GL01260

Economic Evaluation of Low Temperature Geothermal Resources: Production Costs and Geographic Distribution of Potential Demand

ABSTRACT

As part of the evaluation of the economic viability of low temperature (45°C to 100°C) geothermal resources on the Eastern Coastal Plain, the Center for Metropolitan Planning and Research of The Johns Hopkins University developed an interactive computer program to estimate average costs of delivered energy under specified resource, design, and economic conditions, and generated a series of thermal energy density maps for the principal urban area in each of the three sub-regions within the overall study area. Only a few projects of limited scale have been implemented in this country to make use of low temperature geothermal resources. Thus, data needed for cost projections must be taken from diverse sources, including studies dealing with higher temperature resources, nongeothermal district heating systems, and oil production. In order to bring together available information and permit extensive testing of the impact on average costs of specific cost estimates for individual system components (e.g., wells), as well as the influence of specific resource characteristics (e.g., temperature and required pumping energy), and economic conditions (e.g., housing density), a computer simulation model was developed. The Geothermal Resource Economic Evaluation System (GREES) calculates average cost per million BTU's delivered through a district heating system or to a process heat user at the plant gate. The model will undergo further refinements, but in its present form provides a convenient method of estimating the impact of changes in specific economic, design, and resource conditions. Because of the high cost of hot water distribution systems, high housing densities are crucial to the economic viability of geothermal energy for most residential uses. Population and housing data at the census tract level and estimates of thermal energy requirements for space and hot water heating for various types of housing and population levels were used as input to a computer mapping program which calculates the areas of roughly equal energy needs within each of the major urban areas within the mid-Atlantic study region. These maps complement the cost estimates developed by the GREES model by showing the level and spatial configuration of a principal cost component, density of low grade thermal energy requirements.

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I. INTRODUCTION

Economic cost is likely to be a primary criterion in evaluating the merits of alternative energy developments in the case of low temperature, direct utilization geothermal. The costs, both marginal and average, of delivered energy in a geothermal residential district heating system and in geothermal industrial process heating are estimated in a computer simulation model, GREES (Geothermal Resource Economic Evaluation System). While marginal costs are more relevant for the setting of prices to obtain an efficient allocation of resources, average costs provide a useful first approximation of the expense of providing geothermal-derived space heating, and are the costs which a private entrepreneur must recover. Marginal costs are obtained from the model by varying selected output parameters. The results of the model runs are discussed in the second section of this paper.

Computationally, the average cost model is simple and straightforward. The annual costs of each system component are summed and divided by the number of BTU's applied by participants in the system. Complexity arises, however, from the interdependence of various system parameters. A change in one parameter value (e.g., design temperature) will affect several other system parameters (e.g., the number of households served, length of the distribution system, and in-well pumping energy requirements). For this reason, and because of the relatively lengthy calculations involved in determining the costs of some components under given conditions, the model has been converted to a computer program to permit examination of the sensitivity of costs to varying conditions.

The GREES model differs from models such as GEOCITY[1] in that it does not involve internal optimization routines and deals with data at a higher level of aggregation. Given the preliminary nature of much of the data on resource characteristics and economic conditions, the additional refinements of the GEOCITY model do not appear to offer significant improvements in cost estimation at this stage in the analysis. However, the GREES model does provide, through its capacity to accept varying design temperatures for a geothermal/fossil fuel peaking hybrid district heating system and to accept varying levels of market saturation, the opportunity to estimate marginal costs for specific consumer classes and to allow the user to parametrically optimize the size of the system.

Debt Service and the Average Cost Calculation

Before discussion of the results of the model runs, it is important to consider the impact of inflation on the average costs as calculated in the GREES model. Projects such as geothermal space or process heating involve very large fixed investments relative to total costs. Assuming, as we have in the model, that funds for the well, distribution system, and other capital components are borrowed, the debt service charges (annual capital recovery factor times the amount borrowed) represent a large proportion of outlays each year. The capital recovery factor is calculated from the interest rate and the length of the repayment period. The interest rate is composed of a real rate of interest (a time preference or opportunity cost of funds and a risk premium), and the expected rate of inflation over the length of the repayment period, and their cross product. Thus, a nominal interest rate of 15.7 percent may be composed of an 8 percent expected inflation rate for each year of the loan, and a 7 percent real interest rate. Since any borrower must pay the interest rate which includes the inflation factor, his costs are influenced by this nominal interest rather than by the real interest rate, even though it may be analytically preferable to consider only real prices. If inflation does, in fact, occur at the rate expected, then the real worth of the debt service, which is uniform in nominal dollars, will decline by the inflation rate.

The effects of the uniform debt service charges can be complex, and will be explored in some detail in a later Metro Center report. Planned extensions of the GREES model will also allow a more convenient treatment of the decreasing real cost (due to fixed nominal capital payments) and income stream which can be expected from a geothermal project.

Thus, the estimates of average costs are actually the real average costs for the first year of the project, and should not be taken as typical of each successive year. Generally, if inflation is moderately high, real costs will decline significantly as the value of the debt service increases.

II. RESULTS OF MODEL RUNS

The residential subroutine was run under a wide variety of resource and economic conditions. Because many of the parameters can be expected to vary greatly under actual field operating conditions, the number of possible combinations of conditions is quite large. Therefore, only a few values were changed in any single run, and the default values for the remaining parameters take on particular importance.

Default Values

The default values are shown in Table 1. Generally, each was selected from the middle ranges of the values considered feasible, although the default values for well-head resource temperature (160°F) and for market saturation (80%) are toward the optimistic end of the scale of values. In the following description of the impact on average costs from changes in specific parameter values, the reader should keep the significance of these default values in mind.

The set of conditions which make up the default values may be described as follows: the area is one composed of townhouses, in Salisbury, Md., of which 80

Table 1. Default Scenario for Residential Estimates

Option	Current Residential Scenario Parameters			Value
10	Area under consideration:			Salisbury
11	Well-head water temperature (°F):			160
12	Depth of upwell (feet):			5500
13	Housing type:			3
14/24	System design temperature (°F):			36
15/27	Capital equipment	Yrs.	Int.%	
	Wells	20	12.00	
	Distribution system	30	12.00	
	Heat exchanger	10	12.00	
	In-well pumps	10	12.00	
	Hookup costs	30	12.00	
	Peaking boiler	20	12.00	
--	Original pump costs:			$ 84711
--	Annual pump replacement costs:			32390
18	Cost per hookup:			384
19/25	Market saturation by geothermal (%):			80.00
20	Cost of electricity (¢/kwh):			4.000
21	Reject temperature (°F):			85
22	Pipe cost calculation ($K/mi.)			I = 250
23	Depth of reinjection well (feet)			2500
26	Drawdown of upwell (%)			50.00
--	Full pumping energy (megkwh/year):			4.07
28	Minimum ambient temperature (°F):			-5.
29	Fossil fuel cost ($/megBTU)			4.50
30	Boiler cost ($/100K BTU)			$ 1500.00

percent of the households within the service area are hooked up to the district heating system; all space heating demand down to 36° F is served exclusively by geothermal energy, and additional energy demand for colder temperatures, down to -5° F, is served by a fossil fuel peaking system which raises the temperature of the circulating water; the resource is topped by a 5,500 foot production well which experiences an average drawdown of 50 percent (2,750 feet) as the water is pumped to the surface; the water temperature at the well-head is 160° F and is reinjected at 85° F, leaving a Δt of 95° F; the water is reinjected to a separate aquifer lying at a depth of 2,500 feet and hydrostatic pressure alone is sufficient to dispose of the water; the economic conditions include a 12 percent charge on borrowed funds, with the system capital components amortized individually over their expected lives; electricity to operate the pumps is purchased at 4¢ per kilowatt hour and fossil fuel for the peaking plant is purchased at $4.50 per million BTU's; and the distribution system costs $250,000 for each mile of installed insulated dual pipe. In the tables and description which follow, any parameter not specifically listed takes on its default value.

The results of running the default values are shown in Table 2. Note that, under default conditions, over 90 percent of all space heating requirements for the approximately 830 households on the single well system are served by geothermal energy. Although the distribution system is amortized over a 30-year period (see Table 1), it nevertheless represents the single largest annual cost. Interestingly, production and reinjection well costs (exclusive of pumps), amortized over 20 years, are less on an annual basis than the cost of the pumping energy required for the 5,500 foot well with a 50 percent drawdown and 4¢ per kilowatt hour electricity charge. The default values result in an average cost of $5.70 per million BTU's of delivered energy.

Table 2. Default Scenario for Residential Estimates

Length of distribution system:	2.62 miles
Number of households:	829
Total geothermal BTU's (millions):	59347.04
Total system BTU's (millions):	64828.71
Percentage geothermal utilization:	36.13
Percentage service geothermal:	91.54
Pumping energy:	1.471 million kwh
Annualized costs (thousands of dollars)	
Well costs:	50
Distribution system costs	81
Heat exchanger costs:	15
Original pump costs:	15
Hookup costs:	39
Annual replacement costs:	32
Annual pumping costs:	59
Peaking boiler costs:	53
Fossil fuel costs:	25
Total annual well-head costs:	171
Well-head cost per geo. megBTU($)	2.90
Total annual system costs:	370
System cost per megBTU($):	5.70

Resource Conditions

Until deep wells are in place, the effects of such factors as resource temperature, well depth, and in-well drawdown can best be evaluated through variation in the relevant parameters in the model. GREES was run for a series of temperatures based on differing assumptions regarding temperature gradients and depth to the most attractive aquifer. Aquifer depths which are considered here are 9,000 feet; 7,000 feet; 5,500 feet (default); 4,000 feet; and 3,000 feet. Gradients used to estimate well-head resource temperature are 1.5° F, 2° F (default), and 2.5° F per 100 feet of depth. Allowance is made for average ground temperatures in each of the three study areas, and for a 5° F temperature drop from aquifer to well-head. Average in-well drawdown levels of 100 percent, 50 percent (default), and 10 percent which might result from pumping required to maintain a flow rate of up to 500 gallons per minute were considered.

Assuming a 50 percent average production well drawdown, the deeper resources at any given gradient always result in lower cost, i.e., the value of the additional thermal energy from the deeper (warmer) resource is greater than the cost of deeper wells and additional pumping requirements. However, it is only at the shallower depths (e.g., 3,000 and 4,000 feet) that such differences are significant. Small average cost reductions resulting from deeper depths and correspondingly higher temperatures (i.e., uniform gradient) could thus be more than outweighed by increases in the pumping costs if drawdown increased with use of deeper wells. Further, it is interesting that, even with uniform drawdown, the shallower aquifers, when accompanied by higher gradients, provide costs close to those from deeper resources with lower gradients. This result is due in large part to drawdown.

The average in-well drawdown has significant impact on pumping energy

Table 3.

Aquifer Depth (ft)	Temperature Gradient (°F/100ft)	Approximate Well-Head Resource Temperature (°F)	Average Cost per Million BTU's Delivered	
9,000	1.5	185	$ 6.50	
"	2.0	230	5.30	
"	2.5	275	4.70	
7,000	1.5	155	6.60	
"	2.0	190	5.50	
"	2.5	225	4.80	
5,500	1.5	135	6.80	
"	2.0	160	5.70	Default case
"	2.5	190	5.00	
4,000	1.5	110	8.30	
"	2.0	130	6.00	
"	2.5	150	5.20	
3,000	1.5	95	13.30	
"	2.0	110	7.30	
"	2.5	125	5.80	

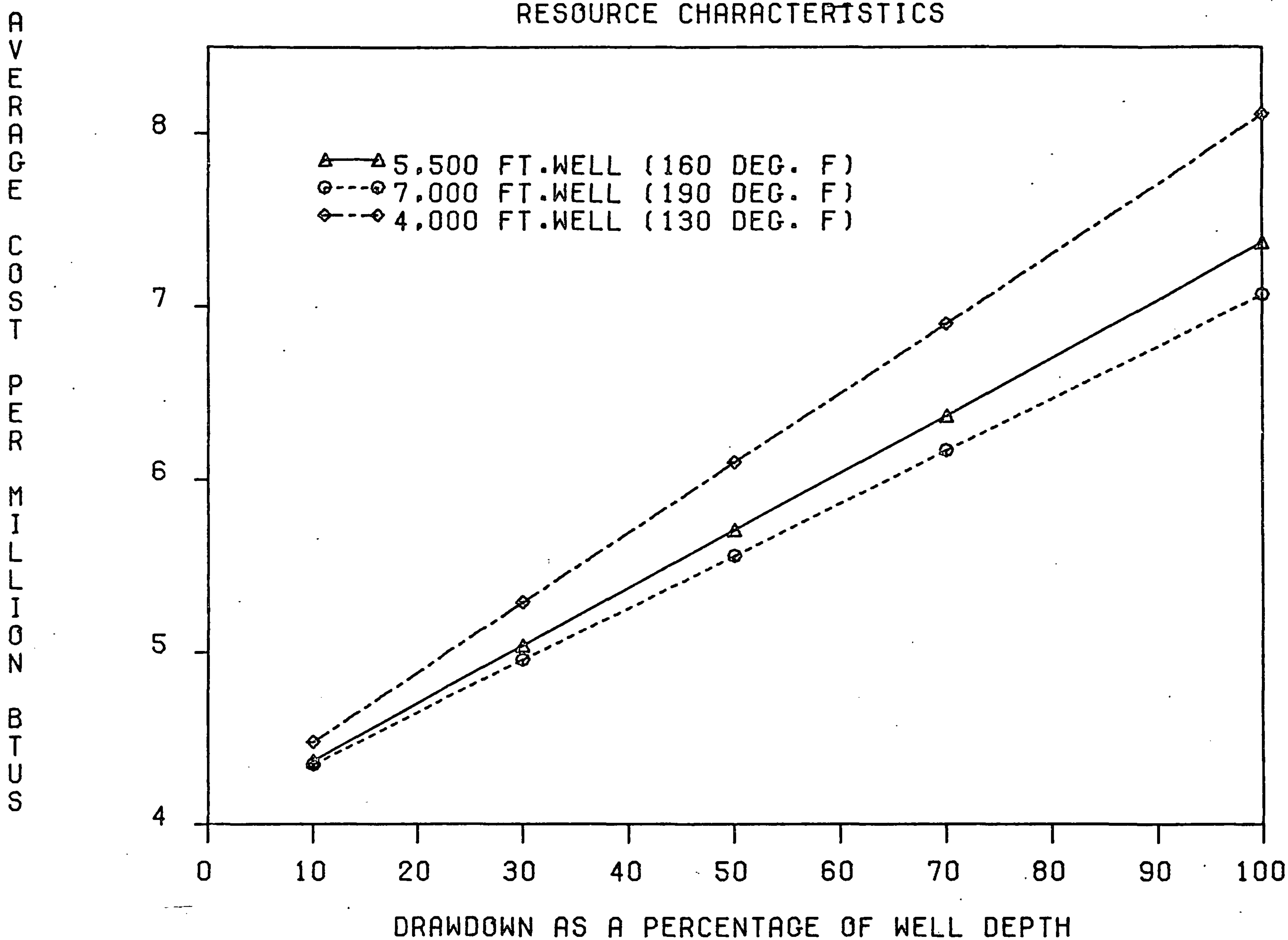
requirements, which is the single largest annual cost after that of the distribution system. In the model, the drawdown is determined as percentage of well depth, and therefore the pumping energy charge is more significant for deeper wells. As an example, for a 5,500 foot well with a 160° F well-head temperature and a drawdown of 50 percent, average costs are $5.70. When the drawdown is changed to 100 percent, average costs rise to $7.40, while a drawdown of only 10 percent results in an average cost of $4.40. Thus, with all other values equal, average costs can change by over $3.00 per million BTU's by changing the drawdown. As another example, assuming a 4,000 foot well and a 130° F resource temperature, changing the drawdown from 100 percent to 10 percent results in a drop in average costs from about $8.00 to $4.40. This suggests that the tradeoff between such aquifer characteristics as saturated thickness and permeability, which affect drawdown, and the characteristics of higher temperatures from deeper aquifers will require careful consideration. Figure 1 displays several resource depths, temperatures, and drawdowns; and the resulting average costs.

Costs for Well, Pumps, Heat Exchangers, Boiler, and Hookups

The costs for these components are not varied in the model. As described in Appendix A, this is an area of future refinement in the GREES model. As presently structured, the model can be run with different values for these components only by changing the internal program data. This approach was taken to reduce the complexity of the model, and to allow concentration on the major and most variable cost components. Although the costs currently being used for these components are still estimates, it is believed that the actual values are unlikely to change to an extent sufficient to cause a major change in average costs. Since the well, pumps, heat exchangers, boilers, and hookups are amortized

FIGURE 1

AVERAGE COST AS A FUNCTION OF
RESOURCE CHARACTERISTICS



over comparatively long periods of time (10 to 30 years), changes in the total cost of a single component have comparatively little impact when such costs are annualized.

Distribution System Costs

As described in Appendix A, the GREES model at present does not calculate distribution system costs by considering changes in pipe diameter, but rather bases the costs on the overall length of the system (determined from a formula using uniform densities for specific types of housing units and market saturation level), and a cost per mile of installed insulated dual pipe. The approach currently used in the model has the advantage of utilizing cost estimates per mile based on experience gained with actual systems, and thus should be reasonably accurate for systems of given length. Its disadvantage is that the change in the marginal cost of expanding the system and increasing the diameter of the mains is not reflected. Inclusion of the capability of tracking changes in pipe size is a modification planned for the future.

For a system of given length, changes in the cost of installed pipe have a moderate impact on average cost. Under default values, each $100,000 change in pipe costs per mile results in a change of 50¢ per million BTU of delivered energy. The survey by John Beebee ("Cost of Hot Water Pipes," presented at The Ogle Conference, University of Virginia, Summer 1976) indicated a range of from $100,000 to $500,000 per mile for distribution system piping. This entire range would be reflected in a change of about $2.00 per million BTU's. While such a difference could well be very important under specific conditions, it is far less significant than the change in average costs resulting from different, but still plausible, values for resource conditions such as well depth, temperature, and drawdown.

It should be noted that this result is influenced by the saturation level. At lower saturation levels, changes in pipe costs would have a greater impact; however, average costs tend to rise very quickly as saturation level is decreased, regardless of the specific cost of the distribution system per mile. Likewise, when the length of the amortization period for the pipe is changed, the impact of the total cost per mile changes, though again such changes are quite small. For example, when the distribution system is amortized over 10 years instead of 30, a change of $100,000 per mile results in 60¢ change in average cost.

Cost of Purchased Energy

Under the default values, the single production well system consumes just under 1 1/2 million kilowatt hours (about 5 billion BTU's) annually for in-well pumping and just under 5 1/2 billion BTU's of fossil fuel for peaking, compared with the annual energy obtained from the well of over 59 billion BTU's (see Table 2). With the default values for electricity of 4¢ per kilowatt hour and a fossil fuel price of $4.50 per million BTU's, average delivered cost of geothermal heat is $5.70. When electricity costs are raised to 4.5¢ and fossil fuel to $6.50, average costs increase only about 30¢. With a price of 5¢ for electricity and $8.00 for peaking fuel, average cost increases only about 55¢ over that under default values for the purchased energy. Thus, even in a period during which the real price of purchased energy inputs to the system rises significantly (25% for electricity and 78% for fossil fuel), the impact on the geothermal district heating system would probably be relatively small, provided the system is in operation at the time of the price rise. Since well drilling and pipe laying are energy intensive activities, such costs would likely rise at a higher rate than the overall price level in an energy stimulated round of inflation.

Interest Rates, Amortization Periods, and Uncertainties

Major uncertainties remain in important geologic and economic considerations for a geothermal district heating system. Little is known with certainty about the long-term reliability of the deep aquifers on the East Coast in providing relatively large volumes of water at constant or only slowly decreasing temperatures.

It is possible that, over time, drawdown may increase (and hence pumping energy increase) or that the water will become significantly cooler after only a few years. The GREES model reflects the characteristics of the hot water bearing aquifer in a limited way through changes in the drawdown. While this feature captures the effect of lowering the water level in the aquifer, the model currently cannot readily reflect the impact of lowering the temperature of the aquifer.

A district heating system represents a large capital investment relative to the energy utilized within a comparatively short time period (e.g., a heating season). Since many of the major cost components have long life expectancies, this feature alone is not an insurmountable obstacle to development. However, acceptable cost levels are only possible if the system components can be amortized over comparatively long periods at modest interest rates.

An important economic uncertainty is the cost of alternative heating systems. During the long period over which the capital costs of the geothermal system are being recovered, major changes could occur in the picture for competing energy systems (e.g., a series of major oil strikes could at least temporarily reduce oil prices and increase supplies). Even if traditional fuels continue to rise in real price, the geothermal system could face competition from major breakthroughs in other unconventional energy resources, such as synthetic liquid fuels.

The market for capital funds would reflect the importance of such uncertainties in its assessment of the risks involved in backing a venture to utilize low temperature geothermal energy, and hence in the interest rate and the length of the payback period it would require. As mentioned in Appendix A, an economic, as distinct from financial, analysis amortizes each major component over the period of its expected life, since this approach more accurately reflects social welfare costs. However, since a prospective developer and potential lender of funds are more likely to consider a single loan period, both approaches are used here in estimating the impact of interest charges on the cost of delivered energy.

The amortization periods used in the economic approach are listed in Table 1. Average costs resulting from changes in interest rates with the repayment periods for each component are shown in Table 4.

Thus, for each two-point increase in interest rate, average cost rises about 50¢. While increases from about 10 percent to about 16 percent could probably be accepted, an even higher interest rate could be a major obstacle to a prospective developer.

Table 5 shows the resulting average costs at varying interest rates when a single amortization period is used for all components. Under the financial approach, changes in interest rates have about the same impact as under the economic approach. It can be seen, however, that, even under favorable interest rates, a comparatively short repayment period would likely be a major obstacle to development of low temperature geothermal energy systems.

In general, the higher the level of uncertainty involved in the geologic and economic considerations, the shorter the time period and the higher the interest rate which the market will require to fund a geothermal system.

Saturation Level

The number of customers within a service area is a crucial factor for any district heating system. The GREES model addresses this consideration through changes in the saturation level. The length of the distribution system is determined by the number of households of a specific type and the preprogrammed density

Table 4. Effects of Changes in Interest Rates on Average Cost (Each Component Amortized Separately)

	Interest Rate					
	10%	12%	14%	16%	18%	20%
Average Cost	$5.20	$5.70	$6.20	$6.80	$7.30	$7.90

Table 5. Single Amortization Period for All Components

		Interest Rate		
		12%	18%	
Amortization Period	10 yrs.	$7.00	$8.40	Average Cost
	20 yrs.	5.70	7.30	

levels for each type, assuming a system at 100 percent saturation. To indicate the impact of some households not participating in the system, the length of the system is multiplied by the reciprocal of the user-specified saturation level. For example, a system designed to service about 830 townhouses would be about 2.1 miles in length under 100 percent saturation, 2.6 miles with an 80 percent saturation, and 21.0 miles at 10 percent saturation. Of course, for housing types of differing densities, the saturation level changes in relative importance, but remains very significant for all types.

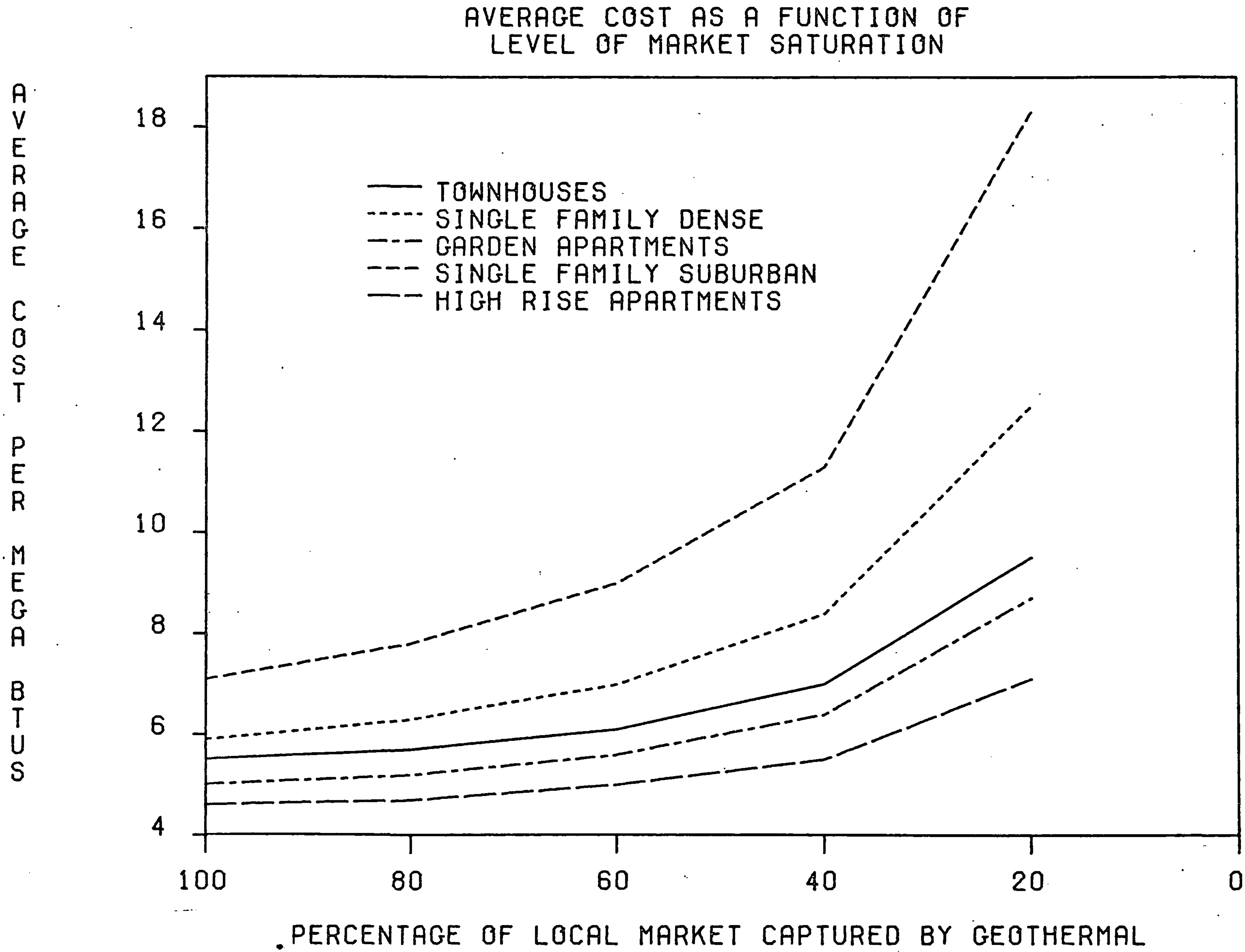
In terms of average cost, a change in saturation from 100 percent to 60 percent for townhouses increases average costs from \$5.50 to \$6.10. With a saturation of 20 percent, costs rise to \$9.20. Figure 2 shows the exponential character of the increase in average costs as the saturation level is progressively lowered.

Area Specific Model Runs

Data internal to the GREES model distinguish among the three cities of interest with respect to the hourly weather data, which in turn influence the total number of BTU's sold and the in-well pumping energy required. The model was run to determine the optimal design temperature for each city. All subsequent model runs for a specific city were made using this design temperature. To further distinguish among the cities, types of housing and likely well depths and temperatures are varied. (Also, the mean surface temperature varies among the cities, and this has a slight influence on the bottomhole temperature found at any given depth and gradient. The same gradient and depth in Atlantic City and Norfolk, for example, lead to about a 5° F higher resource temperature in the latter city.)

The demand for spaceheating in a particular locale depends on the prevailing climatic conditions. To separate out the impact of climate, a series of runs were made with uniform resource conditions (i.e., well depth, resource temperature,

FIGURE 2


AVERAGE COST AS A FUNCTION OF
LEVEL OF MARKET SATURATION
TOWNHOUSES
SINGLE FAMILY DENSE
GARDEN APARTMENTS
SINGLE FAMILY SUBURBAN
HIGH RISE APARTMENTS
AVERAGE COST PER MEGA BTUS
18
16
14
12
10
8
6
4
100
80
60
40
20
0
PERCENTAGE OF LOCAL MARKET CAPTURED BY GEOTHERMAL

and drawdown) and economic factors (e.g., housing type and saturation level). Each city run was made using the optimal design temperature for that city (32° F in Atlantic City, 36° F in Salisbury, and 38° F in Norfolk). As can be seen in Table 6, climatic differences between Atlantic City and Norfolk favor the former area by about $1.40 per million BTU's. Salisbury is just about in the middle, with average costs about $.70 below those for Norfolk and above those for Atlantic City.

These results suggest that, if resource conditions appear to be uniform, then the colder areas have a modest advantage. However, as shown in Table 6, the variation in resource conditions has a much greater impact on costs. Thus, in any ordering of potential geothermal developments, resource condition considerations would probably outweigh climatic factors.

Although only very preliminary data on depth to the basement and temperature gradients are currently available, it does appear that the basement is relatively shallow in Norfolk (probably less than 4,000 feet) and that the gradient is relatively low in Atlantic City. On the other hand, housing densities are highest overall in Atlantic City. Estimates based on different resource and housing conditions for each city are displayed in Tables 7 and 8. To reflect a wider range of possible parameter value change, a separate set of estimates were made under "optimistic," "intermediate," and "pessimistic" conditions. The results of these estimates are shown in Table 9.

Marginal Costs

Through changes in the design temperature, the utilization of a production well can be varied as a function of the number of households served and BTU's of geothermal energy produced. Figure 3 shows average and marginal costs as a function of BTU's of geothermal energy produced and number of households served, respectively. Figure 4 shows the marginal cost of increasing the number of BTU's

Table 6. City by City Comparison with Same Resource and Economic Conditions

City	Well Depth	Resource Temp.	Housing Type	Saturation Level	Average Cost
Atlantic City	5,500	160	Townhouses	80%	$ 5.00
Salisbury	"	"	"	"	5.70
Norfolk	"	"	"	"	6.40
Atlantic City	4,000	130	Garden Apartments	60	$ 5.20
Salisbury	"	"	"	"	6.00
Norfolk	"	"	"	"	6.70

Table 7.

Well Depth (in feet)	Well-Head Temp.	Drawdown (%)	Housing Type	Market Saturation	Atlantic City Average Cost	Salisbury Average Cost	Norfolk Average Cost
5,500	190	50%	Townhouse	80%	$ 4.27	$ 5.02	--
"	160	"	"	100	4.70	5.50	--
"	"	"	"	40	6.00	7.00	
"	"	10	"	40	4.65	5.63	--
"	130	50	"	80	6.49	7.32	--
4,000	150	"	"	80	4.48	5.23	5.86
"	130	"	"	100	5.11	5.85	6.48
"	"	"	"	40	6.34	7.35	8.26
"	"	10	"	40	4.75	5.74	6.56
"	110	50	"	80	7.49	8.34	9.17

Table 8.

Well Depth (in feet)	Well-Head Temp.	Drawdown (%)	Housing Type	Market Saturation	Atlantic City Average Cost	Salisbury Average Cost	Norfolk Average Cost
5,500	160	50%	Single family dense	100%	$ 5.10	$ 5.90	--
"	"	"	"	40	7.10	8.90	--
"	"	"	Garden apartments	100	4.30	5.00	--
"	"	"	"	40	5.50	6.40	--
"	"	"	High rise apartments	100	4.00	--	--
"	"	"	"	40	4.80	--	--
4,000	130	"	Single family dense	100	5.50	6.33	7.05
"	"	"	"	40	7.50	8.77	9.93
"	"	"	Garden apartments	100	4.70	5.34	5.89
"	"	"	"	40	5.84	6.74	7.53
"	"	"	High rise apartments	100	4.40	--	--
"	"	"	"	40	5.16	--	--

Table 9.

	Distribution System ($K/mi.)	Capital Recovery Period	Interest Rate	Well Depth	Resource Temperature	Saturation	Drawdown	Housing Type	Average Cost
Atlantic City									
Pessimistic	500	10 yrs.	16%	4,000	110	60%	50%	Single family dense	$ 15.20
Intermediate	250	15	14	"	130	80	"	Garden apts.	5.50
Optimistic	200	20	12	5,500	160	"	10	High rise apts.	2.70
Salisbury									
Pessimistic	350	10 yrs.	16%	4,000	110	60%	50%	Single family dense	$ 15.00
Intermediate	250	15	14	5,500	160	80	"	Townhouses	6.60
Optimistic	150	20	12	5,500	180	"	10	Garden apts.	3.20
Norfolk									
Pessimistic	350	10 yrs.	16%	3,000	115	60%	50%	Single family dense	$ 14.80
Intermediate	250	15	14	4,000	135	80	50	Townhouses	7.50
Optimistic	150	20	12	4,000	150	"	10	Garden apts.	3.50

FIGURE 3

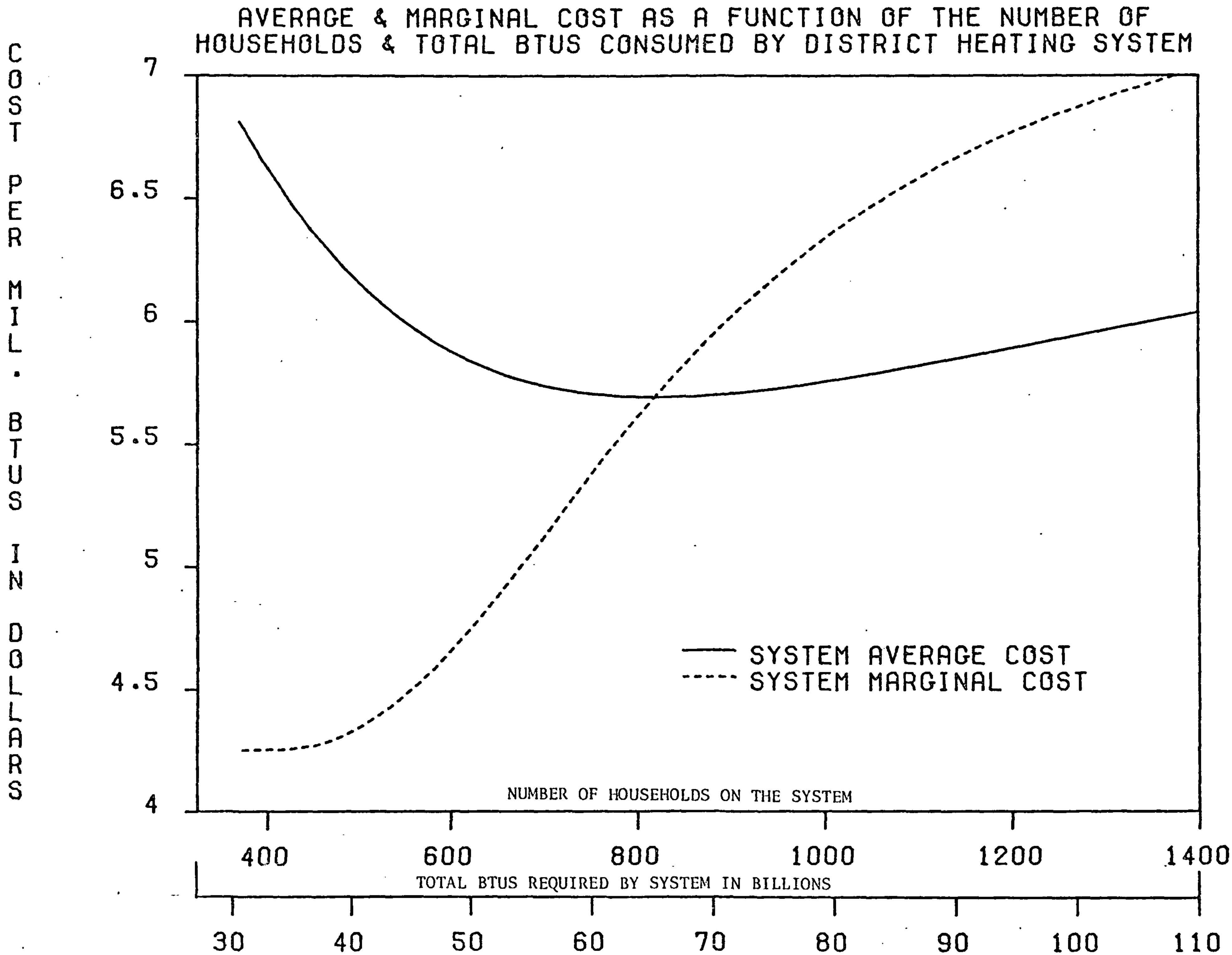
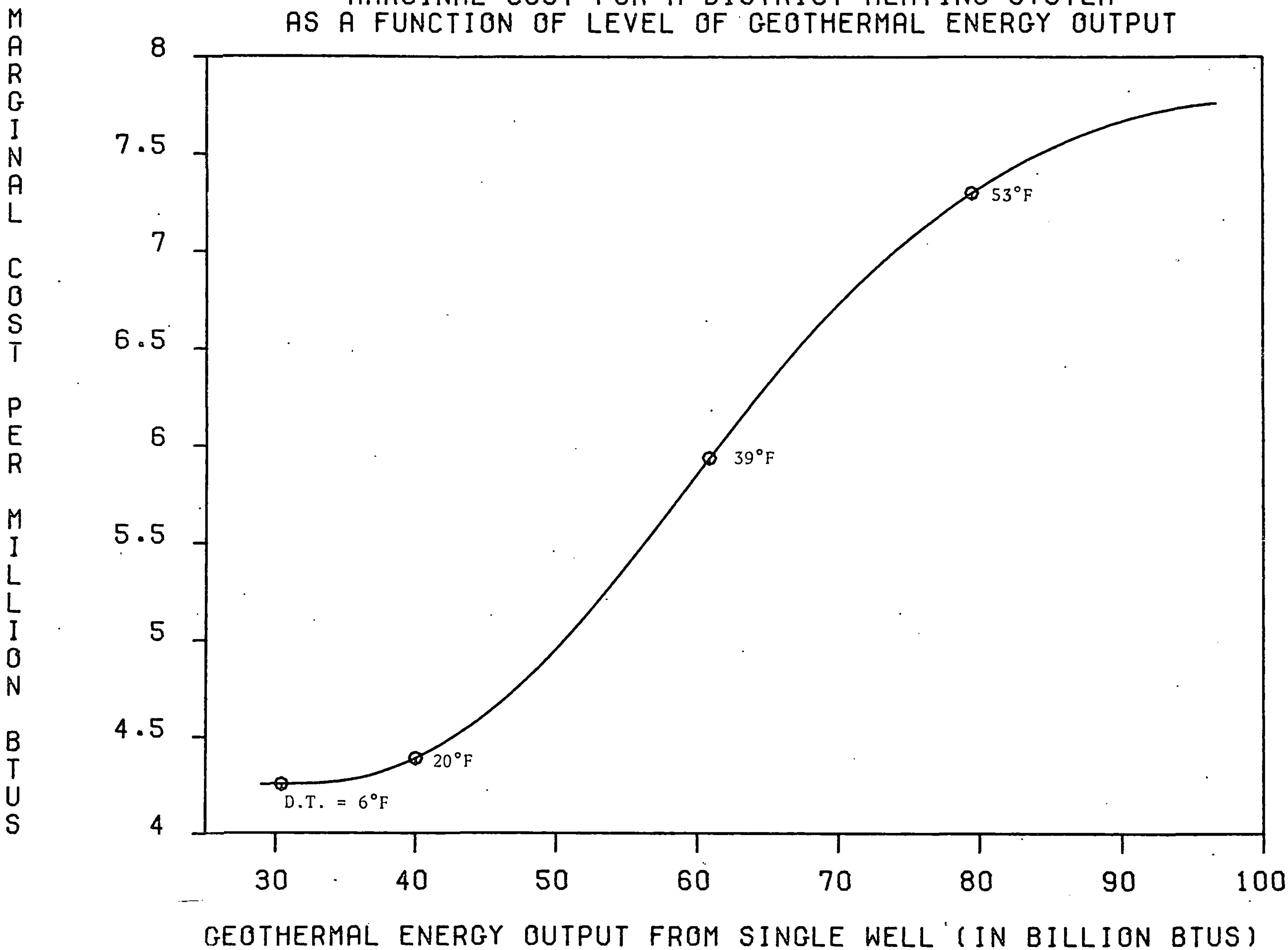

AVERAGE & MARGINAL COST AS A FUNCTION OF THE NUMBER OF
HOUSEHOLDS & TOTAL BTUS CONSUMED BY DISTRICT HEATING SYSTEM
COST PER MIL. BTUS IN DOLLARS
7
6.5
6
5.5
5
4.5
4
SYSTEM AVERAGE COST
SYSTEM MARGINAL COST
NUMBER OF HOUSEHOLDS ON THE SYSTEM
400
600
800
1000
1200
1400
TOTAL BTUS REQUIRED BY SYSTEM IN BILLIONS
30
40
50
60
70
80
90
100
110

FIGURE 4

MARGINAL COST FOR A DISTRICT HEATING SYSTEM
AS A FUNCTION OF LEVEL OF GEOTHERMAL ENERGY OUTPUT



produced from the well. It should be noted that the marginal costs in Figures 2 and 3 are "system marginal costs" rather than "geothermal marginal costs." When the system is operating without a topping cycle in operation and at less than peak capacity (i.e., marginal capital cost is not of concern), in-well pumping energy is the only variable cost directly related to increasing the output from the well. Since geothermal water production is assumed to be a linear function of pumping energy (simplistically, drawdown is assumed to be invariant with pumping rates), geothermal marginal costs are constant. However, as the system is expanded, significant nonlinear changes do occur in the system in relation to distribution costs and peaking system costs. In the absence of a theoretical or practical justification for dividing such costs between the geothermal portion of the system and the fossil fuel peaking portion, they are not addressed separately.

Industrial Subroutine

As described in Appendix A, the industrial subroutine of the GREES model bypasses weather data and distribution system considerations. It determines average well-head costs (i.e., costs for wells, pumps, pumping energy, and heat exchanger) on the basis of the user-specified utilization factor. Table 10 displays the results of runs made varying resource temperature and utilization factor.

The figures in Table 10 illustrate the significance of the utilization factor in determining average well-head costs, and the sensitivity of these costs to drawdown, and hence pumping energy requirements. It is interesting that a change in drawdown from 50 percent to 10 percent in a 5,500 foot well has the same impact on average well-head costs as a change in utilization from 25 percent to 75 percent. As an aside, this suggests that there is likely to be an important interaction between pumping rate in the well and the advantage of greater utilization which may prove to have a net negative effect if this higher utilization results in

Table 10. Well-Head Cost as a Function of Utilization Factor

[Other values used: Well depth, production = 5,500 feet
Well depth, reinjection = 2,500 feet
Amortization: Economic approach
Interest Rate = 12%]

	Resource Temperature	Utilization Factor 15%	25%	40%	75%	100%	
Average Well-Head Cost per Million BTU's at Plantgate	130° F	$8.90	6.00	4.40	3.10	2.70	Drawdown: 50%
	160° F	5.60	3.70	2.70	1.90	1.70	
	130° F	4.90	3.10	2.00	1.20	1.00	Drawdown: 10%
	160° F	3.20	2.00	1.30	.80	.60	

substantially greater drawdown. By including resource conditions in the consideration, similar effects are observable; for example, at a 25 percent utilization factor and a 10 percent drawdown, a 5,500-foot well with a 130° F resource temperature results in average costs less than those for a 160° F resource at the same depth with a 50 percent drawdown.

III. CONCLUSIONS FROM MODEL RUNS

Conclusions based on estimates produced by GREES suggest that, under favorable, though still very plausible, geologic and economic conditions, low temperature geothermal resources can be utilized at reasonable costs to serve the space heating needs of communities with climatic conditions found on the Middle Atlantic Coastal Plain. Unlike traditional fossil fuels, where distribution costs are only a modest portion of total cost, significant cost differentials exist between geothermal-based space heating supplied to residences through a district heating system, and space or process heat supplied via a very short distribution system to an industry. Thus, even in cases where residential use may prove unattractive, industrial use may be attractive. Given the apparent advantages of industrial applications, such uses should probably be undertaken before residential applications.

As discussed in the earlier review of energy price projections,[2] the cost of electric resistance space heating is likely to set the ceiling for the retail price of geothermal-based heating. As the more attractive fossil fuels (oil and natural gas) become more scarce, geothermal energy, like electric heating, may be marketable on the basis of its "premium attributes," such as projected price stability and security of supply, cleanliness, and ease of maintenance. However, since electric space heating offers these same attributes, and electricity prices are projected to remain relatively stable, geothermal energy will need to be priced

Table 11. Well-Head Cost as a Function of Interest Rate

[Other values used: Well depth, production = 5,500 feet
Well depth, reinjection = 2,500 feet
Amortization: Financial approach
Repayment period = 15 years
Utilization factor = 25%]

Resource Temperature and Drawdown		Interest Rate 12%	18%
(50%)	130° F	$6.00	$7.00
	160° F	3.70	4.40
[Other values used: Repayment period = 10 years]			
(50%)	130° F	6.60	7.60
	160° F	4.10	4.70
(10%)	130° F	3.70	4.50
	160° F	2.40	2.90
[Other values used: Well depth = 4,000 feet, Repayment period = 15 years]			
(50%)	110° F	7.40	8.60
	130° F	4.20	5.00
[Other values used: Repayment period = 10 years]			
(10%)	110° F	4.30	5.30
	130° F	2.60	3.10

below the level of electric heating. Projections indicate that electricity prices should remain at about \$10 or \$11 per million BTU's (constant dollars). To capture a significant portion of the existing electric heating market and a portion of the existing oil or natural gas market as well, a geothermal energy price of several dollars below that of electricity will likely be needed. Although the designation of a specific "competitive price" is somewhat arbitrary, \$8 per million BTU's is used here as the cutoff point. Prices above this level are considered relatively "uncompetitive," and below \$8 are considered "potentially competitive."

Residential Subroutine

Generally, under somewhat favorable conditions, the average cost of delivered thermal energy through a geothermal-based district heating system would likely be below, and, in a number of cases, well below, \$8 per million BTU's. Under more favorable conditions, particularly a lower capital recovery factor, average costs can be well below \$6. It is important to note that no single factor is likely to make or break the competitiveness of the geothermal-based system, but the combination of several unfavorable conditions can rapidly push costs to very uncompetitive levels. Thus, the specific resource and economic conditions become crucial.

The model runs indicate that several factors and groups of related factors are particularly important in determining the level of average cost. These include well depth and temperature gradient, average drawdown in the well, market saturation level (particularly for single-family detached homes and townhouses at saturation levels below about 60 percent), and the capital recovery factor (interest rate and repayment period). An unfavorable situation in any of these factors or groups of factors will raise average costs to moderately high levels, even when all other conditions are generally favorable. The combination of unfavorable conditions in two or more of the items listed above (e.g., high drawdown and high capital recovery factor) would likely make the cost level uncompetitive regardless of other conditions.

Factors which are somewhat less important, but which should still be carefully evaluated, are housing type; resource temperature, even with lower gradients; and changes in the distribution system cost, particularly if coupled with short capital recovery periods. In any district heating system, costs rise as housing densities decline. It appears from the results of the analysis that single-family "suburban" neighborhoods (7 households per 400' by 200' block - street center to street center) are uneconomical. This conclusion agrees with Swedish district heating (non-geothermal) studies.[3] Single-family "dense" (15 households per block) neighborhoods are marginal. If most other factors are reasonably favorable, and if saturation levels are above about 60 percent, such areas can probably be served at acceptable cost. The higher resource temperatures obtained by drilling deeper in areas of uniform temperature gradient are worth the added well cost so long as the deeper aquifer is not significantly less permeable or has such reduced saturated thickness or other characteristics as to cause an increase in drawdown (measured as a percentage of well depth). An 8,000 foot well with a 4,000 foot drawdown is still preferable to a 6,000 foot well at the same temperature gradient with a 3,000 foot drawdown, but, if the drawdown in the former should be increased to 5,000 or 6,000 feet, then the shallower well with its lower temperature will provide geothermal energy at a lower cost. The implication is, of course, that, while "depth to the basement" is certainly important, this feature must be weighed against other geologic considerations.

Under an economic accounting approach in which a system component is amortized over its entire expected useful life, the distribution system remains the largest annual cost, even when it is repaid over a 30-year period at moderate interest rates. However, even large changes in the cost per mile of installed insulated dual pipe, e.g., from $250,000 per mile to $450,000, raises average costs only about $1.50 per million BTU's when the neighborhood is one of townhouses (30 households per block) and market saturation is 80 percent. Of course, for denser housing types and higher saturation levels, a large increase in distribution system cost has less impact, and, for less dense neighborhoods and lower saturation levels, it becomes more significant. The distribution system costs per mile also take on increased importance when the capital recovery factor is high. A $100,000 increase in the cost per mile raises average costs by $.50 per million BTU's under default conditions (see Table 1). Under a 10-year repayment period and 14 percent interest, this same increase results in a change of $.80 per million BTU's. With this same capital recovery factor and a 40 percent saturation, average costs increase about $1.60 per million BTU's with each $100,000 per mile increase in distribution system costs.

One interesting result of the model runs is the relatively minor role played by climatic differences (at least as they vary between Norfolk and Atlantic City) and the cost of purchased energy in determining average costs. The colder climates raise the level of demand per household so that the same number of BTU's can be sold to fewer residents, and thus through a shorter distribution system. Such an advantage results in average costs being about $1.50 less in Atlantic City than in Norfolk for identical resource and economic conditions. Salisbury is just about in the middle climatically. The differences are far less than those resulting from differences in changing either resource conditions (depth, temperature, or drawdown) or economic conditions (type of neighborhood, saturation level, capital recovery factor).

Although about 10 percent of the thermal energy supplied by the district heating system under default conditions is provided by a fossil fuel peaking system, and the pumping energy requirements are just under 1.5 million kilowatt hours per well per year, large increases in the real costs of fossil fuel and electricity have only a very modest impact on average costs. Electricity prices are projected to remain relatively stable and fossil fuel prices to rise steadily over the next decade.[4] When the model was run with a 25% increase in electricity costs and a 78 percent increase in fossil fuel costs, average costs for the geothermal-based heating system increased only about $.50 per million BTU's under default conditions. This suggests that price rises for traditional fuels will increase the competitiveness of geothermal energy (so long as such increases do not disrupt capital markets).

Industrial Subroutine

The results of the industrial portion of the GREES model suggest that, if a well can be drilled near a plant gate, and if the industry or industries can utilize a sufficient portion of the annual potential production, then geothermal energy can be supplied at very competitive prices, even under resource conditions which would likely preclude its use for residences. An interesting result of the model runs is the apparent tradeoff between utilization factor and drawdown. Just as there appears to be an important tradeoff between resource temperature and depth on the one hand and drawdown on the other, the tradeoff between drawdown and utilization level should be carefully evaluated. If increased utilization of the resource results in an increase in drawdown (due to higher pumping rates), then the advantage of the higher sales may well be outweighed by higher pumping costs.

Competitiveness of Mid-Atlantic Coastal Plain Geothermal Energy

Although the data and the model will be improved over time, the results of the GREES model analyses to date suggest that geothermal energy on the Eastern Coastal Plain can be utilized at costs below that for electric resistance space heating and, in some cases, at costs only slightly above current oil and natural gas prices, so long as resource and economic conditions are not too unfavorable. Favorable industrial situations should allow use of the resource at costs well below current prices for traditional fuels. Even relatively cool resources (e.g., 110° F) can be utilized at reasonable cost if the wells are not too deep, drawdown is slight, and if demand is sufficiently concentrated. It is also important to note that, in the absence of apparent economies of scale in arranging large district heating systems, it is the concentration of potential demand rather than the overall size of the market which is crucial in determining the economic viability of the geothermal resource. Of course, since concentration tends to increase with overall size of the market area, only cities and towns of at least modest size are likely to offer the opportunities for development. The next section of this report considers the nature of the market in the principal urban area of each of the three study regions.

IV. THERMAL ENERGY USE DENSITY MAPS FOR PRINCIPAL CITIES IN THE MID-ATLANTIC STUDY REGIONS.

For policy purposes, both size and shape of potential markets for geothermal energy are important, since only extensive utilization of the resource will significantly supplant the consumption of fossil fuels. However, the direct application of low temperature geothermal energy involves relatively capital intensive distribution systems, and significant costs are incurred as the thermal energy is transported to the user site. Thus, it is important to know not only the overall size of a potential market, but also its spatial configuration. As part of the market analysis of the three East Coast study regions, the Metro Center developed a series of thermal energy use maps for the principal cities in each region. Maps were developed to show residential space heating alone, residential and commercial space heating, and residential and commercial space and hot water heating requirements for the cities of Norfolk, Va.; Salisbury, Md.; and Atlantic City, N.J. The results are displayed in two-dimensional contour maps (i.e., contours of relatively uniform space and hot water heating energy requirements) and in three-dimensional perspective. The methodology and analysis of the implications drawn from the maps are discussed below.

Methodology

The residential space heating requirements[5] were estimated using 1970 housing data at the census tract level, and parameter estimates provided by Brookhaven National Laboratory (BNL) and the JHU Applied Physics Laboratory (APL). The number of housing units of various types (e.g., single-family detached, those in building of 5 to 9 units, etc.) was compiled for each census tract in each of the three areas from the 1970 Census of Housing. The average annual space heating energy requirements for housing units of each type were taken from estimates supplied by BNL. On the basis of these figures, an average single-family home in the Middle Atlantic Region consumes about 22,000 BTU's (net) per degree day per year. It should be noted that the range of this consumption level is quite large. Consumption varied from 7,000 to 56,000 (i.e., by a factor of eight) within this housing type. Thus, any single figure must be used with caution. Townhouses consumed about 14,000 BTU's per degree day per year, or about 65 percent of the level of the single-family house, with multifamily low-rise apartments consuming about 35 percent and high-rise apartments consuming about 29 percent of the level of a single-family house. The number of housing units of each type in each census tract was multiplied by the appropriate estimate of annual BTU consumption to provide total annual space heating requirements for that tract. This number was then divided by the area of each tract to provide the estimate of BTU consumption per square mile. The area of each tract was measured exclusive of water and large uninhabited areas on the basis of topography and land use maps for each area. The annual BTU consumption per square mile is presented in a series of two- and three-dimensional maps. The two-dimensional maps show contours of equal energy consumption, and the three-dimensional perspective maps illustrate the comparative "heights" of the energy demand within each contour (see Figure 5).

Commercial space heating demand was somewhat more difficult to estimate due to the absence of data at the level of the census tract. Data are available for Standard Metropolitan Statistical Areas (SMSA's) and for counties on the number of employees in each Standard Industrial Classification (SIC) code. The number of employees in the commercial SIC codes (i.e., 50 through 99) was combined with data from studies conducted by Metro Study Corporation, which estimated the average floor space per employee for a number of different types of commercial establishments, and estimates developed by BNL[6] for the average space heating requirements per area of floor space in various types of commercial buildings.

Land use maps for each of the cities or urban areas were used to measure the area which is zoned commercial in each tract. In cases where the spatial aggregation of the employee data was larger than the area to be displayed in the map (e.g., county vs. central city), it was assumed that 90 percent of the commercial activity occurred within the tracted areas, i.e., Atlantic City and adjacent island and mainland communities for Atlantic County, and Salisbury and Fruitland, Maryland, for Wicomico County. The total commercial activity (and the resulting estimate of space heating required) was then allocated to each tract on the basis of the proportion of total commercial area for the urban area contained within that tract. Although such an approach is subject to error due to systematic variations in building height as well as other factors, given the relatively low magnitude of commercial space heating requirements compared to that for residences, the size of errors should not be great.

Hot water demand for residential and commercial sectors was estimated from a population-based formula supplied by BNL, and population data for each census tract. The effect of adding the hot water demand is illustrated in Figures 7 and 8 for Norfolk. Although the general shape of the plot remains about the same, the overall height is slightly raised in a non-uniform fashion. The hot water demand tends to reduce the variation between the peaks and valleys slightly (see points A, B, and C on the two figures). The difference in peakedness results from the differences between population concentration (the basis of the hot water estimate) and concentration of housing types (the basis of the residential space heating demand). Overall, however, the differences are obviously small. The annual thermal energy requirements for hot water and commercial space heating were added to those for residential space heating to complete the data inputs into the mapping program.

Implications of the Map Configuration

The maps of relative annual thermal energy requirements serve an important purpose in illustrating the shape (and hence the length and cost) of a district heating system which would service each area. They are also useful in suggesting the most favorable areas within each city for initiating a district heating system.

Based strictly on population size, the Norfolk metropolitan area would offer the largest potential market for geothermal energy in the three study regions of Southern Coastal New Jersey, the lower Delmarva Peninsula, and the Virginia Tidewater area. Norfolk itself had a 1970 population of just over 300,000, with another 160,000 in Virginia Beach. The coastal communities of of eastern Atlantic County, New Jersey, had a 1970 population of just under 125,000, while the Salisbury/Fruitland area on Maryland's eastern shore had a 1970 population of under 20,000. However, the determination of the costs of delivered geothermal energy, and hence the likely market penetration of this alternative energy source, is greatly influenced by the spatial distribution of this population and the type of housing units it occupies.

Although Norfolk has the largest population of the three areas, and the greatest concentration of thermal energy requirements, the peak is concentrated in the extreme northwestern portion of the area and falls off very rapidly as one moves away from this location. This corner is part of an area managed by the U.S. Department of Defense. Most of the land area of Norfolk has a thermal energy requirement near that of Salisbury, and below much of the Atlantic City region (see Figure 6).

In contrast, Atlantic City has a larger area of relatively high demand which is spread out along the coast. This area is separated by an estuary which isolates it (except for a narrow isthmus) from a strip of lower thermal energy requirement running roughly parallel along the mainland coast (see Figure 10).

Salisbury, being removed from the constraints and incentives on development resulting from a coastline, spread in a radial pattern. Although its peak demand is much lower than either of the other two areas, levels are much more uniform. Its peak is near the central business district and falls off gradually as one moves away from the city center (see Figure 12). Overall, Salisbury has an energy requirement density not much lower than most of Norfolk or the mainland and lower island communities of the Atlantic City area.

These maps indicate that distribution systems designed to serve each of these areas would have very different configurations. In the northwestern corner of

Figure 5. Norfolk Residential and Commercial Space and Hot Water Heating

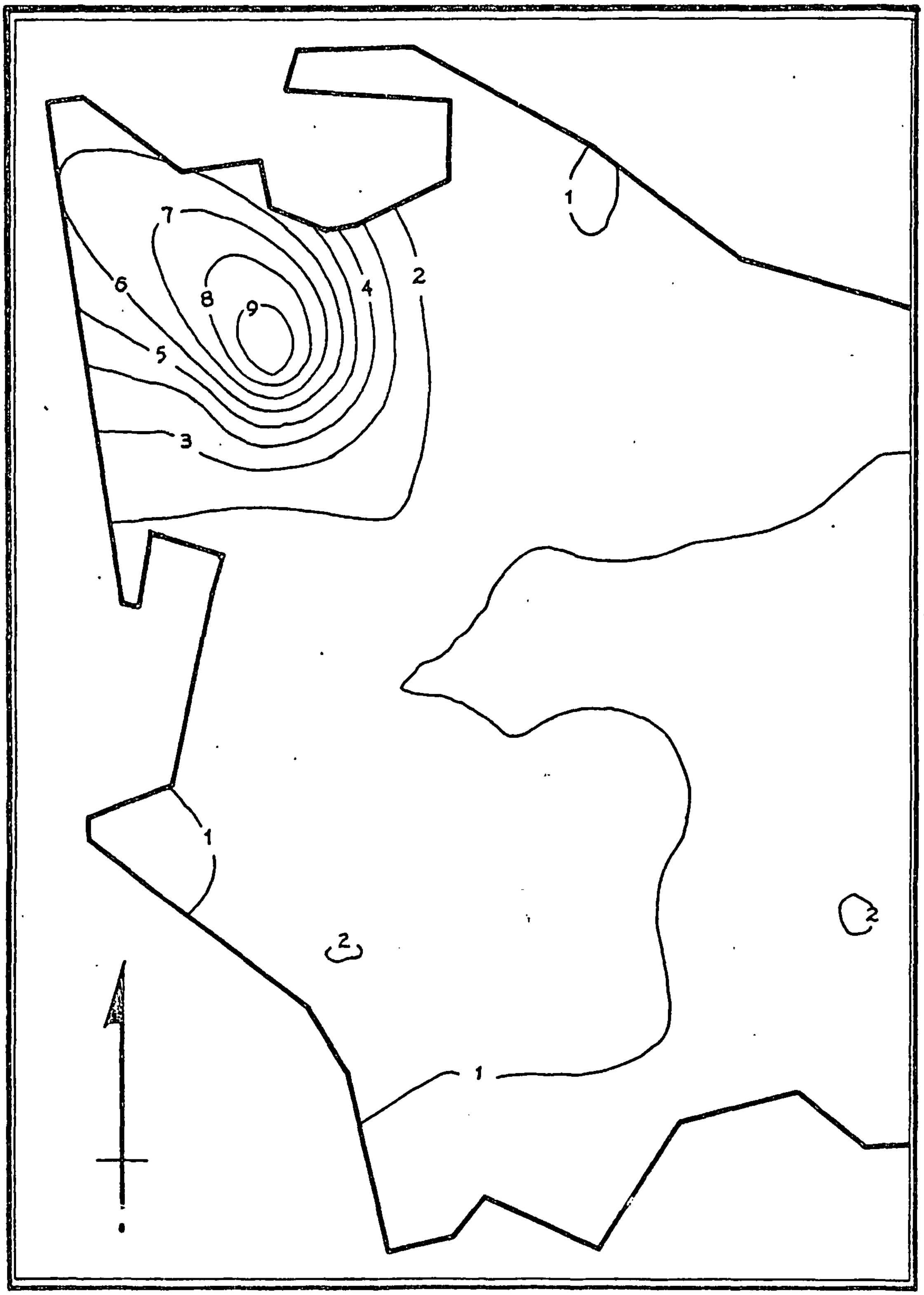


Figure 6. Thermal Energy Requirements for Residences and Commercial Establishments in Norfolk

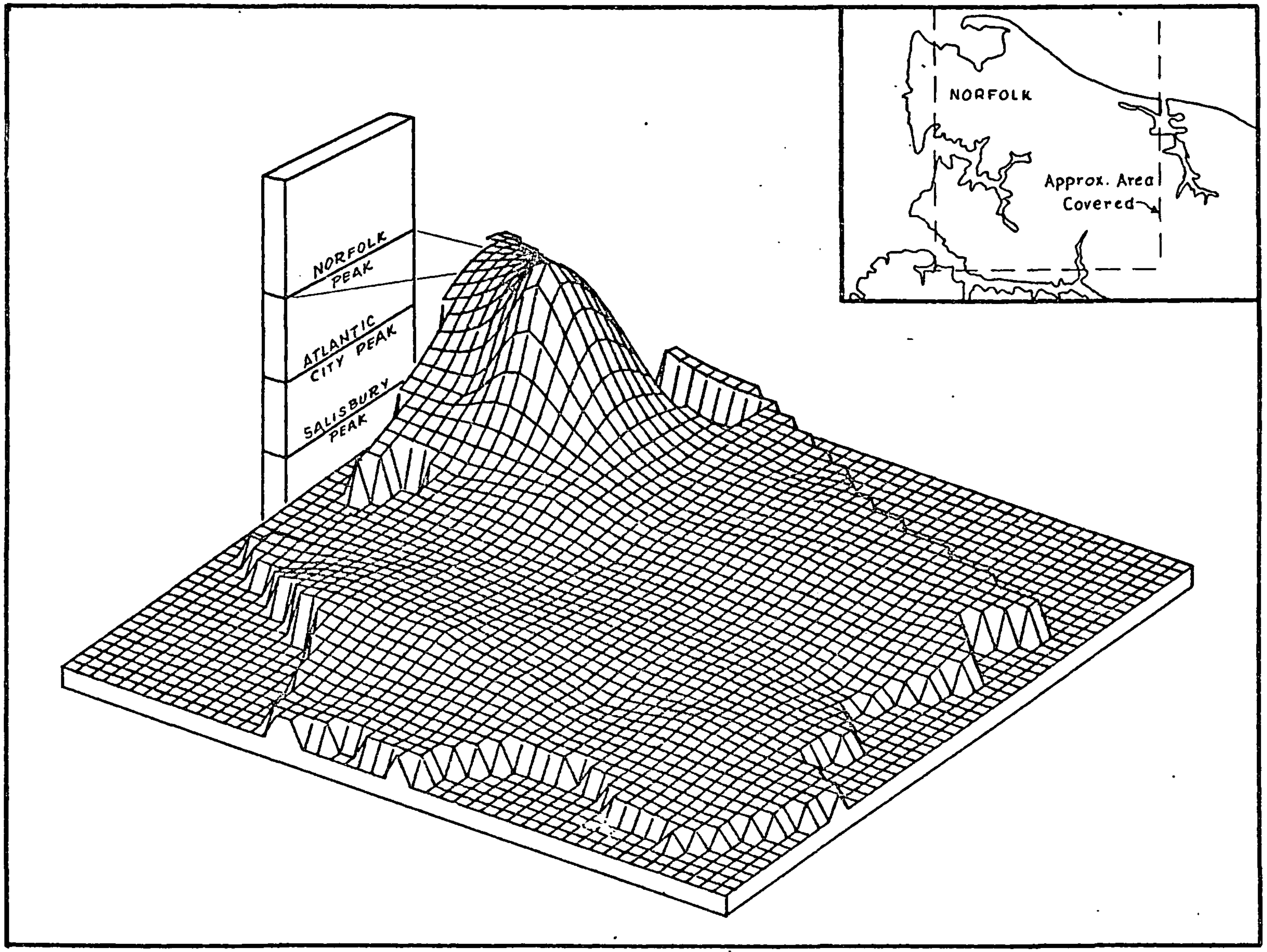


Figure 7. Norfolk Residential and Commercial Space Heating Requirements

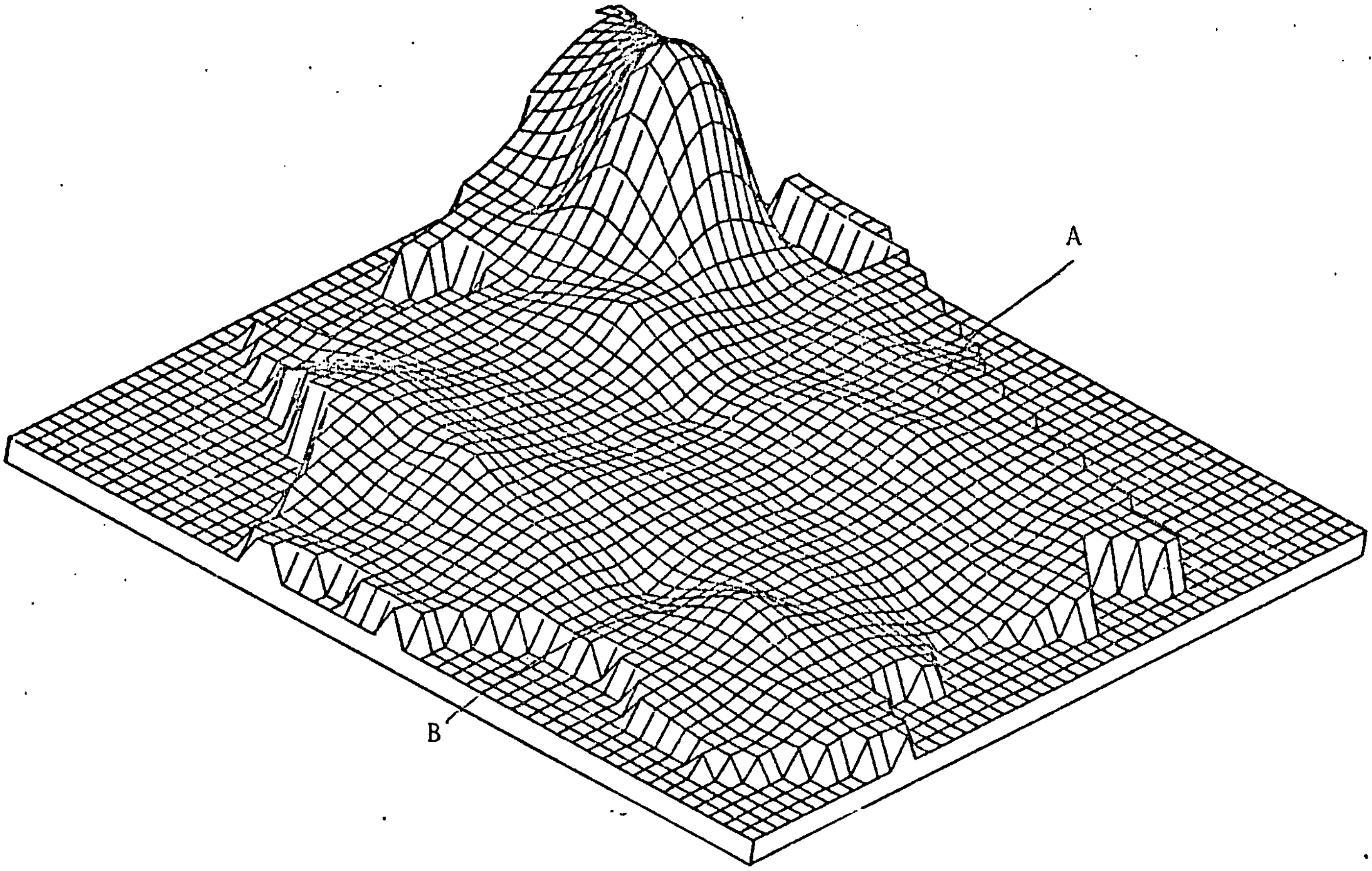
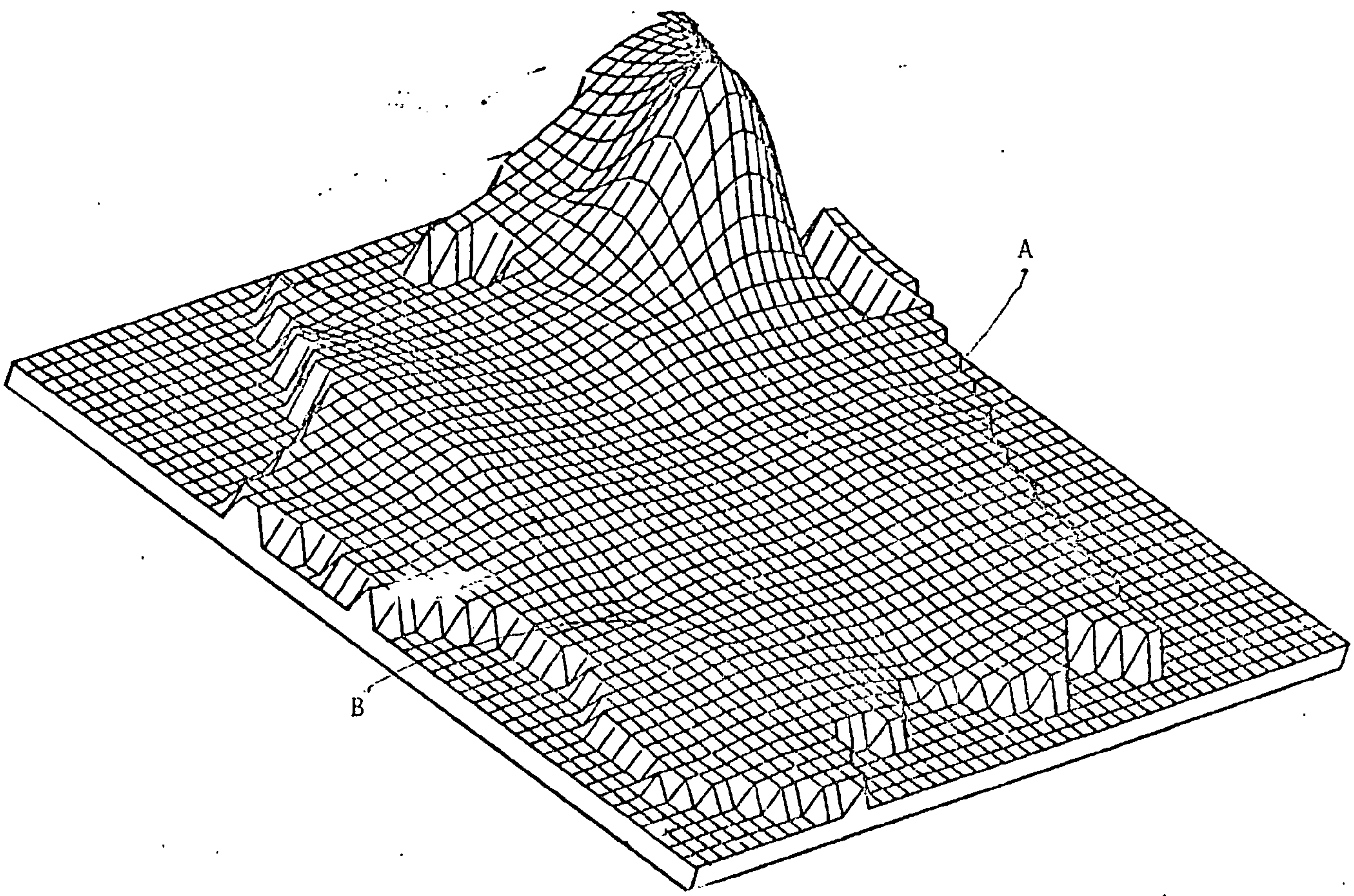


Figure 8. Norfolk Space Heating Plus Hot Water Heating Requirements



Norfolk, the distribution system would be short relative to the level of geothermal energy used. However, if more than this corner were to be served, distribution costs would rise considerably. The average level of the remainder of Norfolk is not too much greater than that for Salisbury, and well below the thermal energy requirement density of Atlantic City and adjacent communities along the coast.

In Atlantic City, the coastal areas could be served most efficiently starting in Atlantic City and then moving south along the coast. It should be noted, however, that some coastal communities have more than a minor portion of their housing units unoccupied during the winter, and so estimates based on housing density tend to overstate the demand for space heating in cities such as Margate and Longport by about 10 percent to 20 percent.[7] The mainland communities such as Pleasantville and Absecon have relatively little seasonal variation in the number of occupied housing units, but the thermal energy requirements are generally low, being lower than those for all mapped areas except for the outer areas of Salisbury. Thus, extension of an Atlantic City based district heating system to the mainland would be discouraged by the lower density of potential demand. The cost penalties of crossing the estuary would likely eliminate any economies of scale in tying in the mainland system to the island system.

A district heating system to serve Salisbury would likely face few natural barriers (e.g., only minor rivers or streams). The relatively uniform energy requirements would tend to favor a system spread out in all directions from the town center.

Figures 9 through 12 show the thermal energy requirement levels for Atlantic City and Salisbury in terms of contours of approximately equal density and the same information displayed in three-dimensional perspective. These may be compared with Figures 8 and 9 for Norfolk. Maps presented are for residential and commercial space and hot water heating.

Figure 9. Atlantic City Residential and Commercial Space and Hot Water

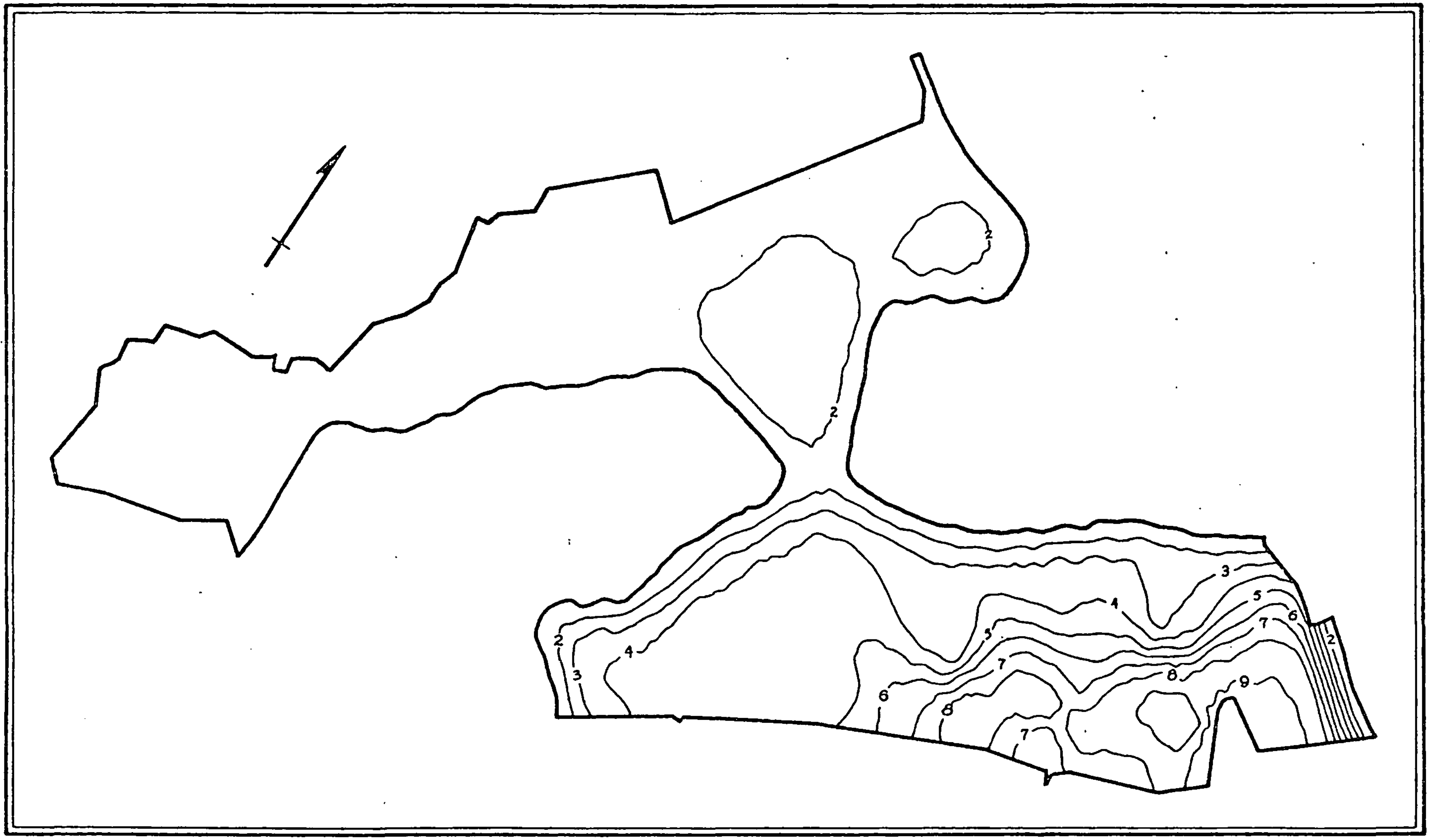


Figure 10. Atlantic City Residential and Commercial Space and Hot Water

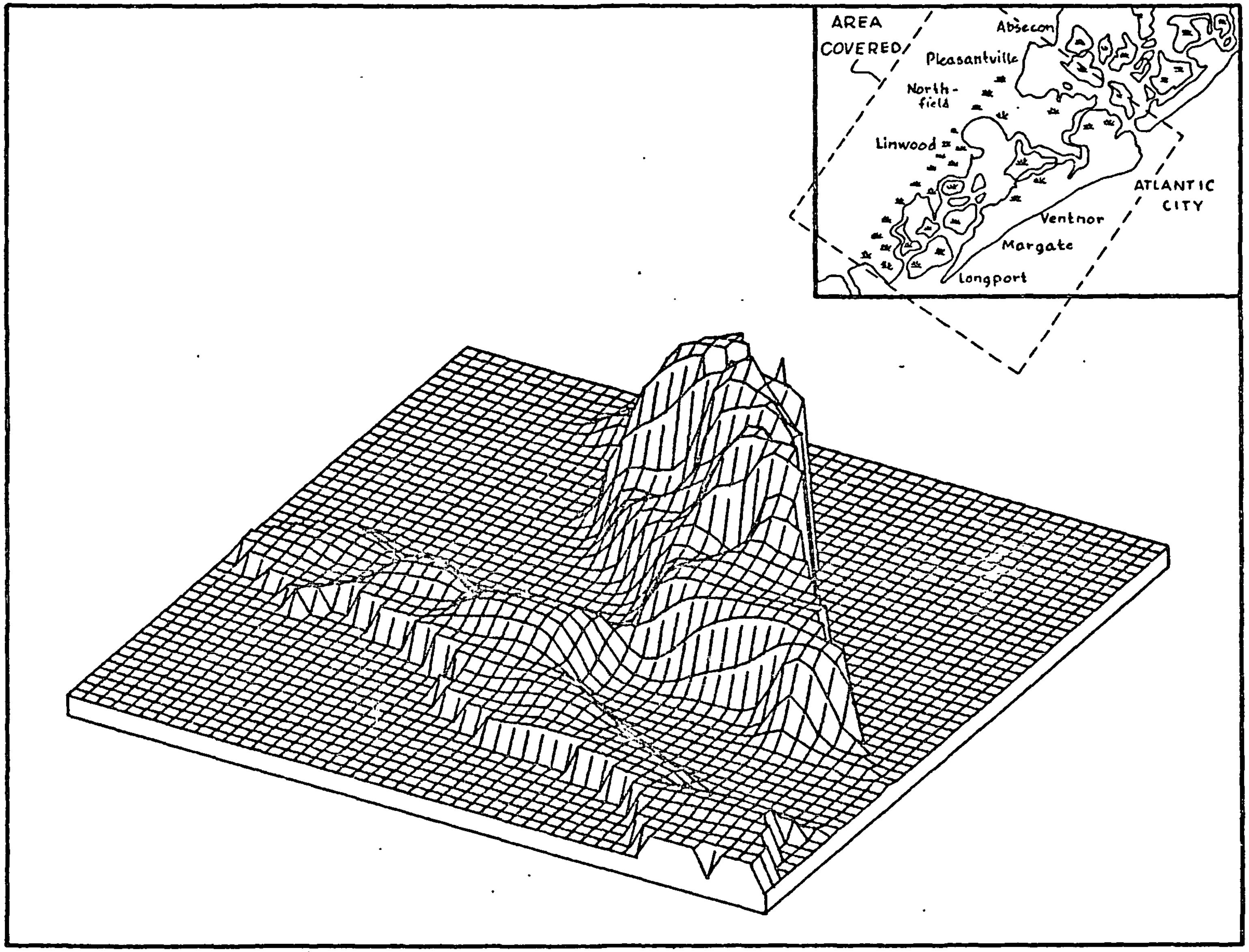


Figure 11. Salisbury Residential and Commercial Space and Hot Water Heating

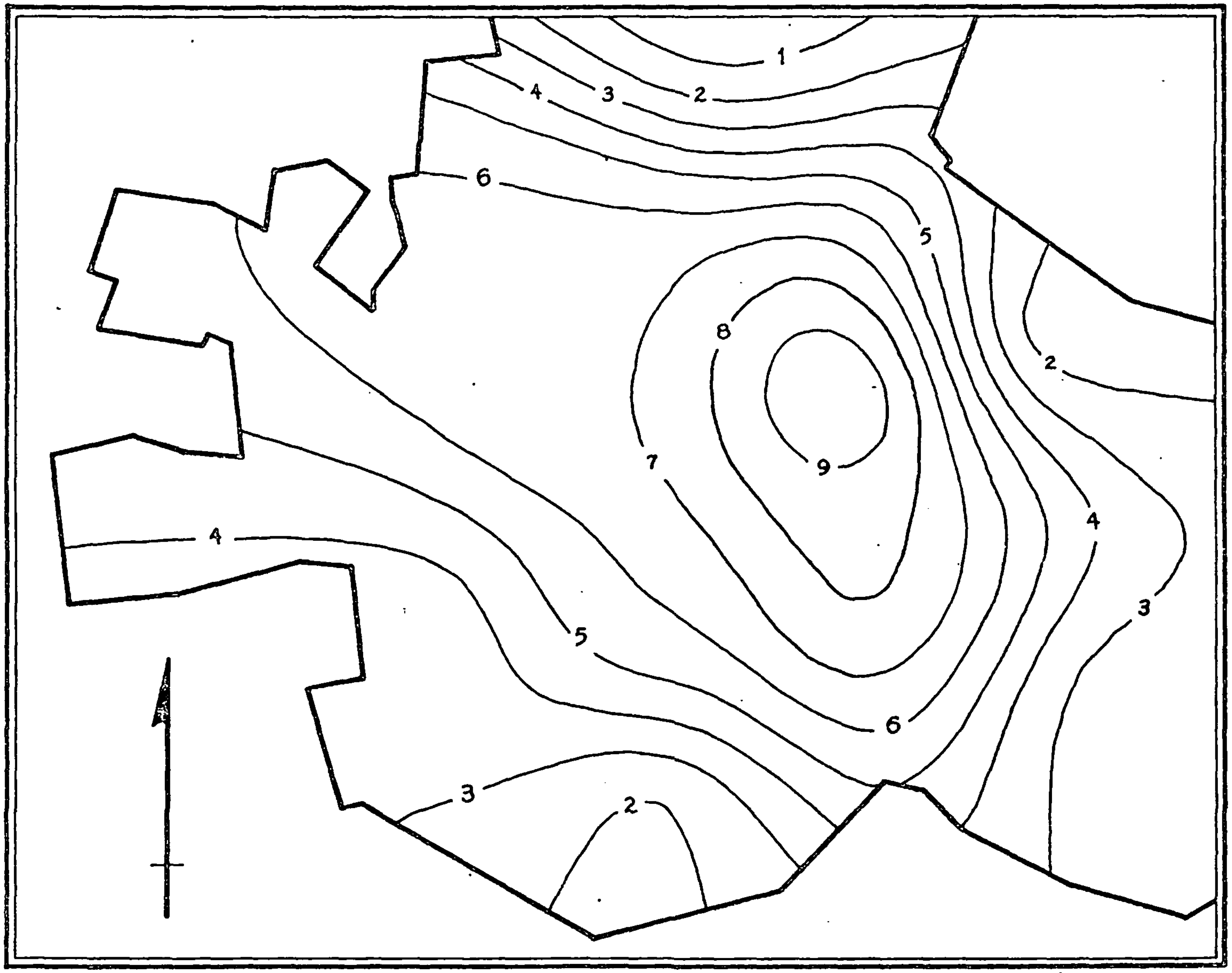
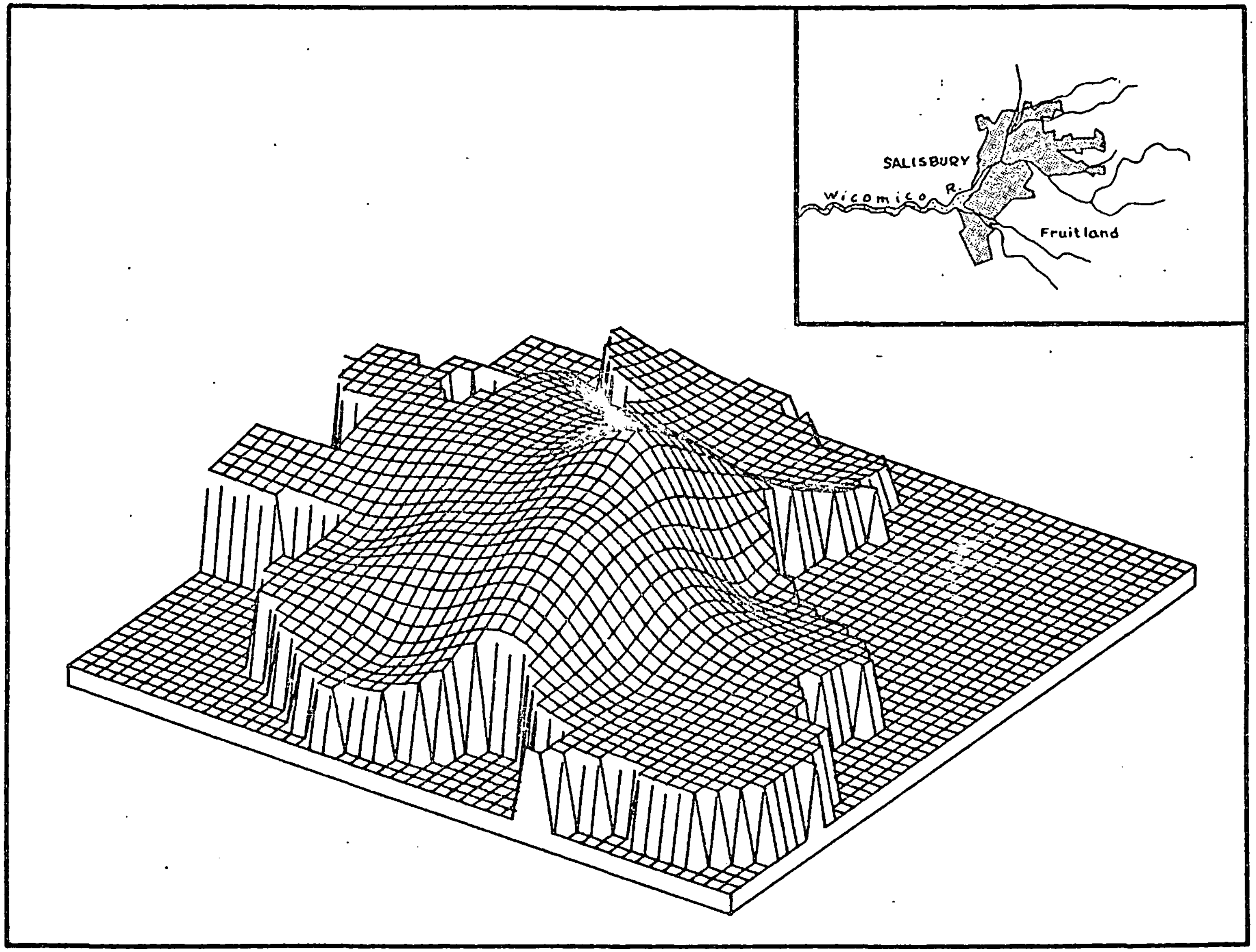


Figure 12. Salisbury Residential and Commercial Space and Hot Water Heating



V. MARKET ANALYSIS OF LOW-TEMPERATURE GEOTHERMAL RESOURCES ON THE EAST COAST: FINDINGS TO DATE

The results of the Geothermal Resources Economic Evaluation Model (GREES) underscore the importance of specific geologic and economic conditions in the determination of average costs for geothermal energy from low-temperature resources. The range of variation in average costs due to parameterization around even a single important resource or economic factor is far greater than differences in climate among the three study regions. However, all else being equal, the colder climates do increase the attractiveness of the resource.

In addition to climate, the three study regions are distinguished by the concentration of thermal energy requirements and in the overall size of the market. The results of the GREES model suggest that housing densities of townhouses or lots between 2,500 and 2,000 square feet or higher offer reasonably good prospects for a geothermal district heating system. At this time, there is no information to suggest possible distinction among the three study cities in regard to likely market saturation levels. Although the higher thermal energy requirement densities in the island portion of the Atlantic City area, and those in the northwestern corner of Norfolk, will offer the most attractive locations strictly in terms of potential demand, such advantages are still comparatively small for saturation levels above about 50 percent. At about 80 percent saturation, the difference in average cost between high rise apartments and townhouses is less than $1.50 per million BTU's. In contrast, differences in resource characteristics can easily result in changes of several dollars per million BTU's in average cost. So long as an area has minimally acceptable densities, any differences in resource conditions, or assessment of risk by potential financiers, would likely have a far greater impact on the attractiveness of the resource than climate or somewhat higher housing densities. Further, it must be remembered that total cost savings on the distribution system in the more populous areas will be restricted by the spatial configuration of the market, as a more circuitous route to reach all high density areas will raise costs. Only the island portion of the Atlantic City region and the northwestern corner of Norfolk have thermal energy requirement densities appreciably higher than most of Salisbury. Labor costs in the larger cities may possibly offset even this advantage.

In the absence of significant economies of scale, the overall size of the market is only meaningful to the extent that the resource can support a high degree of exploitation without losing its temperature or require much greater pumping energy over time. For a demonstration project, the ultimate size of the market should only be important insofar as a demonstrable use of the geothermal energy closer to the large market would stimulate more interest in local resource development than a demonstration program 100 miles away would. Development of the most attractive resource for even a relatively small market may be the most appropriate use of demonstration project funds. The bottom line is, then, that the most geologically attractive resource in terms of temperature, depth, and drawdown, which is near to any of the larger towns or cities, appears to offer the best site for location of the deep well.

VI. DEMAND ELASTICITIES

The state of the art of modeling demand for new energy resources still suffers from numerous conceptual and data availability problems. The Metro Center has reviewed the work of the Mitre Corporation's SPURR model, as well as related work at Oak Ridge National Laboratory and by other researchers on market penetration of appliances and other energy intensive consumer goods.[8]

A favored model in some of these studies is the "S" shaped "logit" curve as shown in Figure 13.

Economic analysis traditionally uses the ordinate axis for cost. A logit model showing market saturation as a function of cost would probably look like one of the graphs in Figure 14: i.e., slow penetration in the beginning until the technology becomes more familiar, then more rapid penetration, and, finally, the remainder of the market, where higher costs faced by more individuals make market penetration difficult. As discussed above, if the retail price of electric resistance space heating is taken as the maximum price for geothermal energy, then this price level would determine point "A". Obviously, the price of the two other principal competing fuels, oil and natural gas, would have a significant influence on the position of the curve, particularly in its lower ranges. Unfortunately, there is very limited historical information for a period of steadily rising real prices for traditional fuels which could be used to econometrically estimate the exact shape of the curve. During the coming year, the Metro Center will continue to examine available studies for further insights into possible methods of estimating the demand elasticity for new energy technologies such as low-temperature geothermal energy.

FOOTNOTES

[1]C. McDonald, C. Bloomster, and S. Schulte, "GEOCITY: A Computer Code for Calculating Costs of District Heating Using Geothermal Resources," Battelle, Pacific Northwest Laboratories, Richland, Washington, February 1977.

[2]R. Weissbrod and W. Barron, "An Economic Analysis of Potential Geothermal Sites on the Eastern Coastal Plain: A Review of Recent Energy Price Projections for Traditional Space Heating Fuels, 1985-2000," Occasional Paper, The Johns Hopkins University Center for Metropolitan Planning and Research, Baltimore, Md., July 1978.

[3]C-E Lind, "Setting the Stage," Swedish District Heating Workshops in the United States of America, 10-20 October 1978, Washington, D.C.

[4]R. Weissbrod and W. Barron, "An Economic Analysis...," op. cit.

[5]The word "requirements" rather than "demand" is used here because the data on which these maps are based implicitly assumes a perfectly price inelastic demand for energy. Since it is plausible that price elasticity would be relatively uniform in the three study areas, if data on price elasticity in the post-1974 period were included, the effect would probably simply be to move the scale of each map down somewhat as real energy prices were increased.

[6]John Williams and Richard Murray, "Commercial Floor Space: An Analysis of the Methodologies Used to Estimate the National Inventory," Metrostudy Corporation, Washington, D.C., 1975; and John Karkheck, E. Beardsworth, and J. Powell, I.E.C.E.C., 1977.

[7]1970 U.S. Census of Housing.

[8]The Mitre Corp., "A System for Projecting the Utilization of Renewable Resources, SPUR Methodology," McLean, Va., September 1977; W. Lin, E. Hirst, and S. Cohn, "Fuel Choices in the Household Sector," ORNL, October 1976; E. Hirst and J. Carney, "The ORNL Engineering-Economic Model of Residential Energy Use," ORNL, July 1978; J. Hausman, "Consumer Choice of Durables and Energy Demand," MIT, January 1978; J. Griffin and P. Gregory, "An Intercountry Trans-Log Model of Energy Substitution Responses," American Economic Review 66 (1976):845-857.

[9]American Petroleum Institute, "1976 Joint Association on Drilling Costs," 1977.

APPENDIX A

MODEL DESCRIPTION

The GREES model is an economic accounting system which estimates average costs per unit of energy for geothermal-based space or process heating. The model is also designed to optimize the relative sizes of a geothermal base plant and fossil fuel peaking plant in a hybrid system. In its present form, the GREES model deals primarily with economic as distinct from financial costs. Financial considerations such as allowable rates of depreciation and other tax considerations, as well as rates of return, expectations regarding the price of traditional fuels, and uncertainty due to unresolved institutional issues, may well prove crucial to prospective developers. Some of these financial considerations, such as depreciation rates and level of uncertainty, can be addressed indirectly through changes in the capital charges as reflected in the capital recovery factors used in the model. Inclusion of rates of return would require minor modifications to the model. At this preliminary stage in the evaluation of the geothermal resources, the refinement of the economic cost estimates is more relevant, since it is economic efficiency issues rather than financial considerations which are the primary concern of public policy at this stage.

The model calculates average costs at the well-head and average costs for energy delivered to the door step or plant gate. Average costs for the geothermal portion of the hybrid system (i.e., well-head costs) are provided separately. Capital costs for the distribution system are also provided. Figure A-1 outlines the structure of the model.

Although hookup charges (i.e., costs for installed connecting pipe running to the door step and for water meters) are included, in-house or in-plant equipment for a water-to-air heating system is not included.

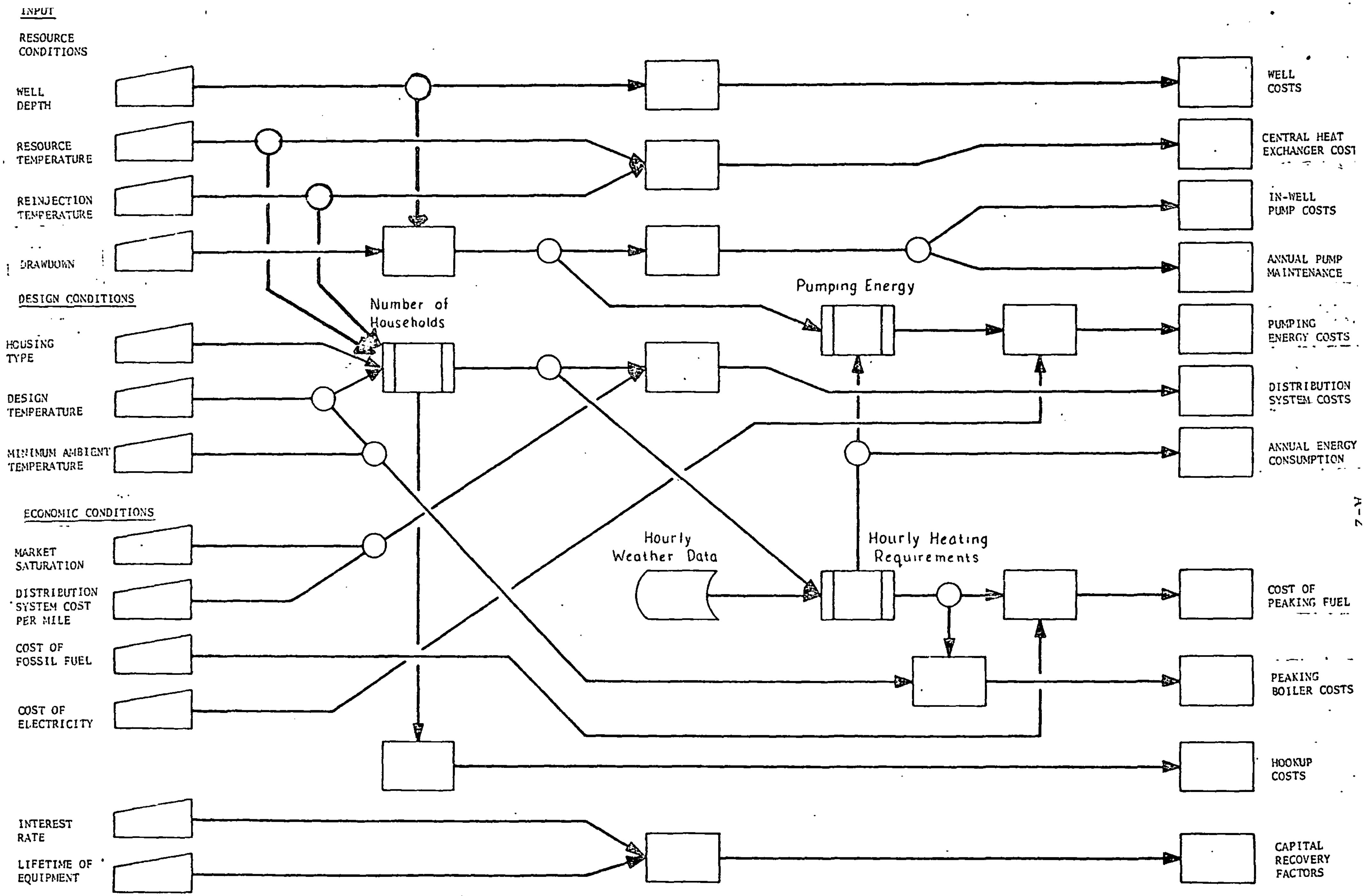


Figure A-1 The GREES Model

This section of the paper is a narrative description of the GREES model, and describes in full detail the computational relationships and some of the specific numerical values used in the model. It should be noted that, in many cases, the cost estimates were derived from applications which differ somewhat from those for a low temperature geothermal system. It is to be expected that some of these estimates will be refined as better data become available.

The Residential Subroutine

The residential portion of the model computes average costs by summing the annual costs of each system component and dividing this total cost by the number of BTU's sold to participants in the system. The cost components comprising the numerator area the production and reinjection wells, in-well pumps, well-head heat exchanger, distribution system, hookup charges, the peaking system fossil fuel boiler (each of these components is multiplied by the appropriate capital recovery factor); and the annual in-well pump maintenance costs, in-well pumping energy (to maintain the required flow rate), and the annual cost of fossil fuel used for peaking. The value comprising the denominator is the total number of BTU's of space heating energy required annually by participants in the system (for a district heating system, this is a function of housing type and weather). Except where otherwise stated, specific values were obtained from the Applied Physics Laboratory.

$$AC = \frac{CRF_w(W_u+W_d)+CRF_p(P)+M_p+P_e+CRF_d(D)+CRF_e(E)+CRF_h(H)+CRF_b(B)+F}{\text{Total BTU's Required}}$$

CRF_i = capital recovery factor for component i (a function of interest rate and life expectancy)

W_u = production or "up" well cost

W_d = reinjectio[illegible] "down" well cost

P = in-well pump cost

M_p = annual maintenance of in-well pumps

P_e = annual in-well pumping energy cost

D = distribution system cost

E = well-head heat exchanger cost

H = hookup cost

B = peaking system boiler cost

F = peaking system fossil fuel cost

Total BTU's: based on formula using hourly ambient temperature levels, with modification for specific housing types.

Well Costs

The well cost estimates are a function of depth. The user of the model inputs the expected depth of each well. Default values are 5,500 feet for the production well and 2,500 feet for the reinjection well. These well costs are about $225,000 and $100,000 respectively. The formula for all costs is[9]

$$x = \text{depth (in feet)}$$

$$\text{Cost} = x([(d \cdot x + c)x + b]x + a)$$

where $a = 28$

$b = -3.833 \times 10^{-3}$

$c = 1 \times 10^{-6}$

$d = -4.17 \times 10^{-11}$.

These costs are in 1976 dollar values and are inflated to 1978 levels by

$1978\$ = (1.2578554)^2 \cdot (1976\$)$.[1]

Pump Cost

Pump costs are determined by the following formula: $170 x horsepower, where the horsepower requirement is determined by (.184 x well depth x drawdown -7.7). Annual pump maintenance costs are taken as $65 x horsepower.

Pumping Energy[2]

Pumping energy for the production well is a function of yield from the well (determined by such characteristics of the aquifer as saturated thickness and permeability) and of heating demand. The characteristics of the aquifer are accounted for through a user-specified average in-well drawdown which is assumed to result from pumping levels to maintain a flow rate above that which would result from artesian pressure. The default drawdown level is 50 percent of the depth of the well (i.e., over the course of a heating season, pumping requirements varying up to 500 gallons per minute from the well result in a drawdown which averages 2,750 feet). If the well were operated around the clock for an entire year, the number of kilowatt hours of electricity required is given by the following formula: 1500 x well depth (in feet) x percentage drawdown - 63,000. Demand for heat is a function of the ambient temperature, the number of households, and the type of dwelling unit. Demand at ambient temperatures at or above the design temperature is used to calculate the flow rate from the well required to supply sufficient BTU's to the system. Average hourly weather data for the major city climatically closest to the study area are used to estimate the length of time the demand would remain at a given level. Although pumping energy is a nonlinear (convex) function of flow rate, the model uses a linear approximation of the fraction of the energy required to maintain that rate compared to the energy for a 500-gallon per minute flow rate. (The linear approximation was purposely used to make the pumping energy estimates more conservative, by slightly overstating the pumping energy required at most levels.) The number of hours at each flow rate is then multiplied by this fraction to obtain "full pumping equivalent hours," which are then summed and taken as a fraction of the number of hours in a year. The model calculates the energy required for around-the-clock pumping at 500 gallons per minute on the basis of user-specified drawdown and well depth. This value is then multiplied by the fraction described above to obtain the estimate of actual pumping energy required. The user also specifies an electric charge per kilowatt hour. The default value is 4¢ per kilowatt hour.

Demand for Space Heating

The demand for space heating energy per hour in a single-family detached large home is determined from the Idaho National Engineering Laboratory (INEL) formula: $(65 - T_0) \times 1200$.[3] This demand is modified for other types of homes through the use of fractions derived from estimates supplied by Brookhaven National Laboratory (BNL)[4]. Thus, the formula used in the GREES model to determine the hourly demand on the system is

$$(65 - T_0) \times 1200 \times h_i \times N_i,$$

where h_i is the fraction of space heat required by other types of houses relative to the single-family detached, and N_i is the number of houses of type i which are on the system. The heating demands for the five housing types used in the model are

Type	
1. Single family suburban	1.00
2. Single family dense	1.00
3. "Townhouse" or "rowhouse"	0.65
4. Garden apartment	0.35
5. High rise apartment	0.29

The calculation of N_i is described below.

The average number of hours during which the ambient temperature is in a certain range is given in Table A-1. Wilmington, Del., and Richmond, Va., have annual heating degree day levels very close to those in Atlantic City and Salisbury, respectively. Differences in the shape of the distribution of the temperatures between the city under consideration and the city for which the hourly data were available should c[illegible]e only minor distortion in the calculations.

Well-Head Heat Exchanger Cost[5]

The well-head heat exchanger cost is a function of the Δt, i.e., the

Table A-1. Average Hourly Temperatures (number of hours)

	Temperature												
	0/4	5/9	10/14	15/19	20/24	25/29	30/34	35/39	40/44	45/49	50/54	55/59	60/64
Wilmington	1	9	39	107	200	369	682	816	752	708	668	731	721
Richmond	1	-	11	28	186	307	533	702	710	712	695	704	758
Norfolk	-	-	14	61	175	371	558	558	727	724	668	757	820

difference between the water temperature at the well-head and the temperature at which it is reinjected. The user inputs resource temperature with a reinjection temperature of either 75° F or 85° F. The default values are 160° and 85°, which result in a cost of $5.00 for the well-head heat exchanger. Each resource and reinjection temperature pair also yields a specific number of net BTU's which are extracted from the geothermal well at a given flow rate. Table A-2 displays selected values for the net BTU's delivered to the distribution system per hour at a 500-gallon per minute flow rate.

Hookup Charges

Hookup charges for a connecting pipe to the household and a water meter are estimated to be about $380 for single family houses, $340 for townhouses, $60 for garden apartments, and $35 for high rise apartments. The higher costs for the single family and townhouses reflect the assumption that each would require its own pipe and meter, while the apartments would share pipe and meter costs. The initial cost data for the hookups were taken from GEOCITY, but were modified to a considerable extent by the Metro Center.

Boiler Size

The boiler for the peaking system is sized by computing the difference in heating demand at a predetermined lowest temperature for which full heating is planned and the demand at the design temperature. The default value for the lowest temperature is -5° F, and the design temperature is +36° F. Using the INEL formula shown above,[6] the total demand per hour, when the temperature is at the design minimum, is $(65 - T_{min}) \times 1200 \times h_i \times N_i$. However, since the geothermal system supplies heat down to the design temperature (e.g., 36° F), the formula becomes $(DT - T_{min}) \times 1200 \times h_i \times N_i$, where "DT" is the design temperature below which the peaking system comes into use. The boiler costs (including buildings for the boilers) are estimated at $1,500 per 100,000 BTU's

Table A-2. Net BTU's Delivered to the Distribution System Per Hour at 500 Gallons per Minute Flow from the Well (in millions of BTU's)

		Resource Temperature		
		120° F	160° F	200° F
Reinjection Temperature	85° F	8.8	18.8	28.8
	75° F	11.3	21.3	31.3

per hour of capacity.

Fossil Fuel Requirements

The fossil fuel requirements are derived from the hourly weather data. For each temperature below the design temperature, the demand not met by the geothermal system is computed and multiplied by the average number of hours in a year during which the ambient temperature is expected to be at that level. The price of the fossil fuel is a user-specified input with a default value of $4.50 per million BTU's.

Cost of Distribution System [7]

The cost of the distribution system is found by multiplying the total length of the system by a user-specified cost per mile of installed insulated dual pipe (including return pipe), with a default value of $250,000. This amount is just above the cost suggested in BNL's Utah study,[8] and is the median value of pipe costs surveyed by John Beebee ("Cost of Hot Water Pipes," op. cit.)

Length of Distribution System

The length of the distribution system is determined by the number of households and their density and the market saturation level. Density levels for various types of houses are taken from GEOCITY, and converted to a block density based on a grid system of 400' by 200' blocks (street center to street center). This results in the following densities per block:

single family suburban	7 households
single family dense	12 households
townhouses or rowhouses	30 households
garden apartments	60 households
high rise apartments	108 households

The garden and high rise apartments were constrained to their GEOCITY "building" size and thus only one building of either type could occupy a block in this model. The number of households is divided by the appropriate density level to determine the number of blocks they would occupy. The length of the distribution system is then measured directly based on the block length. This is the length which would occur under 100 percent saturation. To account for non-participation by some households, the length of the system is multiplied by the reciprocal of a user-specified market saturation level (default value is 80 percent).

Capital Recovery Factors[9]

While the in-well pump maintenance, pumping energy, and fossil fuel requirements are calculated directly on an annual basis, the remaining cost components must be annualized through the use of a capital recovery factor (CRF) which reflects the cost of borrowed funds and the specific life expectancy of individual system components. The interest rate is generally taken as uniform for all system components under a given model run. Although a developer might choose to amortize all system components over a single period in calculating his financial costs, the actual life expectancy of each component is the more relevant factor in determining economic costs.

The values for the capital recovery factors, the well costs, pumps, heat, and exchanger are determined directly from user-specified or default values. The capital recovery factor reflects the annual payment required to repay a loan at "i%" interest over "n" time periods. The formula is

$$\frac{i}{(1 + i)^n - 1} + 1 .$$

Table A-3 shows the capital recovery factors for a range of interest rates and repayment periods. The repayment periods used in the model are based on the life expectancy of each system component. As noted above, this is an economic rather than a financial approach. Wells are expected to last about 20 years, the distribution system and hookups about 30 years, the well-head heat exchanger and in-well pumps about 10 years. These lifetimes are the default values which may be changed. Thus, a financial, as well as an economic approach, can be

Table A-3. Capital Recovery Factors

		Repayment Period				
		10 years	15 years	20 years	25 years	30 years
Interest Rate	8%	.149	.117	.102	.094	.089
	10%	.163	.131	.117	.110	.106
	14%	.192	.163	.151	.145	.143
	18%	.222	.196	.187	.183	.181

simulated.

Other Cost Components

It is apparent that, while several cost components are calculated directly, other costs are the results of interactions among a number of factors. Calculation of the number of households, while not a direct part of the costs, is needed to determine a wide range of component costs, including hookup charges, the distribution system, as well as total demand. The number of households on the system is determined by calculating the peak energy demand at the design temperature from the INEL formula[10] with the appropriate modifications for the housing type. The energy delivered net to the distribution system from the well is a function of the resource temperature at the well-head, the reinjection temperature, and the flow rate. Taking the maximum flow rate of 500 gallons per minute, assumed in the model, the net BTU's delivered to the system per hour are the values shown in Table A-4. The number of net BTU's is divided by the demand per household of a given type at the design temperature and this gives the number of households which can be served assuming negligible heat losses in the system.

Marginal Costs

Through changes in the design temperature (and consequent changes in the number of households and total energy supplied by the hybrid system), marginal costs of adding additional households (of a particular type and density) can be estimated. It is also possible to show the marginal costs of replacing additional BTU's of fossil fuel through changes in the size of the district heating system and [illegible] the relative sizes of the geothermal base and fossil fuel peaking plants. These results, as well as the average cost estimates under a wide range of resources and economic conditions, are described in the section on model runs.

Industrial Subroutine

The industrial version of the GREES model calculates average well-head cost per million BTU's based on a user-specified "utilization factor." A 100 percent utilization factor would require around-the-clock pumping at 500 gallons per minute and the sale of all the net thermal energy delivered at that pumping rate. Since the thermal energy could probably not be inexpensively stored, such a utilization would require continuous use of all energy output from the well, and so is not likely to be typical. The default utilization factor is 25 percent. Weather data, distribution costs, and other factors related to residential demand are, of course, bypassed in this subroutine.

Areas of Further Improvement

Relatively little information was readily available at the outset of this project which was directly applicable to the economic analysis of low temperature geothermal resources; much of it had to be culled from diverse sources. Whenever information is taken from a wide range of sources and modified to meet somewhat different uses, refinements over time are inevitable. The GREES model is highly flexible with regard to its ability to accept new data. As new information becomes available, the user can input these or the default values can be changed. Modification of the cost equation to include ground level pumping (currently assumed to be negligible) or rate of return to investors or other factors can be easily accomplished when such refinements are warranted.

Specific areas of improvement in the residential portion of the model would include optimization of a 3-part hybrid system including heat pumps; the capability of creating a heterogeneous neighborhood composed of different housing types; calculation of distribution costs to reflect changes in pipe diameter as the system is expanded; direct calculation of resource temperature from user-input well depth and temperature gradient; changes to allow values currently set in the model (e.g., pump cost) to be changed by the user; inclusion of a three-part hybrid system including heat pumps; and inclusion of additional cost components to reflect metering costs, and other systemwide operation and maintenance expenses. The industrial model can be improved through use of several utilization factors to reflect the duration of a peak demand and demands below peak so that a multiple user system can be simulated and optimized.

Much of the effort devoted to the development of the GREES model has been directed to refining its structure to account for the interrelationships among the major economic cost considerations, while providing the flexibility to optimize the mix of the geothermal and fossil fuel plants, and to reveal certain types of marginal costs. The structure of the model appears to be appropriate for the estimation of the relevant economic costs, and only minor modifications to its basic structure should be necessary. However, to expand the uses of the model, subroutines will be developed to evaluate the entire stream of costs over the life of the project under user input values for changes in variable costs, the rate of inflation, and projected price trends for competing fuel systems. This capability will be valuable in helping to assess the attractiveness of resource development by entrepreneurs, public or private.

FOOTNOTES

[1] For well costs, see D. Skiba, "Wellhead Costs for Geothermal Energy," QM-78-126 (26 June 1978), The Johns Hopkins University Applied Physics Laboratory, Laurel, Maryland; D. Skiba, "Wellhead Costs for Geothermal Energy - Ocean City, Maryland," QM-78-192 (23 August 1978); D. Skiba, "The Contribution of Reinjection Well Power Demands to the Wellhead Costs for Geothermal Power," QM-78-135 (7 July 1978); E.L. Fox, "Contribution of Well Costs to the Price of Geothermal Energy," QM-78-078 CLA-1543 (1 June 1978); F.C. Paddison, "Cost of 7000 Foot Well - Eastern Coastal Plain," QM-78-195 (22 August 1978).

[2] For information on heat pumps, see C.A. Wingate, Jr., "The Use of a Heat Pump at the Well Head," QM-78-171 S48-2-275 (8 August 1978); C.A. Wingate, Jr., "Heat Pump System Design Charts for Geothermal Heat Pump Selection," QM-78-200 AS-053 S45-2-280 (6 September 1978), The Johns Hopkins University Applied Physics Laboratory, Laurel, Maryland.

[3] U.S. Department of Energy, Idaho Operations Office, Rules of Thumb for Geothermal Direct Applications. Report prepared by the Idaho National Engineering Laboratory (INEL), September 1978.

[4] W.F. Barron and W.J. Toth, "BNL Progress Report to DOE/DGE," QM-78-227 AS-062 (5 October 1978), The Johns Hopkins University Applied Physics Laboratory, Laurel, Maryland.

[5] See Roy von Briessen, "Flow Rates to Meet Required Heat Loads," QM-78-160 (28 July 1978); R.W. Newman, "Heat Exchange Costs," EAM-5797 AS-039, QM-78-164 (11 August 1978); Roy von Briessen, "Residential Water to Forced Air Heat Exchange Cost Near Ocean City," QM-78-183 (14 August 1978), The Johns Hopkins University Applied Physics Laboratory, Laurel, Maryland.

[6] U.S. Department of Energy, Idaho Operations Office, Rules of Thumb..., op. cit.

[7] See U.S. Department of Energy, Idaho Operations Office, Rules of Thumb..., op. cit.

[8] See W.F. Barron and W.J. Toth, "BNL Progress Report...," op. cit.

[9] See W.F. Barron and W.J. Toth, "BNL Progress Report...," op. cit.

[10] U.S. Department of Energy, Idaho Operations Office, Rules of Thumb..., op. cit.

APPENDIX B

RUNNING THE GREES MODEL

The Geothermal Resource Economic Evaluation System (GREES) calculates average cost per million BTU's, as well as the annual cost of each system component, and nonmonetary values, such as the number of households, length of the distribution system, and level of pumping energy required. The values of most system inputs can be changed by the user of the program, thus permitting the determination of the impact on average costs, specific annual costs, and nonmonetary values due to changes in a certain parameter. For example, the user may change the resource temperature, and follow its impact on the number of households on the system, as well as the change in average cost of delivered thermal energy. If a parameter value is not changed, the program implements its default values. The default values are displayed in Table B-1.

The GREES program may be accessed through the DEC-10 computer facility at The Johns Hopkins University, Homewood Campus. After the user has entered the system and accessed the program, by typing RUN GREES, a brief introduction is printed. The introduction is followed by a list of parameters and their corresponding option numbers. The program will then ask which parameter the user wishes to change by printing out OPTION ?.

The user simply types in an option number from 10 to 31, associated with the parameter of interest, and then pushes the return key. The program will specify the unit of value to be used (e.g., cost in thousands of dollars per mile), and wait for input. For some parameters, e.g., reject temperature, a limited range of values is accepted by the program. These values are displayed on the screen. If the user types in an unacceptable value, the message is repeated.

Table B-1. Current Residential Scenario Parameters

Option	Current Residential Scenario Parameters			Value
10	Area under consideration:			Salisbury
11	Well-head water temperature (°F):			160
12	Depth of upwell (feet):			5500
13	Housing type:			3
14/24	System design temperature (°F):			36
15/27	Capital equipment	Yrs.	Int.%	
	Wells	20	12.00	
	Distribution system	30	12.00	
	Heat exchanger	10	12.00	
	In-well pumps	10	12.00	
	Hookup costs	30	12.00	
	Peaking boiler	20	12.00	
--	Original pump costs:			$ 84711
--	Annual pump replacement costs:			32390
18	Cost per hookup:			384
19/25	Market saturation by geothermal (%):			80.00
20	Cost of electricity (¢/kwh):			4.000
21	Reject temperature (°F):			85
22	Pipe cost calculation ($K/mi.)			I = 250
23	Depth of reinjection well (feet)			2500
26	Drawdown of upwell (%)			50.00
--	Full pumping energy (megkwh/year):			4.07
28	Minimum ambient temperature (°F):			-5.
29	Fossil fuel cost ($/megBTU)			4.50
30	Boiler cost ($/100K BTU)			$ 1500.00

After typing in the value for the parameter to be changed from its default value, the user hits the return key and the program responds by again printing OPTION?. After all desired changes have been made, the user may check the current set of values before execution of the program by calling Option #1. Options 7 and 8 execute the program and print out only average costs or full details (see Table B-2) respectively.

After execution of the program and the display of average cost or full program results, the program indicates its readiness to begin assembling another set of values for a second run by again printing OPTION?. When the user has completed all the runs he wishes to make, he types in 9 in response to OPTION?.

The values from the previous run are retained for the next run unless the user changes them. Thus, if the well depth on the first run is changed from its default value of 5,500 feet to 7,000, the well depth value will remain 7,000 for the second run, unless changed again by the user.

The first ten options are methods for manipulating the operation of the program, rather than for altering parameter values.

OPTION ? 1

The list of current parameter values is displayed on the screen. (This is useful as a check before executing the program.)

OPTION ? 2

Name of file to receive the printed (hardcopy) output of the runs of the model. DEC-10 file names must be in the following format: 6 letters period 3-letter extension; e.g., ATLNTC.WDT. No blanks or special letters may be used in the file name. If the user simply hits the return key without specifying a file name, data for the runs will not be stored for a hardcopy.

OPTION ? 3

Return to default values. (Useful to "clear" the program when making a separate set of runs in which a different set of parameters is being

Table B-2. Results of Residential Model

Length of distribution system:	2.62 miles
Number of households:	829
Total geothermal BTU's (millions):	59347.04
Total system BTU's (millions):	64828.71
Percentage geothermal utilization:	36.13
Percentage service geothermal:	91.54
Pumping energy:	1.471 million kwh
Annualized costs (thousands of dollars)	
Well costs:	50
Distribution system costs	81
Heat exchanger costs:	15
Original pump costs:	15
Hookup costs:	39
Annual replacement costs:	32
Annual pumping costs:	59
Peaking boiler costs:	53
Fossil fuel costs:	25
Total annual well-head costs:	171
Well-head cost per geo. megBTU($)	2.90
Total annual system costs:	370
System cost per megBTU($):	5.70

manipulated.)

OPTION ? 4

Title of the run (up to 60 characters).

OPTION ? 5

Select the residential or industrial subroutine. (The specific features of each routine are described in the body of this report.)

OPTION ? 6

Displays the results of the scenario most recently executed.

OPTION ? 7

Executes the program and prints out only average cost per million BTU's on the screen.

OPTION ? 8

Executes the program and prints out detailed results for each component cost and most intermediate values (e.g., # of households).

OPTION ? 9

Ends the execution of GREES and returns the user to the DEC-10 monitor mode.

To obtain the printed (hardcopy) results of the model runs after using Option 9, the user types PRINT filename/DEL/FILE:FOR. If extra copies are desired, the command is PRINT filename/DEL/FILE:FOR/COPIES:n, where n is the number of copies desired. The file name, of course, must be exactly as specified in Option 2.

Options 10 through 31 are used for changing parameter values. These options are displayed below.

Option No.	Parameter
10	Area under consideration 1 - Atlantic City 2 - Salisbury 3 - Norfolk
11	Water temperature at well-head (degrees Fahrenheit)

Option No.	Parameter
12	Depth to Aquifer (in feet)
13	Housing type, either 1 - single family suburban 2 - single family dense 3 - townhouses 4 - garden apartments 5 - high-rise multi-family housing
14	Design temperature of system (degrees Fahrenheit)
15	Capital equipment life for: 1 - wells 2 - distribution system 3 - heat exchanger 4 - hookup costs 5 - in-well pumps 6 - peaking system boiler (fossil fuel)
18	Cost per hookup (dollars)
19	Market saturation by geothermal (in percent)
20	Cost of electricity (cts/kwh)
21	Reject temperature (degrees Fahrenheit)
22	Calculation of pipe costs: F(unction) - using functional relationship I(nput) - as user input
23	Depth of reinjection well
24	Stepwise design temperature of system (& data for plotting)
25	Stepwise market saturation by geothermal
26	Well drawdown (in percent)
27	Interest rate (in percent)
28	Minimum ambient temperature (degrees Fahrenheit)
29	Fossil fuel price (dollars per kwh)
30	Boiler cost (dollars per hundred thousand BTU's)
31	Industrial utilization factor (percent)

A hypothetical run of the GREES model is illustrated below.

Option No.	Parameter
12	Depth to Aquifer (in feet)
13	Housing type, either 1 - single family suburban 2 - single family dense 3 - townhouses 4 - garden apartments 5 - high-rise multi-family housing
14	Design temperature of system (degrees Fahrenheit)
15	Capital equipment life for: 1 - wells 2 - distribution system 3 - heat exchanger 4 - hookup costs 5 - in-well pumps 6 - peaking system boiler (fossil fuel)
18	Cost per hookup (dollars)
19	Market saturation by geothermal (in percent)
20	Cost of electricity (cts/kwh)
21	Reject temperature (degrees Fahrenheit)
22	Calculation of pipe costs: F(unction) - using functional relationship I(nput) - as user input
23	Depth of reinjection well
24	Stepwise design temperature of system (& data for plotting)
25	Stepwise market saturation by geothermal
26	Well drawdown (in percent)
27	Interest rate (in percent)
28	Minimum ambient temperature (degrees Fahrenheit)
29	Fossil fuel price (dollars per kwh)
30	Boiler cost (dollars per hundred thousand BTU's)
31	Industrial utilization factor (percent)

A hypothetical run of the GREES model is illustrated below.

RUN GREES

<u>OPTION ?</u> 11

<u>INPUT WATER TEMPERATURE AT WELLHEAD</u> (DEG. FAHRENHEIT) 120

<u>OPTION ?</u> 12

<u>INPUT DEPTH OF UP WELL</u> (IN FEET) 4000

<u>OPTION ?</u> 27

<u>INPUT INTEREST RATE</u> (IN PERCENT) 18

<u>OPTION ?</u> 10

<u>WHICH AREA IS TO BE CONSIDERED</u> 1
1 - ATLANTIC CITY
2 - SALISBURY
3 - NORFOLK

<u>OPTION ?</u> 7

<u>AVERAGE COST PER MILLION BTUS</u> $ 7.45

<u>OPTION ?</u> 9

<u>END EXECUTION OF GREES</u>