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ECONOMICS OF GEOTHERMAL DIRECT HEAT APPLICATIONS

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ABSTRACT

Cost and production data from five commercial-scale geothermal direct heat application projects are reviewed. Unit costs of geothermal energy under a variety of assumptions about production levels, costs, tax treatment, financial structure, and cost of capital are calculated and compared to prices of conventional fuels which would be displaced over the life of a geothermal project. Geothermal energy is found to be less costly than distillate fuel oil for all cases examined and cheaper than natural gas in many cases.

INTRODUCTION

Five commercial-scale geothermal demonstration projects partially funded by the Department of Energy serve as the basis for this assessment of the economic attractiveness of geothermal energy for direct heat applications. The projects under review include two institutional space and hot water heating systems (at the Klamath County, Oregon YMCA and at St. Mary's Hospital in Pierre, S.D.), one agricultural application (grain drying at the Diamond Ring Ranch in Haakon, S.D.), two small-scale district heating systems (at Philip, S.D. and the Diamond Ring Ranch) and one moderate size district heating system (in Pagosa Springs Colorado). Four of the five projects are operational; the Pagosa Springs district heating system is expected to begin operations during the 1981-1982 heating season. For each of the five projects, Table 1 provides information on eight important project features: well depth, geothermal fluid temperature, initial year of operations, expected system life, capital and operating and maintenance costs, energy delivered, and application. (For additional project information, see DOE (1980)).

To determine the commercial potential of geothermal direct heat applications, geothermal costs are compared to the costs of supplying equivalent amounts of energy using conventional fossil fuels. The analysis incorporates recent DOE world oil price projections and ICF's coal and natural gas market models to project price paths for distillate fuel oil, low sulphur residual fuel oil, high sulphur residual fuel oil, natural gas, and coal. The analysis assumes that the geothermal project would constitute a retrofit of an existing heating system. Capital costs for equipment to store and burn fossil fuels are excluded from the calculation of conventional fuel costs for this retrofit decision. Inclusion of these costs would make the results even more favorable for geothermal energy.

METHODOLOGY

An assessment of the economic attractiveness of geothermal energy for direct heat applications requires an appropriate basis for comparison of geothermal with conventional energy systems. The basis must provide for consistency in terms of the economic costs and the physical measures of the energy supplies compared. Several steps help develop this consistency. Financial calculations are made in nominal (current year) dollars on the basis of consistent inflation assumptions; the results for all energy options are then converted to constant (1980) dollars to facilitate cost comparisons. (For inflation rates, see DOC (1981) and CBO (1981)). These calculations incorporate consistent assumptions regarding tax treatment, capital structure, and the cost of capital.

The geothermal project cost streams generated through the financial analysis and the alternative conventional fuel cost streams have significantly different profiles over the life of a project. For instance, geothermal supplies involve large up-front costs and minimal operating costs thereafter, whereas conventional fuel costs would increase over the life of the project. Application of discounted cash flow principles leads to an estimate of the present value of each cost stream. This present value figure is then used to derive the constant real unit cost of each geothermal project and conventional fuel supply stream. The unit cost equals the minimum price that a supplier could accept to cover all costs of providing an energy supply (e.g., capital and O&M expenses, taxes, and required return on investment), and is often called the Minimum Acceptable Supply Price (MASP). (For an expanded discussion of MASP, see ICF (1980)). Unit price measures allow comparisons among projects with differences in production quantities and expenditure patterns.

TABLE 1

PROJECT DATA SUMMARY

Project (Sponsor Status)	Application	Well Depth (feet)	Fluid Temperature (°F)	Start-up of Operations	Planned Project Life a/ (years)	Capital Cost (1980 Dollars)	O&M Cost	Annual Energy Delivered (10^9 Btu)
Diamond Ring Ranch (private firm)	grain drying; space & water heating	4100	152°F	1979	20	$ 489,000b/	$ 5,000	7.9
Klamath YMCA (private, non-profit)	institutional space & water heating	1400	147	1980	25	285,000	2,100	7.0
Pagosa Springs (local government)	district heating	275 300	131 148	1981 c/	30	1,462,000	50,400	56.7
Philip, S.D. (local government)	district heating	4300	157	1980	30	1,188,000	4,000	14.8 d/
St. Mary's Hospital (non-profit, tax-exempt bonds)	institutional space & water heating	2200	106	1980	30	769,000	10,800	11.4

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a/ Period prior to major capital re-investment.

b/ Adjusted to include cost of building new well and exclude costs of extending pipeline to existing well site.

c/ Planned.

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

Energy supply measures also require consistent treatment. Typically, geothermal energy is measured in terms of usable energy delivered, while fossil fuels are measured in terms of gross energy input into a fuel conversion system. To permit meaningful comparisons of energy costs, the analysis measures geothermal energy in terms of the amount of conventional fuel displaced.

Together, all these steps assure a comparison using consistent thermodynamic and economic measures of each energy source.

GEOTHERMAL ENERGY SUPPLY COSTS

Two sets of cost estimates are developed for each geothermal project reviewed. The estimates are labelled "actual" and "base case." Both sets use actual expenditure figures from the projects reviewed, but the cost of capital and tax treatment vary according to the assumptions relevant for the "actual" or "base" case. The "actual" unit costs reflect actual project sponsor tax and financial status, while the base case unit costs incorporate a set of tax and financial assumptions standardized across projects. The economic analysis of the five projects finds that on the basis of actual project sponsor status, outlays, and production, the project sponsors could have supplied themselves with geothermal energy for $1.20 to $2.40 per million Btu without federal assistance. (See ICF (1981) for a discussion of the financial assumptions for each project.) The differences in project unit costs arise because the costs incurred vary considerably with project sponsor status (e.g., private firms must pay taxes; non-profits and governments do not) and because of variations in resource and application characteristics such as well depth, fluid temperature and flow, and percent of well capacity used.

The "base case" analysis estimates the geothermal supply costs that a private developer would face in providing geothermal direct heat energy given a set of standard assumptions concerning taxation and financing of a project. Assumptions made in the base case analysis include the following:

- o 15% energy tax credit
- o Federal, state and local income and property taxes
- o 10% royalty
- o initial debt/equity ratio of 50/50
- o 3% real corporate interest rate
- o 9.5% real return on equity

For the base case, geothermal costs vary from $2.37 to $5.73 per million Btu. Because the taxation and financial assumptions were standardized for these base case estimates, the differences in unit costs result entirely from the range of variations encountered for the physical characteristics associated with the resources and applications at each project. Well depth appears to be especially important to cost differences. Fluid temperature and other factors may also have major effects on geothermal costs but additional data must be gathered before conclusive statements about these variables are possible.

The sensitivity analysis is performed on the base case estimate from the most costly of the projects reviewed, Philip. It finds that geothermal costs decrease when the cost of capital is lowered either through local government use of tax exempt bonds or through high debt/equity ratios. Proposed accelerated depreciation measures, such as "10-5-3" depreciation, could also reduce geothermal costs substantially. "10-5-3" depreciation would apply double declining balance depreciation to structures, equipment, and vehicles for tax lives of 10, 5, and 3 years, respectively.

The combination of high leverage (perhaps with the help of loan guarantees), "10-5-3" depreciation, and the avoidance of royalties through the use of one's own resource could reduce costs 62 percent from the Philip base case estimate. The more important unit cost increases could arise through serious capital cost increases, major production declines, and removal of the energy tax credit (currently scheduled for 1985).

COMPARATIVE ANALYSIS

Figure 1 shows that for the base case assumptions, each project is economically superior to conventional alternative fuels on a lifecycle basis. Compared to current conventional fuel prices, however, geothermal costs are not nearly as attractive. Coal appears superior to some of the geothermal options, but the unique problems of using solid fuels in such small applications make coal an unlikely alternative except, perhaps, for projects located close to existing mine mouths.

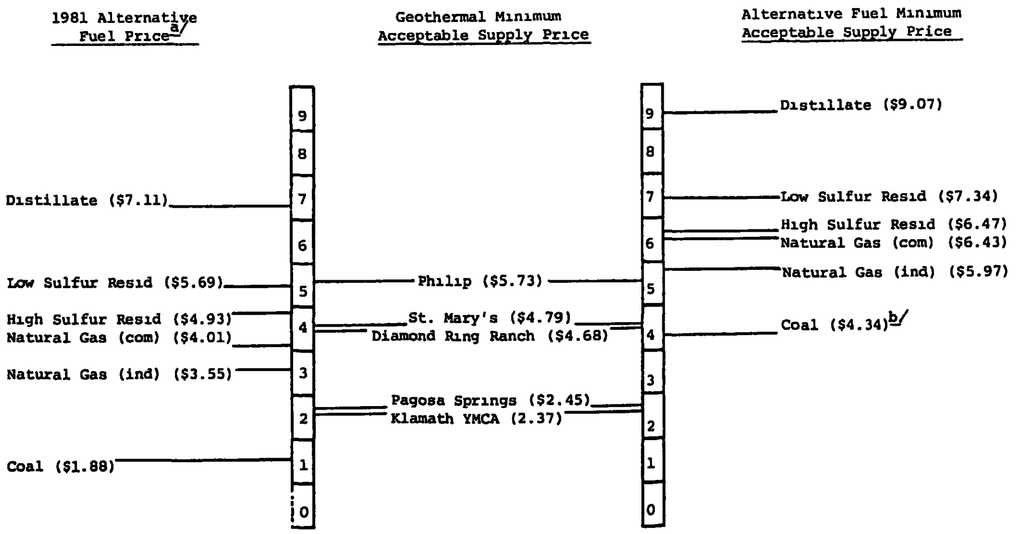
A comparative sensitivity analysis was also performed for the Philip project, the most costly of the five. Although this approach "biased" the analysis against geothermal by using a high-cost project, the project remained superior to distillate fuel oil for all cases examined and superior to natural gas in many cases. Natural gas would be superior to Philip geothermal if the required real return on equity increased by 25 percent, the initial equity share grew to 75 percent, capital costs increased (perhaps to provide an injection well), or the energy tax credit were removed. Table 2 lists the levelized unit costs of the Philip geothermal project and of distillate fuel oil and commercial natural gas for selected sensitivity analysis cases.

FINDINGS

The economic attractiveness of the geothermal direct heat application projects reviewed here remains substantial compared to conventional alternative fuels under a variety of assumptions about project sponsor status and project costs. The demonstration of economic viability at commercial scale represents the attainment of a technology development milestone achieved by few unconventional energy supply technologies. The extent to which geothermal energy can continue to provide an economically attractive alternative depends on whether the projects reviewed represent typical or unusual opportunities to exploit geothermal moderate temperature resources. This question was not addressed in this analysis. Nevertheless, the results of this preliminary assessment strongly suggest that geothermal resources can provide economically attractive direct heat energy in selected circumstances.

FIGURE 1

BASE CASE COMPARISON OF
GEOTHERMAL AND CONVENTIONAL ENERGY COSTS
(1980 Dollars per Million Btu)



a/ Fuel only.

b/ Capital, O&M, and fuel costs.

TABLE 2

SELECTED SENSITIVITY ANALYSIS

Parameter	Parameter Change	Philip Geothermal MASP b/ ($/million Btu)	Minimum Acceptable Supply Price a/	
			Distillate ($/million Btu)	Natural Gas (Commercial) ($/million Btu)
Capital Cost	25% Increase	$7.10	$9.07	$6.43
	25% Decrease	4.35	9.07	6.43
Yearly Production Rate	Declining to 1/2 initial Rate[c]	6.40	8.78	6.22
	Declining to 0[c]	7.26	8.42	5.96
Debt/Equity Ratio	25/75	7.22	9.07	6.43
	75/25	4.23	9.07	6.43
Real Return on Equity	25% increase	6.80	8.79	6.20
	25% decrease	4.72	9.40	6.68
Tax Treatment	Remove energy tax credit	7.19	9.07	6.43
	"10-5-3" accelerated depreciation	3.88	9.07	6.43
Royalties	Remove royalty charge	5.15	9.07	6.43
Project Sponsor Status	Private, not-for-profit (no tax-exempt debt)	3.68	10.12	7.17
	Local government (tax-exempt debt)	2.65	10.61	7.48

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a/ Conventional fuel prices are levelized assuming the same energy quantities and applying the same discount rate as the corresponding geothermal project costs.

b/ Minimum acceptable supply price.

c/ Linear decline beginning year 6.

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