting geologists based upon the best geologic data and other information available at the present time.

To assess the maximum "up-side" potential each R&D program might have, the foregoing assumption was relaxed. A sensitivity test was made assuming each of the uncertain resources is eventually confirmed with a probability of 100%. Expected development levels under this scenario total 1300 MWe by 2000 for the Base Case and Case I, more than double the power forecast derived under the more pessimistic assumption. Capacity would be expected

to exceed 2800 MWe by 2000 if a low cost advanced binary power plant were available for commercial applications (Case II).

1.4 POWER PLANT PERFORMANCE AND COST TRADEOFF ANALYSIS

1.4.1 Overview of Tradeoff Analysis

The previous analysis has demonstrated the ability of the integrated modeling procedures described in Chapter 2 to assess the effectiveness of specific R&D goals. Each of the three test cases has demonstrated the importance of designing R&D programs which would achieve plant performance increases, without raising capital costs to the point where the net effect would be to deter development. In the formulation of R&D programs, this tradeoff between improvements in the energy conversion efficiencies and coincident increases in plant investment costs must be addressed.

In this section, our methodology for assessing the goals of specific R&D programs is generalized to perform parametric tests of "expected power" sensitivity to varying levels of power plant performance and capital cost. As shown below, 3-dimensional response surfaces are constructed to illustrate the relationship between plant performance, plant cost and expected power development at low (300-350F) and moderate (350-400F) temperature resources. The results of this analysis are useful for: (a) estimating marginal affordable cost increases to achieve better power plant performance; (b) setting goals for R&D programs in terms of performance increases and capital cost constraints; (c) forecasting the expected development of geothermal power that may be achieved by successful R&D initiatives; and (d) targeting R&D activities to resources offering appreciable potential for expected power development.

To analyze the potential tradeoffs between improved plant performance and increased capital cost, the modeling procedure is repeated for multiple combinations of plant brine effectiveness and plant capital cost. For each combination, "expected" power development levels are forecast for the year 2000, and compared to a Base Case corresponding to current technology. The incremental megawatts of power brought on-line over the Base Case can be interpreted as a measure of the benefits brought about by an R&D program designed to achieve the cost and performance objectives. Separate analyses

are prepared for low and moderate temperature resources. As demonstrated below, the "response surface" generated for each resource type may be used to efficiently examine alternative cost/performance tradeoffs, and to target R&D program objectives.

1.4.2 Performance/Cost Tradeoffs at 300-350F Resources.

Current geothermal power plant technology, according to EG&G Idaho, Inc. has net brine effectiveness ratings on the order of 5 watt hrs/lb at low temperature resources in the 300-350F range. EG&G estimates the capital cost of such a plant to be on the order of \$1400/kW in 1983 dollars. Our analysis, as illustrated in Figure 1-2 and Table 1-7, indicates that this current state of geothermal technology offers no hope of expected power development by 2000 at known and forecasted resources in the 300-350F temperature range. As further shown in Figure 1-2, at current capital cost levels of \$1400/kW, plant performance must be improved by a factor of two if appreciable development of low temperature resources is to be realized.

The results illustrated in Figure 1-2 and Table 1-7 are based upon uncertain confirmation of the low temperature resource at Soda Lake (see Chapter 3). If, instead, a 100% probability of confirmation is assumed for Soda Lake, the expected power estimates for this class of resources more than doubles. Figure 1-3 and Table 1-8 illustrate the performance/cost tradeoff results if we assume the Soda Lake discovery is eventually confirmed to be a producible resource.

Nevertheless, these figures illustrate that current geothermal power plant technology, as defined by EG&G, is far from being commercially practical at resources in the 300-350F temperature range. The very substantial improvements in energy conversion efficiency that are required to achieve appreciable resource development suggest that R&D funding for low temperature resources may yield only marginal, if any, commercial benefits.

1.4.3 Performance/Cost Tradeoffs at 350-400F Resources.

Current geothermal power plant technology, according to EG&G, has a net brine effectiveness of from 6.5 - 9.5 watt hrs/lb and a capital cost of

**Figure 1-2. COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 300-350° F. RESOURCES
- BENEFITS TO THE YEAR 2000 -**

Table 1-7
COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 300-350°F RESOURCES
- BENEFITS TO THE YEAR 2000 -

DIFFERENTIAL DEVELOPMENT ABOVE CURRENT TECHNOLOGY ESTIMATES OF 0 MWe:

Hydrothermal Power Plant Capital Cost (\$/kW) ¹	Net Brine Effectiveness (W hr/lb. of Fluid)										
	5	6	7	8	9	10	11	12	13	14	15
1000	0	0	0	24	56	108	199	272	332	434	464
1250	0	0	0	1	32	85	132	217	291	395	425
1500	0	0	0	0	1	37	95	147	186	340	378
1750	0	0	0	0	0	1	15	68	114	208	235
2000	0	0	0	0	0	0	0	1	1	66	83
2250	0	0	0	0	0	0	0	0	0	0	0
2500	0	0	0	0	0	0	0	0	0	0	0
2750	0	0	0	0	0	0	0	0	0	0	0
3000	0	0	0	0	0	0	0	0	0	0	0

¹1982 Dollars

**Figure 1-3. COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 300-350° F. RESOURCES***

- BENEFITS TO THE YEAR 2000 -

Table 1-8
COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 300-350°F RESOURCES
- BENEFITS TO THE YEAR 2000 -

DIFFERENTIAL DEVELOPMENT ABOVE CURRENT TECHNOLOGY ESTIMATE OF 0 MWe¹:

Hydrothermal Power Plant Capital Cost (\$/kW) ¹	Net Brine Effectiveness (W hr/lb. of Fluid)										
	5	6	7	8	9	10	11	12	13	14	15
1000	0	0	1	96	225	400	535	698	783	984	1054
1250	0	0	0	3	126	335	455	643	743	937	1009
1500	0	0	0	1	4	149	375	557	629	882	962
1750	0	0	0	0	1	2	60	271	450	727	806
2000	0	0	0	0	1	1	1	3	5	265	332
2250	0	0	0	0	1	1	1	1	1	1	2
2500	0	0	0	0	1	1	1	1	1	1	1
2750	0	0	0	0	1	1	1	1	1	1	1
3000	0	0	0	0	1	1	1	1	1	1	1

²Assumes Resource at Soda Lake is Confirmed

from \$1100-1250/kW for moderate temperature resources in the 350-400F range. Our analysis, as illustrated in Figure 1-4 and Table 1-9, indicates that development of 530 MWe is expected by the year 2000 at known and forecasted resources given this current state of geothermal technology.

As further shown in Figure 1-4, substantial benefits can be achieved by modest successes in R&D programs. For example:

- o A 15% improvement in geothermal power plant performance without a capital cost increase is expected to provide for the development of an additional 500 MWe of power at moderate temperature resources. A 33% performance improvement is expected to provide for an additional 1000 MWe.
- o A 20% increase in plant capital cost can be afforded while providing for an additional 500 MWe of development if this added cost buys a 25% improvement in plant performance. If this same added cost buys a 40% performance improvement, an additional 1000 MWe of power may be expected.

The results illustrated in Table 1-9 are based upon uncertain confirmation of moderate temperature resources at Brady Hazen, Steamboat, Clear Lake and Sulfur Bank (see Chapter 3).¹ If, instead, 100% probability of confirmation is assumed for these resources, the estimates of "expected power" for this class (350-400F) of resources substantially increases. Figure 1-5 and Table 1-10 illustrate the performance/cost tradeoff results if we assume Brady Hazen, Steamboat, Clear Lake and Sulfur Bank are eventually confirmed to be producible resources.

From this analysis, it appears that R&D efforts can achieve substantial benefits in terms of increased development at moderate temperature geothermal resources. With expected development levels on the order of 1,000 to 2,000 MWe by the year 2000, moderate temperature resources would provide more installed generating capacity than is currently operational at the successful Geysers resource area. Improvements in plant performance, even if reached with moderate cost penalty, offer a realistic possibility of raising development levels by 1,000-1,500 MWe over and above the current technology forecast.

¹Note that confirmation of moderate temperature resources at Heber and East Mesa is assumed to be certain throughout this analysis.

Expected Development by 2000
with Current Technology = 530 MWe

Figure 1-4. COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 350-400 F. RESOURCES
- BENEFITS TO THE YEAR 2000 -

Table 1-9
COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 350-400°F RESOURCES
- BENEFITS TO THE YEAR 2000 -

DIFFERENTIAL DEVELOPMENT ABOVE CURRENT TECHNOLOGY ESTIMATE OF 530 MWe:

Hydrothermal Power Plant Capital Cost (\$/kW) ¹	Net Brine Effectiveness (W hr/lb. of Fluid)										
	5	6	7	8	9	10	11	12	13	14	15
1000	-474	-473	-457	-171	186	587	855	1248	1474	1931	2161
1250	-474	-474	-473	-407	-46	432	753	1141	1389	1806	2035
1500	-474	-474	-474	-468	-373	38	583	1006	1177	1701	1916
1750	-474	-474	-474	-474	-470	-421	-164	353	816	1410	1632
2000	-474	-474	-474	-474	-472	-471	-460	-403	-334	415	668
2250	-474	-474	-474	-474	-472	-472	-472	-471	-471	-460	-437
2500	-474	-474	-474	-474	-472	-472	-472	-472	-472	-472	-472
2750	-474	-474	-474	-474	-472	-472	-472	-472	-472	-472	-472
3000	-474	-474	-474	-474	-472	-472	-472	-472	-472	-472	-472

Expected Development by 2000
with Current Technology = 1300 MWe

Figure 1-5. COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL POWER PLANT TECHNOLOGY AT 350-400° F. RESOURCES*

- BENEFITS TO THE YEAR 2000 -

* Assumes resources at Brady Hazen, Steamboat Hot Springs, Clear Lake and Geysers.

Table 1-10
COST/PERFORMANCE TRADEOFFS FOR HYDROTHERMAL
POWER PLANT TECHNOLOGY AT 350-400°F RESOURCES
- BENEFITS TO THE YEAR 2000 -

DIFFERENTIAL DEVELOPMENT ABOVE CURRENT TECHNOLOGY ESTIMATE OF 1300 Mwe²:

Hydrothermal Power Plant Capital Cost (\$/kW) ¹	Net Brine Effectiveness (W hr/lb. of Fluid)										
	5	6	7	8	9	10	11	12	13	14	15
1000	-1255	-1253	-1187	-435	415	1072	1649	2307	2736	3493	3941
1250	-1255	-1254	-1248	-1001	-104	845	1519	2201	2651	3357	3805
1500	-1255	-1255	-1253	-1236	-893	123	1235	2000	2404	3245	3676
1750	-1255	-1255	-1253	-1253	-1243	-1058	-321	844	1760	2897	3336
2000	-1255	-1255	-1253	-1253	-1251	-1247	-1203	-983	-769	1085	1638
2250	-1255	-1255	-1253	-1253	-1251	-1251	-1251	-1249	-1246	-1203	-1139
2500	-1255	-1255	-1253	-1253	-1251	-1251	-1251	-1250	-1248	-1248	-1248
2750	-1255	-1255	-1253	-1253	-1251	-1251	-1251	-1250	-1248	-1248	-1248
3000	-1255	-1255	-1253	-1253	-1251	-1251	-1251	-1250	-1248	-1248	-1248

²Assumes resources at Brady Hazen, Steamboat H.S., Clear Lake, and Sulfur Bank are confirmed.

Chapter Two

METHODOLOGY FOR FORECASTING THE EFFECTS OF R&D ON GEOTHERMAL RESOURCE DEVELOPMENT

The purpose of this chapter is to describe the methodology used to perform R&D program evaluations, the results of which are presented in the preceding chapter. This methodology estimates the expected levels of future development (i.e., megawatts of electric power placed in service) at U.S. geothermal resources under varying degrees of technological improvements. For the purposes of this study, technological improvements were confined to those associated with geothermal power plant cost and performance. In previous studies (see, for example, Cassel, et al. 1982 and Cassel, et al. 1981) we have also examined the expected benefit of technological improvements associated with geosciences, well drilling, well maintenance and materials research.

2.1 OVERVIEW OF METHODOLOGY

Figure 2-1 illustrates the sequence of steps that are followed in our evaluations of geothermal R&D programs. The procedure begins with a characterization of the U.S. geothermal resource base comprising both known and forecasted resource discoveries. This step is described in detail in the following chapter. Each known and forecasted resource discovery is characterized in terms of 10 variables that describe its quality, uncertainties and present state of development. Table 2-1 lists these resource-specific variables and the computer code name of each.

Given a characterization of each resource, two parallel procedures are performed to estimate: (a) the technological potential for development at each resource; and (b) the numerical likelihood that this development will take place. Results from this methodology are expressed in terms of "expected power" which is the product of these two estimated values. A listing of the computer code and its variables which has been developed and implemented by Technecon specifically for this study of R&D initiatives is provided in the appendix of this report.

Figure 2-1. METHODOLOGY FOR GEOTHERMAL R&D EVALUATION

Table 2-1
RESOURCE-SPECIFIC GEOTHERMAL CASH FLOW INPUT VARIABLES

Code	Description
A50	Producible acreage estimate at or above 50% level of confidence assuming resource is confirmed.
A99	Producible acreage estimate at or above 99% level of confidence assuming resource is confirmed.
BCI	Brine contamination index: = 0 for resources having less than 2000 ppm total dissolved solids content = 1 for resources having 2000-100000 ppm TDS content = 2 for resources having greater than 100000 ppm TDS content.
DV10	For resources with existing or committed power plant development, this binary "switch" (0 = no committed development; 1 = committed development) prompts the input of both the net power capacity (MWe) and the initial year on-line for each existing or committed plants at the resource.
FDISC	Numerical joint likelihood (expressed as a decimal) of discovery and confirmation for forecasted, and as yet undiscovered, resources.*
PCFM	Numerical likelihood (expressed as a decimal) of confirmation for currently discovered resources.**
TDSC	Year of discovery for currently known or forecasted resources.
WC	Total cost of completing one producer well excluding redrills and dry holes (1982 \$1000's).
WF	Producer well flow rate without downhole pumps (1000 lbs/hr).
WT	Resource temperature (F).

* FDISC is set equal to 1 for all currently discovered resources (see PCFM).

** PCFM is set equal to 1 for all forecasted, and as yet undiscovered, resources (see FDISC).

2.2 TECHNOLOGICAL POTENTIAL FOR RESOURCE DEVELOPMENT

2.2.1 Estimating Resource Potential

Estimates of technological potential exclude any consideration of developmental constraints that may be imposed by resource economics. Technological potential simply addresses the question of the level of electric power development (megawatts) that could be achieved over time based upon given resource characteristics and in the absence of economic considerations.

The basic equation for estimating a resource's technological potential in megawatts (MW) is expressed as:

$$MW = \frac{AC \times BE \times WF}{1000 \times WS \times \left[1 + \frac{SW}{1-SW} \right]} \quad (2.1)$$

where: AC is the estimated producible acreage of the resource;

BE is the "brine effectiveness" (i.e. energy conversion efficiency) of geothermal power plant technology in watts per lb/hr of fluid supply;

WF is the resource's well flow rate in thousands of pounds per hour;

WS is the required spacing of producer wells at the resource in acres per well (a typical value of 40 acres/well is used in this study); and

SW is the fraction of producer wells that are maintained as spare, stand-by capacity (a typical value of 0.20 is used in this study).

2.2.2 Producible Acreage

As shown in the table of resource characteristics (Table 2-1), the producible acreage of each resource is provided in terms of 2 variables:

A50 which is the producible acreage estimate at a 50% degree of confidence; and

A99 which is the producible acreage estimate at a 99% (i.e. practically certain) degree of confidence -- a smaller value than A50.

During the course of this study these values were provided to us for each U.S. resource by E. Giancanelli (consulting geologist and president of Cascadia Exploration Corp., San Diego) under subcontract to Technecon, and by D. Foley of the Earth Science Laboratory of the University of Utah Research Institute.

From these 2 values, a relationship is established to estimate the numerical probability, $P(AC)$, of variable levels of producible acreage. By assuming a "logistic curve" as illustrated in Figure 2-2, this relationship may be expressed as:

$$P(AC) = \frac{1}{1 + e^{(a + b \times AC)}} \quad (2.2)$$

where: $b = \frac{4.595}{A50 - A99}$; and

$$a = -A50 \times b.$$

Implicit in this relationship is the concept that, assuming a given resource is successfully confirmed, we are highly confident that a producing zone at the center of the resource exists but as we progress radially away from this center our confidence in finding additional producible acreage diminishes.

2.2.3 Probabilistic Estimates of Resource Potential

By considering equations 2.1 and 2.2 together, we are able to develop a stochastic (i.e. "probabilistic") relationship between the megawatt potential of a resource and the probability of achieving this potential based upon uncertain estimates of producible acreage. This relationship, expressing the probability, $P(MW)$, of achieving a given megawatt level, may be written as:

$$P(MW) = \frac{1}{1 + e^{a + b \left[\frac{WS \times 1 + \left(\frac{SW}{1-SW} \right) \times 1000 \times MW}{BE \times WF} \right]}} \quad (2.3)$$

**Figure 2-2. RELATIONSHIP BETWEEN
PRODUCIBLE ACREAGE AND
PROBABILITY OF ITS OCCURRENCE**

2.2.4 Geothermal Power Plant Brine Effectiveness

The thermodynamic performance of a geothermal power plant is often referred to as its "brine effectiveness" expressed in terms of watts of net electric power output per pound per hour of geothermal fluid flow. For illustrative purposes, Figure 2-3 shows the relationship between brine effectiveness and resource temperature for current state of the art power systems.

For the purposes of this study, brine effectiveness is one parameter that was hypothetically improved to various levels above the current state of the art. This allows us to analyze the expected benefits of R&D programs, the goals of which are to achieve such improvements. Expected benefits of such improvements are discussed in the preceding chapter.

2.2.5 Potential Rate of Resource Development

Once the megawatt potential of a resource has been estimated, the potential rate of development is addressed. If there is no existing development or planned commitments, the resource's megawatt potential is assumed to be reached by following a development profile that begins with the placing in service of an initial 20 MWe unit 5 years after resource confirmation. After a subsequent lag of 3 years, a 50 MWe unit is assumed to be placed in service and is followed, 2 years later, by a second 50 MWe unit. In the year following the second 50 MWe unit, a 100 MWe unit is assumed to be placed in service. Thereafter, 200 MWe are assumed to be placed in service each year until the megawatt potential of the resource is achieved.

After the initial "learning period", the assumption that 200 MWe will be placed in service each year is based upon the actual growth rate realized during the mature development stages at The Geysers resource in Northern California. Figure 2-4 illustrates this development profile at The Geysers.

In the cases of geothermal resources where development is either underway or planning commitments are firm, the above assumptions are preempted to the extent that actual developmental decisions have been made.

**Figure 2-3. NET BRINE EFFECTIVENESS OF
GEOTHERMAL POWER PLANT SYSTEMS**

Figure 2-4. RATE OF DEVELOPMENT AT THE GEYSERS

2.3 LIKELIHOOD OF RESOURCE DEVELOPMENT

Once the megawatt potential of a resource has been estimated (as described above), the remaining procedure in our "expected power" analysis is to estimate the numerical likelihood of achieving this potential. As illustrated back in Figure 2-1, this is estimated by, first, performing a cash flow analysis of developmental investments at the resource and, then, examining several attributes of the cash flow (e.g., rate of return, net present value, etc.) in view of the investment objectives of resource developers. Using the decision science techniques of "multiattribute utility analysis" and "logit estimation of positive choice", we are able to estimate the numerical likelihood of positive investment decisions within a statistically-sound level of confidence.

2.3.1 Developmental Impacts of PURPA Legislation

The development of geothermal resources for electric power production has typically depended upon joint investment decisions by: (a) energy resource companies to invest in well field development for geothermal fluid supply, and (b) electric utilities to invest in power plants that use this fluid for power generation. A negotiated geothermal fluid sales agreement has coupled these two entities.

Enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA) appears to be having a noticeable effect upon the traditional geothermal decision process. Section 210 of this legislation defines the terms and conditions under which electric power from geothermal plants, owned and operated by non-utility entities (e.g., resource developers), may be sold to local utilities. Power sold to utilities under such transactions is priced at rates equivalent to the marginal cost that the utility would otherwise incur for generating or otherwise obtaining this electricity from other sources (i.e., "Avoided Cost" rates). If sufficient returns (net of operation and maintenance expenses) on investments can be realized with power sales based on Avoided Cost rates, then total development of well field and power plant facilities by a resource producer and/or third party investor is feasible.

The language and intent of PURPA is also impacting the terms of fluid sales contracts at more conventional ventures involving joint resource producer/electric utility participation. Recent rulings by the California Public Utility Commission (CPUC) have set avoided cost rates as the maximum cost obligation which could be passed through to a utility's ratepayers. Any costs in excess of such avoided costs would be born by the utility (out of earnings) and its stockholders. In several recent hearings before the CPUC, utility representatives have testified that they would be disinclined to pursue site development work if they or their stockholders were at risk for expenditures over and above those recoverable at the avoided cost ceiling.

Largely because of the provisions of PURPA, we observe two alternative courses of action in the development of geothermal resources. Under one course of action, as observed of Occidental Geothermal's recent project at The Geysers resource area, the resource developer (a non-utility) is financing and plans to operate a geothermal power plant. Power sales will be made to the regional utility company (Pacific Gas and Electric) under the provisions of PURPA.

Under the second course of action, as observed at Southern California Edison's recent project in the Heber resource area, the utility company (Southern California Edison) was planning to finance and operate a geothermal power plant and was to purchase fluid from the resource developer. In this project, the state public utility commission appears to be embracing the PURPA "avoided cost" concept in its unfavorable ruling on the acceptability of a proposed contract for geothermal fluid sales between the resource developer and the utility. The PUC's unfavorable ruling was attributed to a fluid sales price that resulted in an ultimate cost of power higher than the utility's avoided cost.

In granting Southern California Edison's request for a Certificate of Public Convenience and Necessity (CPCN), the California Public Utilities Commission summarized their findings regarding rate treatment of the costs associated with the 47 MW geothermal plant as follows:

"While granting Edison's request for a CPCN, we decline to accept Edison's proposed ratemaking treatment for the project. Instead we find the (CPUC) staff's recommendation that Heber cost recovery be limited to avoided costs is a more reasonable arrangement. With avoided cost recovery the risks of project cost competitiveness are borne by Edison stockholders rather than ratepayers. We conclude this is an appropriate allocation of risks for this project. In essence, Edison will recover costs for power produced from the Heber geothermal project in a manner that is consistent with cost recovery by non-utility small power producers that operate similar alternative energy projects. This ratemaking treatment is a reasonable way to protect the interest that ratepayers have in obtaining cost-effective power from the Heber plant." (CPUC; October 20, 1982; Decision 81-10-049).

Under the aegis of PURPA, a utility's "avoided cost" becomes a significant factor in the geothermal investment decision process. It greatly diminishes the utility's decision-making role in geothermal resource development. As demonstrated in field practice, resource development now primarily depends upon the decision of the resource developer to provide geothermal fluid at a price which affords power production at, or within, a utility's "avoided cost". Therefore, if the risk/reward characteristics of a geothermal opportunity are attractive within the "avoided cost" power pricing constraints of PURPA, the resource developer's investment decision becomes the driver of the resource development process.

Past Technecon publications (see, for example, Cassel et al. 1981) have focused on the joint investment decisions of resource developers and utility companies. We focus here, however, on the resource developer alone as being the key decision-maker in the development of geothermal power. As described above, investment returns to the resource developer are constrained by the economics afforded by ultimate "avoided cost" pricing of geothermal power. In the cash flow analysis discussed below, "avoided cost" pricing provides the basis for well field revenue estimates.

2.3.2 Geothermal Project Cash Flow Analysis

A discounted cash flow model is used to analyze the geothermal well field investment opportunity. This model accounts for a time-series of capital investments, expenses, taxes, royalties and revenues incurred in

the exploration, confirmation, development and production of geothermal resources for electric power generation. This cash flow analysis represents an updated version of basically similar models discussed in earlier Technecon publications (see, for example, Cassel, et al. 1981 and Blair, et al. 1982).

Vendor quotations and literature reviews have been used to substantially update field development and maintenance costs reported in previous studies. Special attention is also drawn to considerations of resource pricing in view of recent California Public Utility Commission rulings.

Tax treatment of the several cash flow cost elements as to whether each is expensed as incurred or capitalized and subsequently amortized over a specified depreciable life, follows the suggestions of Arthur Young & Co. (1982), Porter (1965) and Commerce Clearing House (1983). 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 portion of successful well costs is expensed and the tangible portion is capitalized.

Sunk Costs. For the purposes of this study, we model and analyze the cash flow associated with the development of a typical 50 MWe well field project. The sunk costs associated with early resource reconnaissance, exploration, discovery and confirmation are not explicitly included in this cash flow analysis. Instead, following the advice of several resource developers, we assume that these sunk costs are recovered in the risk-adjusted rate of return that developers require of subsequent investments to develop projects at confirmed well fields. As discussed later in this chapter, the estimated likelihood of a positive investment decision depends, to a large degree, upon the anticipated realization of such a risk-adjusted rate of return.

In Section 3.1 of Part II of this report, a discussion of estimated sunk costs for the Heber Geothermal Demonstration Project is presented. These costs are itemized in Table 3-2 of Part II. This Table serves to illustrate the nature and magnitude of estimated front-end sunk costs for a typical 50 MWe geothermal project.

Well Drilling Costs. Well drilling costs for a typical 50 MWe geothermal power project comprise the costs of active production wells, standby spare production capacity, injection wells, initial redrilling to achieve production, dry holes, reworking to maintain production, and replacement of old wells that cannot be reworked. For the purposes of our cash flow model, these cost elements are expressed as a fraction of the cost (WC) of completing one successful production well, exclusive of redrills and dry holes at a resource. As noted back in Table 2-1, production well cost (WC) is a resource-specific variable -- typically ranging from \$500,000 to \$1,500,000 (1983 \$) -- that is provided to us by consulting geothermal geologists and reservoir engineers for each area in the U.S. resource base. Well costs vary with resource location, drilling depth, lithology and casing schedule.

The active producing well requirement (NACT) is estimated by the following relationship:

$$NACT = \frac{kW}{(BE \times WF)} \quad (2.4)$$

where kW represents the generating capacity being supported (kilowatts, net), BE is the net brine effectiveness, and WF is the resource-specific flow rate per active producer well (1,000 lb/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). 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 poorly understood 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 typically 2:1 according to the 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 producer and injector well requirements (PDRL and IDRL, respectively) for field development are therefore:

$$PDRL = \left[1 + \frac{SWF}{1-SWF} \right] \times NACT \quad (2.5)$$

$$IDRL = \frac{NACT}{PIR} \quad (2.6)$$

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 achieve satisfactory fluid flow. The cost of redrilling a well is estimated to be about 35 percent (RDC) of the original completed well cost (WC).

During field development and after resource confirmation, a fraction (DWF) of the total number of wells drilled as producers are expected to be unsuccessful dry wells. This dry well fraction may be about 10 percent, but will depend upon the geologic characteristics of the resource. Abandoned wells are not fully cased and, therefore, are estimated to cost 90 percent (DWC) of the cost (WC) of a successful deep well. Total well costs (TWC) -- including producers, injectors, spares, redrills and abandoned wells -- may be expressed as:

$$TWC = WC \times \left\{ IDRL + \left[PDRL \times \left(1 + \left(\frac{DWC \times DWF}{1 - DWF} \right) + (IRD \times RDC) \right) \right] \right\} \quad (2.7)$$

The useful life expectancy of geothermal wells is influenced by the chemistry of geothermal fluids which causes erosion, corrosion, scaling and plugging of well bores. As shown back on Table 2-1, we use a resource-specific variable, "brine contamination index" (BCI), to indicate the level of dissolved solids content at each resource. Given a value for BCI, the average the average useful well life (WLF, in years) at a resource is expressed as:

$$WLF = 15 - (5 \times BCI) \quad (2.8)$$

To maintain production capacity as wells degrade over time, wells are either reworked or replaced. For cash flow modeling purposes, we assume that a fraction (RWF) of wells are reworked rather than replaced, and that the reworking cost is expressed as a fraction (RWC) of the cost of replacing a well (WC). Therefore, at average intervals of WLF years, the cash flow incurs the following expense (WEX) to maintain production capacity:

$$WEX = WC \times (PDRL + IDRL) \times [1 + RWF \times (RWC - 1)] \quad (2.9)$$

Well Field Surface Facilities. The cost of surface piping between the well heads and power plant may be expressed as a function of the power plant energy conversion efficiency and well flow rates. Included in this capital cost estimate are site improvements, civil/structural requirements, mechanical equipment (excluding downhole pumps), tanks and vessels, piping, and electrical equipment and controls. Surface piping costs are somewhat reduced when downhole well pumps are used in the well field because of smaller pipe diameters and single pipe runs that are afforded by the pressurized, single-phase liquid flow. From data supplied by EG&G Idaho, the following expressions are derived for well field surface equipment costs (in 1982 \$/kWe, net) for the cases of unpumped and pumped wells, respectively:

$$SRP \text{ (unpumped)} = e^{(6.882 - 0.102BE - 0.00115WF)} \quad (2.10)$$

$$SRP \text{ (pumped)} = e^{(7.025 - 0.177BE - 0.00135WF)} \quad (2.11)$$

where: BE is the geothermal power plant "brine effectiveness" as defined back in section 2.2.4; and

WF is the resource-specific flow rate per producer well in 1000 lb/hr.

Figure 2-5 illustrates these surface piping costs as a function of the variables BE and WF.

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 are required. These costs, in addition to expenses incurred in environmental testing and

Figure 2-5. WELL FIELD SURFACE EQUIPMENT COSTS

permitting, can be expected to total in excess of \$200,000 (1982 \$). 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 second year following confirmation, and are estimated to be \$400,000 (1982 \$).

Downhole Well Pumps. The installation of downhole well pumps is, in many cases, an effective means of improving well field production economics. At the present time, pumping technologies are limited to applications at those resources with temperatures under 375°F. A continuation of on-going 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 the provision of downhole pumping capability was cost-effective at all resources with an unpumped well flow rate of less than 500,000 lbs/hr, and a temperature of less than 375°F. The installed capital cost of downhole well pumps (PC, in 1982 \$1000's) was derived from data supplied by EG&G Idaho and pump manufacturers (see also Figure 2-6):

$$PC = PF \times e^{-(0.408 + 0.000995 PF)} \quad (2.12)$$

where: PF is the pumped well flow rate in 1000 lb/hr.

From industry-supplied data, we estimate that the average annual cost of maintaining a downhole pump is approximately \$87,000 per pump (1982 \$). In addition to this cost, each pump consumes approximately 0.57 kWh of electricity for every 1000 pounds of geothermal fluid pumped.

Well Field Operation and Maintenance. Expenditures for well field operation and maintenance (exclusive of pump maintenance as discussed above) include provisions for field labor expense, surface equipment maintenance, and producer and injector well maintenance. Based on surveys of previous studies and vendor quotations, the following annual expenditures can be anticipated (1982\$):

- o Field Labor: \$420,000/yr

- o Surface Equipment Maintenance: Annual expenditures equivalent to 1-2 percent of installed capital cost of field equipment, depending on resource salinity.

**Figure 2-6. DOWNHOLE WELL PUMP
INSTALLED CAPITAL COST**

- o Well Maintenance: \$50,000 - \$150,000 per year for each production and injection well, depending on resource salinity.

Equation (2.13) defines the relationship used to estimate annual well field operation and maintenance costs (WFOM: 1982 \$1,000's).

$$WFOM = \left[420 \times \left(\frac{MW}{100} \right)^{0.7} \right] + \left[0.01 \times SRP \times (BCI^2 - BCI + 2) \right] + \left[47.5 \times (PDRL + IDRL) \times (BCI + 1) \right] \quad (2.13)$$

where: MW is the geothermal project size in megawatts, net;

SRP is the well field surface piping cost per equation (2.10) or (2.11);

BCI is the resource-specific "brine contamination index" as defined back in Table 2-1;

PDRL is the required number of producer wells per equation (2.5); and

IDRL is the required number of injector wells per equation (2.6).

Geothermal Fluid Pricing. It is clear from recent rulings by state public utility commissions that the cost to a utility of geothermal power must be competitive with other types of generation available to the utility (see California Public Utility Commission, 1980 and 1982). The relatively expensive cost of oil- or gas-fired generation, which in the case of many California utilities is their "avoided cost" of generation, is presently allowed as an upper limit to a utility's cost of geothermal power from either: (a) initial utility-owned plants at an undeveloped resource, or (b) qualified non-utility-owned plants under the power purchase provisions of the Public Utility Regulatory Policies Act (PURPA). The text of recent PUC rulings implies, and discussions with utility and commission staffs substantiate, that the less expensive cost of coal-fired generation is likely to dictate an allowable upper limit for geothermal power costs in the future for utility-owned plants which follow the initial demonstration plants at a new resource.

With the utility's allowable total cost (comprising both "fuel" and plant-related costs) for geothermal generation dictated by a PUC, the

allowable cost of geothermal fluid ("fuel") alone can be determined by backing out all non-fuel costs associated with the geothermal power plant. As illustrated in Figure 2-7, these non-fuel costs include fixed plant capital charges, plant operating and maintenance costs, plant insurance and local tax expenses, and other related utility costs for working capital, administrative and general expense. A method for estimating a competitive geothermal fluid price in this manner is described below.

As stated above, to ensure public utility commission acceptance of proposed geothermal power projects, recent case studies¹ indicate that the production cost per kilowatt-hour of the proposed geothermal power should be competitive with that of other forms of baseload generation that are available to a utility. Production cost comprises fuel expenses, plant operating and maintenance expenses, taxes, insurance and the recovery of plant capital with a regulated rate of return. The production cost per kilowatt-hour of generation can be written as:

$$PC = P + \frac{C_c + C_r}{Q} \quad (2.14)$$

where: P is the price (\$/kWh) of power plant fuel (e.g., geothermal fluid, coal, oil, etc.);

C_c is the annual fixed cost per kilowatt of plant capacity (\$/kW yr) for plant capital recovery;

C_r is the annual recurrent cost per kilowatt of plant capacity (\$/kW yr) for operation, maintenance, administration, insurance and local property taxes; and

Q is the annual hours of generation which can be expressed as:

$$Q = 8760 \times CF \quad (2.15)$$

where: CF is the plant capacity factor (i.e. fraction of a year during which the plant is in operation).

Whereas the capital recovery term, C_c , is a level annual amount (much the same as a level mortgage payment), other terms in equation (2.14) such as plant fuel cost, P, and recurrent operating costs, C_r , account for

¹Technecon personnel have published many recent papers, reports and a book on the topic of geothermal investment decisions. For more in-depth discussion of this topic, readers may refer to Cassel, (1982), Cassel et al. (1979, 1981, 1982 and 1983), and Blair et al (1982).

**ALTERNATIVE
BASELOAD
GENERATION**

**GEOHERMAL
GENERATION**

Figure 2-7.
COMPETITIVE GEOTHERMAL FLUID PRICING

expenses that are expected to escalate over time. To properly account for this component escalation, it is necessary to consider production costs on a plant life-time basis when assessing competitive generation economics. This can be accomplished by evaluating equation (2.14) in terms of the present value of each component cost stream.

The present value of the escalating power plant fuel price component may be written as:

$$P' = P \times \left[\frac{1 + g_f}{K - g_f} \right] \times \left[1 - \left(\frac{1 + g_f}{1 + K} \right)^N \right] \quad (2.16)$$

where: P is the initial fuel price (\$/kWh);

g_f is the annual rate of escalation of P ;

N is the economic life of the plant (yrs);

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

$$K = (1 - \tau)K_d f_d + K_c f_c + K_p f_p \quad (2.17)$$

τ , the effective corporate income tax rate, is:

$$\tau = \tau_s + (1 - \tau_s) \tau_f \quad (2.18)$$

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

Terms to the right of P in equation (2.16) represent the expression for determining the present value of stream of uniform payments of P initial value escalating at rate g_f for a period of N years.

Similarly, the present value of the escalating recurrent cost component may be written as:

$$C'_r = C_r \times \left[\frac{1 + g_c}{K - g_c} \right] \times \left[1 - \left(\frac{1 + g_c}{1 + K} \right)^N \right] \quad (2.19)$$

where: C_r is the present annual recurrent cost (\$/kW); and g_c is the annual rate of escalation of C_r .

The present value of plant capital costs must account for tax benefits (i.e., depreciation and investment tax credits) and tax liability (i.e., taxes on the utility's investment return) that are associated with this component. From Cassel, et al. (1979) and Doane (1976), this can be written as:

$$C'_c = \left[\frac{1 - (\tau \times \text{DPF}) - \alpha}{1 -} \right] \times \text{CI} \quad (2.20)$$

where: CI is the capital cost of the plant inclusive of interest during construction;

α is the investment tax credit fraction;

DPF, the accelerated tax depreciation factor, is:

$$\text{DPF} = \frac{2 \left[n - \left(\frac{1 - (1 + K)^{-n}}{K} \right) \right]}{n(n + 1)K} \quad (2.21)$$

and n is the tax life of the plant (yrs).

For the purposes of this analysis, and consistent with the abovementioned utility commission requirements for competitive geothermal power costs, the competitive production cost situation between geothermal power and some other form of generation can be expressed as:

$$P'_g + \frac{C'_{c,g} + C'_{r,g}}{Q_g} = P'_b + \frac{C'_{c,b} + C'_{r,b}}{Q_b} \quad (2.22)$$

where the subscripts g and b denote terms associated with geothermal power and the competing form of baseload generation, respectively. To estimate the present value of the escalating competitive price stream for geothermal fluid, P'_g , if all other terms in equation (2.22) are known, the equation can be rewritten as:

$$P'_g = P'_b + \frac{C'_{c,b} + C'_{r,b}}{Q_b} - \frac{C'_{c,g} + C'_{r,g}}{Q_g} \quad (2.23)$$

If the negotiated geothermal fluid price is escalated at the same rate, g_f , as the competing plant fuel, then equations (2.16) and (2.23) can be combined to give the following expression for the competitive price of geothermal fluid in the initial year of production:

$$P_g = P_b + \frac{C'_{c,b} + C'_{r,b}}{Q_b \times V_f} - \frac{C'_{c,g} + C'_{r,g}}{Q_g \times V_f} \quad (2.24)$$

where: P_g and P_b are the initial prices (\$/kWh) of geothermal fluid and competing baseload plant fuel, respectively; and

$$V_f = \left[\frac{1 + g_f}{K - g_f} \right] \times \left[1 - \left(\frac{1 + g_f}{1 + K} \right)^N \right] \quad (2.25)$$

Next, by defining:

$$V_c = \left[\frac{1 + g_c}{K - g_c} \right] \times \left[1 - \left(\frac{1 + g_c}{1 + K} \right)^N \right] \quad (2.26)$$

and:

$$V_t = \frac{1 - (\tau \times \text{DPF}) - \alpha}{1 - \tau} \quad (2.27)$$

the competitive geothermal fluid price from equation (2.24) can be rewritten as:

$$P_g = P_b + \frac{(V_t \times CI_b) + (V_c \times C_{r,b})}{Q_b \times V_f} - \frac{(V_t \times CI_g) + (V_c \times C_{r,g})}{Q_g \times V_f} \quad (2.28)$$

Recurrent costs during the first year of power plant operation for operation, maintenance, administration, insurance and local property taxes are frequently expressed as a fraction of the plant's capital cost (see Cassel, et al., 1979). By defining this recurrent cost fraction as B , equation (2.28) can be rewritten:

$$P_g = P_b + \frac{[V_t + (V_c \times B_b)] \times CI_b}{Q_b \times V_f} - \frac{[V_t + (V_c \times B_g)] \times CI_g}{Q_g \times V_f} \quad (2.29)$$

where, as stated above, P_g is the initial competitive price of geothermal fluid (\$/kWh) that escalates at an annual rate, g_f , throughout the plant's economic life, and P_b is the initial fuel price for competing baseload generation escalating at the same annual rate.

As an example of this method of fluid pricing, Figure 2-8 illustrates the maximum allowable geothermal fluid prices for geothermal power plants having an installed capital cost ranging from \$1000 - 2600/kW when competing with a utility's avoided cost of either coal-fired or oil-fired generation. The difference, in Figure 2-8, between utility and non-utility ownership of the geothermal power plant is attributable to differing costs of capital and tax credits as shown in Table 2-2.

For the cash flow analyses used in performing the studies discussed here, geothermal fluid prices are determined in this manner with coal-fired generation as the competitive standard.

Well Field Revenues. Annual revenues from geothermal fluid sales (REV in \$1000's) are estimated by the following expression:

$$REV = 8760 \times CAPH \times MW \times P_g \quad (2.30)$$

where: CAPH is the annual capacity factor of the geothermal power plant;

MW is the net output of the geothermal power plant in megawatts; and

P_g is the geothermal fluid price in \$/kWh as estimated by equation (2.29) above.

Revenues estimated in this manner escalate throughout the life of the geothermal project at an annual rate, g_f .

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

Local 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 to 25 percent of the book value of installed well field capital prior to commercial production and at 5

Figure 2-8. COMPETITIVE GEOTHERMAL FLUID PRICES

TABLE 2-2. ECONOMIC & FINANCIAL ASSUMPTIONS FOR
GEOTHERMAL FLUID PRICING (FIGURE 2-8)

GENERATION TYPE:	COAL	OIL	GEOTHERMAL	
Power Plant Ownership:	Utility	Utility	Utility	Non-Utility
Fuel Cost (1983 Mills/kWh)	18.8	51.8	(Fig.3)	(Fig.3)
Fuel Escalation Rate	7.0%	7.0%	7.0%	7.0%
Plant Capital Cost (1983 \$/kW)	1200	785	(Fig.3)	(Fig.3)
O&M Expense*	6.2%	2.0%	4.0%	4.0%
Common Stock Fraction	0.35	0.35	0.35	0.25
Preferred Stock Fraction	0.15	0.15	0.15	0
Long-Term Debt Fraction	0.50	0.50	0.50	0.75
Cost of Common Stock	0.16	0.16	0.16	0.25
Cost of Preferred Stock	0.11	0.11	0.11	0
Cost of Long-Term Debt	0.11	0.11	0.11	0.12
Federal Income Tax Rate	0.46	0.46	0.46	0.46
State Income Tax Rate	0.09	0.09	0.09	0.09
Investment Tax Credit	0.10	0.10	0.10	0.25
Tax Life (Years)	15	15	15	5
Book Life (Years)	30	30	30	30

*Includes annual operation, maintenance, insurance, local taxes administrative and general expense expressed as a percentage of initial plant capital cost.

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.

State and Federal Corporate Income Taxes. During well field development and prior to resource production, well field 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.

Once commercial production commences at a resource, state and Federal 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 become legally permissible with the passage of the National Energy Act (NEA) in 1978. Depletion allowances, computed by the percentage method, may be estimated as 16% of gross revenues less royalties in 1983 and 15% in 1984 and thereafter (Young, 1982).

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 energy investment tax credit of 15%, above the regular investment credit of 10%, for "alternative" or "specially-defined energy property". Geothermal well field capital, in many instances, qualifies as such property as do capital investments in major portions of non-utility-owned geothermal power plants (see Young, 1982, for additional discussion of tax credits and various geothermal tax deductions).

Net After-Tax Cash Flow. The resource developer's cash flow is estimated in this analysis by accounting for the following elements:

- o Gross geothermal fluid sales revenues (per equation 2.30);
- o Total well costs including producers, injectors, spare capacity, redrilling, and dry holes (per equation 2.7);
- o Downhole well pumps (per equation 2.12);
- o Surface facility costs (per equation 2.10 or 2.11);
- o Well replacement and reworking expenses to maintain production capacity (per equation 2.9);
- o Well field operation and maintenance expenses (per equation 2.13);
- o Royalty payments (see discussion above);
- o Local ad valorem taxes (see discussion above);
- o State and Federal income taxes (see discussion above).

Year-by-year after-tax cash flow estimates starting with well field development for a power plant project and continuing through, typically, 30 years of commercial production are analyzed in this study. To evaluate the impact of technology improvements brought about by R&D activities, relevant cost and performance parameters are adjusted in this cash flow analysis.

2.3.3 Investment Attributes.

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 and the probability of incurring this loss).

In view of these objectives, five key investment attributes are estimated from the cash flow analysis described in section 2.3.1, above. These attributes are: (1) net after-tax internal rate of return; (2) discounted after-tax weighted average investment payback time; (3) net present value of after-tax profits; (4) after-tax investment capital at risk; and (5) the numerical probability of losing investment capital (per equation 2.3). Decision-makers weigh the risks and returns that are described by these five attributes for a particular geothermal opportunity. Positive investment decisions follow if the geothermal opportunity appears attractive relative to alternative investment opportunities that may be available to the firm.

These attributes 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; and (b) correlation of model estimates with historical data on hydrothermal power development in the United States.

Modeling efficiency is crucial to achieving the purposes of this work. Resource assessment and R&D analysis on a national level require the processing of a great number of known and projected resource sites through the computer 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.

2.3.4 Investment Decision Analysis

In several recent reports and a book, we have discussed, in considerable detail, Technecon's computerized methodology for analyzing the cash flow of geothermal well field investments and, then, estimating the numerical likelihood of positive decisions to make these investments (see, for example, Cassel, et al. 1981 and Blair, et al., 1982). These programs were adapted for this project to perform R&D evaluations with consideration of the geothermal investment decision process described above.

In summary, cash flow models account for all capital investments, revenues, operating expenses and taxes associated with a geothermal well field and power plant project. Elements of the cash flow are keyed to a utility company's "avoided cost" for power and to certain resource qualities including temperature, salinity, well cost, well flow rate and producible acreage. These resource qualities are provided from either an inventory of currently discovered resource areas or from a sub-model which predicts future resource discoveries. The cash flow analysis provides estimates of five important investment attributes discussed earlier (i.e., rate of return, payback time, present value of profits, capital exposure, and risk of loss).

Using a modern decision science technique known as "multiattribute utility analysis", these five key investment attributes are transformed into a single numerical value that expresses an investor's relative preference for (or aversion to) the geothermal project opportunity. Using a second technique known as "logit analysis of positive choice", this single value is, in turn, transformed into a numerical probability (between 0 and 1) expressing the likelihood of a positive investment decision. This expresses the probability (between 0 and 1) that a resource company would choose to invest in a given geothermal opportunity given the five investment attributes. Figure 2-9 conceptually illustrates this investment decision model.

Investment Attributes:

IRR: Internal Rate of Return on Investment.

PAY: Discounted Weighted Average Payback Time.

NPV: Net Present Value of Profits.

PVLS: After-Tax Present Value of Capital At-Risk.

CONF: Likelihood of Project Success.

**Figure 2-9. GEOTHERMAL WELL FIELD INVESTMENT
DECISION MODEL**

2.4 FORMAT OF RESULTS

2.4.1 "Expected Power" Estimates

As discussed in section 2.2, part of our analysis is concerned with the potential quantity of power (in megawatts) that may be developed at a specified resource area over time. The potential amount of development is based upon a function of producible acreage, well spacing, well flow rate and power plant efficiency. The rate of development is based upon historical lead times and plant intervals as experienced in geothermal resource development.

From the decision analysis discussed in section 2.3.4 and the above, we derive two parameters by which to evaluate geothermal resource development. The first is the estimated probability that a resource company will decide to invest in a specified geothermal project. The second, noted above, is the estimated amount of electric power that will be brought on-line over time if such a positive investment decision is made. The product of these two parameters, known as "expected power", reflects both the probability and the amount of geothermal power at a given area withintime (t), i.e....

$$\text{"Expected" MW}(t) = [\text{Potential MW}(t)] \times [\text{Probability of Investment}]. \quad (2.31)$$

In this study, expected power estimates are provided for each known and forecasted geothermal resource in the U.S. at 5-year intervals between 1985 and 2000. National estimates of expected geothermal power are provided by summing over the U.S. resource base.

2.4.2 Analyzing R&D Initiatives

The desired effect of R&D programs is to enhance the decision-maker's perception of geothermal projects by reducing investment risks and/or improving investment returns. For example, an R&D goal of improving power plant efficiency will reduce geothermal fluid requirements and thereby reduce well field capital expenditures. If this gain in plant efficiency can be achieved without an excessive increase in plant capital cost, then the economies realized by decreased well field costs will serve to enhance the geothermal opportunity. An increased likelihood of a positive investment decision follows.

A second benefit of the R&D goal used in the above example is the potential production of more electric power from a given resource area because of the improved utilization efficiency. Therefore, not only do we realize an increased likelihood of investment for resource development as described above, but we also realize a greater amount of power generation from such a positive investment decision.

The effectiveness of R&D achievements can be examined in terms of their estimated impact upon both the likelihood of positive investment decisions and the amount of geothermal power brought on-line. To evaluate these impacts, the cash flow model is modified such that it incorporates enhancements in project cost and/or performance which are attributable to the scientific or technological goals of the R&D programs. Resulting changes in investment likelihood and power on-line can then be examined on site-specific, regional or national levels. The results of such an analysis of specific R&D initiatives are provided and discussed in Chapter One of this report.

Chapter Three
U.S. GEOTHERMAL RESOURCES
-- KNOWN AND FORECASTED --

As discussed in Section 2.1 of the preceding chapter, our evaluation of the benefits of geothermal R&D is presented in terms of differential power development at both known and forecasted geothermal resources in the low-to-moderate (300-400F) temperature range. This chapter provides a brief discussion of both the known geothermal resources in the U.S. and the forecasted resources that combine to provide a foundation for this study. For the purposes of this study, each resource is characterized in terms of the parameters listed on Table 2-1 in the preceding chapter (e.g., resource temperature, well flow rate, well cost, salinity, producible acreage, etc.).

3.1 KNOWN RESOURCES

The presently known U.S. geothermal resource base was defined for this study by a team of consulting geologists, including E.V. Ciancanelli of Cascadia Exploration Corporation, San Diego, and P.M. Wright and D. Foley of the University of Utah Earth Science Laboratory. A total of nine discovered resources in the 300-400°F temperature range were identified, and further defined in terms of resource temperature, well flow rate, well cost, salinity, and producible acreage. Table 3-1 presents a listing of these currently discovered resources. Each of these resources are known today, but not all have been confirmed as producible resources. Therefore, the team of geologists assigned a probability of confirmation to each resource. This probability, (PCFM in Table 2-1), reflects the estimated likelihood that the resource will be confirmed, based on current geologic data.

3.2 PROJECTED FUTURE RESOURCE DISCOVERIES

To estimate the quantity and quality of future resource discoveries, a forecasting model has been developed by Technecon which sequentially addresses the level of wildcat drilling in future years, the number of resource confirmations expected, and the quality of future resources. Similar modeling techniques have been extensively used in recent oil and

Table 3-1
DISCOVERED U.S. GEOTHERMAL RESOURCES
(300-400°F.)

Resource Area	Down Hole Temperature (°F)	Unpumped Flow Rate (1000 lbs/hr)	Brine Contamination Index	Well Cost (\$1000)	Producible Acreage (@50% Conf.)	Probability of Confirmation (%)
Brady Hazen, NV	360	500	1	600	5,000	25.0
Sulfur Bank, CA	390	500	1	1000	10,000	5.0
East Mesa, CA	360	500	1	1000	7,000	100.0
Heber, CA	360	500	1	1000	7,000	100.0
Clear Lake, CA	380	500	0	1000	10,000	25.0
Soda Lake, NV	320	500	1	1000	7,000	25.0
Steamboat H.S., NV	375	700	1	1000	3,000	50.0

Brine Contaminatin Index:

0 = <2,000 ppm

1 = 2,000 - 100,000 ppm

2 = >100,000 ppm

gas industry evaluations, and are applied here for the first time to geothermal resources. The techniques have been shown to accurately replicate past trends in geothermal exploration, discovery and resource quality. Following is a brief summary of the methodology. A complete description and documentation of the exploration, discovery, and resource quality model can be found in Cassel, et al. (1982).

3.2.1 Resource Discovery Forecasting Methodology

The number and quality of future discoveries is estimated by a three step process. As shown in Figure 3-1, the extent of exploratory activity (defined in terms of new wildcat wells drilled per year) is first estimated, based on expected rates of return of geothermal and oil ventures. The number of new discoveries which can be anticipated, given the exploratory effort expended, is then estimated. This is accomplished through an "effort/success" relationship, determined on the basis of historical trends and includes provisions for resource depletion. Finally, the quality of new resources is forecast. Resource quality projections reflect the characteristics of the undiscovered resource base, as well as the observed high-temperature bias of new discoveries. A more detailed description of the forecasting procedure is provided below.

Estimating Geothermal Wildcat Drilling Activity. A careful review of more than 2000 records of geothermal well drilling activity reveals that, from 1958 to 1980, there were 110 wildcat wells drilled in the United States outside The Geysers resource area. Table 3-2 summarizes this drilling activity. Using statistical regression techniques we found that this wildcatting activity can be explained in terms of three parameters; namely: (a) the expected real, risk-adjusted rate of return on geothermal projects as estimated by detailed probabilistic cash flow analyses based on marginal competition with coal-fired power generation; (b) the risk-adjusted return for new oil discoveries adapted from short-term forecasts of new U.S. crude oil discoveries; and (c) the enactment of the Geothermal Steam Act in 1970. These three parameters combine in a linear equation (estimated by ordinary least squares techniques) to accurately fit historic wildcat data and to provide the basis for forecasts of future wildcatting activity.

**Figure 3-1. HYDROTHERMAL RESOURCE EXPLORATION
AND DISCOVERY FORECASTING MODEL**

Table 3-2
U.S. GEOTHERMAL EXPLORATION ACTIVITY

<u>Year</u>	<u>Wildcat Wells</u>	<u>Discoveries</u>	<u>Cumulative Drilling Success Ratio</u>	<u>Discovered Areas</u>
1958	1	0	0	
1959	4	0	0	
1960	1	1	16.7	Mono-Long Valley
1961	2	0	12.5	
1962	2	0	10.0	
1963	3	0	7.7	
1964	9	3	18.2	Salton Sea; Brady-Hazen; Sulfur Bank
1965	2	0	16.7	
1966	0	0	16.7	
1967	2	0	15.4	
1968	1	1	18.5	Wilbur
1969	0	0	18.5	
1970	1	1	21.4	Baca
1971	0	0	21.4	
1972	10	2	21.1	East Mesa; Heber
1973	7	1	20.0	Power Ranches
1974	9	1	18.5	Soda Lake
1975	9	3	20.6	Brawley; Beowawe; Roosevelt
1976	5	1	20.6	Westmoreland
1977	7	2	21.3	Coso; Clear Lake
1978	10	1	20.0	Humboldt House
1979	15	3	20.0	Dixie Valley; Steamboat; Redondo
1980	10	1	19.1	S. Brawley

The direct relationship that we find between annual wildcat drilling and the expected return on geothermal projects is readily understandable. Likewise, it is understandable that the enactment of the Geothermal Steam Act, which expanded leasing opportunities and improved the investment climate for geothermal resource development, caused a jump of about 10% in the average rate of drilling. However, our initial perception of geothermal projects "competing" with oil projects for drilling funds proved invalid. Instead, we find that geothermal wildcatting increases with increases in oil profitability. This is verified by oil industry executives who indicate that their geothermal budgets tend to reflect discretionary investment of oil-related income.

Geothermal Wildcat Success Ratios. In the next step of the forecasting procedure we estimate the numerical probability that the wildcat wells will be successful in discovering a producible resource. As shown in Table 3-2, the success ratio for wildcat wells was 19.1% through 1980. However, due to depletion effects as more discoveries are made, we expect this success ratio to eventually decline. To estimate the probability of wildcat success, we use a technique known as "probit analysis" based upon data from geothermal well records. We derived a statistically-sound discovery function based upon three parameters; namely: (a) the geographic area of exploration; (b) cumulative number of successes to date; and (c) exploratory effort measured in cumulative well depth.

Geothermal Resource Quality Forecast. Future geothermal resource discoveries will be drawn from an underlying resource base. Early estimates of this geothermal potential appeared in USGS Circular 726, later updated in 1978 (USGS Circular 790). In response to requirements of the work discussed here, however, the Earth Science Lab of the University of Utah Research Institute, assisted by Eugene Ciancanelli of Cascadia Exploration Corp. and Dr. Subir Sanyal of Geotherm-Ex, Inc. under subcontract to Technicon, developed an updated and considerably refined characterization of the undiscovered resource base. A limited set of "generic" resource types was constructed, each of which described a class of reservoirs having similar characteristics. These included temperature, well cost, well flow, salinity, areal extent and volume. Characterization of the undiscovered resource base then is completed by estimating the regional frequency of occurrence of each generic type.

As resources are discovered and withdrawn from the undiscovered resource base, increasing effort must be devoted to find additional reservoirs. Not only are reservoirs increasingly difficult to find, but the average quality of newly found discoveries will tend to decline. Following Barouch and Kaufman's analysis of oil supply (1976) and subsequent elaborations by Smith and Ward (1980), we view the discovery process as a sampling experiment in which a population of reservoirs is sequentially sampled without replacement according to a probability law that reflects the industry's search for high, rather than medium or low, temperature resources.

3.2.2 Resource Discovery Forecast

Using the methodology described above, the number and quality of future resource discoveries was forecast. Following is a brief summary of the resource discovery forecast to the year 2000.

Wildcat Drilling Forecasts. Historical and projected wildcat completions are shown in Figure 3-2 and Table 3-3. With the exception of the 1966-1970 period when prospective returns on geothermal ventures fell sharply, drilling activity has shown a generally increasing trend since 1958. Assuming only those technological advancements brought about by private sector initiative, drilling is forecast to continue to increase over the near term, but stabilize after the mid-1980's. The anticipated commercial availability of binary cycle plants in the late 1990's is expected to provide a substantial stimulus to resource exploration.

New Discovery Forecast. As discussed above, the primary determinants of the rate of hydrothermal reservoir discovery are (1) the level of wildcat well drilling; (2) the technological effectiveness of this drilling; and (3) the size of the remaining resource base. Cumulative depletion of a finite resource base ensures, in the long run, a decrease in the marginal returns from drilling. The effect of these factors clearly is evident in Figure 3-3 and Table 3-4, a display of historical and forecast hydrothermal reservoir discovery rates.

During the period 1958-1980, rapidly increasing drilling rates, combined with the entrance of technically advanced firms during the early 1970's resulted in the discovery of 21 new resource areas (see Table 3-1). This represents a cumulative drilling success ratio of 20 percent. Due to

**Figure 3-2. HISTORICAL AND FORECAST
WILDCAT WELL COMPLETIONS**

Table 3-3
HISTORICAL AND PROJECTED WILDCAT DRILLING

	<u>Wells Completed in Period</u>	<u>Cumulative Total to Date</u>
1958-1960	6	6
1961-1965	18	24
1966-1970	4	28
1971-1975	35	63
1976-1980	47	110
1981-1985	63	173
1986-1990	65	238
1991-1995	65	303
1996-2000	80	383

Table 3-4
HISTORICAL AND PROJECTED HYDROTHERMAL RESOURCE DISCOVERIES

	<u>Wells Completed in Period</u>	<u>Cumulative Total to Date</u>
1958-1960	1	1
1961-1965	3	4
1966-1970	2	6
1971-1975	7	13
1976-1980	8	21
1981-1985	11	32
1986-1990	8	40
1991-1995	6	46
1996-2000	6	52

**Figure 3-3. HISTORICAL AND FORECAST
RESOURCE DISCOVERIES**

depletion effects, this success ratio is expected to decrease gradually throughout the projection period. Despite this decrease in drilling efficiency, the total hydrothermal discovered resource base is expected to almost double by 1990. By 2000, a total of 31 new discoveries of greater than 300°F are forecast.

Resource Quality Forecast. As discussed in Cassel et al. (1982), the observed average downhole temperature of new discoveries to date is significantly above the average temperature of the underlying base of undiscovered resources (as estimated by consulting geologists). The average temperature of the 21 discoveries to date is estimated to be 415°F, while the average temperature of the entire hydrothermal resource base suitable for electric power generation (>300°F) is thought to be approximately 370°F. This bias for discovering resources of above average temperature is due to exploratory procedures that attempt to screen out lower temperature in favor of higher temperature resource prospects.

Figure 3-4 illustrates the regional temperature profile of historical discoveries, and the estimated average temperature of future discoveries. The projected temperature profile of future discoveries is based on the observed historical discovery sequence, and was derived from the following forecast of discoveries, disaggregated by temperature class.

Table 3-5
PROJECTED RESOURCE DISCOVERIES

	<u>300-350°F.</u>	<u>350-400°F.</u>	<u>400-450°F.</u>	<u>>450°F.</u>
1983-1990	2	5	7	5
1990-2000	<u>3</u>	<u>4</u>	<u>3</u>	<u>2</u>
Total Forecast	5	9	10	7

To fully characterize the quality of future discoveries, discoveries within each temperature class were further defined in terms of well flow, salinity, well cost, and producible acreage. This disaggregation procedure is based upon the predicted frequency of occurrence of specific resource types, as determined by consulting geologists. Table 3-6 illustrates the expected number and quality of future resource discoveries.

**Figure 3-4. HISTORICAL AND FORECAST
REGIONAL EXPECTED TEMPERATURES OF DISCOVERY**

Table 3-6
 EXPECTED QUALITY OF FUTURE
 LOW AND MODERATE TEMPERATURE RESOURCE DISCOVERIES

Unpumped Well Flow Rate (1000 lbs/hr)	Brine Contamination Index ¹	Well Cost (\$1000/well)	Producible Acreage		Expected Number of New Discoveries	
			90% Confidence	50% Confidence	1982-1990	1991-2000
<u>350°-400°F Resources</u>						
500	1	1500	1000	7000	.47	.33
300	1	1000	1000	7000	1.04	.83
300	1	1000	3000	7000	.16	.13
300	1	1500	1000	7000	1.20	.96
150	1	1000	1000	7000	.42	.33
150	1	1500	3000	7000	.29	.26
75	1	1500	650	3000	1.43	1.17
<u>300-350°F Resources</u>						
300	1	600	650	1500	.23	.30
300	1	1000	3000	7000	.44	.57
300	1	1500	650	3000	.48	.74
300	0	1000	650	3000	.25	.30
150	0	600	650	1500	.02	.07
75	1	1000	650	3000	.31	.54
75	0	600	650	1500	.04	.10
50	1	1000	650	1500	.15	.24
50	1	1500	3000	7000	.08	.13

¹Brine Contamination Index: 0 = < 2,000 ppm TDS
 1 = 2,000 - 100,000 ppm TDS
 2 = > 100,000 ppm TDS

3.3 SUMMARY

By the year 2000, a total of 23 low-to-moderate temperature resources are expected to have been discovered. Of these, 9 are currently available for further development (recall Table 3-1), while the remaining 14 are projected future discoveries by 2000 (recall Table 3-5). These resources are technically-capable of supporting over 6,000 MWe of capacity, using energy conversion technology available at the present time. As noted in Chapter One, less than one-tenth of this capacity is expected to be on-line by 2000 because power cannot be generated at most sites at economically competitive costs. Chapter One has however, demonstrated that an appreciably larger share of this potential may be realized through R&D advancements in geothermal power plant design.

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APPENDIX

Listing of computer code and input variables (Table A-1) developed by Technecon for this study. See, also, Table 2-1 in Chapter 2, for listing of resource-specific input variables. Computer code is in APL language.

TABLE A-1
GLOBAL INPUT VARIABLES FOR GEOTHERMAL CASH FLOW

Code	Description	Assigned Value
ACRS	Depreciation schedule for well field capital	.15,.22,.21,.21,.21
ADV1	Local ad valorem tax rate on assessed value	.04
ADV2	Assessment rate for local tax purposes	.25
BETAA	Coal-fired power plant operating cost fraction*	.06
BETAH	Geothermal power plant operating cost fraction*	.04
CALT	Capital cost of coal-fired power plant (\$/kW,1982)	1200
CAPA	Capacity factor for coal-fired power plant	.70
CAPH	Capacity factor for geothermal power plant	.80
DR	Resource developer's discount rate for present valuing	.12
DVT	Post-confirmation well field development lead time (years)	3
DWC	Dry well cost (expressed as fraction of producer well cost)	.90
DWF	Dry hole fraction of production well attempts	.10
FC	Common stock fraction of utility's capital structure	.35
FD	Long-term debt fraction of utility's capital structure	.50
FP	Preferred stock fraction of utility's capital structure	.15
GC	Long-term escalation rate for field and plant expenses	.06
GF	Long-term escalation rate for delivered utility coal	.07
IF	Intangible fraction of completed well cost	.75
IRD	Redrilled fraction of producer wells	.30
ITC2	Investment tax credit on well field capital	.10
KC	Annual cost of utility's common stock	.16
KD	Annual cost of utility's long-term debt	.11
KP	Annual cost of utility's preferred stock	.11
PALT	Price of delivered utility coal (mills/kWh,1982)	18.8
PDPL	Percentage depletion allowance for geothermal income	.15
PIR	Ratio of producer to injector wells	2:1
PLF	Economic life of power plant (years)	30
RDC	Redrill cost (expressed as fraction of producer well cost)	.35
RLF	Royalty fraction of gross well field revenues	.10
RWC	Reworking cost (expressed as fraction of producer well cost)	.35
RWF	Reworked fraction of replacement wells	.33
SWF	Standby spare fraction of producer wells	.20
TF	Federal corporate income tax rate	.46
TS	State corporate income tax rate	.09
UITC	Investment tax credit on utility-owned plant	.10
UTLF	Tax life of utility-owned plant (years)	15
WSPACE	Production well spacing (acres/well)	40

* Power plant annual operating cost (1982\$) is expressed as a fraction of plant capital cost and includes operation, maintenance, insurance, local taxes, administrative and general expenses.

WSID
IS US7100
WA
129776

FNS
DIFFN FLIST TCN7100 TCN7110 TCN7120 TCN7121 TCN7122 TCN7130 TCN7140
VARS
ACRS ADV1 ADV2 BETAA BETAH CALT CAPA CAPH CH
DR DVT DWC DWF FC FD FP GC GF
IF IRD ITC2 KC KD KP LC MCP MW
NSE1 PALT PDPL PIR PLF PTYPE PUMP RDC RLF
RWC RWF RX1 RX2 SWF TF TS TYF UC
UITC UTLF WSPACE X

TCN7100[]
M←TCN7100 RX;N;N1;NR;TT;T2;TP;TD;WT;WF;BCI;WC;A99;A50;PCFM;PC;NS
E;TDSC;NPC;PYV;NU;C;MWX;CONF;PVLS;PAY;IRR;FDISC;X
[1] $z(1=fPRX)/PRX(1,PRX)PRX$
[2] $NR(1+1)PRX$
[3] (+NSE VECTOR),+NSE1
[4] (+CAPITAL COST VECTOR),+CH
[5] TCN7110
[6] $M(0.3,(PCH),(PNSE1),4)P0$
[7] L0;TCN7120 RX[N1;]
[8] TCN7130
[9] TCN7140
[10] $M+M,[1](3,(PCH),(PNSE1),4)P0.5+EMW1,[1] EMW2,[1] EMW3$
[11] $→L0X(NR)N1+1$
[12] $M+M,[1]+/[1] M+ 1 3 4 5 2 qm$
[13] $X+DEX 3 4 P'EMW1EMW2EMW3'$
[14] ''
[15] ''
V

TCN7110[]
TCN7110;K;CRF2;DPF;V;V1;V2
[1] MARGINAL PRICING ALGORITHM
[2] $TT(TD+DVT)+TP+PLF$
[3] $T2+TS+(1-TS)XTF$
[4] $K((1-T2)XKDxFD)+(KPXFP)+FCXKC$
[5] $CRF2+K(1-(1+K)X-UTLF$
[6] $DPF+2X(UTLF-÷CRF2)÷KXUTLFXUTLF+1$
[7] $V(1-(T2XDPF)+UITC)÷1-T2$
[8] $V1(((1+GC)÷K-GC)X(1-((1+GC)÷1+K)XTF)$
[9] $V2(((1+GF)÷K-GF)X(1-((1+GF)÷1+K)XTF)$
[10] $MCP+PALT+(((VXCALT)+V1XBETAAXCALT)÷V2X8.76XCAPA)-(((VXCH)+V1X
BETAHXCH)÷V2X8.76XCAPH$
V

```

      TCN7120[0]
      TCN7120 R;DV10;MWV;MWV5;AL;BE;MW25;M25;PIV5;R;PYN;C
[1] SITE SPECIFIC DATA
[2]
[3] ('RESOURCE NO. '),N1
[4] WT+R[1]
[5] WF+R[2]
[6] BCI+R[3]
[7] WC+R[4]
[8] A99+R[5]
[9] A50+R[6]
[10] FDISC+R[7]
[11] PCFM+R[9]
[12] PC+0
[13] NSE+NSE1
[14] (PUMP=1)/'TCN7121'
[15] TDSC+R[8]
[16] DV10+R[10]
[17] MWV+PYV+(NPC+N+0)*0
[18] (DV10=1)/'TCN7122'
[19] MWV+MWV,(0LN-5)*MWV5+ 20 50 50 100 200
[20] AL+(-A50*BE+4.595/(0.1*A50))*A50-A99
[21] M25+((1.0986-AL)/BE)*NSE*WF+1000*WSPACE*1+SWF+1-SWF
[22] +L1*(M25)/MWV
[23] MWV+MWV,M25-+/MWV+(M25)/MWV
[24] +L2
[25] L1;MWV+MWV,M25-+/MWV+MWV,(L(M25-+/MWV)/MWV5[5]),MWV5[5]
[26] L2;NU+,MWV
[27] PIV5+ 0 3 2 1 1
[28] R+,MW25
[29] C+,MWV
[30] +L3*N=0
[31] +L4*NU=,PYV+(NULN)*PYV
[32] PYN+1986*(-1*PYV)+PIV5[5LN+1]
[33] PYV+NU*PYV,(-1*PYV)+10*NU-,PYV+PYV,PYN,PYN+*(0LN-4)*PIV5
[34] +L4
[35] L3;PYN+1986*TDSC+5
[36] PYV+(PYN+*(NULN)*PIV5),(PYN+7)+10*NU-5
[37] L4;MWX+0*(MWX+MW25+,-+MWV)*MWX+(R,C)*MWV
[38] CONF+(MWX+0)*1+150*AL+BE*WSPACE*(1+SWF+1-SWF)*1000*(+MWX)/Q(C,R)
      )NSE*WF
      TCN7121[0]
      TCN7121
[1] WF+750L78+1.22*WF
[2] PC+1.22*WF*-0.607+0.995*WF+1000
[3] NSE+NSE-0.57
      TCN7122[0]
      TCN7122
[1] 'SERIAL MWE ON-LINE AND COMMITTED'
[2] NPC+N+,MWV+
[3] 'CORRESPONDING YEARS ON-LINE AND COMMITTED'
[4] PYV+

```

▽TCN7130[]▽

▽ TCN7130;WLF;NACTM;PDRL;IDRL;SRF;RY;EXP;CAP;DPR;WFOM;V;TLF;REV;ROY;NET;ADV
VT;IRRM;V1

```
[1] C+p,CH
[2] N+p,NSE
[3] WLF+15-5xBCI
[4] PDRL+L0.5+(1+SWF÷1-SWF)xNACTM+L0.9+1000xMW÷NSExWF
[5] IDRL+[(NACTM÷PIR
[6] 1(PUMP=0)/'SRF+1.25xMWx6.6588-(.1024xNSE)+.00115xWF'
[7] 1(PUMP=1)/'SRF+1.25xMWx6.8024-(.177xNSE)+.00135xWF'
[8] CAPITAL AND EXPENSE COSTS FOR FIELD DEVELOPMENT AND OPERATION
[9] DPR+CAP+EXP+(TT,N,C)P0
[10] RY+([TP÷WLF)-1
[11] EXP[TD+WLFx(RY;)]+(WCx1+RWFxRWC-1)x 1 3 2 Q(RY,C,N)P PDRL+IDRL
[12] CAP[TD;]+WCxQ(C,N)P PDRL+IDRL
[13] CAP[TD;]+CAP[TD;]-EXP[TD;]+IFxCAP[TD;]
[14] EXP[TD;]+EXP[TD;]+WCx((DWCxDWF÷1-DWF)+IRDxRDC)xQ(C,N)P PDRL
[15] CAP[TD;]+CAP[TD;]+(Q(C,N)P SRF)+PCxQ(C,N)P PDRL
[16] WFOM+Q(C,N)P (420x(MW÷100)x0.7)+(0.01xSRFx2-BCI-BCIx2)+(PUMPxPDRLx87)+47.5x
(PDRL+IDRL)xBCI+1
[17] EXP[TD+TP;]+EXP[TD+TP;]+(TP,N,C)P WFOM
[18] CAP[2;]+325x1.17
[19] EXP[1;]+180x1.17
[20] EXP+EXPxV+(1+GC)x 2 3 1 Q(N,C,TT)P TT
[21] V+CAP+CAPxV
[22] DPR[TD+TLF;]+(V[TD+TLF;])x 2 3 1 Q(N,C,TLF+PACRS)PACRS
[23] REV+((-TT,N,C)P 8.76xCAPxMWx(TP,N,C)P MCP)x(1+GF)x 2 3 1 Q(N,C,TT)P TT
[24] NET+(ITC2xCAP)+(V+REV-EXP+ROY+RLFxREV)-CAP
[25] ADVT+0[ADV1x(ADV2x+(TD,N,C)P CAP),[1](-TP,N,C)P V+V-DPR+PDRLxREV-ROY
[26] NET+NET-ADVT+T2xV-ADVT
[27] PVLS+(1-T2)x+/[1] NET[TD;]÷(1+DR)xV+ 2 3 1 Q(N,C,TD)P TD
[28] IRR+(IRRM+DR)+0xPAY+(+/[1] 0)+/[1] NET÷(1+DR)xV+ 2 3 1 Q(N,C,TT)P TT)-1
[29] V+ 2 3 1 Q(N,C,TT)P TT
[30] TOP;IRR+IRR+0.005xV1+0(+/[1] NET÷(1+IRRM)xV
[31] +(((+/(V1)≠0)^(IRRM+IRRM+0.005)<0.3)/TOP
▽
```

▽TCN7140[]▽

▽ TCN7140;UR;UP;UV;UL;UG;EU;PINV;V

```
[1] UR+0[1-xUC[TYF;1]-UC[TYF;2]xIRR-0.02
[2] UP+0[1+x-UC[TYF;3]-UC[TYF;4]xPAY
[3] UV+1
[4] UL+1-x-UC[TYF;5]xPVLS÷1000
[5] 1(TYF=1)/'UG+(LC[TYF;1]xUR)+(LC[TYF;2]xUV)+LC[TYF;3]xURxUP'
[6] 1(TYF=3)/'UG+(LC[TYF;1]xUV)+(LC[TYF;2]xURxUV)+LC[TYF;3]xURxUPxUV'
[7] EU+(((C,N,NU)P CONF)x 3 2 1 Q(NU,N,C)P UG)+(1-(C,N,NU)P CONF)x 3 2 1 Q(NU,N,C)
PUL
[8] PINV+1+x7[UC[TYF;6]-UC[TYF;7]xEU
[9] CONF[;NPC]+PINV[;NPC]+1
[10] EMW1+FDISCx((C,N,NU)P MWXxCONF)+.xV+PYV+.1 1990 1995 2000 2005
[11] EMW3+PCFMxEMW2+(PINVxFDISCx(C,N,NU)P MWXxCONF)+.xV
▽
```

▽DIFFN[]▽

▽ M DIFFN V

```
[1] 8 0 +M[V[1];];- 3 4 1 2 Q 9 11 4 3 P M[V[1];];(LV[2]);V[3]]-(V[2]-LV[2])x
M[V[1];];(LV[2]);V[3]]-M[V[1];];(V[2]);V[3]]
▽
```

- PART II -

HEBERY BINARY-CYCLE DEMONSTRATION PROJECT ECONOMICS

Chapter One
EXECUTIVE SUMMARY

1.1 BACKGROUND AND PURPOSE

The purpose of the Heber Binary Cycle Demonstration Project is to design, construct and operate the world's first commercial binary cycle geothermal power plant. From the knowledge and experience gained by plant operation, project co-sponsors hope to:

- o Demonstrate the viability of binary cycle technology,
- o Demonstrate the environmental acceptability of the technology,
- o Provide a stimulus to the development of hydrothermal resources in the United States, and
- o Establish the technology as an alternative source of electric power generation, thereby reducing U.S. dependence on uncertain supplies of foreign oil [20].

If these objectives are to be achieved, plant operation must successfully demonstrate that power can be generated reliably, and at costs approaching that of conventional fossil-fueled base load units.

The purpose of this analysis is to assess the likelihood that the Heber Demonstration Project, and second generation "mature" binary cycle plant designs, can meet the stated economic objectives of the project. Included in this assessment is an independent review of each of the major cost components of the project, including (1) construction cost, (2) well field development costs, (3) fluid purchase costs, and (4) the provisions for revenue sharing among project participants. The total cost of power generated from the Heber Plant (in terms of mills per kWh) is then compared to the cost of power from alternative fossil-fueled base load units.

1.2 SUMMARY OF FINDINGS

A summary evaluation of project economics is presented below. A detailed assessment of major project cost components is presented in the body of this report.

1.2.1 Review of Construction Cost Estimate

Technecon Analytic Research, Inc. subcontracted the firm of United Engineers and Constructors, Inc. to conduct an independent review of the

project construction cost estimate, as prepared by Fluor Power Service, Inc. [17]. This review (presented in Chapter Two) includes a detailed analysis of the documentation and capital cost estimate prepared by Fluor. A general review of the scope of the estimate was also conducted. Spotchecks of quantities for selected construction materials were also made to verify accuracy.

In summary, United Engineers and Constructors, Inc. (UEC) found the estimate to be well done and thoroughly documented. However, it is the opinion of UEC that Fluor's estimate neglected to include adequate allowances for contingencies and adequate escalation in certain wage and material costs. UEC strongly recommends that a contingency allowance be included to provide for design changes and additional costs which are expected to be incurred in a project of this scope but which cannot be specifically itemized at this time. Inclusion of a contingency allowance would add \$16.7 million to the Fluor estimate of \$82.1 million. An examination of supporting documentation indicates that Fluor apparently failed to account for one year of escalation in labor and material costs. Correction of this miscalculation would increase the construction cost by approximately \$4.1 million. Finally, UEC reported several other areas in which the Fluor estimates appear overly optimistic and, therefore, called for miscellaneous increases of \$3.1 million. In all, the increases in the cost estimate called for in the UEC report would raise construction cost from \$82.1 to \$106.0 million -- an increase of 29 percent.

1.2.2 Well Field Development Costs

The expenditures necessary to develop the well field and operate and maintain production facilities will have a major impact on generation economics. The costs incurred by well field developers must be recovered through fluid sales revenues once production begins. These revenues must also permit field developers to earn a reasonably attractive return on their investment. Field development costs were estimated for both the effort expended to date in the exploration and confirmation of the resource, and anticipated future expenditures for installation of production and injection facilities. The estimated cost of field development and operation and maintenance is summarized below. A detailed analysis of these costs is presented in Chapter Three.

An estimated \$25 million (1982 \$) has been expended since 1969 for activities relating to resource exploration and confirmation that are attributable to the Heber resource. This includes costs incurred for field reconnaissance, lease acquisition and rental, resource modeling, and the drilling of confirmation wells. Through this effort, a resource believed capable of supporting 500 MWe (net) has been identified [21]. The Heber Demonstration Plant is expected to produce 45 MWe (net), or 9% of the total KGRA capacity. Therefore, 9 percent of the total sunk cost to date will be allocated for recovery by the Demonstration Project. This amount, totaling \$2.2 million (1982 \$), will be incorporated into the well field cash flow analysis as reported in Section 1.2.3.

Capital costs for well field development are estimated to total \$46.0 million (1982 \$). Approximately 70 percent of this cost is directly related to the drilling of 13 production wells and 7 injection wells. These costs, allocated over a 2-3 year construction period, are also incorporated into the well field cash flow analysis.

Annual well field operation and maintenance costs are estimated to be \$3.9 million (1982 \$) per year. These costs include expenditures for surface facility maintenance, well maintenance, labor, and general and administrative expenses. This estimate is somewhat lower than the Union Oil estimate of \$5.8 million [18]. Because 100 percent of well field O&M costs are to be paid by DOE, SDGE and the other power plant operators, we recommend that this difference be examined by DOE.

1.2.3 Analysis of Resource Pricing Agreement

To assess the equity of the Heat Sales Agreement between parties, a detailed cash flow analysis was conducted to determine the expected rate of return on investment which would be earned by well field developers. The details of the pricing agreement, and the assumptions used in this analysis are provided in Chapter Four. The results of this analysis are summarized below.

The cash flow analysis included outlays for already incurred sunk cost and well field construction costs. Revenue accruing from fluid sales was assumed to begin in 1985. A discounted cash flow was prepared for two

different field development paths: (1) a Base Case with immediate startup and operation at full capacity (45 MWe net) in 1985, and (2) startup at 20 MWe (net) in 1985, and gradual buildup to 45 MWe (net) in 1987. Under "Base Case" assumptions, and under gradual capacity buildup, analysis of the net after-tax income stream reveals that well field operators realize a 26% internal rate of return, 8 year payback, and a net present value of profits of about \$30 million. Based on Technecon's prior work in the area of geothermal investment decision analysis, these returns describe an attractive, though not excessive, project return.

1.2.4 Analysis of Credits

Included in the Cooperative Agreement [19] are revenue sharing provisions which may allow DOE to recover 100 percent of its allowable costs over the demonstration and commercial operation phases of the project. An analysis of the magnitude of such project credits, and an assessment of the equity of the current revenue sharing provisions is provided in Chapter Five. Conclusions of this analysis are summarized below.

Of foremost importance is the displaced power cost savings (or net revenue credit). Operation of the plant may enable San Diego Gas and Electric to alter its dispatch schedule such that generation from more expensive oil and gas fired units is reduced. The Cooperative Agreement currently recognizes that such savings should be shared on the basis of each participant's share of total project contributions. However, the Cooperative Agreement stipulates that the gross revenue credit be valued according to "Spinning Reserve Rates" in the California Power Pool Agreement. We were unable to obtain current data on typical spinning reserve rates, and propose, instead, that the credit be valued on the basis of "Avoided Cost" rates. These rates, mandated under Section 210 of the Public Utilities Regulatory Policies Act (PURPA), represent the cost to the utility of generating the last kWh needed to satisfy load demand. Valued at current PURPA rates, and using Base Case assumptions, total gross revenues earned during the Demonstration Period can be expected to total \$63.4 million (current dollars).

The remaining credits -- including tax credits, resource credits, and depreciation credits -- are of considerably less importance. We found that the income tax credits and liabilities associated with project construction and operation should in general not be passed through to DOE, although the treatment of the investment tax credit is somewhat ambiguous.

Available data were insufficient to permit a comprehensive analysis of credits which may have been gained by SDG&E's wholly-owned subsidiary New Albion Resources following its sale of landholdings in the Heber Geothermal Unit Area. Finally, we found no basis for reducing DOE's "Reimbursement Amount" by any calculated depreciation during the Demonstration Period, as called for in the Cooperative Agreement. We recommend that this clause be removed from the Agreement.

1.2.5 Comparative Generation Economics

The cost of generating power from the Heber plant was compared to the cost of power from newly constructed fossil fueled base load units. The comparison was made in terms of the levelized busbar cost of power using the computational procedure recommended by the Electric Power Research Institute [10]. The assumptions used in this analysis are presented in Chapter Six.

As shown in Figure 1-1, under Base Case assumptions the cost of power generated by the Heber plant was found to be considerably more expensive (in mills per kWh) than power produced from new coal burning units. Assuming a 1985 startup, the lifetime levelized busbar cost (reported in current dollars) of the Heber plant is estimated to be 33¢/kWh, compared to a cost of 12.4¢/kWh for a coal-fired unit.

The Heber plant was also slightly more expensive than residual oil-fired base load plants. In second generation plants of this design, however, the removal of one-time R&D costs will likely render the binary cycle as an economic alternative to oil-fired power plants.

Based on this analysis, the Heber binary cycle design does not offer immediate hope of being economically competitive with coal-fired generation. Substantial reductions in capital cost, fuel cost and operating cost will be required of second generation plants if the Heber design is to compete with coal-fired plants. The Heber design does,

Figure 1-1.
LEVELIZED ANNUAL BUSBAR COST OF THE HEBER PLANT
VERSUS CONVENTIONAL BASE LOAD POWER PLANTS
(1985 Startup)

however, appear to offer an economically competitive alternative to oil-fired generation.

Chapter Two

REVIEW OF HEBER PLANT CONSTRUCTION COST ESTIMATE

United Engineers and Constructors, Inc.(UEC), under subcontract to Technecon, prepared a review of the Fluor Power Service Definitive Cost Estimate [17]. Reviewed in detail were the documentation and the capital cost estimate prepared by Fluor, particularly with respect to material pricing and labor. A general review of the scope and completeness was made, and spot-checks of quantities for selected construction material items were also conducted. The scope of this review did not include the cost of land, costs for developing and furnishing geothermal fluids, energy credits from sale of electricity, power plant operation and maintenance costs, and other costs incurred by San Diego Gas and Electric.

In summary, UEC found the estimate to be well done and thoroughly documented. The substantial detail in the Fluor estimate subaccount summaries was thoroughly documented and supported in detailed backup material. The compilation of crew mixes and crew wage rates, indirect costs, sales tax, escalation, freight and fee was complete and easily understood. Spotchecks of quantities for selected construction material revealed no significant discrepancies. Equipment prices, based on supporting vendor quotations, also seemed reasonable and were accepted. Estimates for Fluor Engineering Services and Dravo's Construction Management Service also were judged to be reasonable.

The UEC review did, however, uncover several areas in which the estimate appears to be deficient. The estimate does not provide a contingency allowance to protect against design changes and additional costs which are expected to occur, but cannot be specifically itemized at this time. UEC recommends that a contingency allowance of 20% be applied to the site development, civil/structural, mechanical, electrical, paving, landscaping, and painting contracts. A contingency allowance of 10% is applied to the cost of major equipment procurement. In all, a contingency allowance of \$16.7 million is called for by UEC.

The second area in which the estimate appears deficient is in the allowance for labor and material cost escalation. An analysis of back-up documentation indicates that the Definitive Estimate fails to account for a year of escalation. This increase is required because union labor rates and vendors' budgetary quotes are not "firm" at this time, and will be subject to escalation prior to the time contracts are negotiated and finalized. UEC therefore recommends that an additional \$4.1 million be added to the estimate to adequately account for cost escalation.

Finally, UEC found the labor costs (including benefits and burdens) to be somewhat underestimated. A \$1.7 million increase in the cost of labor contracts is judged to be necessary. This increase in labor cost occurs mainly in the mechanical contract because labor manhours were found to be overly optimistic based upon UEC's historical records. In the other contract estimates, labor appears adequate provided design work is essentially complete by the time the contracts are awarded, thus minimizing field changes and delays. The UEC review notes several other miscellaneous areas in which cost increases are recommended. These other increases are expected to add \$1.4 million to the Fluor estimate.

In all, the UEC review suggests that the Definitive Estimate of June 25, 1982, which totals \$82,117,645, should be increased by approximately \$23.9 million or 29 percent, and is summarized as follows:

Labor, including benefits and burdens	\$1.7 million
Miscellaneous Other Increases	1.4
Escalation	4.1
Contingency	<u>16.7</u>

Recommended Cost Increase.....\$ 23.9 million

Table 2-1 provides a summary of the Fluor/UEC cost estimates for major construction contracts. A detailed comparison of both estimates for individual construction contracts is provided in Tables 2-2a -- 2-2g. An explanation for the cost estimate discrepancies noted in each contract is provided in Tables 2-3a -- 2-3g.

The deficiencies noted by UEC have apparently not been corrected in San Diego Gas and Electric Company's most recent cost proposal. SDG&E's

Optional Form 60 (June 7, 1982) [18] reports that the total cost for performing WBS 1.2.2 and 1.2.3 (Phase II) total \$89,408,978. Of this total, \$6,512,371 is allocated to cover SDG&E's own costs (primarily Other Direct Costs and General Administrative Costs). These would not be included in the Fluor estimate. The only other costs for WBS 1.2.2 and 1.2.3 not included in the Fluor estimate would be Other Subcontracts (\$34,000), Vendor Surveillance (\$324,891), and the 9 month extension of the DRAVO contract (\$430,000). Combined with the abovementioned SDG&E costs, the total costs for performing WBS 1.2.2 and 1.2.3 exclusive of those work elements included in the Fluor estimate amount to \$7,301,262. Added to the Fluor estimate of \$82,117,645 the total cost would be \$89,418,907. This total is virtually identical to the total reported in the Optional Form 60 of \$89,408,978. Based on this analysis, SDG&E does not appear to have made any additions or adjustments to the Fluor estimate.

Table 2-1

DETAIL ESTIMATE

PRICED BY

APPROVED BY

DATE 9/3/82

Joe Heber Binary Project - Phase II

PRELIMINARY

SHEET NO. S-1
J.O. NO. 7513.001

[illegible]

Table 2-2a
ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
SITE DEVELOPMENT CONTRACT

FORM 477

DETAIL ESTIMATE

PRICED BY _____
APPROVED BY _____ PRELIMINARY
DATE 9/3/82 Job Heber Binary Project - Phase II

SHEET NO. 1
JOB NO. 7513.001

ACCT NO.	DESCRIPTION	QUANTITY	UNIT	RATES	AMOUNTS	TOTALS														
					SDG&E Cost	Estimate		UE&C Cost	Estimate		Difference									
						\$			\$		\$									
	<u>SITE DEVELOPMENT CONTRACT</u>																			
	Bare Labor	51,429	Mhr			782,820		56,529	Mhr	860,820	+	78,000								
	Craft Benefits and Burdens					555,630				610,630	+	55,000								
	Subcontracts					641,140				641,140	-									
	<u>Permanent Materials</u>																			
	Procured by Fluor					946,080				946,080	-									
	Procured by Contractor					983,550				993,550	+	10,000								
	Field Salaries and Expenses					75,300				75,300	-									
	Field Staff Overhead					57,370				57,370	-									
	Relocate Field Supervisory Personnel					5,000				5,000	-									
	<u>Temporary Construction</u>																			
	Construction Facilities					27,100				27,100	-									
	Field Office Furniture, Supplies,																			
	Telephone, etc.					13,920				13,920	-									
	Utilities					1,800				1,800	-									
	Miscellaneous Supplies					12,510				12,510	-									
	Testing and Lab Analysis					-				-	-									
	Performance Bond					26,500				26,500	-									
	Public Liability and Property																			
	Damage Insurance					20,000				22,000	+	2,000								
	Construction Equipment					449,160				449,160	-									
	Small Tools, Repairs, Construction																			
	Consumables					32,550				34,550	+	2,000								
	Sales Tax					127,300				166,300	+	39,000								
	Escalation					357,700				501,700	+	144,000								
	Freight					37,140				40,140	+	3,000								
	Contractor's Fee					327,630				340,630	+	13,000								
	Contingency					-	20%			1,165,000	+	1,165,000								
	Total Site Development Contract, -					5,480,200				6,991,200	+	1,511,000								

Table 2-2b
ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
CIVIL/STRUCTURAL CONTRACT

FORM: 4777

PRICED BY _____
APPROVED BY _____
DATE 9/3/82 JOB Heber Binary Project - Phase II

DETAIL ESTIMATE

PRELIMINARY

SHEET NO. 2
JOB NO. 7513.001

ACCT NO	DESCRIPTION	QUANTITY	UNIT	RATES	AMOUNTS	TOTALS														
					SDG&E Cost	Estimate		UE&C Cost	Estimate		Difference									
						\$			\$		\$									
	<u>CIVIL/STRUCTURAL CONTRACT</u>																			
	Bare Labor	108,149	Mhr			1,538,000	113,149 Mhr		1,613,000		+ 75,000									
	Craft Benefits and Burdens					1,091,980			1,144,980		+ 53,000									
	Subcontracts					17,300			29,300		+ 12,000									
	Permanent Materials																			
	Procured by Fluor					-			-		-									
	Procured by Contractor					1,981,200			2,401,200		+ 420,000									
	Field Salaries and Expenses					112,000			112,000		-									
	Field Staff Overhead					78,270			78,270		-									
	Relocate Field Supervisory Personnel					10,000			10,000		-									
	Temporary Construction																			
	Construction Facilities					12,700			12,700		-									
	Field Office Furniture, Supplies,																			
	Telephone, etc.					24,130			24,130		-									
	Utilities					9,500			9,500		-									
	Miscellaneous Supplies					48,110			48,110		-									
	Testing and Lab Analysis					10,000			10,000		-									
	Performance Bond					32,200			36,200		+ 4,000									
	Public Liability and Property																			
	Damage Insurance					30,000			31,000		+ 1,000									
	Construction Equipment					318,520			318,520		-									
	Small Tools, Repairs, Construction																			
	Consumables					92,230			95,230		+ 3,000									
	Sales Tax					157,630			184,630		+ 27,000									
	Escalation					1,026,500			1,310,500		+ 284,000									
	Freight					-			-		-									
	Contractor's Fee					514,620			582,620		+ 68,000									
	Contingency					-	20%		1,348,000		+1,348,000									
	Total Civil/Structural Contract, -					7,104,890			9,399,890		+2,295,000									

Table 2-2c
ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
MECHANICAL CONTRACT

FORM 4777
DRAFTED BY: _____
APPROVED BY: _____
DATE: 9/3/82 JOB: Heber Binary Project - Phase III

DETAIL ESTIMATE

SHEET NO. 3
J.O. NO. 7513.001

ACCT NO.	DESCRIPTION	QUANTITY	UNIT	RATES	AMOUNTS	TOTALS													
					SDG&E Cost	Estimate		UE&C Cost	Estimate		Difference								
						\$			\$		\$								
	MECHANICAL CONTRACT																		
	Bare Labor	133,441	Mhr			2,092,310	188,441 Mhr		2,930,310		+ 838,000								
	Craft Benefits and Burdens					1,485,540			2,080,540		+ 595,000								
	Subcontracts					287,000			287,000		-								
	Permanent Materials																		
	Procured by Fluor					33,936,115			33,936,115		-								
	Procured by Contractor					595,010			595,010		-								
	Field Salaries and Expenses					318,600			318,600		-								
	Field Staff Overhead					159,650			159,650		-								
	Relocate Field Supervisory Personnel					10,000			10,000		-								
	Temporary Construction																		
	Construction Facilities					49,000		1	49,000		-								
	Field Office Furniture, Supplies,																		
	Telephone, etc.					40,060			40,060		-								
	Utilities					23,800			23,800		-								
	Miscellaneous Supplies					69,680			69,680		-								
	Testing and Lab Analysis					10,000			10,000		-								
	Performance Bond					70,000			90,000		+ 20,000								
	Public Liability and Property																		
	Damage Insurance					60,000			84,000		+ 24,000								
	Construction Equipment					350,280			350,280		-								
	Small Tools, Repairs, Construction																		
	Consumables					195,710			254,710		+ 59,000								
	Sales Tax					2,219,110			2,236,110		+ 17,000								
	Escalation					1,155,780			4,422,780		+3,267,000								
	Freight					2,035,900			2,197,900		+ 162,000								
	Contractor's Fee					582,660			738,660		+ 156,000								
	Contingency					-	20%		10,177,000		+10,177,000								
	Total Mechanical Contract. -					45,746,205			61,061,205		+15,315,000								

Table 2-2d
ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
ELECTRICAL CONTRACT

DETAIL ESTIMATE

PRICED BY: _____
APPROVED BY: _____
DATE: 9/3/82 JOB: Heber Ripary Project - Phase II

SHEET NO. 4
A.O. NO. 7513.001

ACCT NO.	DESCRIPTION	QUANTITY	UNIT	RATES	AMOUNTS	TOTALS														
					SDG&E Cost	Estimate		VE&C Cost	Estimate		Difference									
						\$			\$		\$									
	<u>ELECTRICAL CONTRACT</u>																			
	Bare Labor	59,373	Hour			945,860		59,373	Hour		945,860		-							
	Craft Benefits and Burdens					671,560					671,560		-							
	Subcontracts					-					-		-							
	Permanent Materials																			
	Procured by Fluor					5,628,680					5,628,680		-							
	Procured by Contractor					138,970					138,970		-							
	Field Salaries and Expenses					169,500					169,500		-							
	Field Staff Overhead					85,350					85,350		-							
	Relocate Field Supervisory Personnel					5,000					5,000		-							
	Temporary Construction																			
	Construction Facilities					30,600					30,600		-							
	Field Office Furniture, Supplies,																			
	Telephone, etc.					24,970					24,970		-							
	Utilities					18,750					18,750		-							
	Miscellaneous Supplies					19,220					19,220		-							
	Testing and Lab Analysis					-					-		-							
	Performance Bond					35,000					35,000		-							
	Public Liability and Property																			
	Damage Insurance					30,000					30,000		-							
	Construction Equipment					200,990					200,990		-							
	Small Tools, Repairs,																			
....	Construction Consumables					55,590					55,590		-							
	Sales Tax					412,590					412,590		-							
	Escalation					911,160					1,289,160		+ 378,000							
	Freight					560,860					581,860		+ 21,000							
	Contractor's Fee					236,650					243,650		+ 7,000							
	Contingency					-		20%			2,118,000		+2,118,000							
	Total Electrical Contract, -					10,181,300					12,705,300		+2,524,000							

Table 2-2f

ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
LANDSCAPING AND PAINTING CONTRACT

DETAIL ESTIMATE

PRICED

APPROVED BY

DATE 9/3/82

Heber Binary Project - Phase II

SHEET NO. 6

J.E. NO 7513.001

[illegible]

Table 2-2g
ITEMIZED CONSTRUCTION COST ESTIMATE COMPARISON:
ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES

FORM 477

DETAIL ESTIMATE

PREPARED BY _____
APPROVED BY _____
DATE 9/3/82 JOB Heber Binary Project - Phase II

SHEET NO 7
A.O. NO 7513.001

ACCT NO	DESCRIPTION	QUANTITY	UNIT	RATES	AMOUNTS	TOTALS														
					SDG&E Cost	Estimate		UE&C Cost	Estimate		Difference									
						\$			\$		\$									
	F.P.S. ENGINEERING FOR PHASE II																			
	Salaries, Expenses, Overhead and																			
	Fee					5,068,690			5,068,690		-									
	Escalation					Included			Included		-									
	Contingency					-	15%		760,000		+ 760,000									
	Total F.P.S. Engineering, -					5,068,690			5,828,690		+ 760,000									
	D.U.C.I. CONSTRUCTION																			
	MANAGEMENT																			
	Salaries, Expenses, Overhead																			
	and Fee					2,938,480			2,938,480		-									
	Escalation					Included			Included		-									
	Contingency					-	15%		441,000		+ 441,000									
	Total D.U.C.I. Construction																			
	Management, -					2,938,480			3,379,480		+ 441,000									
	Total, -					\$ 82,117,645			\$ 105,958,645		\$ +23,841,000									

Table 2-3a
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - SITE DEVELOPMENT CONTRACT

<u>Site Development Contract</u>	<u>Amount</u>
<u>Bare Labor</u>	
Increase manhours for fire water pumps; circulating water piping; earthwork for settling ponds; main building structural steel, suspended ceilings and electrical wiring; and miscellaneous iron in the firewater pump structure	\$ +78,000
<u>Comment</u> - Crew rates used in the estimate are based on crew mixes which utilize a significant percentage of "Helpers" at the common laborer wage rate. If the contractor is unable to negotiate a labor agreement permitting this favorable proportion of helpers to journeymen and use of the laborer wage rate, the cost of labor and labor-related items in the estimate will increase accordingly.	
<u>Craft Benefits and Burdens</u>	
71% of increase in bare labor cost	+55,000
<u>Permanent Materials</u>	
Increase unit cost for fabricated structural steel in main building	+10,000
<u>Public Liability & Property Damage Insurance</u>	
Based on increase in bare labor cost	+2,000
<u>Small Tools</u>	
Based on increase in bare labor cost	+2,000
<u>Sales Tax</u>	
6% of increase in escalated cost of permanent materials	+8,000
6% of material portion of subcontracted work including escalation	+31,000

Table 2-3a (cont'd)
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - SITE DEVELOPMENT CONTRACT

<u>Site Development Contract (Cont'd)</u>	<u>Amount</u>
<u>Escalation</u>	
Recalculate escalation as follows:	
Bare Labor \$860,820 X 15% - Fluor Estimate =	\$ +27,000
Materials \$1,939,630 X 8% - Fluor Estimate =	+117,000
 <u>Comment</u> - Labor rates used in the estimate are assumed to expire mid-1982 and are estimated by Fluor to escalate 13% per year. This contract is scheduled to begin approximately January 1983 and run for 8 months. The 1982 increase will have taken effect prior to the start of the work and the 1983 increase will be implemented before the contract is complete.	
 Material prices in the estimate are 1st quarter 1982. Escalation is generally determined by dates of shipment. Midpoint of construction is 2nd quarter 1983.	
 <u>Freight</u>	
9% of increased cost for equipment listed under this item in estimate resulting from addition of escalation	+3,000
 <u>Contractor's Fee</u>	
8% of increases listed above excluding sales tax, and escalation and freight for material procured by Fluor	+13,000
 <u>Contingency</u>	
20% of total estimated cost	+1,165,000
 <u>Comment</u> - Based on review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	
 Net Increase, -	 <u>\$ 1,511,000</u>

Table 2-3b
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - CIVIL/STRUCTURAL CONTRACT

Civil/Structural Contract

<u>Bare Labor</u>	<u>Amount</u>
Increase the manhour unit cost for erection of miscellaneous supports, racks, platforms, ladders, railings, etc. from 13 mhr/ton to 25 mhr/ton	\$ +75,000
<u>Comment</u> - Crew rates used in the estimate are based on crew mixes which utilize a significant percentage of "Helpers" at the common laborer wage rate. If the contractor is unable to negotiate a labor agreement permitting this favorable proportion of helpers to journeymen and use of the laborer wage rate, the cost of labor and labor-related items in the estimate will increase accordingly.	
<u>Craft Benefits and Burdens</u>	
71% of increase in bare labor cost	+53,000
<u>Subcontracts</u>	
Increase the unit price for the Painting Enclosure and the Sand Blasting Enclosure from \$12.50 per square foot to \$25 per square foot.	+10,000
Increase the unit price for the Water Treatment Area Pavilion from \$10.00 per square foot to \$12.50 per square foot	+1,000
Increase the unit price for switchyard fencing	+1,000
<u>Permanent Materials</u>	
Increase the unit cost for fabricated structural steel	+70,000
Increase the unit cost for miscellaneous supports, racks, platforms, ladders, railings, etc.	+350,000
<u>Performance Bond</u>	
Based on increase in contract value	+4,000
<u>Public Liability & Property Damage Insurance</u>	
Based on increase in bare labor cost	+1,000

Table 2-3b (cont'd)
 ANALYSIS OF CONSTRUCTION COST ESTIMATE:
 EXPLANATION OF DIFFERENCES - CIVIL/STRUCTURAL CONTRACT

<u>Civil/Structural Contract - (Cont'd)</u>	<u>Amount</u>
<u>Small Tools</u>	\$
Based on increase in bare labor cost	+3,000
<u>Sales Tax</u>	
6% of increase in escalated cost of permanent materials	+26,000
6% of material portion of subcontracted work including escalation	+1,000
<u>Escalation</u>	
Recalculate escalation as follows:	
Bare Labor \$1,613,000 X 36% - Fluor Estimate =	+174,000
Subcontracts \$ 29,300 X 18% - Fluor Estimate =	+2,000
Materials \$2,401,200 X 17% - Fluor Estimate =	+72,000
Indirects \$2,109,270 X 15% - Fluor Estimate =	+36,000
 <u>Comments</u> - Labor rates used in the estimate expire June 30, 1982, and are estimated to escalate 13% per year. This contract is scheduled to begin approximately October 1983 and run for 9-10 months. The 1982 and 1983 increases will have taken effect prior to the start of the work and the 1984 increase will be implemented before the contract is complete.	
<u>Contractor's Fee</u>	
8% of increases listed above, excluding sales tax	+68,000
<u>Contingency</u>	
20% of total estimated cost	+1,348,000
 <u>Comment</u> - Based on review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	
Net Increase, -	<u>\$ 2,295,000</u>

Table 2-3c
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - MECHANICAL CONTRACT

<u>Mechanical Contract</u>	<u>Amount</u>
<u>Bare Labor</u>	\$
Increase manhours for erection of pumps, tanks, heat exchangers, compressors, turbine generator and other mechanical equipment by 30,000 mhrs. including hot weather inefficiency	+433,000
Increase manhours for erection of piping and valves by 25,000 mhrs. including hot weather inefficiency	+405,000
<u>Comment</u> - Crew rates used in the estimate are based on crew mixes which utilize a significant percentage of "Helpers" at the common laborer wage rate. If the contractor is unable to negotiate a labor agreement permitting this favorable proportion of helpers to journeymen and use of the laborer wage rate, the cost of labor and labor-related items in the estimate will increase accordingly.	
<u>Craft Benefits and Burdens</u>	
71% of increase in bare labor cost	+595,000
<u>Performance Bond</u>	
Based on increase in contract value	+20,000
<u>Small Tools</u>	
Based on increase in bare labor dollars	+59,000
<u>Sales Tax</u>	
6% of increase in escalated cost of small tools +40,000	+4,000
6% of material portion of subcontracted work including escalation	+13,000
<u>Public Liability & Property Damage Insurance</u>	
Based on increase in bare labor cost	+24,000

Table 2-3c (cont'd)
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - MECHANICAL CONTRACT

Mechanical Contract (Cont'd)

Amount

Escalation

\$

Recalculate escalation as follows:

Bare Labor	\$ 2,930,310 X 36% - Fluor Estimate =	+626,000
Materials	\$34,531,125 X 8% - Fluor Estimate =	+2,622,000
Indirects	\$ 2,945,320 X 19% - Fluor Estimate =	+19,000

Comment - Labor rates used in the estimate expire June 30, 1982, and are estimated to escalate 13% per year. This contract is scheduled to begin approximately July 1983 and run for 17 months. The 1982 and 1983 increases will have taken effect prior to the start of the work and the 1984 increase will be implemented before the contract is complete.

Material prices in the estimate are 1st quarter 1982. Escalation on equipment and piping materials is frequently determined by the dates of fabrication or shipment. Midpoint of construction is 2nd quarter 1984.

Freight

9% of increase in material cost subject to freight resulting from addition of escalation	+162,000
--	----------

Contractor's Fee

8% of increases listed above excluding sales tax, and escalation and freight on material procured by Fluor	+156,000
--	----------

Contingency

20% of total estimated cost	+10,177,000
-----------------------------	-------------

Comment - Based on review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection

Net Increase, -

\$15,315,000

Table 2-3d
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - ELECTRICAL CONTRACT

Electrical Contract

Amount

Bare Labor

\$

Comment - Crew rates used in the estimate are based on crew mixes which utilize a significant percentage of "Helpers" at the common laborer wage rate. If the contractor is unable to negotiate a labor agreement permitting this favorable proportion of helpers to journeymen and use of the laborer wage rate, the cost of labor and labor-related items in the estimate will increase accordingly.

Escalation

Recalculate as follows:

Bare Labor	\$ 945,860 X 36% - Fluor Estimate =	+147,000
Materials	\$5,767,650 X 12% - Fluor Estimate =	+231,000

Comment - Labor rates used in the estimate are assumed to expire mid-1982 and are estimated to escalate 13% per year. This contract is scheduled to begin approximately September 1983 and run for 15 months. The 1982 and 1983 increases will have taken effect prior to the start of the work and the 1984 increase will be implemented before the contract is complete

Material prices in the estimate are 1st quarter 1982. Escalation on equipment and cable is frequently determined by date of shipment. Midpoint of construction is 1st quarter 1984.

Freight

9% of increase in material resulting from addition of escalation

+21,000

Table 2-3d (cont'd)
 ANALYSIS OF CONSTRUCTION COST ESTIMATE:
 EXPLANATION OF DIFFERENCES - ELECTRICAL CONTRACT

<u>Electrical Contract (Cont'd)</u>	<u>Amount</u>
<u>Contractor's Fee</u>	\$
8% of increases listed above excluding escalation and freight on material procured by Fluor	+7,000
<u>Contingency</u>	
20% of total estimated cost	+2,118,000
<u>Comment</u> - Based on review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	<hr/>
 Net Increase, -	 <u>\$ 2,524,000</u>

Table 2-3e
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES -
COOLING TOWER, HYDROCARBON STORAGE TANK, AND PAVING CONTRACT

<u>Cooling Tower Contract</u>	<u>Amount</u>
	\$
<u>Sales Tax</u>	
6% of material portion of subcontracted work including escalation	+182,000
<u>Contingency</u>	
10% of total estimated cost	+417,000
<u>Comment</u> - Based on our review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	
Net Increase, -	<u>\$ 599,000</u>

<u>Hydrocarbon Storage Tank Contract</u>	
<u>Sales Tax</u>	
6% of material portion of subcontracted. work including escalation	+45,000
<u>Contingency</u>	
10% of total estimated cost	+98,000
<u>Comment</u> - Based on our review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	
Net Increase, -	<u>\$ 143,000</u>

Table 2-3e (cont'd)
 ANALYSIS OF CONSTRUCTION COST ESTIMATE:
 EXPLANATION OF DIFFERENCES -
 COOLING TOWER, HYDROCARBON STORAGE TANK, AND PAVING CONTRACT

<u>Paving Contract</u>	<u>Amount</u>
<u>Sales Tax</u>	\$
6% of material portion of subcontracted work including escalation	+10,000
<u>Contingency</u>	
20% of total estimated cost	+44,000
<u>Comment</u> - Based on our review of the estimate and backup, this is the minimum contingency we would suggest for budgetary protection	
	<hr/>
Net Increase, -	\$ 54,000

Table 2-3f
ANALYSIS OF CONSTRUCTION COST ESTIMATE:
EXPLANATION OF DIFFERENCES - LANDSCAPING AND PAINTING CONTRACT

Landscaping Contract

Amount

Sales Tax

6% of material portion of subcontracted
work including escalation

+4,000

Contingency

20% of total estimated cost

+27,000

Comment - Based on our review of the
estimate and backup, this is the
minimum contingency we would suggest
for budgetary protection

Net Increase, -

\$ 31,000

Painting Contract

Subcontract

\$

Increase surface area of piping to be
painted from 32,000 to 100,000 square
feet based on Definitive Estimate

+54,000

Sales Tax

6% of material portion of subcontracted
work including escalation

+12,000

Escalation

34% of increase in contract value

+18,000

Contingency

20% of total estimated cost

+84,000

Comment - Based on our review of the
estimate and backup, this is the
minimum contingency we would suggest
for budgetary protection

Net Increase, -

\$ 168,000

Table 2-3g
 ANALYSIS OF CONSTRUCTION COST ESTIMATE:
 EXPLANATION OF DIFFERENCES -
 ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES

F.P.S. Engineering for Phase II

Amount

Contingency

15% of Phase II estimated cost

+760,000

D.U.C.I. Construction Management

Contingency

15% of total estimated cost

\$ +441,000

Comment - D.U.C.I. has submitted proposals for vendor surveillance and a 9-month extension to the construction schedule totalling \$430,000. This amount does not appear to be included in the estimate and should be added if these services are contemplated. The above contingency does not reflect the cost of these additional services

Net Increase in Total
 Installed Cost, -

\$23,841,000

Chapter Three

ANALYSIS OF WELL FIELD COSTS

The costs associated with well field development and operation are analyzed in this chapter. These costs include: (1) expenditures already incurred in the exploration and confirmation of the Heber Known Geothermal Resource Area ("sunk costs"), (2) capital costs required to install the wells and surface equipment necessary for fluid production and injection, and (3) well field operation and maintenance costs once production begins. These costs, although directly incurred by the well field operators, must eventually be recovered through sale of fluid to the Heber power plant operators. Sales revenues must also be sufficient to provide an adequate return on the field operators' capital investment. The magnitude of field development and operating costs is estimated below. Investment returns, given the current resource pricing agreement, are addressed in Chapter Four.

3.1 SUNK COSTS

The Heber KGRA was confirmed in 1972 when the first deep production wells were drilled and tested. Prior to 1972 the field operators incurred costs for reconnaissance, exploration and lease acquisition. Following resource confirmation, the operators have incurred additional costs for rental payments, resource modeling, and continued deep well drilling, testing and evaluation. Tables 3-1 and 3-2 summarize the drilling activity and estimated sunk costs, respectively, as incurred to date at the Heber KGRA.

The sunk costs given in Table 3-2 represent estimated expenditures to date for the entire Heber KGRA including unretained acreage related to its discovery (see Ref. 5, p. 21a). The Heber KGRA is expected to have the capacity for supporting about 500 MWe (net) of electric power generation [21]. The Demonstration Project will produce 45 MWe (net), or 9% of the total KGRA capacity. Therefore, in this analysis, we will allocate 9% of the total \$24,900,000 (in 1982 constant dollars) sunk cost for recovery by the Demonstration Project; i.e., a 1982 sunk cost of \$2,240,000 will be factored into the Project's well field cash flow analysis.

Table 3-1
HEBER KGRA
DEEP WELL DRILLING HISTORY

<u>Year</u>	<u>Well Name</u>	<u>Section</u>	<u>Firm</u>	<u>Type</u>	<u>Depth (m)</u>
1972	Holtz #1	32	NARCO	Producer	1,569
1972	Holtz #2	31	NARCO	Producer	1,524
1972	Nowlin #1	33	Chevron	Producer	1,533
1974	Hulse #1	29	Chevron	Producer	1,951
1974	C. Jackson #1	32	Chevron	Producer	1,829
1974	J. Jackson #1	33	Chevron	Producer	1,843
1975	GTW #1	27	Chevron	Observation	1,054
1975	GTW #2	27	Chevron	Observation	915
1975	GTW #3	34	Chevron	Observation	1,193
1976	Bacon #1	7	Union	Observation	1,230
1976	GTW #5	3	Chevron	Observation	2,161
1976	Murdy #1	10	Union	Observation	1,299
1976	Saikhon #1	34	Union	Observation	1,372
1976	Thompson #1	4	Union	Producer	2,174
1976	Thompson #1	3	Union	Producer	2,957

Sources: Ref. 21 (p. 1-17, 1-18, 1-19) and Ref. 13

Table 3-2
HEBER KGRA
ESTIMATED SUNK COSTS

<u>Year</u>	<u>Description</u>	<u>Cost As Incurred</u>	<u>Cost To 1982*</u>
1969	Reconnaissance Activities	\$900,000	\$3,140,000
1970	Lease Bonus, Rental and Surface Exploration	1,600,000	5,360,000
1971	Geophysical Study, Rental and Temperature Gradient Holes	810,000	2,250,000
1972	Detailed Exploration, Rental and 3 Production Wells	1,365,000	3,450,000
1973	Studies and Rental	75,000	180,000
1974	Studies, Rental and 3 Additional Production Wells	1,260,000	2,910,000
1975	Studies, Rental and 3 Observation Wells	880,000	1,830,000
1976	Studies, Rental, 4 Observation Wells and 2 Production Wells	2,530,000	4,680,000
1977-1981	Well Field Modeling and Rental	650,000	1,100,000
TOTAL ESTIMATED SUNK COSTS TO 1982:			<u>24,900,000</u>

*Based upon well field operators' opportunity cost of capital estimated to be U.S. Treasury Bill Rate plus 4%.

Sources: Ref. 21 (p. 1-5 and 1-16), Ref. 5 (p. 21a), Ref. 4 (p. 4-19), Ref. 6 (p. 15-17), Ref. 16.

3.2 CAPITAL COSTS

Estimated well field capital costs for the Demonstration Project are provided in Table 3-3. These costs are based upon the following supporting documentation:

- o Piping and Instrumentation Diagram of the Geothermal Fluid Handling System (Ref. 21, Fig. 1-37, p. 1-47).
- o Production Island Plot Plan (Ref. 21, Fig. 1-38, p. 1-53).
- o Injection Island Plot Plan (Ref. 21, Fig. 1-39, p. 1-58).
- o Injection Pipeline Route Map and Specifications (Ref. 21, p. 1-60).
- o Injection Pipe Layout (Ref. 21, Fig. 1-42, p. 1-61).
- o Well field site and reservoir description (Ref. 21, Section 1).

Working from the descriptions provided in these documents, capital costs were estimated by using: (a) vendor quotations for major components; (b) published rates for labor, overhead and materials; and (c) in-house historical data for unit manhours incurred on similar projects. The resulting well field cost estimate of \$46 million is in 1982 dollars for the San Diego region. Well costs, which comprise more than 70% of the total field cost, are based upon an estimate provided by GeothermEx, Inc. [11] from their recent experience in the Heber area.

A contingency allowance is included as normal cost estimating practice to account for expected, but unidentifiable, costs during construction. The \$1.6 million contingency allowance included in Table 3-3 includes: (a) a 10% allowance on all costs associated with the relatively uncomplicated injection pipeline (i.e., trenching, concrete, supports, pipe, expansion joints, insulation and fittings); and (b) a 20% allowance on all production and injection island costs excluding the \$32.4 million cost for production and injection wells.

3.3 OPERATING COSTS

Recurrent costs for operating and maintaining the well field during production are to be reimbursed to the field operator on a dollar-for-dollar basis by the power plant operators [12]. This pass-through is, therefore, excluded from the fluid pricing formula in the Heat Sales Agreement [12], and does not enter into the well field cash flow analysis presented in Chapter Four.

Table 3-3
 HEBER DEMONSTRATION PROJECT
 WELL-FIELD CAPITAL COST ESTIMATE
 (1982 \$)

Description	Installed Cost*
SITE IMPROVEMENTS	\$170,000
Surveying, clearing, grading, berm earthwork, chain link fencing with gates, crushed rock, paving, landscaping, outdoor lighting.	
CIVIL/STRUCTURAL	620,000
Concrete-lined pipe trenches on islands, injection pipe trench, overflow basin, well cellars, concrete footings and slabs, maintenance sheds, switchgear sheds, production office.	
PRODUCTION/INJECTION WELLS	32,400,000
13 production and 3 injection wells to 6000 feet, and 4 injection wells to 4000 feet. Directionally drilled, fully cemented with casing schedule per SDG&E Proposal, v. III, p. 1-64, dated December 1979. Jet perforated last 2000 feet. Includes rig, casing, mud, chemicals, bits, reamers, logging, fuel, water, transportation, directional services.	
MECHANICAL EQUIPMENT	2,950,000
Downhole pumps, injection booster pumps, instrument air compressor, in-line filters and fan-driven cooler for downhole pump bearing cooling, production office equipment.	
TANKS/VESSELS	550,000
Holding tank and sand pit (atmospheric design), insulated desander and start-up desander (325 psi design), portable holding tank.	
PIPING	4,890,000
Above-ground welded carbon steel with aluminum covered fiberglass insulation, expansion joints, fittings, supports and small valves. Includes erection, welding, testing. Large pipe (>12") is shop fabricated; other pipe is field fabricated. Includes 30" injection pipeline (12000LF), large 16"-30" piping on islands (1300LF), medium 3"-12" piping on islands (2400LF), and small <3" piping on islands (3700LF).	

Table 3-3 (cont'd)

Description	Installed Cost*
LARGE VALVES	\$1,210,000
Steel 300 lb. valves per diagram on p. 1-47 of SDG&E Proposal, v. III. Includes gate, globe, pressure relief, check, pneumatic and solenoid valves in large 16"-30" sizes (9 valves) and medium 3"-12" sizes (184 valves). Small <3" valves included in piping cost above.	
INSTRUMENTATION/CONTROLS	650,000
Transducers, meters, wiring, instrumentation and controls. Includes 30" venturi flowmeter.	
ELECTRICAL	960,000
Transformers, switchgear, motor and local control centers, distribution panels, relay and meter boards, conduit, wire and cable, communications, and preoperational testing.	
SUBTOTAL	<u>\$44,400,000</u>
CONTINGENCY ALLOWANCE	<u>1,600,000</u>
TOTAL ESTIMATED COST	<u><u>\$46,000,000</u></u>

* Installed costs include material, sales taxes, equipment, material handling, labor, subcontracts, engineering, permits, fees and overhead. Overhead includes cleanup, management, project insurance, workers compensation insurance, main-office expense, bonds, scaffolding, scheduling, tools, rental equipment, consumable supplies, payroll taxes, payroll fringe benefits, travel and subsistence, temporary construction, field office costs, testing, watchmen, contractors profit.

Table 3-4 presents the estimated annual cost in 1982 dollars for operating and maintaining the Demonstration Project well field. This estimated cost of \$3.9 million/year is based upon the following factors:

- o Labor requirements are taken from estimates by EG&G Idaho, Inc. [8] and Bechtel Corporation [2]. It may be noted that the Bechtel data were developed specifically for a Heber project and uses information provided by Chevron. Labor rates are from published sources for the San Diego region [15].
- o Well maintenance requirements and costs are taken from the Bechtel Heber study [2] as provided by Chevron.
- o Downhole well pump maintenance costs are based on estimates provided by the proposed supplier, Peerless Pumps, Inc.
- o Surface facility maintenance costs are estimated by using factors provided in the abovementioned EG&G and Bechtel references. For low maintenance components such as structures, vessels and piping, a factor of 0.5% of capital cost is used. For components such as pumps, compressors, instrumentation, and electrical equipment, a factor of 2% of capital cost is used.
- o Administrative and general overhead expenses are estimated to be within the range of 10-15% of operation and maintenance costs based upon information from major resource corporations.

As stated in Reference 21 (page 2-23), (and subsequently verified in conversation with DOE officials), electric energy required to operate well field pumps and ancillary equipment will be provided at no cost from the Demonstration Plant. This electric power requirement is deducted from the gross plant output when estimating the 45 net megawatts to be exported by the plant. Therefore, no recurrent cost item is included in Table 3-4 for this electric power requirement.

It may be noted that Union Oil estimates pass-through costs for well field operation and maintenance to be between \$3 million and \$9 million per year with a "probable" estimate of \$5.8 million [see Ref. 14 and 18]. This range of values (in 1981 dollars) is considerably higher than the estimate provided in Table 3-4. We recommend that these differences be examined by DOE.

Table 3-4
 HEBER DEMONSTRATION PROJECT
 WELL-FIELD OPERATION AND MAINTENANCE EXPENSE ESTIMATE
 (1982 \$)

Description	Annual Cost
LABOR*	\$420,000
Site Manager: full time @ \$300/day	
Foreman: full time @ \$262/day	
Electrician: full time @ \$255/day	
Mechanic: full time @ \$178/day	
Roustabout: full time @ \$167/day	
Secretary/Clerical: full time @ \$100/day	
Production Engineer: 1/2 time @ \$400/day	
Mechanical Engineer: 1/2 time @ \$400/day	
WELL MAINTENANCE	1,900,000
Yearly downhole surveys, acidizations and stimulations. Reworking every 4 years for 13 production wells and every 2 years for 7 injection wells. Miscellaneous maintenance supplies.	
SURFACE FACILITY MAINTENANCE	150,000
Maintenance of all well-field surface piping, down-hole pumps, other mechanical and electrical equipment, and structures.	
SUBTOTAL	\$2,470,000
ADMINISTRATIVE & GENERAL EXPENSE	330,000
TOTAL ESTIMATED ANNUAL COST	<u>\$2,800,000</u>

*Labor rates include allowances for wages, payroll taxes, benefits, and labor overhead.

Chapter Four

ANALYSIS OF FLUID SALES AGREEMENT

In this chapter, a comprehensive review of the fluid sales agreement is presented. The major terms and provisions of the sales agreement are first analyzed, including: (1) the proposed project development schedule, (2) the initial commodity and demand charges imposed on fluid sales, and (3) allowances for future price escalation. A detailed cash flow analysis of well field investment returns is then performed. This cash flow analysis evaluates the sunk costs and well field capital costs (estimated in Chapter Three), and the fluid sales revenue once production begins. Well field returns are measured in terms of (1) after-tax internal rate of return on investment, (2) net present value of profits, and (3) payback period. Finally, an analysis of the reasonableness of the investment return is made, compared to the overall quality of alternative investment opportunities.

4.1 GEOTHERMAL FLUID PRICING

The Union Oil Geothermal Sales Contract [12] defines the terms and conditions under which the fluid will be purchased by SDG&E. Its provisions include:

- o The timetable for increasing field capacity from 3.75×10^6 lbs/hr to 7.5×10^6 lbs/hr.
- o The actual commodity and demand charges in effect during the duration of the contract, including provision for annual escalation.
- o The penalties associated with failure by either party to meet specific provisions of the contract.

Each of these items is addressed in the following analysis.

4.1.1 Project Time Schedule

A clear understanding of Union Oil's contractual obligation to supply fluid for the plant is critical because it impacts both the fluid purchase price and the length of time elapsed before full plant capacity is achieved. The contract stipulates that during "Startup and Test and Inspection" Union's Supply Obligation shall be set initially at 3.75×10^6

lbs/hr. No date is specified at which "Startup" is to begin, and the contract states only that the "Test and Inspection" period is to conclude "no earlier" than 18 months following synchronization of the plant to the electrical transmission line. During this period, the contract stipulates that the Supply Obligation may be increased if the fluid taken by SDG&E exceeds Union's then-existing Supply Obligation by more than 450,000 lbs/hr over 30 consecutive calendar days. However, no monetary penalties are imposed on Union if this Supply Obligation is not met.

The period of Full Operation is to commence when field facilities capable of delivering 7.5×10^6 lbs/hr of fluid have been installed, and the plant has operated at sustained, near capacity levels (roughly 60 MW gross and 75% capacity if fluid is delivered at 360°F) over a three month period. Based on the provisions of the current contract, SDG&E may request Union to install additional field facilities to accomplish Full Operation at any time after the first six months of the Startup period (see section 13.15 Ref.12). Union, at its own risk and expense, is to install such facilities within 12 months. This obligation may be deferred, or eliminated entirely, only if Union's startup expenditures or operation and maintenance costs are excessive, or reservoir characteristics are significantly below expectations (See Ref. 12, Sections 18.6.1-18.6.7 for full details regarding these provisions). However, SDG&E's only recourse if the capacity is not in place (and the abovementioned clauses pertaining to relief from Union's obligation cannot be documented) appears to be to charge Union with breach of contract or to install the additional facilities themselves. No direct monetary penalty may be assessed on Union for failure to comply with these terms.

Figure 4-1 illustrates the most rapid capacity buildup which would be consistent with the contractual provisions. Assuming synchronization of the plant to the grid in January 1985, the Startup period would conclude six months later in June 1985. The Test and Inspection period would conclude after the minimum 18-month duration, ending in December 1986. Assuming that fluid delivery capacity reaches 7.5×10^6 lbs/hr in October 1986, and the plant operates reliably at or near capacity, Full Operation would commence in January 1987.

Figure 4-1.
ACCELERATED PROJECT SCHEDULE

* Base Price of \$1.30/MBTU
 ** Base Price of \$1.15/MBTU

It should be noted that the project schedule shown in Figure 4-1 is roughly equivalent to that provided by Union (see Figure 4-2) in their April 16, 1982 Economic Analysis [14]. As discussed above however, it may be difficult to guarantee that the field will be developed at the pace shown.

4.1.2 Fluid Pricing Provisions

The contract stipulates that during the Startup and Test and Inspection period, the fluid sale price will be assessed according to a Commodity Charge. The charge (in 1982 constant dollars) will be assessed monthly, and will be determined by: (1) total fluid delivered to the plant; (2) the differential between fluid enthalpy entering and leaving the plant; (3) gross plant output; and (4) parasitic losses. Specifically, the Commodity Charge (CC) will be determined as follows:

$$CC = P \times Z \times (BTU_{IN} - BTU_{OUT}) \times (1 - \frac{ff}{gg}) \quad (1)$$

where:

Z = total pounds of fluid delivered to the plant
P = Base Price (\$/10⁶ BTU)
BTU_{IN} = Enthalpy of fluid delivered to the plant (BTU/lb)
BTU_{OUT} = Enthalpy of Fluid leaving the plant (BTU/lb)
ff = Parasitic losses (MW)
gg = Gross Plant output (MW)

To evaluate the magnitude of fluid purchase costs during the Startup and Test and Inspection period, it was assumed that capacity will gradually be built up according to the project schedule shown in Figure 4-2. Under this schedule, gross generation is held to 20-21 MW during 1985. Following a 3-month shut down in 1986, gross generation is gradually increased to 67.9 MW during the course of the nine remaining months in 1986. Based on this assumed capacity buildup and expected power plant performance parameters (see Ref. 14 and 21), fluid purchase charges (in 1982 constant dollars) would total \$5,700,000 and \$5,800,000 for 1985 and 1986 respectively.

Once the Full Operation period begins, the Base Price (P) for heat delivered to the plant is reduced from \$1.30 to \$1.15/10⁶ BTU. The Commodity Charge shown in Equation (1) remains in effect until such time as

FIGURE 4-2.
UNION OIL PROPOSED PROJECT SCHEDULE

Source: Ref. 21

Union Oil notifies SDG&E that it will deliver its Supply Obligation on a continual basis. The date of notification (the Date of Firm Supply Obligation) shall be set at some time during the Full Operation period, provided that Union has installed and operated for three months facilities capable of delivering 7.5×10^6 lbs/hr of fluid. At such time, the pricing provision will be changed, and both a Demand and Commodity Charge will be in effect.

The Commodity Charge, with a Base Price of \$1.15/10⁶BTU, is reduced by one fourth following the Date of Firm Supply Obligation. A Demand Charge (DC) is to be imposed, based in part on Union's Supply Obligation:

$$DC = 503.7 \times U \times (BTU_{IN} - BTU_{154}) \times (1 - \frac{ff}{gg}) \quad (2)$$

where:

U = Union's Supply Obligation (10³ lbs/hr)
 BTU_{IN} = Average Enthalpy of fluid delivered to plant (BTU/lb)
 BTU₁₅₄ = Enthalpy of fluid at 154°F (121.96 BTU/lb)
 ff = Parasitic Losses (MW)
 gg = Gross Output (MW)

In our analysis, to estimate total fluid purchase costs during the period of Full Operation, it is assumed that the Date of Firm Supply Obligation occurs 3 months after the start of Full Operation (i.e., April 1987). This again represents the earliest date at which Firm Supply could be achieved. If this schedule is met, fluid purchase costs are expected to be approximately \$11,000,000 in 1987 (1982 constant dollars).

4.1.3 Fuel Cost Escalation Provision

The contract stipulates that the 1981 commodity and demand charges shall be subject to annual increases based on the movements of four specific price indices. The composite escalation rate (F) is calculated as a weighted average of the annual rate of change of each index:

$$F = .10 (\Delta d) + .27 (\Delta w) + .27 (\Delta c) + .09 (\Delta p) + .27 (\Delta m) \quad (3)$$

where:

(Δd) is the annual percentage change in the Bureau of Labor Statistics (BLS) Producer Price Index for "Diesel to Commercial Customers"
 (Δw) is the annual percentage change in the hourly wage rate for "Crude Petroleum, Natural Gas, and Natural Gas Liquids Workers";

- (Δc) is the change in the BLS Producer Price Index for "Oilwell Casing Alloy"
- (Δp) is the change in the BLS Producer Price Index for cement (the "Portland" Index)
- (Δm) is the change in the BLS Producer Price Index for "Miscellaneous Machinery: Oilfield and Natural Gas Field."

Table 4-1 presents a summary of how these indices moved relative to the Consumer Price Index over the past 5 years. As shown, wage rates for oil and gas workers and the price for cement have not shown significant real increases on average over the past five years. The prices for diesel fuel, well casing, and well field machinery are observed to have risen at rates significantly above the Consumer Price Index. Table 4-1 also provides long term forecasts for the movement of each index, based on analysis of historic trends since 1970.

4.2 WELL FIELD CASH FLOW ANALYSIS

As noted in the SDG&E Proposal (Ref. 22, p. 3-9), the well field operators are approaching the Heber Project as a commercial venture, not as an R&D project, and therefore they expect to earn a return that is comparable with other undertakings of similar risk. To examine the returns that the operators will realize from fluid sales to the Demonstration Project, we constructed a computer-based cash flow model. This model evaluates the well field investment in terms of: (a) its after-tax internal rate of return, (b) its after-tax payback time, and (c) its after-tax net present value at a 12% discount rate.

4.2.1 Cash Flow Components

The cash flow model incorporates the following components:

- o Sunk costs of \$2.24 million are allocated to the Demonstration Plant well field in 1982, the first year of analysis (recall section 3.1).
- o Capitalized Costs include the estimated well field costs (from Table 3-3) exclusive of the intangible portion (75%) of the cost of the wells themselves. Well field capital expenditures are divided equally over 1983 and 1984, including annual escalation of 8% from 1982. Capital expenditures for wells are allocated on a 25%, 25%, 50% basis for 1983, 1984, and 1985 respectively to reflect the proposed capacity buildup.
- o Expensed costs are the intangible portion of well costs. These are estimated to be \$24.3 million (1982\$) and are allocated \$6.1 million in 1983 and 1984, and \$12.2 million in 1985 due to the gradual capacity buildup assumed in this analysis.

Table 4-1
ANNUAL ESCALATION RATES
(percent change)

Price Index	1977	1978	1979	1980	1981	Unweighted Average	1981-1990 Forecast ¹
Diesel Fuel to Commercial Consumer	11.6	4.6	74.9	23.7	17.4	26.4	10.0
Wage Rate for Petroleum and Natural Gas Workers	6.5	11.6	10.4	10.4	10.3	9.84	6.0
Oil Well Casing, Alloy	17.5	7.7	7.1	25.7	43.7	20.3	9.0
Portland Cement	6.6	11.0	11.8	8.4	5.3	8.6	6.0
Oil and Gas Well Field Machinery	9.2	9.8	12.2	17.7	17.7	13.2	9.5
All-Urban Consumer Price Index	6.5	7.7	11.3	13.5	10.4	9.9	6.0

Source: 1977-1981 data from the United States Bureau of Labor Statistics

¹Forecast based on analysis of relative price movements over the 1970-1981 period.

- o Tax depreciation is assumed to be based on a 5-year life according to ACRS guidelines. The abovementioned capitalized costs are depreciated according to proposed Internal Revenue Service guidelines (15% for the year equipment is first placed in service, 22% the second year, and 21% for years 3, 4, and 5). All well field equipment costs and half of the capitalized well costs are depreciated in this manner from 1985 through 1989. The remaining capitalized well expenditures are depreciated from 1986 through 1990. It may be noted that about 2% of the capitalized costs (i.e., site improvements and civil/structural items) may be classified as 15-year property.
- o Gross revenues are based upon the pricing provisions described in Section 4-1. Variables in the gross revenue estimates are: (i) net plant capacity, MWe; (ii) plant capacity factor; (iii) Consumer Price Index, CPI, rate of escalation; and (iv) the annual rate of increase in the four price indices which determine fluid price escalation rates.
- o Royalty payments to well field land lessors which are estimated to be one-eighth of gross revenues.
- o Depletion for California tax purposes is estimated to be 22% of gross revenues less royalty payments.
- o Depletion for Federal tax purposes is estimated to be 15% of gross revenues less royalty payments.
- o Local ad valorem taxes are estimated to be 1% of the net present value of the resource as estimated for the Demonstration Project. This is estimated in the cash flow model by an iterative converging method because the net present value is itself dependent on the ad valorem tax expense.
- o California corporate income tax is estimated to be 9.6% of taxable income. Taxable income is gross revenues less expensed costs (i.e., intangible well costs), depreciation, royalties, depletion and ad valorem taxes. In pre-production years (i.e., pre-1985), deductions are assumed to be applied against unrelated income.
- o Investment tax credits, for Federal taxes only, are estimated to be 25% of capitalized costs. These credits comprise the regular 10% investment tax credit plus the 15% credit for qualified energy property.
- o Federal corporate income tax is estimated to be 46% of taxable income, less the abovementioned investment tax credits. For Federal tax purposes, taxable income is gross revenues less expensed costs, depreciation, royalties, depletion, ad valorem taxes and California income taxes. In pre-production years, deductions and credits are assumed to be applied against unrelated income and taxes.

- o Net after-tax income is estimated to be gross revenues less capitalized costs, expensed costs, royalties, ad valorem taxes, California taxes and Federal Taxes.

Internal rate-of-return, payback and net present value estimates are based upon the net after-tax income stream.

4.2.2 Analysis Results

To evaluate the Union geothermal fluid sales contract (per Ref. 12), a cash flow analysis and several parametric sensitivity analyses were performed for the well field. Cash flows are evaluated for a 15-year production period, which is the assumed economic life of the production and injection wells. Well replacement is assumed to be required, on the average, after this 15-year span.

As described earlier, gross revenue estimates in the cash flow are highly dependent upon four variables. For this analysis, the following values are assigned to these variables:

- o Plant capacity: 45 MWe (net)
- o Capacity factor: 70%
- o CPI escalation rate: 6%
- o Real fluid price escalation above the CPI rate: +2.2%

Table 4-2 presents the cash flow estimate for the Demonstration Project well field under these parameters.

Analysis of the net after-tax income stream reveals that the well field operators realize a 26% internal rate of return, 8 year payback, and \$30 million net present value of profits under these assumptions. Recent work by Technecon pertaining to geothermal investment decisions (see Ref. 5) indicates that these three attributes describe a reasonably attractive investment opportunity for major well field operators. The estimated investment returns appear reasonable, and not excessive, for a commercial geothermal venture.

4.2.3 Sensitivity Analysis

Because of the considerable uncertainties in key revenue variables such as plant capacity factor and inflation rates, we performed additional cash flow analyses to examine the sensitivity of rate of return, payback and net present value to these uncertain parameters. Throughout these sensitivity analyses, the net plant capacity is held constant at 45 MWe and

Table 4-2
HEBER DEMONSTRATION WELL FIELD CASH FLOW ANALYSIS

Plant Capacity: 45MWe(net)
Capacity Factor: 70%
General Inflation: 6%
Fluid Price Escalation: 8%

Year	Capital Cost	Expensed Cost	ACRS Dprcn	Gross Revenue	Royalty	Calif Depltn	Federal Depltn	Local Tax	Calif. Tax	Tax Credit	Federal Tax	Net Income
1982	2240	0	0	0	0	0	0	0	0	0	0	-2240
1983	9531	6561	0	0	0	0	0	0	-630	2383	-5111	-10351
1984	10293	7086	0	0	0	0	0	0	-680	2573	-5520	-11179
1985	5102	15306	2974	7109	889	1368	933	477	-1335	1276	-6857	-6472
1986	0	0	5127	7795	974	1501	1023	477	-27	0	102	6269
1987	0	0	5285	16678	2085	3210	2189	477	540	0	2807	10770
1988	0	0	5234	18664	2333	3593	2450	477	675	0	3448	11732
1989	0	0	5234	20186	2523	3886	2649	477	774	0	3923	12489
1990	0	0	1071	21833	2729	4203	2866	477	1282	0	6168	11177
1991	0	0	0	23613	2952	4545	3099	477	1501	0	7169	11515
1992	0	0	0	25539	3192	4916	3352	477	1628	0	7769	12473
1993	0	0	0	27621	3453	5317	3625	477	1764	0	8419	13509
1994	0	0	0	29874	3734	5751	3921	477	1912	0	9122	14629
1995	0	0	0	32310	4039	6220	4241	477	2071	0	9882	15841
1996	0	0	0	34945	4368	6727	4587	477	2244	0	10704	17152
1997	0	0	0	37795	4724	7275	4961	477	2431	0	11593	18570
1998	0	0	0	40877	5110	7869	5365	477	2632	0	12555	20103
1999	0	0	0	44210	5526	8510	5803	477	2851	0	13595	21762

Attributes: 26% After-Tax Internal Rate of Return
8 Year After-Tax Payback
\$30 Million After-Tax Net Present Value

the differential rate of escalation of fluid prices above general inflation is held constant at +2.2%.

Figures 4-3 and 4-4 present the results of sensitivity tests for internal rate of return and net present value, respectively. Payback time, the third attribute, was found to be relatively insensitive to these tests. Within the range of variables in these tests, the two investment attributes indicate an attractive opportunity for major corporate field operators. Returns appear reasonable through moderate levels of inflation and capacity factor.

As a final test, the well field operator's cash flow was re-estimated with the assumption that the plant would operate at full capacity (45 MWe net) from the date of synchronization (January 1985). This operating plan does not materially effect the return on investment likely to be realized by Union. The payback period is shown to be somewhat shorter because of the substantially increased revenues earned during the Demonstration Period. The net present value of profit and the internal rate of return are left virtually unchanged. The project's overall return on investment remains attractive, though not excessive, for a commercial geothermal venture.

Figure 4-3. SENSITIVITY OF NET PRESENT VALUE TO INFLATION AND CAPACITY FACTOR

Figure 4-4. SENSITIVITY OF RATE OF RETURN
TO INFLATION AND CAPACITY FACTOR

Chapter Five

ANALYSIS OF CREDITS

An important element of the Cooperative Agreement [19] is the Revenue Sharing provision which may allow DOE to recover 100 percent of its allowable costs (less costs for data acquisition and dissemination) over the demonstration and commercial operation phases of the project. Several credits have been proposed including:

- o Revenue Credits
- o Income Tax Credits
- o Resource Credit
- o Depreciation Charges

The following analysis will address each of the proposed credits in an effort to assess the magnitude of each, and the manner in which the credits can be equitably shared among project participants.

5.1 BACKGROUND

To properly assess the treatment of project-related credits, it is important to make frequent reference to the manner in which the California Public Utility Commission intends to treat several key issues. In the CPUC Decision Number 91271 [3], the Commission explicitly defined how project-related costs and benefits would be shared among SDG&E ratepayers and shareholders. In something of a landmark decision, the Commission allowed all of SDG&E costs to be recovered directly from its ratepayers as a Research Development and Demonstration (RD&D) Expense. The Commission predicated this finding on the basis that (1) a commercial-sized binary facility has never been built or operated and (2) SDG&E's financial situation was such that its financial health would be jeopardized if the Commission followed its "normal ratemaking practices" of treating the "construction-related portion of a demonstration project" as a capital investment financed out of the utility's capital budget.

The implications of this finding are critical to the analysis of project-related credits. SDG&E will recover, on a dollar-for-dollar basis, all of its project costs directly from its ratepayers. The firm's

stockholders will thus be subject to no project risk. The Commission ruled further that as "risk bearers" of the venture, the ratepayers share all benefits associated with the power produced from the project with DOE.

5.2 DISPLACED POWER COST (OR NET REVENUE) CREDIT

Once geothermal power is provided to the grid, SDG&E will be able to alter its dispatching schedule so that generation from more expensive oil or gas fired units is reduced. Such "avoided power cost" savings can then be made available to SDG&E ratepayers and DOE for reimbursement. The CPUC recognizes SDG&E's obligation to repay both DOE and SDG&E ratepayers. Two alternative methods of quantifying this credit are outlined below.

5.2.1 Spinning Reserve Rates.

The Cooperative Agreement correctly identified the basis of the credit as "gross revenue" less any geothermal fluid purchase expenses, plant O&M expenses, and power transmission expenses. Although the project-related expenses are readily quantified from available project documentation, we are not so readily able to provide "gross revenue" estimates. As specified in the Cooperative Agreement:

"Gross revenue" shall be the sum of the capacity value, if any, and the energy value. The capacity value shall be based on the rates per kilowatt per month established in the California Power Pool Agreement for capacity service from Spinning Reserve multiplied by the rated net output of the Project. The rated net output of the Project shall be established upon completion of the acceptance test. The energy value shall be based on the average price per kilowatt-hour of recorded transactions for energy associated with capacity service from Spinning Reserve multiplied by the total kilowatt-hour output of the Project for that quarter (Ref. 19, pg. 14).

Despite repeated attempts to obtain current "Spinning Reserve Rates" from FERC and California Power Pool Members, we have been unable to adequately quantify this rate.

Based on our investigations, we believe the rate agreement was last filed and approved by the Federal Energy Commission in 1964 (Pacific Gas and Electric Schedule #26). The rate is applied to generating units which are "on-line" but unloaded to provide emergency backup supplies. Such units are generally (but not always) the least expensive units not needed to meet load demand. The capacity payment is 10¢/kW-day, and has not been

changed since the 1964 rate hearing. Energy payments, on the other hand, are highly volatile, because time-of-day production costs vary widely. Our attempts to obtain copies of energy payment transaction prices from California Power Pool Members were unsuccessful. Until we are able to obtain historic energy payment rates, we will be unable to determine whether such a rate is equitable or to estimate the magnitude of gross revenues. A representative of a major California utility did, however, express the opinion that the spinning reserve rate was not an equitable basis for pricing power purchases because it does not reflect the utility's true costs of displaced generation. We recommend that DOE obtain from SDG&E an "Equivalent Average Annual Spinning Reserve Energy Rate" as observed from actual system performance over the last several years.

5.2.2 Avoided Cost Rates.

An alternative method of valuing the production cost of displaced power is at "Avoided Cost" rates. Mandated under the Public Utility Regulatory Policies Act (PURPA), this rate is the cost to a utility of generating the last kWh needed to satisfy load demands. Small power producers owning "Qualifying Facilities" should be eligible to sell power to local utilities at this rate. Like the "Spinning Reserve" rates cited above, payments are made for both energy and capacity, the former differentiated on a time-of-day basis. It is our opinion that valuing gross revenue credits at avoided cost rates is appropriate, at least until a determination can be made on the value and equity of spinning reserve rates. Anticipated gross revenues, valued under avoided cost pricing methods, will be a function of unit capacity (net), capacity factor, and future escalation rates. As shown in Table 5-1 and 5-2, gross revenue credits may range from \$25-80 million (current dollars) during the 27 month demonstration period, depending upon future price escalation rates and the electric energy produced by the project. These credit estimates are based upon SDG&E's published "avoided costs" for energy payments only and exclude the capacity payment component. Should the Demonstration Plant provide reliable baseload generation, then it may also qualify for capacity credits under the PURPA guidelines. Gross revenues would then be increased accordingly.

Table 5-1

EQUIVALENT ANNUAL ENERGY PRODUCTION:
 RATED NET CAPACITY vs. AVERAGE ANNUAL CAPACITY FACTOR
 (GWh)

Capacity Factor	Rated Capacity (MWe net)				
	25.0	30.0	35.0	40.0	45.0
30.0%	65.7	78.8	92.0	105.1	118.3
40.0%	87.6	105.1	122.6	140.2	157.7
50.0%	109.5	131.4	153.3	175.2	197.1
60.0%	134.5	157.7	184.0	210.2	236.5
70.0%	153.3	184.0	214.6	245.3	275.9
80.0%	175.2	210.2	245.3	280.3	315.3
90.0%	197.1	236.5	275.9	315.4	354.8

Table 5-2

ESTIMATED TOTAL GROSS REVENUE CREDIT
 EARNED OVER 27 MONTH DEMONSTRATION PERIOD
 (1,000 Dollars)

Average Annual Energy Output (GWh)	Assumed Revenue Escalation Rate					
	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%
120	25,400	26,200	27,200	28,100	29,100	30,100
160	33,800	35,000	36,200	37,500	38,800	40,100
200	42,300	43,700	45,300	46,900	48,500	50,100
240	50,700	52,500	54,400	56,200	58,200	60,200
280	59,200	61,200	63,400	65,600	67,900	70,200
320	67,600	70,000	72,500	75,000	77,600	80,200

5.2.3 Net Revenue Credit.

With gross revenues valued at SDG&E's avoided cost, net revenues available for DOE's cost repayment may be estimated. This credit comprises project gross revenues (defined above) less geothermal fuel costs and plant O&M expenses. Possible repayment schedules are provided in Figures 5-1 and 5-2 for cases of 45 MWe(net) and 40 MWe(net) plant ratings, respectively.

5.3 INCOME TAX DEDUCTIONS AND CREDITS

Construction and operation of the plant will have three major tax impacts on SDG&E ratepayers:

- o Increased tax liability during construction
- o Accelerated depreciation tax deductions during operation
- o Availability of a 10% Investment Tax Credit.

The impacts occur because SDG&E expenditures are partially capitalized for tax purposes rather than totally expensed per ratemaking directives. Roughly \$24 million of SDG&E's share of project costs will be capitalized and therefore eligible for accelerated depreciation and investment tax credits. However, SDG&E will be subject to increased taxes during the construction period because of this capitalization. Each of these tax implications is discussed below.

5.3.1 Increased Tax Liability.

Per CPUC directives, ratepayers will provide SDG&E revenue on a dollar-for-dollar matching basis. In CPUC Decision #91271 [3], this revenue inflow was estimated to be \$37.6 million. For computation of project-related taxes, however, the company estimated tax expense deductions of only \$13.6 million. The remaining \$24 million in revenues which match SDG&E's capitalized costs will be subject to tax. SDG&E reported that the increased tax liability of the company over the seven year period would be \$3.0 million. These costs are not chargeable to DOE but, rather, are assumed in their entirety by SDG&E ratepayers (per CPUC directive). These costs must eventually be repaid to the ratepayers from other project credits.

Figure 5-1.

PROJECTED COST RECOVERY SCHEDULE:

CUMMULATIVE RETURNS TO DATE

- 45 MWe Net -

Figure 5-2.
PROJECTED COST RECOVERY SCHEDULE:
CUMMULATIVE RETURNS TO DATE

- 40 MWe Net -

5.3.2 Accelerated Depreciation Deductions.

The \$24 million capitalized expenditure would qualify for accelerated tax depreciation under current Accelerated Cost Recovery Systems (ACRS) guidelines. This is only the capitalized share of SDG&E ratepayer's contribution, and excludes any DOE contributions. As stated during testimony before the CPUC, the ability to utilize these deductions effectively offsets the abovementioned increased tax burden incurred during the construction phase. Based on this assessment, it would appear that these tax deductions should not be shared with DOE as long as the incidence of higher taxes during the construction phase falls on SDG&E ratepayers.

5.3.3 Investment Tax Credit.

SDG&E would be eligible for the standard 10% investment tax credit on the \$24 million capitalized cost of its contributions to the project. However, the treatment of this credit is somewhat ambiguous. For example, it could be argued that if SDG&E would elect not to participate in the project, but instead pursue other investment alternatives to gain equivalent capacity, the investment tax credit would be available. If the \$2.4 million credit for the geothermal plant is to be shared with DOE, this would seem to needlessly penalize SDG&E ratepayers.

Viewed differently, however, the availability of the credit is made possible by the participation of DOE. The investment tax credit helps reduce the capital cost of the project, and thus enables the project co-sponsors to save on project contributions. As such, this "other revenue" source can be seen as a project cost refund that should be shared equally among SDG&E ratepayers and DOE. Further discussions with DOE and SDG&E are necessary before this matter can be satisfactorily be resolved.

5.4 RESOURCE CREDITS

New Albion Resources Company (NARCO) and Japatul Corporation are wholly-owned subsidiaries of SDG&E which deal in fuel resource and real estate transactions, respectively. Both of these SDG&E subsidiaries have been involved in the Heber Geothermal Unit Area and both could realize financial gains from the sale of geothermal fluid to the Demonstration

Plant. Any such financial gains should be credited to the demonstration project and shared among the project's supporters. Without going directly to SDG&E, there is insufficient information available at this time to determine the exact nature or amount of these potential credits.

According to SDG&E's Proposal to DOE of December 1979 (see Ref. 22, p. 1-5) then current lease ownership at the Heber Geothermal Unit Area comprised Chevron (61.03%), Union (29.74%) and NARCO (9.23%). Under common terms of a unit operating agreement, these firms would share costs and revenues associated with development and production of the geothermal resource in direct proportion to their percent lease holdings. Neither state nor Federal agencies have copies of the Heber unit agreement because there are no state lands involved and only a small parcel of Federal land (lease #CA-9062 issued in 1981). Federal agencies would have to approve the unit agreement only if greater than 50% of the lands involved were Federal.

SDG&E has reportedly recently sold its subsidiaries' interests in the Heber Geothermal Unit Area to Chevron and Union. DOE may wish to ascertain the dollar value of this transaction and then evaluate what, if any, portion of this value represents a gain to SDG&E attributable to present valuing of anticipated income from the demonstration project. It is likely that lease values at the Heber Area have benefitted from the planned sale of fluids to the Demonstration Plant. Any related asset appreciation that SDG&E may have realized in this recent sale could be viewed as a credit to the project and, therefore, subject to sharing with the other project supporters.

The California PUC has no information on this recent land transaction yet. However, they were able to advise us that Japatul's original land cost at Heber was \$165,381 and that NARCO, in early 1980, had \$1,200,000 invested at Heber (presumably for wells).

5.5 DEPRECIATION CHARGES DURING DEMONSTRATION PERIOD

The Cooperative Agreement states that DOE's "Reimbursement Amount" shall be reduced by any calculated depreciation during the demonstration period. The method of depreciation is defined to be double declining balance, amortized over the 25 year life of the project. The depreciation

clause appears to have been included in the agreement in response to the CPUC ruling regarding ratemaking treatment of the project. During discussions with CPUC representatives, it was their contention that DOE's contributions should be viewed as a capital investment. Such an investment would normally be subject to depreciation, and the "book value" of the asset correspondingly reduced yearly. Thus the book value of DOE's contribution would be diminished at the end of the demonstration period.

However, depreciation accounting is used as means of capital repayment, not asset valuation. Under normal accounting procedures, depreciation allows a firm to recover 100 percent of its initial investment over the life of the asset. If the depreciation clause remains unaltered in the Agreement, DOE's investment would not be fully recovered, with the unrecovered share accruing to SDGE ratepayers. Therefore, it seems that depreciation charges are groundless, and should be removed from the Agreement.

Chapter Six
ECONOMIC COMPARISON OF HEBER POWER PLANT
AND FOSSIL-FUELED BASE LOAD ALTERNATIVES

In the following analysis, the cost of power generated by the Heber Geothermal Power Plant is compared to that of newly constructed coal and oil fueled units. The comparison is made in terms of the levelized busbar cost of electricity from these power plants. A sensitivity analysis is presented to assess the relative competitiveness of the Heber plant if reductions in the construction cost, fuel cost, and operation and maintenance cost can be achieved.

6.1 METHODOLOGY

To assess the economic competitiveness of the Heber plant relative to fossil-fueled base load units, a "Revenue Requirements" technique is employed. This method provides comparisons of the revenues that must be earned to cover all costs associated with construction and operation over the economic life of each alternative. By identifying the investment alternative that will provide the least costly source of power, utility planners are better able to achieve one of their primary objectives -- that of minimizing customer rates.

As shown in Figure 6-1, revenue requirements are composed of both fixed and variable cost components. The fixed component is made up of costs associated with the initial capital outlay, including (1) depreciation (or capital repayment), (2) debt and equity returns (or return on capital), (3) taxes on investment return, and (4) provisions for insurance and miscellaneous taxes. Variable costs include expenditures required for fuel, operation and maintenance expenses. Unlike fixed costs which are recovered as a constant obligation throughout the life of the investment, variable costs are subject to annual escalation.

Because year-by-year revenue requirements are composed of a constant fixed cost and an escalating variable cost, a levelized revenue requirement is often used to facilitate comparison of alternatives. A levelized revenue requirement is a constant annual amount, the present value of

Figure 6-1.
REVENUE REQUIREMENT COMPONENTS

which, if collected over the life of the investment, would equal the present value of the actual escalating year-by-year revenue requirement. By condensing the results of a year-by-year revenue requirement analysis into a single levelized value, economic comparisons of investment alternatives are easily made.

In evaluating the levelized annual revenue requirements of the Heber and fossil-fueled power plants, the computational procedure recommended by the Electric Power Research Institute was adopted. This is a methodology commonly used by the utility industry today. The equations used in the computation are not reproduced here, but may be found in the EPRI Technical Assessment Guide [10].

6.2 BASE CASE ANALYSIS

The general assumptions used in this analysis are presented in Table 6-1. The economic comparison assumes a 1985 startup for all plants. The analysis is performed in terms of current dollars and normalized treatment of tax preference allowances is assumed in all cases. Hydrothermal power plant performance data, provided in Table 6-2, are based on SDG&E's Request for Consent document [18]. To maintain consistency in the comparisons, the hydrothermal plant is assumed to operate at full capacity from 1985 (rather than with a gradual capacity buildup). Data for both a coal-fired and residual oil burning base load plant were obtained from EPRI's Technical Assessment Guide [9]. Capital and delivered fuel costs for both plants have been adjusted for a "Pacific" or "Western" plant site.

As shown in Figure 6-2, the estimated levelized busbar cost of the hydrothermal plant totals 33.0¢/kWh (1985 startup, current dollars). Of this cost, 13 percent is allocated to fixed costs, 49 percent to fuel costs, and 38 percent to power plant and well field operation and maintenance expenses. Also shown in Figure 6-2 is the expected rate of increase in the year-by-year revenue requirements. As noted, both fuel and operation and maintenance costs increase substantially over the period, rising at an assumed escalation rate 2% above the Consumer Price Index.

Figure 6-3 provides a comparison of levelized costs of the Heber plant relative to fossil-fueled alternatives. The coal power plant (with flue gas desulfurization) is shown to be the least costly of the three

Table 6-1
ECONOMIC AND FINANCIAL PARAMETERS¹

Financial Variables

Cost of Common Stock	15.3%/Yr
Cost of Preferred Stock	11.5%/Yr
Cost of Long Term Debt	11.0%/Yr
Common Stock Fraction	35.0%
Preferred Stock Fraction	15.0%
Long Term Debt Fraction	50.0%

Tax Variables

Power Plant Book Life	30 years
Power Plant Tax Life	20 years
Corporate Income Tax Rate	50.0%
Investment Tax Credit Rate	10.0%

Annual Escalation Rates

Consumer Price Index	8.5%
Coal	10.0%
Residual Fuel	11.5%
Conventional Plant O&M Costs ²	8.5%
Diesel Fuel ²	12.5%
Petroleum Industry Wages ²	8.5%
Oil Well Casing (Alloy) ²	11.5%
Cement ²	8.5%
Well Field Machinery (Misc.) ²	12.0%

¹Parameters are based on EPRI Technical Assessment Guide (1982) unless otherwise noted.

²Projections by Technecon Analytic Research, Inc. based upon trends observed in U.S. Bureau of Labor Statistics price indices.

Table 6-2
POWER PLANT PERFORMANCE PARAMETERS

	Hydrothermal ¹ Plant	Coal Plant ² (with FGD)	Residual Oil Plant ²
Capital Cost (\$/kW)	1860	1670	1000
Capacity Factor	.77	.75	.80
Fuel Commodity Charge (mills/kWh)	13.47	26.5	77.1
Fuel Demand Charge (\$/kW)	286.61	0	0
Variable O&M (mills/kWh)	15	5.27	2.20
Fixed O&M (\$/kW)	195	22.75	2.40

¹Based on Request for Consent Document (1982). Fixed and variable O&M cost include the estimated "Most Probable" well field O&M passthrough.

²EPRI Technical Assessment Guide (1982).

Figure 6-2.
'LEVELIZED POWER PLANT COST AND
YEAR-BY-YEAR REVENUE REQUIREMENTS
FOR THE HEBER PLANT (1985 Startup)

Figure 6-3.
LEVELIZED ANNUAL BUSBAR COST OF THE HEBER PLANT
VERSUS CONVENTIONAL BASE LOAD POWER PLANTS,
(1985 Startup)

alternatives. At a levelized cost of 12.4¢/kwh (current dollars), the coal alternative is less than one half the cost of the Heber plant. The residual oil fueled plant is shown to be the second most expensive base load alternative at a cost of 30¢/kwh (current dollars). This is due to the very high market price of residual oil fuel today, and the 3.0% per year real price increases anticipated in the future. An examination of the estimated year-by-year revenue requirements (as shown in Table 6-3) clearly indicates the adverse impact that real escalation has on the fuel cost of each of the three alternatives.

Based on the above analysis, the hydrothermal plant, under base case assumptions, is not competitive with a coal plant as a base load alternative. As noted, the inability of the Heber plant to produce power at costs approaching those of new coal units cannot be traced to a single revenue requirement component. All three components -- fixed, fuel, and operation and maintenance -- are found to be above those of the coal unit.

The fact that the Heber plant is expected to be only slightly more expensive than an oil fueled base load unit should be viewed with some optimism. As noted in Part I, Chapter 2, of this report, public utility commissions currently appear willing to approve operation of hydrothermal plants if power can be generated at costs approximating that of oil or gas-fired units. Areas of likely cost reduction in the Heber design, and their impact on generation economics, are addressed in the following sections of this report.

6.3 SENSITIVITY ANALYSIS

To evaluate the extent to which the economics of the Heber plant could be enhanced if certain cost reductions could be achieved, key cost parameters were adjusted, and the Heber busbar cost was re-estimated. The results of this analysis are reported below.

As shown in Table 6-4, the competitiveness of the Heber plant does not appear to be highly sensitive to variations in the capital cost. If the capital cost could be reduced by 25% of the base case estimate, an improvement of only 3.4% in the busbar cost would be achieved. Alternatively, if the additions in construction cost identified in the United Engineers & Constructors, Inc. report (see Chapter Two) are

Table 6-3
COMPARISON OF YEAR-BY-YEAR REVENUE REQUIREMENTS
HEBER PLANT VERSUS FOSSIL-FUELED BASE LOAD ALTERNATIVES

	Year-By-Year Revenue Requirement (mills/kWh)				
	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>	<u>2005</u>
Heber Plant					
Fixed Cost	45.0	45.0	45.0	45.0	45.0
Fuel Cost	56.0	93.0	154.0	256.0	424.0
O & M Cost	44.0	72.0	119.0	195.0	320.0
Total	145.0	210.0	318.0	496.0	789.0
Coal Plant					
Fixed Cost	41.0	41.0	41.0	41.0	41.0
Fuel Cost	24.0	38.0	60.0	94.0	148.0
O & M Cost	8.0	13.0	20.0	30.0	44.0
Total	73.0	92.0	120.0	160.0	233.0
Residual Oil Plant					
Fixed Cost	23.0	23.0	23.0	23.0	23.0
Fuel Cost	77.0	133.0	229.0	395.0	680.0
O & M Cost	3.0	5.0	7.0	10.0	15.0
Total	103.0	161.0	259.0	428.0	718.0

Table 6-4
LEVELIZED BUSBAR COST SENSITIVITY ANALYSIS
HYDROTHERMAL VERSUS FOSSIL-FUELED BASE LOAD ALTERNATIVE

	Fixed Cost	Fuel Cost	O&M Cost	Total Cost
Coal (with FGD) Plant	41.8	63.6	19.1	124.5
Residual Oil Plant	23.5	267.8	5.8	297.1
Heber Plant (Base Case)	45.3	161.4	123.1	329.8
<u>Capital Cost Variation</u>				
UEC Estimate	58.5	161.4	123.1	343.0
25% Below FPS Estimate	31.0	161.4	123.1	318.5
<u>Fuel Cost Reductions</u>				
15% Reduction	45.3	137.2	123.1	305.6
30% Reduction	45.3	112.9	123.1	281.4
<u>O&M Cost Reduction</u>				
15% Reduction	45.3	161.4	104.6	311.4
30% Reduction	45.3	161.4	86.2	292.9
<u>Escalation Rate Reductions</u>				
0% Real Escalation of Fuel and O&M	45.3	121.7	95.5	262.6

required, the levelized cost would increase by a relatively modest 4.0 percent. Reductions in the operation and maintenance cost of 15 and 30 percent would improve the economic performance by 5.6 and 11.2 percent, respectively, over the base case. If the heat sales agreement could be renegotiated at a lower cost, somewhat greater improvements could be realized. Reducing the fuel cost (demand and commodity) by 15% would enable a busbar cost of 30.6¢/kwh to be achieved. If a 30% decrease in the fuel cost were possible, the levelized cost would be lowered to 29.3¢/kwh -- a 14.7 percent improvement over the base case. Finally, the impact of changing the fuel and operation and maintenance escalation provisions in the contract was examined. If no real escalation, above that of the Consumer Price Index, was allowed in the fuel price or O&M pass-through, the busbar cost would be reduced by over 20 percent to 26.3¢/kwh.

6.4 CONCLUSION

Based on the analysis presented above, it appears that the Heber binary cycle design will provide a viable economic alternative to oil-fired base load units. Although an aggressive cost-cutting program in the areas of capital cost and operation and maintenance costs would bring about relatively minor improvements in the plant's economic performance, somewhat more substantial gains could be realized if a less expensive heat sales agreement could be negotiated.

The extent to which fuel prices can be lowered, while still assuring the participation of the resource developer, may be limited. If, as in the preceding example, the fuel cost were reduced by 15 or 30 percent, the internal rate of return earned on the resource developer's investment would fall from 27 percent in the base case to 25 or 22 percent, respectively. Based upon Technecon's previous analyses of well field investment decisions, these lower rates are still likely to be attractive to field developers (see Ref. 5). Investment returns will likely be viewed as marginal, however, if an effort is made to further reduce fluid sales revenues to enhance the competitiveness of the Heber plant.

Chapter Seven
ANALYSIS OF CAPITAL COST SAVINGS ASSOCIATED
WITH FACILITY OF PROVEN DESIGN

The Heber Demonstration Power Plant is designed as a research and development facility, the operation of which is expected to demonstrate the commercial viability of the binary system design. It is likely that the plant design may incorporate a number of contingency factors or equipment redundancies that may not prove necessary once power generation begins. Costs for some electrical or mechanical plant components may also include a premium to account for unique start-up cost associated with design and manufacturing of a "first-of-its-kind" plant component. Technecon employed the firm of United Engineers and Constructors (UEC) to examine the relative cost savings for a second "mature" plant of the same capacity located adjacent to the Heber Demonstration Facility but constructed as a proven design rather than as an R&D design. The comments of UEC are summarized below.

UEC reported that it is likely some contingency factors have been incorporated in the plant design because of the uncertainties associated with an R&D facility. For example, heat exchanger surfaces, pump capacity, or pipe diameters may be sized conservatively for the demonstration plant to allow for uncertain operating conditions. Extra instrumentation, beyond that required for normal plant operation, may be specified to obtain data for scientific purposes and to specially monitor and evaluate plant performance. Spare conduit and wiring may also be installed to ensure its availability if the need arises.

UEC reported, however, that only operation of the plant will demonstrate whether or not such design contingencies will be required. Their review of the Definitive Cost Estimate [17] and its backup did not disclose any obvious areas where sizes, quantities, or labor requirements had been inflated in recognition of the R&D nature of the Heber Demonstration Plant.

UEC reported that some features of the R&D plant would not require duplication for a plant at an adjacent site. Gate house, shop and

warehouse, some perimeter fencing, office space, etc. are examples of such facilities. However, the cost associated with these items is small relative to total plant cost. UEC noted that there may also be some reduction in the cost of Phase II engineering and design services, especially if the same personnel are involved. They caution, however, that this assumption is probably not practical, and that significant cost savings would probably not materialize. Finally, no cost savings are anticipated in the area of construction management. Based on the experience of UEC, the cost of construction management is usually directly proportional to the construction duration. UEC believes that the schedule for the second plant would be roughly the same, therefore producing no cost reductions.

Cost savings may be readily identified in the Phase I costs. UEC reported that a significant portion of these costs may be eliminated, primarily in preliminary engineering, design, procurement, and construction management. In all, Phase I costs total almost \$15 million, or 18 percent of the capital costs of the Heber Demonstration Plant.

It does not appear likely that a "mature" geothermal plant of the Heber-type binary design can economically compete with coal-fired generation. However, as discussed earlier in Section 6.3, only minor cost reductions may render a plant of the Heber design marginally competitive with an oil-fired power plant. Based upon this analysis, capital cost reductions attributable to a second "mature" plant would enable this form of geothermal generation to economically compete with oil-fired generation.

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