ECONOMIC ASSESSMENT OF GEOTHERMAL
DIRECT HEAT TECHNOLOGY
A Review of Five DOE Demonstration Projects

Interim Topical Report
October 1980 to June 1981

William F. Hederman, Jr.
Laura A. Cohen

June 1981

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U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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EXECUTIVE SUMMARY

In this report the cost of using low temperature geothermal energy resources for direct heating applications is compared to the costs associated with conventional heating fuels. The projects compared all involved replacing conventional fuels (e.g., natural gas and fuel oils) with geothermal energy in existing heating systems. The cost of using geothermal energy in existing systems was also compared with the cost of new coal-fired equipment.

The costs for the geothermal retrofit projects were estimated based on the results to date in five projects partially funded by the U.S. Department of Energy (DOE). These cost estimates are highly realistic since four of the five projects are operational and the other project is currently under construction. The five projects examined are:

- Diamond Ring Ranch, which uses geothermal water from a previously existing well to heat several small buildings and to dry grain on a private ranch in South Dakota. (Operational: 1979)
- Klamath YMCA, which uses geothermal energy to heat a swimming pool and to provide space and water heating to a YMCA Building in Klamath Falls, Oregon. (Operational: 1980)
- Pagosa Springs, Colorado, where the local government is developing a near-the-surface geothermal resource to provide district heating for at least 127 businesses, residences, and public facilities. (Operation planned: 1981)
- Philip, South Dakota, where a local government has developed a small district heating system to heat five school buildings and at least eight businesses. (Operational: 1980)
- St. Mary's Hospital, which provides space heating and hot water preheating to a hospital in South Dakota. (Operational: 1980)

APPROACH

The approach used to compare the projects was a discounted cash flow analysis. The costs of the different projects were adjusted to account for the particular financial situation faced by each of three types of investors:

- private, for-profit firms
- non-profit organizations without tax exempt bond authority, and
- local governments (or non-profit organizations with tax-exempt bond authority)

The costs of all the alternatives for each investor type were then converted to a levelized unit cost (in constant dollars) of conventional energy displaced over the projected life of the geothermal project. Conventional fuel prices were estimated based on a recent DOE world oil price forecast in which oil prices increase about three percent annually.

Subsequently, a sensitivity analysis was performed to assess the effect of changes in the original assumptions. The assumptions which were altered in the sensitivity analysis included project costs, geothermal fluid flow over time, financing, federal tax policy, and world oil prices.

RESULTS

Table S-1 summarizes the results of the Base Case economic comparison. The table shows that for each of the potential investor categories examined, the full range of geothermal energy costs lies below the range of the conventional fuel costs. The sensitivity analysis indicated that geothermal energy maintains its economic advantage under most circumstances.

The difference between the geothermal costs and conventional fuel costs (except for new coal projects) are least for the private, for-profit investor and greatest for the local government investor. The major cause of the differences between investor groups is that the private, for-profit firm must pay taxes and faces a higher cost of capital and relevant discount rate than government and non-profit institutions.

Within each investor category, the costs for different geothermal projects vary significantly. Five projects are not sufficient to assess conclusively the relative importance of different application or resource characteristics in the determination of unit costs, but it appears that well depth is a particularly important determinant of geothermal energy supply costs. Other factors that may prove to be important include geothermal fluid temperature, flow rate, and well capacity utilization.

CONCLUSIONS AND NEXT STEPS

The economic assessment performed in this study indicates that geothermal energy can provide an economical alternative to conventional fossil fuels in low temperature heating applications. The cost estimates developed should be applicable to similar projects when the geothermal resource to be used is known to resemble to the resources used in the projects examined. Consequently, potential investors in geothermal direct heat applications can use the results of this study to evaluate the economic attractiveness of proposed projects in some specific locations.

The generally favorable preliminary findings in this report about the economic attractiveness of geothermal energy indicates the need for additional

TABLE S-1

COMPARISON OF BASE CASE COST ESTIMATE RANGES
(1980 dollars per million Btu)

<u>Investor Type</u>	<u>Range of Cost Estimates</u>	
	<u>Geothermal</u>	<u>Conventional Fuels</u>
Profit, for-profit	\$2.37 - \$5.73	\$5.82 - \$ 9.33
Non-profit ¹	\$1.77 - \$4.17	\$6.10 - \$10.34
Local government ²	\$1.33 - \$2.65	\$6.28 - \$10.79

¹ Without tax-exempt bond authority.

² Or non-profit with tax-exempt bond authority.

analysis along two avenues of inquiry. First, the preliminary findings based on projects using known geothermal resources should be verified. Second, the economic assessment must expand its scope of analysis to include the costs associated with identifying and confirming the presence of a useful geothermal resource.

The validity of the study's results would be enhanced by improving both the geothermal and the conventional energy cost estimates. The geothermal cost estimates can be improved by expanding the geothermal direct heat project data base with data from additional projects. For conventional fuel costs, future work should refine the efficiency estimates used for heating equipment and examine the likelihood of different fuel price escalation rates in greater detail.

The identification of a geothermal resource and the confirmation of its quality requires an analysis of the costs and risks of such activities and the means to finance them. The act of identifying and confirming the quality of a geothermal reserve may or may not lead to an exploitable resource. Future work on the economics of geothermal direct heat applications should estimate the costs of identifying and confirming the required resources and the risks at each stage that a resource could prove unacceptable. Means of reducing the effective costs of such activity through full use of the tax advantages available and through creative financing approaches should also be explored.

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I. INTRODUCTION

During the last ten years, world oil prices have increased from \$7 to \$35 per barrel (measured in 1980 dollars). Although currently controlled at much lower levels, natural gas prices are following oil price trends and will increase substantially when price controls are eliminated in the near future. As a result, several alternative energy forms are becoming competitive with oil and gas for some purposes.

One promising alternative source is geothermal energy, which includes resources with a wide range of temperatures. These resources are suitable for numerous applications from low temperature heating to the production of high temperature steam for use in generating electricity.¹

This report focuses on low temperature direct heat applications, such as space heating and cooling, agricultural uses, and industrial process heat, which utilize geothermal resources with temperatures in the range 100°F to 160°F. The report examines the economic feasibility of replacing conventional fuel in existing low temperature space, water, or process heat applications with geothermal energy. The retrofit investment decision is analyzed for three kinds of potential investors:

- Private firms,
- Non-profit organizations, and
- Local governments.

Due to the different costs of capital and tax treatment for different kinds of organizations, the relative costs and benefits of investing in geothermal energy differ for these three investor types.

This report has been prepared for two purposes. First, to provide potential investors in geothermal heating projects with the best information currently available on (1) the costs of operating such projects and (2) the economics of these projects relative to conventional alternatives. Second, to identify areas of uncertainty with respect to geothermal project economics that require more attention.

This preliminary analysis of the comparative economics of several geothermal direct heat applications is based on the experience to date in only five projects. Consequently, the findings developed in this report are not conclusive. Nevertheless, the projects reviewed appear to utilize low temperature geothermal energy in circumstances which are not unique and which could be repeated in other locations:

¹ Geothermal electricity generation applications were the first large scale uses of geothermal energy, and such high temperature applications as the Geysers field in Northern California represent the most significant use of geothermal energy in the United States today.

- The projects examined include a variety of typical geothermal direct heat applications.
- The characteristics of the geothermal resources used for the projects appear to be typical of resources which might be tapped for future projects. Resource conditions are not, in general, unusually favorable. Rather, the geothermal resources utilized by the projects under review vary substantially in temperature, depth, and level of impurities. One project requires a fluid treatment plant prior to disposal of fluid into surface waters; another reinjects the geothermal fluid back into underground reservoirs. Well depths vary from 275 to 4300 feet, and temperatures range from 100 to 160 degrees Fahrenheit.
- For the most part, the costs utilized in the financial analysis represent actual project experience, rather than uncertain engineering estimates. Four of the projects are already operational, and the remaining project (Pagosa Springs) is expected to begin operations later this year.

However, the geothermal resource was adequate for the application in all the projects analyzed, and for an untapped geothermal resource, this is not always the case.

Consequently, the analysis presented in this report can be of value to potential investors under two sets of circumstances. First, when the investor has a rough estimate of a geothermal resource's depth and temperature and needs to determine the potential payoff in a particular application, this information should assist in deciding to invest in a complete resource assessment. Second, when an investor has a relatively complete understanding of the geothermal resource characteristics (depth, temperature, flow rate, impurities, etc.), this analysis can help the investor decide whether to develop a system to apply the resource to a set of energy uses.

Opportunities for the utilization of geothermal resources in direct heat applications exist throughout the western portion of the United States. The map in Figure I-1 displays known geothermal resource areas and indicates the locations of the five projects reviewed in this report.

BACKGROUND

Through two Program Opportunity Notices, DOE has provided financial support for twenty-two geothermal energy projects to obtain data about actual operating conditions and evidence of economic attractiveness for a variety of direct heat applications. Although the operating experience from these projects remains limited, several of them have achieved routine commercial scale operation or are close enough to such operation that costs and performance can be estimated with confidence. Of the 22 DOE-supported projects, five were chosen for this analysis. These projects were all retrofit applications in which conventional fuels were replaced with geothermal energy. These five projects cover three main applications:

FIGURE I-1

KNOWN AND POTENTIAL HYDROTHERMAL RESOURCES

LS8020918-1/9

SOURCE: Interagency Geothermal Coordinating Council, Geothermal Energy, Research, Development and Demonstration Program: Fourth Annual Report (DOE/RA-0050; IGCC-5) Washington, D.C., June 1980, p. 20.

- District Heating: The district heating system in Pagosa Springs, Colorado will provide space heating for more than 100 structures. A smaller scale district heating system in Philip, South Dakota serves several school and business district buildings.
- Agricultural Process Heat: At the Diamond Ring Ranch in Haakon, South Dakota, geothermal energy provides heat for grain drying, as well as for space and water heating.
- Space and Water Heating in a Commercial Structure: The St. Mary's Hospital in Pierre, South Dakota and the Klamath County, Oregon YMCA utilize geothermal resources for space and water heating.

PROJECT SUMMARIES

Following are brief descriptions of the geothermal direct heat application projects reviewed. The project summary reports from the latest semi-annual geothermal direct heat program meeting provide more information on these projects. They are included in Appendix A. In the project summary paragraphs below, all capital and operating costs are presented in constant 1980 dollars.¹ The costs shown have been adjusted for consistency as described in Chapter II.² Table I-1 presents a summary of six important project parameters: well depth, geothermal fluid temperature, planned project life, capital cost, annual operating and maintenance (O&M) cost, and annual energy delivered.

Diamond Ring Ranch

At the Diamond Ring Ranch, a privately-owned enterprise in Haakon County, South Dakota, geothermal energy provides space heating for six ranch buildings and process heat for a 700 bushel per hour grain dryer. The system, which began operations in the fall of 1979, delivers 7,800 million Btu per year, displacing 185,000 kwh of electricity and 49,400 gallons of propane. 152°F fluid from a 4100 foot well drilled into the Madison aquifer in 1959 flows at approximately 170 gallons per minute (gpm). After circulating through the grain dryer or through a plate-type isolation heat exchanger, the geothermal fluid is discharged to surface reservoirs. Project capital costs, including the costs which would have been incurred in drilling a new well, total \$489,000; yearly operating and maintenance (O&M) expenses are expected to be \$5,000.

¹ Unless otherwise stated, all dollar figures throughout this report are in 1980 dollars.

² Appendix B presents unit costs for each project based on the unadjusted data.

TABLE I-1
PROJECT DATA SUMMARY

<u>Project</u>	<u>Well Depth</u> (feet)	<u>Fluid Temperature</u>	<u>Planned Project Life a/</u> (years)	<u>Capital Cost b/</u> (1980 dollars)	<u>Annual O&M Cost</u>	<u>Annual Energy Delivered</u> (10 ⁹ Btu)
Diamond Ring Ranch	4100	152°F	20	\$ 489,000 <u>c/</u>	\$5,000	7.9
St. Mary's Hospital	2200	106	30	769,000	10,800	11.4
Klamath YMCA	1400	147	25	285,000	2,100	7.0
Pagosa Springs	275	131	30	1,462,000	50,400	56.7
	300	148				
Philip, S.D.	4300	157	30	1,188,000	4,000	14.8 <u>d/</u>

a/ Project life is the period prior to major capital re-investment.

b/ See text for explanation of adjustment to reported capital costs.

c/ Adjusted to include the cost of a new well and to exclude the cost of extending the pipeline to the existing well site.

d/ Data not available from project; estimated from energy displacement data.

St. Mary's Hospital

The geothermal heating system at St. Mary's hospital in Pierre, South Dakota has been operational since October 1980. 106°F water from the Madison aquifer is used for space heating and preheating of domestic hot water in an existing, retrofitted hospital building and in a new hospital wing. The 2200 foot well flows at 375 gpm. After flowing through plate-type heat exchangers, the geothermal fluid is discharged to the Missouri River. The geothermal system will deliver up to 11,440 million Btu per year (supplying 55 percent of hospital heating needs), allowing a yearly savings of approximately 115,000 gallons of fuel oil. Capital costs for the St. Mary's system total \$769,000; project staff estimate that yearly O & M costs over the life of the project will be approximately \$10,800.

Klamath YMCA

Operation of the geothermal system at the YMCA in Klamath Falls, Oregon began in April 1980. A plate-type stainless steel heat exchanger transfers heat from the 147°F geothermal fluid to a supply of boiler fluid which is circulated to heat a swimming pool and provide space and domestic hot water heating to the YMCA building. Geothermal fluid flows at 60 to 250 gpm (depending on heating needs) from a 1400 foot production well and is reinjected into a 2000 foot injection well. The system provides approximately 7,000 million Btu per year. Total capital costs for the project were \$285,000; yearly operating costs are \$2,100.

Pagosa Springs

In the town of Pagosa Springs, Colorado, a geothermal district heating system will supply heating to at least 127 businesses, residences, and public buildings. Two shallow wells (300 feet and 275 feet) will provide 131°F and 148°F fluid, respectively, from a Dakota sandstone aquifer at a combined total flow rate of up to 1800 gpm. Clean city water will be heated using two plate heat exchangers; afterward, the geothermal fluid will be discharged to the San Juan River. The heated city water will be circulated to users through two independent closed loops. Construction for the distribution system and building retrofit will begin shortly. At capacity, the system is expected to deliver 56,700 million Btu annually, replacing approximately 82,500 million Btu of natural gas. In the first year of operations, now scheduled for the 1981 - 1982 heating season, the geothermal system will operate at approximately 38 percent capacity. Total project capital costs are estimated at \$1,462,000; yearly O&M costs will be \$50,400 at full capacity.

Philip, South Dakota

The Philip geothermal project comprises a small-scale district heating system. 157°F fluid flowing at 300 gpm from a 4300 foot well in the Madison aquifer is supplied to five school buildings and then cascaded to eight business district buildings. After treatment in a barium chloride plant to

remove Radium 226, the fluid is discharged to the Bad River. The geothermal system displaces 17,800 million Btu's currently supplied by fuel oil, propane, and electricity. Operation of the system began in November 1980. The total project capital costs were \$1,188,000; yearly O&M costs will total approximately \$4,000.

ORGANIZATION OF REPORT

The next chapter of this report explains the approach used to perform the economic assessment. Chapter III presents geothermal direct heat unit cost estimates and compares these to the unit costs of conventional fuels. The sensitivity of the results of the comparative analysis to changes in key factors and assumptions is explored in Chapter IV. The final chapter discusses the general economic competitiveness of geothermal direct heat applications and briefly considers the implications of this study's results.

II. ASSESSMENT APPROACH

This study was undertaken to evaluate the economic potential of geothermal energy in direct heat applications based on the experience to date in commercial projects. This chapter presents the approach used to analyze the geothermal projects undertaken to date.

Investment projects can be analyzed using a variety of analytic techniques. For this study, we use a discounted cash flow analysis to compare geothermal and fossil fuel project costs. The results of the analysis are presented in terms of levelized unit cost estimates for geothermal energy and conventional fuels over the life of the geothermal projects.

There are two advantages to using levelized unit costs rather than the equivalent net present value of total discounted project costs. First, project costs are developed in terms which should be familiar to energy users, namely, the cost per million Btu's of energy. Second, the unit cost approach makes it easy to compare projects of different sizes.

To permit a meaningful comparison of cost estimates, it was necessary to develop a consistent set of assumptions which could be applied across all geothermal projects and conventional energy alternatives. The major assumptions that must be supplied to perform the analysis include:

- The capital structure (debt to equity ratio), costs of capital, and the discount rate associated with investments made by each type of investor,
- Inflation rate,
- Specific capital and operating and maintenance (O&M) costs to be included in the geothermal project cost calculations,
- Taxes and the tax treatment of geothermal project costs,
- Point of measurement of energy quantities used in each system,
- Geothermal project start-up date, project life, and the amount of energy supplied in each year, and
- The fossil fuels to be compared to geothermal energy and the projected prices of these fuels over the lives of the geothermal projects.

The specific assumptions and the rationale for choosing them are discussed below.

FINANCIAL ASSUMPTIONS

In computing the costs of investment alternatives, assumptions must be made about the investor's capital structure (debt to equity ratio), interest rate on debt, and return on equity. These factors can vary greatly depending on the legal status of the investor. For this analysis, three sets of financial assumptions were made, corresponding to each of the three types of investor situations under review.

The assumptions made about capital structure and the cost of capital affect the discount rate used to compute the unit energy costs faced by each investor. A dollar saved in the future through reduced fuel consumption is not worth as much to an investor as a dollar that must be invested today. In comparing energy supply options which have differing cash flow patterns, therefore, the value of future cash flows must be discounted. The discount rate applied to an energy supply project should equal the rate of return from the best alternative investment available to the project sponsor.

The choice of the discount rate is an important determinant of the outcome of the analysis. Investments in geothermal systems, which have large initial capital costs, will not look as attractive when a high discount rate is used because the present value of future savings will be small. The following paragraphs discuss the discount rate, capital structure and cost of capital assumptions used for each investor type. A detailed list of the economic and financial assumptions used in the analysis is contained in Appendix B.

Private Firms

In analyzing the geothermal retrofit decision for private business firms, an initial debt to equity ratio of 50/50 was assumed. This may be a conservative estimate of the debt share. Although geothermal projects are still considered to be risky ventures, some lending institutions have indicated that they may be willing to finance up to 75 percent of project capital costs. Use of a relatively low debt to equity ratio results in higher unit geothermal costs, since a low debt to equity ratio implies a large share of high cost equity capital and a small share of lower-cost debt capital.

The real rate of interest on corporate debt and the rate of return on equity for private firms are assumed to be three percent and 9.5 percent, respectively. These rates are based upon DOE cost estimation guidelines for capital investment projects.¹ With 10 percent annual inflation, these real debt and equity rates are equivalent to nominal rates of 13 percent and 20 percent.² This required rate of return on equity is set very high to

¹ DOE, Office of Policy and Evaluation, "Standardized Cost Estimation," SP-052, December 4, 1978 draft, p. 48.

² $(1.095 \times 1.10) - 1.0 = 0.20$.

capture the risk generally associated with investments in geothermal energy; the use of a lower rate of return would make the results more favorable for geothermal projects.

In performing the financial analysis, interest expenses are treated as fixed costs and all cash flows are discounted at the 9.5 percent per year (real) return on equity rate. This method assures that the unit cost which is calculated will be just large enough to cover all project costs including the rate of return required by equity holders.

Non-profit Organizations and Local Governments

We have assumed that local governments and private, not-for-profit institutions undertaking geothermal investments would finance these projects entirely from new debt issues. The discount rate for these two investor types was set equal to the interest rate, which represents the cost of capital to these organizations. For non-profit organizations that cannot issue tax-exempt bonds, we assumed that the real interest rate would equal the private firm interest rate of 3 percent. Based on a review of interest rates during the last few years, the nominal interest rate for local governments and other institutions which can issue tax-exempt bonds (e.g., hospitals) was set at 75 percent of the nominal corporate interest rate.

INFLATION RATE

The GNP deflator was used to represent the general inflation rate for all cost and revenue streams. The actual GNP deflator was employed for all years prior to 1981 and the Congressional Budget Office projections were used for 1981 through 1986. Beyond 1986, the analysis assumes a constant 7 percent annual inflation rate. Using these assumptions, the average annual inflation rate for a 30-year project which starts operations in 1981 is 7.2 percent. Table II-1 provides a year-by-year listing of the inflation rates used in the analysis.

COSTS

The geothermal unit cost estimates are based on cost data from five commercial scale geothermal projects. All of the costs associated with a geothermal project using a known resource are incorporated into the financial analysis. These costs include the costs of resource assessment, well drilling, system design and construction, testing, project management, anticipated capital equipment replacement, and expected yearly operating and maintenance activity. The cost data used in the analysis were obtained from geothermal project documentation as well as discussions with DOE personnel and geothermal project staffs. These data reflect the actual capital costs incurred by the four operational projects and the best engineering estimates of capital costs for the remaining project. The O&M cost data incorporate the latest estimates of annual O&M expenses over the life of each project.

TABLE II-1
INFLATION RATE
(annual percent change)

<u>Year</u>	<u>Rate</u>
1979	8.5%
1980	9.0%
1981	10.3%
1982	9.2%
1983	8.6%
1984	8.1%
1985	7.5%
1986	7.0%
thereafter	7.0%

Sources: 1979 and 1980 rates from Survey of Current Business, March 1981, p. 14; rate projections from U.S. Congressional Budget Office, Economic Policy and the Outlook for the Economy, March 1981, p. 62.

To insure consistency across projects and make the analysis more useful for future investors, minor adjustments were made to the cost data reported by the projects. For instance, the cost data received from the projects did not include royalties or resource acquisition costs because all five project sponsors already held title to the geothermal resources prior to project initiation. In order to more closely approximate the situation of future project sponsors who do not own resources, a 10 percent royalty charge on the energy supply costs was assumed.

An additional adjustment was made to the Diamond Ring Ranch capital costs. The Diamond Ring Ranch project made use of an existing well drilled in 1959, which significantly reduced required capital expenditures. In performing the financial analysis, project capital expenditures were increased by the costs of drilling a new well and decreased (to a lesser extent) by the piping costs which would have been saved had a new well been drilled closer to the site where the energy is used.

Finally, expenditures for attending DOE conferences and publicizing project results were deleted from all project cost calculations, since these expenditures have no direct bearing on normal resource development, system construction, or project operations. (These expenses generally amounted to less than two percent of total reported project costs.) In addition to these

DOE-related costs, many other project costs may have been incurred indirectly due to DOE involvement or to the "first-of-a-kind" nature of the projects. No attempt was made to exclude such costs. Rather, these issues are dealt with through a sensitivity analysis, which is presented in Chapter IV.

TAXES AND TAX BENEFITS

For projects undertaken by private for-profit firms, the tax treatment of geothermal costs and revenues has a significant effect on lifecycle project costs and levelized unit costs. Three kinds of taxes are incorporated into the analysis: Federal income taxes, state income taxes, and local property taxes. The Federal income tax rate is set at the current maximum Federal corporate tax rate of 46 percent.

Actual state income taxes for the projects range from zero to 9.4 percent, and local property tax rates and methods of property tax calculation vary widely. For all the projects analyzed the state income tax rate was assumed to be five percent and the property tax rate was assumed to be two percent of the undepreciated historical value of capital equipment.

Several tax benefits reduce the Federal income tax liability born by geothermal projects. Depletion allowances and the expensing of intangible drilling costs serve to reduce taxable income, while the recently enacted energy tax credit provides for a direct reduction of income tax liability. Accelerated depreciation allows the project sponsor to write off project costs more quickly than straight line depreciation, thus reducing income tax liability and saving money in the early project years. In computing Federal income taxes, all four tax benefits are taken into account by assuming that the sponsor has enough taxable income from other operations to enable him to take full advantage of all benefits in the first year in which they would be available.¹

Some states provide similar tax benefits for geothermal energy projects which may be applied against state income tax liability. To deal with these variations, a standard set of assumptions was used to calculate state income taxes. These assumptions include expensing of intangible drilling costs, accelerated depreciation, and no state energy tax credit. A more complete discussion of these tax issues is included in Appendix C.

MEASUREMENT OF ENERGY QUANTITIES

Another important measure requiring consistent treatment across alternative energy supply options is the unit of energy supplied. This does not mean simply converting all energy units to Btu's or barrels-of-oil-equivalents. Typically, geothermal energy is measured in terms of usable energy delivered,

¹ Because of the complexities in computing percentage depletion, the Base Case analysis deducts cost depletion allowances and explores the effect of percentage depletion through sensitivity analysis. See Appendix C for an explanation of cost and percentage depletion deductions.

while fossil fuels are measured in terms of gross energy input into a fuel conversion system. To take account of the inefficiencies in burning fossil fuels and to permit meaningful comparisons of energy costs, all geothermal energy quantities are expressed in terms of the equivalent amount of conventional fuel displaced.

As with project cost data, the energy quantities used in the analysis were those actually reported by the projects. Thus, the amount of conventional fuel displaced reflects both the amount of energy delivered and the efficiency of the existing boiler(s) at each particular project site. In the few cases where no data were available on energy displaced, a 70 percent boiler efficiency was assumed to convert the quantity of energy delivered to the amount of conventional fuel displaced.¹

PROJECT START-UP, LIFE, AND ANNUAL ENERGY USE

Consistent with the desire to use data reflective of actual project experience or plans, the financial analysis incorporates the start-up date, project life, and the annual use of geothermal energy reported by each project. The four operational projects all started in 1979 or 1980; the Pagosa Springs project is expected to begin operation in the fall of 1981. Anticipated project life varies from 20 to 30 years. The two district heating projects plan to increase capacity utilization over the first few years of operations; geothermal energy use for the other projects do not include scale-up periods.

Levelized fossil fuel unit costs vary with the assumptions made regarding the start-up year, project life, and the energy use pattern because fossil fuel prices are expected to increase over time. To be completely consistent, a levelized unit cost for the conventional fuel alternatives should be calculated for each of the projects. This would entail calculating a separate unit fuel cost corresponding to each geothermal project for every conventional fuel and investor type analyzed. For the sake of simplicity, only one unit cost for each fuel is included in our cost comparisons. All fossil fuel costs

¹ Ideally, the same assumed boiler efficiency would have been used for all projects. This was not possible because of a lack of data on the quantities of energy delivered for some projects. Fuel displacement data reported by the projects were expressed in volumetric units such as barrels of oil or thousand cubic feet of natural gas. These quantities were converted to a common unit of measurement (Btu's) using the following conversion factors:

1,000 cubic feet of natural gas = 1.02×10^6 Btu
1 barrel No. 2 fuel oil = 5.825×10^6 Btu
1 barrel residual fuel = 6.283×10^6 Btu
1 gallon propane = 91.6×10^3 Btu
1 kWh electricity = 3.413×10^3 Btu

were calculated using the start-up year, project life, and geothermal energy use pattern for one representative geothermal project: the Philip district heating system. Because the differences in the timing of energy use for the projects analyzed were not large, this simplification has only a minor effect on fossil fuel unit costs and does not significantly bias the conclusions drawn from the comparisons.

FOSSIL FUELS AND FUEL PRICES

The projects reviewed for this report employ geothermal resources to replace energy previously supplied by natural gas, propane, fuel oil, and, to a small extent, electricity. Due to their high costs, these energy sources are all likely candidates for displacement by future geothermal direct heat projects located in the western United States. Alternatively, as liquid and gaseous fuel prices continue to climb, energy users may consider switching to coal.

To determine the competitive potential of geothermal energy, geothermal costs were compared to the costs of five alternatives: natural gas delivered to commercial users, natural gas delivered to industrial users, high-sulfur residual fuel, distillate (home heating oil), and coal. The use of propane as an alternative was not examined; however, propane prices are expected to be between residual fuel and distillate prices in the future.¹

In this analysis, geothermal energy is considered to be a retrofit option. Therefore, the calculation of the unit costs for gas and liquid fuels includes only the fuel costs which would be incurred if an energy user continued to employ an already existing boiler using these fuels. Because equipment to store and burn these fuels is assumed to be already in place, capital costs are excluded from the analysis. In contrast, coal (like geothermal) is assumed to be a retrofit option which requires capital investment to convert existing liquid or gas fired heating systems to coal use. Therefore, the levelized unit coal costs include both capital and O&M costs as well as the projected cost of delivered coal in South Dakota.

This analysis uses a recent DOE world oil price projection, ICF's petroleum product price formulas, and ICF's coal and natural gas market models to project the price paths for the fossil fuels under consideration. The DOE

¹ Propane is used as a substitute for natural gas in isolated areas. It is a premium fuel that historically has been similar to distillate fuel oil in value. Recent oil and gas market conditions, however, have led to a glut of propane supplies, and propane prices currently approximate residual fuel oil prices more closely than distillate rates. As the conditions generating the over-supply of propane subside, the price is likely to increase.

projection shows world oil prices increasing from about \$34 per barrel of crude oil in 1980 to \$47 per barrel in 1990. This projection is equal to an average (real) annual price growth of about three percent throughout the 1980's.

The crude oil price projections were converted to petroleum product price projections using pricing formulas based on the cost of producing products in a new 100,000 barrel per day refinery and the relative market value of different petroleum products. The price functions for distillate fuel oil (P_d), and high sulfur (2.5% S) residual fuel oil (P_r) follow:¹

$$P_d = 0.183 P_c + 0.43$$

$$P_r = .144 P_c - 0.30$$

where P_c = average price per barrel of imported crude oil in 1980 dollars and P_d , and P_r are the prices in dollars per million Btu.

These formulas estimate wholesale product prices at the refinery gate. Distribution costs could increase the prices significantly, depending on the the location where the fuels must be delivered and the amount used. The product prices used in this preliminary analysis are conservative because they include no distribution costs.²

¹ ICF Inc., "Refined Petroleum Product Price Estimation," memorandum to C. Abbott, DOE, January 27, 1981, p. 15, as revised in ICF, "Revised Petroleum Product Price Equations," internal memorandum, March 6, 1981.

² U.S. DOE, Energy Information Administration, Energy Data Report, DOE/EIA-0013 (81/01), January 1981, Table 4, estimates the December 1980 national average gross margins at 14.1 cents per gallon (\$1.02 per million Btu) for distillate heating oil. However, this price is largely based on deliveries to homes, and the projects examined were generally much larger fuel users and who would pay lower distribution costs.

The petroleum product price projections are presented for each year in Table II-2. Clearly, if the DOE projection proves accurate and the projected price trends continue beyond the projection period, the price of these alternative fuels will grow significantly over the typical thirty year project life of a geothermal direct heat supply project.

Continued use of natural gas represents another likely alternative to using geothermal direct heat energy. Projection of natural gas prices involves greater uncertainty than oil price projections because the timing of wellhead price deregulation -- currently scheduled for 1985 -- is unclear and because the clearing price for gas will depend heavily on the demand for gas in the future. This analysis uses a recent preliminary DOE natural gas price projection through 1995¹ and assumes the trend for the last five years of the projection would continue throughout the life of the geothermal project.

Coal is the final alternative conventional fuel included in this analysis. Because most geothermal direct heat applications would occur in the West, Northwest, or Great Plains regions, the analysis is based on the use of low-sulfur subbituminous coal. Because the Philip project would need a ten million Btu per hour coal-fired boiler, this size boiler was used for the cost estimates presented in the Base Case analysis. The capital costs used for the coal boiler were 1.08 million dollars for a ten million Btu per hour coal-fired boiler and \$68,000 per year for O&M costs.² Coal price projections are presented year-by-year in Table II-2. They are developed for coal delivered to South Dakota.³

¹ DOE, OPPIA, "Preliminary Results of Gas Decontrol Analysis," Draft, April 17, 1981. The DOE projection was developed using ICF's Natural Gas Market Evaluation System. It assumes "new" natural gas is decontrolled in 1985.

² These costs were estimated conservatively prorating ICF Industrial Boiler Fuel Choice Model coal equipment and price estimates (May 1981) for a 20 million Btu per hour boiler.

³ In 1980, the delivered price is \$1.30 per million Btu, which is based on costs of \$0.43 per million Btu at the minemouth and \$0.87 per million Btu truck transport costs.

TABLE II-2
CONVENTIONAL FUEL PRICES USED IN THE ANALYSIS¹
(1980 \$/MMBtu)

Year	Distillate Fuel Oil ²	High-Sulfur Residual Fuel Oil ²	Natural Gas (Commercial)	Natural Gas (Industry)	Coal (low-sulfur, subbituminous) ³
1981	7.11	4.93	4.01	3.55	1.37
1982	7.26	5.06	4.22	3.75	1.44
1983	7.43	5.19	4.43	3.97	1.51
1984	7.60	5.31	4.61	4.15	1.58
1985	7.76	5.45	6.50	6.04	1.64
1986	8.00	5.64	6.52	6.07	1.65
1987	8.25	5.83	6.59	6.13	1.65
1988	8.51	6.04	6.78	6.32	1.65
1989	8.77	6.25	6.92	6.46	1.65
1990	9.05	6.46	7.07	6.61	1.66
1991	9.32	6.68	7.20	6.74	1.66
1992	9.61	6.90	7.35	6.89	1.66
1993	9.90	7.13	7.44	6.98	1.67
1994	10.21	7.37	7.59	7.13	1.67
1995	10.51	7.61	7.75	7.29	1.67
1996	10.77	7.81	7.87	7.41	1.68
1997	11.03	8.01	7.98	7.53	1.68
1998	11.30	8.22	8.10	7.65	1.68
1999	11.57	8.43	8.23	7.77	1.68
2000	11.85	8.65	8.35	7.89	1.69
2001	12.14	8.88	8.48	8.02	1.69
2002	12.43	9.11	8.61	8.15	1.70
2003	12.74	9.34	8.73	8.28	1.70
2004	13.05	9.59	8.87	8.41	1.71
2005	13.37	9.84	9.00	8.54	1.71
2006	13.69	10.09	9.13	8.68	1.72
2007	14.02	10.36	9.27	8.82	1.72
2008	14.36	10.62	9.41	8.96	1.73
2009	14.71	10.90	9.55	9.10	1.73
2010	15.07	11.18	9.69	9.25	1.74

¹ Based on a world oil price of \$34/barrel in 1980, increasing at an average of approximately 3% annually in real terms.

² Refinery gate prices; does not include any product distribution costs.

³ Coal costs must be increased to account for capital and O&M costs incurred in the retrofit application before they can be compared to geothermal project costs.

III. BASE CASE RESULTS

The potential economic reward for investing in geothermal direct heat projects is the monetary savings that a geothermal energy supply system could provide relative to the cost of continuing to purchase conventional fuels. This chapter presents the results of the cost analysis performed for geothermal energy and several conventional fuel alternatives for five heating applications.

As discussed previously, the costs of geothermal energy and conventional fuels depend on the status of the organization paying the costs. Consequently, cost estimates are presented for the three major types of potential investors in geothermal energy projects:

- private, for-profit firms,
- non-profit organizations that cannot issue tax-exempt bonds, and
- local governments (or non-profit organizations with tax-exempt bond authority).

The cost estimates are presented separately for each type of investor to facilitate the comparison of alternative energy forms.

PRIVATE, FOR-PROFIT FIRM

Table III-1 presents the levelized unit costs that a private, for-profit firm would incur to fulfill the heating requirements in each of the projects using each type of energy beginning in 1981.¹

The results in Table III-1 shows that geothermal energy represents the most economical energy supply option for each heating project when a private firm would be making the supply investment. Only natural gas at industrial user prices comes close to geothermal costs, and an investor in the small scale applications considered here could only obtain such prices if the project were part of a much larger industrial load.²

As discussed previously, any exploration costs required to identify the geothermal resource and to determine the resource's suitability for each project are not included in the geothermal cost estimates. It appears that in at least four of the five projects examined here the resource was well known

¹ See Appendix D for an illustrative financial model output.

² Moreover, the natural gas prices shown may be optimistic because they include the four years of low cost gas prices that will precede decontrol of new domestic gas supplies in 1985.

TABLE III-1

COMPARATIVE ENERGY COST ESTIMATES FOR
A PRIVATE, FOR-PROFIT FIRM INVESTMENT
GEOTHERMAL VERSUS CONVENTIONAL FUELS
(1980 dollars per million Btus)

<u>Project</u>	<u>Geothermal*</u>	<u>Distillate</u>	<u>High-Sulfur Residual</u>	<u>Natural Gas (Commercial)</u>	<u>Natural Gas (Industrial)</u>	<u>Coal</u>
Diamond Ring Ranch	4.68	8.56	6.07	6.11	5.65	6.39
Klamath YMCA	2.37	8.83	6.29	6.28	5.82	6.78
Pagosa	2.56	9.33	6.68	6.75	6.29	6.55
Philip	5.73	9.07	6.47	6.43	5.97	9.30
St. Mary's	4.79	9.05	6.46	6.41	5.95	6.86

* Excludes any exploration costs required to identify the geothermal resource and assess its suitability for the project.

prior to project initiation. The three South Dakota projects, for instance, use geothermally heated water from the large Madison aquifer, which has served as a South Dakotan water supply. Similarly, the Pagosa Spring resource was already employed for many individual uses, and the original plan called for the use of existing wells.¹

This omission means that the geothermal cost estimates provided for all the cases examined in this analysis relate to sites with well-understood geothermal resources. Analysis of the costs of exploring for and assessing a geothermal resource has not been part of this effort.

All the fossil fuel costs presented in Table III-1, except coal, are the levelized unit cost for the fuel displaced (i.e., saved) only and do not include any capital or O&M costs for fuel-burning equipment. A comparison of these costs is appropriate for an investor deciding whether to modify an existing fossil fuel-burning facility to use geothermal energy. For a new facility an investor would compare the geothermal costs presented here to the fuel costs plus related fuel-burning equipment costs.

As noted earlier, the coal cost figures include equipment costs because coal currently has been used so rarely in such small scale applications in recent years that the retrofit comparison is not useful. The costs represent estimates of the capital, O&M (fixed and variable), and the coal required to supply the amount of energy provided by each geothermal project.

NON-PROFIT ORGANIZATION

The energy supply costs relevant to a non-profit project sponsor such as the Klamath YMCA are presented in Table III-2. These cost estimates are levelized using a discount rate equal to the cost of corporate debt because the potential sponsor is assumed to finance capital investment projects entirely through debt instruments which are not tax-exempt.

Some non-profit organizations can issue tax-exempt bonds. Hospitals are often able to issue such debt instruments. A potential investor who has access to tax-exempt bond authority would use the "local government" cost figures (Table III-3) as a guide.

The cost estimates in Table III-2 show that geothermal's cost advantage relative to conventional fuels is greater for a non-profit agency without tax-exempt bond authority than it is for a private, for-profit investor. Because the cost of capital (i.e., the discount rate) is lower than in the

¹ Problems with well integrity led to the drilling of two new wells into the same aquifer.

TABLE III-2

COMPARATIVE ENERGY COST ESTIMATES FOR
A NON-PROFIT ORGANIZATION INVESTMENT
GEOTHERMAL VERSUS CONVENTIONAL FUELS
(1980 dollars per million Btus)

<u>Project</u>	<u>Geothermal*</u>	<u>Distillate</u>	<u>High-Sulfur Residual</u>	<u>Natural Gas (Commercial)</u>	<u>Coal</u>
Diamond Ring Ranch**	N/A	N/A	N/A	N/A	N/A
Klamath YMCA	1.77	9.57	6.87	6.88	5.49
Pagosa**	N/A	N/A	N/A	N/A	N/A
Philip	3.68	10.12	7.25	7.17	7.28
St. Mary's	4.17	10.11	7.29	7.16	5.41

* Excludes any exploration costs required to identify the geothermal resource and assess its suitability for the project.

** Listed as not applicable because a non-profit organization is unlikely to install grain drying or a large district heating system.

for-profit case, the capital intensive options (geothermal and coal) have lower levelized costs and the conventional fuel options with cost growth over time have higher levelized costs than in the for-profit case.¹

¹ Two cases, Diamond Ring Ranch and Pagosa, are listed as "not applicable" to non-profit organizations because such potential sponsors are unlikely to implement such applications as gain drying or a large district heating system.

LOCAL GOVERNMENT

Table III-3 presents the cost estimates for investments made by local government or non-profit institutions with the authority to issue tax-exempt bonds. The tax-exempt bond status leads to a discount rate applicable for this type of investor which is lower than for either of the other types of sponsors.

The results show lower geothermal costs and higher conventional fuel costs (except coal) than for the other investor categories, which further enhance geothermal energy's economic advantage. Geothermal also remains far superior to coal for the small scale applications reviewed.

INTER-PROJECT GEOTHERMAL COST DIFFERENCES

Within each of the three investor classes just examined, the unit costs of the geothermal energy projects vary significantly. The highest unit costs are 2.0 to 2.4 times the lowest unit costs.

Five projects do not provide an adequate data base for a definitive evaluation of the cause of geothermal cost variations. However, a review of the cost data and the project characteristics suggests that well depth is quite important to geothermal energy project costs. Other factors that appear likely to influence costs are the temperature of the geothermal fluid, the rate at which the fluid flows from the well, and the extent to which the full capacity of each geothermal well is used.

INTERNAL RATE OF RETURN

The Base Case analysis presented in this chapter presents the levelized unit cost for geothermal projects, given an assumed cost of capital to project sponsors. An alternative way of examining the competitive advantage of geothermal energy is to calculate the after tax internal rate of return which could be earned by a project when the value of the geothermal energy used is set equal to the cost of the fuel replaced. Table III-4 shows the real internal rates of return which result when geothermal energy is valued at the same price per Btu as commercial natural gas, the cheapest of the gas and liquid fossil fuels examined. These internal rates of return vary from 17 percent (real) for Philip, the project with the highest unit energy cost, to 34 percent (real) for Pagosa Springs, which has the lowest unit geothermal cost.

Geothermal direct heat energy systems appear to offer an attractive investment opportunity if a potential investor has access to a geothermal resource similar to that at any of the five projects reviewed, given the base case assumptions. These assumptions may not all prove to be valid. The next chapter explores the sensitivity of the economic attractiveness of geothermal direct heat when some of these assumptions change.

TABLE III-3

COMPARATIVE ENERGY COST ESTIMATES FOR
A LOCAL GOVERNMENT INVESTMENT
GEOTHERMAL VERSUS CONVENTIONAL FUELS
(1980 dollars per million Btus)

Project	Geothermal*	Distillate	High-Sulfur Residual	Natural Gas (Commercial)	Coal
Diamond Ring Ranch**	N/A	N/A	N/A	N/A	N/A
Klamath YMCA	1.34	9.90	7.13	7.11	4.94
Pagosa**	1.33	10.79	7.83	7.66	4.35
Philip	2.65	10.61	7.68	7.48	6.48
St. Mary's	2.28	10.60	7.67	7.47	4.85

* Excludes any exploration costs required to identify the geothermal resource and assess its suitability for the project.

** Listed as not applicable because a local government is unlikely to install a grain drying system.

TABLE III-4

INTERNAL RATES OF RETURN TO FOR GEOTHERMAL PROJECTS
(Geothermal Energy Value Set Equal to the Price of
Natural Gas Delivered to Commercial Users)

<u>Project</u>	<u>Internal Rate of Return (real)</u>
Diamond Ring Ranch	19.9%
Klamath YMCA	31.4%
Pagosa Springs	34.1%
Philip	17.4%
St. Mary's	19.6%

IV. SENSITIVITY ANALYSIS RESULTS

The Base Case analysis presented in Chapter III makes certain assumptions about geothermal project costs, sponsor tax status, project financing conditions and conventional fuel prices; however, some of these assumptions may not apply to all future projects. For instance, project capital structure or cost of capital may differ from the Base Case situation. In addition, capital costs could be higher for some future projects, because of particular resource characteristics or complications in the geothermal system. These costs might also be lower, due to removal of indirect DOE-related or first-of-a-kind costs.

Tax treatment of geothermal costs may also change. This will be true, for example, if the energy tax credit is not renewed upon its expiration at the end of 1985. Furthermore, because experience with geothermal energy is still limited, geological and engineering estimates of production streams may be incorrect, and yearly operating costs for the projects examined may prove to be atypical.

Comparisons of geothermal and conventional energy alternatives depend on the price path projections used for conventional fuels as well as on the assumptions made regarding geothermal costs and production. The fossil fuel costs used in the base case analysis are based on a recent DOE forecast of world oil prices and corresponding estimates of coal and natural gas prices from ICF's coal and gas market models. These forecasts assume annual crude oil price increases of approximately three percent; actual price increases may prove to be lower.

We have addressed these areas of uncertainty by performing a sensitivity analysis of the assumptions used to generate the Base Case results. The sensitivity analysis evaluates the effects on project economics and conventional fuel unit prices of changes in cost, production, financial, and economic assumptions.

To simplify the analysis required, the effect of changes in the assumptions was only examined for the Philip district heating project. As Tables III-2 and III-3 indicate, the Philip, S.D. project represents a relatively deep-well, high fluid temperature project that has the highest unit costs for the Base Case.

The alternative fuel costs for distillate and natural gas (to commercial users) are presented for comparison. With the possible exception of propane, these fuels are the fuels most likely to be displaced in significant quantities by geothermal energy. The propane price will most likely be between the prices of these two fuels.

For the sensitivity analysis, the tax and financial assumptions associated with a private, for-profit firm were used in computing the geothermal and conventional fuel unit costs. As shown in the previous chapter, the relative

economics of geothermal energy are even more favorable for non-profit organizations and local governments than for private firms.

By focusing the sensitivity analysis on the cost faced by private business investors for the highest cost geothermal project and the lowest cost fossil fuel, we can identify any cases for which different assumptions would make continued reliance on conventional fuels superior to the use of geothermal energy.

TECHNOLOGICAL UNCERTAINTY

As a result of technological and geological uncertainty, costs and production rates for future similar projects could differ from those assumed in the Base Case. In addition, the elimination of indirect costs of DOE involvement and the first-of-a-kind project costs discussed earlier could result in lower capital costs for future projects.

Both geothermal and conventional fuel unit cost estimates are influenced by these technological and geological assumptions. Although geothermal project cost data have no effect on fossil fuel unit costs, fossil fuel costs are affected by assumptions regarding the geothermal project life and energy use pattern. As geothermal project life is extended to include continued real fuel price increases in later years, the levelized unit costs for displaced fossil fuels rise. Similarly, if geothermal energy use is assumed to decline over the life of the project, a greater proportion of conventional fuel displacement would occur in the early project years when real fuel prices are lower. Hence, the correct unit fuel cost to use in comparison with geothermal costs would be lower than the fuel cost used in the Base Case analysis, which assumed nearly level geothermal energy use over the project's life.

Table IV-1 shows the effects on levelized unit cost of changes in the geothermal cost and production assumptions. Not surprisingly, the results show that the costs for this capital-intensive geothermal energy supply project are much more sensitive to changes of equal proportion in capital costs than in O&M costs. Large decreases in capital costs for future projects or increases in well capacity utilization would result in substantial reductions in the geothermal unit cost.

The data in the table indicates that serious capital cost increases, major production shortfalls, or requirements to add an injection well could make geothermal energy more costly than natural gas in the Philip project. Nevertheless, geothermal energy remains superior to distillate in the Philip project for all cost and production changes examined. In addition, it must be remembered that the unit costs for the Philip geothermal project are the highest of all projects examined. Less costly geothermal projects may be able to withstand major production or capital cost setbacks and still remain more economical than natural gas.

TABLE IV-1
SENSITIVITY ANALYSIS
Technological Uncertainty

<u>Parameter Change</u>	<u>Geothermal Levelized Unit Cost (\$/million Btu)</u>	<u>Ratio of Geothermal to Distillate Levelized Unit Costs</u>	<u>Ratio of Geothermal to Natural Gas (commercial) Levelized Unit Costs</u>
For-Profit Base Case ¹	5.73	1.0	1.0
25% Capital Cost Increase	7.10	.78	1.10
25% O&M Cost Increase	5.78	.64	.90
100% Peak Capacity ²	2.09	.23	.33
Add Injection Well ³	6.95	.77	1.08
Production Decline to 1/2 ⁴	6.40	.73	1.03
Production Decline to 0 ⁴	7.26	.86	1.22
33% Project Life Increase ⁵	5.70	.61	.86
33% Project Life Decrease ⁶	6.11	.71	1.00

¹ Philip data.

² Assumes higher capacity without any cost increases.

³ Injection well cost assumed to equal Philip production well cost

⁴ Linear decline assumed to begin in year 6.

⁵ 40-year levelized price.

⁶ 20-year levelized price.

CAPITAL STRUCTURE AND COST OF CAPITAL

There are several financial variables that have important effects on the relative attractiveness of capital intensive geothermal investments compared to the no-capital liquid and gas fuel options. Table IV-2 presents the results of the sensitivity analysis performed on the financial assumptions. Greater leverage (i.e., a higher share of debt financing) lowers geothermal costs by lowering the effective cost of capital. This factor accounts for the improved economic comparison between the geothermal costs and those for the conventional fuels when the debt to equity ratio is increased. As shown in Table IV-2, however, lowering the debt to equity ratio has the opposite effect on the geothermal price. For a 25/75 debt to equity ratio, geothermal energy would be more costly than natural gas.

The table also shows the effects of a 25 percent change in either the interest rate on debt or the rate of return on equity. The low sensitivity of geothermal costs to changes in interest rates, combined with the fact that interest changes do not affect the discount rate applied to the alternative fuel prices for private firms, leads to little change in the relative economics of geothermal and the alternatives.

Changes in the return on equity, however, affect both the geothermal and conventional fuel costs. As explained earlier, the discount rate for private firms is set equal to the required rate of return on equity. An increase in the discount rate reduces the importance of distant year cash flows relative to near-term cash flows. This has the effect of raising the unit costs for geothermal projects, which are highly capital-intensive, and lowering the unit costs of conventional fuels, whose real prices increase with time. Table IV-2 shows that a real rate of return of 11.875 percent (a 25 percent increase) would make Philip geothermal energy more costly than natural gas. A decrease in the rate of return on equity has the opposite effect.

TAX TREATMENT

For the Base Case analysis, we assumed accelerated depreciation of the geothermal system capital costs using the double declining balance method. Cost depletion, the existence of the Federal energy tax credit, and the existence of local property taxes were also assumed. Changes in these tax treatments lead to changes in geothermal project cost but have no effect on the alternative fuel prices. Table IV-3 presents the results of the sensitivity analysis of the tax treatment assumptions.

Removal of the 15 percent energy tax credit would increase geothermal energy costs by 25 percent, putting geothermal at a disadvantage relative to natural gas. Under current tax law, as established by the Energy Tax Act of 1978 and the Crude Oil Windfall Profits Tax Act of 1980, the energy tax credit will expire in 1985. Either the use of percentage depletion with the break-even revenue requirements examined here or a moderately decreased tax

TABLE IV-2
SENSITIVITY ANALYSIS
Capital Structure and Cost of Capital

<u>Parameter Change</u>	<u>Geothermal Levelized Unit Cost (\$/million Btu)</u>	<u>Ratio of Geothermal to Distillate Levelized Unit Costs</u>	<u>Ratio of Geothermal to Natural Gas (commercial) Levelized Unit Costs</u>
For-Profit Base Case ¹	5.73	1.0	1.0
75/25 Initial Debt/Equity Ratio	4.23	.47	.66
25/75 Initial Debt/Equity Rate	7.22	.80	1.12
25% Increase in Interest Rate (real)	5.81	.64	.90
25% Decrease in Interest Rate (real)	5.64	.62	.88
25% Increase in Return on Equity (real)	6.80	.77	1.10
25% Decrease In Return on Equity (real)	4.72	.50	.71

¹ Philip data.

TABLE IV-3
SENSITIVITY ANALYSIS
Tax Treatment

<u>Parameter Change</u>	<u>Geothermal Levelized Unit Cost (\$/million Btu)</u>	<u>Ratio of Geothermal to Distillate Levelized Unit Costs</u>	<u>Ratio of Geothermal to Natural Gas (commercial) Levelized Unit Costs</u>
For-Profit Base Case ¹	5.73	1.0	1.0
Remove Energy Tax Credit	7.19	.79	1.12
Percentage Depletion	5.44	.60	.85
Tax Life Reduced to 60% of Book Life	5.39	.59	.84
Tax Life Increased to 100% of Book Life	5.96	.66	.93
"10-5-3" Depreciation	3.88	.43	.60
Remove Property Tax	5.27	.58	.82
Remove Royalty	5.15	.57	.80

¹ Philip data.

life would reduce costs by about five percent. Use of the proposed "10-5-3" depreciation scheme, however, could reduce geothermal costs by almost one-third.¹

When the property tax charge is eliminated from geothermal cost calculations, unit costs fall by eight percent from the base case. This indicates that the potential variations in property taxes from county to county could have important implications for the economic attractiveness of geothermal energy at any particular site. Removal of royalty charges (through the use of one's own geothermal resource, for example) would reduce the Base Case costs by ten percent.

CONVENTIONAL FUEL PRICE ESCALATION

The natural gas and petroleum products unit costs employed in this analysis were computed using fuel price projections which incorporated an assumed three percent annual growth in real world oil prices. To test the sensitivity of our results to this assumption, we calculated the unit distillate oil and natural gas costs which correspond to a slower, one percent annual increase in petroleum prices.

As shown in Table IV-4, geothermal remains more economical than distillate, for all three investor types, even with the lower oil price growth assumption. Natural gas is still more costly than geothermal energy for non-profit organizations and local governments. For private firms, natural gas costs become five percent lower than the Philip geothermal costs in the low price growth case.

CIRCUMSTANCES IN WHICH GEOTHERMAL COSTS WOULD BE LOWER

The sensitivity analysis has identified three circumstances in which geothermal costs would be lower that have practical importance because they have significant favorable effects on geothermal costs and they have good chances of being available to potential investors. These three circumstances are:

- a capital structure where the initial debt-to-equity ratio is 75/25
- the passage of legislation allowing "10-5-3" depreciation
- a site where no royalties have to be paid.

These circumstances individually reduce Base Case costs by 26, 32, and 10 percent, respectively.

¹ "10-5-3" depreciation applies double declining balance depreciation to structures, equipment, and vehicles for tax lives of 10, 5, and 3 years, respectively.

TABLE IV-4

SENSITIVITY ANALYSIS
Low Petroleum Price Growth Assumption¹

<u>Investor Category</u>	<u>Geothermal Levelized Unit Cost² (\$/million Btu)</u>	<u>Ratio of Geothermal to Distillate Levelized Unit Costs</u>	<u>Ratio of Geothermal to Natural Gas (commercial) Levelized Unit Costs</u>
Private, for-profit firm	5.73	0.78	1.05
Non-profit organization	3.68	0.50	0.64
Local government	2.65	0.34	0.46

¹ Assumes crude oil prices rise at one percent annually instead of the three percent rate assumed in the Base Case.

A high initial debt to equity ratio may be achievable, especially if geothermal loan guarantees were made available for direct heat application projects. Proposals to enact "10-5-3" depreciation for business investments are already receiving serious Congressional attention. Finally, an investor would pay no royalties if he owned geothermal resources.

For the Philip private firm case, these combined assumptions would reduce the levelized unit cost to \$2.15 per million Btu, a 62 percent reduction. These results indicate that private, for-profit investor costs for geothermal energy could vary by more than a factor of two depending upon the status of the three components combined here.

V. CONCLUSIONS

FINDINGS

This study used the experience of five DOE-supported geothermal direct heat application projects as a basis for geothermal energy cost estimates, and it has found geothermal energy to be competitive with conventional fuels. The Base Case results indicate that over the projected useful life of each of the projects reviewed, geothermal direct heat energy supplies will be less costly than conventional options. This remains true whether the investor is a:

- private, for profit firm
- non-profit organization, or
- local government.

The conventional fuels considered in these comparisons included distillate fuel oil, high-sulfur residual fuel oil, natural gas (at commercial and industrial rates), and coal.

The variations in assumptions explored in the sensitivity analysis included the potential effects of technological uncertainty about costs and production, financing modifications, tax policy modifications, and uncertainty about conventional fuel price escalation.

The sensitivity analysis indicated that the comparative economic advantage of geothermal direct heat energy for the projects reviewed persists over a broad range of alternative assumptions. For the variations examined, the geothermal energy costs consistently remained below the cost of distillate fuel oil. In some instances, described below, projected natural gas costs were less expensive than geothermal cost estimates.

With respect to technological factors, serious capital cost increases or major production shortfalls could lead to geothermal project lifecycle costs that would exceed natural gas costs. The sensitivity analysis indicates that a 25 percent increase in capital costs or the addition of a requirement to provide a geothermal fluid re-injection well could increase costs to levels above natural gas costs. If production from a geothermal well were to decline over a project's life, the unit costs (for the Philip case) could also exceed natural gas costs.

Other variations examined that led to geothermal costs above natural gas costs included rather unlikely conditions such as a 25/75 debt to equity ratio. Variations in geothermal project tax treatment are more likely to occur, however. Removal of the energy tax credit leads to a geothermal cost disadvantage compared to natural gas. On the other hand, the analysis indicates that accelerated depreciation options now under serious consideration (e.g., "10-5-3") could reduce geothermal costs substantially. Reducing the assumed world oil price escalation to one percent (real) also leads to natural gas costs below geothermal costs.

The sensitivity analysis also points out that the combined effects of circumstances possibly available to some future private investors could more than cut geothermal costs in half. These circumstances include 10-5-3 accelerated depreciation, high debt leverage (75 percent of financing), and ownership of the geothermal resource.

NEXT STEPS

This analysis has found strong preliminary evidence that geothermal direct heat energy can provide an economical alternative to conventional energy use in selected applications when the resource is well known. Several important follow-on efforts can help improve the reliability of this preliminary assessment.

The first step might be to expand the geothermal direct heat data base by incorporating cost and performance data for additional application projects that have reached an advanced stage of development. Likely additions would include Torbett-Hutchings-Smith Memorial Hospital in Texas, Carrie-Tingley Hospital, Aquafarms International in California, and Boise, Idaho district heating. Also, updating of cost and performance data on the five projects reviewed here should continue.

Another important set of issues that future analysis needs to address relate to the investment decisions that the potential adopter of geothermal direct heat technology might face when considering a project where the geothermal resource is less well understood. Assessing the attractiveness of an expenditure to identify and confirm the quality of geothermal resource requires knowledge of both the costs involved and the risks that the resources may prove to be unacceptable for commercial applications. This interim report has not addressed these points. The economics of finding and confirming geothermal resources should receive attention in the near future because the extent of the attractiveness of geothermal direct heat technology in new areas depends upon the answers.

Future efforts could refine the comparative economic analysis presented in this report. Refinements could include incorporating regional-specific information about the prices of the conventional fuel alternatives to account for potentially important market differences between West Coast, Rocky Mountain, and Great Plains locations. Exploration of how changes in the projected growth of alternative fuel prices would affect the commercial viability of geothermal direct heat projects could also provide useful insights to potential investors.

In addition, the next round of analyses could examine tax policy issues in greater detail. In this report the benefits of percentage depletion were only analyzed for the break-even revenue stream case. Because percentage depletion benefits are proportional to the revenues from resource sales, revenues tied to an alternative fuel price that are much higher than break-even revenue requirements could yield substantially higher depletion benefits to investors. Full examination of this issue requires financial modeling tools more sophisticated than those currently available.

Follow-on financial analysis can also examine how changes in project organization might further reduce the effective costs of geothermal development. For instance, the splitting of responsibility for implementing a geothermal energy supply between a private sector geothermal resource developer, who could take advantage of all tax subsidies available to encourage resource development, and a local government agency to finance district heating service delivery through tax-exempt bonds has been mentioned. Use of drilling funds to explore for geothermal resources is another creative financing mechanism suggested for broad application. With some modifications, the financial model used in this analysis could explore the benefits of these options for potential project sponsors.

An enhanced understanding of these issues will contribute to potential investors' ability to properly assess geothermal direct heat technology as an investment opportunity.

APPENDIX A
PROJECT SUMMARIES

This appendix contains summary reports from the Geothermal Direct Heat Applications Program Summary (November 1980) for each of the five projects under review. The Program Summary is a collection of project summary reports presented at the semi-annual review meeting sponsored by the U.S. Department of Energy, Geothermal Energy Division in Las Vegas, Nevada on November 20-21, 1980.

PROJECT TITLE: Direct Utilization of Geothermal Energy for Philip Schools

PRINCIPAL INVESTIGATOR: Charles A. Maxon, Superintendent of Schools
(605) 859-2679

PROJECT TEAM: Haakon School District 27-1
Hengel, Berg & Associates

LOCATION DESCRIPTION: Philip, South Dakota
80 miles (128 km) east of Rapid City, SD
Population: 1000
Area Activities: Agriculture, light industry, and
trade center

RESOURCE DATA:

Well Depth: 4266 ft (1300 m)
Date Complete: 2/23/79
Completion Technique: Open hole
Wellhead Temperature: 157 degrees F. (69 degrees C)
Flowrate: 300 gpm (18.9 l/s) artesian
Summary: The Madison Formation extends under the western half of South Dakota and into the bordering states of Wyoming, Montana and North Dakota. Most Madison wells in South Dakota are naturally flowing with temperatures ranging from 110 degrees F (43 degrees C) to 170 degrees F (77 degrees C).

SYSTEM FEATURES:

Application: Space, water and district heating
Heatload (Design): 5.5×10^6 BTU/hr (1.61 MW)
Yearly utilization (Maximum): 9.53×10^9 BTU/yr (.32 MW-yr)
Energy Replaced: Electricity - 122,989 kWh
Fuel Oil - 54,729 gals.
Propane - 23,858 gals.

Facility Description: 5 school and 8 business district buildings

Disposal Method: Surface discharge to the Bad River after treatment to remove Radium 226.

Summary: The school heating project has stimulated the development of a business district heating system, Philip Geothermal, Inc. In addition, Little Scotchman Industries, the city water plant and county maintenance building use geothermal fluids from other wells for space heating.

STATUS:

Construction complete. Adjustment of the flow through the system and monitoring to start.

CURRENT ESTIMATED PROJECT COST:

Total:	\$1,205,804	
DEO Share:	\$ 936,199 78%	Participant Share: \$269,605* 22%

LESSONS LEARNED:

The initial phase of this project was the development of the geothermal resource. A well was drilled into the Madison Formation. The total depth of the well is approximately 4,266 feet. During the drilling operations we had a full time drilling consultant at the well site during drilling operations. He was to be available in the event that drilling problems would shift the drilling operation from a footage basis to a day rate. We would recommend that on a future well that the drilling consultant be placed on a retainer so that he would be available to come to the well site with 24 hours notice. This would reduce the cost of the drilling consultant by eliminating that expense when the drilling operation is proceeding without any problems.

After setting the main casing the open hole completion of the well was drilled. Problems developed during the open hole drilling which included shale lenses and sand pockets in the limestone. This condition could create future problems during operation of the well such as sloughing of the sands and shale into the open hole. A 5" O.D. flush joint casing was suspended inside of the 7 5/8" casing previously installed. On any future wells drilled into the Madison Formation we would recommend that the open hole completion be completed before setting the main casing. If shale lenses or sand pockets that are drilled through they can be cased out with the main casing at a considerable savings in cost.

Samples of the geothermal fluid were tested by the Federal Environmental Protection Agency. Their tests indicate the presents of Radium 226 in the geothermal waters. The level of Radium 226 is approximately 99 pico curies per liter. This exceeds the EPA standards for drinking water 5 pico curies per liter or less. To obtain a discharge permit to discharge the geothermal fluid into the Bad River, the Radium 226 level had to be reduced to less than the 5 pico curies per liter.

Among the various methods investigated for removal of Radium 226, was the method used by the Uranium Mining and Milling Companies. The method they used involved adding a 10% aqueous solution of Barium Chloride to the water. The resulting chemical reaction provides a Barium Sulfate to which the Radium 226 adheres. The result is a flocculation that will settle out of the water. This process has a 99% efficiency. The Barium Chloride Treatment facility consists of a building to house the mixing tanks, a short section of discharge line, and an in-line static mixer. The Barium Chloride solution is added by metering pumps to the in-line static mixer. The barium chloride solution is mixed into the geothermal fluid and piped to the holding pond. The holding pond was designed for a three day retention time. The retention pond was divided into two cells so that maintenance could be performed on one cell while operating would be the one remaining cell.

The heating system in the High School-Armory building and in the Elementary School building were low pressure steam systems. During the planning for the modification of these systems to a low temperature hot water it was anticipated that the control valves could be reused. However, as the modification contract proceeded it became apparent that the seals in many of the control valves had deteriorated. This showed up when the contractor pressurized the system during standard test procedures.

Another problem that became apparent during the testing of the system was that a few of the baseboard radiation units had developed pin holes at their connections from the years of use. When the pressure test was applied, these areas started to leak water and had to be repaired. On future conversion projects, consideration should be given to pressure testing sections of the system prior to design to determine if that portion of the system could be used or if would have to be replaced. This would add additional cost to the preliminary engineering phase of the project. However, under certain circumstances this may be money well spent.

The contractual arrangement between the Owner and Contractor on this project has been very good. Changes to the construction contract have been kept to a minimum. The negotiated Change Orders with the contractor have been reasonable.

In some of the classrooms the existing steam fin tube radiation and the baseboard radiation units were replaced with hot water fin tube radiation units. The hot water fin tube radiation units were sized based on using water at approximately 140 degrees F. Engineering calculations show that in some instances it was more economical to add a cabinet unit heater along with the baseboard radiation units to provide the required heat for the room. The cabinet unit heaters were installed at the end of the baseboard radiation units where possible, however, in several instances the cabinet unit heater was placed in the middle of a baseboard radiation run. This created a problem because the baseboard radiation covers had to be cut. To make a neat joint between the baseboard radiation cover and the cover on the cabinet unit heater, the contractor provided a PVC window glazing gasket with a profile that covered the raw edge of the baseboard radiation cover.

The piping the boiler room of both the High School and the Elementary School is designed to vary the flow to the space heat exchanger. During periods of maximum heat demand, all of the geothermal fluid is directed to the space heat exchanger. From the space heat exchanger, the geothermal fluid flows to the domestic hot water heat exchanger. During periods of moderate to low space heating demand, the geothermal fluid is diverted around the space heat exchanger to the domestic hot water heat exchanger. The flow is controlled by a pneumatic actuated three way valve. The pneumatic actuated three way valves normally used in commercial installations would not operate against the artesian flow of this project. We were directed by the manufacturer to their industrial division. All of the three way valves on the geothermal side of the system are of the industrial type.

Pipeline

The geothermal fluid is piped to the school buildings, the business district buildings, and to the Barium Chloride Treatment plant using a filament wound fiberglass epoxy resin pipe. This pipe is designed for applications up to 210 degrees F (99 degrees C).

This pipe is assembled in a bell and spigot method. Whenever the pipe has to be cut in the field the cut end has to be shaved to provide a new spigot. This shaving is done with a specialized pipe shaver provided by the manufacturer.

All of the fittings, sockets, pipe ends and pipe sockets must be clean and dry and must be sanded within 2 hours of assembly. The sanding was accomplished using a flapper type sander on a drill.

If there is just the least bit of moisture or grease from the hands of the individuals handling the pipe, a perfect bond is not obtained. During the construction of this project we had only two joint failures. The contractor was exceptionally careful butting the pipe together because of the high cost of repairing the pipe failure. The joints if made properly are as strong or stronger than the pipe itself.

To repair a joint failure requires that a section of the pipe be cut out and new bell and spigots be cut on each then sanded and the pieces put back together.

The pipe was bedded in a layer of sand. The sand all passing a 3/8" screen was obtained locally. Approximately 6" of sand was placed under the pipe and another 6" was placed over the pipe. The soil in which the trench was excavated is composed primarily of the pier shale. This soil will expand and contract with changes in moisture. The sand was placed to provide a cushion to the pipe during these periods when the soil around it is moving.

The discharge line from the school is the supply line for the business heating district. The heating district was designed to provide a geothermal fluid at the same relative elevation to all of the eight building to be heated.

The construction of the system was recently completed. We have entered the adjustment and monitoring phase. All of the building in the heating district have not been connected to the system as of this date. As each building is added to the system a readjustment of the valves in the fire-hall and the various businesses will have to be made.

PROJECT TITLE: Diamond Ring Ranch Geothermal Demonstration
Heating Project

PRINCIPAL INVESTIGATOR: Dr. S. M. Howard, Professor of Metallurgical
Engineering, (605) 394-2341

PROJECT TEAM: South Dakota School of Mines and Technology
Re/Spec, Inc.
Diamond Ring Ranch

PROJECT OBJECTIVE: Utilize existing Madison well to provide grain drying,
and space heating for homes.

LOCATION DESCRIPTION: Haakon County, Central South Dakota
50 miles (80 km) west of Pierre, SD
Population: 2900 (Haakon County)
Area Activities: Agriculture

RESOURCE DATA:

Well Depth: 4112 ft (1253 m)

Date Complete: 1959

Completion Technique: Open hole

Wellhead Temperature: 152°F (67°C)

Flowrate: 170 gpm (10.7 l/s) artesian

Summary: The Madison Formation extends under the western half of South Dakota and into the bordering states of Wyoming, Montana, and North Dakota. Most Madison wells in South Dakota are naturally flowing with temperatures varying from 110°F (43°C) to 170°F (77°C).

SYSTEM FEATURES:

Application: Space heating and grain drying

Heatload (Design): 3.35×10^6 Btu/hr (.98 MW)

Yearly Utilization (Maximum): 7.87×10^9 Btu/yr (.26 MW-Yr)

Energy Replaced: Electricity - 185,288 kWh
Propane - 49,415 gal.

Facility Description: Six structures and a 700 bushel/hr grain dryer are served by geothermal water.

Disposal Method: Surface discharge to ranch reservoirs

Summary: Two heating loops circulate water through water-to-air heat exchangers and fan coil units to provide space heating for the hospital barn, mobile homes, shop, employee's home and owner's home. An additional loop provides hot water to the 700 bushel/hr commercial grain dryer.

Diamond Ring Ranch (cont'd)

STATUS:

The system is operating. Monitoring equipment is being installed.

CURRENT ESTIMATED PROJECT COST:

Total: \$403,098

DOE Share: \$250,725
62%

Participant Share: \$152,373
38%

LESSONS LEARNED:

1. The 4,000-ft. long pipeline carrying geothermal water to the isolation heat exchangers has three high spots along its length which could have been avoided only at greatly increased pipeline expense. A degasser at the wellhead proved insufficient to prevent gas pockets from forming in the line's high spots. This problem was eventually overcome by installing PVC air vent valves at the first two of the high spots.
2. The space heating system is comprised of a plate-type isolation heat exchanger used to heat recirculating water to six structures: four homes, a hospital barn, and a shop building. These structures are supplied by two loops with the return water mixing as it re-enters the isolation exchanger. The problem of freezing arises in the event of a power failure. Freezing is most likely in the barn and shop since these structures have low thermal mass unlike the homes. To prevent freezing, the recirculating system will be charged with antifreeze. The cost of the antifreeze would have been substantially reduced by use of smaller recirculating lines (2 inch rather than 3 inch) and by dividing the isolation exchange into two units so as to put the structures subject to freezing all on one loop. It should be noted that this would have increased the capital cost but lowered operating cost assuming the antifreeze is lost several times during the system's life.
3. Dividing the exchangers as described above would also have allowed subjugating the heating demands of the barn and shop to the other space heating demands. This would be a distinct advantage since the ambient temperatures of those structures are lower.

PROJECT TITLE: Geothermal Application of the Madison Aquifer for
St. Mary's Hospital

PRINCIPAL INVESTIGATOR: James Russell, Hospital Administrator
(605) 224-5941

PROJECT TEAM: St. Mary's Hospital
Kirkham, Michael and Associates
Sherwin Artus, Reservoir Consultant
Dr. J. P. Gries, Geologist

PROJECT OBJECTIVE: To demonstrate that 106°F (41°C) water can be used
for preheating domestic hot water and space heating.

LOCATION DESCRIPTION: Pierre, South Dakota
Population: 14,500
Area Activities: Government (Pierre is the state
capitol) and agriculture.

RESOURCE DATA:

Well Depth: 2176 ft (663 m)

Date Complete: 4/21/79

Completion Technique: Perforated casing

Wellhead Temperature: 106°F (41°C)

Flowrate: 375 gpm (23.7 l/s) artesian

Summary: The Madison Formation extends under the western half of
South Dakota and into the bordering states of Wyoming,
Montana and North Dakota. Pierre is located on the
eastern edge of this formation.

SYSTEM FEATURES:

Application: Domestic water preheating and space heating

Heatload (Design): 5.55×10^6 Btu/hr (1.63 MW)

Yearly Utilization (Maximum): 11.44×10^9 Btu/yr (.38 MW-Yr)

Energy Replaced: Fuel oil - 115,000 gals.

Facility Description: The existing 83,000 ft² (7710 m²) hospital and
a new 65,000 ft² (6038 m²) addition will be served.

Disposal Method: Surface discharge to the Missouri River.

Summary: Three plate-type heat exchangers provide make-up air heating,
space heating via fan coil units and domestic water preheating.
The new addition heating system is designed to utilize the
geothermally heated water in the hot deck coil of the air
handling units and the heat pump.

St. Mary's Hospital (cont'd)

STATUS:

The well was completed in April of 1979. The original flow rate was approximately 250 gpm. After further perforations of the well casing and by pumping 8,000 gallons of 20 percent HCL solution into the well, the flow rate was increased to the present level of 375 gpm.

The construction work for the application of the geothermal resource to the existing hospital and the new addition is completed. The systems were put into operation in mid-October of 1980 and balancing and final adjustments of control systems are now under way. System performance to date have exceeded the anticipated capability as follows:

Completed Well

System Operation

Well Supply Temp. = 106°F

108°F

Closed Loop Supply Temp. = 100°F

104° to 105°F

Domestic Hot Water Supply = 100°F

106°F

CURRENT ESTIMATED PROJECT COST:

Total: \$718,000

DOE Share: \$538,500
75%

Participant Share: \$179,500
25%

LESSONS LEARNED:

1. There is great difficulty in estimating the cost of a producing geothermal well. Our original estimated cost for the well was \$125,000. The final well cost was \$316,000 which exceeded our original estimate by 150%.
2. Resource and discharge permits can be a problem. We were not familiar with all that was required when we began and, had we been, it could have speeded up the process. Cooperation of the reviewing agency was excellent.
3. Perseverance pays off. In proposing the project, we originally hoped to find 117°F water. When our well came in producing 106°F water there was considerable skepticism even among ourselves that we could accomplish much of what we had set out to do. With the support of DOE, our project continued and is now complete and operational. It appears that our annual fuel savings may be even greater than originally projected. In addition, the temperature of the geothermal fluid increased 2°F in production.

Project Title

Klamath County Direct Use Space and Water Heating Project -
Project No. 1978-YMCA-1

Principal Investigator

Brian C. FitzGerald

Project Team

Engineering - James K. Balzhiser

Drilling Contractor - E. E. Storey & Son

Retrofit Contractor - Patterson Plumbing

Electrical Contrator - East Side Electric

Pump Supplier - Valley Pump

Pump Components - Nelson Drive

Legal - Alan M. Lee

Well Testing - OIT Geothermal Heat; Lawrence Berkeley Laboratories

Environmental Reporting - OIT Department of Natural Sciences

Project Description

The project is a direct use-extraction, exchange-retrofitted to an existing boiler system, reinjection format. Water is extracted from a production well 1410' in depth, piped 540' to an exchanger, and then pumped into the reinjection well some 90' from the heat exchanger. The heat exchanger circulates boiler fluid which in turn maintains necessary heat levels in a swimming pool air coil, swimming pool water heat exchanger, domestic hot water heat exchanger, and multi-zone air heated deck.

Location Description

The project is located on the grounds of the Klamath County YMCA, 1221 South Alameda, Klamath Falls, Oregon 97601. The YMCA is centrally located to the 30,000 population base approximately three miles south of the central business district and two miles north of a suburban population center. The area is well-known as Klamath K.G.R.A. with proven resources ranging from 110°F to 230°F.

Resource Data

Well Depth -- Production well - 1410'
Reinjection well - 2016'

The main production zones within the production well are located at 1150' with approximately 135° and at 1350' with approximately 165° water.

Completion Date -- January, 1979

Completion Techniques -- Six hours of 300 psi air surge followed three days later by a 22 hour pump test at a variable rate averaging 310 gpm.

Note: Eight hours into the pump test the geothermal fluid was still clearing up.

Wellhead Temperature -- 147°F - flow rate of 310 gpm capacity with actual use set at 250 gpm, bowls set at 320'. Drawdown from static of 91 to a total of 270'.

Flow Rate -- Available source is 310 gpm. However, the system is designed to fluctuate according to need from a minimum of 60 gpm to a maximum of 250 gpm. Reinjection well capacity for acceptance of water is such that reinjection at 250 gpm requires a head pressure of 31 pounds. Water flowing into the reinjection well at a rate of 110 gpm requires no pressure whatsoever. It is beyond the 110 gpm rate that pressure is increasingly necessary.

Summary -- The system appears to be intact, completed, and functional. The most critical element of work completed in process in our opinion was proper cleaning of the well through air surge and extended, continuous pump testing.

System Features

Application -- Geothermal fluid moves through a 66 plate, stainless steel heat exchanger heating boiler fluid for delivery of heat to various locations within the facility.

Heatload (Design);

Yearly Utilization;

Energy Replaced -- The system was designed to replace a gas-fired, low temperature boiler unit originally engineered to deliver 77,000 Therms of heat per year. Actual practical heat loads averaged 66,000 Therms per year over a nine year conventional heating history. In order to determine necessary heating requirements, our conventional system was preset to generate 140°F boiler fluid delivered from the boiler, in order to approximate a geothermal supply system. The nine-month program provided through practical experience that a 147°F geothermal supply at 250 gpm would more than adequately serve the needs of the facility.

Facility Description -- Klamath County YMCA is a 30,000 square foot masonry building located on 14 acres of ground in Klamath Falls, Oregon. The structure has approximately 20% of its exterior walls in thermopane glass, the remainder is in brick. Within the facility exists a gymnasium (40x20x24), three classroom facilities (averaging 20x20), two racquetball courts (20x20x20 ea), a martial arts and fitness area (40x40), five offices, mens' and womens' locker room facilities housing 100 lockers and eight showerhead rooms, and a swimming pool (44x74) holding 95,000 gallons of water with an average temperature of 87°, and swimming pool area (60x95x25) with an average temperature of 85°.

Disposal Method -- Reinjection pressure range from 60-110 gpm, zero pounds pressure required. 11-250 gpm, maximum load required is 31 pounds of pressure.

Summary -- The system is intact, functional, and capable of delivering heat at an effective level beyond the conventional system. We have also been able to renegotiate our maintenance contract with Honeywell, Inc. for care of our heating facility from a previous average of \$500 per month cost down to \$280 per month since we have removed two direct gas fired heating units previously taking care of our gymnasium and swimming pool area as well as being able to shut down our boiler system.

Status

Complete - BTU Meter ordered - expect delivery

Reinjection wellhead cover repaired

Electrical panel moved

Cooling system for Nelson Drive unit recalibrated

Current Estimated Project Cost

Total Cost - \$267,254

DOE Share - \$209,000

Participant Share - \$58,254

Lessons Learned

Our experience is limited to this one project, of course, but, should we be entering this project with what we now feel to be true the following areas seem to be valuable.

1. Problem: Signing the driller's contract without the benefit of the competitive bid process places the owner in a poor position.

Solution: Take the time to specify what is desired in an Original bid specification package.

2. Problem: Lost circulation

Solution: Not always lost circulation material, often drilling blind and temporary casing off of the flow can solve the problem. Watch for mud ring of the drilling shaft.

3. Problem: Should we test reinjection.

Solution: We tested the reinjection capacity of a 2016' hole which produced an excess of 500 gpm 110°F with a drawdown of only 60' to 70' as an afterthought. It turned out that it takes 35 pounds of head pressure to push 250 gpm back into the hole. Without the test, we would have assumed negative head pressure.

4. Problem: How far do you case.

Solution: Our first hole was cased only to 512', some 400' from the beginning of basaltic layers. This uncased area allowed mixing of cooler ground water with the warmer geothermal fluid. Using log data from the first hole, we were able to decide to case the second hole to 968' insuring correction of the mixing problem.

5. Problem: How soon should you test, how long, in what way, and who should do it.

Solution: We built air and pump testing into the contract signed by the driller. After desired depth was reached, the driller was required to develop the hole with air. The bit was lowered into the hole within 24 hours of depth attainment to 300' - 300 to 400 psi was developed intermittently, thus alternately blowing off the top 210' of fluid and then allowing the fluid to subside. This exerted tremendous surging forces on the well. We think this cleaned the well properly and avoided the problem of sour bentonite caking the production zones. We also had the driller pump test the hole for 24 hours (8 hours of it in reinjection phase). The well cleaned up after 4 hours of surging and 10 hours of pumping. Presently, the fluid has a suspended solid level of less than 350 ppm. With the exception of 8.2 Ph and the sulfate content the fluid passes city code for drinking water. Incidentally, since the driller could not remove the rig until the test was complete, he borrowed a large tractor and used the power take-off to drive the test pump since local pump people could not meet his time schedule. At \$100 per hour cost to the driller for rig time, they can get very creative!

6. Problem: How do you determine the system's ability to provide necessary heat in a retro-fit situation?

Solution: Turn the existing boiler down in cycle temperature and expand the quick recovery capacity of the boiler to approximately the specifications of available geothermal fluid. We had nine months of demonstration data going in which proved that a 135° fluid at 250 gpm - exchanger approach of 7° and draw of 40° would take care of our complete needs.

Presently, the system, functioning at full 250 gpm capacity, is entering 146° geothermal fluid at the exchanger - reinjecting at an average of 142° - boiler fluid in is averaging 133° - boiler fluid out after exchanger is being maintained at a constant 146° - approach of 0.

A sample test can be run by shutting off the swimming pool air boiler fluid loop allowing that to cool fro 133° to 70°. After circulation is created, boiler fluid in drops from 133° to 85°, geothermal fluid out drops from 142° to 125°. Boiler fluid out moves from 146° to 145° for about five seconds.

We also discovered that retrofit of conventional systems allows for renegotiation of maintenance contracts for heating systems and for insurance costs for boiler and pressure vessels since a 147° geothermal system can be guaranteed to never exceed boiling temperature creating pressure stresses.

PROJECT TITLE: Pagosa Springs Geothermal Heating and Distribution System

PRINCIPAL INVESTIGATOR: Fred A. Ebeling, Planning Administrator
(303) 264-5851

PROJECT TEAM: Town of Pagosa Springs
Archuleta County
School District #50-Joint
Corry and Associates, Inc.

PROJECT OBJECTIVE: To provide the community with a means of using its natural hydrothermal resource for space heating.

LOCATION DESCRIPTION: Pagosa Springs, Colorado
60 miles (97 km) east of Durango, CO
Population: 1500
Area Activities: Ranching, Lumbering, & Tourism/Recreation

RESOURCE DATA:

	<u>PS-3</u>	<u>PS-5</u>
Well Depth:	300 ft. (91 m.)	275 ft. (84 m.)
Date Complete:	7/2/80	7/31/80
Completion Technique:	Open hole	Open hole
Wellhead Temperature:	131°F. (55°C.)	148°F. (64°C.)
Flowrate:	600 gpm (38 l/s) for 12 hr test	1200 gpm (76 l/s) for 12 hr test

Summary: The geothermal resource in Pagosa Springs has been used since the early 1900's. Nearly 30 wells have been drilled for heating and recreation purposes. These wells are drilled to depths of less than 500 feet (152 m) and produce waters ranging in temperature from 130°-170°F. (54°-77°C.). The hydrothermal fluids are produced from a Dakota Sandstone aquifer.

SYSTEM FEATURES:

Application: District Heating

Heatload (Design): 27×10^6 BTU/hr (7.9 MW)

Yearly Utilization (Maximum): 28.6×10^9 BTU/yr (.96 MW-yr)

Energy Replaced: Natural gas - 40.8×10^6 cu.ft.

Facility Description: 10 public buildings, 54 businesses, and 63 residences

Disposal Method: The State of Colorado has agreed to discharge of the geothermal fluid to the San Juan River.

Summary: The district system will provide heating for users located along U.S. Highway 160. For the proposed closed distribution system, two independent loops have been designed. The initial system will utilize 900 gpm (57 l/s) but will be capable of expansion to 1800 gpm, (113 l/s).

STATUS:

Technical Scope

The objective of this project is to demonstrate the engineering and economic feasibility of the utilization of a moderate temperature geothermal resource for space heating.

For the proposed closed distribution system, two independent loops have been designed, one for the east side of town and the other for the west side, to provide a safety factor in the event of a pipeline breakage. The east loop is designed to carry 1350 gpm. The west loop has been designed for 1000 gpm; however, initially it will carry only 500 gpm. This is to permit future expansion of the distribution system into the growth areas of Pagosa Springs. A schematic diagram of the overall design is shown on Figure 1. Briefly, the system will operate as follows:

- 1) Clean city water will be heated with the geothermal fluid using two plate heat exchangers. The geothermal fluid leaving the plate heat exchangers is then discharged to the San Juan River.
- 2) The clean heated city water will be circulated in each of two closed loops by means of one to four pumps, depending on user demand. Each of the loops consists of large diameter concrete asbestos pipes, 6 inches to 10 inches, referred to as trunklines, and smaller diameter service pipes carrying the water to the individual users. Two parallel trunklines are in each loop. An insulated supply trunkline carries the heated circulating water, and an uninsulated return trunkline directs the cooled circulating water back to the heat exchangers.
- 3) At the terminal point of the supply line, in each loop, there will be flow control valves to ensure a minimal amount of hot water being circulated at all times.
- 4) The circulating water is collected in the return trunkline and then routed to the heat exchangers where the entire process is repeated.

SCHEDULE:

The wells required for the project were completed earlier this summer. Based on results from the well drilling program, the final design was completed in October and has been reviewed by DOE. Recommendations coming from this review are currently being incorporated into the design and bid documents. The major milestones for the remainder of the project are now scheduled as follows.

SCHEMATIC DIAGRAM OF THE TOWN GEOTHERMAL HEATING SYSTEM

FIGURE #1

1. Send out bid documents	Mid-November 1980
2. Construction contracts	January 1981
3. Construction	March - July 1981
4. System testing	August 1981
5. System operation	September 1981

CURRENT ESTIMATED PROJECT COST

Total	1,364,280	
DOE share	1,111,000	81%
Participant share	253,280	* 19%

* Includes \$115,500 of existing facility credits. Also, Participant has agreed to pay back \$60,000 from revenues after the system becomes operative.

LESSONS LEARNED

1. With the rapidly escalating costs of materials and labor, an appropriate contingency factor should be included in all cost estimates and should be acknowledged and accepted by grantor agencies. A good portion of our cost overrun from original agreement estimates made over two years ago are because of inflationary cost escalation during that time.
2. Keeping the public informed of project progress is important for successful acceptance, and to minimize erroneous information and rumors. Interviews by media reporters frequently result in partial, misleading information being published or broadcast. Carefully written news releases are best but even then the media space or time limitations result in editing which often changes the context. If at all possible a person should be designated to communicate with the media and the public on a regular basis.
3. Predicting the existence of geothermal fluid underground, and especially quantification, is not reliable even in close proximity to existing wells. It seems the only dependable way to determine the existence of, and to quantify, geothermal sources is by means of test holes.

In our project a new well located only 30 feet from a previously drilled test well produced fluid 10°F cooler than had been obtained from the test well at comparable depth. A second new well located 350 feet southwest of the first one did not produce fluid quantity or temperature comparable to the first new well nor as expected from geological analysis of the sub-strata. The well could not be used and was cemented up. A third new well located 180 feet east of the first one and about 30 feet south of an existing old well produced much greater quantity of fluid than either of them and 17°F hotter and at a depth considerable less than predicted by geological analysis of the sub-strata.

4. Drilling geothermal wells, particularly artesian wells, presents problems and situations not encountered in usual water well drilling. This applies not only to the temperatures and pressures involved but also to the subsurface strata which may have been affected by the geothermal conditions. Anomalies from usual geologic situations should be expected.

5. Keeping state agencies and local government bodies informed on the progress of the project and particularly about well drilling is of great value in assisting various permitting and approval requirements.

APPENDIX B

GENERAL FINANCIAL AND ECONOMIC ASSUMPTIONS AND DISCOUNT RATES

<u>Inflation Rate:</u> ¹ (percent change, year over year)	1979	8.5%
	1980	9.0%
	1981	10.3%
	1982	9.2%
	1983	8.6%
	1984	8.1%
	1985	7.5%
	1986	7.0%
	thereafter	7.0%

Federal Income Tax Rate: 46%

State Income Tax Rate: variable by state
 South Dakota 0%
 Colorado 5%
 Oregon 7.5%

Base Case Assumption 5%

Other Taxes: Property Tax variable by county
 base case assumption: 2% of
 undepreciated historic value
 of capital assets.

Royalty: 10% of gross receipts

¹ GNP deflator figures, 1979 and 1980 data from Survey of Current Business, March 1981, p. 14; projections from U.S. Congressional Budget Office, Economic Policy and the Outlook for the Economy, March 1981, p. 62.

<u>Rates of Return:</u>	Rate of Return on Equity	9.5% (real) after tax ¹
	Corporate Debt Rate	3% (real) ¹
	Tax-exempt Bonds Rate	75% of nominal corporate rate ² (average real rate: 0.56%)

Tax Life-to-Book
Life Ratio: 80%¹

Tax Status and Financial Structure Assumptions, By Sponsor Type

Private, for Profit Firm

- subject of federal and state income taxes and property tax
- taxable bonds
- initial debt-to-equity ratio of 50/50

Private, Non-Profit Agency (no tax-exempt bonds)

- no income or property taxes
- taxable debt
- 100 percent debt financing

Local Government or Non-Profit (with tax-exempt bonds)

- no income or property taxes
- tax-exempt bonds
- 100 percent debt financing

¹ Based upon DOE guidelines in DOE, Policy and Evaluation, "Standardized Cost Estimation," draft, SP-052, December 4, 1978, p. 48.

² Based upon empirical observations of recent relationship between AA corporate and tax-exempt bonds.

DISCOUNT RATES

Private Firm

Discount Rate = rate of return on equity investment
= 9.5% (real)

Non-Profit Agency

Discount Rate = cost of raising capital
= 3% (real), without tax-exempt bonds
= 0.56% (real), with tax-exempt bonds

Government

Discount Rate = cost of raising capital
= 0.56% (real), with tax-exempt bonds

APPENDIX C

FEDERAL INCOME TAX TREATMENT OF GEOTHERMAL COSTS

For private sector geothermal developers, income taxes and tax benefits have a significant impact on total project costs and levelized unit costs. Three kinds of tax benefits have particular importance for geothermal projects: the percentage depletion allowance, the energy tax credit, and the expensing of intangible drilling costs. These benefits are outlined in the paragraphs below and discussed in more detail in the following sections of this appendix. The analysis has assumed that the geothermal developer has a large enough taxable income from other operations to enable him to take full advantage of all tax benefits in the first year in which these benefit would be available.

Intangible drilling costs are defined as all costs for labor, fuel, repairs, hauling, and supplies incurred in well site preparation, and in drilling, completing, and testing production wells. That is, the intangible drilling cost category includes all well development costs except those incurred for tangible well equipment, such as pumps, valves, and casing. Normally, similar construction costs would have to be capitalized as assets in the year they were incurred, and only gradually written off as expenses, through yearly depreciation deductions over the life of the equipment. However, for oil, gas, and geothermal wells, Congress has allowed the full amount of intangible drilling costs to be deducted from taxable income as expenses in the year incurred.

Depletion is normally used to recover the costs of nonrenewable natural resources which are used up through extraction. For geothermal resources, all costs of acquiring property and determining its potential for production must be capitalized and depleted, that is, deducted as expenses from taxable income over the life of the resource. These costs include the sales price of land or lease bonus bids, costs incurred in obtaining drilling permits, geological and geophysical exploration costs, and environmental assessment costs. The basic method of depletion is "cost depletion," in which the depletion deduction is tied to the quantities produced and to actual resource costs. To encourage resource development and to compensate developers for the particular financial risks which they face, Congress has allowed a special kind of depletion called "percentage depletion," which usually results in a higher deduction and hence a lower income tax liability. Percentage depletion may be used for geothermal resources, mines, and certain oil and gas wells.

To promote the development of alternative energy sources and lessen dependence on nonrenewable fossil fuels, the Congress has enacted an Energy Tax Credit applicable to investments in geothermal and other alternative energy property. This energy credit may be applied in addition to the regular investment tax credit.

For each kind of geothermal project cost, Table D-1 details the appropriate tax treatment, including the applicability of the energy and regular investment tax credits.

Cost and Percentage Depletion Allowances

Two methods of depletion are available to the geothermal producer: COST DEPLETION, which is similar to depreciation, and PERCENTAGE DEPLETION, based on a percentage of gross income from the geothermal property. Because

TABLE D-1

TAX TREATMENT OF PROJECT COSTS

<u>COST CATEGORY</u>	<u>TAX TREATMENT</u>
<ul style="list-style-type: none"> ● Resource Acquisition and Related Costs: <ul style="list-style-type: none"> -- Lease Bonus Bid -- Purchase Price of Land -- Permitting -- Geological & Geophysical Exploration -- Environmental Assessment -- Other ● Well Drilling: <ul style="list-style-type: none"> -- Tangible Well Equipment¹ -- Intangible Drilling Costs² -- Design and Planning Well ● Distribution System and Retrofit: <ul style="list-style-type: none"> -- Design/Planning/Bidding -- Pump Houses and Other Structures to House Equipment -- Geothermal Space Heating System in New Buildings -- Any Equipment Not Used Exclusively with Geothermal Energy³ -- Disposal Equipment -- All Other Construction Costs 	<p>All resource acquisition and related costs are capitalized and subsequently recovered through cost or percentage depletion allowances.</p> <p>Capitalized and depreciated; eligible for regular ITC and energy tax credit.</p> <p>May be expensed or capitalized at taxpayer's option. If expensed, intangible drilling costs become an item of tax preference subject to minimum tax.</p> <p>Divided between tangible well equipment category and intangible drilling cost category, as appropriate, and treated accordingly.</p> <p>Capitalized and depreciated; apportioned among the following categories, as appropriate, and treated accordingly.</p> <p>Capitalized and depreciated; eligible for energy tax credit only.</p> <p>Capitalized and depreciated; eligible for energy credit only.</p> <p>Capitalized and depreciated; eligible for regular ITC only.</p> <p>Capitalized and depreciated; eligible for regular ITC; no definitive ruling yet on whether eligible for energy credit.</p> <p>Capitalized and depreciated, eligible for both regular ITC and energy credit.</p>

TABLE D-1 (continued)
TAX TREATMENT OF PROJECT COSTS

<u>COST CATEGORY</u>	<u>TAX TREATMENT</u>
● General and Administrative Expenses	Expensed
● Direct DOE-Related Costs	Not applicable to future projects.
-- Conferences	
-- Publicity	
-- Reporting	
-- Other	

- ¹ Tangible well equipment includes all physical well property with salvage value (e.g., pumps, valves, casing).
- ² Intangible drilling costs include amounts paid for labor, fuel, repairs, hauling, and supplies used in well site preparation and in well drilling, completion, and testing.
- ³ Equipment not used exclusively with geothermal energy includes, for example, piping and coils which will normally be used with both geothermally heated fluids and boiler fluids heated by conventional fuels.

percentage depletion is computed as a percentage of income derived from the sale of resources produced, it may only be used by taxpayers who extract geothermal resources and sell them to distributors or end users. Taxpaying producers who extract geothermal resources for their own energy use (e.g. Diamond Ring Ranch) must use cost depletion rather than percentage depletion.

In cases where both cost and percentage depletion are allowed (i.e., whenever geothermal resources are sold) the producer must calculate both the cost and percentage depletion each year and must use that method which yields the largest deduction for that year. In practice, most depletion is taken as percentage depletion, since percentage depletion generally yields much larger deductions than cost depletion. In addition, deductions for cost depletion end when the book value of the property (i.e., the accumulated acquisition and exploration costs, as listed above, less the accumulated depletion deductions) is reduced to zero. In contrast, percentage depletion continues indefinitely, even after the book value of the property has been reduced to zero. The methodology for calculating each of the two kinds of depletion is described below.

COST DEPLETION

Cost depletion is calculated on a units of production basis. (The IRS is not yet certain what units will be applicable for geothermal resources. It is likely that Btu's may be used to calculate cost depletion, although it is possible that a volumetric measure such as gallons of fluid would be required.) To calculate cost depletion, the book value of the property (cost less previous depletion deductions) is multiplied by the ratio of the number

of units produced and sold during the year to the estimated total number of units that will be produced over the remaining life of the property. The book value is reduced after each year by the amount of depletion deducted for that year, no matter whether cost or percentage depletion is used.

PERCENTAGE DEPLETION

Percentage depletion is calculated as a percentage of gross income from the geothermal property. Applicable percentages vary by year, as follows:

1978 - 1980	22%
1981	20%
1982	18%
1983	16%
thereafter	15%

The maximum allowable percentage depletion deduction is 50% of taxable income from the property (before the depletion deduction).

Percentage depletion continues indefinitely, even after the book value of the property has been reduced to zero. However, the excess of percentage depletion deductions over the original cost is considered a "preference item" subject to a minimum tax. A discussion of minimum tax on tax preference items is presented in the next section. Table D-2 provides examples of costs and percentage depletion calculations.

Minimum Tax on Tax Preference Items

Two kinds of expensed items associated with geothermal projects may be considered tax preference items subject to a minimum tax. These are:

- expensed intangible drilling costs, and
- percentage depletion deductions over and above the original value of the property.

The minimum tax is currently equal to 15 percent of net tax preference items. To compute the net preference items, a corporation first adds together all its

TABLE D-2

COST AND PERCENTAGE DEPLETION
Sample Calculations

3 Year Project--\$50,000 Resource Cost--15% Percentage
 Depletion Allowance--100 Units Produced During Project Life

	<u>YEAR 1</u>	<u>YEAR 2</u>	<u>YEAR 3</u>
Gross revenues	\$150K	\$200K	\$150K
Other Expenses	<u>-130</u>	<u>-110</u>	<u>-100</u>
Taxable Income Before Depletion	\$20K	\$90K	\$50K
A) 15% of Gross Revenues	\$22.5K	\$30K	\$22.5K
B) 50% of Taxable Income	\$10K	\$45K	\$25K
PERCENTAGE DEPLETION (smaller of A and B)	\$10K	\$30K	\$22.5K
C) Production	30 units	40 units	30 units
D) Production this year plus quantity remaining to be produced in subsequent years	100 units	70 units	30 units
E) Book value	\$50K	\$35K	\$5K
COST DEPLETION (C - D x E)	\$15K	\$20K	\$5K
DEPLETION DEDUCTION (larger of percentage and and depletion)	\$15K	\$30K	\$22.5K
Beginning Book Value	\$50K	\$35K	\$ 5K
Depletion	<u>-15</u>	<u>-30</u>	<u>-22.5</u>
Year End Book Value	\$35K	\$5K	0
Amount subject to minimum tax (depletion deduction over and above basis in property)			\$17.5K

tax preference items for the year and then subtracts an exemption from this total. The exemption is equal to the greater of \$10,000 and the corporation's regular income tax liability. Thus, if the total of a corporation's tax preference items is smaller than its regular income tax liability, net tax preferences will be less than zero, and the corporation will not be required to pay the minimum tax. (It will, however, still have to pay the full amount of its regular income tax liability). This analysis of geothermal projects assumes that the project sponsor's regular income tax liability is always large enough to shield any depletion deductions and intangible drilling costs which might otherwise be subject to minimum tax.

REGULAR INVESTMENT TAX CREDIT

In general, a taxpayer investing in certain business property may claim an investment tax credit (ITC), which serves to directly reduce his income tax liability by the amount of the credit.¹

Amount of Credit. For qualifying equipment with a life greater than seven years,, the credit equals 10 percent of the cost of acquiring the property and placing it in service. The credit is reduced to two-thirds of the full amount for equipment with a five to seven year life and to one third of the full amount for equipment with a three to five year life. This analysis assumes all geothermal equipment receives the full 10 percent credit.

Upper Limit on ITC. The ITC may be used to offset 100% of the taxpayer's tax liability up to \$25,000. For 1980 and 1981, the tax credit may offset 70%

¹ See Internal Revenue Code Section 1.46 for complete regulations governing the regular investment tax credit.

and 80%, respectively, of the tax liability over \$25,000. From 1982 on, the ITC may offset 90% of the tax liability over \$25,000. To avoid undue complexity, the analysis assumes that the ITC may be used to offset 100% of the tax liability in all years, regardless of amount.

Carry-backs and Carry-forwards. If the taxpayer's income tax liability in the year of investment is smaller than the income tax credit, the credit may be "carried back" and applied to the three previous years' income tax liabilities or "carried forward" for seven years.

Qualifying Property. To qualify for the credit, the business property must be tangible, depreciable property used in manufacturing, production, or extraction, or in furnishing electricity, gas or water. All costs associated with acquiring qualified property and placing it in service, such as design and installation charges, are also eligible. Buildings and structural components of buildings are not eligible for the regular ITC.

Timing of ITC. Ordinarily, property is eligible for the tax credit in the year in which the property is placed in service, or placed in a condition of readiness and availability for service. However, for equipment which has a construction period of two or more years, the taxpayer may elect to claim advance tax credits for construction progress payments, as they accrue.

ENERGY TAX CREDIT

Amount and Dates of Energy Credit. In addition to the regular investment tax credit, taxpayers may claim a tax credit for investing in geothermal and other "alternative" energy property. The energy tax credit is 40%, up to a maximum credit of \$4,000, for residences and 15% (with no

ceiling) for businesses. The energy credit was created by the Energy Tax Act of 1978 and increased under the Crude Oil Windfall Profit Tax Act of 1980 and is applicable to investments made from 1978 through 1985.¹

Qualified Equipment. Equipment used to produce, distribute, or use geothermal energy is eligible for the energy credit. This would include piping, radiators, fan coils, and heat exchangers, as well as well-head and downhole equipment for production wells. Disposal equipment, including reinjection wells, will probably also be eligible for the Energy credit, although the IRS has not yet made a definitive ruling on this issue.

Minimum Temperature Requirement

In order for any geothermal equipment to qualify for the energy credit, the geothermal fluid must be hotter than 50°C (122°F) under the current regulations.

Exclusive Use Rule. In addition, the existence of a backup, conventional fuel system for peaking or topping disqualifies those items of equipment which use both geothermal and conventional energy. Thus, for example, pipes and fan coils which receive fluids both from a conventional boiler and from a geothermal heat exchanger would not qualify for the energy credit. However, those items of equipment which are associated exclusively with geothermal energy, such as the well, heat exchanger, and distribution equipment between the well and the heat exchanger, would still qualify.

Other Rules Applicable to Energy Credit. In general, the rules for the regular investment tax credit also apply to the energy credit, with two major

¹ Regulations governing the Energy Tax Credit appear in the Federal Register, Vol. 46, No. 15, January 23, 1981.

exceptions. 1) Buildings and structural components of buildings do not qualify for the regular investment tax credit, but they may qualify for the energy credit. Items that fall in this category include geothermal heating systems in new buildings (since heating systems are considered structural components) and structures to house pumps and other qualifying geothermal energy property. 2) The energy credit may offset 100% of the income tax liability remaining after taking any applicable regular investment tax credits. (i.e., the credit is not reduced above \$25,000, as it is for the regular ITC.)

APPENDIX D

ILLUSTRATIVE FINANCIAL MODEL OUTPUT
(For Philip Base Case)

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
PRO FORMA INCOME / CASH FLOW STATEMENT
BREAK-EVEN REVENUE STREAM

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
1 REVENUES	0.	0.	0.	122265.	144811.	157265.	170003.	182753.	195546.	209234.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	12227.	14481.	15726.	17000.	18275.	19555.	20923.
4 : O&M	0.	0.	0.	4412.	4818.	5232.	5656.	6080.	6506.	6961.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	80713.	75001.	68778.	63073.	57844.	53051.	48658.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	0.	631.	6791.	55907.	52287.	50250.	48367.	45812.	43428.	43000.
9 : PROPERTY TAX	0.	0.	0.	19070.	18412.	17754.	17097.	16439.	15782.	15124.
10 : OTHER EXPENSES	12203.	246638.	6575.	807.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-12203.	-247269.	-13366.	-50869.	-20188.	-476.	18810.	38302.	57225.	74568.
12 LESS: INCOME TAX	-5943.	-120420.	-6509.	-24773.	-9832.	-232.	9161.	18653.	27869.	36315.
13 PROFITS AFTER TAX	-6260.	-126849.	-6857.	-26096.	-10356.	-244.	9650.	19649.	29356.	38253.
14 LESS: CAP. EXPENDS.	10755.	100276.	710589.	164739.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	25069.	171647.	40358.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	0.	0.	0.	80713.	75001.	68778.	63073.	57844.	53051.	48658.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	-17015.	-202056.	-545799.	-69765.	64645.	68533.	72723.	77493.	82407.	86911.
19 LESS: DEBT REPAYMENT	-5377.	-50138.	-355294.	-8289.	-4669.	-2633.	-749.	1806.	4190.	4618.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	-11637.	-151918.	-190504.	-61476.	69314.	71166.	73471.	75687.	78217.	82293.
22 NPV CASH FLOW (PV ROEQ)	-11637.	-127896.	-134418.	-35914.	33865.	29238.	25501.	22317.	19685.	17676.
23 CUM. NPV CASH FLOW	-11637.	-139534.	-273952.	-309866.	-276001.	-246763.	-221261.	-198944.	-179259.	-161583.
24 DEBT BALANCE (END YR.)	5377.	55515.	410810.	419099.	423768.	426401.	427149.	425343.	421153.	416535.
25 EQUITY (END YR.)	11637.	165741.	388259.	530409.	564916.	600615.	637472.	674696.	712289.	752260.
26 CASH BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
PRO FORMA INCOME / CASH FLOW STATEMENT
BREAK-EVEN REVENUE STREAM

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
1 REVENUES	223880.	239552.	256320.	274262.	293461.	314003.	335983.	359501.	384666.	411593.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	22388.	23955.	25632.	27426.	29346.	31400.	33598.	35950.	38467.	41159.
4 : U&M	7449.	7970.	8528.	9125.	9764.	10447.	11178.	11961.	12798.	13694.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	44630.	40939.	37556.	34454.	31612.	29006.	28990.	28990.	28990.	28990.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	42528.	42009.	41436.	40805.	40109.	39342.	38498.	37566.	36540.	35409.
9 : PROPERTY TAX	14467.	13809.	13151.	12494.	11836.	11179.	10521.	9864.	9206.	8548.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	92418.	110870.	130017.	149958.	170794.	192628.	213198.	235171.	258666.	283792.
12 LESS: INCOME TAX	45008.	53994.	63318.	73030.	83177.	93810.	103827.	114528.	125970.	138207.
13 PROFITS AFTER TAX	47411.	56876.	66699.	76929.	87617.	98818.	109370.	120643.	132696.	145586.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	44630.	40939.	37556.	34454.	31612.	29006.	28990.	28990.	28990.	28990.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	92041.	97815.	104255.	111383.	119229.	127824.	138360.	149632.	161685.	174575.
19 LESS: DEBT REPAYMENT	5090.	5609.	6182.	6813.	7509.	8275.	9120.	10052.	11078.	12209.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	86951.	92206.	98073.	104570.	111720.	119549.	129240.	139581.	150608.	162366.
22 NPV CASH FLOW (PV ROEQ)	15941.	14428.	13097.	11919.	10869.	9926.	9159.	8443.	7775.	7154.
23 CUM. NPV CASH FLOW	-145642.	-131215.	-118117.	-106198.	-95330.	-85403.	-76244.	-67802.	-60027.	-52873.
24 DEBT BALANCE (END YR.)	411445.	405836.	399654.	392841.	385332.	377057.	367937.	357885.	346807.	334598.
25 EQUITY (END YR.)	794432.	838589.	884458.	931704.	979909.	1028559.	1075869.	1120958.	1162760.	1199978.
26 CASH BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
PRO FORMA INCOME / CASH FLOW STATEMENT
BREAKEVEN REVENUE STREAM

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 REVENUES	440404.	471232.	504218.	539513.	577279.	617688.	660926.	707191.	756694.	809662.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	44040.	47123.	50422.	53951.	57728.	61769.	66093.	70719.	75669.	80966.
4 : UGM	14652.	15678.	16775.	17950.	19206.	20551.	21989.	23528.	25175.	26938.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	28990.	28990.	28990.	28990.	28990.	28990.	28990.	359.	359.	359.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	34163.	32789.	31275.	29606.	27767.	25740.	23507.	21045.	18332.	15342.
9 : PROPERTY TAX	7891.	7233.	6576.	5918.	5261.	4603.	3945.	3288.	2630.	1973.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	310668.	339419.	370181.	403098.	438328.	476036.	516403.	588251.	634528.	684085.
12 LESS: INCOME TAX	151295.	165297.	180278.	196309.	213465.	231829.	251488.	286478.	309015.	333149.
13 PROFITS AFTER TAX	159373.	174122.	189903.	206789.	224862.	244206.	264915.	301773.	325513.	350936.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	28990.	28990.	28990.	28990.	28990.	28990.	28990.	359.	359.	359.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	188362.	203112.	218893.	235779.	253852.	273196.	293904.	302132.	325872.	351295.
19 LESS: DEBT REPAYMENT	13455.	14829.	16343.	18012.	19851.	21878.	24111.	26573.	29286.	32276.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	174907.	188283.	202549.	217767.	234001.	251319.	269793.	275559.	296586.	319019.
22 NPV CASH FLOW (PV RDEQ)	6578.	6043.	5549.	5092.	4670.	4281.	3922.	3419.	3141.	2883.
23 CUM. NPV CASH FLOW	-46295.	-40252.	-34703.	-29611.	-24942.	-20661.	-16739.	-13320.	-10180.	-7296.
24 DEBT BALANCE (END YR.)	321143.	306314.	289971.	271959.	252108.	230231.	206119.	179546.	150260.	117984.
25 EQUITY (END YR.)	1231044.	1254067.	1266775.	1266447.	1249829.	1213041.	1151464.	1073551.	961238.	807214.
26 CASH BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
PRO FORMA INCOME / CASH FLOW STATEMENT
BREAKEVEN REVENUE STREAM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 REVENUES	866338.	926982.	991870.	0.	0.	0.	0.	0.	0.	0.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	86634.	92698.	99187.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	28823.	30841.	33000.	0.	0.	0.	0.	0.	0.	0.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	359.	359.	359.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	12046.	8414.	4412.	0.	0.	0.	0.	0.	0.	0.
9 : PROPERTY TAX	1315.	658.	0.	0.	0.	0.	0.	0.	0.	0.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	737160.	794011.	854912.	0.	0.	0.	0.	0.	0.	0.
12 LESS: INCOME TAX	358997.	386684.	416342.	0.	0.	0.	0.	0.	0.	0.
13 PROFITS AFTER TAX	378163.	407328.	438570.	0.	0.	0.	0.	0.	0.	0.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	359.	359.	359.	0.	0.	0.	0.	0.	0.	0.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	378523.	407687.	438930.	0.	0.	0.	0.	0.	0.	0.
19 LESS: DEBT REPAYMENT	35572.	39204.	43206.	2.	0.	0.	0.	0.	0.	0.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	342951.	368484.	395723.	-2.	0.	0.	0.	0.	0.	0.
22 NPV CASH FLOW (PV ROEQ)	2646.	2426.	2224.	-0.	0.	0.	0.	0.	0.	0.
23 CUM. NPV CASH FLOW	-4651.	-2225.	-1.	-1.	-1.	-1.	-1.	-1.	-1.	-1.
24 DEBT BALANCE (END YR.)	82412.	43208.	2.	0.	0.	0.	0.	0.	0.	0.
25 EQUITY (END YR.)	602819.	337808.	69.	0.	0.	0.	0.	0.	0.	0.
26 CASH BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

THE MINIMUM ACCEPTABLE SUPPLY PRICE IS (\$/MMBTU) 5.73

THE DISCOUNTED LIFE CYCLE COSTS ARE 828256.44

THE CAPITAL CHARGE RATE IS 0.1170

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
CASH FLOW AND INCOME STATEMENT
USING ALTERNATIVE REVENUE STREAM

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
1 REVENUES	0.	0.	0.	72449.	90303.	102949.	115809.	175535.	188400.	203752.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	7245.	9030.	10295.	11581.	17553.	18840.	20375.
4 : O&M	0.	0.	0.	4412.	4818.	5232.	5656.	6080.	6506.	6961.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	80713.	75001.	68778.	63073.	57844.	53051.	48658.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	0.	631.	6791.	55907.	52287.	50250.	48367.	45812.	43428.	43000.
9 : PROPERTY TAX	0.	0.	0.	19070.	18412.	17754.	17097.	16439.	15782.	15124.
10 : OTHER EXPENSES	12203.	246638.	6575.	807.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-12203.	-247269.	-13366.	-95704.	-69246.	-49361.	-29964.	31806.	50794.	69634.
12 LESS: INCOME TAX	-5943.	-120420.	-6509.	-46608.	-33723.	-24039.	-14593.	15490.	24737.	33912.
13 PROFITS AFTER TAX	-6260.	-126849.	-6857.	-49096.	-35523.	-25322.	-15372.	16317.	26057.	35722.
14 LESS: CAP. EXPENDS.	10755.	100276.	710589.	164739.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	25069.	171647.	40358.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	0.	0.	0.	80713.	75001.	68778.	63073.	57844.	53051.	48658.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	-17015.	-202056.	-545799.	-92765.	39478.	43455.	47701.	74160.	79108.	84380.
19 LESS: DEBT REPAYMENT	-5377.	-50138.	-355294.	-8289.	-4669.	-2633.	-749.	1806.	4190.	4618.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	-11637.	-151918.	-190504.	-84476.	44147.	46088.	48450.	72354.	74918.	79762.
22 NPV CASH FLOW (PV ROEQ)	-11637.	-127896.	-134418.	-49351.	21569.	18935.	16817.	21335.	18854.	17133.
23 CUM. NPV CASH FLOW	-11637.	-139534.	-273951.	-323302.	-301733.	-282798.	-265982.	-244647.	-225792.	-208660.

SIMPLIFIED BALANCE SHEET

1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 NET PLANT IN SERVICE	10755.	111031.	821620.	953848.	920957.	888066.	855174.	822283.	789392.	756500.
3 OTHER ASSETS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 *** TOTAL ASSETS	10755.	111031.	821620.	953848.	920957.	888066.	855174.	822283.	789392.	756500.
5 DEFERRED TAXES	0.	0.	0.	23474.	43982.	61458.	76157.	88309.	98126.	105804.
6 DEBT BALANCE (END YR.)	5377.	55515.	410810.	419099.	423768.	426401.	427149.	425343.	421153.	416535.
7 EQUITY BALANCE	5377.	55515.	410810.	511275.	453207.	400207.	351868.	308631.	270112.	234161.
8 *** TOTAL LIAB+NET WORTH	10755.	111031.	821620.	953848.	920957.	888066.	855174.	822283.	789392.	756500.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
CASH FLOW AND INCOME STATEMENT
USING ALTERNATIVE REVENUE STREAM

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
1 REVENUES	224301.	244957.	267786.	291799.	318730.	345217.	376829.	411707.	447347.	485351.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	22430.	24496.	26779.	29180.	31873.	34522.	37683.	41171.	44735.	48535.
4 : O&M	7449.	7970.	8528.	9125.	9764.	10447.	11178.	11961.	12798.	13694.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	44630.	40939.	37556.	34454.	31612.	29006.	28990.	28990.	28990.	28990.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	42528.	42009.	41436.	40805.	40109.	39342.	38498.	37566.	36540.	35409.
9 : PROPERTY TAX	14467.	13809.	13151.	12494.	11836.	11179.	10521.	9864.	9206.	8548.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	92797.	115735.	140336.	165741.	193536.	220721.	249959.	282155.	315078.	350175.
12 LESS: INCOME TAX	45192.	56363.	68344.	80716.	94252.	107491.	121730.	137410.	153443.	170535.
13 PROFITS AFTER TAX	47605.	59372.	71992.	85025.	99284.	113230.	128229.	144746.	161635.	179640.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	44630.	40939.	37556.	34454.	31612.	29006.	28990.	28990.	28990.	28990.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE O/E RETIRE.	92235.	100311.	109548.	119480.	130896.	142236.	157219.	173735.	190625.	208629.
19 LESS: DEBT REPAYMENT	5090.	5609.	6182.	6813.	7509.	8275.	9120.	10052.	11078.	12209.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	87145.	94702.	103366.	112667.	123387.	133960.	148099.	163684.	179547.	196421.
22 NPV CASH FLOW (PV ROEQ)	15976.	14818.	13804.	12842.	12004.	11123.	10495.	9900.	9269.	8655.
23 CUM. NPV CASH FLOW	-192684.	-177865.	-164061.	-151219.	-139216.	-128093.	-117597.	-107697.	-98428.	-89773.

SIMPLIFIED BALANCE SHEET

1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 NET PLANT IN SERVICE	723609.	690718.	657826.	624935.	592044.	559153.	526261.	493370.	460479.	427587.
3 OTHER ASSETS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 *** TOTAL ASSETS	723609.	690718.	657826.	624935.	592044.	559153.	526261.	493370.	460479.	427587.
5 DEFERRED TAXES	111521.	115441.	117712.	118473.	117850.	115958.	114058.	112158.	110258.	108358.
6 DEBT BALANCE (END YR.)	411445.	405836.	399654.	392841.	385332.	377057.	367937.	357885.	346807.	334598.
7 EQUITY BALANCE	200642.	169441.	140460.	113621.	88862.	66138.	44267.	23327.	3414.	-15369.
8 *** TOTAL LIAB+NET WORTH	723609.	690718.	657826.	624935.	592044.	559153.	526261.	493370.	460479.	427587.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
CASH FLOW AND INCOME STATEMENT
USING ALTERNATIVE REVENUE STREAM

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 REVENUES	527135.	573086.	622143.	676057.	734470.	796836.	866287.	940513.	1020884.	1109095.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	52713.	57309.	62214.	67606.	73447.	79684.	86629.	94051.	102088.	110910.
4 : UEM	14652.	15678.	16775.	17950.	19206.	20551.	21989.	23528.	25175.	26938.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	28990.	28990.	28990.	28990.	28990.	28990.	28990.	359.	359.	359.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	34163.	32789.	31275.	29606.	27767.	25740.	23507.	21045.	18332.	15342.
9 : PROPERTY TAX	7891.	7233.	6576.	5918.	5261.	4603.	3945.	3288.	2630.	1973.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	388726.	431088.	476313.	525987.	579800.	637269.	701228.	798241.	872299.	953574.
12 LESS: INCOME TAX	189309.	209940.	231964.	256156.	282362.	310350.	341498.	388743.	424809.	464391.
13 PROFITS AFTER TAX	199416.	221148.	244349.	269832.	297437.	326919.	359730.	409498.	447489.	489184.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	28990.	28990.	28990.	28990.	28990.	28990.	28990.	359.	359.	359.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	228406.	250138.	273338.	298821.	326427.	355909.	388720.	409857.	447849.	489543.
19 LESS: DEBT REPAYMENT	13455.	14829.	16343.	18012.	19851.	21878.	24111.	26573.	29286.	32276.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	214951.	235309.	256995.	280810.	306576.	334031.	364608.	383284.	418563.	457267.
22 NPV CASH FLOW (PV ROEQ)	8083.	7553.	7040.	6566.	6118.	5689.	5300.	4756.	4432.	4133.
23 CUM. NPV CASH FLOW	-81690.	-74137.	-67097.	-60531.	-54413.	-48724.	-43423.	-38668.	-34235.	-30103.

SIMPLIFIED BALANCE SHEET

1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 NET PLANT IN SERVICE	394696.	361805.	328913.	296022.	263131.	230239.	197348.	164457.	131565.	98674.
3 OTHER ASSETS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 *** TOTAL ASSETS	394696.	361805.	328913.	296022.	263131.	230239.	197348.	164457.	131565.	98674.
5 DEFERRED TAXES	106457.	104557.	102657.	100757.	98857.	96957.	95057.	79214.	63371.	47528.
6 DEBT BALANCE (END YR.)	321143.	306314.	289971.	271959.	252108.	230231.	206119.	179546.	150260.	117984.
7 EQUITY BALANCE	-32905.	-49067.	-63715.	-76694.	-87835.	-96948.	-103828.	-94303.	-82066.	-66838.
8 *** TOTAL LIAB+NET WORTH	394696.	361805.	328913.	296022.	263131.	230239.	197348.	164457.	131565.	98674.

BASE CASE ANALYSIS
PHILIP, SOUTH DAKOTA GEOTHERMAL PROJECT
CASH FLOW AND INCOME STATEMENT
USING ALTERNATIVE REVENUE STREAM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 REVENUES	1204654.	1308156.	1420247.	0.	0.	0.	0.	0.	0.	0.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	120465.	130816.	142025.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	28823.	30841.	33000.	0.	0.	0.	0.	0.	0.	0.
5 : RAW MATERIALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	359.	359.	359.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 : INTEREST	12046.	8414.	4412.	0.	0.	0.	0.	0.	0.	0.
9 : PROPERTY TAX	1315.	658.	0.	0.	0.	0.	0.	0.	0.	0.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	1041643.	1137066.	1240450.	0.	0.	0.	0.	0.	0.	0.
12 LESS: INCOME TAX	507280.	553751.	604099.	0.	0.	0.	0.	0.	0.	0.
13 PROFITS AFTER TAX	534363.	583315.	636351.	0.	0.	0.	0.	0.	0.	0.
14 LESS: CAP. EXPENDS.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
15 PLUS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPRECIATION	359.	359.	359.	0.	0.	0.	0.	0.	0.	0.
17 : DEPLETION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 CASH BEFORE D/E RETIRE.	534722.	583674.	636710.	0.	0.	0.	0.	0.	0.	0.
19 LESS: DEBT REPAYMENT	35572.	39204.	43206.	2.	0.	0.	0.	0.	0.	0.
20 : CASH RETAINED	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
21 NET CASH FLOW TO EQUITY	499151.	544471.	593504.	-2.	0.	0.	0.	0.	0.	0.
22 NPV CASH FLOW (PV ROEQ)	3851.	3585.	3335.	-0.	0.	0.	0.	0.	0.	0.
23 CUM. NPV CASH FLOW	-26252.	-22667.	-19332.	-19332.	-19332.	-19332.	-19332.	-19332.	-19332.	-19332.

SIMPLIFIED BALANCE SHEET

1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 NET PLANT IN SERVICE	65783.	32892.	0.	0.	0.	0.	0.	0.	0.	0.
3 OTHER ASSETS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 *** TOTAL ASSETS	65783.	32892.	0.	0.	0.	0.	0.	0.	0.	0.
5 DEFERRED TAXES	31685.	15842.	0.	0.	0.	0.	0.	0.	0.	0.
6 DEBT BALANCE (END YR.)	82412.	43208.	2.	0.	0.	0.	0.	0.	0.	0.
7 EQUITY BALANCE	-48314.	-26159.	-2.	0.	0.	0.	0.	0.	0.	0.
8 *** TOTAL LIAB+NET WORTH	65783.	32892.	0.	0.	0.	0.	0.	0.	0.	0.

THE INTERNAL RATE OF RETURN IS 17.35 PERCENT.

THE LEVELIZED UNIT PRICE IS (\$/MMBTU) 2.26

THE DISCOUNTED LIFE CYCLE REVENUES ARE 326610.25