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MEMORANDUM

TO: Randall Stevens
DOE, Office of Geothermal Energy

DATE: November 4, 1980

FROM: David Meyers, Eric Wiseman, Valérie Bennett
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RE: An Analysis of How Changed Federal Regulations and Economic Incentives Affect Financing of Geothermal Projects

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0. Introduction

This project included six tasks. Tasks 1, 2, 4, 5, and 6 studied the effect of various financial incentives on potential developers of geothermal electric energy. Task 3 assessed the impact of timing of plant construction costs on geothermal electricity costs.

In Task 1, ERCO examined the effect of the geothermal loan guarantee program on decisions by investor-owned utilities to build geothermal electric power plants. By guaranteeing 75 percent of the cost of building a geothermal generating station, the loan guarantee program attempts to lower the risks associated with geothermal development. Interviews with members of this investment community, however, indicated that while utilities can use the loan guarantee program by structuring non-recourse debt, there are a variety of factors limiting the attractiveness of this fundraising vehicle.

Task 2 focused on the usefulness of additional investment tax credits as a method for encouraging utilities to invest in geothermal energy. It determined whether current regulations allow utilities to retain the benefits associated with investment tax credits or whether these benefits must be passed on to consumers. It also studied the profitability of utilities potentially involved in geothermal energy. While the accounting systems of most utilities allows them to benefit from additional ITC's, the amount of unused credits available now indicates that additional credits may not be usable.

In Task 3, an ERCO computer model was utilized to determine the effect of the timing of construction costs on the cost of geothermally generated electricity. Busbar capital costs were calculated under a variety of assumptions about project construction schedules. In addition, an analysis was made of the sensitivity of busbar capital costs to interest rates. We found that capital costs are highly sensitive to interest rates and moderately sensitive to the timing of construction costs.

Task 4 described the independent firms which specialize in geothermal resource development. An analysis of the finances of two independents, Magma Power and Republic Geothermal was made. Next, the ERCO geothermal financial model was used to compare independent capital costs to those of the investor-owned utilities and the oil companies. The model was also used to assess the effect of financial incentives on independent capital costs. It was shown that because of the independent's capital structure, financial incentives such as investment tax credits can have a large impact on their costs.

Task 5 was a detailed assessment of the role of municipal and cooperative utilities in geothermal resource development. It included a study of the institutional and historical environment municipals and cooperatives operate in. Capital costs related to geothermal development were determined for municipals and cooperatives and were compared to those under other forms of ownership. Finally, a detailed survey was made of thirteen municipals and cooperatives located in or near western geothermal resource areas. These utilities were asked about their planned or on-going ventures in geothermal development. The survey focused on the impact of the geothermal loan guarantee program on municipal and cooperative development of geothermal energy and on problems with the loan guarantee program. The survey suggested that municipal and cooperative utilities are very interested in geothermal development. Primary factors preventing them from undertaking geothermal ventures are a lack of loan guarantees for exploration, difficulties in obtaining drilling permits, an inability to use the geothermal loan guarantee program to finance joint ventures with private firms, and an unwillingness to commit funds until specific geothermal reservoirs have been identified by others.

Task 6 required Energy Resources to calculate busbar capital costs for geothermal energy under a variety of ownerships with several assumptions about financial incentives. These results are reported in the sections covering the other tasks.

TASK I: Task Description

Utility Default on a Loan Guarantee

Electric utilities argue that they cannot default on a loan guarantee because of the effect this action would have on their credit rating and stock prices. As a result, they do not look at the loan guarantee program as a means of lowering the risks associated with building a generating plant at a geothermal site.

In Task One, we tested the assumption that utilities cannot default on a loan guarantee because of the effect on other securities. We sought answers to four questions:

- Can utilities default on a guaranteed loan?
- Do present debt convenants forbid default of this type?
- What effect would default on a loan guarantee have on other securities?
- Can the project be structured or financed in a way that they can take advantage of a goethermal loan guarantee?

The purpose of the task was to provide insight into the viability of the present loan guarantee program and to indicate the direction of possible future changes in the program.

TASK I: Task Results

1.1 Introduction

This task addressed the question of whether investor-owned utilities can take advantage of the geothermal loan guarantee programs. Utilities make the argument that a loan guarantee does not remove the risk involved in geothermal investments. They state that a default on any loan, even if guaranteed, would lower their credit rating and stock prices, thus hindering their ability to raise capital.

ERCO used a two-phased approach to evaluate this argument. First, the institutional environment in which investor-owned utilities operate was examined. This study provided background to the main section of this task, a survey of seven firms which evaluate utility securities. These included two prominent bond-rating houses, a mutual fund, a life insurance company, two stocks and bonds brokers, and a large commercial bank. These members of the investment community were asked what effect, if any, a default on a geothermal loan guarantee would have on a utility's other securities.

1.2 Institutional Environment

Utilities must operate within a regulated environment. In return for obtaining a local monopoly on the production of electric power, the revenues and profits of the electric utility industry are controlled by public regulatory agencies. The purpose of the controls is to prevent utilities from obtaining monopoly profits, to ensure non-discriminatory rate structures, and at the same time to guarantee an adequate return on investment so that there is sufficient capital available to produce the capacity needed for adequate and reliable service. The local state regulatory agencies or public utility commissions (PUC's) control the sale of electricity to the ultimate consumer. The Federal Energy Regulatory Commission (FERC) controls the rates of wholesale electricity sold across state lines.

Because the PUC's govern their profits, utilities usually do not benefit from taking large risks. Instead, the PUC will usually only allow utilities a "fair" rate of return, in which there is rarely an allowance for a higher return on untried technologies. (California does allow 1 percent extra return on innovative technologies.)

In the event of the failure of a new project, the PUC's can either allow the utility to pass along the cost of the project to the consumer or can force the utility to absorb the loss on its own. Even if the PUC is amenable to allowing the utility to pass costs of failure along to the consumer, two factors may prevent the utility from benefiting from this policy: First, the PUC may define failure differently from the utility. If a geothermal project yields power at a cost far above that of its other facilities, the utility may consider the project a failure. The PUC may not consider the project a failure because it produces some electricity. Second, there may be a long delay between the time the project actually fails and the time when the PUC allows the utility to recover its investment.

Because of the regulation of their rate of return and the uncertainty of recovering their losses in the event of failure, utilities may be reluctant to undertake a risky geothermal project. If the project is a success, the consumer will reap most of the benefits because the PUC will hold down the utility's rate of return. If the project fails, the utility may have to absorb the costs of the project. The benefits of success are small while the penalties for failure may be great.

1.3 Survey of Investment Community

The previous section lends important background to ERCO's survey of the investment community. A utility investor chooses a utility stock or bond because of its low risk and substantial rate of return. As was described above, investments in a geothermal project may risk a utility's earnings while promising no greater return. An investor evaluating a utility would then be less likely to choose a utility investing in unproven technologies than one investing in conventional generating facilities. Otherwise, the investor may endanger his/her return on investment.

The Geothermal Loan Guarantee Program, by guaranteeing loans to finance up to 75 percent of the cost of the project, seeks to eliminate most of the downside risk associated with a geothermal project. A utility taking advantage of this program would possibly not endanger its credit rating and stock price. ERCO's survey attempted to determine whether this program would actually protect the securities of utilities involved in geothermal projects. We asked seven utility security analysts two major questions:

- First, could a public utility default on a loan, even if guaranteed?
- Second, what effect would the default on the geothermal loan have on the utility's stock price and credit rating?

We spoke first to utility analysts at the two most prominent bond rating houses. In answer to the first question, they stated that if the geothermal project could be financed off the books of the utility, a default on a guaranteed loan would be possible. The utility would have to set up a separate corporation to undertake the geothermal project, the debts of which would not be guaranteed by the non-geothermal revenues and assets of the firm (which is called "non-recourse" debt). This debt, which would finance 75 percent of the project, would only be guaranteed by the GLGP and the project itself. The utility could then default on the loan if the project were a failure. The utility would lose only the 25 percent of the cost of the project financed through equity. These analysts pointed out that geothermal projects are relatively inexpensive when compared to the total capital budget of a utility, and so the loss of 25 percent of the project's cost would not seriously weaken the finances of a utility.*

When asked whether the default would hurt the stock price or credit rating of the utility, these analysts stated that if the debt was non-recourse, then only the 25 percent of the project financed by the utility itself would be lost. As was noted above, this 25 percent would represent only a small portion of the firm's normal capital spending, and so it would not weaken firm finances. The credit rating and stock price would not be seriously affected, if at all.

These bond analysts suggested that the news of the default might have a negative psychological effect on investors and exert some downward pressure on stock prices. They also noted that the PUC's might allow the utility to pass some or all of its loss on to the consumer.

*A geothermal power plant will typically cost less than $100 million while a utility such as Pacific Gas and Electric spends over $300 million a year on capacity expansion.

In general, they did not believe that a default on a geothermal loan guarantee would have much effect on a utility's other securities.

The views of the utility analysts at the bond rating houses were shared by a utility analyst at a mutual fund and by a large stock brokerage firm. The analyst for the mutual fund believed that investors are interested solely in returns on their own investment. Investors would not be concerned about default on a guaranteed loan, but instead worry only about the 25 percent of the project financed by equity. This would be a relatively small amount, and the PUC might allow the utility to pass along the loss to the consumer. The mutual fund analysts suspected that the utility's reluctance to undertake geothermal projects was not associated with problems with the loan guarantee program but instead with an institutional bias against small projects. The stock broker agreed that a default would have little effect on stock prices.

The analyst for the life insurance company stated that he had attempted to structure a non-recourse geothermal loan guarantee for a large utility and had been unsuccessful. He thought it would be very difficult for anyone to structure such a loan. Furthermore, this analyst doubted that DOE would actually pay the creditors if the project failed. Finally, he stated that a default on a geothermal loan, even if guaranteed, could hurt the utility's reputation on credit markets and cause the utility's cost of debt to rise.

Many of the views of the insurance company analyst were shared by a pension fund manager at a large commercial bank. She stated that investors would not view sympathetically a firm that risked its investor's money on an unproven geothermal technology because its return from the project would be regulated. She did not believe that the PUC's would allow the utility to pass the cost of the project on to consumers if it failed. Finally, like the life insurance investor we interviewed, she doubted that DOE would actually pay the creditors in the event the utility declared the project a failure. The pension fund manager did, however, note that the cost of geothermal projects was a relatively small sum. Loss of 25 percent of the cost of such a project would place little downward pressure on the utility's securities prices.

ERCO interviewed a utility bond analyst with a large brokerage firm last. He believed that a default on a guaranteed loan would drive up the interest rate on that firm's bonds by 50-75 basis points. This is because the management of the utility would appear to have problems.

1.4 Summary

This task sought to determine whether utilities can use a geothermal loan guarantee to lower the risk of building a generating station at a geothermal site. There was no strong consensus among the seven utility analysts ERCO interviewed. They did agree, however, that if the loan guarantee is to be useful, it must be for non-recourse debt. Otherwise, the utility would risk the entire cost of the project when venturing into geothermal energy. They also agreed that the cost of a geothermal generating facility is small when compared to the average spending of a utility. As a result, losses on a geothermal project would put only a slight damper on earnings and thus on securities prices.

There was substantial disagreement over whether a truly non-recourse loan could be structured. There was also disagreement over whether DOE could be trusted to actually reimburse creditors after a default. Finally, some analysts believed that the psychological effect of a default on a guaranteed loan would moderately depress the stock prices and credit rating of a utility while others, because of the small size of a geothermal project, did not believe it would have a noticeable effect.

ERCO research points to several factors which may influence a utility's decision to build a geothermal generating station through the use of the GLGP:

- The utility's Public Utility Commission (PUC) might force the utility to absorb all costs of failure.
- The PUC might not allow the utility extra returns to compensate for the risks it takes by investing in geothermal energy.
- A loan guarantee will only reduce the utility's risk if the loan is non-recourse.
- Some evidence suggested that non-recourse loans are difficult to arrange.
- Even if a non-recourse guaranteed loan can be structured, a utility will still risk the 25 percent of the project's cost the utility must finance through equity. While loss of this equity would have minor financial impacts on a utility, there may be psychological impacts on investor confidence which exert downward pressure on the value of the utility's securities.

TASK 2: Task Description

Utility Accounting Procedures and the Usefulness of Additional Investment Tax Credits (ITC's)

In Task Two, we sought answers to two questions:

- How do accounting procedures influence the attractiveness to utilities of additional ITC's?
- Which utilities would be in a position to take advantage of increased levels of ITC's?

A tax credit is effective in stimulating investment only if the credit increases the potential after-tax profits of the utility. Because profits of the utility are regulated, it is not obvious that a tax credit offers even a potential increase in profits. To answer the first question posed above, we explored utility accounting systems in the states with major geothermal resources to see if these systems allowed the capture of additional profits offered by investment tax credits.

The second question posed above deals with the utility's ability to benefit from ITC's. Even if a utility's accounting system allows for the capture of additional profits via ITC's, the utility may not be able to use ITC's because law requires that ITC's can only be used to offset 70 percent of a utility's tax liability. ERCO examined financial data on five potential geothermal utilities to determine whether these utilities could take advantage of additional tax credits.

TASK 2: Task Results

2.1 Introduction

The task determined whether an increased investment tax credit will encourage utilities to invest in geothermal energy. ERCO first surveyed utilities in six states to determine whether their accounting systems allowed them to benefit from investment tax credits. If an investment tax credit (ITC) does not add to the profits of a utility, then they have no incentive to utilize the technology which offers the credit. ERCO also determined which utilities (among those that can benefit from ITC's) can absorb extra ITC's.

2.2 Accounting Treatment of Investment Tax Credits

Two accounting treatments of ITC's are used by utilities. Under flow-through accounting, the utility receives none of the benefits of the ITC. Instead, the tax credit is simply subtracted from the utility's revenue requirements as it occurs and the benefits of the ITC accrue to the utility's customers. Under normalization accounting, the ITC is subtracted from the utility's revenue requirement gradually over the life of the investment. Because the utility receives the ITC at the beginning of the life of the investment, it is able to retain a decreasing portion of the ITC over the life of the investment and so its profits increase. In short, under flow-through accounting, an ITC does not add to a utility's return on investment, while under normalization accounting, an ITC will increase the return on investment.[1]

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[1] For a more thorough and technical discussion of flow-through and normalization accounting, see Technical Assessment Guide, Electric Power Research Institute, June, 1978, Report No. PS-866-SR, pp. V-1 - V-23.

Under tax law changes in 1978, utilities have the discretion to choose between flow-through or normalization accounting. Individual state Public Utility Commissions (PUC's), however, attempt to influence the accounting method chosen.

In New Mexico, Utah, Oregon, Washington, and Nevada, all private utilities use normalization accounting. In California, San Diego Edison (SDE) and Southern California Edison (SCE) use normalization accounting, while Pacific Gas and Electric uses flow-through accounting.

Because most utilities use normalization accounting, it appears that the PUC's do not force them to use flow-through accounting.

2.3 Utilities' Ability to Benefit From ITC's

The ability of five utilities to benefit from additional investment tax credits was examined. These utilities were chosen because they are either presently involved in or potentially involved in geothermal electric energy production and include: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Public Service of New Mexico (PSNM), and Utah Power and Light (UP&L).

PG&E uses flow-through accounting, and so cannot benefit from ITC's. SCE, SDG&E, PSNM, and UP&L use normalization accouting and so these firms can benefit from additional investment tax credits, if they can use them. A firm must have a certain level of profit before it can take advantage of an investment tax credit. ITC's can only offset 70 percent of the utility's tax liability. Utilities which have large ITC's may not be able to use all their credits in a given year. These unused credits may be placed in a pool for use in future years. There is, however, a seven year limit on the period in which the use of an ITC may be deferred. As a result, if the utility has low profits and a large pool of unused credits, its ability to use additional ITC's is limited.

The ability of the four utilities which can use ITC's to absorb additional investment tax credits is shown in Table 2-1. Southern California Edison does not have a pool of unused ITC's and so additional ITC's could offset its tax liability. San Diego Gas and Electric, Public Service of New Mexico, and Utah Power and Light all have large pools of unused ITC's. The existence of these pools of unused ITC's, which have been growing in recent years, suggests that these utilities may have difficulty in using new ITC's. As a result, they may derive no benefit from additional ITC's.

2.3 Conclusion

Public utilities in the six states examined may choose between flow-through and normalization accounting. Most choose normalization accounting, under which utilities receive some benefit from additional ITC's. Of five utilities currently participating in geothermal power projects, only Southern California Edison could absorb the full benefits of additional geothermal tax credits now. Some benefits may accrue, in decreasing order of impact, to San Diego Gas and Electric, Public Service of New Mexico, and Utah Power and Light.

TABLE 2-1

UTILITY ABILITY TO ABSORB TAX CREDITS

UTILITY	ACCOUNTING METHOD	UNUSED ITC* (million $)	1977-1978 ADDITIONS TO UNUSED ITC'S (million $)
Southern California Edison	Normalization	0	0
San Diego Gas and Electric	Normalization	27.8	16.5
Public Service of New Mexico	Normalization	19.4	19.4
Utah Power and Light	Normalization	39.6	39.6

*As of December 13, 1978.

TASK 3: Task Description

Construction Costs and Schedules

Task 3 investigated the impact of construction timing on busbar electricity costs for geothermal projects. Since different technological options (e.g., binary or flash systems) will have different construction schedules, it is useful to explore the impact of construction scheduling on busbar costs.

TASK 3: Task Results

Task 3 required a sensitivity analysis of the impact of the timing of construction costs on the busbar capital costs for geothermal generating facilities. Geothermal plants are constructed in approximately two years in most cases. For example, the construction of the geothermal plant at the Geysers for the Northern California Municipal Power Corporation was begun in early 1980 and is scheduled for completion in 1982. The binary cycle plant to be built at Heber will be under construction in 1982 and on-line by 1984.[1]

Given a two-year construction period, capital costs are not very sensitive to the timing of construction expenses. Table 3-1 shows the busbar costs of capital for a 55 megawatt plant which is built over two years. The plant is assumed to operate at an average of 75 percent of capacity, have a thirty year life, and be on-line at the beginning of the third year. Plant cost is a total of $67 million (real).[2]

In order to demonstrate the sensitivity of capital costs to the timing of construction, two extreme cases and an intermediate case were chosen. In the first case, all construction expenses occur in the first year. In the intermediate case, construction expenses are $34 million in the first year, and $33 million in the second year. In the second case, all construction expenses occur in the second year. With a 10 percent interest rate, which is approximately

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[1]"Tapping the Main Stream of Geothermal Energy," EPRI Journal, May 1980, p. 9.

[2]Formula for calculating busbar cost of capital may be found in Electric Power Institute's "Technical Assessment Guide," June 1979, No. EPRI PS-866-SR, pp. V-17 to V-23.

TABLE 3-1

SENSITIVITY OF CAPITAL COSTS TO CONSTRUCTION TIMING

(2 YEARS OF CONSTRUCTION)

TAX FREE COST OF CAPITAL	CONSTRUCTION COST (million $) YEAR 1	2	PRESENT VALUE OF CONSTRUCTION COST AT START OF OPERATION (million $)	BUSBAR CAPITAL COSTS (Mills/kWh)
8%	67	0	78.14	19.21
	34	33	75.29	18.51
	0	67	72.36	17.79
10%	67	0	81.07	23.80
	34	33	77.44	22.74
	0	67	73.70	21.64
12%	67	0	84.04	28.87
	34	33	79.61	27.35
	0	67	75.04	25.78

the current yield on tax-free municipal bonds, busbar costs of capital would vary from 21.64 to 22.74 to 23.8 mills/kilowatt hour across the three cases. The variation across the two extreme cases is 9.9 percent. With an 8 percent cost of capital, the busbar cost of capital varies from 17.79 to 19.21 mills/kilowatt hour across the two extreme cases, while with 12 percent cost of capital, the busbar costs increase from 25.78 to 28.87 mills/kilowatt hour. This is shown in Table 3-1.

ERCO also evaluated the effect of construction timing when the same $67 million plant is built over a period of four years. The first row of four year costs reflect those used in an earlier ERCO study ("An Analysis of Geothermal Electric Power Plant Financing," January 1980). The second set of four year costs are an increasing cost schedule while the third set is a decreasing cost schedule. Busbar capital costs at a 10 percent cost of capital vary from 24.38 mills/kWh for the increasing cost schedule to 25.84 mills/kWh for the decreasing cost schedule. The four year sequence of costs is also shown on Table 3-2.

Given a four year construction period, busbar capital costs are, therefore, not very sensitive to construction timing.

Another point can be noted in Tables 3-1 and 3-2. While the busbar capital costs were not sensitive to the timing of construction costs within a given construction period (e.g., two or four years) busbar capital costs are highly sensitive to interest rates. This can be shown by comparing the costs in the various interest rate categories in Table 3-1. These range from 17.79 - 20.52 mills for 8 percent interest to 25.78 - 31.89 mills for 12 percent interest, an approximately 50 percent swing.

TABLE 3-2

SENSITIVITY OF CAPITAL COSTS TO CONSTRUCTION TIMING

(4 YEARS OF CONSTRUCTION)

TAX FREE COST OF CAPITAL	CONSTRUCTION COST (million $) YEAR 1	2	3	4	PRESENT VALUE OF CONSTRUCTION COST AT START OF OPERATION (million $)	BUSBAR CAPITAL COSTS (Mills/kWh)
8%	12	18	24	13	81.03	19.90
	12	13	18	24	79.62	19.57
	24	18	13	12	83.50	20.52
10%	12	18	24	13	84.86	24.92
	12	13	18	24	83.05	24.38
	24	18	13	12	88.02	25.84
12%	12	18	24	13	88.83	30.52
	12	13	18	24	86.61	39.76
	24	18	13	12	92.80	31.89

TASK 4: Task Description

Independent Financing

Some geothermal powerplant construction involves small independent companies which specialize in geothermal resource development. These independents have different operating and financial characteristics than do the large oil companies and utilities which are active in geothermal development.

This task analyzed the finances and activities of two independents, Magma Power and Republic Geothermal.

In addition, independents' capital costs were compiled using the ERCO geothermal financing model and compared to those of other geothermal developers.

The purpose of this task was to provide information on the role of independents on geothermal development. It also served to analyze the sensitivity of independents' costs of geothermal development to various financial incentives and to compare independents' costs to those of the utilities and oil companies.

TASK 4: Task Results

4.1 Introduction

The development of geothermal electric conversion facilities has involved the participation of firms other than the large oil companies (e.g., Union, Phillips and Chevron) and the utilities. These other firms are referred to as "the independents." The independents are fairly small and devoted to a single product -- the development and/or conversion of geothermal energy into a useful energy source.

The independents who have entered the geothermal field generally do not have as many investment opportunities competing for resources as do the large oil companies. The developers or possibly "converters" (such as Magma Power and Republic Geothermal) are small enough to focus solely on geothermal. This focus eliminates many of the internal "institutional barriers" to new investments inherent in companies with more than one product. In addition, because their investors are not risk adverse, they may forge ahead with a project where more conservative companies with other profitable business opportunities would take a "wait and see" attitude.

4.2 Effect at Risk on Geothermal Development

Geothermal development is quite risky. Drilling is expensive and may not locate any steam reservoirs. Reservoirs which are identified may not be suitable for electrical generation. Even if a suitable reservoir is found, technical problems may arise in the conversion of geothermal steam to electricity.

The independents expect to be compensated for their failures by high returns on successful ventures. If, however, geothermal conversion facilities are treated as public utilities and subject to regulated returns on assets, there would be no possibility for them to realize high rates of return. As a result, there would be no incentive for them to build geothermal conversion facilities.

Under recent amendments to the Public Utilities Regulatory Policies Act (PURPA), enacted as part of the Energy Security (Synfuels) Act, a geothermal power producer with a plant capacity of 80 MW or less will be exempt from regulation. The law states that a cluster of plants whose total capacity on a single site exceeds 80 MW would be regulated, however. So far, no independent has succeeded in building an electric plant exceeding 11 MW (the Magma Plant at East Mesa) at a single site, so the question of regulation of independents has not yet been confronted.

A more important problem is that of the price the purchasing utility will offer the owner for geothermally generated electricity. It is unlikely that the utility would agree to pay more than the statutory minimum price for geothermally generated electricity. This minimum, set under PURPA, is the minimum cost of producing electricity from any other available source. The utility would not force its consumers to subsidize an independent geothermal producer by paying high rates for geothermally generated electricity. In addition, the PUC would probably not allow the utility to pay more than the minimum.

Another potential problem is whether the PUC would allow utilities to buy power at a price yielding higher returns on equity to the independent than are permitted to the utility owners. The case of the Geysers suggests that the PUC will approve the purchase price if it is less than that of the utility's alternatives, even if the rate of return is higher. Magma Power sells steam to Pacific Gas and Electric at the Geysers and realizes a large profit. The cost of the steam to Pacific Gas and Electric, however, is only two-thirds the cost of fossil-fuel derived steam.

In short, a risk facing an independent geothermal power producer is that its returns may be regulated once geothermal technology is perfected and several large plants have been built. The independent would have taken large risks and would receive only a normal rate of return.

4.3 Specific Independents

There are many independent participants in the development of geothermal energy.[1] The following section describes two of the more prominent independents, Magma Power and Republic Geothermal. They are typical examples of independent companies which are developing geothermal generating facilities.

4.3.1 Magma Power

Magma Power's primary business is to explore for, develop and sell geothermal resources to generate electric power or for other uses. Magma Power has a number of subsidiaries

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[1]See the Geothermal Resource Council Directory for a sample listing of companies.

that are also involved in geothermal resource development. These include 66 percent owned Magma Energy, and 100 percent owned Magma Electric, and its 50 percent investment in Magma-Thermal. Magma-Thermal, via the Geysers project, is the source of Magma Power's revenues. Magma-Thermal is a joint venture with Thermal Power Company. Magma-Thermal derives all of its revenues from geothermal steam sales to Pacific Gas and Electric.

In 1976, Magma Energy, Imperial Magma and New Albion Resources (a wholly-owned subsidiary of San Diego Gas and Electric) exchanged interests in the Heber and East Mesa areas of the Imperial Valley. Magma Energy exchanged its interest in the Heber area for New Albion Resources' interest in the East Mesa area. As a result, Magma Energy hopes to supply the geothermal energy necessary to generate 65,000 kW of installed capacity at East Mesa.

In 1978, Magma Electric began construction of a pilot 11,000 kW geothermal power plant located in East Mesa. The $8.3 million pilot plant was built to demonstrate a practical method of extracting geothermal energy and converting it to electric power through the use of the Magmamax Process. In March, 1978, as construction and operating cost estimates were refined, Magma Electric reevaluated its ability to recover those costs. As a result of the uncertainty of recovering the costs, Magma Electric decided to expense all costs as research and development, rather than to capitalize them. This resulted in much lower 1978 income. The plant was finished in February, 1980, and is being tested now.

Magma Power's strategy is to further develop geothermal resources including hot water by using the cash generated (Table 4-1) by the Geyser's steam project. This project has been immensely successful because the price of steam is pegged to the costs of steam that Pacific Gas and Electric (PG&E) incurs in its other projects. For geothermal steam, PG&E pays roughly two-thirds of the cost of making steam from fossil fuels. The price of steam for 1980, 1979, and 1978 was 18.63, 17.08 and 16.02 mills per net kWh of electricity produced.

Since 1977, Magma has been involved in litigation with the Internal Revenue Service over tax returns filed in 1972 and 1973. An adverse decision would reduce stockholder's equity by about $9.2 million or by over a third of its present value. Other than this significant problem, Magma has been quite successful experiencing a return on equity of 15 percent in 1979. Return on equity was higher before 1978, when the decision to expense investments on East Mesa was made. Magma takes numerous risks but these risks are counterbalanced by the certainty of the cash flow at the Geysers. Overall, Magma Power does not seem to be stretching itself too thin and will be able to invest more in future years. Again, however, the final decision on the 1972 and 1973 tax returns will impact the company significantly.

4.3.2 Republic Geothermal

Republic Geothermal is a privately held corporation and as such does not file annual reports or Form 10-K's with the Security and Exchange Commission. It was organized in 1973

TABLE 4-1

MAGMA POWER

FINANCIAL STATISTICS
($ million unless otherwise indicated)

	1979	1978	1977	1976	1975	1974
Sales	14.0	12.9	12.8	10.6	6.4	3.2
Net Income	5.5	3.3	5.3	6.6	3.4	.9
Preferred Dividends	--	--	--	--	--	--
Common Dividends	--	--	--	--	--	--
Earnings Per Share	.57	.35	.56	.69	.36	.09
Assets	54.7	43.1	26.5	21.6		
Long-Term Debt	2.4	--	--	2.3		
Preferred Stock	--	--	--	--		
Common Equity	32.4	24.8	21.5	16.2		
Capital Expenditures	N/A	N/A	4.8	4.3		
Internally Generated Cash	N/A	10.3	8.2	8.2		
Total Cash Flow	N/A	11.1	8.9	8.8		

to engage in the exploration and development of geothermal resources. These activities include exploration, development, production, engineering and property management. The company's prime objective is to discover, develop, and sell hot water or steam for electric power generation.[1]

Republic Drilling Company, a wholly-owned subsidiary of Republic Geothermal, as of March 1978, has five drilling and workover rigs and can drill wells up to 13,000 feet. Since its founding, Republic has successfully drilled and completed numerous geothermal production wells and heat flow holes and has a record of drilling and completing wells considerably faster than the industry average.

The strategy of Republic is to form a number of partnerships in which Republic is the general partner and operator. These partnerships are formed around industrial geothermal ventures. As of June 30, 1978, the limited partners have invested some $24 million in the various partnerships. The limited partners have at times lent money to Republic and also have a chance to purchase stock in Republic. The company as a general partner receives 4 percent of the capital contributions at the closing of each partnership deal, and also receives other fees during the drilling program. The limited partners in each of these ventures receive certain tax benefits, and if the geothermal resource is discovered and developed, they also receive certain capital gains.

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[1] Report entitled "48 MW Net Geothermal Dual Flash Power Plant," prepared by General Electric and Rust Engineering in March 1978.

Table 4-2 presents financial statistics for Republic. As opposed to Magma, Republic's revenues are not from the sale of steam or hot water or from the generation of electricity; their income is derived from drilling and management fees charged to the partnerships. In 1978, however, Republic proposed to construct a conventional steam turbine electric generating plant using steam flashed from hot water at East Mesa. The total capital cost for this 55 MW plant is estimated at $51 million (1978 dollars) and does not include wells, well development or well pumps.

As of September, 1980, East Mesa is still under construction.

4.4 Model Analysis Using GeoFin*

4.4.1 Introduction

The following section describes an analysis of the capital costs associated with a geothermally fueled electric generating facility for various types of corporate ownership. The costs do not include the fuel cost (for the hot water), transmission costs of the generated electricity or O&M for the plant when it is in operation. These operations costs (in mills) could be as large or larger than the capital cost associated with the generating facility.

TABLE 4-2

REPUBLIC GEOTHERMAL
FINANCIAL STATISTICS
($ million unless otherwise indicated)

	1978	1977
Sales	3.35	2.33
Net Income	.66	.44
Preferred Dividends	--	--
Common Dividends	--	--
Earnings Per Share ($/share)	.77	.53
Assets	8.39	5.14
Long-Term Debt	1.61	.02
Preferred Stock	--	--
Common Equity	4.52	3.76
Capital Expenditures	4.03	2.05
Internally Generated Cash	1.2	.93
Total Cash Flow	3.04	3.12

The plant is assumed to cost $67 million and have a capacity of 55 MW.[1] The "planned" construction and shake-down period is four years and the cash flows associated with the plant were for a typical construction project of this type.[2] Once operating, the facility was assumed to have a capacity factor of 75 percent.

4.4.2 Independents - Parameters

Although one independent currently involved with the development of geothermal (Magma Power) does not employ any debt in its capital structure, other firms, such as Republic Geothermal, Westmoreland and a former Magma Power subsidiary, Geothermal Food Processors, have taken advantage of the high leverage (75 percent) permitted by the Geothermal Loan Guarantee Program (GLGP). As a result, the subsequent analysis has assumed that the GLGP would be employed.

In conjunction with the previous discussion of the capital costs and the structure of independents, and following base case parameters were employed:

Cost of Debt	(r_D)	10.5%
Cost of Equity	(r_E)	25%
Debt/Equity	(D/E)	75/25
Investment Tax Credit	(ITC)	10%

The plant and tax life are 30 years, Sum of the Year's Digit depreciation. ITC during construction and the effective tax rate 60 percent.

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*A geothermal computer program developed for "An Analysis of Geothermal Powerplant Financing," ERCO, January 1980.

[1] Westmoreland Geothermal, Imperial Valley, The Oil and Gas Journal, July 17, 1979, p. 38.

[2] Estimated by ERCO design engineers.

ITC's were absorbed during construction as permitted by law, and the structure of the company was assumed to be a partnership (limited) and not a corporation. The tax rate on this form of ownership can be substantially higher than on a corporation (as high as 70 percent). We assumed that only investors in high tax brackets would be involved in the ownership (higher than 50 percent).

4.4.3 Independents - Busbar Capital Costs

The results of the analysis on the independents' capital costs associated with their ownership of a geothermal generating facility are presented in Tables 4-3 and 4-4. The base case busbar cost of capital is 33.9 mills, which compares with 56.4 mills for oil company ownership and 31.6 mills for utility ownership.* The range of busbar costs is larger than that for utilities; however, in some cases the costs are lowest with the independent ownership (20 percent ITC).

Table 4-3 summarizes the effect of tax rate, investment tax credits and the period of depreciation for the independent's capital costs. The busbar cost is remarkably insensitive to the tax rate. Increasing the rate from 50 percent to 70 percent results in only a 2.7 percent increase in costs. The higher tax rates shelter more of the interest expenses, especially in the construction phase, but increase the revenue requirements in the operations phase (the returns are all based on after-tax cash), in the case of the independents these two factors cancel out fairly closely, resulting in little sensitivity of costs to the tax rate. Increasing the investment

*See "An Analysis of Geothermal Electric Powerplant Financing," Energy Resources Co., January 1980.

TABLE 4-3

THE EFFECT OF TAX RATE, INVESTMENT TAX CREDITS AND DEPRECIATION OF AN INDEPENDENT'S CAPITAL COSTS FOR ELECTRICITY

TAX RATE (t)

t (%)	50	60*	70
Total Capital Cost ($M)	121.9	136.5	157.8
Annualized Revenue Requirements ($M)	12.2	12.3	12.5
Busbar Cost (mills)	33.8	33.9	34.7

INVESTMENT TAX CREDITS (TC)

ITC (%)	10*	20
Total Capital Cost ($M)	136.5	103.1
Annualized Revenue Requirements ($M)	12.3	7.2
Busbar Cost (mills)	33.9	20

DEPRECIATION (d)

d (years)	10	30*
Total Capital Cost ($M)	111.8	136.5
Annualized Revenue Requirements ($M)	10.0	12.3
Busbar Cost (mills)	27.8	33.9

*Base case.

TABLE 4-4

THE EFFECT OF THE COST AND AMOUNT OF EQUITY ON INDEPENDENTS' CAPITAL COSTS FOR ELECTRICITY

COST OF EQUITY (r_E)			
r_E (%)	20	25*	30
Total Capital Cost ($M)	126.2	136.5	147.3
Annualized Revenue Requirement ($M)	10.0	12.3	15.3
Busbar Cost (mills)	27.6	33.9	42.2
EQUITY (E)			
E (%)	25*	50	
Total Capital Cost ($M)	136.5	183.9	
Annualized Revenue Requirement ($M)	12.3	29.5	
Busbar Cost (mills)	33.9	82	

*Base case.

tax credit from 10 percent to 20 percent results in a drop in the busbar cost from 33.9 mills to 20.0 mills (or 41 percent reduction). The cost of 20 mills is the lowest busbar cost which is obtained in any of our sensitivity runs on all forms of ownership.

The depreciation period was reduced from 30 years to 10 years to assess the impact of that policy option (e.g., accelerating the write-off period) on the busbar costs. The result was an 18 percent drop in costs. In addition to alterations in the depreciation schedule, the impact on the busbar costs of varying ability to absorb investment tax credits and interest expenses during construction results in the base case busbar cost of 33.9 mills.

Table 4-4 illustrates the impact of the amount and cost of equity on the independent's capital costs. Increasing the cost of equity from 20 percent to 30 percent increases the busbar cost from 27.6 mills to 42.2 mills (or a 52.9 percent increase). The busbar cost is quite sensitive to assumptions about the cost of equity which is somewhat surprising given the small amount (25 percent) of equity assumed in their capital structure. If an independent were not to use the 75 percent debt permissible under the GLGP and employed only 50 percent (or a debt/equity ratio of one) the busbar cost increases from the base case value of 33.9 mills to 82.0 mills (or an increase of 141.9 percent). This increase illustrates the importance of leverage (amount of debt in the capital structure), especially in the case of the independents for whom the cost of equity is very high.

4.5 Conclusions

This section places the analysis of indepedents in perspective with other forms of ownership which were analyzed previously.* The base case of the independent ownership was approximately 7 percent higher than that of the utilities. However, the lowest cost was produced by independent ownership in several of the additional scenarios run. Independent ownership demonstrated the highest sensitivity to assumptions made about the capital structure and the cost of the capital components.

Of all of the types of ownership examined, the independents were also the most sensitive to an additional 10 percent investment credit and the utilities were the least sensitive (even assuming that they could absorb the added 10 percent credit). Shortening the tax life (to effectively accelerate depreciation) had the greatest impact on the independents' costs. For the various incentives examined in this report, the largest cost reductions accrued to the independent companies.

Of the corporate structures examined, the oil companies had the highest capital costs. Although slightly more expensive (comparing base cases), the independents were more responsive (in terms of cost reduction) to fiscal incentives such as ITC's and shorter tax life than the utilities.

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*They were utility and oil company ownership -- as reported in the study "An Analysis of Geothermal Electric Powerplant Financing," ERCO, January 1980.

Task 5: Task Description

Municipalities and Cooperatives

Municipal and cooperative utilities are important developers of geothermal energy. Their size makes them well suited to the small scale of geothermal generating stations. Many municipal and cooperative utilities are located on or near geothermal resource areas.

The institutional and historical environment municipal and cooperative utilities (munis and co-ops) operate in has a powerful influence over their decision-making process. The task began with a study of this environment. Next, muni and co-op capital costs were assessed. Finally, ERCO made a detailed survey of munis and co-ops currently or potentially making investments in geothermal energy. This survey included most munis and co-ops in western geothermal resource areas. The survey focused on the effect of the Geothermal Loan Guarantee Program on decisions by munis and co-ops to invest in geothermal energy. Special attention was paid to problems with the loan guarantee program.

TASK 5

5.1 Introduction

The conversion of geothermal energy to produce electricity was examined in the context of private ownership and the capital costs associated with the conversion facility were determined in a previous study (see An Analysis of Geothermal Powerplant Financing, ERCO, January 1980). This Task extends the previous work to examine the financing of geothermal power plants by public entities, specifically, municipal and cooperative ownership.

The municipal and cooperative ownership of electric generating capacity represents approximately eight percent of the total electric utility industry capacity. Unlike the dominant segment of the electric utility industry, the investor-owned utilities,[1] the municipal and cooperatives are not motivated by profits, do not pay income taxes, and can finance their facilities entirely with bonds (or some other long term debt vehicle).

Table 5-1 illustrates the share of the installed generating capacity of the cooperatives and the municipalities as compared to the total electric utility industry, as well as the generation mix of that capacity. One feature which is readily apparent is that although their capacity is only eight percent of the total, the municipals and cooperatives own 66.6 percent of the internal combustion capacity. In the following sections, the

[1]In 1978, 78.3 percent of the installed generating capacity was investor owned, 13.7 percent Federal and Power Districts, State Projects and 8 percent municipal and cooperatives. Statistical Year Book of the Electric Utility Industry. Edison Electric Institute, November 1979.

Table 5-1

INSTALLED GENERATING CAPACITY

	TOTAL ELECTRIC UTILITY INDUSTRY	COOPERATIVES	MUNICIPAL UTILITIES
Total (MW)	579,312	11,635	34,426
(%)	(100)	(2.01)	(5.94)
Hydro (MW)	71,014	67	4,694
(%)	(100)	(0.09)	(6.61)
Conventional Steam (MW)	449,231	11,073	25,511
(%)	(100)	(2.46)	(5.68)
Nuclear Steam (MW)	53,527	65	963
(%)	(100)	(0.12)	(1.80)
Internal Combustion (MW)	5,540	430	3,258
(%)	(100)	(7.76)	(58.81)

[1] Statistical Year Book of the Electric Utility Industry, Edison Electric Institute, November 1979.

differences between the municipal and cooperative utilities and the rest of the industry, and their own unique characteristics will be discussed, especially where it would impact upon their decision to employ geothermal energy to produce electricity.

5.2 Municipal-Ownership

From the electric utility industry's beginnings in the late 1800's up to the early 1920's, there was a definite trend toward municipal ownership.[1] In many instances, municipal ownership came about because private electric services were not available except at very high prices, or even at any price. Many communities were faced with a practical choice between municipal ownership or no electricity for many years into the future. During the 1920's, though, partly because of better organization and more integration in the private sector of the industry (as well as increasing economies of scale) and partly, perhaps, because of expensive and aggressive public relations and propaganda campaigns by privately owned utilities, the trend toward public ownership was reversed for a time.

During the 1930's, the trend again turned in favor of municipal electric ownership. Several factors contributed to this. The development of diesel technology made small-scale municipal generating operations more efficient than formerly. Low-priced federal power, combined with "preference clauses" favoring public purchasers, greatly stimulated municipal ownership in

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1 M.T. Farris and R.J. Sampson. Public Utilities: Regulation, Management and Ownership, Houghton Mifflin Company, Boston, Massachusetts.

some areas. Federal government loans to cooperative associations and other public bodies were of considerable importance. Also, there was a strong popular reaction against the abuses of electric utilities during and following the 1920's, as revealed by various holding company difficulties and congressional investigations. Finally, during the depression of the early and middle 1930's, private firms often were unable, or unwilling, to expand their services in small communities.

In 1975, almost 2,000 municipalities sold electricity (over 1,000 fewer than at the early 1920's peak). Most of these communities, however, are fairly small, and only a very few are of major size.

5.2.1 Municipals-Generation

Municipal utilities own approximately 5.9 percent of the total electric industry's generating capacity, as is shown in Table 5-1. Although conventional steam turbines provide 74 percent of municipal generating capacity, 9.5 percent of their capacity is provided by less efficient internal combustion engines. In the entire electric industry, 78 percent of total capacity is provided by conventional steam while only 1 percent is provided by internal combustion engines. Thus, municipal utilities rely more heavily on inefficient and expensive methods of power generation than does the entire electric industry.

Purchased power represented 41.6 percent of the total net energy generated and received in 1977 by municipals and 42.3

percent in 1978.* Of the approximately 2,000 municipal electric systems in the U.S. well over half purchase all of their electricity externally.** The purchase of power by municipals has been facilitated by the requirement that all federal systems, including the TVA, must give preference in the sale of output to them.

However, there is a force driving the municipals to generate more of their power sold. One factor is the desire to be assured of an adequate supply of power at a price which is controlled by the municipal. Another factor is the decline of generation additions by investor-owned utilities (the source of much of the purchased power). For example, planned additions from 1980 on by the investor-owned segments are 42.1 percent of their 1978 installed generation capacity vs. 45.5 percent for the total electric industry.***

There is an increasing tendency for municipals to purchase shares of larger, more efficient, fossil fueled and nuclear capacity in cooperative ventures with other municipals, cooperatives and investor-owned utilities. This tendency is born out by the observation that planned additions of nuclear and fossil fueled capacity by the municipals is 88 percent of capacity (vs. 77 percent historically) while the investor-owned segment is maintaining its current generation mix.***

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*Statistics of Publicly Owned Electric Utilities in the United States--1978, DOE, October 1979.

**Financing the Growth of Electric Utilities, D.L. Scott, Praeger Publishers, New York, 1976

***1980 Annual Statistical Report, Electrical World, March 15, 1980, p. 49.

5.2.2 Municipals-Management: Risk and Constraints

Most municipals are not subject to the special regulatory laws which are applicable to investor owned utilities. Rather, they are governed by their own enabling legislation and charters, which are not too restrictive. Municipal management is not usually judged by a profit standard (or value of the stock) and, as a result, pricing and investment decisions in new generation capacity are judged by other standards.*

Management structure of a municipal utility usually consists of an elected management which oversees the administrative managers, who perform the actual operations. It is not uncommon for the elected managers to use the utility to win favor with voters and further advance their political careers. As a result, utility strategy is likely to be often influenced by election returns. Administrative managers, on the other hand, are usually appointed because of their technical competence and operational experience. The two managements often have conflicting objectives--economics vs. politics.

It has been suggested that "the major constraints faced by managers of privately owned regulated utilities are, in order of importance, (1) the necessity for making a profit, (2) special utility regulatory laws, (3) general laws applicable to all businesses, and (4) public opinion. This order of constraints is probably reversed in the case of publicly owned utilities."**

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*Such as lowest short term prices subject to minimum requirements to fund operations, fund the debt and maintain the bond rating so that sufficient capital can be retained to assure future capacity expansions.

**Public Utilities: Regulation, Management and Ownership, M.T. Farris and R. J. Sampson, Houghton Mifflin Company, Boston Massachusetts, P. 284.

It is within this politically charged environment that a decision to develop geothermally generated electricity will be made by a municipality. Primary factors which would probably predominate would be initial cost of the electricity and the risk of failure (with the political risk of bad press about "abusing the public good by making imprudent investments with public funds"). The benefits, which would be the use of a clean alternative energy source, would have to be weighed against the risk and cost.

5.2.3 Municipals-Capital Structure and Financing

In financing capital investments municipal systems have typically relied less upon external sources of funds than have investor-owned systems. The principal sources of funds are municipal investment or contributions, long term debt, depreciation and amortization and operating surpluses.* Regardless of the source of the funds, its cost can be approximated as the tax-free rate of funds necessary to construct the facility (assuming a 100 percent debt structure). As a result, the rest of this section discusses the raising of debt by municipal utilities.

Municipal systems participate in the capital markets by issuing bonds which are tax-exempt from federal income taxation.** These bonds may either be revenue bonds, which are secured by a portion of the revenue from the issuing utility,

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*Financing the Growth of the Electric Utilities, D.L. Scott, Praeger Publishers, New York, 1976.

**Review of New Source Performance Standards for Coal-Fired Utility Boilers," Vol. II--Economic and Financial Impact, Teknekron, Inc., March 1976.

or general obligation bonds, which are guaranteed by the taxing power of the issuing governing unit (municipality). Generally, municipal utilities finance utility expansion with revenue bonds for the following reasons: additional general obligation debt cannot be issued because of statutory limitations and revenue bonds are not generally included in the legal debt limit, legal restrictions exist on the employment of tax revenues from general obligation sources, revenue bonds may require a mere majority from the governing body to be issued (as opposed to two-thirds for general obligation bonds), and when the general credit of a municipality is not highly regarded, revenue bonds may command a more favorable market than general credit bonds and can be sold at lower interest rates.

In issuing long-term debt the municipal utility must first obtain authorization by the governmental unit. The sale of bonds can either take place on a competitive bidding or negotiated basis. The latter predominates for revenue bonds.

The costs (yield) of municipal bonds (independent of the specific issuing utility) is determined by: the general level of interest rates determined by the supply of, and demand for, funds in the capital market; the value to investors of the tax-exempt privilege; and the particular factors in the municipal bond market. Yields are also affected by the size, quality (bond rating) and marketability of the issuance.

The quality of a specific municipal revenue bond is influenced by the image of the municipality as well as the financial integrity of that municipality's utility. The utility will suffer with or benefit from the actions of the municipal borrower in past years and its use of funds on unrelated municipal undertakings. These actions may be little connected to the utility enterprise, but they will affect the market evaluation nevertheless.

If a municipality has missed an interest payment on street improvement bonds, that lapse will affect the financial marketplace image of its electric power revenue bonds, even though there is little connection between the municipal power operation and the paving of streets. Or, if a municipality overextended itself in an expansion of a sewerage system in the 1920's and had financial difficulty, it will affect the ability of a municipal power enterprise to borrow in the 1970's.

5.2.4 Summary

Municipal utilities are significantly different than investor owned utilities. They tend to be smaller, use smaller generation sources (such as internal combustion generators), and to purchase approximately 40 percent of their power needs. However, municipal systems are becoming more integrated into the total electric generating network and are purchasing shares in larger fossil fueled and nuclear powered facilities.

Municipal utilities are managed at two levels. One level is elected and plays a directive and strategic role. The other level, administrative, is responsible for the actual operations of the utility system. The direction of a specific municipal utility with respect to generation decisions would be expected to be politically, rather than purely economically, based.

Municipal utilities raise the capital for their generation capacity through the issuance of tax-exempt bonds.

Usually revenue bonds are issued for the utility expansion. The cost of these bonds depends on the general level of demand for bonds in the capital markets as well as factors specific to a municipal utility (quality). This latter factor is based both on the financial integrity of the muncipality as well as its issuing utility.

5.3 Cooperative-Ownership

From the early 1880's, when the first central generating system went into service, until 1935 only 11 percent of the farms in the United States had electricity.[1] The Rural Electrification Administration (REA) was created on May 11, 1935 by executive order. It empowered the REA administrator to "initiate, formulate, administer and supervise a program of approved projects with respect to the generation, transmission and distribution of electric energy in rural areas." The Rural Electrification Act of 1936 established REA as a lending agency with responsibility for developing rural electrification.

The REA was necessitated by the reluctance of investor owned utilities to provide service in rural areas. This reluctance was principally caused by the high distribution cost per customer, making their rates prohibitive or reducing profits. For example, the REA systems serve an average load density of about four customers per mile of transmission line, which is approximately one-tenth the load density in urban areas.

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1 U.S. Department of Agriculture. "The Story of Cooperative Rural Electrification" and "REA Loans & Loan Guarantees for Rural Electric & Telephone Service"

As a result of the high cost of power transmission, the initial efforts of the REA were to develop a low cost distribution network for rural areas. Organizationally this was accomplished by helping to set up local non-profit co-operatives. Technically, work was successfully focused on developing lower cost transmission lines. Financially, the lower costs for delivered electricity were achieved through a combination of federally subsidized low-cost loans (2 percent until 1973) and the preferential purchase of wholesale power from federal projects and the TVA. By the mid-1970's nearly 99 percent of the nation's farms and ranches were electrified.

5.3.1 Cooperatives--Transmission and Generation

As just mentioned, originally REA loans were made to cooperatives to establish distribution systems and power was purchased wholesale from federal projects and investor owned utilities. As load factors grew with time, generation and transmission (G&T) cooperatives were developed to supply the member cooperatives' power requirements. Despite this growing tendency to produce their own power, by 1978 only 22.6 percent of REA sales were generated by G&T's or by the local cooperatives.* In 1979, cooperatives owned 2.0 percent of the total electric industry installed capacity yet served 10.2 percent of the U.S. customer base.** At the present time, the REA can still be considered a distribution system.

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* 1978 Annual Statistical Report of Rural Electric Borrowers, U.S. Department of Agriculture, REA Bulletin 1-1.

** 1980 Annual Statistical Report, Electrical World, March 15, 1980, p. 49.

The installed generating capacity which is owned by the cooperatives, by generating source, was shown in Table 5-1. Two features are apparent from the table. First, the use of internal combustion by cooperatives in its generation mix is approximately 3.9 times greater than for the total electric utility industry (corresponding to the use of smaller diesel generators by small cooperatives). Second, cooperatives use and generate little hydro or nuclear power, but instead rely mostly on conventional steam.

Cooperatives (co-ops) generally buy most of their power, as was noted above. Because the ability of the large federal systems to provide additional inexpensive power to co-ops is being exhausted, cooperatives are attempting to generate more of their own power. Through G&T cooperatives, several small co-ops can band together to build a large, efficient generating station. G&T co-ops also benefit co-ops in that they are more directly accountable to the individual co-ops they serve than are the large federal systems. G&T's provided 32.8 percent of cooperative system input in 1978*, up from 8.9 percent in 1941.** This tendency to generate a larger share of their needs is illustrated by the cooperatives' planned capacity expansions (from 1981 and beyond) of 156 percent of their 1978 capacity as opposed to an increase of 45 percent for the total electric utility industry.***

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* System input differs from sales due to transmission losses and internal use of the power by the cooperative.

** This increase from 8.9 percent to 32.8 percent from 1941 to 1978 corresponds to an actual input increase of 63,130 percent, as opposed to a 369 percent increase (32.8 percent divided by 8.9 percent). The increase in generated input increased so rapidly due to a corresponding rapid increase in sales and customers served by the REA system from 1941 to 1978--1978 Annual Statistical Report--Rural Electric Borrowers, U.S. Department of Agriculture, REA Bulletin 1-1.

***As reported in 1980 Annual Statistical Report, Electrical World, March 15, 1980, p. 49.

This capacity expansion will consist of 95.3 percent nuclear and fossil fuel generators vs. 88.6 percent for the total electric industry. This type of generating capacity implies a movement to larger, more efficient, more centralized generating capacity.

In summary, cooperatives primarily distribute purchased power. There is a trend for them to generate more of their own power requirements. They represent one of the fastest growth segments in new capacity expansions in the total electric utility industry. The major thrust of this capacity expansion is through the use of nuclear and fossil fueled generators. This investment is being accomplished through the formation of G&T cooperatives which are large enough to wholesale the output or through the purchase of shares (or founding of joint ventures) of a large facility jointly owned with other municipals, investor owned utilities or cooperatives.

5.3.2 Cooperatives-Management, Risks and Constraints

The Electric Cooperative Corporation Act of 1937 was designed to give the cooperatives (which are nonprofit) powers to organize and build. Specifically, it exempted them from regulation by state public utility commission, since consumer-owned organizations are self-regulating.

The cooperatives are directed by managers responsible to their consumers--they are also accountable to their consumers. This fact clearly influences their thinking on pricing and capacity expansion decisions. The REA is a source of most of the funds used by cooperatives to generate new power (either through direct loans or loan guarantees--see Section 5.3.3).

The REA exerts some control over the cooperatives by virtue of this funding power. For example, rates are reviewed, the non-profit status of the cooperative is verified, and all transmission costs to the consumers of a particular cooperative must be normalized so that all consumers pay the same rate (the so-called "postage stamp" rate). However, it is in the area of new capacity expansion that the REA exerts its largest influence. The cooperative must prove a need for the extra generating capacity. Alternatives must be evaluated and the best one selected (such as conventional fuels, repurchase, etc.), and the expected costs and prices be competitive before REA supported funding will be approved.

Cooperative managers must operate within the constraints imposed by their consumers and the REA. There is one other factor which influences their thinking (as well as the REA's), less than one percent of REA loans have defaulted--an incredible record, but one which would ensure very conservative thinking. In assessing the decision to employ geothermal energy as an electric power source, the managers would have to assess the benefits of having their own, controllable (in terms of cost and supply) source of electricity vs. the risk of its failure.

5.3.3 Cooperatives--Capital Structure and Financing

The sources and cost of capital required to make necessary investments for cooperatives depends on their structure--distribution or G&T. Distribution cooperatives raise money from depreciation, net margin and long-term debt. This latter source was usually issued by the REA at 5 percent interest over a 35 year term. G&T cooperatives, on the other hand obtain most of their financing from long-term debt. Unlike distribution cooperatives, G&T's must raise the majority of their funds from external, non-REA sources. The cost of capital for new generating capacity by a G&T can be approximated, for financial purposes, as the cost of debt (for a 100 percent debt financed facility). The rest of this section discusses the sources and costs of funds available to a G&T which might consider constructing a geothermal electric generating facility.

A G&T can receive a loan directly from the REA "only where no adequate or dependable source of power is available or where the rates offered by existing power sources would result in a significantly higher cost of power to the consumer than the cost from facilities to be financed by REA."* Typically, however, other sources of non-REA funds are available and must be used first.

A G&T has available to it a REA loan guarantee to facilitate the obtaining of funds for large scale electric facilities from non-REA sources. Guarantees are considered if the loans could have been financed by REA under the Act. Presently the Federal Financing Bank purchases the obligations guaranteed by the REA. Interest rates on the REA guaranteed (or actually

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* "REA Loans and Loan Guarantees for Rural Electric and Telephone services," U.S. Department of Agriculture.

Federal Financing Bank loans) are usually the rate for long-term (35 year) treasury securities plus a nominal fee of one-eighth of one percent. These costs are substantially above the 5 percent REA loan rates and depend critically on general economic conditions rather than the financial integrity of the specific cooperative.

Another source of funds available to a G&T (of short, intermediate or long-term loans) is the National Rural Utilities Cooperative Finance Corporation (CFC). The CFC was established in 1970 to provide supplemental financing from non-governmental sources. Its initial capital was raised from contributions from 785 rural electric cooperatives. Additional capital comes from its operations, further contributions and the issuance of long-term securities in the capital markets.

Lastly, a G&T can raise funds from banks and other institutions and cooperative oriented banks. The cost of the funds is the going market rate.

Funds for generating capacity for cooperatives come chiefly from non-REA sources. In 1978 only 22.6 percent of all debt outstanding on generating capacity were REA loans.* Of the non-REA sources of funds used by cooperatives in 1978: 89.1 percent came from the Federal Financing Bank, 7.5 percent from CFC, 2.3 percent from other banks and institutions and 1.1 percent from Banks for Cooperatives. Almost 90 percent of the funds came from REA loan guarantees.

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* This is a cummulative historical value, the incremental REA investment in 1978 on generating capacity was less than 1 percent, 1978 Annual Statistical Report -- Rural Electric Borrower, U.S. Department of Agriculture, REA Bulletin 1-1.

5.3.4 Summary

Cooperatives were formed to expand the use of electricity in the rural areas and to provide it at a reasonable cost. They are non-profit organizations who receive most of their funding through REA loans or guarantees.

Currently, cooperatives generate only 23 percent of the electric power that they sell. There is however, a tendency for cooperatives to produce an increasing share of their power. The cooperatives are achieving this expansion through better network integration which permits the formation of larger G&T cooperatives or through the sharing of larger facilities with municipals, investor owned utilities or other cooperatives. As a result, large facilities, such as nuclear and fossil fueled plants are predominating in their new generating mix.

As with municipals, the cooperatives are directed by managers who are accountable to their consumers. However, cooperative managers are additionally constrained by the REA.

Cooperatives raise most of their funds for new generating capacity with REA guaranteed loans. The cost of the funds is influenced to a very large degree by current economic conditions which are beyond the control of the individual cooperative.

5.4 Capital Costs for Municipal and Cooperative Geothermal Generating Facilities

The financial analysis for the levelized busbar capital costs for municipal and cooperative ownership was conducted on a hypothetical geothermal generating facility with identical construction costs and schedule, lifetime and capacity factor to the facility examined in "An Analysis of Geothermal Powerplant Financing" (ERCO, January, 1980).* The municipals and cooperatives were expected to raise all of the funds for the facility's construction through debt offerings and both modes of ownership to be tax-exempt.

Figure 5-1 shows the impact of the interest rate paid for the debt on the levelized busbar capital costs for the geothermal generating facility for either municipals or cooperatives. The costs for "typical" oil companies, utilities and independents obtained from the aforementioned ERCO study are included on the figure for reference. The interest rates at which the municipals or cooperatives would be competitive (or uncompetitive in this case) are approximately 19.3 percent, 13.2 percent, and 12.3 percent respectively. The actual levelized busbar cost for a specific municipal or cooperative depends on the interest rate for that specific entity.

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*The plant cost $67 M , generated 55 Mw, had a construction and "shakedown" period of four years (see Task 3 for an example of the investment schedule), and had an assumed capacity factor of 75 percent, and a 30 year operating lifetime.

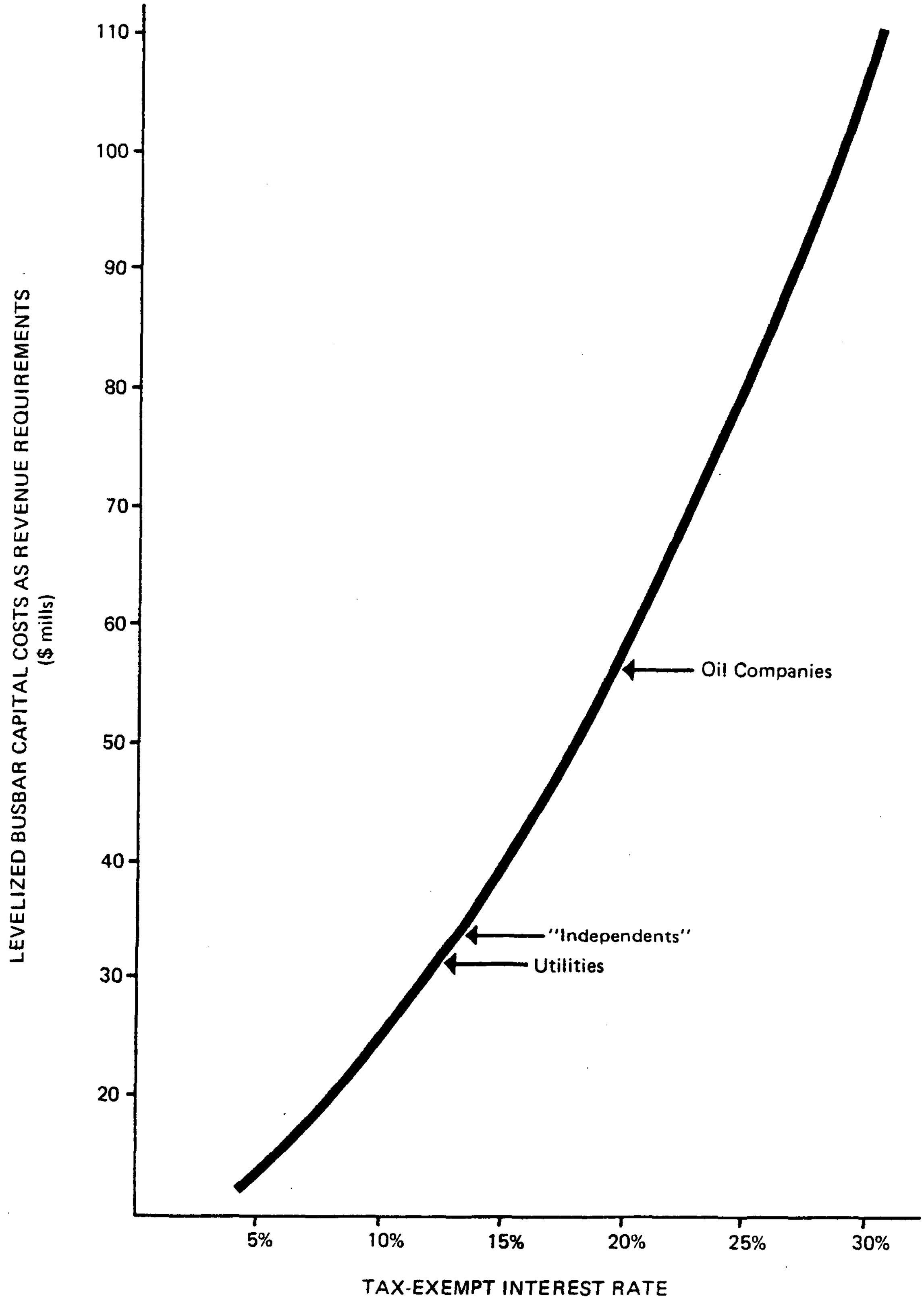

Figure 5-1. The effect of the tax-exempt interest rate for municipal and cooperative geothermal electric generating facilities on their levelized busbar capital costs—oil company, "Independents" & utility reference taken from *An Analysis of Geothermal Electric Powerplant Financing*, ERCO, January, 1980.

5.5 Individual Municipal and Cooperative Utilities

5.5.1 Introduction

The previous sections provided an overview of the current status of municipal and cooperative utilities. In order to gain more specific information, ERCO interviewed thirteen municipal and cooperative utilities located near Known Geothermal Resource Areas (KGRA's). A literature search was conducted on three more, and so the study encompassed sixteen small utilities in all. These utilities account for most of the municipals and cooperatives near western geothermal resource areas.

The literature search and interviews focused on three main issues:

- plans for expansion of generating facilities
- interest in geothermal energy
- interest in the geothermal loan guarantee program.

Because all of the utilities interviewed are in the rapidly growing western states, most of them are experiencing rapid increases in demand. Growth in the Springfield, Oregon, area is 7.5 percent a year; and growth averages about 4-5 percent in the areas surveyed. As a result, all these utilities are seeking new sources of electric power. Every utility interviewed expressed at least some interest in generating their own power (if they are not already doing so) or for expanding generation capacity.

There was considerable interest in geothermal energy at the utilities studied. Eleven of them are already involved in geothermal projects. Two utilities (Bountiful City Light and Power and the Fall River, Idaho Co-op) had made attempts to develop geothermal power but gave up because of regulatory and/or permitting problems. The remainder of the utilities interviewed are interested in geothermal power, but are taking a "wait and see" attitude, because they do not have the resources needed to begin geothermal exploration and development on their own.

The utilities which were involved in geothermal power production were generally aware of the loan guarantee program. Because the municipals have tax-free bond-issuing authority, their capital costs are low, and so not all utilities studied plan to take advantage of the loan guarantee program. Others, however, were quite interested in obtaining loan guarantees (if they have not already) because municipal bond issues can cause political problems and because DOE will refund the difference between the guaranteed loan cost and the tax-free bond cost.

5.5.2 Statistical Background

Most of the utilities studied are fairly small and have peak demand under 500 megawatts. Exceptions are the Sacramento and Los Angeles municipal systems, which have summer peaks in excess of 1500 megawatts. The small size of these municipal and cooperative utilities makes them well-suited to the small scale (10-110 MW) of geothermal plants. These utilities do not need the huge baseload plants of the investor-owned power producers. Peak loads for all utilities in the sample are shown in Table 5-2.

At the same time, most of these utilities currently enjoy low electrical rates, which would seem to preclude geothermal power, which is more expensive. Rates vary from a low of 1.5¢/kWh (as of December 31, 1978) in the Raft-River Co-op in Idaho to the September 1980 price of 8.5¢/kWh in Glendale, California and averaged under 4¢/kWh. This compares to a 1979 estimate of about 4¢/kWh for geothermal energy from resources above 300° F.[1] Current low electrical rates are based on cheap hydroelectric power, of which most available sources have been tapped. The cost of new coal and nuclear facilities will be in the same range as geothermal projects.[1] Although existing facilities of utilities produce power more cheaply than does geothermal, new facilities will not. Thus, the inexpensive electric rates now charged by these municipal and cooperatives do not imply that future geothermal investments will not be competitive.

Another institutional barrier to geothermal investment is the fact that many of these small utilities currently own no generating capacity and buy all their power. This is shown in Table 5-3. This inexperience in generation will not present major problems, however. Although these utilities may have no experience in building or operating a power plant, they are generally interested in owning some generating capacity. Joint ventures allow them to use the expertise of others to develop their own capacity.

These municipals and cooperatives buy most of their power from two sources, the Bonneville Power Administration (EPA) and the U.S. Bureau of Reclamation (USBR). This is shown in Table 5-3.

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[1]Source: Lawford, J.W. "Today's Geothermal Power Economics and Risks" presented at the 14th IECEC Conf. in August 1979. Mr. Lawford is with EG&G, Idaho, Inc.

TABLE 5-1

GENERAL INFORMATION ON MUNICIPAL AND COOPERATIVE UTILITIES NEAR GEOTHERMAL RESOURCES (1980)

UTILITY	PEAK DEMAND (10^3 kW)[a]	GENERATOR[a] CAPACITY (10^3 kW)	POWER[c] PURCHASED/ USED RATIO
Burbank, California	197	228	42%
Bountiful, Utah	24	8	100%
Eugene, Oregon	483	204	77%
Fall River, Idaho Co-op	N/A	0	100%
Glendale, California	195	268	49%
Hetchy Hetch (S.F., CA)	456	293	41%
Los Angeles	4090[b]	9320	11%
Lodi, California	70	0	100%
Plains, N.M. Co-op		49.5	97%
Plumas-Sierra Co-op	10	0	100%
Raft-River, Idaho Co-op	59		
Sacramento, California	1578	1562	22%
Santa Clara, California	194	0	100%
Springfield, Oregon	145	0	100%
Surprise Valley, CA (Co-op)	23	0	100%
Ukiah, California	23	0	100%

[a]As of December 31, 1978. Source: Electrical World Directory of Electric Utilities, 1979-80 (McGraw-Hill, New York).

[b]Source: Utility Company, September 1980.

[c]Source: DOE, Statistics of Publicly Owned Electric Utilities in the U.S., 1978.

N/A = not available.
NR = no residential customers.

TABLE 5-3

INFORMATION ON MUNICIPAL AND COOPERATIVE UTILITIES RELATED TO GEOTHERMAL DEVELOPMENT (1980)

UTILITY	POWER SOURCES[1] MAIN SUPPLIER	OWN GENERATION	YEARLY RATE OF DEMAND GROWTH 1980[2] (%)
Burbank, California	BPA[3], PP&L[4]	Gas-Oil	3%
Bountiful, Utah	USBR[5]	Gas	4.6%
Eugene, Oregon	BPA	Hydro-wood	5%
Fall River, Idaho Co-op	BPA	Hydro	N/A
Glendale, California	USBR[4], BPA	Gas-Oil	3.1%
Hetchy Hetch, California	PG&E[6]	Hydro	N/A
Los Angeles	SCE[7], BPA	Coal-Oil-Gas-Hydro	N/A
Lodi, California	PG&E	--	0
Plains, N.M. Co-op	USBR	Oil	7%
Plumas-Sierras, CA, Co-op	USBR	--	N/A
Raft-River Idaho Co-op	BPA	Geothermal	N/A
Sacramento, California	USBR	Hydro-nuclear	4%
Santa Clara, California	USBR, PG&E	--	6%
Springfield, Oregon	BPA	--	7.5%
Surprise Valley, CA	BPA	--	7-8%
Ukiah, California	PG&E	--	N/A

[1]Source: Electrical World Directory of Electric Utilities 1979-80 (McGraw-Hill, New York, 1979).

[2]Source: engineering departments of utility.

[3]BPA (Bonneville Power Administration)

[4]PP&L (Pacific Power & Light).

[5]USBR (United States Bureau of Reclamation).

[6]PG&E (Pacific Gas and Electric).

[7]SCE (Southern California Edison)

N/A = not available.

BPA markets power for the Corps of Engineers and the USBR, and the USBR also markets some of its own power. Both of these agencies rely exclusively on hydropower, which is both inexpensive, and now, scarce. Realizing that these traditional suppliers are running out of excess capacity, most of the utilities surveyed are trying to develop their own generating facilities, usually through joint ventures.

This interest in developing their own generation facilities includes much interest in geothermal power. Many of the firms in the sample group are participating in joint ventures to build full-scale generation facilities or pilot plants. Two utilities were frustrated in efforts to begin plant construction by regulatory problems. The relevant geothermal resource area and level of interest of each municipal and co-op is shown in Table 5-4.

5.5.3 Individual Municipals

This section discusses the municipal utilities ERCO interviewed.

5.5.3.1 Burbank Public Service Department

Burbank, California has a fairly large municipal utility with peak demand at about 200 MW and growing at the rate of 3 percent a year.[1] At present, Burbank procudes about 42

[1]This information is based on a discussion with a Burbank engineer in September 1980.

TABLE 5-4

INTEREST IN GEOTHERMAL ENERGY: SELECTED UTILITIES

UTILITY	GRA*	LEVEL OF INTEREST
Burbank, California	North Brawley	pilot plant
Bountiful, Utah	Roosevelt Hot Springs	owned land; could not get permits
Eugene, Oregon	Cascades	leases; awaiting discovery
Fall River, Idaho Co-op	Yellowstone	cannot get leases
Glendale, California	North Brawley	pilot plant
Hetchy Hetch, (S.F., CA)	Geysers	"wait and see"
Los Angeles	North Brawley	pilot plant
Lodi, California	Geysers	own part of commercial plant
Plains, N.M. Co-op	Valles, N.M.	feasibility study
Plumas-Sierras (CA) Co-op	Geysers	own part of commercial plant
Raft-River, Idaho Co-op	Raft-River	own pilot plant
Sacramento, California	Geysers	building commercial plant
Santa Clara, California	Geysers	own part of commercial plant
Springfield, Oregon	Cascades	"wait and see"
Surprise Valley (CA) (Co-op)	Surprise Valley	awaiting discovery in area
Ukiah, California	Geysers	own part of commercial plant

*Geothermal Resource area utility is near.

SOURCE: ERCO.

percent of the power it uses, and generates the rest from oil and gas. Burbank purchases the remainder from Bonneville, Pacific Power and Light, and other large producers. Burbank holds an A rating for its electric power revenue bonds.[1] Thus, it has little trouble raising capital for new generating facilities.

In order to satisfy its growing needs, Burbank is participating in three large coal projects. In the first of these, the Intermountain Project in Utah, due to come on-line in July 1986, Burbank will have a 48 MW share. In the White Pine Project, in Nevada, due to be finished in 1990-92, Burbank will have a 26 MW share. Both Intermoutain and White Pine are under the direction of the Los Angeles Department of Water and Power (LADWP). Burbank will also participate in the California Coal Project, directed by Southern California Edison (SCE), which will yield Burbank 24 MW of baseload capacity beginning in 1992.

Despite the fact that these coal plants should maintain or reduce Burbank's ratio of power purchase/sold, Burbank is also pursuing geothermal energy development. Burbank has a 3/10 MW share of the new 10 MW geothermal facility at North Brawley, California. It financed its share of the project's costs out of its own funds. Burbank intends to join Glendale, Pasadena, LADWP, SCE, and the Imperial Irrigation District in a Joint Powers Agency to further development of geothermal resources at North Brawley. Because this plan is still in its infancy, Burbank has not yet determined how it will finance its share of the project. It has not studied the Geothermal Loan Guarantee Program.

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[1] Source: Moody's Municipal and Government Manual, 1980, Moody's Investor Service, New York.

5.5.3.2 Bountiful City Light and Power

The city of Bountiful, Utah currently purchases 100 percent of its power from USBR.[1] Peak demand is 24 MW, which is growing at 4.6 percent yearly. Residential power, after the first 840 kW, costs 2.8¢/kWh.

Bountiful is negotiating to buy 13 MW of the capacity of Utah Light and Power's 446 MW Hunter Unit 1 plant. Bountiful has also filed for a 2,500 kW hydropower license.

Bountiful was extremely interested in geothermal power but two factors combined to thwart its use. Bountiful had purchased some drilling rights in the Roosevelt Hot Springs Geothermal area, where it intended to drill for geothermal steam. The main hindrance to Bountiful's project was a refusal by DOE and BLM to grant it permits to drill for geothermal steam. In addition, Bountiful wanted to use the Geothermal Loan Guarantee Program (GLGP) to finance the exploration. This loan guarantee was not forthcoming. The power plant was to be financed through tax-exempt revenue bonds. Thus, Bountiful could get neither the permits to drill on its leases or the financing for its exploration. Because of these problems, Bountiful recently sold its leases. There are legal problems with the sale, however, and the leases may revert back to the town.

Bountiful would like to take advantage of the geothermal resources nearby. It perceives DOE and BLM as unfairly denying

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[1]This information from interview with Bountiful engineer, September 18, 1980.

it drilling rights. It would also like to see a loan guarantee program for exploration.

5.5.3.3 Eugene Water and Electric Board

Eugene, Oregon buys most of its power from BPA.[1] It also generates 23 percent of its power from hydro and wood wastes. Peak demand is currently 483 MW and is growing at 30 MW a year. As of September 1980, power cost just under 2.0¢/kWh to residential users.

Eugene is very concerned about its ability to satisfy its future demand. It has no further hydro sites, and so is actively considering geothermal power production. Eugene has taken out leases on 7,000 privately owned acres in the Cascades KGRA and has made lease applications on 27,000 acres of federal land in the same area.

Eugene does not want to take the risk of exploring for geothermal energy on its own. Instead, it is waiting for someone else to make a discovery. At that time, Eugene will drill.

Eugene would like to set up small well-head electric generators at geothermal sites, rather than attempting to build large plants at once. The spokesman said that Eugene believes in limiting its risk. By relying on small projects such as well-head generators, it will keep its costs down.

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[1] Information from Tables 5-1 and 5-2 and conversation with Eugene engineer in September 1980.

Eugene would rather wait until a geothermal investment would have fairly certain rewards and then use its own money for the investment. The city has a high Aa bond rating and so capital is easily obtainable.[1] As a result, it does not intend to take advantage of the GLGP.

5.5.3.4 Glendale Public Service Department

Glendale, California has a mid-sized municipal utility. Peak demand is 195 MW and is growing at the rate of 3.4 percent a year. The average residential rate is 8.5¢/kWh. It currently produces 51 percent of its energy needs from its 268,000 kW oil and gas generator.[2]

Glendale is aggressively pursuing new sources of energy. Its expansion program mirrors that of Burbank. Glendale owns shares in the Intermountain, California Coal and White Pine coal projects. It also owns a share of the North Brawley geothermal project from which Glendale eventually hopes to receive 10 MW of generating capacity.

The spokesman did not know how Glendale would finance its share at North Brawley. Expenses to date have been financed from operating revenues.

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[1] Source: Moody's Municipal Government Manual, 1980 (Moody's Investor Service, New York: 1980)

[2] Source: Electrical World Directory of Electric Utilities, 1979-1980 (New York, 1980) and discussion with engineer at Glendale Utility.

5.5.3.5 Lodi Electric Department

Lodi, California currently buys all its power from Pacific Gas and Electric.[1] Residential power cost averages 5.5¢/kWh and peak demand is 70.7 MW. Growth has been near zero for the last three summers.

Lodi intends to reduce its purchasing needs to 39 percent of total energy from the current 100 percent by 1984. Along with 10 other Northern California cities and the Plumas-Sierras cooperative, Lodi formed into the Northern California Municipal Power Corporation (NCMPC), Lodi is building a plant at the Geysers field. Lodi has a 15 percent share in the 106 MW this plant will produce. This project recently received a $45 million DOE loan guarantee. Lodi is also participating in the Calaveras Hydro Project, which will have 140 MW of dependable power. Lodi will receive 10 percent of this power.

There is currently much controversy in Lodi about whether to join another NCMPC project to develop and operate a site in Lake City, California, which is also in the Geysers KGRA. Because a loan guarantee for exploration and development of the site is not available, members of NCMPC will have to finance exploration from their own funds. As a result, there is hesitancy in Lodi to join the project. Members of the city council are not anxious to spend public money on what is essentially a businessman's risk. If the geothermal wells do not yield plentiful steam, much tax money will have been lost. A town meeting will be held shortly to decide the issue.

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[1] Based on September 18, 1980 conversation with the director of Lodi Utility.

5.5.3.6 Los Angeles Department of Water and Power

The Los Angeles Department of Water and Power (LADWP) is a large utility, with generating capacity, as of 1980, over 9000 MW.[1] LADWP generates about 89 percent of its power needs, with oil providing 60 percent of the power it generates. Demand is growing at the rate of 2-3 percent a year.

LADWP reports it has an excellent capacity outlook over the short run, but is aggressively pursuing increased capacity and substitutes for oil. LADWP will own 1000 MW of the capacity of the Intermountain Project in Utah. The White Pine coal project in Nevada will also supply LADWP with increased base load capacity.

LADWP is also developing non-coal sources of energy. Although it has exhausted its available possibilities in hydropower, it is developing wind, landgas/biomass and geothermal energy.

LADWP has a number of possibilities in geothermal energy. It hopes to eventually receive 180 MW from the North Brawley geothermal project, which is being developed by Union Oil, LADWP and a number of other municipal utilities. It also may undertake a joint geothermal venture with Republic Geothermal. LADWP may also develop geothermal resources on its own land sometime in the future.

Financing for these geothermal projects will be off the balance sheet of LADWP. Tax-free bonds will be issued not by LADWP, but by a joint power authority of Southern California.

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[1] Information from interview with LADWP, September, 1980.

LADWP would like to take advantage of the GLGP, but perceives the eligibility requirements as ruling out joint ventures with private companies.

Because LADWP plans to develop geothermal resources together with private firms such as Union Oil and Republic Geothermal, LADWP does not believe it will be able to structure geothermal loan guarantee financing for its projects. This is because the loan guarantee program is designed for municipals to use alone. When they combine with private firms, DOE has difficulty determining how to refund the difference between the taxable, guaranteed loan cost and the tax-free municipal bond cost to the municipal. Without this refund, municipal tax-free financing is less expensive (if more risky) than guaranteed, taxable loans.

5.5.3.7 Sacramento Municipal Utility District

Power in Sacramento is supplied by the Sacramento Municipal Utility District (SMUD). SMUD is a large municipal, with peak demand of 1,578 MW and demand growth of 4 percent a year.[1] SMUD's current residential rate is just under 2.0¢/kWh, and so Sacramento residents enjoy some of the cheapest power in the country.

SMUD needs to expand generator capacity, but its proposals for new plants have all been denied for environmental reasons. The one plant that has been approved is a 55 MW geothermal plant to be located in the Geysers KGRA. Aminoil Incorporated will supply steam. Because of the large amounts of radioactive radon gas and hydrogen sulfide this plant will release, the licensing procedure for the plant has been lengthy. The

[1] Source: Discussion with SMUD systems engineer, September 18, 1980.

plant will be financed through SMUD revenue bonds, which are currently rated a very high Aa by Moody's. Because low-interest tax-free bonds are available, SMUD is not interested in using the GLGP to finance this project.

5.5.3.8 Santa Clara Electric Department

Like Lodi, Santa Clara, California is part of NCMPC, and so it is participating in the Aminoil/NCMPC geothermal project at the Geysers.[1] Its peak demand is growing at 6 percent a year, and is expected to continue growing at that rate. Santa Clara did not generate any power as of September, 1980.

Santa Clara is interested in further development of geothermal power. It is involved in the smaller NCMPC geothermal project which was described in the section about Lodi. Santa Clara also has leases on 10,000 acres in the Sierras which have potential for geothermal development.

Difficulties with financing may hinder Santa Clara's use of geothermal power. Although it could finance development through the sale of municipal bonds, this would entail political problems within the town. In addition, there is the fear that the geothermal development will fail and the town's money will have been lost. As a result, Santa Clara will seek some alternative method, possibly the GLGP, to finance its geothermal projects. Unfortunately, the GLGP will not finance exploration on Santa Clara's leases.

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[1] Based on discussion with Santa Clara engineer, September, 1980.

5.5.3.9 Springfield Utility Board

Springfield, Oregon has a small (145 MW peak) municipal utility which as of September, 1980, does not generate any power. Besides some research and development directed towards wind and geothermal power, Springfield is not actively pursuing new sources of electricity. It is considering joining some joint ventures to develop new power sources.

5.5.4 Individual Cooperatives

This section describes the individual cooperatives interviewed.

5.5.4.1 Fall River Cooperative, Ashton, Idaho

The Fall River Co-Op serves nearly 6,000 customers in Western Idaho.[1] It owns one standby hydro plant, but currently purchases 100 percent of its power from BPA.[2]

Fall River is located at the edge of Yellowstone National Park, which is known for its geysers. In the past few years, Fall River tried to obtain some leases from the Forest Service and already had some others. It was not allowed to drill, however, and was denied its new lease applications. The Forest Service feared that drilling by Fall River would have a detrimental impact on the geysers within Yellowstone. As a result, Fall River is terminating its remaining leases and is shifting its attention away from geothermal. Instead, it is developing a few hydroelectric sites.

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[1]Source: Electrical World Directory of Electric Utilities, 1979-1980 (McGraw-Hill, New York: 1980)

[2]Source: Conversation with Fall River official.

5.5.4.2 Plains Electric G&T Cooperative, Plains, New Mexico

Plains is a wholesale distributor to eleven rural co-operatives. Peak demand was 226 MW (winter) as of December 31, 1978 and is growing at about 7 percent a year.[1]

Plains is building a 210 MW coal plant. It also just received an $120,000 DOE grant to conduct a feasibility study on the generation of power from hot dry rock in the Valles KGRA. It plans to finance the generating plant (if feasible) with funds supplied by the GLGP and the Rural Electricfication Administration.

5.5.4.3 Raft River Co-Op, Malta, Idaho

Raft River has been involved in geothermal since 1972. From 1972-1978, exploration in the Raft River KGRA was carried on by ERDA and then DOE. Beginning in 1978, a 5 MW binary plant was built at Raft River. This plant began operation in August and is being operated by the Raft River Co-Op and EG&G Idaho.

Over the next three years, EG&G will phase out its participation until 1983, when Raft River will operate the plant itself.

The plant was financed through a joint venture of Raft River, Washington Public Power System, Idaho Power Co. and other utilities. BPA was originally involved in the project

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[1]Source: Peak demand from Electrical World Directory of Electric Utilities, 1979-80 (McGraw Hill, New York, 1980). Growth rate and subsequent information from interview with Plains engineer.

but withdrew. The original plant was financed out of the participants own funds. Raft River is interested in obtaining a loan guarantee for future development.

5.5.4.4 Surprise Valley Electrification Co-Op, Alturas, California

Surprise Valley is a small co-op with only 23 MW peak demand.[1] Although it currently generates no power, it is part of an organization of 19 co-ops (P&GC) exploring new power sources.[2] P&GC will own 5 MW of the 50 MW coal-fired plant to be built in Bordman, Oregon.

Surprise Valley is interested in geothermal power and is located near the Surprise Valley KGRA. It has noticed much exploration in the area by the oil companies, but apparently no major geothermal steam sources have been found. Because Surprise Valley is so small, it will wait for an oil company to find steam in the area before it attempts to use geothermal power.

5.5.5 Individual Municipals and Cooperatives: Conclusions

The municipals and cooperatives discussed in Sections 5.3 and 5.4 represent typical municipals and cooperatives likely to become involved in geothermal energy. Because the survey spanned utilities as large as LADWP and as small as the Surprise Valley Co-Op, it was able to describe the plans of all sizes of municipals and cooperatives. The survey

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1 Source: Electrical World Directory of Electric Utilities, 1979-80. (McGraw-Hill, New York: 1979).

included a large number (13) of municipals and cooperatives and included plans for seven KGRA's. Thus, it is unlikely that many major geothermal ventures to be undertaken by municipals and cooperatives were overlooked. This survey probably well represents the current state of municipal and cooperative plans for, and problems with, geothermal energy.

As was noted in Section 5.2, even the smallest utility is interested in developing geothermal energy. The normal route for small utilities to develop these power sources is through a joint venture with other utilities. For example, through the Northern California Municipal Power Corporation, eleven cities and one co-op are building a geothermal plant at the Geysers. The North Brawley plant and the Raft River plants were also built through joint ventures. These joint ventures allow utilities with no experience in power generation to develop their own capacity by using the expertise of others. In addition, because costs are shared, the risk of all participants is reduced.

A number of factors seem to be slowing geothermal power development. Environmental concerns eliminated the geothermal plans of the Fall River, Idaho Co-op. The release of hazardous gases from its wells at the Geysers Field has hindered the construction of the SMUD plant there.

More important are questions of finance. Under the Synfuels Act, municipals and cooperatives have 90 percent loan guarantees available to them. In addition, DOE refunds the difference between their tax-free cost of capital (the cost of their own municipal bonds) and the guaranteed loan rate. As a result, it appears that financing should be readily available for geothermal projects.

This, however, is not the case. Exploration is the riskiest element of geothermal development, but there are currently no loan guarantees for exploration. The financial risk associated with exploration is preventing several utilities from attempting to use geothermal energy.

In addition, it is difficult to use the GLGP when structuring financing for a joint project between municipal utilities and private companies. (An oil company, for example, might provide drilling expertise.) LADWP is having this problem.

In short, municipals and cooperatives are interested in geothermal power. The GLGP as it now stands does not remove all the risk of geothermal development, however. Because municipals and cooperatives are reluctant to take risks, their use of geothermal power may grow slowly. Loan guarantees for exploration of geothermal resources and an easier system for financing joint ventures would speed municipal and cooperative use of geothermal power.