A Comparative Analysis of Energy Costing Methodologies

Appendix: Report on Levelized Busbar-
Costing Workshop Held at
MITRE / Metrek, June 29 & 30, 1978

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ABSTRACT

This document describes the proceedings of a workshop on leveled busbar costing methodologies which was held at MITRE/Metrek on June 29 and 30, 1978. The workshop was sponsored by the Division of Geothermal Energy within the Department of Energy and particular emphasis was placed on consideration of geothermal energy sources. The objective of the workshop was to determine whether a consensus could be developed regarding the most appropriate methodologies and assumptions for leveled energy costing. The workshop was attended by representatives from energy resource, utility and engineering design companies, and by representatives of the Division of Geothermal Energy and R&D contractors for this Division.

It was found that year-by-year calculations in current dollars were generally preferred, using either Discounted Cash Flow or Revenue Requirements methods. No consensus emerged on choice of discount rate or financial parameters such as debt/equity ratio, and tax credit carry forward/carry back provisions. It was felt that engineering aspects deserve close attention.

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1.0 INTRODUCTION

1.1 Background

In 1977, the Division of Geothermal Energy (DGE) in the Department of Energy asked MITRE/Metrek to examine different methodologies which were in use for projecting expected costs of electricity from geothermal sources. This request was motivated by the discovery that radically different electricity costs were being projected by different organizations for the same geothermal and conventional (i.e., coal and nuclear) energy sources. This finding generated some concern because reliable cost projections are fundamental to the proper direction and management of DGE's programs in fiscal incentives, RD&D and loan guaranties.

During this work, MITRE/Metrek compiled and analysed the financial methodologies and assumptions used by 14 organizations active in the geothermal field. These organizations included energy resource companies, electric utilities, engineering companies, and R&D contractors for DGE. The detailed results of this investigation have been published.* Here, it is sufficient to note that it rapidly became apparent that differences in financial methodologies and assumptions could lead to projected electricity costs differing by a factor of 2 for identical physical geothermal resources and generating plants.

*See the main volume of this report.

The preliminary results of this work were circulated to DGE and the participating organizations during the early part of 1978. Because of the response generated, it was decided to hold a workshop for representatives from these organizations, in order to obtain the benefit of face-to-face interchange and discussion. The workshop objective was to, if possible, reconcile differences between approaches and to develop recommendations to DGE for preferred methods and assumptions. The workshop was held at MITRE/Metrek on June 29 and 30, 1978. A list of attendees is given in Attachment A.

1.2 Organization of This Report

The main body of this report (Section 2) consists of synopses of discussions which took place during the workshop. These have been organized into topics which represent areas where significant choices have to be made in developing a financial methodology. The topics are:

- Choice of Methodological Approach
- Treatment of Inflation
- Selection and Use of Discount Rate
- Choice of Depreciation Method
- Other Financial Assumptions and Parameters
- Engineering Aspects

In addition to summarizing, as far as possible, the differing views expressed by workshop participants, MITRE/Metrek has attempted to give the consensus of the group in cases where this was felt to

exist. It must be emphasized that this material represents MITRE/Metrek's impressions only, and has not been formally reviewed by the other workshop participants. However, every effort has been made to present differing opinions fully and fairly.

Section 3 of this report contains a list of recommendations which emerged from the workshop, and, finally, Attachments A and B contain a list of participants and copies of materials presented, respectively.

2.0 WORKSHOP DISCUSSIONS

For ease of presentation, the wide-ranging discussions which took place during the workshop sessions have been summarized under a number of separate headings covering the major topics of importance. These synopses are presented in this section. Conclusions and recommendations are summarized in Section 3.

2.1 Choice of Methodological Approach

There are several possibilities for the choice of the basic methodological approach or structure of the financial model. These include the use of year-by-year calculations versus the use of closed-form equations, and the use of discounted cash flow (DCF) methods versus the use of revenue requirements (RR) methods.

Year-by-year calculations, as the name implies, involve the successive calculation of expenditures (capital, O&M costs, etc.), depreciation, taxes, etc. for each year of the project (including pre-start-up investment). Levelization of the cash flow or cost stream is carried out to arrive at a levelized cost. In contrast, closed-form methods employ algebraic equations to express the present values of all costs, revenues, taxes, etc., relying upon the substitution of particular values in the equations to evaluate specific cases.

Year-by-year calculations are more flexible and can be more detailed than closed-form methods, and they can capture procedures which would be cumbersome to express mathematically. An example is

the common practice of switching from double declining balance to straight line depreciation half way through the project life. This is easy to do in year-by-year calculations, but awkward to handle as a closed form equation. Year-by-year methods also generally make more information available. However, closed-form methods generally require less computation. It was the feeling of the participants that year-by-year methods are preferable.

DCF methods generally compute the present value (in the start-up year) of the cash flow associated with the projects. It is usual to choose a price (i.e., levelized cost) which makes the present value of the cash flow zero. RR methods, on the other hand, work from a knowledge of the expected costs (including "profit" or returns to equity), and then derive the revenue which would cover these costs. Thus the profits are explicitly built in, while in DCF methods profits are implicitly present in the choice of discount rate.

There was little agreement as to whether DCF or RR methods were preferable. It appears that utility companies tend to use RR, while energy resource companies tend to use DCF. It is probably true that DCF represents a more sophisticated approach to the problem, since this technique was historically developed later than RR. It may well be that the choice may depend on the organization being modelled (to reflect the perceptions of that organization). However, this is hardly appropriate for a national effort such as DGE's. It has been shown that, if all parameters including especially discount rate, are

correctly chosen, then DCF and RR lead to equivalent results*.

Failing this, a possible compromise would be to perform RR calculations, but also give the internal rate of return to which these lead.

Under the circumstances, MITRE/Metrek feels that no consensus emerged from the workshop on this point.

On further methodological questions, the participants felt very clearly that the development of geothermal resources would be split between field developers and utility-type companies, and the view was expressed that different financial approaches might be appropriate for these organizations. In particular, DCF might be used for the field developer, and RR for the utility.

2.2 Treatment of Inflation

The participants felt that inflation will continue to be an important factor in financial calculations for the foreseeable future, and that any methodology used must have the capability of accurately accounting for its effects. It was felt that the preferred method of achieving this would be to perform (year-by-year) calculations in current (i.e., inflated) dollars. The alternative method of making computations in constant (uninflated) dollars was felt to require too many counter-intuitive actions to be easily applicable. For instance, when working in constant dollars, inflation cannot simply be ignored, because the depreciation schedule is fixed in current dollars and

* See Attachments.

therefore must be deflated, or reduced in value by the amount of inflation.

2.3 Choice of Discount Rate

The discount rate to be used in the levelizing calculations is one of the most important parameters in the financial model. It was generally recognized that the discount rate should be calculated on the basis of the financial structure and costs of the organization under consideration. This calculation, however, may be performed with or without considering the income tax deduction available from interest payments. The after-tax discount rate may be expressed as:

$$R_1 = (1 - t) d r_d + (1 - d) \tau_e$$

where t = effective income tax rate

d = proportion of debt (hence $1 - d$ = proportion of equity)

r_d = interest rate on debt

τ_e = required rate of return to equity.

The without-tax discount rate is given by:

$$R_2 = d r_d + (1 - d) \tau_e$$

It can be seen that R_1 will always be smaller than R_2 , if d is non-zero. Hence, assuming a cash-flow pattern which is initially heavily negative (due to e.g., investment in plant), the use of R_1 will lead to a lower levelized cost. (Numerical calculations indicate that the difference in costs could be larger than 15% for typical cases).

There was no clear consensus among the workshop participants as to whether R_1 or R_2 should be used. It appears that a majority of utility companies use R_2 ; the position in other industries is unknown.

The use of R_1 is valid only if the organization has sufficient income to take advantage of the interest tax deduction. However, under those circumstances it represents the true cost of capital better than R_2 .

2.4 Depreciation Method

The clear feeling of the workshop participants was that the fastest possible depreciation schedule should be adopted for tax purposes. This will generally either be double declining balance, changing to straight line half way through the project tax depreciation life, or sum-of-the-year's-digits.

Equipment lifetimes for tax depreciation purposes are not clear, since IRS has no rulings or guidelines for geothermal energy. Currently, IRS will allow 28 years $\pm$ 25% for steam plant depreciation life.

2.5 Other Financial Assumptions and Parameters

Parameters of prime concern here include debt/equity ratio, rate of return to equity, and interest rate on debt. Other elements of interest are tax rates (for both income and property taxes), inflation rates, and treatment of tax credits (e.g., depletion allowance, investment tax credit, etc.).

Two distinct views were expressed by the workshop participants

concerning the proper debt/equity ratio for the field developer. Large energy resource companies, it was felt, will operate with debt/equity ratios of about 25/75 or lower. On the other hand, smaller developers, especially if covered by the loan guaranty program, may well have debt/equity ratios near 75/25, since the conditions of the loan guaranty program allow the proportion of equity capital to be as low as 25%.

No reconciliation of these views was possible. It was felt that the choice of debt/equity ratio for the developer should depend on the particular circumstances under consideration.

There was general agreement that debt/equity ratios of roughly 50/50 are appropriate for utilities. It must be noted that the equity portion is often divided into common and preferred equity, and the different rates of return for these types of stock must be taken account of when calculating the discount rate. Weighted (pre-tax) costs of capital of 15% to 20% were suggested for large energy resource companies, and 10% to 12% for utilities. These rates may change in the future as the result of changes in general financial conditions.

The treatment of tax credits may depend upon the size of the organization being considered. Small companies with limited incomes may be forced to defer tax credits acquired during the development phase until after plant start-up, when income will be available, while large companies can use credits against income from other ongoing projects. Because of discounting and inflation, deferred credits

are less valuable than ones taken immediately, so that smaller companies will tend to have higher costs.

Conversely, smaller companies engaged in oil and gas production are at present eligible for higher depletion allowances than larger companies.

Due to pending legislation, the exact tax credits and deductions which would be applicable to geothermal energy after 1978 were unknown at the time the workshop was held.

No consensus emerged from the workshop as to preferred assumptions and methods for handling tax credits. It was felt that the choice should be dependant upon the particular case under consideration. However, it was felt that assumptions used in analyses should be clearly stated in published material.

2.6 Engineering Aspects

It was recognized by the participants that the methodological questions involved in plant design and cost estimation are as complex and as important as those involved in financial analysis. It was generally felt that a subsequent workshop could profitably be held to discuss engineering matters, such as field productivity and life, equipment lives, thermodynamic design methods, component cost estimating, and O&M costs.

No detailed discussions took place in any of the above areas, except for well lives, and well replacement schedules.

Insofar as any consensus emerged, the feeling seemed to be that

well lives would be at least 10 years, and that replacements would be necessary according to some relatively unpredictable decay/failure curve for wells. It was felt that a uniform rate of well replacement was too pessimistic in that probably fewer replacements would be needed in the early years of operation, but that lumped replacement with all wells failing more-or-less together at the end of their life would be too optimistic, because wells could decline in productivity earlier.

3.0 CONCLUSIONS AND RECOMMENDATIONS

The following conclusions emerged from the workshop sessions:

- (1) The Division of Geothermal Energy at a minimum, and preferably the Department of Energy as a whole, should establish a standard financial analysis methodology for use by all its contractors (the use of the standard methodology would be in addition to the use of whatever methodology the contractor chose for internal decision making).
- (2) This methodology should take the basic form of a year-by-year calculation method, with costs being expressed in current dollars. Either discounted cash flow or revenue requirements methodology would be generally acceptable.
- (3) Where possible, guidelines should be established by DGE or DOE regarding the choice of financial parameters such as discount rate debt/equity ratio, treatment of taxes and tax credits, and equipment lifetimes, since widespread differences exist regarding preferred choices for these highly significant parameters.
- (4) A similar workshop should be held to consider engineering aspects of geothermal electric generation, with particular emphasis being placed on thermodynamic design methods and cost estimating methods.

ATTACHMENT A
LIST OF ATTENDEES

LIST OF ATTENDEES
LEVELIZED BUSBAR COSTING METHODS WORKSHOP

The MITRE Corporation

June 29-30, 1978

<u>NAME</u>	<u>ADDRESS</u>
KEITH MCKINNON	SDG&E P.O. Box 1831 San Diego, California 92112
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ATTACHMENT B
PAPERS PRESENTED
AT THE WORKSHOP

(Some items retyped for clarity)

BECHTEL NATIONAL INC.

RESEARCH & ENGINEERING

L I F E C Y C L E C O S T I N G

U S I N G T H E

R E S O U R C E P R O G R A M

JUNE 1978

BECHTEL NATIONAL INC.

RESEARCH & ENGINEERING

INTRODUCTION

Bechtel National Inc. has been involved in the engineering and economic evaluations of many geothermal facilities. The capital cost and operating costs estimated are combined to yield the busbar cost of electric energy, using an interactive computer system for calculations. The Cost Engineering group has recently developed a life cycle costing computer program RESOURCE (Revenue from Energy Sales Of Utility to Recover Capital and Expenses) to achieve this.

Life cycle costing methods usually differ from utility to utility, as there are many ways to analyze the cash flows. In order to deal with the various utility models, many computational options have been built into the RESOURCE program. At the discretion of the program user, calculation is made according to one of the wide variety of common life cycle costing models.

The following description outlines the basic features of RESOURCE, its capabilities and its output.

PROGRAM OUTPUT

RESOURCE calculates the levelized production cost of energy and expresses the results both in thousands of dollars per year and mills per kilowatt-hour. The levelized energy cost is the amount of revenue which over the plant life would exactly compensate for the recovery of all invested capital, the required return on investment and the payment of all taxes and expenses.

The types of capital involved in capital recovery and return on investment are:

- o bonded debt
- o preferred equity
- o common equity

The various types of taxes and insurance included are:

- o federal income tax
- o state income tax
- o ad valorem property tax
- o revenue tax or royalty
- o property insurance

The various types of expenses included are:

- o operation and maintenance
- o administrative and general
- o fuel
- o other expenses

The program output consists of three yearly cash flow tables and a summary. Cash flow Table 1 is the Capital Balance Sheet which shows the yearly capital return and recovery. The following is an example of the Table 1 output.

CASH FLOW TABLE 1. CAPITAL BALANCE SHEET
 **** *

Year	Capitl Invest	Debt Intrst	Prefer Equity	Common Equity	Total Return	Capitl Recvry	Yr-End Balance	Subttl Cost
1977	19,048	857	257	933	2,048		21,095	
1978	30,000	2,299	690	2,504	5,493	5,831	45,264	11,324
1979	0	2,037	611	2,218	4,866	1,171	44,094	6,037
1980	0	1,984	595	2,161	4,740	1,059	43,035	5,799
1981	0	1,937	581	2,109	4,626	987	42,048	5,613
1982	0	1,892	568	2,060	4,520	954	41,093	5,474
1983	0	1,849	555	2,014	4,418	959	40,134	5,377
1984	0	1,806	542	1,967	4,314	1,001	39,133	5,316
1985	0	1,761	528	1,918	4,207	1,080	38,053	5,287
1986	0	1,712	514	1,865	4,091	1,197	36,856	5,287
1987	0	1,659	498	1,806	3,962	1,478	35,379	5,440
1988	0	1,592	478	1,734	3,803	1,803	33,576	5,606
1989	0	1,511	453	1,645	3,609	2,165	31,411	5,774
1990	0	1,414	424	1,539	3,377	2,568	28,844	5,945
1991	0	1,298	389	1,413	3,101	3,016	25,828	6,116
1992	0	1,162	349	1,266	2,777	3,512	22,316	6,289
1993	0	1,004	301	1,093	2,399	4,063	18,253	6,462
1994	0	821	246	894	1,962	3,661	14,592	5,623
1995	0	657	197	715	1,569	4,250	10,342	5,819
1996	0	465	140	507	1,112	4,814	5,528	5,926
1997	0	249	75	271	594	5,528		6,122

Cash flow Table 2, Taxes and Insurance, shows in its various columns the income taxes, local taxes and insurance. A sample printout of Table 2 is shown below.

CASH FLOW TABLE 2. TAXES AND INSURANCE

**** ***** * ***** *** *****

Year	FD-TAX DEPREC	ST-TAX DEPREC	INV-TX CREDIT	FED IN-TAX	STATE IN-TAX	REVENU TAX	PROPTY TAX	INSURE PREMIUM	SUBTTL COST
1978	6,131	5,450	4,905	-7,553	- 478	78	1,022	182	-6,829
1979	5,365	4,844	0	-1,260	- 208	82	1,022	97	- 267
1980	4,694	4,306	0	- 812	- 129	86	1,022	92	259
1981	4,107	3,828	0	- 397	- 54	90	1,022	87	747
1982	3,594	3,402	0	- 11	17	94	1,022	82	1,204
1983	3,145	3,024	0	353	85	99	1,022	77	1,636
1984	2,752	2,688	0	700	150	104	1,022	72	2,048
1985	2,408	2,390	0	1,032	214	109	1,022	66	2,445
1986	2,107	2,124	0	1,355	278	115	1,022	61	2,831
1987	2,107	1,888	0	1,546	340	121	1,022	56	3,084
1988	2,107	1,888	0	1,760	384	127	1,022	51	3,344
1989	2,107	1,888	0	1,991	432	133	1,022	46	3,623
1990	2,107	1,888	0	2,238	483	140	1,022	41	3,923
1991	2,107	1,888	0	2,503	537	147	1,022	36	4,245
1992	2,107	1,888	0	2,788	596	154	1,022	31	4,590
1993	2,107	1,888	0	3,093	659	162	1,022	26	4,961
1994	0	1,888	0	4,432	727	170	1,022	20	6,371
1995	0	1,888	0	4,765	795	178	1,022	15	6,775
1996	0	0	0	5,040	1,038	187	1,022	10	7,298
1997	0	0	0	5,422	1,117	196	1,022	5	7,762

Cash flow Table 3, Expenses and Revenue, shows the various operating expenses, total revenue requirements and present worths. The following is a sample Table 3 printout.

CASH FLOW TABLE 3. EXPENSES AND REVENUE
 **** *

YEAR	OPERAT & MAIN	ADMIN & GEN	FUEL COST	OTHER EXPENS	SUBTTL COST	TOTAL REVENU	P-W FACTOR	REVENU P-W	CUMMUL P-W
1978	1,022	255	1,000	1,000	3,277	7,772	.92268	7,171	7,171
1979	1,073	268	1,050	0	2,391	8,161	.85135	6,947	14,119
1980	1,127	282	1,103	0	2,511	8,569	.78552	6,731	20,849
1981	1,183	296	1,158	0	2,636	8,997	.72479	6,521	27,370
1982	1,242	311	1,216	0	2,768	9,447	.66875	6,318	33,688
1983	1,304	326	1,276	0	2,907	9,919	.61705	6,121	39,809
1984	1,369	342	1,340	0	3,052	10,415	.56934	5,930	45,738
1985	1,438	359	1,407	0	3,205	10,936	.52532	5,745	51,483
1986	1,510	377	1,477	0	3,365	11,483	.48471	5,566	57,049
1987	1,585	396	1,551	0	3,533	12,057	.44723	5,392	62,441
1988	1,665	416	1,629	0	3,710	12,660	.41265	5,224	67,665
1989	1,748	437	1,710	0	3,895	13,293	.38075	5,061	72,727
1990	1,835	459	1,796	0	4,090	13,957	.35131	4,903	77,630
1991	1,927	482	1,886	0	4,294	14,655	.32415	4,750	82,380
1992	2,023	506	1,980	0	4,509	15,388	.29909	4,602	86,983
1993	2,124	531	2,079	0	4,735	16,157	.27596	4,459	91,442
1994	2,231	558	2,183	0	4,971	16,965	.25463	4,320	95,762
1995	2,342	586	2,292	0	5,220	17,814	.23494	4,185	99,947
1996	2,459	615	2,407	0	5,481	18,704	.21678	4,055	104,001
1997	2,582	646	2,527	0	5,755	19,639	.20002	3,928	107,929

The final table, Summary, shows the levelized costs of individual items as well as the total levelized cost of electric energy. When escalation of energy cost is taken into account in the calculations, the levelized energy cost will be expressed in terms of the initial cost.

SUMMARY TABLE OF LEVELIZED COSTS
 ***** ** *****

<u>COST ITEM</u>	<u>SK/YR</u>	<u>(MIL/RWH)</u>
Return on Investment	2,759	8.39
Capital Recovery	1,529	4.65
Income Taxes	314	.96
Gross Revenue Tax	78	.24
Property Tax	703	2.14
Property Insurance	46	.14
Operation & Maintenance	1,022	3.11
Administration & General	255	.78
Fuel	1,000	3.04
Other Expenses	66	.20
TOTAL ENERGY PRODUCTION COST	7,772*	23.65*

*First year cost, i.e., Year 1978 Level Cost

AFDC = 2048 Including interest = 857

Iterations = 17

PROGRAM INPUT

RESOURCE is a flexible program which provides various options for treating capital recovery, discount rate, tax depreciation, AFDC, etc. The user selects a specific methodology by his interactive input to the computer. The options established are described below.

Capital Recovery Options

- o Use the sinking fund method for book depreciation and calculate the uniform revenue requirement.
- o Use the straight-line method for book depreciation and calculate revenue requirements year by year.

Discount Rate Options

- o Use the after-tax discount rate, ie., the rate of return on investment less the tax credit for interest.
- o Use the rate of return on investment as the discount rate.
- o Use a discount rate specified by the user.

Income Taxes Options

- o Allow negative income taxes in the calculations.
- o Allow tax losses and unused investment tax credit to be carried over to subsequent years in accordance with IRS guidelines.

Tax Depreciation Options

- o Use sum-of-the-year-digits method
- o Use double-declining-balance method
- o Use straight-line method
- o Use different methods for different capital investments, to be specified by the user.

Property Tax Options

- o Calculate property tax as a constant percentage of the original invested capital.
- o Calculate property tax as a percentage of the capital depreciated linearly over the life of the plant and escalate according to the capital cost escalation rate.

Operating Expenses Options

- o Calculate operation and maintenance costs as a percentage of the capital cost and administrative and general costs as a percentage of the operation and maintenance costs.
- o Use operation and maintenance costs and administrative and general costs over the life of the plant, specifically furnished by the user.
- o Calculate operation and maintenance costs based on the installation schedules of production wells, injection wells and surface facilities specified by the user, and administrative and general costs as a percentage of the operation and maintenance costs. (This option is provided solely for geothermal wellfields).

Escalation Options

- o Exclude escalation in the calculations.
- o Use escalation rates for the capital cost, operation and maintenance, administrative and general, fuel and electric energy costs as specified by the user.

AFDC Options

- o Calculate the return on investment during pre-operational years according to the established return rate over the plant life with debt interests deducted for income tax purposes in the first year of operation.

- o Use the effective AFDC rate during pre-operational years supplied by the user without specifying debt interest and equity return. (There is no income tax deduction since tax credits for the interest are taken into consideration in establishing the effective AFDC rate).
- o Use the treatment of AFDC as above, but with the amount of AFDC included in the capital cost bases for tax depreciations during operational years. (Although this procedure is incorrect, it is used in some life cycle models, and is included as an option for comparative purposes).

Financial and Tax Data Options

- o Use the set of data on finances, return rates and tax rates built in the program.
- o Use data on finances, return rates and tax rates supplied by the user.

The above options provide an almost unlimited number of combinations. Thus, RESOURCE is capable of performing life cycle costing calculations according to the economic models used by most organizations.

Once the life cycle costing model is chosen, the program user inputs numerical data to the computer on the interactive terminal. In the case that a set of data is derived by the computer, as provided by some of the options, the numerical values are printed out on the terminal.

Because of its flexibility and responsiveness to the users needs, RESOURCE is also ideally suited to sensitivity analysis. This is possible through a special feature built into the program which permits the user to quickly vary certain data points.

In summary, RESOURCE has been designed to perform economic evaluations so necessary to the emerging energy technologies.

Y.C. Wong
R&E Cost Engineering
Bechtel National Inc.

June 1978

BECHTEL ELECTRIC ENERGY COST ESTIMATING PROGRAMS

- "BUSCOST" : Computes Levelized Energy Costs for Geothermal Well Field and Power Plant Using Electric Utility Methodology.
- "RESOURCE" : Computes Economic Parameters for Capital Plants Using Flexible Financial Methodologies.

BECHTEL "BUSCOST" WELL FIELD ENERGY COST INPUT

Enter Life of Wells (Yrs): 10

Enter Life of Well-Field Surface Facilities (Yrs): 30

Enter Life of Power Plant (Yrs): 30

No. of Yrs in Which Investments Are Made: 3

Yr. Well Investment (\$R), Surf.Fac.Investment (\$R): 1,4000,8000

Yr. Well Investment (\$R), Surf.Fac.Investment (\$R): 11,4000,0

Yr. Well Investment (\$R), Surf.Fac.Investment (\$R): 21,4000,0

Yr: 1

Prod Wells Added, Reinj Wells Added: 8,4

Yr: 11

Prod Wells Added, Reinj Wells Added: 8,4

Yr: 21

Prod Wells Added, Reinj Wells Added: 8,4

Productive Exploration Costs (\$R): 2000

Cost of Capital Data

Percent Debt Financing, Annual Cost of Debt (%): 0,0

Percent Equity Financing, Annual Cost of Equity (%): 100,20

Weighted Avg Cost of Capital: 20%

Enter Present Value Discount Rate (%): 20

Income Tax Data

Federal Tax Rate (%): 48

State Tax Rate (%): 9

Effective Tax Rate: 52.68%

Investment Tax Credit (%): 10

Royalties: % Of Gross Revenues: 10

Annual O&M Expense (\$R) - Enter 0 if to be Computed: 0

Admin & Genl Expense as % of O&M: 10

Ad Valorem (Production) Tax as % of Gross Revenues: 10

BECHTEL "BUSCOST" WELL FIELD ENERGY COST OUTPUT

Exploration Costs Capitalized From Year 1 (\$K): 2000

Yr	PR-WLS	RE-WLS	WL-INV	SP-INV	BK-VAL	BK-DPR	ROI	TX-DPR	INTRST	ITC	IN-TAX	O&M	A&G	ROYLT	AD-V
1	8	4	4000	8000	14000	732	2808	1466	0	746	721	1048	104	675	675
2	0	0	0	0	13268	732	2653	1261	0	653	984	1048	104	690	690
3	0	0	0	0	12536	732	2507	1092	0	0	2390	1048	104	847	847
4	0	0	0	0	11804	732	2360	950	0	0	2384	1048	104	828	828
5	0	0	0	0	11072	732	2214	832	0	0	2353	1048	104	806	806
6	0	0	0	0	10340	732	2068	733	0	0	2301	1048	104	781	781
7	0	0	0	0	9608	732	1921	702	0	0	2171	1048	104	747	747
8	0	0	0	0	8876	732	1775	673	0	0	2041	1048	104	712	712
9	0	0	0	0	8144	732	1628	645	0	0	1909	1048	104	677	677
10	0	0	0	0	7412	732	1482	619	0	0	1775	1048	104	642	642
11	8	4	4000	0	10680	732	2136	1133	0	400	1086	1048	104	638	638
12	0	0	0	0	9948	732	1989	951	0	0	1970	1048	104	730	730
13	0	0	0	0	9216	732	1843	803	0	0	1972	1048	104	712	712
14	0	0	0	0	8484	732	1696	680	0	0	1945	1048	104	690	690
15	0	0	0	0	7752	732	1550	580	0	0	1894	1048	104	666	666
16	0	0	0	0	7020	732	1404	498	0	0	1823	1048	104	638	638
17	0	0	0	0	6288	732	1257	498	0	0	1659	1048	104	600	600
18	0	0	0	0	5556	732	1111	498	0	0	1497	1048	104	561	561
19	0	0	0	0	4824	732	964	498	0	0	1333	1048	104	522	522
20	0	0	0	0	4092	732	818	498	0	0	1171	1048	104	484	484
21	8	4	4000	0	7360	732	1472	1036	0	454	454	1048	104	476	476
22	0	0	0	0	6628	732	1325	876	0	0	1314	1048	104	565	565
23	0	0	0	0	5896	732	1179	748	0	0	1294	1048	104	544	544
24	0	0	0	0	5164	732	1032	645	0	0	1245	1048	104	520	520
25	0	0	0	0	4432	732	886	563	0	0	1174	1048	104	493	493
26	0	0	0	0	3700	732	740	498	0	0	1084	1048	104	463	463
27	0	0	0	0	2968	732	593	498	0	0	920	1048	104	424	424
28	0	0	0	0	2236	732	447	498	0	0	758	1048	104	386	386
29	0	0	0	0	1504	732	300	498	0	0	594	1048	104	347	347
30	0	0	0	0	772	732	154	490	0	0	431	1048	104	308	308

*** LEVEL ANNUAL COSTS (\$K) ***

1. Book Depreciation.....	732
2. Return on Investment.....	2230
3. Income Tax Liability.....	1708
4. Operation & Maintenance.....	1048
5. Administrative & General....	104
6. Ad Valorem Taxes.....	727
7. Royalty Payments.....	727

7277

BECHTEL "BUSCOST" POWER PLANT ENERGY COST INPUT

Enter Expected Plant Life (Yrs): 30

Enter Beginning-of-Yr Investment Schedule

No. of Investments During Plant Life: 1

Yr of Plant Life, Capital Invested (\$K): 1,50000

Cost of Capital Data

Percent Debt Financing, Annual Cost of Debt (%): 50, 9.5

Percent Equity Financing, Annual Cost of Equity (%): 50, 12.5

Weighted Avg Cost of Capital: 11%

Enter Present Value Discount Rate (%): 11

Income Tax Data

Note: Following 3 Tax Rate Inputs are 0 for Publicly-Owned Utility

Federal Tax Rate (%): 48

State Tax Rate (%): 9

Effective Tax Rate: 52.68%

Investment Tax Credit (%): 10

O&M as % of Capital Cost = 2% Typical (%): 2

Real, Uninflated Annual O&M Escalation Rate (%): 0

Admin & Genl As % of O&M = 25% Typical (%): 25

Ad Valorem Tax as % of Capital Cost = 2.5% Typical (%): 2.5

Plant Insurance as % of Capital Cost = 0.1% Typical (%): .1

BECHTEL "BUSCOST" POWER PLANT ENERGY COST OUTPUT

YR	INVT	BK-VAL	BK-DPR	ROI	TX-DPR	INTRST	ITC	IR-TAX	O&M	A&G	AD-TAX	INS
1	50000	50000	1666	5500	3333	2375	529	504	1000	250	1250	50
2	0	48334	1666	5316	3111	2295	571	546	1000	250	1250	50
3	0	46668	1666	5133	2903	2216	608	583	1000	250	1250	50
4	0	45002	1666	4950	2710	2137	640	615	1000	250	1250	50
5	0	43336	1666	4766	2529	2058	667	642	1000	250	1250	50
6	0	41670	1666	4583	2360	1979	691	666	1000	250	1250	50
7	0	40004	1666	4400	2203	1908	709	684	1000	250	1250	50
8	0	38338	1666	4217	2056	1821	580	1005	1000	250	1250	50
9	0	36672	1666	4033	1919	1741	0	2269	1000	250	1250	50
10	0	35006	1666	3850	1791	1662	0	2296	1000	250	1250	50
11	0	33340	1667	3667	1671	1583	0	2315	1000	250	1250	50
12	0	31673	1667	3484	1560	1504	0	2323	1000	250	1250	50
13	0	30006	1667	3300	1456	1425	0	2322	1000	250	1250	50
14	0	28339	1667	3117	1359	1346	0	2314	1000	250	1250	50
15	0	26672	1667	2933	1268	1266	0	2300	1000	250	1250	50
16	0	25005	1667	2750	1183	1187	0	2278	1000	250	1250	50
17	0	23338	1667	2567	1183	1108	0	2163	1000	250	1250	50
18	0	21671	1667	2383	1183	1029	0	2046	1000	250	1250	50
19	0	20004	1667	2200	1183	950	0	1930	1000	250	1250	50
20	0	18337	1667	2017	1183	871	0	1814	1000	250	1250	50
21	0	16670	1667	1833	1183	791	0	1698	1000	250	1250	50
22	0	15003	1667	1650	1183	712	0	1583	1000	250	1250	50
23	0	13336	1667	1466	1183	633	0	1466	1000	250	1250	50
24	0	11669	1667	1283	1183	554	0	1350	1000	250	1250	50
25	0	10002	1667	1100	1183	475	0	1234	1000	250	1250	50
26	0	8335	1667	916	1183	395	0	1118	1000	250	1250	50
27	0	6668	1667	733	1183	316	0	1003	1000	250	1250	50
28	0	5001	1667	550	1183	237	0	887	1000	250	1250	50
29	0	3334	1667	366	1183	158	0	770	1000	250	1250	50
30	0	1667	1667	183	1183	79	0	654	1000	250	1250	50

LEVEL ANNUAL COSTS (\$K)

1. Book Depreciation.....	1666
2. Return on Investment.....	4084
3. Income Tax Liability.....	1204
4. Operation & Maintenance.....	1000
5. Administrative & General.....	250
6. Ad Valorem Taxes.....	1250
7. Plant Insurance.....	50

9505

BECHTEL "BUSCOST" WELL FIELD EXPLORATION COSTS

Costs on Retained Acreage for
200 MWe Producing Area.

<u>ITEM</u>	<u>1975 COSTS</u>
Geological and Geophysical Studies	\$ 85,000
Land (estimate 7500 acres @ \$7)	53,000
1 Exploratory well	410,000
3 Step-out wells @ \$365,000	1,095,000
Testing to establish potential	<u>540,000</u>
	\$2,183,000

BECHTEL "BUSCOST" WELL FIELD ANNUAL O & M EXPENSES

\$70,000	:	Foremen & Site Managers
$\$250,000 \times \left(\frac{\text{No. Prod. Wells}}{13} \right)^{0.3}$	:	Manual & Technical Labor & Operating Materials
$\$50,000 \times (\text{No. Prod. Wells})$	:	Production Well Maintenance
$\$80,000 \times (\text{No. Reinj. Wells})$	:	Reinjection Well Maintenance
$0.5\% \times (\text{Surface Piping Capital})$	:	Surface Piping Maintenance

BECHTEL "BUSCOST" INCOME TAX EQUATIONS

- Combined State & Federal Income Tax Liability in Year "n":

$$TL_n = \frac{T(CR + ROI_n - DT_n - B_n) - ITC_n}{1-T}$$

- Effective State & Federal Tax Rate:

$$T = T_s + T_f (1 - T_s)$$

- Tax Depreciation in Year "n":

$$DT_n = \begin{cases} (C_0 - \sum_{i=1}^{n-1} DT_i) \times (2/L) & \text{for } \frac{2}{L} > \frac{1}{L-(n-1)} \\ (C_0 - \sum_{i=1}^{n-1} DT_i) / (L-(n-1)) & \text{for } \frac{2}{L} \leq \frac{1}{L-(n-1)} \end{cases}$$

BECHTEL "BUSCOST" ENERGY COST LEVELIZING TECHNIQUE

$$\sum_{i=1}^L \bar{p} E_i PWF_i = \sum_{i=1}^L \left(\sum_{n=1}^7 C_{n,i} \right) PWF_i$$

$$\bar{p} = \frac{\sum_{i=1}^L \left(\sum_{n=1}^7 C_{n,i} \right) PWF_i}{\sum_{i=1}^L E_i PWF_i}$$

$$PWF_i = \frac{1}{(1+r)^i}$$

$$E_i = P_i \times CF \times 8.760 \times 10^6$$

BECHTEL "BUSCOST" A.F.D.C. ESTIMATES FOR GEOTHERMAL PLANTS

SCHEDULE DURATION AND ALLOWANCE FOR FUNDS DURING CONSTRUCTION (AFDC) FOR GEOTHERMAL POWER PLANTS

Geothermal Power Plant Capacity	Engineering and Construction Schedule Duration	AFDC as Percent of Project Cost ⁽¹⁾
10 MWe	34 Months	9.4%
50 MWe (1-50 MWe Unit)	40 Months	11.2%
100 MWe (2-50 MWe Units)	48 Months	13.6%
200 MWe (4-50 MWe Units)	58 Months	16.6%

- (1) Project cost includes engineering, construction and owner's costs. AFDC based on 10% annual rate applied to project cost and compounded annually from center-of-gravity of cash flow schedule to beginning of commercial operation

SUMMARY

GEOCOST combines both technical and economic factors into one systematic cost accounting framework. The program, which simulates production of electricity from most types of geothermal resources, is composed of two parts: a model that simulates the costs associated with the exploration, development, and operation of a geothermal reservoir; and a model that simulates the costs associated with the design, construction, and operation of the power plant. The costs from the reservoir model become the energy supply costs to the power plant. The combined reservoir and power plant models form the complete energy production system. GEOCOST can simulate the financial and tax structure of almost any corporate or economic entity through varying rates of return on equity and debt, the debt-equity ratios, and tax rates.

Generation of electricity from geothermal energy involves a sequence of costs and revenues. Starting with exploration for a geothermal reservoir, the process continues through the location and development of the reservoir, power plant construction, and power production, and ends when either the power plant or the reservoir reaches the end of its useful life.

These events can be represented by a sequence of cash flows which form the basis for the GEOCOST model. Using discounted cash flow analysis, the program calculates the costs of energy by equating the present worth of the revenues and expenses over the economic life of the plant or reservoir.

Wellhead conditions of the geothermal fluid, power plant design and capacity, cost of the wells, and annual power production are the principal input requirements. The two main components of the program, the reservoir and the power plant models, are linked through the fluid transmission and the power plant system submodels. The latter calculates the total fluid flow requirements from the reservoir at the wellhead conditions. From this total flow, the fluid transmission submodel calculates the number of wells required, pipe lengths and diameters, pumping requirements, and the temperature and pressure drop between the reservoir and the power plant. The program iterates between the power plant systems submodel (which calculates the additional flow required under the degraded fluid conditions) and the fluid transmission submodel until the successive flow requirements converge within preset criteria.

Dr. Momtaz Mansour

After establishing the total fluid flow that meets the specified power production requirements, the program determines the cash flow for the reservoir. This includes capital costs and operating expenses from the beginning of exploration through the life of the power plant. Based on the cash flow and energy supplied, the unit cost of energy is calculated that will equate the present worth of the revenues and expenses for the reservoir. The useful life of the power plant is the operating period of the reservoir since energy must be supplied throughout this period.

In the power plant model the revenue to the reservoir is the energy supply expense to the power plant. This expense is combined with the power plant capital costs and operating expenses to generate the cash flow for the plant. Based on the power plant cash flow and the electricity generated, the unit cost of electricity is calculated by equating the present worth of the revenues and expenses.

GEOTHERMAL DEVELOPMENT AND THE PRODUCTION OF ELECTRICITY

Summary

Introduction

The purpose of the following presentation is to describe the logic underlying research performed, as well as the tools used and the results of that research concerning the potential contribution of geothermal development to electricity production in the five state area including New Mexico, Arizona, Nevada, Utah, and Colorado. The following section outlines the underlying philosophy of the research program. The next section discusses the simulation model used to evaluate the potential profitability of Geothermal sites for electric use, the geothermal Internal Rate of Return Algorithm (GIRORA-Electric). The third section following this introduction presents a discussion of the sensitivity of profits to changes in physical and policy variables circumscribing the development of geothermal electric power. The section following the discussion of profit sensitivity analysis presents site by site profitability as determined by use of GIRORA-Electric, and aggregation of resulting power estimate and a discussion of power-on-line projections. In addition, the sensitivity of power-on-line estimate to policy initiatives is discussed. Finally, preliminary estimates of electric power supply and demand conditions are presented. The feed back or impact upon the development of geothermal electric plants is discussed under three possible

sets of alternative assumptions. We turn first to a discussion of the philosophy underlying the research accomplished concerning the development of geothermal electric power.

Research Philosophy

Underlying all considerations of this research was the assumption that electric plants driven by geothermal energy, and the fields which deliver that energy, will be developed by the private or non-Federal government sectors. For the most part, this means private developers in conjunction with regulated electric utilities (although, exceptions may and will likely exist). A concomitant of this assumption is that a geothermal resource will be developed only if it is economic to do so (that is, economic feasibility is a necessary, but not sufficient condition). Because private developers and electric utilities are the actors, it is necessary to consider economic feasibility (profitability) from their point-of-view.

The second principal assumption is that geothermal energy is only one of a variety of energy sources at the disposal of an electric utility (or anyone, for that matter, in need of electric power). A concomitant of this second assumption is that geothermal energy must compete in the market place for energy. Because geothermal energy is a marginal energy source, marginal^{not} in the sense that it is a relatively small source, and in this region enters the scene chronologically late, it must compete at prices established by other fuels, (coal, nuclear, oil, gas, and hydroelectric).

The result of the first two principal assumptions is that if geothermal energy is not profitable for both the geothermal developer and the electric utility, at a price which enables the electric power thus generated to be competitive with that generated by other fuels, the resource will not be developed. This is the bottom line. Given other institutional, attitudinal, and economic factors, a particular resource may not be developed, even if it is economically competitive.

Moreover, even though a particular resource is economically competitive and faces no noneconomic barriers, being a marginal fuel it may not be developed for lack of effective demand. This could occur under two conditions: (1) increases in the price of electricity result in sufficient consumer substitutions to reduce quantity of electricity demanded below some critical level, or (2) general economic growth is insufficient to require the capacity that would be added by a geothermal development. The first condition may have some general applicability, while the second might occur only in remote, sparsely populated areas (due to the portability of electricity).

At each juncture, government policy makers may have an option to affect the environment in which private developers make decisions or perceive opportunities. It was the aim of the research effort described below (1) to ascertain what elements under the influence of DOE-DGE could efficiently alter the profitability of geothermal resources as perceived by the investors, (2) to identify the magnitude of impact policy action might reasonably be expected to have, and (3) to estimate in a preliminary way the level of market potential for electricity driven by geothermal energy.

Because geothermal energy is not to be had for free, it is an economic resource which should be developed efficiently with due concern for its place in a total energy perspective. Private entrepreneurs cannot discount the value of national balance of payments deficits, or other social concerns when considering the desirability of an investment. It must be DOE-DGE's role to consider this broader perspective and insure the availability of sufficient incentives (or the absence of disincentives) so that private entrepreneurs will perceive geothermal energy as an attractive opportunity.

The criterion for evaluation chosen for this research is the rate-of-return on equity investment. There are a variety criteria which could be used, each having their own special strengths and weaknesses. The one chosen for this research

seems most appropriate because of the overall capital intensity of the process. It should be added that in the process of ranking geothermal sites, or judging the relative effectiveness of policy actions, any criterion of profitability or economic feasibility would yield approximately the same answer as another, so long as the methodology is consistent.

As will be noted in the next section, the simulation model used to evaluate geothermal electric projects uses the rate-of-return as the basis for comparison rather than the price of electricity. This is due to our assumption that geothermal energy must compete at the margin with established fuels. The price of electricity is then an independent rather than dependent variable. Moreover, using a rate-of-return on equity as the dependent variable focuses our attention on the profit motive of the developer. The developer can invest in geothermal energy, or any other income yielding prospect. If the rate-of-return on geothermal energy is not high enough (at a price where it can effectively compete), the developer will place investments elsewhere.

Summary of Geothermal Algorithm - Electric Uses

The model which follows posits the very simple economic idea that an investment should be made if the present value of all net income streams is equal to the investment required to generate them when discounted at an interest rate appropriately high.^(fn) If the amount of an investment is known, and the net income streams are known, the rate-of-return can be calculated. This model attempts to calculate the internal rate-of-return to a producer from a geothermal field for which electricity production is planned. This model can easily be modified to fit any type of energy production from a geothermal field.

The basic equation is of the simple form for discounting cash flows:

$$(1) \text{ Investment} = \sum_{t=1}^T (\text{Net Income}_t) (1 + R)^{-t}$$

(fn) For a discussion of this principal, see Fred R. Glahe Macroeconomics (New York: Harcourt, Brace, Jovanich, Inc., 1973), pp. 91-95.

where Net Income = (Total Revenues) - (Total Operating Cost) - (Taxes)

Total Revenues = (Price) (Quantity Output)

Total Operating Cost = A Percentage of Investment

R: Rate-of-Return

t: Each year, $t = 1, 2, \dots, T$.

T: Expected life span of the Investment.

However, this rather fundamental notion is modified somewhat in GIRORA-Electric due to the fact that some investments are made throughout the life of the project and thus must also be discounted to the present for proper evaluation. This yields the equation,

$$(2) \sum_{t=1}^T (\text{Investment}_t) (1 + R)^{-t} = \sum_{t=1}^T (\text{Net Income}_t) (1 + R)^{-t}$$

which reduces to

$$(3) \sum_{t=1}^T (\text{Investment}_t - \text{Net Income}_t) (1 + R)^{-t} = 0$$

If we set $(1 + R)^{-1} = b$, then

$$(4) \sum_{t=1}^T (\text{Investment}_t - \text{Net Income}_t) b^t = 0$$

Equation (4) is a polynomial with T roots. Assuming a monotonic function there will be one real (non-imaginary) root (b) which permits a solution for the equation. This root can be found iteratively by Newton's technique using a computerized program. (fn) Fortunately, GIRORA-Electric has generated only monotonic functions.

GIRORA-Electric simulates all investment, revenue, and cost flows for a specified resource site, and inputs the flows to equation (3) and solves for R.

(fn) For a description of the mathematical technique involved, see C. C. T. Baker, Dictionary of Mathematics, (New York City, Hart Publishing Co., 1966), p. 206.

Investment, revenue and cost flows are divided into two sectors, a geothermal developer sector, and an electric utility sector. The geothermal developer's revenues are operating costs as perceived by the electric utility. The electric utility demand for geothermal fluid (or steam) is derived from the demand for electricity. Once a quantity of electricity has been specified, given resource characteristics, the quantity of fluid or steam is automatically specified. The price of the geothermal energy is the highest price consistent with the competitive price of electricity and the electric utility's regulated rate-of return (both which are assumed to be known). The description of GIRORA-Electric begins with a description of the Electric Utility Sector.

Electric Utility Sector

The model first identifies the principal components of cost to the electric utility for each year (t) of electricity production: capital costs (CC_t), operating costs (OMC_t), income taxes (ITX_t), property taxes (PTX_t), and energy costs (ENC_t).

Capital costs are a function the investment (K) required for a specified level of capacity in kilowatts (CAP).

$$(1) K = (CAP) (CAPC)$$

CAPC: capacity cost in dollars per KW; an input parameter

Capital costs are also a function of the regulated return to equity (ER), the bond rate (BR), the debt to equity ratio, and depreciation ($DEPR_t$).

$$(2) E = (EK) (K) (ER) \quad , \text{ equity costs } ,$$

$$(3) D = (DK) (K) (BR) \quad , \text{ debt costs } ,$$

$$(4) DEPR_t = (DEP_t) (K) \quad , \text{ depreciation } ,$$

and therefore

$$(5) CC_t = E + D + DEPR_t$$

where, EK: equity share of capital; an input parameter,

DK: debt share of capital; an input parameter

$$(EK = 1-DK)$$

DEP_t: depreciation rate in year t;

$$(6) \text{ DEP}_t = (T + 1 - t) / \sum_{t=1}^T t ,$$

where T is the length of time for electricity production. The model provides
for a ^{fast} write-off option.

Operating costs are a function of total investment and escalate through time.

$$(7) \text{ OMC}_t = (\text{OC}_t) (K)$$

$$(8) \text{ OC}_t = (\text{OCB}) (1 + \dot{\text{OC}})^t$$

OC_t: operating percent of investment in year t; input variable

OCB: base rate; input variable,

$\dot{\text{OC}}$: escalation rate; input variable

Likewise, property taxes are a function of investment.

$$(9) \text{ PTX} = (\text{PTP}) (K).$$

PTP: property tax rate; input variable.

Before income taxes are calculated, total revenues must be known.

They are, of course, a function of the price of electricity (PE_t) and the quantity of electricity (QE), which is a function of plant capacity. PE_t is specified as an exogenous busbar price of electricity which is determined by the market and escalates over time.

$$(10) \text{ PE}_t^{\text{r}} = (\text{PB}) (1 + \dot{\text{P}})^t$$

PB: Base busbar price of electricity; input variable.

$\dot{\text{P}}$: escalation factor; input variable.

$$(11) \quad QE = (CAP) (8760) (LF) (1-UF)$$

LF: Plant factor; an input variable,

UF: Plant use of power; an input variable.

Income taxes and energy costs must be determined simultaneously, because the price of the geothermal energy (PHW_t) is an element of both and moreover, PHW_t is the output of the utility sector for the model. The quantity of geothermal energy is determined by electricity plant requirements.

$$(12) \quad QHW = (CAP) (8760) (LF)$$

$$(13) \quad ENC_t = (PHW_t) (QHW)$$

$$(14) \quad ITX_t = \{TXRT\} \{[(PE_t) (QE)] - [OMC_t] - [PTX] - [ENC_t] - [DEPR_t]\} - \{[CRRT][K_{t=1,t=2,t=3}]\}$$

TXRT: income tax rate; input variable

CRRT: investment tax credit rate; input variable

Therefore,

$$(15) \quad PHW_t = \frac{(TXRT)(DEPR_t) + (CRRT)(K_{t=1,t=2,t=3}) - (CC_t)}{(QHW)(1-TXRT)} + \frac{(PE_t)(QE) - (OMC_t) - (PTX)}{(QHW)}$$

The price of energy in year (t) from (15) and the quantity of energy from (12), that is, ENC_t (equation 13), become total revenue for the geothermal energy producer.

Geothermal Energy Producer Sector

We will recall equation (13) ENC_t for the producer, REV_j , or total revenues.

OR,

$$(16) \quad REV_j = ENC_t$$

First, a discussion of the time period involved is necessary. The producer's time horizon is different from that of the electric utility. The years t are elements of T, while the years j are elements of J. $J - T = PPY$, the

"pre-production years". PPY is composed of two periods. The exploration period (EXP) and the development period (DVP), and thus $EXP + DVP = PPY$.

Thus the determinative direction is $EXP + DVP + T = J$. EXP is the period during which only exploratory wells are drilled. The development period begins with the drilling of the first production well.

The producer's activity is modeled somewhat differently from the utilities because the output of the simulation is a rate of return on the producer's equity. Thus, the first order of business is to determine what the level of the investment is in each year of the project. The producer's investment (PNV_j) is a share of the total investment in year j (PKK_j).

$$(17) PNV_j = (EPK)(PKK_j)$$

$$(18) PKK_j = (LNV_j) + (DNV_j) + (IDC_j) + (OPNV_j)$$

EPK : Equity portion of capital; an input variable,

LNV_j : Leasing investment in year j , in \$,

DNV_j : Drilling investment in year j , in \$,

IDC_j : Interest Cost during Construction in year j , in \$,

$OPNV_j$: Other producer investments in year j , in \$,

Total investment by the producer, cumulative to year j is

$$(19) PK_j = \sum_{i=0}^j PKK_i$$

We will first describe the calculation of each element of PKK_j , beginning with DNV_j .

$$(20) \text{DNV}_j = \left[\left(\frac{\text{NPW}_j}{\text{PSS}} \right) (\text{ADDP}) (\text{CPFP}) \right] + \left[\left(\frac{\text{NIW}_j}{\text{ISS}} \right) (\text{ADDI}) (\text{CPFI}) \right]$$

NPW_j : New producing wells in year j ,

PSS : Production Well Success ratio,

CPFP : Cost per foot, producing wells,

NIW_j : New injection wells in year j ,

ISS : Injection well success ratio (≈ 1 usually),

ADDI : Average depth of injection wells,

CPFI : Cost per foot of injection wells,.

The calculation of the elements of DNV_j is shown below.

$$(21) \text{NPW}_j = \text{RPW}_j - \text{RPW}_{j-1}$$

RPW_j : required producing wells, $\text{RPW}_j = 0$ when $j < \text{EXP} + 1$.

$$(22) \text{RPW}_j = \frac{\text{RFR}_{\text{CAP}}}{\text{FR}}$$

FR : flowrate in lb/hr per producing well,

RFR_{CAP} : required flowrate for rated capacity in lb/hr.^(fn)
(CAP is stated here in MW, not KW, and is net of UF.)

$$(23a) \text{RFR}_{50} = 1374.912 e^{-0.01379 (\text{TEMP})}$$

$$(23b) \text{RFR}_{100} = 2667.012 e^{-0.01372 (\text{TEMP})}$$

$$(23c) \text{RFR}_{150} = 3959.226 e^{-0.013655 (\text{TEMP})}$$

$$(23d) \text{RFR}_{200} = 5251.44 e^{-0.01359 (\text{TEMP})}$$

*Site
Bechtel
Report* (fn) Bechtel Corporation, Advanced Design and Economic
Considerations for Commercial Geothermal Power Plants at
Heber and Niland, California. SAN-1124-2, San Francisco,
Ca 1977.

Temperature decline is estimated, and resulting need for increased flow rate, thus producing wells, is modeled in the following way:

$$(24a) \text{ Temp} = \frac{T_0}{360} [358.344 e^{-0.00144(\text{Time})}], \text{ for CAP} = 50\text{MW}$$

$$(24b) \text{ Temp} = \frac{T_0}{360} [357.474 e^{-0.00233(\text{Time})}], \text{ for CAP} = 100\text{MW}$$

$$(24c) \text{ Temp} = \frac{T_0}{360} [357.12 e^{-0.00322(\text{Time})}], \text{ for CAP} = 150\text{MW}$$

$$(24d) \text{ Temp} = \frac{T_0}{360} [357.769 e^{-0.00411(\text{Time})}], \text{ for CAP} = 200\text{MW}$$

T_0 : ^{downhole} Initial temperature of brine in °F, an input variable.

$$(25) \text{ NIW}_j = \text{RIW}_j - \text{RIW}_{j-1}$$

RIW_j : required injection wells in year j .

$$(26) \text{ RIW}_j = \text{RPW}_j (\text{PIR})^{-1}$$

PIR : required ratio of producing wells to injection wells, in year j , an input variable.

After initiation of power generation, NPW_j and NIW_j will generally take on a value of 0 or 1, but are arbitrarily allocated during DVP.

The remaining elements of PKK_j are discussed below:

$$(27) \text{ LNV}_j = [(\text{DPAC})(\text{ACPW})(\text{NPW}_j)] + [(\text{DPAC})(\text{ACIW})(\text{NIW}_j)]$$

DPAC : dollars per acre leasing cost; input variable,

ACPW : acres per producing well; input variable,

ACIW : acres per injection well; input variable.

$$(28) \text{OPNV}_j = \text{EXP}_j + \text{PIP}_j + \text{ONV}_j$$

EXP_j : exploration investments, year j ,

PIP_j : piping investments, year j ,

ONV_j : other investments, year j .

$$(29) \text{EXP}_j = f(\text{EXP})$$

$$(30) \text{EXP} = (\text{EXD})(\text{CAP})$$

EXD: dollars per unit of capacity (electric) needed for exploration, on average; input variable.

$$j > \text{EXP}, \text{EXP}_j = 0$$

EXP: total exploration investment in \$

(Note: $\text{EXP} = \sum_{j=0}^{\text{EXP}} \text{EXP}_j$, where the distribution function is chosen arbitrarily)

$$(31) \text{PIP}_j = (\text{PIP})(\text{DNV}_j)$$

PIP: average percentage of drilling investment required for piping and similar field developments.

$$j < \text{EXP} + 1, \text{PIP}_j = 0; j > \text{EXP}, \text{PIP}_j = 0.$$

$$(32) \text{ONV}_j = (\text{OPE}_j)(\text{DNV}_j)$$

$$(33) \text{OPE}_j = (\text{OPEB})(1 + \text{OP})^j$$

Equations (32) and (33) calculate estimate additional investments in field development which are related to drilling expenses.

$$(34) IDC_j = [BR][DPK] \left[\sum_{i=0}^j LNV_i + \sum_{i=0}^j DNV_i + \sum_{i=0}^j OPNV_i \right]$$

$$IDC_j = 0 \text{ for } j > PPY.$$

DPK: debt portion of capital; $DPK = 1 - EPK$.

Thus, total revenues and all elements of investment have been calculated. What remain are uncanceled elements of cost. $OMCP_j$ are operating and other current outlays.

$$(35) OMCP_j = [(OCP_j)(PK_j)] + [(BR)(PK_j)(DPK)] + [PTXP_j]$$

$$(36) OCP_j = (OCPB)(1+OCP)^j$$

OCP_j : operating percentage of investment outlay,

$OCPB$: base percentage; input variable,

OCP : escalation factor.

$PTXP_j$: property taxes.

$$(37) PTP_j = (PTPP)(PK_j)$$

$PTPP$: property tax rate; input variable.

Income taxes are as follows:

$$(38) ITXP_j = \{TXRT\} \{[(REV_j)(1-\lambda)(1-Z)] - [(OMCP_j) - (BR)(PK_j)(DPK)] - [(Y)(DNVD_j)]\} - \{[CRRT][(1-Y)(\sum_{i=j-2}^j DNV_i)]\}$$

$$(39) DNVD_j = \sum_{i=1}^j DNV_i (DEPRP_{j-i+1})$$

$$(40) \text{ DEPRP}_j = (D + 1 - j) / \sum_{j=1}^D j$$

D: period chosen for depreciation; input variable,

λ : royalty rate, input variable,

Y: percentage tangible investment, input variable,

Z: depletion allowance, input variable,

DNVD_j: depreciation allowance in year j, \$

DEPRE_j: depreciation rate in year j. Program contains fast write-off option.

Finally, the model solves for R, the rate of return to equity for the geothermal energy producer from the Jth degree polynomial given by

$$(42) \sum_{j=0}^J \{[(\text{REV}_j)(1-\lambda) - (\text{OMCP}_j) - (\text{ITXP}_j)]\} e^{-Rj} = 0$$

The R thus solved is one criterion for ranking geothermal resource sites and for comparing the outcomes of policy variable changes.

DISCUSSION OF
PACIFIC GAS AND ELECTRIC COMPANY
COST OF POWER ANALYSIS PROCEDURES

The intent of PGandE economic analysis is to give our management realistic information about probable total costs of available engineering alternatives. We, therefore, attempt to include all future cost impacts of such alternatives. Given the large number of variables involved and the need to make the results of the analysis understandable we find comparison of Level Annual Revenue Requirements the most appropriate economic analysis procedure.

Generation plant capital costs are developed by the Engineering Department, broken down by California Public Utility Commission accounts. Estimates of plant engineering, construction supervision and corporate overheads, escalation, AFDC and ad valorim taxes during construction are provided by our Economics and Statistics Department.

The Economics and Statistics Department also provides fixed charge rates for each capital account which are used to convert plant capital costs to level annual revenue requirements. The components of these fixed charge rates include the Company's weighted cost of capital, salvage forecasts, retirement dispersion effects on capital recovery, state and federal income taxes and insurance.

Operating and maintenance expense forecasts are made by the Operating Department. Fuel cost estimates are obtained from a variety of sources. Nuclear fuel cycle cost analysis is performed by the Engineering Department. Coal costs are developed by the Coal Resources Department. Oil and natural gas cost forecasts are made by the Materials Department. Geothermal energy costs are based on a contractual relationship of actual fossil and nuclear plant operating costs so forecasts of future costs are developed from detailed production cost analysis.

Basic cost escalation forecasts are made by the Economics and Statistics Department based on analysis of data from various national economic forecasting services.

Using the data discussed above the Engineering Planning Department performs several types of economic analysis. Generic analysis of generation alternatives provides cost of power comparisons for different generating technologies at various average annual capacity factors. Production cost analysis forecasts monthly production costs for alternative long-range resource plans. Site specific analysis gives management and regulatory agencies detailed cost of power estimates for proposed generation projects.

PGandE uses its cost of capital as the discount rate used in levelizing and present worth calculations. Economic results are expressed in both current and constant dollar terms.

J. H. Malinowski
June 29, 1978

PG&E FOSSIL 1&2
COST OF POWER CALCULATION
1600 MW PLANT

ENGINEERING PLANNING DEPT.	MILLS/KWHR (35 YEARS)		
	1977	1986 LEVELIZED	1977 CONSTANT \$
COST OF POWER *			
CAPITAL (70% CF)	21.924	33.029	13.200
FIXED O&M	.948	2.568	1.026
FUEL INV. COAL	.847	1.431	.572
OIL	.181	.392	.156
FIXED COSTS	23.900	37.420	14.954
VARIABLE O&M	.453	1.233	.493
FUEL - COAL	11.904	36.372	14.536
VARIABLE COSTS	12.357	37.605	15.029
TOTAL	36,257	75,026	29,983

* Adjusted for losses to load center

Discussion of Levelizing and Constant Dollar Economic Analysis

Comparison of Level Annual Revenue Requirements (LARR) of alternatives is the generally accepted method of utility economic analysis. The LARR of a project includes the economic effect of all expected expenditures associated with the project. Constant Dollar Analysis is a useful and equivalent version of LARR analysis.

Levelizing procedures are key elements of the LARR method and therefore of utility economic analysis. The levelized value of a time varying series of expenditures is the constant (or level) series of expenditures with the same present worth as the time varying series. In mathematical form, this statement is:

$$\sum_{k=0}^{n-1} \frac{L_e}{(1+i)^k} = \sum_{k=0}^{n-1} \frac{E_k}{(1+i)^k} \Rightarrow L_e = \frac{\sum_{k=0}^{n-1} \frac{E_k}{(1+i)^k}}{\sum_{k=0}^{n-1} \frac{1}{(1+i)^k}}$$

where L_e is the levelized value of the series E_k

n is the number of time periods considered

i is the cost of capital

E_k is the K th expenditure of the time-varying series and should include expected escalation.

While comparison of the levelized cost of alternatives correctly considers the economic impact of all known future expenditures, the levelized costs include the effect of today's high inflation in both expenditures and cost of capital. The actual and levelized expenditures are both defined as current (escalated) dollar expenditures. In periods of sustained general inflation the value of current dollars decline with time in real terms. The effects of general inflation can be eliminated by evaluating alternatives in constant dollar terms. This does not eliminate the effect of real price changes. Constant dollars maintain their real value by escalating at the general inflation rate in current dollar terms. The process of levelizing in constant dollar terms is:

$$\sum_{k=0}^{n-1} \left(\frac{1+g}{1+i} \right)^k L_c = \sum_{k=0}^{n-1} \frac{E_k}{(1+i)^k} \Rightarrow L_c = \frac{\sum_{k=0}^{n-1} \frac{E_k}{(1+i)^k}}{\sum_{k=0}^{n-1} \left(\frac{1+g}{1+i} \right)^k}$$

where L_c = constant dollar levelized value of the series E_k

g = the general escalation or inflation rate

i, n, E_k as previously defined

Levelized current dollar and levelized constant dollar expenditures are directly proportional,

$$L_c = K_n L_e \quad \text{where} \quad K_n = \frac{\sum_{k=0}^{n-1} \frac{1}{(1+i)^k}}{\sum_{k=0}^{n-1} \left(\frac{1+g}{1+i}\right)^k}$$

and these two economic measures are equivalent since K_n is independent of any alternative specific parameter, (i.e., it is only dependent on life, n , discount rate, i , and general inflation rate, g).

K_n can be generalized to include m = the number of years between the constant dollar year and the initial operation year. The resulting equation becomes:

$$K_{m,n} = \frac{1}{(1+g)^m} \frac{\sum_{k=0}^{n-1} \frac{1}{(1+i)^k}}{\sum_{k=0}^{n-1} \left(\frac{1+g}{1+i}\right)^k}$$

Constant dollar analysis will result in the same economic choices as current dollar analysis. Constant dollar costs, however, are more easily compared to present-day costs since general inflationary effects are factored out.

Attachments

1. Sample calculations
2. Detailed discussion of constant dollar analysis

SAMPLE CALCULATIONS

Cost of power estimates for Fossil 1 & 2 illustrate the results of levelized current dollar and levelized constant dollar analysis. For the Butte site, the cost of power components with no escalation assumed are:

<u>Cost of Power Component</u>	<u>Mills/Kwhr</u>
Capital	20.946
O&M Fixed	.967
Coal Inventory	.890
Oil Inventory	.357
Total Fixed Cost (70% C.F.)	23.160
O&M Variable	.453
Fuel (Coal)	11.908
Total Cost of Power	35.521

We do not consider this a valid economic measure since it includes inflationary impacts in the cost of capital, but not other cost of power components.

The escalation assumptions currently used for resource alternative economic analysis include:

General Inflation Rate	5%
Steam Cycle Plant Escalation Rate	5.7%
Coal Fuel Cost Escalation Rate	6.0%
Oil Fuel Cost Escalation Rate	10% to 1983
	7% beyond
O&M Escalation	5.4%

Using these escalation assumptions and a 35-year economic life results in the following escalation factors for coal plants operational in 1980, 1985 and 1990.

Current Dollar Escalation Factors

	<u>Current Dollar</u>			<u>Levelized</u>		
	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Capital	1.107	1.460*	1.926	1.107	1.460	1.926
O&M	1.171	1.523	1.981	1.975	2.570	3.343
Coal Fuel	1.191	1.594	2.133	2.154	2.882	3.857
Oil Fuel	1.331	2.028	2.845	2.930	4.141	5.808

* GM escalation assumed.

The 1977 constant dollar multipliers (Km,n) for these start dates and a 35-year life are:

<u>Start Date</u>	<u>Multiplier</u>
1980	.536
1985	.420
1990	.329

ATTACHMENT 1

Applying these multipliers to the current dollar escalation factors yield 1977 constant dollar escalation factors.

1977 Levelized Constant Dollar Escalation Factors

	<u>1980</u>	<u>1985</u>	<u>1990</u>
Capital	.593	.613	.634
O&M	1.058	1.078	1.100
Coal Fuel	1.154	1.210	1.268
Oil Fuel	1.569	1.739	1.910

Using the unescalated cost of power components and these escalation factors results in the following current dollar and constant dollar levelized cost of power estimates:

Levelized Cost of Power (35-year life)

Component	Mills/Kwhr					
	Current Dollar			1977 Constant Dollar		
	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Capital	23.178	30.581	40.348	12.413	12.832	13.266
O&M Fixed	1.911	2.485	3.233	1.023	1.043	1.063
Coal Inventory	1.060	1.418	1.898	1.027	1.076	1.129
Oil Inventory	.475	.724	1.015	.560	.641	.681
Total Fixed Cost (70% C.F.)	26.623	35.208	46.494	15.023	15.593	16.139
O&M Variable	.900	1.170	1.522	.482	.491	.500
Fuel (Coal)	<u>25.649</u>	<u>34.324</u>	<u>45.933</u>	<u>13.736</u>	<u>14.403</u>	<u>15.102</u>
Total Cost of Power	<u>53.172</u>	<u>70.702</u>	<u>93.949</u>	<u>29.241</u>	<u>30.487</u>	<u>31.741</u>

A coal plant built in 1990 will produce power at a levelized current dollar cost 77% higher than the same plant built in 1980. The difference in 1977 constant dollar costs is 8.5% reflecting real escalation of plant and operating costs.

**GENERALIZED POWER PRODUCTION COSTS
FOR VARIOUS TYPES OF GENERATING FACILITIES**

	Nuclear 2x1200 MW	Coal		Combined Cycle 400 MW	Gas Turbine 4x75 MW	Geysers Geothermal 110 MW
		FCD ⁽¹⁾ 2x800 MW	W/O FCD 2x800 MW			
1977 Cost Plus ADC⁽²⁾						
Plant \$/kW	843	761	544	264	178	323
Step-up & Switching	20	20	20	15	15	15
Transmission	30	10	30	10	0	35
Total \$/kW	893	791	594	289	193	358
Total Completed Cost						
1980 \$/kW	878	804	604	320	215	396
1985	1159	1061	797	412	271	522
1990	1529	1400	1051	541	354	689
Fixed Charge Rates	15.9	15.4	15.0	15.5	15.3	15.0
Fuel Type	Uranium	Coal	Coal	Distillate	Distillate	Natural Steam
Fuel Costs \$/MMBTU						
1977	73	125	122	263	263	65
1980	87	149	145	370	370	80
1985	116	199	194	530	530	90
1990	156	267	260	743	743	102
2000	279	477	466	1462	1462	147
Fuel Inventory (Days)	~ 700	90	90	60	10	--
Average Heat Rate	10,300	9,700	9,250	8,600	11,500	22,000
O&M Cost Fixed (\$/kWyr)	2.8	5.8	4.3	5.0	.5	2.7
Variable (Mills/kWh)	0	.5	.1	.4	1.6	.1
Peak Transmission Loss %	1.4	-.4	2.0	-2.0	-5.7	3.8
Average	.1	.5	1.9	-.7	-2.2	3.5
35 Year Levelized Power Production Costs for Plants Completed in 1985						
Fixed \$/kWyr	201	193	147	90	43	87
\$/kWhr @ 70%CF	3.3	3.2	2.4	1.5	.7	1.4
Variable \$/kWhr	2.1	3.6	3.3	9.4	12.6	2.9
Total	5.4	6.8	5.7	10.9	13.3	4.3
35 Year Levelized Costs on a 1977 Constant \$ Basis⁽³⁾						
\$/kWhr, 10% CF	--	10.8	8.4	8.3	7.4	5.4
30	4.3	4.6	3.8	5.4	6.0	2.6
50	2.9	3.4	2.8	4.8	5.7	2.0
60	2.5	3.1	2.6	4.7	5.6	1.9
70	2.3	2.9	2.4	4.6	5.6	1.8
80	2.1	2.7	2.3	4.5	5.6	1.7

(1) FCD = Flue Gas Desulfurization (Scrubbers)

(2) ADC = Allowance for Funds During Construction

(3) Cost with effects of general escalation factored out

**GENERALIZED POWER PRODUCTION COST ESTIMATES
FOR VARIOUS FUTURE DISPATCHABLE GENERATION TYPES**

	<u>Integrated Coal Gasifier</u>		<u>Biomass</u>	<u>Geothermal</u>
	<u>Combined Cycle (1)</u>	<u>Fuel Cell (1)</u>	<u>Direct Combustion</u>	<u>Liquid Dominated (1)</u>
1977 Cost Plus ADC (2)				
Plant \$/kW	781	656	971	589
Step-up & Switching	20	20	15	15
Transmission	30	15	35	100
Total \$/kW	831	691	1021	704
Total Completed Cost				
1980 \$/kW	844	703	1128	778
1985	1115	927	1488	1026
1990	1471	1223	1964	1354
Fixed Charge Rates	15.0	15.4	15.4	15.0
Fuel Type	Coal	Coal	Biomass	Hot Water
Fuel Cost ¢/MMBTU				
1977	122	125	125	72
1980	145	149	149	85
1985	194	199	199	114
1990	260	267	267	153
2000	466	477	477	273
Fuel Inventory (Days)	90	90	60	-
Average Heat Rate (Btu/kWhr.)	7,900	8,500	16,000	30,000
O&M Cost Fixed (\$/kWyr.)	5.8	5.8	23.3	9.2
Variable (Mills/kWh)	.5	.5	3.8	1.5
Peak Transmission Loss %	2.0	-2.0	3.8	7.3
Average	1.9	-.7	3.5	6.7
35 Year Levelized Power Production Costs for Plants Completed in 1985				
Fixed \$/kWyr	192	164	309	190
¢/kWhr @ 70% CF	3.1	2.7	5.0	3.1
Variable ¢/kWhr	3.0	3.2	7.0	4.8
Total	6.1	5.9	12.1	7.9
1977 Constant \$ Levelized Costs (3) ¢/kWhr 10% CF	10.5	9.2	17.7	11.1
30	4.3	4.0	7.9	5.1
50	3.1	2.9	5.9	3.8
60	2.8	2.6	5.4	3.5
70	2.6	2.5	5.1	3.3
80	2.4	2.3	4.8	3.2

- (1) This technology is not commercially available today.
 (2) ADC = Allowance for Funds During Construction.
 (3) Cost with effects of general inflation factored out.

In the absence of proven or commercially available technology, many assumptions regarding performance characteristics and costs must be made. Information currently available produces a wide range of possible assumptions. Those used for these estimates are neither the most optimistic nor the most pessimistic. The accompanying data and explanation discusses the assumptions used. These estimates are provided without regard to when the resource may be commercially available, whether it would be suitable for a baseload resource without backup capacity or the relative reliability of the resource.

* fuel costs = 50% more than geysers.

**GENERALIZED POWER PRODUCTION COST ESTIMATES
FOR VARIOUS SOLAR GENERATION TYPES (1)**

	<u>Solar Thermal</u>		<u>Solar Photovoltaic</u>		<u>Wind</u>	
	<u>Fuel Saving</u>	<u>GT Back-up (3)</u>	<u>Fuel Saving</u>	<u>GT Back-up (3)</u>	<u>Fuel Saving</u>	<u>GT Back-up (3)</u>
1977 Cost Plus ADC (2)						
Plant \$/kW	1621	1773	2075	2227	762	914
Step-up & Switching	20	33	20	33	0	13
Transmission	100	100	100	100	50	50
Total \$/kW	1741	1906	2195	2360	812	977
Total Completed Cost						
1980 \$/kW	1924	2108	2425	2550	910	1094
1985	2538	2769	3200	3431	1200	1431
1990	3349	3651	4222	4524	1584	1886
Fixed Charge Rate	15.3	15.3	15.3	15.3	15.3	15.3
Energy Source	Sun	Sun Plus Distillate	Sun	Sun Plus Distillate	Wind	Wind Plus Distillate
Supplemental Fuel Cost \$/MWHBTU						
1977	-	263	-	263	-	2.3
1980	-	370	-	370	-	370
1985	-	530	-	530	-	530
1990	-	743	-	743	-	743
2000	-	1462	-	1462	-	1462
GT Fuel Inventory Days	-	10	-	5	-	10
GT Heat Rate	-	11,500	-	11,500	-	11,500
Solar System CP %	40	40	20	20	35	35
O&M Cost Fixed \$/kWyr	10.5	10.9	8.8	9.2	3.1	3.5
GT Variable Mills/kWyr	0	1.6	0	1.6	0	1.6
Solar System Peak Transmission Losses %	7.3	7.3	7.3	7.3	3.8	3.8
Average (4)	6.7	6.7	6.7	6.7	3.5	3.5
35 Year Levelized Power Production Costs for Plants Completed in 1985						
Fixed \$/kWyr	445	487	549	590	198	239
\$/kWhr	12.7	11.1	31.3	26.9	6.5	6.1
Variable GT Energy 10% CP Operation	-	2.6	-	2.6	-	2.8
Total \$/kWhr	12.7	13.7	31.3	29.5	6.5	8.9
1977 Constant \$ Levelized Costs (5)						
GT & CP 0	5.3	5.8	13.1	14.1	2.7	3.3
5	-	5.8	-	12.4	-	3.5
10	-	5.7	-	11.2	-	3.7
15	-	5.7	-	10.3	-	3.9
20	-	5.7	-	9.7	-	4.0

- (1) These technologies are not commercially available today.
(2) ADC = Allowance for Funds During Construction.
(3) This analysis assumes 15% of the solar resource capacity is firm. Gas turbine back-up capacity of 85% is assumed.
(4) Gas turbine losses are assumed to be -5.7% peak, -2.2% average.
(5) Costs with effects of general inflation factored out.

In the absence of proven or commercially available technology, many assumptions regarding performance characteristics and costs must be made. Information currently available produces a wide range of possible assumptions. Those used for these estimates are neither the most optimistic nor the most pessimistic. Accompanying data and explanation discusses the assumptions used. These estimates are provided without regard to when the resource may be commercially available, whether it would be suitable for a baseload resource, without backup capacity or the relative reliability of the resource.

CAPITAL COST, REVENUE REQUIREMENTS AND NET SALVAGE FOR THE BUTTE SITE

CPUC	ACCOUNT DESCRIPTION	DIRECT COSTS	PRORATA OTHER COSTS	TOTAL COSTS	CAPITAL RECOVERY	FEDERAL & STATE IN-TAX	INSURANCE	AD VALOREM TAX	TOTAL FIXED CHARGES	NET SALVAGE
		\$1000	\$1000	\$1000 %	\$1000 %	\$1000 %	\$1000 %	\$1000 %	\$1000 %	\$1000
310	LAND & LAND RIGHTS	1276	1651	2927 11.00	322 7.91	232 0.1	3 0.83	24 19.84	581 0	0
311	STRUCTURES & IMPROVEMENTS	46450	60093	106543 11.18	11912 2.16	2301 0.1	107 0.83	884 14.27	15204 -10	-10654
312	BOILER PLANT EQUIPMENT	555090	718131	1273219 11.88	151259 2.30	29284 0.1	1273 0.83	10568 15.11	192383 -5	-63661
314	TURBOGENERATOR UNITS	155460	201122	356582 11.77	41970 2.39	8522 0.1	357 0.83	2960 15.09	53808 0	0
315	ACCESSORY ELEC. EQUIPMENT	85530	110716	196296 11.77	23104 2.47	4849 0.1	196 0.83	1629 15.17	29778 0	0
316	MISC POWER PLANT EQUIPMENT	4010	5188	9198 11.69	1075 2.06	189 0.1	9 0.83	76 14.68	1350 10	920
311	STRUCT & IMP - EQUIPMENT	9930	12847	22777 11.18	2546 2.23	508 0.1	23 0.83	189 14.34	3266 -10	-2278
	COMMUNICATIONS EQUIPMENT	650	841	1491 12.23	182 0.67	10 0.1	1 0.83	12 13.83	206 10	149
353	PLANT STEP-UP & SWITCHING	22878	29598	52476 11.38	5972 2.08	1091 0.1	52 0.83	436 14.39	7551 10	5248
		881324	1140182	2021506	238341	46987	2022	16779	304128	-70276

SITE LABOR COSTS	284685
MATERIAL & OTHER COSTS	596639
SUBTOTAL	881324
ENGR & OTHER ALLOCATED COSTS	97397
SUBTOTAL	978721
GENERAL ENGINEERING AND ADMINISTRATION	137021
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (1)	217276
AD VALOREM TAX DURING CONSTRUCTION (2)	10178
TOTAL CURRENT COST	1343195
ESCALATION (3)	678313
TOTAL ESTIMATED PROJECT COST	2021508

CAPITAL COST, REVENUE REQUIREMENTS AND NET SALVAGE FOR THE BUTTE SITE

IC ACCOUNT DESCRIPTION	DIRECT COSTS	PRORATA OTHER COSTS	TOTAL COSTS		CAPITAL RECOVERY		FEDERAL & STATE IN-TAX		INSURANCE		AD VALOREM TAX		TOTAL FIXED CHARGES		NET SALVAGE
	\$1000	\$1000	\$1000	%	\$1000	%	\$1000	%	\$1000	%	\$1000	%	\$1000	%	\$1000
50 LAND & LAND RIGHTS	4520	5046	9566	11.00	1052	7.91	757	0.1	10	0.83	79	19.84	1898	0	0
52 STRUCTURES & IMPROVEMENTS	1772	1978	3750	11.18	419	6.16	231	0.1	4	0.83	31	18.27	685	0	0
53 STATION EQUIPMENT	18703	20881	39584	11.85	4691	2.21	875	0.1	40	0.83	329	14.99	5934	25	9896
54 TOWERS & FIXTURES	21200	23668	44868	11.04	4953	2.09	938	0.1	45	0.83	372	14.06	6308	-5	-2243
56 OH CONDUCTORS TOWER LINES	12377	13818	26195	11.76	3081	1.97	516	0.1	26	0.83	217	14.66	3840	15	3929
TOTALS	58572	65392	123964		14196		3316		124		1029		18665		11582
SITE LABOR COSTS	13897														
MATERIAL & OTHER COSTS	44675														
SUBTOTAL		58572													
ENGR & OTHER ALLOCATED COSTS		6130													
SUBTOTAL		64702													
GENERAL ENGINEERING AND ADMINISTRATION		9058													
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (1)		6988													
AD VALOREM TAX DURING CONSTRUCTION (2)		168													
TOTAL CURRENT COST		80916													
ESCALATION (3)		43047													
TOTAL ESTIMATED PROJECT COST		123964													

ATTACHMENT C

AN ANALYSIS OF RR AND DCF APPROACHES

AN ANALYSIS OF RR AND DCF APPROACHES

The following symbols will be used:

C = Capital cost

f_e = Equity fraction

ρ_e = Required rate of return to equity

ρ_d = Interest rate on debt

D_{B_j} = "Book" depreciation in year j

D_{T_j} = Tax depreciation in year j

W_j = O&M costs in year j

G_j = Gross Revenue Requirement in year j (RR method)

R_j = Revenue in year j (DCF method)

r_j = Total profit required in year j

i_j = Total interest on debt in year j

n = Project life (years)

For the RR method, income tax liability in year j is:

$Tax_j = t (G_j - D_{T_j} - W_j - i_j)$ where t = tax rate and the required profit is:

$$r_j = G_j - D_{B_j} - W_j - i_j - Tax_j$$

assuming that negative tax liabilities can be counted as income.

So that

$$G_j = W_j + i_j + \frac{1}{1-t} (r_j + D_{B_j} - tD_{r_j}) \quad (1)$$

Now, the unleveraged cash flow in year j is:

$$\begin{aligned}
 CF_j &= R_j - W_j - \text{Tax}_j \\
 &= R_j - W_j - t(R_j - D_{r_j} - W_j - i_j) \\
 &= (1-t)R_j - (1-t)W_j + tD_{T_j} + ti_j \quad \text{---(2)}
 \end{aligned}$$

Let $P_d ()$ be the present-value operator, where $P_d(x_j) = \sum_{d=1}^n x_j d^j$ where d is some discount rate. Then by definition, R_j is chosen so that, for a given d , from equation (2):

$$C = (1-t) P_d (R_j) - (1-t) P_d (W_j) + tP_d (D_{T_j}) + tP_d (i_j)$$

Dropping the subscript d , we obtain:

$$P(R_j) = \frac{C}{1-t} + P(W_j) - \frac{t}{1-t} (P(D_{T_j}) + P(C_j)) \quad \text{---(3)}$$

For the RR method, G_j is chosen so that, from eqn (1):

$$P(G_j) = P(W_j) + P(i_j) + \frac{1}{(1-t)} (P(r_j) + P(D_{B_j}) - tP(D_{T_j})) \quad \text{---(4)}$$

If $P(R_j) = P(G_j)$, from equations (3) and (4):

$$\begin{aligned}
 \frac{C}{(1-t)} + P(W_j) - \frac{t}{(1-t)} P(D_{T_j}) - \frac{t}{(1-t)} P(i_j) &= P(W_j) + P(i_j) + P(V_j) \\
 + \frac{1}{(1-t)} P(D_{B_j}) - \frac{t}{(1-t)} P(D_{T_j}) \\
 \therefore C &= P(i_j) + P(r_j) + P(D_{B_j})
 \end{aligned}$$

Assuming that $D_{B_j} = 1/n$, and that debt and equity are retired at the same uniform rate, then:

$$C = C \sum_{j=1}^n d^j \left(\frac{(n+1-j)}{n} \cdot (1 - f_e) \rho_d + \frac{(n+1-j)}{n} f_e \rho_e + \frac{1}{n} \right)$$

$$\therefore n = d \left(\frac{1-d^n}{1-d} \right) + [(1-f_e)\rho_d + f_e\rho_e] \frac{d}{(1-d)^2} [n - (n+1)d + d^{n+1}]$$

Write $(1 - f_e) \rho_d + f_e \rho_e = r$. Then

$$n = \frac{d}{(1-d)} (1-d^n) + \frac{dr}{(1-d)^2} [n - (n+1)d + d^{n+1}]$$

Solving for r yields

$$r = \frac{1}{d} \left[\frac{n - (2n+1)d + (n+1)d^2 + d^{n+1} - d^{n+1}}{n - (n+1)d + d^{n+1}} \right] = \frac{1-d}{d}$$

$$\therefore d = \frac{1}{1+r}$$

This indicates that the revenue streams derived by the DCF and RR methods are equivalent if the tax-free discount rate is used*.

* A more detailed treatment of the situation may be found in Wong, Y.C.: "The Discounted Cash Flow (DCF) and Revenue Requirements (RR) Methodologies in Energy Cost Analysis", Institute for Energy Analysis, Oak Ridge Associated Universities, Oak Ridge, Tennessee 37830.