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A CASE-STUDY APPLICATION OF VENTURE ANALYSIS:

THE INTEGRATED ENERGY UTILITY

Volume 2: Technical Report

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2. VENTURE ANALYSIS

PRIVATE-SECTOR ANALYSIS

Introduction

A general definition or application of venture analysis would, at a minimum, need to address the following issues:

- Careful definition of the product/service being considered
- Market needs that the product will satisfy
- Investment/manufacturing costs
- Minimum selling price needed to achieve desired ROI or other financial measure
- Market potential at relevant prices
- Potential for competitors to obsolete the product before investment is recovered
- Assessment of companies' resources and capabilities to supply the product.

In addition to the above partial set of considerations, in many companies a strong advocate is needed to guide the product through the corporate decisionmaking process.

There is clearly no single method for performing every venture analysis, because the economic and structural environment associated with each industry has a wide variation. For example, some industries are labor intensive, while others are capital intensive; some sell directly to consumers while others sell to other manufacturing companies. These factors along with a myriad of others produce differences in cost structure, marketing organizations, and

nature of products that dictate that an appropriate method of venture analysis must be tailored to each industry. Nevertheless, there are many elements common to all analyses.

Therefore, the approach taken in this chapter will be to make some brief remarks concerning the important concepts that all venture analyses must consider and then describe in more detail the method used for the venture analyzed in this report.

Review of Venture Analysis Concepts

There exists little in the open literature directed to the venture analysis process per se. There is, however, a large body of literature related to the financial aspects of venture analysis under topics such as capital budgeting and discounted cash flow analysis. This literature treats the philosophy surrounding the detailed financial analysis associated with a variety of product and investment decisions. An implicit assumption in most of this work is that all important values are known with certainty, and the remaining task is to perform an appropriate economic analysis. Examples of these ideas are found in Bierman and Smidt (1), Markowitz (9), Solomon (12), and Smith (11). In addition there are articles that discuss specific approaches for specific products, an example being (6).

In this report a relatively simple financial framework based on standard utility practice is utilized. The form of this analysis is discussed in a subsequent section. Since the above literature is now well known and does not have direct bearing on the analysis, its content will be omitted in this discussion.

In recent years there has been a growing realization that a proper approach to new venture analysis involves much more than the financial analysis, and in fact that this analysis, while necessary, may be one of the less important tasks. These ideas have been advanced in the papers by Blackman (2) and Mathey (10).

Blackman has attempted to provide some logical structure to the venture analysis process by selecting a variety of analytic techniques from such disciplines as technological forecasting, decision analysis, and systems dynamics, and by synthesizing an organized approach. In technological forecasting, Blackman focuses on the use of market substitution models that describe rates at which new markets may be created when innovations are substituted for existing products. Decision analysis manifests itself in risk analysis (discussed later in this section) and decision trees, which combine the risks associated with events under the control of the decisionmaker and chance events (not under his control). The tree is used to provide an overall expected value of an appropriate financial measure that can be ranked with values from other ventures under consideration. Systems Dynamics* simulation models were used to relate the R&D allocations to sales and growth objectives.

The paper by Mathey further emphasizes the importance of nonfinancial tasks in new venture analysis. The additional techniques suggested here include force field analysis, the experience curve, visual screening, and multiple scenarios. Force field analysis considers the external and internal factors that can dramatically affect a business and its products. External factors include social, political, and technological trends, while internal

*This technique was developed by J. W. Forrester at MIT and involves the use of feedback loops in the simulation.

factors consist of the attitudes, policies, and resources existing during the relevant time period. Force field analysis can be used within the context of multiple scenario building, which constructs alternative futures in which the new venture will find itself. The experience curve is an enhancement of the well-known learning curve concept. The proper use of this tool can greatly affect the profitability of a new product.

Of particular interest here is the visual screening document, which can be tailored to any organization. This checklist raises most of the critical questions that can spell success or failure for a particular venture. Some considerations here are legal and patent positions, customer benefits, market growth rates, and market share. A ranking mechanism can be associated with the screening process to provide an overall assessment of the product's potential. If this phase of the analysis is done carefully, a higher success rate can be expected from those ventures that are ultimately undertaken.

In addition to the techniques discussed here, there have been a number of developments in the fields of operations research, economics, statistics, and futures research that can be applied to the new venture study. These include Delphi interviews or questionnaires, simulation gaming, econometric modeling, regression analysis, trend impact analysis, cross-impact analysis, and relevance trees.

It is therefore clear that venture analysis has begun to move from a predominantly financial framework to a more structured exercise using an expanding array of appropriate tools relevant to the new venture under consideration.

Risk Analysis

The concept of risk analysis was introduced in a paper by Hertz (8) in 1964. The main contribution of this work was to present a viable method for characterizing the uncertainty inherent in all new venture financial analyses and to use it to assess the risks associated with the venture.

Figure 2.1 portrays this process with parameters taken from the venture studied in this report. Instead of single number estimates for the important parameters, probability distributions are constructed from all relevant information. These are indicated on the left side of the figure. A sample analysis can be made by selecting at random values from each of the distributions, then combining these using the desired financial measure, e.g., return on investment or payback time. By repeating this process a large number of times, each of the parameters is allowed to enter the venture in accordance with its own set of probabilities, thus yielding a histogram of the financial measure as shown on the right side of the figure. In this case, what has been constructed is a distribution of the cost per million Btu for a district heating system. This provides us with a range of possible values along with their probabilities of occurring.

In a typical commercial setting, one might wish to know the probability that a particular venture will lose money or attain an internal rate of return greater than some designated value. A very perceptive discussion of the value of risk analysis is contained in a recent letter to the editor of Business Week in response to a previous article on utility demand forecasting. The entire letter is as follows:

Economists and engineers appear ready to debate the fine points of electrical demand forecasting in "Why it's tougher to justify rate boosts" (Energy, Nov. 7). Their argument may be academic. More important issues are the relative costs of

DISTRIBUTIONS OF IMPORTANT FACTORS

Figure 2.1. Pictorial Representation of Risk Analysis

too much or too little generating capacity and the uncertainty in demand growth. The debate should not be whether annual growth "will" be 4.3 percent or 3.9 percent, but rather "What is the likelihood it will exceed 6 percent or fall short of 2 percent?"

Uncertainty matters because the burden of excess capacity is different from the cost of falling short. A recent analysis for the California Energy Resources Conservation and Development Commission has shown that the decision maker who explicitly considers uncertainty in demand and the costs of under or over-building will add generating capacity at a substantially different rate from one who builds to meet an economist's (or an engineer's) single-point demand estimate. Quantifying the rate of demand growth is important, but before settling on the second or third digit of precision, we must admit and quantify our level of uncertainty and understand how that changes capacity-expansion decisions.

Bruce R. Judd*

In moving away from a deterministic financial analysis, it may seem sufficient initially to construct ranges for all parameters and perform analyses with all parameters set at their worst, best, and most likely cases. However, this approach does not assess the likelihood of these cases occurring (indeed the two extremes should be highly unlikely), nor does it allow the various combinations of worst, best, and likely values to come together in a given analysis. Note that the lowest value of cost per million Btu in the histogram in Figure 2.1 will be greater than the result of the combination of all costs taken at their lowest level. This is because this event has such low probability that it never occurs in the analysis.

An assumption that is implicit in the above discussion is that the various cost factors are independent, i.e., the value selected from one distribution has no effect or is not affected by the value selected from any other distribution. However, this is often not true. For example, if several

*Business Week (December 5, 1977), p. 8.

of the cost factors are highly labor dependent, then their values will tend to move in concert or, in statistical terms, the values are correlated.

This situation can be dealt with in two ways. The computer programs available for performing risk analysis usually have correlation statements built into the program so that one can specify correlations between variables. However, a remaining problem is the specification of the correlation coefficient. This may be a highly judgmental decision depending on the availability of past data for estimating the coefficient. Another approach, which has been successfully adopted in this study, is to group the various cost factors that are presumed correlated into a single distribution. This method also is somewhat judgmental and will not always be feasible. However, it was possible to partition the important costs in this study so that it was reasonable to assume independence among them.

Summarizing the above discussion, the use of risk analysis allows the uncertainty in a venture analysis to be properly displayed and used to assess the financial risks in probabilistic terms.

Integrated Utility Venture

The general approach that The Futures Group/GE-TEMPO has taken in its analysis is described as follows:

- Definition of the systems needed to provide HTW and operating characteristics at an appropriate level of detail
- Calculation of the minimum price the utility must charge assuming sale of all heat generated
- Market penetration of heat sales in new residential/commercial dwellings and new and existing industrial sites

- Consideration of new or existing products that equipment suppliers must provide and their current attitudes toward this market
- Measurement of current utility and regulatory attitudes toward entering this market via telephone and personal interviews.

Our analysis was originally conceived as one that would provide DOE with macro information as to whether utilities and suppliers would wish to enter the heat sales market in the existing economic environment. Since the energy situation varies widely over the United States, it was necessary to make a number of simplifying assumptions and compromises in order to carry out an analysis that provided reasonable answers. Therefore, our analysis has not been done at the level of local detail that would be expected from an individual utility.

System Definition

The proposed systems for delivering heat include the following characteristics:

- A central plant generating electricity and providing heat via extraction, backpressure, or stack recovery methods.
- An aquifer storage capability for short- and long-term load balancing.
- A transmission/distribution system to deliver heat to customers.
- A heat exchanger on the customer's premises to obtain heat from the distribution system and use it for space/ water heating or process heat.

Cost Analysis Framework

The method used for the financial analysis in this report is a modification of the so-called required revenue approach that is typically used by utilities. This method is explained in detail in an ERDA/EPRI document (5).

Computations using this approach often are done on a levelized basis, a process that discounts yearly costs of energy generation to a present value. This approach allows alternative energy systems starting and ending at different times and with a different associated investment and operating costs to be compared on the basis of a single number for each system, i.e., the present value of the cost of delivering energy. This method of analysis is useful for ranking when one is considering a detailed look at a number of energy systems with the above differences.

However, we have modified the analysis in this report by replacing the levelizing and present value operations with the calculation of actual costs per year in current dollars over the time span of interest. This method is useful for several reasons. All of the proposed heat delivery systems are assumed to have 30-year lifetimes (or are financed over 30 years), and we have made the simplifying assumption that all investment is concentrated in the first year.* This avoids consideration of interest during construction, which is a proper concern of a utility doing its own specific venture analysis, but is an unnecessary complication for the macro analysis presented in this report. The most important reason, however, is to display the dynamic economic relationship over time between the proposed systems and alternative systems that customers are now using or may use in the future. It was recognized early in the study that capital-intensive energy systems may have distinct advantages over fuel-intensive systems in an inflationary, energy-short environment. Once a large plant is built, the major cost of operation consists

*If a plant is built over several years the investment costs are less because the money can be invested while waiting; however, inflation then raises the total cost of construction. Therefore if one can invest at the inflation rate, these two effects tend to cancel.

of paying back the money borrowed for construction. These costs are constant over the lifetime of the plant, and in the case of a nuclear plant for example, where fuel and operating costs are relatively minor, this results in the total cost of energy rising very slowly over the system lifetime.

In contrast, most estimates of future fuel prices, which are the appropriate alternative systems in the residential/commercial case,* predict fuel prices rising faster than general inflation during the period of interest in this study. Therefore there is interest in several aspects of the relationship between the proposed system and alternative fuels.

The first matter of concern is whether the proposed system is competitive with any alternative fuels at the outset. If not, then interest focuses on whether the system becomes competitive in the future, i.e., since fuel prices will be rising faster than system costs, the annual cost curves may cross during the lifetime of the project. At this time the proposed system becomes cheaper than the alternative fuel and remains so for the life of the project.

This method of analysis can then be used to address questions such as how much government support might be needed to implement district heating schemes if they are not competitive at the outset, and for what length of time the support would be needed.

Initial Modeling

Our preliminary financial modeling approach was a good deal more detailed than our final method and was more appropriate for use by an individual utility for a specific venture analysis. We considered such items as investment tax credits and effective income tax rates, but quickly learned that these items

*As discussed in Chapter 4, the cost of a heat exchanger is assumed to be similar in price to conventional heat delivery systems.

can vary appreciably from state to state. Therefore, we abandoned this approach in favor of the "fixed charge rate" method which is standard utility practice when using the required revenue approach. The fixed charge rate is a factor applied to total capital investment to yield the revenue the utility must obtain to pay back its loan, pay income taxes, and provide an internal rate of return equal to the cost of capital.* In keeping with the guidelines in (5), we have assumed a cost of capital of 8 percent, general inflation at 6 percent, and a fixed charge rate of 0.15.

As a means of clarification here, it is noted that a typical commercial venture analysis would calculate an internal rate of return as a function of all the cost and market inputs. If the calculated rate were higher than an established corporate minimum rate for new ventures (often called the hurdle rate), the venture would be given further consideration. In the case of utilities, whose rates are regulated, the internal rate of return is assumed fixed and equal to the cost of capital. Therefore the process used in the commercial case is reversed and one seeks to find the revenue stream that accomplishes this goal.

Another concept that was examined in our preliminary analysis was the proper treatment of the cost and lifetimes of the transmission/distribution system. There is some evidence to suggest that the usable lifetime of the piping would be considerably longer than the assumed 30-year life of the generating plants. Therefore at the end of the 30-year venture the utility would own a valuable asset that could continue to be used in a district heating scheme, but with only operating costs involved (the capital costs having

*This relationship insures that the utility receive enough revenue to exactly cover its loan repayments and operating expenses. The internal rate of return is often confused with the book rate of return, which is calculated in a different manner. A particularly lucid discussion of these two concepts can be found in reference (13).

been paid back). One method of treating this in a venture analysis is to credit the venture with an assumed liquidation value of the pipes, thereby reducing the energy costs over the life of the project. However, the utility usually cannot obtain financing for more than 30 years, and therefore it must obtain enough revenue to pay back the cost of the pipe over that period regardless of its possible extended life.

Since the transmission/distribution system is a major expense in a district heating system, this situation raises questions as to who should receive the benefits of the extended life. Presumably after the pipes have been paid for, the utility then could sell heat at a sharply reduced price because prior customers have been paying rates that assume a 30-year pay back. Also, since the utility is regulated, these benefits most likely would be passed on to customers rather than be allowed as retained earnings for the utility.

We raise this question because in our heavily consumer-oriented society that manifests itself in many state utility commissions, this question, if recognized, may prove to be one of many hurdles that a district heating system may have to overcome to be accepted. A parallel situation may have occurred earlier in this century when natural gas pipelines were first laid down. However, the regulatory and business climate then was considerably different than exists today, and this question was not important.

In this report we have taken a conservative approach and have priced the heat to pay back all capital costs associated with energy production and distribution in 30 years. Therefore any benefits accruing from extended lifetimes of the transmission/distribution system in district heating systems operating after 30 years will be received solely by future customers or utilities.

Summary

A simplified example of the form of analysis used in this report is shown in Table 2.1. The analysis incorporates all the concepts discussed in this section and provides a rapid method for arriving at a final cost for any proposed system. The calculational assumptions for the deterministic case and additional assumptions used in the probabilistic case are described in detail in Chapter 4 and Appendix C.

The Economic and Investment Environment

The following excerpt from a letter to the editor of Business Week provides a revealing statement concerning the present state of utility finances:

Your thorough and informative summary of the virtues and dangers of energy conservation, "Carter's conundrum: Will energy conservation throttle economic growth?" (Energy, April 25), contains one inadvertent error.

You indicate that "...much to the annoyance of conservationists, power companies can easily raise money for these supply investments because their income is virtually guaranteed by regulatory authorities." The only thing that has been guaranteed to the electric utilities by most regulation is an inability to earn the rates of return that the regulators themselves have found just and reasonable. A combination of rapid inflation and regulatory lag--some of it inevitable--has produced a situation in which earnings on equity by utilities have been so far below those utilities' cost of capital as to cause stocks to sell substantially below book value, and to cause cancellation of investments which, on the base of a pure economic calculus, would clearly be required. This has been particularly true of the most capital-intensive technologies.*

It is clear that many private utilities are beset today by a host of problems that are restricting their ability to invest in needed plant and equipment, and virtually closing off their enthusiasm for new ventures. The

*Business Week (May 16, 1977), p. 5.

Table 2.1

EXAMPLE CALCULATION FOR ENERGY PLANT SERVING
RESIDENTIAL/COMMERCIAL CUSTOMERS
(All Costs in \$1985 x 10⁶ in 1985)

<u>Electric Generating Plant Charges</u>			
Total Capital Cost of Plant			700.0
Annual O&M Costs			10.0
Annual Fuel Charges			100.0
<u>Annual Charges for Heat Customer*</u>			
Plant	= .25 x .15 x 700	=	26.25**
O&M	= .25 x 10	=	2.50
Fuel	= .25 x 100	=	25.00
Aquifer	= .15 x 75	=	11.25**
Transmission	= .15 x 125	=	18.75**
Distribution	= .15 x 300	=	45.00**
Total Annual Costs			128.75
Heat Output of Plant			15.6 x 10 ⁶ Million Btu
Final Cost to Heat Customer in 1985 = $\frac{128.75}{15.6}$ = \$8.25/Million Btu***			

*As discussed in Chapter 4, the heat customer pays for the electric revenues lost as a result of heat generation. In this example it is assumed that electricity generation is reduced by 25 percent.

**The annual capital cost is derived using the fixed charge rate of 0.15 as discussed in the text.

***Costs in future years are obtained by escalating O&M costs at 6 percent per year and fuel costs at 7 percent per year. The capital costs for a plant built in 1985 remain fixed, while capital costs for plants built in future years also escalate at 6 percent per year.

above excerpt touches on three of these problems--environmental and regulatory restrictions, and inflation. Environmental and regulatory considerations are discussed in detail elsewhere in this report. However, it is noted here that recent articles in the financial press have raised caution signals about the attitudes of regulators concerning needed rate increases and the subsequent damaging effect on utility attempts to raise capital.

The pernicious effects of inflation on profitability and the investment attitudes in the business community are now becoming well known. A recent study by Tatom and Turley (14) uncovers the fact that

Inflation, in conjunction with the accounting convention of recording transactions at their historical values, reduces the returns generated by investment projects. In addition, the combined effects of inflation and the personal income tax structure tend to drive up the cost of obtaining the funds necessary for a given capital investment program. Each of these adverse effects of inflation should be high on the list of culprits responsible for the lackluster performance of business investment spending.

An example in the paper shows that an investment that yields an internal rate of return of 10.4 percent in a stable environment, yields 8.5 percent with 5 percent inflation and only 6.9 percent with 10 percent inflation. This illustrates the dramatic effect that inflation is having on investment returns and partially explains the low level of capital investment in recent years.

A concomitant phenomenon that is now occurring is the emphasis on cash management in many medium and large corporations (3). Corporate cash is piling up because, as indicated above, inflation has diminished the desire for capital investment. Thus corporations have temporarily turned to investing cash in bonds and money market instruments, rather than in plant and equipment.

The occurrence of these corporate moves further highlights the difficulties utilities find themselves in that are exacerbated by a regulatory environment not permitting them to move quickly to protect themselves in an inflationary environment.

As if the current list of difficulties were not enough, the Financial Accounting Standards Board recently has appointed an outside task force to study the utility practice of deferring major costs for years (4). The immediate effect of a reversal of present practice would be a lowering of reported earnings by utilities, further depressing their already weakened share prices. This, of course, will further restrict their ability to raise capital for new ventures.

One bright spot in the new high-priced energy era is the fact that investment in energy saving equipment yields high returns and short payback periods in many industrial settings. However, to the extent that these investments reduce the demand for gas and electricity, they put additional pressure on utility finances.

The business community is now painfully aware that the environment in which it operates and consumer purchasing behavior has changed considerably in recent years. It follows that new modes of thinking about corporate strategies and product development will be needed in order to prosper in the new environment. A useful article by Paul C. Harper (7) compares the old and the new environment and advances ideas for strategic and product planning.

Although the corporate mission in private utilities is reasonably well-defined, they still must reflect on the shifting environment and consider what responses are necessary. Until these issues have been clarified, utilities may be reluctant or unable to invest in new energy ventures.

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PUBLIC-SECTOR ANALYSIS

The returns from an innovation accrue not only to the innovator, but also to society at large. The firm can receive profits from a successful innovation; society can also receive benefits, including, for example, lowered prices, increased output in the economy as the result of redistribution of the innovator's profits, and changes in the distribution and quality of shared resources, e.g., improvements in water quality. Therefore, a complete analysis of an innovation should include calculation of social as well as private rates of return. The techniques for determining net social benefits are not as well developed as those for private returns, but some progress in this area has been made.

The Mansfield Approach

Professor Edwin Mansfield of the university of Pennsylvania and his colleagues recently completed a study in which private and social rates of return from industrial innovations were calculated for 17 innovations.*

In Mansfield's work, net social benefits are computed as follows:

$$\begin{aligned} \text{Net social benefits} &= (\text{consumers' surplus}) + (\text{resource savings}) \\ &\quad - (\text{other social costs}) \end{aligned}$$

Consumers' surplus for a product innovation sold by an innovator to an industry results from the lower price that is a consequence of the use of the innovation. It can be computed as follows:

*Edwin Mansfield et al., Social and Private Rates of Return From Industrial Innovations (Philadelphia, PA: University of Pennsylvania, September 1975).

$$(P_1 - P_2) (Q_2) \left(1 - \frac{Kn}{2}\right)$$

where: P_1 equals the initial price or cost per unit output of the industry prior to the introduction of the innovation; P_2 equals the price or cost per unit of output of the industry after the introduction of the innovation; K equals the percentage change in price $(P_1 - P_2)/P_2$; n is the price elasticity of demand for the product in the industry using the innovation; and Q_2 is the quantity sold at the new price.

Consumer surplus for product innovations that reduce the price of a household activity can be computed using the above equation, but in this instance P_1 equals the initial price per unit of household activity; P_2 equals the price per unit of household activity after the introduction of the innovations; and Q_2 equals the number of times per year that the household activity is performed. Consumers' surplus for process innovations is realized if the innovator's use of the process innovation results in a price reduction to the consumer.

In addition to the consumer surplus resulting from decreased costs to the consumer, there is also a resource savings that corresponds to increased output elsewhere in the economy. Since at least some profits are normally retained by the innovator, all of the benefits accrued from the innovation are not represented in the consumer surplus. In fact, the retained profits caused by the innovation are the monetary measure of the resource savings. However, the computation of resource savings must consider the profit that would have been earned by competitors had the innovation not been introduced. Therefore, it is the net profit (profits accrued by the innovator minus profits that otherwise would have been accrued by competitors) that reflects the real resource savings.

In many cases, the innovative process will cause other social costs and benefits that have to be considered in deriving net social benefits. Examples of these include environmental improvement or degradation, increased or decreased

employment due to the innovation, and the savings or use of other societal resources. These costs and benefits must be added to the consumer surplus and resource savings in order to reflect the net social benefits.

Having developed the net social benefits, it becomes necessary to compute the internal social rate of return. This can be calculated by finding the interest rate that makes the present value of the net social benefits equal to zero. That is, finding the interest rate i , when

$$B(t) + \frac{B(t+1)}{(1+i)} + \frac{B(t+2)}{(1+i)^2} + \dots + \frac{B(t+n)}{(1+i)^n} = 0,$$

where: $B(t)$ is the net social benefit in year t , t is the first year in which the net social benefit is nonzero, and $(t+n)$ is the last year where the net social benefit is nonzero.

Mansfield's determination of social benefits has been criticized by many researchers in the field of innovation. Most of these criticisms concern Mansfield's application of the theoretical approach rather than the concepts themselves. Criticism has focussed on the procedures used to gather the necessary data and the almost complete lack of any attempt to calculate other social costs and benefits (pollution, for example), although these costs and benefits are recognized as theoretically important. The arbitrariness of the selection of the last year for which benefits are calculated also has been mentioned as a problem.

The theoretical concepts have not been challenged successfully and remain the best available. This approach is employed in this study. However, one addition to the technique has been explored in this application. Mansfield assumes that the consumer surplus can be calculated by determining the monetary savings accruing to consumers because of the lower price due to the innovation. Thus, a consumer benefits from an innovation because he pays only $X-Y$ dollars

for a product for which he used to pay X dollars. His surplus is, therefore, Y dollars. This is only true, however, if the product itself is unchanged. If an innovation caused a product to be improved substantially but the product continued to sell for the same price, the consumer would still pay the same but would obviously receive additional benefits from the improved product.

An attempt has been made in this study to include factors other than price in the evaluation of the "value" of a product to the consumer. This approach developed from the decision model technique used to determine future market penetrations (described in Chapter 4). Briefly, it involves describing all the attributes of a product that are important to the consumers, including not only price but other attributes as well. These other attributes might include performance characteristics, reliability, etc. In the case of home heating, for example, a consumer might consider safety and cleanliness as attributes that are important in the selection of a home heating fuel. By combining consumer perceptions of these attribute with the price of the products a product "value" can be determined. Consumer surplus is then defined as the change in "value" received due to the innovation. This concept is described in more detail in Chapter 5.

The Integrated Energy Utility

For the Integrated Energy Utility (IEU) examined in this study the major innovator is the electric utility, the final product is energy in the form of heat, and the consumer is the heat user in the industrial, residential, and commercial sectors. Consumer surplus is calculated as the savings of the end users, and resource savings is calculated as the difference between profits gained by the innovator and profits lost by the competitors. To this point the innovation fits the general category of innovations studied by Mansfield.

However, there are at least three important differences. First the analysis involves a future innovation, not a past one. Second, the "other social benefits" are among the most important benefits of the innovation. Third, the innovation leads to the construction of a number of different generating plants at different times, not just a single manufacturing plant.

The fact that the analysis involves a future innovation means that data cannot be collected on the market penetration of the innovation. The analysis is based entirely on forecasts. Not only is it necessary to forecast the expected future characteristics of the IEU but forecasts of possible future competitors must be made as well. Thus the analysis involves the difference in expected benefits if the innovation takes place and if it does not. Even without the innovation, the commercial space heat will evolve from the present market configuration. In some cases the introduction of heat from high-temperature water is expected to cause decrease in the market for traditional heating systems (e.g., oil-fired boiler, electrical resistance heating), while in others it is expected to capture markets that would otherwise have been captured by new technologies (solar, electric heat pump).

The second major difference is even more important. The benefits to be expected from the introduction of the IEU cannot all be encompassed in the calculation of consumers' surplus and resource savings. Due to increased efficiencies, fuel savings are to be expected and air pollution should be reduced. Thermal pollution should also be reduced. The changing fuel mix caused by the innovation will have important consequences for imports of fuel, the balance of payments, the strength of the dollar, etc. The use of aquifer storage raises the possibility of increased risk of damage to drinking water sources.

In view of these additional costs and benefits, it is not sufficient to base the social benefits calculation solely on consumer surplus and resource savings. Thus the study team has attempted to calculate the other costs and benefits as well. In some cases these costs and benefits can be quantified and in other cases they cannot. While it might seem tempting to quantify those impacts that can be quantified, and add these new terms to the net social benefits and to ignore all other impacts, we have not chosen this path. Instead, the consumers' surplus and resource savings have been combined to yield a measure of the direct social benefits comparable to Mansfield's case studies. Other impacts have been quantified where possible and those not quantifiable have been discussed qualitatively. This information is presented separately since the addition of some costs and benefits to the consumer surplus and resource savings, and the exclusion of others solely on the basis of whether or not a particular impact could be quantified could give a distorted picture of the true social benefits.

The third major difference involves the spread of the innovation. In the cases constructed or modified and the analysis concerned the benefits derived during the lifetime of the plant or the process employed in the plant. In the case of the integrated energy utility, however, the first HTW plant will be followed by many other similar plants. In many cases these plants will be connected to the same distribution grid. Thus, the benefits of the initial innovation continue to accrue as long as new HTW plants are built and many consumers derive benefits from the system of interconnected plants rather than a single plant. Therefore, we have calculated the net social benefits accruing from the date of installation of the first plant to an arbitrary cut-off date, 2020.

While these calculations reflect the social benefits derived they cannot be used to determine the social rate of return because of the interconnections in the HTW system. Consumers pay a price for HTW water based on the average costs of generating HTW for all plants connected to the system. By 2020 this means that HTW is being generated by some old plants that have just about finished their economic life, some plants only 10-15 years old, and some new plants. Since the new plants will continue to generate HTW for years after 2020 their total benefits are not realized by 2020. However, they cannot be excluded from the analysis since they do contribute to benefits derived before 2020.

Our approach has been to calculate the net social benefits derived from the innovation by 2020 and express these benefits discounted to present value but without calculating a social rate of return. Separate calculations have been made of the net social benefits derived from individual plants serving a representative market. Rates of return are calculated for these individual plants and are used to indicate the range of social return for the system as a whole.

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3. THE INTEGRATED ENERGY UTILITY

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INTRODUCTION

This case study of venture analysis addresses "The Integrated Energy Utility" as the innovation being considered for commercialization.

There are energy utilities that supply only electricity, or only gas, or only steam as energy forms. Some supply two of these, a few supply all three. Broadly, an integrated energy utility supplies two or more forms, and has them integrated, to complement each other and supply economic benefits. Specifically, in this case study, the type of integrated energy utility to be investigated supplies electricity and thermal energy; the thermal energy is distributed in the form of high temperature water, that is, water from at least 90°C (194°F) upwards to 200°C (400°F).

As will be discussed in the next section there are no investor-owned utilities of this type in the U.S. currently. It is a common form, with significant growth rates, in several European countries.

There are technical benefits to the combining of these energy forms in one utility, which should lead to economic benefits. They should also lead to significant public-sector benefits in energy conservation. Less fuel is used to serve the electricity demands and heat demands, which leads to energy savings, reduction in the problem of waste heat disposal, substitution of coal and nuclear energy for the heat market now served by scarce fuels, oil and gas, and potentially a reduction or removal from the urban area of the pollution emissions from individual urban heating systems.

Cogeneration

The technical benefit mentioned is cogeneration, or the combined production of electricity and useful heat by recovery of the heat from the electric power cycle at a temperature that can be distributed and used. The

conventional approach in electric generation is to maximize the amount of electricity per pound of fuel, or per unit of energy in the fuel. Achievable conversion efficiencies to the electricity end product are not high. They range from 30 to 40 percent for different conversion systems. The unconverted fuel energy is discarded as waste heat from the stack of the boiler plant, and from the cooling system of the steam turbine generators. To maximize electric output this waste heat is rejected at the lowest economic temperature, at considerable cost. It has also been constrained by the environmental impacts on aquatic flora and fauna; heat rejection into bodies of water--the lowest cost method of disposal--is increasingly restricted or forbidden.

For some increase in the capital cost of a plant, and some reduction in the electricity produced, large quantities of useful heat can be produced instead of waste heat at too low a temperature to be useful. Figure 3.1 illustrates the amount of electricity lost, for various amounts of useful heat produced, for one plant. The trend is similar but the numbers differ for other sizes and types of plants and for other temperatures of high temperature water (HTW) produced.

Private-Sector Role

The case study examines the technical and economic feasibility of this approach to energy conservation from the point of view of two decision-makers in the private sector: the electric utility which must decide whether addition or expansion of the sale of heat as product is viable and in its interest; and the equipment supplier who must provide the technology in new products required in the cogeneration systems.

Figure 3.1. For a 226 MW (Electric) Coal-Fired Plant, when Useful Heat in the Form of HTW at 175°C (350°F) is Derived by Steam Extraction, the Electric Output is Decreased at Roughly the Rate of 1 MW per 5 MW (Thermal)

The utility decisionmaker will be very concerned with the economic feasibility, the technical risks, and the market growth risks. When a new plant is to be built, incorporating cogeneration of heat and electricity, a market for the usable heat must be available by the date of initial operation. This market can build over several years, but limited revenues from heat sales in the early years of operation will reduce the attractiveness of the venture. In addition to power plant modifications for heat generation, there is substantial investment required to transport the heat to the load centers served, and to distribute it to the individual customers in the load area.

Entry Scenario

There is a variety of plant sizes and types of electric generating plants that can be chosen to produce electricity, and can be modified to produce usable heat as well. In order to postulate a gradual entry of a utility into the sale-of-heat market, a scenario has been assumed of progression from the smaller and simpler plants to the larger and more complex plants which may be ultimately most economic. Initially, oil-fired gas turbines modified to recover the stack-gas heat from the gas turbine for HTW generation will be located at or near industrial load centers that can use some of the electricity and most or all of the heat. At this stage some of the heat can be supplied to industry as process steam at desired temperatures. Some can be converted to HTW suitable for pipeline delivery to sites removed from the industrial water.

As a local market and local distribution system for HTW develops, coal-fired steam turbine plants of larger sizes, 200 to 800 MW (electric), can be introduced which are designed to produce large amounts of HTW. As these plants will serve a number of load centers and cannot be installed in the urban central regions, a transmission or heat-transport network must be built to interconnect the plants and the load centers. The lower cost of fuel (coal vs. oil) will make these plants more economic than the oil-fired gas turbines for some range of transmission distances. The interconnection network supplied by multiple plants, both coal and gas turbine, will of course improve the reliability and flexibility of market growth.

When the district heating (DH) network is large enough, the extraction of large amounts of HTW from new nuclear plants, designed for cogeneration, can be considered. The lower cost of nuclear fuel and the economies of scale where thousands of megawatts (thermal) of HTW are produced increase

the feasible distance of heat-transmission to many tens-of-miles, so a whole urban area can be interconnected with a thermal grid as well as an electric grid.

The system types listed in the above scenario are described and analyzed in a later part of this chapter.

Thermal Storage

The capital cost of heat producing and heat transmitting equipment will be proportional to the peak demand rate for heat, rather than the average. Where a principal part of the heat demand is for space heating, in severe climates, the load factor for heat (ratio of the peak hourly demand to the annual average) may be less than 0.25. In an earlier study,^{*} the implications of using long-term thermal energy storage in Heat Storage Wells were examined. By using such storage both at the heat generation point and at the interfaces between transmission (large) and distribution (small-scale) networks a more nearly constant use of the heat-producing and heat-transmitting capital equipment can be assured. Since this favorably influences the system's economic viability, seasonal storage with Heat Storage Wells is included as a part of each of the systems analyzed later in this chapter.

^{*} C.F. Meyer, W. Hausz et al., Role of the Heat Storage Well in Future U.S. Energy Systems, Report GE76TMP-27 (Santa Barbara, CA: General Electric-TEMPO, December 1976).

High Temperature Water versus Steam

In all the cogeneration systems considered here, the assumption is that HTW will be the heat-delivery medium, rather than steam, even though all large district heating systems in the United States use steam. The reasons for choosing to consider only HTW are as follows:

- Large district heating companies in the United States were established early in this century as adjuncts of electric utility operations; steam was readily available from turbines used for generating electricity. In recent years, steam sales have declined, because power plants have moved to the suburbs and only the old, small, inefficient plants remain to serve the core city areas. Air pollution problems may be the *coup de grace* for these plants.
- The cost of makeup water has become a major factor. One-way steam systems characterize the U.S. district heating industry; condensate is not returned to be reheated. HTW systems include return lines, and much less makeup water is required.
- Transmission and distribution costs are generally lower for HTW than for steam; energy density in pipelines is higher, pumping costs are lower.
- HTW is the choice of new, expanding district heating systems in Europe.
- HTW is better suited than steam for storage.

HISTORICAL EXPERIENCE

District Heating--The United States

It was just 100 years ago, in 1877, when Birdsill Holly expanded his primitive boiler experiments to provide 14 residences of Lockport, New York with the world's first "district heating" steam service.

To carry out his experiments, Mr. Holly built a boiler in the cellar of his home at 31 Chestnut Street, Lockport. The grate was a sheet of steel with holes drilled in it. Pipe coils were used for radiation. He ran the steam line to a "distributor" in the attic of his home, then down to coils in the various rooms and back to the basement. There a loop served as a trap and condensate was returned to the boiler which operated at 10 psi pressure.

The experiment being a success, Mr. Holly decided to learn if steam could be transported for greater distances under ground. He buried 500 feet of one-inch line in his and adjacent lawns, successfully furnishing heat to his own and nearby homes by this roundabout way. He followed this up with an extension of 490 feet of one and one-half inch line to a neighbor's home. The iron pipe was wrapped with asbestos, felt and manila paper and tied with twine. It was buried from 3 feet to 3 and one-half feet deep in a wooden box 10 by 12 inches filled with sawdust.

The experiment being a success, Mr. Holly decided to start a heating utility in Lockwood. He raised \$25,000 and organized the Holly Steam Construction Company.*

Holly's successful demonstration of a district heating system acted as a catalyst for the development of other systems. At that time the main source of power generation was the reciprocating engine which, as a by-product, produced exhaust steam in the generation process. Pipelines were

*John F. Collins, Jr., "The History of District Heating," District Heating (July-August-September 1976), p. 19.

extended to factories and the exhaust steam was used as a supply of heat for heating systems. Growth in the number of systems was rapid. Within 10 years of Holly's experiment, systems were operating in Pennsylvania in Bellefonte, Bloomburg, Clearfield, Harrisburg, Hazelton, Lock Haven, Phillipsburg, Reading, Wilkes-Barre, and Williamsport, and elsewhere in Auburn, N.Y.; Burlington, Iowa; Belleville, N.Y.; Dubuque, Iowa; Denver, Colo.; Garden City, Long Island; New Haven, Conn.; Springfield, Mass.; and especially in New York City.*

In essence, the expansion of the steam business was a natural concomitant to the electric business. The proliferation of small electric companies generating electricity using reciprocating engines spurred on the development of the steam companies. This growth might have continued unabated if it were not for technical innovations. The most important of these was the replacement of reciprocating engines with electric turbines. According to John F. Collins, Jr., in District Heating:

Three changes in the electric business affected, and for a time almost knocked out the steam business.

1. Electric turbines replaced reciprocating engines in the generating of electricity. There was no longer any exhaust steam available for heating and condensing water did not have a high enough temperature for heating.
2. Larger electric plants became the rule, replacing groups of smaller ones and these plants were moved away from congested areas as electric transmission became possible over greater distances.
3. As generation of electricity became less expensive in larger plants, the smaller ones in town from which steam was obtained became obsolescent.

*Ibid., p. 20.

Steam which has been regarded as an inexpensive by-product and sold by the electric companies at a very low price, had to bring a return or at least balance expenses. Some utilities quit. Others were able to raise their rates.*

Despite these technological discontinuities, the steam district heating business did not cease to exist. The systems did, however, cease to experience dynamic growth. As shown in Table 3.1, there are currently at least 120 district energy suppliers operating in approximately 100 U.S. cities (this does not include all colleges, universities, hospitals, shopping centers, etc. that operate district energy systems). Of these American companies, there were 41 that delivered annual steam loads in excess of 80,000 pounds for a total delivered steam load of 107 billion pounds in 1976. This ranged from 93,000 pounds for the smallest of the 41 to over 42 billion pounds of steam for the largest (approximately 40 percent of the total). While 107 billion pounds of steam represents almost 110 trillion Btu's of thermal energy, it represents less than .1 percent of the total U.S. energy consumed in 1976. Table 3.2 shows statistics of steam sales and production for 1976.**

During the course of this study a series of in-depth interviews was conducted with electric and gas utilities, and regulators.*** The respondents were asked to evaluate different attributes about steam systems and to give their perceptions about the forces that caused the steam systems to develop as they did. Some of the factors that were perceived as important to shaping the growth of the steam systems include the following:

*Ibid., pp. 21-22.

**These figures were obtained from Norman Taylor, President of the International District Heating Association.

***See Chapter 4 for an in-depth discussion of these interviews.

Table 3.1

1977 DISTRICT ENERGY SUPPLIES IN THE UNITED STATES*

ALABAMA	INDIANA
Birmingham	Indianapolis
Alabama Power Co.	Indianapolis Power & Light Co.
ALASKA	IOWA
Fairbanks	Cedar Rapids
Fairbanks Municipal Utilities	Iowa Electric Light & Power Co.
System	
CALIFORNIA	Mt. Pleasant
Beverly Hills	Mt. Pleasant Utilities
Hilton Hotels Corp.	
Los Angeles	Perry
Century City	Iowa Electric Light & Power Co.
San Diego	Sibley
San Diego Gas and Electric Co.	Sibley Municipal Utilities
San Francisco	Sioux City
Pacific Gas and Electric Co.	Iowa Public Service Co.
COLORADO	Spencer
Denver	Spencer Municipal Utilities
Public Service Co. of Colorado	
CONNECTICUT	KANSAS
Hartford	Topeka
Hartford Steam Service Co.	Kansas Power and Light Co.
DISTRICT OF COLUMBIA	MARYLAND
Washington	Baltimore
Capitol Power Plant	Baltimore Gas and Electric Co.
General Services Administration	
FLORIDA	MASSACHUSETTS
Orlando	Boston
Walt Disney World	A. W. Perry Inc.
GEORGIA	Boston Edison Co.
Atlanta	Estate of Frederick Evenson
Georgia Power Co.	Harvard Medical Complex
ILLINOIS	Quincy Market, Storage and
Chicago	Warehouse Co.
Chicago Union Station Co.	
Medical Center Steam Co.	Brockton
Produce Terminal Corp.	Campello Steam Co.
	Cambridge
	Cambridge Steam Corp.

*"District Energy Suppliers in the United States and Canada," District Heating (July-August-September 1977).

Table 3.1 (Cont.)

MASSACHUSETTS (Cont.)

Holyoke
 Holyoke Gas and Electric Dept.
 Holyoke Water Power Co.

Saugus
 Refuse Energy Systems Co.

Worcester
 Worcester Cold Storage and
 Warehouse Co.

MICHIGAN

Detroit
 Detroit Edison Co.
 Detroit Public Lighting
 Commission

Grand Rapids
 Consumers Power Co.

Lansing
 Board of Water and Light

Southfield
 Dayton Hudson Properties

Wyandotte
 Department of Municipal
 Service

MINNESOTA

Austin
 Austin Utilities

Blue Earth
 Blue Earth Light & Water Dept.

Detroit Lakes
 Detroit Lakes Public Utilities
 Dept.

Duluth
 Duluth Steam Corp.

Fairmont
 Fairmont Public Utilities
 Commission

Hibbing
 Hibbing Public Utilities
 Commission

Litchfield
 Litchfield Public Utilities
 Commission

Madison
 Madison Municipal Utilities

Minneapolis
 Central Heating Co. (IDS Properties)

Mountain Iron
 Municipal Water, Light & Heating
 Plant

New Prague
 Municipal Light and Water Plant

New Ulm
 New Ulm Public Utilities
 Commission

Owatonna
 Owatonna Municipal Public Utilities

Rochester
 Franklin Heating Station
 Rochester Public Utilities

Sleepy Eye
 Sleepy Eye Public Utilities

Springfield
 Springfield Electric Light & Water
 Dept.

St. Paul
 Northern States Power Co.

Virginia
 Virginia Dept. of Public Utilities

Willmar
 Willmar Municipal Utilities
 Commission

Worthington
 Worthington Municipal Public
 Utilities

MISSOURI

Jefferson City
 Missouri Power & Light Co.

Table 3.1 (Cont.)

MISSOURI (Cont.)

Kansas City
Kansas City Power & Light Co.

St. Joseph
St. Joseph Light & Power Co.

St. Louis
Union Electric Co.

NEBRASKA

Omaha
Northern Natural Gas Energy
Systems Div.

NEW HAMPSHIRE

Concord
Concord Steam Corp.

NEW JERSEY

East Newark
East Newark Realty Corp.

Elizabeth
Waverly Properties

Fairlawn
Fairlawn Industries

Passaic
Passaic Pioneer Properties Co.

NEW YORK

Arcade
Arcade Municipal Steam Plant

Bronxville
Lawrence Park Heat, Light &
Power Co.

New York City
ATCO Properties & Management
Consolidated Edison Co. of
New York

Rensselaer
General Aniline and Film Corp.

Rochester
Rochester Gas and Electric Corp.

OHIO

Akron
Ohio Edison Co.

Cincinnati
Emery Realty Co.

Cleveland
Cleveland Electric Illuminat-
ing Co.
Medical Center Co.

Dayton
Dayton Power and Light Co.

Piqua
Municipal Power System

Springfield
Ohio Edison Co.

Toledo
Toledo Edison Co.

Youngstown
Ohio Edison Co.

OKLAHOMA

Tulsa
Thermal Systems Inc.

OREGON

Eugene
Eugene Water & Electric Board

Portland
Pacific Power & Light Co.

PENNSYLVANIA

Erie
Pennsylvania Electric Co.

Harrisburg
Pennsylvania Power and Light Co.

Philadelphia
Philadelphia Electric Co.

Pittsburgh
Allegheny County Steam Heating Co.
Bellefield Boiler Plant
Equitable Gas-Energy Co.

Table 3.1 (Cont.)

PENNSYLVANIA (Cont.)

Scranton
Community Central Energy Corp.

Wilkes-Barre
Wilkes-Barre Steam Heat Co.

York
Metropolitan Edison Co.

SOUTH DAKOTA

Brookings
Municipal Utilities

Mobridge
Montana-Dakota Utilities Co.

Watertown
Municipal Utilities Dept.

TENNESSEE

Nashville
Nashville Thermal Transfer
Corp.

TEXAS

Dallas
Hotel Adolphus
Lone Star Energy Co.

Houston
Houston Natural Gas Corp.

San Antonio
City Water Board

UTAH

Ogden
Auerbach Co.
Hotel Ben Loman
Zion Cooperative Mercantile
Corp.

Salt Lake City
Utah Power and Light Co.

VIRGINIA

Arlington
General Services Administration

WASHINGTON

Seattle
Seattle Steam Corp.

Spokane
Washington Water Power Co.

Tacoma
Consumers Central Heating Co.

WISCONSIN

Milwaukee
Milwaukee County Institutions
and Depts.
Wisconsin Electric Power Co.

Rice Lake
Rice Lake Steam Corp.

Waterloo
Waterloo Water & Electric
Commission

WYOMING

Cheyenne
Cheyenne Light, Fuel and Power Co.

Table 3.2

U.S. STEAM PRODUCTION AND SALES--1976

CITY	COMPANY NAME	TOTAL STEAM SOLD MM Lb	TOTAL STEAM DELIVERED MM Lb	MAXIMUM HOURLY SEND-OUT CAPACITY M Lb
New York, N.Y.	Consolidated Edison Co. of N. Y.	35,571	42,819	15,120
Philadelphia, Pa.	Philadelphia Electric Co.	7,735	8,995	3,857
Detroit, Mich.	Detroit Edison Co.	5,911	6,979	2,750
Boston, Mass.	Boston Edison Co.	5,782	6,935	2,385
Indianapolis, Ind.	Indianapolis Power & Light Co.	4,220	4,955	1,881
Rochester, N.Y.	Rochester Gas & Electric Corp.	3,284	3,601	NR
Baltimore, Md.	Baltimore Gas & Electric Co.	2,411	2,784	990
Milwaukee, Wis.	Wisconsin Electric Power Co.	2,375	2,683	1,640
Cleveland, Ohio	Cleveland Electric Illuminating Co.	2,373	2,737	1,320
Cedar Rapids, Iowa	Iowa Electric Light & Power Co.	1,804	1,936	635
St. Louis, Mo.	Union Electric Co.	1,754	1,869	1,375
Dayton, Ohio	Dayton Power & Light Co.	1,647	1,846	982
Pittsburgh, Pa.	Allegheny County Steam Heating Co.	1,346	1,803	1,041
Toronto, Ont., Canada	Toronto Hydro-Electric System	1,249	1,542	560
Denver, Colo.	Public Service Co. of Colorado	1,214	1,314	730
Seattle, Wash.	Seattle Steam Corp.	1,202	1,447	1,095
Chicago, Ill.	Chicago Union Station Co.	988	1,057	340
Kansas City, Mo.	Kansas City Power & Light Co.	877	1,133	600
Harrisburg, Pa.	Pennsylvania Power & Light Co.	845	972	500
Lansing, Mich.	Board of Water & Light	825	958	430
Atlanta, Ga.	Georgia Power Co.	748	861	656
Grand Rapids, Mich.	Consumers Power Co.	743	810	380
Vancouver, B.C., Canada	Central Heat Distribution Ltd.	729	830	535
Portland, Ore.	Pacific Power & Light Co.	721	854	487
San Francisco, Calif.	Pacific Gas & Electric Co.	720	915	375
Minneapolis, Minn.	Central Heating Co.	689	711	550
Eugene, Ore.	Eugene Water & Electric Board	551	620	e580
Spokane, Wash.	Washington Water Power Co.	505	608	457
Erie, Pa.	Pennsylvania Electric Co.	501	720	240
Omaha, Neb.	Energy Systems Division	483	e494	250
Birmingham, Ala.	Alabama Power Co.	473	e581	e476
Winnipeg, Man., Canada	Winnipeg Hydro CSH Div.	447	538	330
St. Paul, Minn.	Northern States Power Co.	441	537	350
Scranton, Pa.	Community Central Energy Corp.	371	503	362
Hartford, Conn.	Hartford Steam Service Co.	349	385	339
Nashville, Tenn.	Nashville Thermal Transfer Corp.	242	254	209
Rochester, Minn.	Rochester Public Utilities	228	e272	150
Cambridge, Mass.	Cambridge Steam Corp.	163	177	825
Concord, N. H.	Concord Steam Corp.	152	176	112
Fairbanks, Alaska	Fairbanks Municipal Utilities	151	202	100
Bronxville, N.Y.	Lawrence Park Heat, Light & Power Co.	120	185	150
Piqua, Ohio	Municipal Power System	114	129	80
Cheyenne, Wyo.	Cheyenne Light, Fuel & Power Co.	70	97	80
Southfield, Mich.	Dayton Hudson Properties	NR	93	110
Rice Lake, Wis.	Rice Lake Steam Corp.	66	66	NR

- There was a general consensus that competition from other types of heating systems was an important factor in terms of the demand for district heating. In almost all cases, the respondents said that the bottom line was cost. If the cost of the heat were less using competitive systems (and they often have been historically), customers would use the competitive systems.
- Maintenance and installation costs of the distribution systems were viewed as problems. While there was some disagreement about maintenance costs being high, there was almost universal agreement about the high installation costs of the distribution system being a barrier to system expansion. Cost estimates of installation range from \$300 to \$1200 a foot depending upon the area. In addition to the cost of installation, the logistics of laying the pipes under already overcrowded city streets was presented as a problem.
- There was general agreement that the heat loads are not sufficiently diverse, resulting in poor load factors. Most of the utilities had high peak loads during the winter and substantially lower seasonal loads in off-peak seasons. (The load factors range from 14 to 56 percent, with an unweighted average of 35.4 percent for the 41 steam systems that generate more than 80,000 pounds of steam annually.)
- There was general consensus that it was difficult to find plant sites to serve new areas. The difficulty in transmitting steam over long distances requires a proximity of the generator to the load and, because of the noise and other pollution problems, siting has been a major problem.

In summary, the state of district heating the United States is one without dynamic growth. The size and number of systems have basically stabilized. While there are some small high temperature water private systems (e.g., hospitals, shopping centers, military bases, etc.), all of the utility-owned or operated district heating systems use steam.

In summation, district heating systems have assumed positions of varying importance in fulfilling energy needs around the world.

- There are at least 23 countries using district heating systems, with connected thermal capacities ranging from 100 megawatts to over 494,000 megawatts.
- International district heating schemes use a variety of different systems configurations using either high-temperature hot water or steam as the transmission media.
- Combined heat and power generation produce much of the energy required for the district heating systems. (This is particularly true for the Soviet Union and Sweden.)
- While the forces that have promulgated district heating vary from country to country, the major forces include
 - ° attitudes towards conservation and energy independence.
 - ° problems with and attitudes towards pollution-control requirements.
 - ° government involvement in the planning process in general, and energy resource planning in particular.

SYSTEM CHARACTERISTICS

Rationale for Selection of Systems

To be realistic and credible and to focus on technical and market risk, simulation of private-sector decisionmaking involved in establishing innovative Integrated Energy Utilities should

- consider only those modes of power and heat generation for which most of the technology and cost factors are well understood by the private sector, and
- be based upon a logical progression from small, simple cogeneration-system components to larger, more complex systems and components.

In order to narrow the scope of the simulation to reasonable proportions, all of the specific Integrated Energy Utility systems to be analyzed include generation of electricity and are connected to existing electric grids in accordance with usual electric-utility practices. Interconnection with the electric grid is assumed to assure reliability of electric service and a market for electricity.

All systems distribute salable thermal energy (loosely, heat) in the form of high temperature water. Typical HTW temperatures are 350°F (175°C) sendout, 150°F (65°C) return. The method of producing or extracting heat varies from system to system. The reasons for choosing HTW as the heat-delivery medium, rather than steam, have been discussed.

Three types of plants are considered, progressing from simple to complex. Each type of plant can be configured for cogeneration.

- Combustion gas turbine, oil-fired
- Coal-fired steam
- Light water reactor (LWR).

Gas Turbines

An oil-fired gas turbine plant is often designed to accommodate exhaust-gas heat-recovery systems, which can be installed during construction or as a field modification. The heat-recovery system in a combined-cycle gas turbine plant drives a steam turbine-generator.

Simple-cycle gas turbines are usually operated by utilities only during peak load periods. For cogeneration, simple-cycle gas turbines would be equipped with a heat-recovery system and become useful (i.e., economic) for operation as intermediate- or base-load electric plants. In fact, unless the gas turbine is operated for substantially more hours than are required for peaking duty, its use for heat production would not be economical.

Coal-Fired Plants

The second type of plant to be considered is the coal-fired steam plant. Industrial cogeneration commonly uses steam turbine-generators, in sizes less than about 300 MW electric, to generate power and furnish process heat. Steam may be extracted from the turbine at desired temperature-pressure conditions, or the system may be non-condensing (backpressure) so that relatively low temperature steam is discharged from the turbine outlet, or both. (The thermal energy of the steam can readily be used to heat water for HTW distribution.) Steam extraction and backpressure operation are obvious candidates for Integrated Energy Utility coal-fired plants; although sizes larger than about 300 MW electric have not been manufactured in the United States, they could be developed.

Nuclear Plants

The third type of plant to be considered is present-day nuclear; i.e., using a light water reactor. Until recently, LWR-powered cogeneration plants have not been seriously considered in the United States, but have been lately in the United States and in Europe. The high capital cost of nuclear plants, the low cost of nuclear fuel, and the desirability of operating the reactor at essentially constant load, all suggest that nuclear plants could play an important role in large-scale cogeneration. As will be discussed in the next section, heat storage appears essential if the cogeneration potential of LWR plants is to be adequately realized.

Common Elements: Storage, Transmission, Distribution

Need for Storage

The amount of electricity produced by a cogeneration plant is determined by the electric load, or demand, which the plant is to satisfy. Depending on how the plant is dispatched (centrally controlled) as part of the electric grid to which it is attached, the annual capacity factor* may be low (0.2), intermediate (0.5), or high (0.7), corresponding roughly to peaking, mid-range, and base loading. Until technology required for its storage becomes available, electricity must be generated in instantaneous response to demand. Perhaps the nearest approach to large-scale storage of electricity is a pumped hydro system: water falls from a reservoir through a turbine to generate electricity during peak load periods, and is pumped

*Ratio of energy generated during a given time period to that which could be generated if the machine were operated continuously at nameplate rating.

back into the reservoir during off-peak periods by utilizing the turbine as a pump and the electrical generator as a motor. Electricity to drive the motor is generated at a base-load thermal plant.

Because electricity must be generated in instantaneous response to demand, heat is a byproduct of electric generation in a cogeneration system. Only rarely will the amount of byproduct heat, the time when it is produced, and the location where it is produced, match the demand for heat.

In small total-energy (cogeneration) systems, the electrical and heat loads are colocated and matching heat supply and demand is achieved--to a limited extent--by storing hot water in a tank. Such storage typically can smooth and match daily fluctuations in supply and demand, but not weekly or longer term cyclic fluctuations.

Larger cogeneration systems may be found in industrial plants where there is immediate use for all the byproduct heat, e.g., paper and pulp plants. Given a large and dependable demand for heat, cogeneration can save money and fuel. In-plant power generation is commonly evaluated in terms of "fuel required for power"--often less than half of the average for fossil-fuel-fired utility plants.* The fuel charged to power generation may be as little as 4,000 Btu/kWh (1.17 J/J), corresponding to an efficiency of 85 percent; this illustrates one way of expressing the benefits of cogeneration.

Large-scale cogeneration by utilities will involve central stations, not located near electric or heat load centers. Just as the electric product must be transmitted and distributed to consumers, the heat must be transmitted and delivered. At this point the analogy fails. The pipeline system which delivers byproduct heat should be like a water-supply system which

*J. M. Kovacik, "How to Evaluate the Effectiveness of Industrial Plant Energy Systems," Combustion (December 1975), pp. 21-28.

conveys water from large, distant reservoirs to a city, where the water is fed into a number of smaller reservoirs and held until needed. However, reservoirs for holding water at temperatures of 350°F (175°C) would have to be insulated to reduce heat loss, and be able to contain pressures of about 150 psig (1030 kPa), which would make them inordinately expensive.

To avoid the need for HTW storage vessels, present-day district heating systems are supplied with only as much HTW from central stations as the district heating system can circulate and return to the station. This implies that the central station must "load-follow," which is neither economically nor technically desirable for large plants, or that the central station must supply only the base (i.e., minimum) heat load during a day, or perhaps a week. The base-loading approach is followed in dispatching large, central electric plants. For central heat plants, it implies that heat loads exceeding the base load must be supplied from sources other than the central station.

In HTW district heating systems in Europe, auxiliary oil- or gas-fired boilers are installed at various points in the load area to handle peak loads and to serve as backup heat sources to improve reliability of service. Although the economics of using auxiliary boilers have proven favorable in numerous district heating systems, this approach limits the amount of centrally generated heat which can be used, and thus limits the overall fuel efficiency of the system and its effectiveness in displacing gas and oil with coal or nuclear fuel. Further, it imposes air-pollution emissions on the urban areas where the heat load centers occur, or at least does not reduce the air pollution from self-generation of heat in industrial, commercial, and residential areas by as much as with central station generation.

Earlier TEMPO studies explored the problem of matching heat supplied from cogeneration plants to heat demands in industrial plants and district heating systems.* It was immediately obvious that large-scale storage of hot water would greatly improve the effectiveness of large cogeneration systems. If all byproduct heat from a cogeneration plant could be delivered to a heat storage, transmission, and distribution system, regardless of when it is generated, the benefits would be

- elimination of expensive facilities for disposing of heat at the central station--cooling ponds or towers, or once-through cooling from streams, lakes, or the ocean.
- elimination of thermal pollution resulting from waste-heat disposal.
- less costly pipelines, because they could be operated at a high capacity factor at all times; hot water would be fed from storage when demand is high, fed into storage at load centers when heat loads are low. Heat loss associated with transmission would be minimized.
- obviate auxiliary boilers otherwise needed to handle peak heat loads and improve heat-service reliability.
- eliminate air pollution from auxiliary boilers near load centers.
- require less real estate than for auxiliary boilers and, for coal- or oil-fired units, the associated fuel-storage areas.
- conservation of fuel if system efficiency is improved.
- ultimate reduction of oil and gas fuels in favor of coal and nuclear fuels.

A method for inexpensive, efficient storage of large amounts of HTW for long periods of time--several months--was proposed by TEMPO, in 1972, as

*C. F. Meyer, D. K. Todd, and R. C. Hare, Thermal Storage for Eco-Energy Utilities, GE72TMP-56 (General Electric-TEMPO: Santa Barbara, CA, December 1972).

the innovation needed in district heating or large industrial cogeneration systems to match heat supply and demand and make attainable the benefits listed above.

Heat Storage Wells

Natural, underground, porous formations have been used for large-scale storage of energy-bearing fluids since at least 60 years ago, when natural gas was first injected into old gas fields for storage during seasons of low consumption. Hundreds of underground gas reservoirs are now in use for seasonal storage so that gas pipelines can be operated year-round at full capacity.*

Aquifers are formations at depths shallower than gas and oil reservoirs, hence less consolidated and therefore of greater porosity and permeability. Aquifer storage of heated water, injected and withdrawn through Heat Storage Wells, appears to be particularly well suited for seasonal storage of large amounts of thermal energy. The volume of inexpensive storage space in aquifers is almost beyond comprehension: the estimated amount of groundwater contained in the upper half-mile of the continental crust is nearly 20 times greater than all of the water in all rivers and lakes.** The land area required for a water well is quite small. The cost of storing and of withdrawing the hot water is low if spread over enough units of heat--i.e., if large, efficient wells are used.

*Donald L. Katz, and Keith H. Coats, Underground Storage of Fluids (Ann Arbor, MI: Malloy Lithographing, Inc., Ulrich's Books, Inc., 1968 [second printing, 1973]), p. 575.

**U.S. Geological Survey, Water of the World, Pamphlet GPO: 1972-472-411 (Washington, DC, 1972), p. 20.

The heat loss per unit of heat stored in an aquifer (for a given period of time) decreases as the amount of stored energy increases. Heat loss occurs principally at the interface between hot and cold water in the aquifer, and between hot water and the layers of low-permeability clay or rock which confine the vertical movement of water in an aquifer. The ratio of surface area to contained volume of hot water decreases with increasing volume, hence with the amount of thermal energy stored. These considerations suggest that aquifer storage of heated water may be particularly well suited to large cogeneration systems. Thus, there is a trade-off between using small storage areas close to load centers in order to maintain high capacity factors in the transmission pipelines and using larger storage near the generation plants to maintain high storage efficiency.

Aquifers that are not confined by impermeable formations cannot contain the vapor pressure of water heated above the local boiling point. This is a limitation on both the energy density and the usefulness of the hot water for space heating, hot tap water, absorption air conditioning, or industrial process heat. Confined aquifers can contain higher temperature, pressurized water.

Liquid-dominated geothermal reservoirs illustrate pressurized storage in confined aquifers at temperatures well above 212°F (100°C).^{*} Impermeable layers overlying these geothermal reservoirs contain the vapor pressure and cause the hot geothermal fluid to remain liquid at temperatures of 400°F (200°C) or higher. Confined, pressurized aquifers containing brackish or saline water are often found beneath aquifers from which potable water is

^{*}The several distinctions between naturally occurring geothermal reservoirs and underground artificial storage of injected hot water limit the analogy between geothermal energy and aquifer thermal energy storage.

produced for municipal and industrial use. The fact that the salty water has not migrated upward into the freshwater aquifers shows that the deeper formation is indeed confined.

A vast amount of information on freshwater aquifers is available; there are 15 million water wells in the United States, and more than a half-million new ones are drilled each year. Much less information is available on saltwater aquifers, because a comparatively small number of wells have been drilled into them--some for waste disposal, some to produce water for industrial purposes. However, saltwater aquifers are known to exist under much of the United States, where bedrock is not close to the surface, because they have been penetrated by many oil and gas wells and their presence has been logged. Use of saltwater aquifers for thermal energy storage is a more promising strategy than competing with water-supply uses of confined freshwater aquifers.

The Heat Storage Well concept developed at TEMPO is sketched in Figure 3.2. Two wells are drilled into a confined aquifer. Groundwater pumped from one well is injected into the same aquifer through another, nearby well, as shown in Figure 3.2. Initially, the aquifer matrix and the native groundwater are cold. To begin storing heat, cold groundwater is pumped through a heat exchanger (HX), heated, and injected into the "hot well." When stored heat is to be recovered and used, water is pumped from the hot well, circulated through the heat exchanger where it gives up its useful heat, then is injected into the "warm well"--no longer cold, because the lowest useful temperature in the heat system is higher than the native groundwater temperature.

For the system to operate properly, the warm and the hot well must be far enough apart to prevent breakthrough. The breakthrough effect in doublet

Figure 3.2. Heat Storage Well Doublet.

wells has been analyzed by BRGM in France,* and others. The separation required between wells will depend upon the aquifer parameters, the maximum injection volume and rate, and the water temperatures. Hot water is less dense and much less viscous than cold water, which produces a tilted interface something like that sketched in Figure 3.2.

Heat Storage Wells will be drilled into confined saline aquifers wherever possible. A reasonable expectation is that deep, saline aquifers will be sufficiently pressurized to maintain hot water injected into the aquifer as a liquid at temperatures of 350°F (175°C) or more; saturation pressure at

*(BRGM) Bureau de Recherches Geologiques et Minières, A Theoretical Study of Heat Extraction from Aquifers with Uniform Regional Flow, by A. C. Gringarten and J. P. Sauty, BRGM Report No. 3672 (Orleans, France: December 4, 1974).

350° is 135 psi (931 kPa), requiring a hydrostatic head of at least 280 feet (85 m) to prevent the water from flashing into steam.

The doublet configuration will avoid land subsidence (all water withdrawn is immediately returned to the aquifer) and minimize the clogging which often occurs when non-native water is injected into an aquifer. It also permits use of a heat exchanger (HX in Figure 3.2) to avoid circulating mineralized groundwater through hot-water transmission or distribution pipelines. Water suitably treated for sending through pipelines passes through one side of the heat exchanger, picking up heat or delivering it to be stored. Only the well-water side of the heat exchanger is exposed to possible corrosive or scaling effects. Conversely, the groundwater and aquifer are protected against possible pollution from the chemicals used to treat the pipeline water. Also, the operating pressures of pipeline and doublet are isolated by the heat exchanger, which is a desirable degree of freedom.

In France, Charroppin and others* and Despois and Nougarede**, *** have examined the technology and economics of thermal energy storage in aquifers. Their conclusions are in general agreement with TEMPO's. The practical

*P. Charroppin, J. Despois, J. C. Fauconnier, and F. Nougarede, "Underground Heat Storage in Captive Aquifers," International Total Energy Conference (Copenhagen, Denmark: October 4-8, 1976), pp. 460-494.

**J. Despois, and F. Nougarede, "Stockages Souterrains de Chaleur," Revue Generale de Thermique, No. 184 (Paris, France: April 1977), pp. 359-366; English abstract, "Underground Heat Storage," Revue Generale de Thermique, No. 184 (Paris, France: April 1977), pp. 357-358.

***J. Despois, and F. Nougarede, "Technologie du Stockage souterrain d'eau chaude," Proceedings, Conference prononcee aux Journees d'etude, des 2 et 3 juin 1977 de la Societe des Electriciens, des Electroniciens et des radioelectriciens [Gif sur Yvette] (France: June 1977).

problems of pumps, valves, and other doublet hardware are treated somewhat more extensively than has been reported elsewhere.

Economics of Heat Storage Well Applications. Recognizing that actual construction and operation of Heat Storage Wells remains to be fully investigated, at least a first-order approximation of the capital and operating costs can be made.

For cogeneration system application, a moderately large Heat Storage Well doublet is assumed, with a capacity of one million gallons ($3,800 \text{ m}^3$) per day. This amount of water heated from 150°F (65°C) to 350°F (175°C) carries thermal energy at a 20-megawatt rate.

The capital cost of a 20-megawatt doublet, including wells, heat exchanger, and controls, is estimated to be from \$400,000 to \$1,100,000. The lower figure might apply for relatively shallow wells, easy drilling, and no water treatment; the higher, for deep, difficult wells producing water requiring treatment. The nominal cost is taken as \$800,000. At a fixed-charge rate of 0.15, the annual capital cost would be \$120,000 nominal, with a range from \$60,000 to \$170,000. The annual variable cost (operation and maintenance) is estimated to be \$3,700, with a range from \$2,100 to \$5,200, for a capacity factor of 0.70.

In contrast to other energy-storage systems, the cost of Heat Storage Wells is essentially independent of the amount of energy to be stored, once a suitable aquifer has been tapped. The cost depends almost entirely on the rate of energy storage or withdrawal, whichever is greater.

Energy Recovery Efficiency. At the end of 90 days of injecting one million gallons ($3,800 \text{ m}^3$) of hot water per day, 44,000 megawatt-hours (158 TJ) of thermal energy will have been injected. The stored hot water will occupy a roughly conical volume of the aquifer, as suggested in Figure 3.2,

with an average radius of approximately 250 feet (76 m). If hot water is pumped from the well until its temperature drops to 310°F (155°C), the thermal energy recovered from the first cycle is estimated to be 65 to 70 percent of that injected. After five cycles, the recovery efficiency is estimated to be 75 to 80 percent.*, **

State of Knowledge of Aquifer Thermal Energy Storage. Geologists and groundwater hydrologists agree without hesitation that hot water can be injected into the ground, stored, and recovered. This is intuitively obvious because sand and rock are good thermal insulators and there is an enormous amount of storage space in the groundwater aquifers that underlie most of the United States. However, actual operation of Heat Storage Wells on a suitably large scale with HTW has yet to be demonstrated.

Incidental storage of warm water in aquifers has occurred during the past several decades in areas where water pumped from wells for cooling air-conditioner coils must be returned to the aquifer from which it was withdrawn. Long Island, New York is one of the best-known examples. There, the local temperature of shallow aquifers has risen as much as 30°F (17°C). In Fresno, California, the Public Works Department reports that waste heat from air conditioners has raised the local groundwater temperature from its normal 69°F (20°C) to 82°F (32°C); since 1973, the Fresno City Hall has been heated entirely by use of this heated groundwater.

*Charles F. Meyer, and David K. Todd, "Conserving Energy with Heat Storage Wells," Environmental Science & Technology, Vol. 7, No. 6 [General Electric-TEMPO Paper P-623] (June 1973), pp. 512-516.

**C. F. Tsang, M. J. Lippmann, D. B. Goranson, and P. A. Witherspoon, "Numerical Modeling of Cyclic Storage of Hot Water in Aquifers," Fall Annual Meeting of the American Geophysical Union [Lawrence Berkeley Laboratory Report LBL-5929] (San Francisco, CA: December 6-10, 1976).

Water-quality regulations require that brines from inland oil wells and from geothermal wells be injected back into the ground. Experience with brine-injection wells and industrial waste-disposal wells can provide site-specific information about the hydraulics of saltwater aquifers, which will be helpful in validating mathematical models of the injection of hot water into similar aquifers. Of greater importance to analyzing thermal energy storage in aquifers is the geochemical information to be gained from brine- and waste-injection wells. The design of injection wells must take into account the potential chemical interaction between the native groundwater and the injected fluid. If precipitates are formed, the pores of the aquifer may clog and the well fail.

Documented experience in large-scale aquifer storage of cold water in winter for use in summer is available. It dates back at least as far as World War II, when distilleries in Louisville, Kentucky, recharged cold municipal water into their own supply wells during the winter, to be withdrawn in the summer for process cooling. A similar purpose was served by recharging aquifers near Peoria, Illinois, along the Illinois River, using cold river water drawn by gravity into a recharge pit. This project was conducted by the Illinois State Water Survey, beginning in 1951.* Currently, two field tests involving aquifer storage of cold water are being funded by the Department of Energy. One is to be conducted at Kennedy Airport in New York, the other at Texas A & M University.**

*David K. Todd, Ground Water Hydrology (New York: John Wiley & Sons, Inc., 1959), pp. 259-265.

**R. R. Davison, W. B. Harris, and John H. Martin. "Storing Sunlight Underground - The Solaterre System," Chemtech, Vol. 5 (December 1975), pp. 736-741.

Three field tests involving injection and recovery of heated water, at temperatures below 200°F (93°C), have recently been performed. One, in Germany, prompted by TEMPO's reports, was conducted in 1973 and reported in 1975.* Unfortunately, only a small amount of warm water was injected, leading to highly questionable conclusions. Another, at Auburn University in Alabama, involves injection of a larger amount of water but has encountered experimental difficulties.** The U.S. Department of Energy is funding a continuation of this important investigation. The third field test, at Moulin de Croz in the Jura mountains of France, is mentioned by Despois and Nougarede*** but results are not reported.

Analytic work based on the extensive knowledge of aquifers available in the literature of hydrology, geology, and petroleum engineering, and on limited field data so far available, supports the belief that aquifer storage of thermal energy is technically feasible. Carver,****

*Wolfram Kley, and Hans-Günter Nieskens, "Möglichkeiten der Wärmepeicherung in einem Porengrundwasserleiter und technische Probleme bei einer Rückgewinnung der Energie" (Practical Ways of Heat Storage in a Porous Aquifer and Technical Problems of Energy Recovery" — in German; English abstract), Z. dt. geol. Ges. (Hannover, Germany: 1975), pp. 397-409.

**Fred J. Molz, James C. Warman, Thomas E. Jones, and George E. Cook, "Experimental Study of the Subsurface Transport of Water and Heat as Related to the Storage of Solar Energy," presented at A Joint Conference 1976 of the American Section of the International Solar Energy Society and the Solar Energy Society of Canada, Inc. (Winnipeg, Canada: August 15-20, 1976).

***J. Despois, and F. Nougarede, "Technologie du Stockage souterrain d'eau chaude."

****John A. Carver, Jr., "Legal and Institutional Planning for Macro-conservation Measures," Public Utilities Fortnightly, Vol. 95, No. 9 (April 24, 1975), pp. 29-33 .

Hausz,* Meyer,** and others have written a number of reports and papers describing results of TEMPO studies of the economic, legal, institutional, regulatory, environmental, and energy-conservation aspects of the Heat Storage Well system concept.

Hot Water Transmission and Distribution

The cost of transmitting high-temperature water from central plants to distribution centers, and of distributing the HTW to consumers, is expected to be a dominant part of the heat system cost. This section describes HTW delivery systems and costs.

Heat transmission and distribution systems will include Heat Storage Wells which may be located at the central plant(s), within load areas, and at intermediate points. The siting of heat storage will be determined in part by availability of suitable aquifers and, to the extent aquifers are available, by opportunities to enable expensive pipelines to be operated at a high capacity factor. Siting heat storage both near the plant(s) and near each load area will smooth both supply and demand fluctuations, making pipeline flow as uniform as possible thus minimizing transmission cost per unit of energy. In addition, the stored heat will provide a backup supply in case of plant or pipeline failure. Figure 3.3 is a schematic of a possible heat-delivery configuration.

*Walter Hausz, "Statement Before the Energy and Power Subcommittee of the Interstate and Foreign Commerce Committee, U.S. House of Representatives," Omnibus Energy Conservation Act HRI2169 [General Electric-TEMPO Paper P-737] (20 July 1976).

**C.F. Meyer, W. Hausz et al., Role of the Heat Storage Well in Future U.S. Energy Systems.

Figure 3.3. Pipeline Network to Load Centers.

Transmission Costs. HTW transmission will be used for long distances and large energy flows: more than 10 kilometers and more than 100 megawatts thermal. The reference case, from earlier studies and current references, uses dual 1.0 meter pipelines, insulated, to send out water at 350°F (175°C) and return it at 150°F (65°C); ΔT is 200°F (110°C). For optimum flow velocity and other conditions, this reference-system pipeline loop will transport thermal energy at a rate of 700 to 800 megawatts thermal. Its cost in 1976 dollars is taken to be \$2.2 million/kilometer (\$675/foot). The optimum is broad. Total costs--capital amortization plus pumping cost, heat loss, and maintenance--are within 20 percent of the optimum from 500 to 1100 MW.

Choice of a reference or "typical" cost is necessarily arbitrary. The reported range of capital costs for transmission is at least 8:1, depending upon terrain and environmental factors. Polymer concrete and armored plastic

pipes are being developed and proven, which cost about half as much as present-day steel pipes. As new technology comes into use, the cost range for transmission will extend further on the low side, and thus increase from about 8:1 to 10:1 or more. For subtransmission--within urban areas, from transmission terminals to various distribution centers--the cost effect may be even greater, causing the cost range to be perhaps 12:1.

Figure 3.4 illustrates several insulated dual-pipeline configurations for HTW, including direct burial (A) and the aboveground trestle (C) employed for the Alaskan oil pipeline. Direct burial is usually the least expensive, but may not be acceptable: adequate moisture-proofing is difficult, inspection of buried pipes is not possible, and heat loss may be high in wet

Figure 3.4. Dual Pipeline Configurations.

ground. For large pipe diameters the wall must be strong enough to support the fill; this requirement may reduce the cost advantage of direct burial. Configurations (B) and (C) of Figure 3.4 may be unacceptable because they interfere with passage of large animals and are highly visible. Configuration (D) is most expensive but provides good protection against groundwater if properly laid and drained. Not illustrated is a practice in Sweden--the use of tunnels drilled through rock as much as 2,000 feet below the surface. According to Margen,* tunnel projects in Stockholm cost about the same as underground steel pipes in covered concrete culverts. In an ongoing study of district heating system expansion in Minneapolis and St. Paul, Minnesota (in conjunction with central cogeneration), Margen suggests that tunnels may be the preferred approach for installing new HTW mains because good tunneling rock underlies the urban areas.

The present and projected costs of HTW transmission have been studied and the results reported in the technical literature by a number of authors. Four of these reports from Europe and three from the United States were selected as a basis for arriving at a typical or reference cost of transmission.

Dr-Ing. Klaus Hannes of STEAG, in Germany, in a May 1976 personal communication to TEMPO, reported contract costs for a 30-km pipeline network, "Fernwärmeschiene RUHR." These costs were higher than any others reported. For a one-meter dual pipeline, the reported cost is \$3.6 million/km (\$1090/foot) for configuration (D) in open country. This cost increases 10 percent for urban installations, and decreases 20 percent for configuration (B) in open country.

*Peter H. Margen, District Heating Development in Work in Sweden, AE-VS-159 (Studsvik, Sweden: Aktiebolaget Atomenergi Sweden, 23 May 1975), 34 pp.

Peter Margen of AB Atomenergi, Sweden, provides costs of various types and configuration of pipeline in different terrain.**,** For a dual one-meter pipeline operating at 300°F (163°C) sendout and 160°F (70°C) return, with his 1975 costs converted to 1976 dollars, the buried-culvert configuration of Figure 3.4(D) in Sweden costs \$2.2 million/kilometer (\$660/foot) for difficult ground conditions, \$1.5 million/kilometer (\$460/foot for average condition. Margen expects plastic pipes armored with fiberglass and polymer concrete pipes laid directly in the ground, to reduce costs by a factor of two for one-meter pipelines.

Professor Bjørn Qvale, of the Technical University of Denmark, has compiled HTW transmission costs in Scandinavia which he communicated to TEMPO in 1976. One-meter pipelines, configuration (D), operating at 250°F (120°C), cost about \$1.6 million/km (\$475/foot)--in close agreement with Margen's estimate.

Neil Muir, of the Swedish firm STAL LAVAL, which has supplied numerous steam turbines for cogeneration plants, reports the results of a detailed study made by the Stockholm Energy Company.*** The cost of installing a district heating system (including production of HTW) is compared to the cost of reinforcing an electrical distribution system to carry an equivalent

*P. Margen, District Heating Development Work in Sweden, Figure 8.

**P. Margen, "New Types of Hot Water Distribution Systems for Low Density Heat Areas," in Official Proceedings of Sixty-Seventh Annual Meeting of the International District Heating Association (Pittsburgh, PA: International District Heating Association, 1977), Figure 7, p. 76.

***Neil Muir, Combined District Heating and Electricity Production in Sweden, STAL-LAVAL Report 1/76, presented at the Symposium on Energy Conservation in the Built Environment (Garston, England: April, 1976), Appendix 3, 20 pp.

heating load. For electric heating, the 1974 production cost for a nuclear plant was 13.8 mills/kWh; electrical transmission and distribution costs would add 2.7 mills/kWh; the total would be 16.4 mills/kWh. For a central district heating plant producing only HTW, a new production plant would be charged to the heat system, plus the cost of tunnels, trunks, distribution and service mains, metering, and engineering. The end result is an estimated production cost of 9.1 mills/kWh and delivery cost of 1.3 mills/kWh for heat, or a total of 10.4 mills/kWh. This cost is to be compared to the 16.4 mills/kWh for electric heating. Muir notes that the cost of heat is based on HTW production in single-purpose plants, and comments that considerable cost advantages could be reaped by combined production of electricity and heat.

Heat transmission costs per unit distance are not given in Muir's report, but the cost of transmission is shown as about 70 percent of the total cost of the heat-delivery system. That this is high compared to another estimate will be brought out later.

The Swedish comparison between the costs of displacing gas- or oil-fired on-premise heating with central electricity or with district heating is of particular interest because it was prepared by an Integrated Energy Utility: the Stockholm Energy Company supplies electricity, gas, and district heating.

In technical literature of the United States, TEMPO appears to be the only organization which has reported on studies of HTW transmission systems coupled with seasonal heat storage. The inclusion of heat storage substantially affects the design of heat systems, as well as their economics, environmental impact, and institutional aspects. A list of TEMPO reports and papers is provided in the Bibliography.

Brookhaven National Laboratory, under contract to ERDA (now the Department of Energy), conducted an extensive study of the technical and economic feasibility of U.S. district heating systems using waste heat from fusion reactors.*,** The typical sendout temperature from the waste heat source assumed by Brookhaven is 210°F (100°C), the return temperature 125°F (52°C). However, the transmission pipes discussed in the Brookhaven reports are capable of withstanding pressures of 325-400 psi (2240-2760 kPa), and thus are suitable from a pressure standpoint for withstanding the vapor pressure of 350°F (175°C) water: 135 psi, 930 kPa.

For rural transmission, Brookhaven estimates a one-meter dual pipeline to cost about \$95/foot, insulated and direct buried. In rural areas, pipe is said to be the dominant cost element, as for oil pipelines. Labor is the dominant cost element in cities. For New York City, Brookhaven's estimated cost for one-meter dual pipeline is \$420/foot. Their discussion of this estimate references one of Peter Margen's reports on 1975 Swedish costs, noted earlier.*** In the second of Margen's reports on 1975 Swedish costs,**** which was presented subsequent to the publication date of the Brookhaven report, he supplements the information given in his earlier report: costs

*J. Karkheck, E. Beardsworth, and J. Powell, The Technical and Economic Feasibility of U.S. District Heating Systems Using Waste Heat from Fusion Reactors, BNL 50516 (Upton, NY: Brookhaven National Laboratory, February 1976), 148 pp.

**J. Karkheck, J. Powell, and E. Beardsworth, "Prospects for District Heating in the United States," in Science, Vol. 195 (11 March 1977), pp. 948-955.

***P. Margen, District Heating Development Work in Sweden, Figure 8.

****P. Margen, "New Types of Hot Water Distribution Systems for Low Density Heat Areas," Figure 7, p. 76.

are shown for different pipes, configurations, and ground conditions. Both of the Margen reports show about \$435/foot (in 1975 dollars) for steel pipe-line in concrete culvert. Only the later report indicates this cost is for average ground conditions and that difficult ground conditions increase the cost to \$625/foot (1975 dollars). Presumably, installation in New York City would at best be considered "difficult," thus Brookhaven's cost estimate appears to be at least 30 percent low. Might their other estimates for transmission costs also be low? An affirmative answer to this question is suggested by noting that Brookhaven's estimated cost of HTW transmission and subtransmission for New York City is about 40 percent of the total delivery cost, with distribution accounting for the remaining 60 percent. This is about 30 percent lower than the 70-percent share of HTW delivery costs attributed to transmission trunks by Muir, noted earlier. Note also that Brookhaven's \$420 estimate is only 39 percent of STEAG's \$1090/foot.

Anderson and others at Oak Ridge National Laboratory, operated by Union Carbide Corporation for ERDA (now the Department of Energy), reported on cost of steam lines extending five to ten miles from plant to distribution points.* A single 36-inch (~1-meter) steam line, surface mounted on concrete piers, with large expansion loops, is estimated to cost \$560/foot (in July 1974 dollars). Pressure and temperature are significantly higher than those for HTW. Average terrain conditions are assumed. This cost estimate of \$560/foot for a single pipe suggests that Margen's \$435/foot for two pipes (1975 dollars) is not too high.

*T. D. Anderson et al., An Assessment of Industrial Energy Options Based on Coal and Nuclear Systems, ORNL-4995 (Oak Ridge, TN: Oak Ridge National Laboratory, July 1975), Appendix B.

Reference Cost of Transmission. Based on the preceding review and discussion, the reference capital cost chosen for HTW transmission using a one-meter dual pipeline carrying 700 thermal megawatts (40 million Btu/minute) is \$675/foot (\$2.2 million/km, \$3.5 million/mile). This includes pumping stations.

Over a range from 500 to 1100 thermal megawatts, the capital cost of transmission in millions of 1976 dollars is then:

$$\text{Cost} = 220 \times \left(\frac{\text{MW}}{700} \right)^{0.48} \times \left(\frac{\Delta T}{110} \right)^{-0.48} \times \frac{D}{100}$$

where

MW = thermal megawatts to be carried

T = temperature difference between sendout and return, °C or K

D = transmission distance in kilometers.

Alternatively, the unit cost is $\$2.2 \times 10^6 \times \left(\frac{\text{MW}}{700} \right)^{-0.52} \times \left(\frac{T}{110} \right)^{-0.48}$ per MW-km, which decreases with energy flow and ΔT as would be expected.

The following constraints are to be observed: For safety reasons, very large pipes at very high pressures (high ΔT) should be avoided. Roughly, energy flow in a single pipe should not exceed 2,000 MW, and ΔT greater than 140°C (280°F) should not be considered at the present state of knowledge. For reliability, redundancy may be an important consideration. Two 1,000 MW lines may be preferred to one 2,000 MW line, although costing 40 percent more.

That a wide range of transmission costs may be encountered is quite clear. The chosen reference cost is felt to be about right for typical urban densities. It could increase by a factor of three or four for difficult, downtown areas. Rural costs in very easy terrain might be lower than the reference cost by at least a factor of two. When plastic, polymer

concrete, or other less-expensive pipes are proven reliable. the cost of new installations could shift downward by a factor of two.

Relative Importance of Transmission and Distribution Costs. An integrated Energy Utility usually will have to build cogeneration plants at some distance from heat-load centers, whereas a typical district heating system employs single-purpose boilers centrally located with respect to heat loads--i.e., at distribution centers. This being the case, a useful question to pose in evaluating the economic attractiveness of large-scale cogeneration versus conventional district heating plant is: Can the large cogeneration plant, located at some distance from distribution centers, deliver HTW to the distribution centers at a cost competitive with that of heat produced by single-purpose plants located at the centers? This line of reasoning has been found useful in earlier studies.*

For large heat loads, such as industrial plants, transmission is also an important cost element in comparing local heat production versus importing heat from large cogeneration plants. No distribution is involved, other than that already in place or needed in any event.

For residences and dispersed commercial consumers, both transmission and distribution are involved. However, distribution costs are so site-specific that typical values are even harder to estimate than for transmission; any economic analysis which is not site-specific must be viewed as quite preliminary. Inclusion of estimated distribution costs is, of course, necessary in evaluating the economics of displacing on-premise heat sources with district heat. At the least, sensitivity of the analytic results to variations in distribution costs can be evaluated.

*C. Meyer, W. Hausz et al., Role of the Heat Storage Well in Future U.S. Energy Systems, Section 5.

Distribution Costs. The most extensive report on district-heating distribution costs is one published by Karkheck, Beardsworth, and Powell, of Brookhaven National Laboratory.* Structures of distribution systems are postulated and their costs estimated for nine regions: New York, Chicago, Philadelphia, Los Angeles, New Orleans, Baton Rouge, and the Standard Metropolitan Statistical Areas of Jersey City, Newark, and Paterson.

As was found to be the case with transmission cost estimates in the February 1976 Brookhaven report, distribution cost estimates published subsequent to the Brookhaven report showed considerably higher costs than those of Brookhaven. In particular, an October 1977 Oak Ridge National Laboratory report authored by M. Olszewski** presents a table of commercial-residential subregion costs derived from an earlier ORNL/HUD/MIUS report by J.T.

Meador.*** The cost estimates of the Meador report, updated to mid-1976 dollars in the Olszewski report, are reproduced in Table 3.3. They are based on conduit applicable for HTW at temperatures up to 400°F (204°C), consisting of steel pipe, insulation, and cast assembly with spacers inside an epoxy-coated casing. An allowance is added to these materials covering prefabrication costs for expansion joints and underground installation. The data appears to give reasonable results for the heat-load densities of garden apartments but are not valid for center city areas. Estimates made by Burns and Roe are considerably higher than those by Olszewski.****

*J. Karkheck, E. Beardsworth, and J. Powell, The Technical and Economic Feasibility of U.S. District Heating Systems Using Waste Heat from Fusion Reactors.

**M. Olszewski, Preliminary Investigations of the Thermal Energy Grid Concept, ORNL/TM-5786 (Oak Ridge, TN: Oak Ridge National Laboratory, October 1977), 104 pp.

***J. T. Meador, MIUS Technology Evaluation - Thermal Energy Conveyance, ORNL/HUD/MIUS-29 (Oak Ridge, TN: Oak Ridge National Laboratory, May 1976).

****L. Ollicken and J. Phillip, "Technical and Economic Aspects of District Heating Systems Supplied from Cogeneration Systems," American Power Conference, Chicago, IL, April 24-26, 1978.

Table 3.3

DESIGN DATA AND INSTALLED COST OF NEW CONDUIT

NOMINAL PIPE DIAMETER		FLOW AREA ^a (10 ³ mm ²)	MAXIMUM FLOW RATE ^b (kg/s)	PRESSURE DROP (kPa/1000 m)	INSTALLED COST	
(inches)	(mm)				(\$/ft)	(\$/m)
0.75	19.1	0.3	0.77	3051	15.0	49.2
1.0	25.4	0.6	1.25	2283	15.7	51.5
1.25	31.8	1.0	2.15	1627	16.6	54.5
1.5	38.1	1.3	2.94	1356	18.0	59.1
2.0	50.8	2.2	4.84	1010	19.7	64.6
2.5	63.5	3.1	6.93	809	21.0	68.9
3.0	76.2	4.8	10.7	633	22.5	73.8
4.0	101.6	8.2	18.4	441	26.6	87.3
6.0	152.4	18.6	41.7	271	36.9	121.0
8.0	203.2	32.3	72.2	191	48.0	157.5
10.0	254.0	50.9	113.9	147	62.6	205.4
12.0	304.8	72.2	161.7	117	82.0	269.0
14.0	355.6	89.0	199.2	90	94.0	308.4
16.0	406.4	117.8	263.7	79	117.0	383.9
18.0	457.2	148.7	322.8	76	150.0	475.7
20.0	508.0	182.9	409.5	63	170.0	557.7
22.0	558.8	223.5	500.3	59	187.0	613.5
24.0	609.6	271.0	606.7	54	215.0	705.4
30.0	762.0	418.1	935.9	42	273.0	895.7
36.0	914.4	611.6	1369.1	33	330.0	1082.7
42.0	1066.8	838.7	1877.7	28	429.0	1407.5
48.0	1219.2	1095.5	2452.5	24	512.0	1679.8
54.0	1371.6	1396.8	3126.9	20	600.0	1968.5
60.0	1524.0	1734.2	3882.1	17	731.0	2398.3

^a Schedule 40 for pipes through 304.8 mm and standard wall for 355.6 through 1524.0 mm.

^b For velocity of 2.4 m/s and density of 918 kg/m³.

SOURCE: M. Olszewski, Preliminary Investigations of the Thermal Energy Grid Concept, ORNL/TM-5786, p. 44.

by Burns and Roe are considerably higher than those by Olszewski.*

For New York City, the Brookhaven distribution cost is based on 4450 miles of 12-inch pipe, at \$68/foot, which is 83 percent of the ORNL cost of 12-inch pipe. For Philadelphia, Brookhaven postulates that most of the distribution is via 10-inch pipe costing \$46/foot, which is 73 percent of the

*L. Olliker and J. Phillip, "Technical and Economic Aspects of District Heating Systems Supplied from Cogeneration Systems," American Power Conference, Chicago, IL, April 24-26, 1978.

cost given by ORNL. For New Orleans, most of the Brookhaven distribution is via 4-inch pipe at \$21/foot, which is 78 percent of the ORNL cost.

To be on the conservative side, the distribution cost data given by ORNL and shown in Table 3.3 were used in this study.

Gas Turbine Systems

The rationale for including simple-cycle and combined-cycle gas turbine systems among those to be analyzed has been discussed earlier in this chapter.

The cost and operating characteristics of the three types of thermal-electric plants considered--gas turbines, coal-fired steam, and light water nuclear reactor--are taken or derived from EPRI's Technical Assessment Guide. EPRI uses this guide in order to establish a consistent data base for assessing the value to the electric utility industry of the results of successful research and development efforts.* They state that their assumptions, data, and methodology represent a compromise based on an analysis of many sources, not all of which agree. EPRI expands, revises, and updates the data from time to time.

EPRI takes capital costs as equal to the total construction costs, including contingencies and startup costs, plus an allowance for funds during construction (AFDC), but not including the effects of inflation. An 8 percent annual interest rate is used to calculate the AFDC. All costs are given in 1976 dollars. For study purposes capital costs are assumed to increase at the rate of inflation, up to the in-service date of the generating unit.

*Electric Power Research Institute (EPRI), Technical Assessment Guide (August 1977).

For the coal power plant, data for the East Central Region were used. Costs for other regions will vary.

EPRI establishes a range of capital costs estimates by considering the combined effect of a one-year change in licensing time, a one-year change in construction time, a one-percent change in construction interest rate, and a two-percent change in contingency allowance. The combined effect of these changes is an overall range of -8.4, +9.1 percent. EPRI's range for estimated fuel costs is ± 12.5 percent; this is used with appropriate real escalation for each fuel.

Ranges in other cost and performance estimates, needed for probabilistic analysis, were supplied by TEMPO. The ranges are estimates of the upper and lower deciles.

Simple-Cycle Gas Turbine

Configuration. Combustion gas turbines are available as packaged units. This minimizes delivery time and cost. A wide variety of accessories are available for starting, field excitation, control, etc. The basic components are shown in Figure 3.5.

Figure 3.5 Simple-Cycle Gas Turbine.

Application. Electric utilities have utilized simple-cycle gas turbines principally for peaking duty, for which they are well suited because of low capital cost. Fuel cost usually is relatively high because natural gas or distillate fuel is preferred. However, 16 heavy-duty gas turbines which have been used for pipeline pumping applications over a 24-year time period are reported to have operated at capacity factors of 85 to 90 percent, and more than 3.6 million operating hours of experience in operating with heavy fuel. (residual) has been obtained. A number of machines have been built which can operate on distillate or be converted to heavy fuel operation if fuel price difference warrants the additional treatment system required for residual operation. Thus, operating experience demonstrates that gas turbines are suitable for mid-range or base-load duty, from the standpoint of availability, reliability, and ability to burn heavy as well as distillate fuels. *,**

Performance and Cost. Table 3.4 gives costs and characteristics of an advanced gas turbine. For "normal load factor cycling operation," EPRI estimates the average heat rate to be 11 500 Btu/kWh; for continuous operation, the heat rate is expected to approach 9 500 Btu/kWh. For this study, as shown in Table 3.4, a heat rate of 10 000 Btu/kWh is assumed.

*General Electric Company Gas Turbine Division, 1976 Report to Association of Edison Illuminating Companies Committee on Power Generation (Schenectady, NY: February 9, 1977), 47 pp.

**A.D. Foster, H. vonE. Doering, and J.W. Hickey, Fuel Flexibility in GE Gas Turbines, Reference Brochure GER-2222L (Schenectady, NY: General Electric Company Gas Turbine Division, 1977).

Table 3.4

COST AND PERFORMANCE OF ADVANCED SIMPLE-CYCLE GAS TURBINE
(All costs given in 1976 dollars.)

REFERENCE: NO HEAT RECOVERY	RATING OR ESTIMATE	RANGE
Megawatts electric (MW_e) output	100	
Capital cost per 100 MW_e , $\$10^6$	15.0	13.7 - 16.4
Fixed charge rate	0.15	0.12 - 0.20
Annual capital charge, $\$10^6$	2.25	
Fixed operation and maintenance (O&M), $\$10^6$	0.06	
Total annual fixed charges, $\$10^6$	2.31	
Availability	0.86	
Heat rate, Btu/kWh	10,000	
Annual fuel energy, 10^{12} Btu/100 MW_e (at 0.70 capacity factor, electric (CFE))	6.13	
Distillate price in 1985, (1976 $\$/10^6$ Btu)	2.93	2.56 - 3.30
Real price escalation rate:	2%	0 - 5%
at general inflation of:	6%	3 - 8%
Annual fuel cost in 1985, $\$10^6$	17.97	
Levelized annual fuel cost, $\$10^6$	44.38	
Annual variable O&M, $\$10^6$	1.27	
Total annual variable, $\$10^6$	45.65	
	(65.21xCFE)	
<u>WITH HEAT RECOVERY</u>		
Recovered heat output, megawatts thermal (MW_t)	140	
MW_e output with heat recovery	98	
MW_e output at zero heat (exhaust bypassed)	100	
Incremental capital cost of heat exchangers, $\$10^6$:	4.53	
Incremental annual fixed cost, $\$10^6$	0.68	
Incremental variable O&M at 0.70 capacity factor, heat (CFH), $\$10^6$	0.30	CFH $\leq$ CFE
Total annual fixed charges, $\$10^6$	2.99	
Total annual variable costs, $\$10^6$	56.96	
	(65.65xCFE)	
<u>EQUATIONS FOR GAS TURBINE:</u>		
<u>E</u> and <u>H</u> in $\$/MWH$; coefficients of <u>E</u> and <u>H</u> in 10^6 MWH/year.		
	Costs, $\$10^6$ /year	Revenues, $\$10^6$ /year
	Fixed + Variable	Electric + Heat
Reference:	$2.31 + 65.21 \times CFE$	$= 0.876 \underline{E} \times CFE + 0$
Heat Recovery:	$2.99 + 65.65 \times CFE$	$= 0.858 \underline{E} \times CFE + 1.23 \underline{H} \times CFH$

SOURCE: Electric Power Research Institute (EPRI), Technical Assessment Guide (August 1977), Table VII-8.

Combined-Cycle Gas Turbine System

Configuration. Combined-cycle gas turbine systems, like simple-cycle systems, are available in factory-packaged units with a number of options for auxiliary components. They can be delivered and installed in two phases: first the gas turbine, in about two years; the additional plant and steam generation apparatus can then be constructed around the already-operating gas turbine and be on-line in six months. This two-phase flexibility is possible only when the combined-cycle system uses separate generators for the gas-turbine and the steam-turbine portions of the systems. (Small systems may use a single shaft for gas turbine, steam turbine, and generator. In these, the gas turbine cannot be operated except with the steam turbine also operating; recovered heat cannot be switched between generating electricity and producing HTW.)

A steam cycle diagram of the multishaft STAG* combined-cycle power system is shown in Figure 3.6. The 1006°F exhaust gas from the gas turbine (Figure 3.5) enters an unfired heat recovery steam generator and is used both to produce superheated steam and for feedwater heating.** Figure 3.7 illustrates the construction features and large size of a heat recovery steam generator manufactured by General Electric for use with a 100 MW_e gas turbine.

*Trademark of General Electric Company.

**General Electric Company, STAG Combined-Cycle Power Systems, GEA-10015 (Schenectady, NY: Gas Turbine Division, December 1976), 11 pp.

Figure 3.6. Multishaft Combined Cycle Diagram.

Application. Combined-cycle power systems combine the advantages of both gas and steam generating technologies. By varying the operation of the components, it is possible to operate a present-day system (as diagrammed in Figure 3.6) over a wide load range while maintaining a heat rate of 8,100 Btu/kWh.* A bypass stack for the gas turbine exhaust is included to provide this flexibility.

The advanced (1985) combined-cycle system described by EPRI, whose cost and performance are the basis for data given below, is expected to achieve a heat rate of 7,500 Btu/kW (2.2 J/J; 46 percent plant efficiency).

*General Electric Company, STAG Combined-Cycle Power Systems.

SOURCE: General Electric Company

Experience with combined-cycle plants dates back to the early 1970s. One manufacturer reported in February 1977 on experience with 11 operating plants, which commenced commercial operation on dates ranging from May 1974 to June 1976; four of these had operated in the simple-cycle gas turbine mode for one to two years before combined-cycle service commenced.* Because of relatively short delivery time, low installed cost, and fuel flexibility, combined-cycle plants are increasingly favored by electric utilities for mid-range generation. For peaking service, the gas turbine may be operated in the simple-cycle mode (exhaust stack bypassed). The application postulated here involves modification of the heat recovery system to permit switching between a normal combined-cycle mode, producing maximum electricity and no HTW, and a simple-cycle-with-heat-recovery mode in which recovered heat is used to produce HTW.

Performance and Cost. Table 3.5 gives costs and characteristics of an advanced gas turbine, based on EPRI estimates. To facilitate comparison of the cost and performance estimates, a 100 MW_e reference is used for both the simple-cycle system (Table 3.4) and the combined-cycle system (Table 3.5). This does not imply that a 100-MW_e combined-cycle system is contemplated. In fact, the most efficient and probably the most economic combined-cycle system may be 400 or 600 MW_e output.

*General Electric Company, 1976 Report to Association of Edison Illuminating Companies Committee on Power Generation (Schenectady, NY: Gas Turbine Division, 1976), pp. 20-21.

Table 3.5

COST AND PERFORMANCE OF ADVANCED COMBINED-CYCLE GAS TURBINE SYSTEM
(All costs given in 1976 dollars.)

REFERENCE: FULL ELECTRIC OUTPUT, NO HTW PRODUCED	RATING OR ESTIMATE	RANGE
Megawatts electric (MW_e) output, gas + steam	100	
Capital cost per 100 MW_e , $\$10^6$	28.5	26.1 - 30.9
Fixed charge rate	0.15	0.12 - 0.20
Annual capital charge, $\$10^6$	4.28	
Fixed operation and maintenance (O&M), $\$10^6$	0.10	
Total annual fixed charges, $\$10^6$	4.38	
Availability	0.79	
Heat rate, Btu/kWh	7500	
Annual fuel energy, 10^{12} Btu/100 MW_e (at 0.70 capacity factor, electric (CFE))	4.60	
Fuel price in 1985 ($1976\$/10^6$ Btu)	2.58	2.26 - 2.90
Real price escalation rate:	2%	0 - 5%
at general inflation of:	6%	3 - 8%
Annual fuel cost in 1985, $\$10^6$	11.87	
Levelized annual fuel cost, $\$10^6$	29.32	
Annual variable O&M, $\$10^6$	0.74	
Total annual variable, $\$10^6$	30.06	
	42.94 x CFE	
<u>REDUCED ELECTRIC OUTPUT, WITH HTW PRODUCTION</u>		
Megawatts electric output, gas turbine only	70	
Heat rate, gas turbine only, Btu/kWh	10 000	
Recovered heat output (HTW), megawatts thermal (MW_t)	95	
Incremental capital cost of heat recovery system, $\$10^6$	1.53	
Incremental annual fixed cost, $\$10^6$	0.23	
Incremental variable O&M at 0.70 capacity factor, heat (CFH), $\$10^6$	0.10	CFH $\leq$ CFE
Total annual fixed charges, $\$10^6$	4.61	
Total annual variable costs, $\$10^6$	30.16	
	(43.09 x CFE)	
<u>EQUATIONS FOR COMBINED-CYCLE SYSTEM</u>		
<u>E</u> and <u>H</u> in $\$/MWH$; coefficients of <u>E</u> and <u>H</u> in 10^6 MWH/year.		
	Costs, $\$10^6$ /year	Revenues, $\$10^6$ /year
	Fixed + Variable	Electric + Heat
Reference:	4.38 + 42.94 x CFE	= 0.876 <u>E</u> x CFE + 0
HTW Produced:	4.61 + 43.09 x CFE	= 0.613 <u>E</u> x CFE + 0.832 <u>H</u> x CFH

SOURCE: Electric Power Research Institute (EPRI), Technical Assessment Guide (August 1977), Table VII-9.

Coal-Fired Steam Plants

In moving from discussing gas-turbine systems to discussing coal-fired steam plants, a brief explanation of the physical reason for a considerable difference between cogeneration systems for the two types of thermal plant is in order. The gas turbine utilizes fuel energy to produce gases that expand and cool as they move through and drive the turbine. Having expanded until their pressure is slightly above atmospheric, the gases are discharged into the air at a temperature of about 1,000°F (540°C). Useful heat can easily be recovered from this exhaust. Steam-electric plants, on the other hand, normally discharge waste heat from their turbines at low temperature--about 120°F (49°C)--into cooling water. The low temperature is achieved by expanding the steam to a pressure well below atmospheric--about 1.7 psia (12 kPa). (This is accomplished by condensing the steam vapor into water, which produces a partial vacuum because the water occupies much less volume than the corresponding weight of steam.) Although a substantial amount of thermal energy is contained in the 100°F cooling water, it is not directly usable for desired purposes such as space and process heat.

To obtain thermal energy (heat) at useful temperatures from a steam turbine requires that steam be extracted from the turbine while still at a useful temperature, or that the turbine discharge all of its steam before it has expanded and cooled to the usual low temperature and pressure, or that a combination of the extraction and "backpressure" mode be employed. In practice, the backpressure mode often is combined with extraction because the combination is thermodynamically more efficient than the simple backpressure mode.

(830 kPa) and 600°F (315°C). It then enters two dual-flow low-pressure turbines; from the four outlets of the LP turbines, at a pressure of 3.5 inches (89 mm) of mercury (1.7 psia, 11.9 kPa), the steam flows into a condenser, is condensed, and is pumped back to the boiler.

The six turbines are shown in tandem, on a single shaft that drives an electric generator producing 800 MW_e when no steam is extracted for district heating, 590 MW_e when 1000 megawatts thermal is needed for the district heating loop.

Both feedwater heat and the heat supply for district heating are supplied via a series of heat exchangers: seven for feedwater heating, four for the district heating loop. For thermodynamic efficiency, the temperature difference between the water to be heated and the steam extracted from the turbines (at the seven numbered points) is kept as small as possible--thus the series of heaters. From extraction points numbered two through five, steam is taken both to feedwater heaters and to the district heating HTW heaters. As shown, the HTW sendout temperature is 350°F (175°C), the return temperature 150°F (75°C). The extracted steam at point 2 will be a few degrees hotter than the feedwater or DH water in the first heater, and so on along the string of heaters until the water reaches the desired temperature.

Figure 3.9 illustrates the physical appearance and construction of an industrial steam-extraction turbine. There are only two extraction points in this machine, rather than seven. Steam from the boiler is admitted at the left-center of the machine, through the large valve system. It moves to the right, through the high-pressure turbine, to the first extraction point and the inlet to the intermediate-pressure turbine. Extracted steam is discharged through the bell-shaped connection underneath the turbine. Steam not extracted flows through the intermediate-pressure turbine to the second

SOURCE: General Electric Company, Steam Turbine Generators for Industrial Applications,
GEA-8510 A-1 (Lynn, MA: Medium Steam Generator Products Department, 1977).

Figure 3.9. Cutaway View of Double Automatic Extraction Condensing Steam Turbine

extraction point, at the inlet to the low-pressure turbine. Steam not extracted then flows through the low-pressure turbine and the outlet to the condenser. *

Application. The double automatic extraction condensing steam turbine illustrated in Figure 3.9 is of the type used in industrial applications that require continuous steam supply at two pressure levels, for process purposes. This turbine is designed to hold automatically the desired extraction pressures, even when the load on the unit fluctuates and extraction steam flows vary. During times of high process-steam flow, the extraction steam generates electric power before reaching the extraction point. At times of low process flow, the steam flowing to the condenser generates the electric power. Thus, wide variations in process flow can be satisfied while meeting electric power requirements, and the need for another, standby source of electric power is eliminated. This historic reasoning, which has been applied to industrial cogeneration where the unit capacity is not larger than about 300 MW_e, can also apply to cogeneration by electric utilities where larger units are involved and either electric power or district heating needs may govern the steam flow and amount of extraction.

Performance and Cost. Table 3.6 gives costs and characteristics of a reference coal-fired steam plant, derived from EPRI's Technical Assessment Guide, August 1977. EPRI estimates cost and characteristics of 1000-MW_e coal plants located in six geographic regions: Northeast, Southeast, East Central, West Central, South Central, and West. The capital cost in dollars per kilowatt, including flue gas desulfurization, ranges from \$567 in the Southeast

*General Electric Company, Steam Turbine Generators for Industrial Applications, GEA-8510 A-1 (Lynn, MA: Medium Steam Generator Products Department, 1977).

Table 3.6

COST AND PERFORMANCE OF COAL-FIRED STEAM EXTRACTION (CONDENSING) SYSTEM
(All costs given in 1976 dollars.)

REFERENCE: NO STEAM EXTRACTION	RATING OR ESTIMATE	RANGE
Rated electrical output	600 MW _e	
Capital cost per 100 MW _e	73.5 M\$	67.3 - 80.2
Fixed charge rate	0.15	0.12 - 0.20
Annual capital charge per 100 MW _e	11.03 M\$	
Fixed O&M cost per 100 MW _e	0.24 M\$	
Total annual fixed charges per 100 MW _e	11.27 M\$	
Availability	0.72	
Heat rate, Btu/kWh	9,930	
Fuel energy used annually by 100 MW _e unit at 0.70 capacity factor, electric (CFE)	6.09 TBtu	
Fuel price in 1985 (1976\$ per MBtu)	\$1.00	0.88 - 1.13
Real price escalation rate:	0.8%	0 - 3%
at general inflation of:	6%	3 - 8%
Annual fuel cost in 1985	6.09 M\$	
Levelized annual fuel cost	12.75 M\$	
Annual variable O&M cost	0.88 M\$	
Total annual variable costs, 100 MW _e , .7 CFE	13.63 M\$	
	(19.47 x CFE)	
<u>STEAM EXTRACTION SYSTEM</u>		
Rated electrical output w/max. extraction*	450 MW _e	
Rated heat output with maximum extraction*	750 MW _t	
Incremental capital cost of heat exchangers and turbines per rated 100 MW _e	3.00 M\$	
Incremental annual fixed charges per 100 MW _e	0.46 M\$	
Total annual fixed charges	11.73 M\$	
Incremental variable O&M per year	0.20 M\$	
Total annual variable costs at boiler capacity factor (CFB) of 0.70	13.83 M\$	
	(19.76 x CFB)	
* Heat extraction factor (HEF) = 1.0		
<u>COST EQUATIONS</u>		
<u>E and H in \$/MWH</u>		
Coefficients of <u>E</u> and <u>H</u> in TWH per year per 100 MW of boiler capacity		
Costs, M\$/year	Revenues, M\$/year	
Fixed + Variable	Electric	+ Heat
Ref: 11.27 + 19.47 · CFE = (0.876 · CFE) <u>E</u>		+ 0
Ext: 11.73 + 19.76 · CFB = (0.876 · CFB) [(1-0.25 · HEF) <u>E</u> + (1.25 · HEF) <u>H</u>]		
HEF = 0 :	= (0.876 · CFE) <u>E</u>	+ 0
HEF = 1 :	= (0.657 · CFB) <u>E</u>	+ (1.1 · CFB) <u>H</u>

to \$696 in the Northeast. EPRI selects as representative a plant in the East Central region, whose capital cost is \$661 per kilowatt of capacity. By scaling, the capital cost of a 600 MW_e plant was estimated to be \$735. For convenience in comparing different systems, cost data are normalized to a 100-MW_e reference as before; \$735 per kilowatt becomes \$73.5 million per 100 MW_e.

Estimates for study purposes of the costs and characteristics of a plant with heat recovery--a steam extraction condensing system that is a modified version of the reference plant--are given in the lower half of Table 3.6. The table with its cost equations reflects the operating conditions of a steam-extraction system. In the simple-cycle gas turbine system the amount of electricity generated, expressed by the electric capacity factor CFE, governs the amount of heat that can be produced; the heat capacity factor CFH cannot exceed the electric capacity factor. The same statement applies to the combined-cycle gas-turbine system, although there is more flexibility in choosing the amount of electricity and of heat to be produced than is the case with a simple-cycle system. In the steam extraction turbine system, as depicted in Table 3.6, the cost equations in particular reflect the interdependence of electric and heat production: as more heat is extracted, the electric capacity factor drops and the heat capacity factor increases. Assumptions implicit in the cost equations are that the boiler is not oversized (it can supply only enough to produce 600 MW_e with zero steam extraction, or 450 MW_e and 750 MW_t at full steam extraction), and that the interdependence between electric and heat production is linear. Two new terms are introduced into the equations: CFB, the boiler capacity factor, and HEF, the heat extraction factor. At zero steam extraction, HEF = 0; at full extraction, HEF = 1. In the reference case and cost equation,

with no steam extraction, $CFE = CFB$. Obviously, if $HEF = 0$ the same is true for the steam-extraction cost equation. When $HEF = 1$, for full steam extraction, maximum amount of electricity produced is reduced from the rated 600 MW with no extraction to 450 MW, which reduces the factor 0.876 by the ratio $600/450$, to 0.657--the number of electric terawatt-hours per year per 100 MW_e of boiler capacity that could be produced if the system operated at full nameplate rating during the entire year. Similarly, 1.1 terawatt-hours of heat could be produced under these conditions because the factor 0.876 is multiplied by $750/600$, or 1.25. (Recall that costs and cost equations are normalized to a 100 MW reference.)

Backpressure System

Configuration. Figure 10 illustrates schematically the configuration of a backpressure (noncondensing) steam turbine system, which also includes steam extraction for better thermodynamic efficiency. This system cogenerates power and heat at somewhat higher overall plant efficiency than the steam-extraction condensing system. (All temperatures and pressures shown are illustrative and approximate.)

The operation is very similar to that of the steam extraction system illustrated in Figure 3.8. Upon comparing Figure 3.8 and 3.10, it is seen that the backpressure system employs one single-flow low-pressure turbine instead of two dual-flow LP turbines as in the steam extraction system. Steam is discharged from the backpressure turbine at a temperature of 250°F (120°C) and a pressure of 30 psia (207 kPa)--substantially higher than in steam-extraction condensing system. In the backpressure system, condensation of the discharged steam occurs in the first heater for the returning district heating water, shown as number 2 in the schematic. Thus, the

Figure 3.10. Schematic of Backpressure Steam Turbine System with Multiple-Stage Heating of Feedwater and District Heating Water

steam's latent heat of vaporization is transferred usefully to the district heating water, instead of being wasted by transfer to a cooling water system to be discharged through cooling towers or into bodies of water.

The feedwater heating (FWH) loop in the backpressure system includes only five stages, compared to the seven employed in the extraction system. District heating water is reheated in four stages in both systems.

Figures 3.11 and 3.12 illustrate the physical appearance and construction of industrial backpressure turbines. In Figure 3.11, the turbine is straight noncondensing with no steam extraction. Such turbines are used in applications requiring large amounts of steam at one pressure for process or other uses, where the unit can be operated in parallel with other units which can absorb electrical load variations: steam flow and electric generation are governed by the requirements for process steam. The double automatic extraction noncondensing turbine shown in Figure 3.12 operated in industrial applications to provide steam at three pressures, with the turbine

SOURCE: General Electric Company, Steam Turbine Generators for Industrial Applications, GEA-8510 A-1 (Lynn, MA: Medium Steam Generator Products Department, 1977).

Figure 3.11. Cutaway View of Straight Noncondensing Steam Turbine

SOURCE: General Electric Company, Steam Turbine Generators for Industrial Applications, GEA-8510 A-1 (Lynn, MA: Medium Steam Generator Products Department, 1977).

Figure 3.12. Cutaway View of Double Automatic Extraction Noncondensing Steam Turbine

control system designed to maintain all of these pressures at the desired levels regardless of fluctuations in the various process requirements. In this turbine there are three sections--high, intermediate, and low pressure --in contrast to the single section in the straight noncondensing turbine.*

Application. Industrial backpressure turbines typically are operated, as explained above, in response to process heat demands. Neither the steam nor the electricity produced is storable; the process heat requirements dictate the rate and amount of electrical generation. For an Integrated Energy Utility an innovation is proposed that makes a major difference in this operating philosophy: a provision for storing heat. This provision makes possible the operation ("dispatching") of the turbogenerator in response to electrical demands. Heat is the byproduct, instead of electricity. Variations in heat production are buffered by storage, so that supply and demand can be matched. Thus, the inflexibility of the backpressure system compared to the extraction-condensing system can be overcome and higher overall thermal efficiency can be achieved.

Performance and Cost. Table 3.7 gives costs and characteristics of a reference coal-fired steam plant, derived as before from EPRI's August 1977 Technical Assessment Guide. In this case, the reference electrical capacity is chosen as 200 megawatts, which makes scaling subject to more uncertainty but should not materially affect conclusions based on the scaling, in view of the already-wide range of cost variations. The reference turbine is a conventional condensing unit; the backpressure turbine, since it expands the steam less than the condensing unit with the same steam supply, is assumed

*General Electric Company, Steam Turbine Generators for Industrial Applications.

Table 3.7

COST AND PERFORMANCE OF COAL-FIRED STEAM BACKPRESSURE SYSTEM
(All costs given in 1976 dollars.)

REFERENCE: CONVENTIONAL CONDENSING TURBINE	RATING OR ESTIMATE	RANGE
Rated electrical output	200 MW _e	
Capital cost per 100 MW _e	89.3 M\$	81.8 - 97.4
Fixed charge rate	0.15	0.12 - 0.20
Annual capital charge per 100 MW _e	13.40 M\$	
Fixed O&M cost per 100 MW _e	0.27 M\$	
Total annual fixed charges per 100 MW _e	13.67 M\$	
Availability	0.75	
Heat rate, Btu per kWh	9,600	
Fuel energy used annually by 100 MW _e unit at 0.70 capacity factor	5.89 TBtu	
Fuel price in 1985 (1976\$ per MBtu)	\$1.10	0.96 - 1.24
Real price escalation rate:	0.8%	0 - 3%
at general inflation of:	6.0%	3 - 8%
Annual fuel cost in 1985	6.48 M\$	
Levelized annual fuel cost	13.56 M\$	
Annual variable O&M cost	0.90 M\$	
Total annual variable costs, 100 MW _e , 0.7 CF	14.46 M\$ (20.66 x CF)	
<u>BACKPRESSURE TURBINE</u> (Same boiler as reference case)		
Rated electrical output	120 MW _e	
Rated heat output at full electric output	370 MW _t	
Incremental capital cost (savings) per 100 MW _e	(15.0) M\$	
Incremental annual fixed charge (savings) per 100 MW _e	(2.25) M\$	
Total annual fixed charges per 100 MW _e	11.42 M\$	
Incremental variable O&M per year	0.20 M\$	
Total annual variable costs at CF = 0.7	14.66 (20.94 x CF)	
<u>COST EQUATIONS</u>		
<u>E</u> and <u>H</u> in \$/MWH; coefficients of <u>E</u> and <u>H</u> in TWH per year per 100 MW _e .		
	Costs, M\$/year Fixed + Variable	Revenues, M\$/year Electric Heat
Reference:	13.67 + 20.66 · CF	= 0.876 · CF <u>E</u> + 0
Backpressure:	11.42 + 20.94 · CF	= 0.526 · CF <u>E</u> + 1.621 · CF <u>H</u>

for study purposes to produce only about 120 MW_e. However, for the 80 MW of electric generating capacity that is given up, 370 MW of heat production is gained. These changes reduce the size of the turbine, generator, and heat exchanger; the effects are shown in the tabulation and cost equations (as first-order approximations).

In the backpressure system, all the steam flowing through the turbine produces electricity and heat. There is thus only one capacity factor, which applies to boiler, turbine, generator, and heat system.

Light-Water Reactor Plants

The nuclear plants considered here include those using two types of light-water moderated reactors--the boiling water (BWR) and the pressurized water (PWR) types. No distinction need be made between these for purposes of this study. Other types, not considered, include heavy-water moderated (CANDU) and gas-cooled. The latter is capable of operation at substantially higher temperature than water-moderated reactors and may, when more fully developed and proven, be well suited for cogeneration applications.

LWR thermal-electric plants are invariably operated to supply base load; that is they operate at essentially constant power output and are not expected to load-follow as do mid-range and peaking plants. Operation at as close to full rated output for as much of the time as possible takes maximum advantage of the low cost of nuclear fuel, spreads amortization of the high capital cost of the plants over as many units of energy as possible, and minimizes changes in operating temperature--hence, thermal and mechanical stress--in the reactor and its fuel rods.

Configuration. Eventually, when large-scale heat storage has been demonstrated and enough experience is available to design and operate heat

storage systems with confidence, the main turbine system of nuclear plants may be configured for operation in the backpressure mode for maximum effectiveness in cogeneration. Conceptually, this is not difficult.* Pragmatically, a conclusion of this study is that it is not realistic to postulate that backpressure or even steam-extraction designs of LWR cogeneration plants will be finalized and placed in operation in the United States within less than two decades. Therefore, the LWR plant configuration chosen for analysis is one (among a number of possible variations) that utilizes a separate noncondensing backpressure turbine system similar to that described for coal-fired plants, with several stages of heating for district-heating water. This configuration is shown in Figure 3.13.

Figure 3.13 Schematic of Separate Noncondensing Backpressure Turbine System for Cogeneration in LWR Plants

*Bjarne Frilund, and Knud Knudsen, Nuclear Steam Turbines for Power Production in Combination with District Heating, presented at the conference on Low-Temperature Nuclear Heat in Helsinki, Finland, on August 23, 1977 (Finspong, Sweden: STAL-LAVAL Turbin AB, 1977).

Steam for the cogeneration turbine system is taken directly from the nuclear steam supply at the same steam conditions as for the main turbo-generator system--assumed to be 545°F (285°C), 965 psia (6.65 MPa), as indicated at the upper left-hand corner of Figure 3.13. (All pressures and temperatures are approximate.) The steam enters a high-pressure turbine, from which a portion of the steam is extracted for raising feedwater returning to the boiler to 420°F (216°C). From the outlet of the HP turbine, steam passes through a moisture separator (MS) to a dual-flow low-pressure turbine and, at 150 psia (1.0 MPa), to heat feedwater and district heating water. District heating HTW leaving this heater is at its sendout temperature of 350°F (175°C), carrying thermal energy at a rate of approximately 800 megawatts.

Steam is discharged from one of the two LP turbines at 60 psia (414 kPa), from the second at 20 psia (138 kPa). The discharged steam is condensed in two heaters, where the latent heat of vaporization is transferred to feedwater and district heating water.

The three turbines are in tandem on a single shaft, which drives a generator rated at 200 MW_e.

The LWR heat source supplies steam to drive only the main turbogenerator (not shown), rated at 1140 MW_e; or to drive both the main turbogenerator, at a reduced output of about 800 MW_e, and the separate cogeneration turbo-generator system at outputs of about 200 MW_e and 800 MW_t; or some intermediate between these two conditions. Thus, the LWR operates at constant thermal load; the total electric output varies from about 1000 to 1140 MW_e; and the district-heating output varies from zero to 800 MW_t (corresponding to an arbitrary Heat Extraction Factor varying from zero to one).

Application. The configuration suggested for a light-water reactor plant with separate cogeneration turbine system may avoid some of the inflexibility of the coal-fired backpressure steam plant as described in the immediately preceding section: the backpressure turbine system in conjunction with the LWR plant may be adjusted to produce varying amounts of electricity and HTW. However, with appropriate adjustments in steam conditions, the same separate cogeneration system could be devised for operation from a coal-fired steam supply. Only the economics would differ, reflecting the different balance between capital and fuel costs of coal and nuclear plants.

The principal merit of the suggestion that a separate, relatively small and conventional cogeneration system be incorporated into a nuclear plant is that this approach is a step toward configuring the main plant for optimum cogeneration (recalling that heat storage appears to be essential for economic operation of large backpressure turbines).

Performance and Cost. Table 3.8 gives costs and characteristics of a reference LWR plant, derived from Table VII-2 of EPRI's August 1977

Technical Assessment Guide. EPRI estimates cost and characteristics of nuclear plants located in the same six geographic regions noted earlier for coal plants: Northeast (\$826/kW), Southeast (\$709/kW), East Central (\$785/kW), West Central (\$752/kW), South Central (\$731/kW), and West (\$778/kW). EPRI's Table VII-2 is for the East Central Region. The cost per kilowatt of capacity has been adjusted (using EPRI's 0.3-power formula) to apply to a plant capacity of 1140 MW_e. This is the plant size given in the source document noted for Table 3.8, which is also EPRI's source document for Table VII-2. As before, costs are normalized to a 100-MW_e reference.

The second part of Table 3.8 gives estimates for study purposes of the effect of adding a separate, 200-MW_e capacity turbine-generator into which a

Table 3.8

COST AND PERFORMANCE OF LIGHT-WATER REACTOR STEAM PLANT
(All costs given in 1976 dollars.)

<u>REFERENCE: CONVENTIONAL PWR PLANT</u>	<u>RATING OR ESTIMATE</u>	<u>RANGE</u>
Rated electrical output	1140 MW _e	
Capital cost per 100 MW _e	75.5 M\$	69.1 - 82.3
Fixed charge rate	0.15	0.12 - 0.20
Annual capital charge per 100 MW _e	11.32 M\$	
Fixed O&M charge per 100 MW _e	0.27	
Total annual fixed charges per 100 MW _e	11.59 M\$	
Availability	0.72	
Heat rate, Btu per kWh	10,400	
Fuel energy used annually per 100 MW _e at 0.70 capacity factor	6.38 TBtu	
Fuel price in 1985 (1976\$ per MBtu)	\$0.63	0.55 - 0.71
Real price escalation rate:	2.4 %	1 - 5%
at general inflation of:	6.0 %	3 - 8%
Annual fuel cost in 1985	4.02 M\$	
Levelized annual fuel cost	10.47 M\$	
Annual variable O&M cost	0.42 M\$	
Total annual variable costs per 100 MW _e at 0.70 CFE	10.89 M\$ (15.56 x CFE)	
<u>WITH SEPARATE BACKPRESSURE STEAM COGENERATION</u>		
Rated electrical output with full HTW output (800 MW _e main + 200 MW _e DH)*	1000 MW _e	
Rated heat output at full electric output*	800 MW _t	
Incremental capital cost per 100 MW _e	23.0 M\$	
Incremental annual fixed charge	3.57 M\$	
Total annual fixed charges per 100 MW _e	15.16	
Incremental variable O&M per year	0.10 M\$	
Total annual variable costs per 100 MW _e of boiler capacity, at CFB = 0.7	10.99 M\$ (15.70 x CFB)	
* Heat extraction factor (HEF) = 1.0		
<u>COST EQUATIONS</u>		
<u>E and H in \$/MWH</u>		
Coefficients of <u>E</u> and <u>H</u> in TWH per year per 100 MW _e of boiler capacity.		
	<u>Costs, M\$/year</u>	<u>Revenues, M\$/year</u>
	<u>Fixed + Variable</u>	<u>Electric + Heat</u>
Ref:	11.59 + 15.56 · CFE = (0.876 · CFE) <u>E</u>	+ 0
DH:	15.16 + 15.70 · CFB = (0.876 · CFB) [(1 - 0.123 · HEF) <u>E</u> + (0.702 · HEF) <u>H</u>]	
HEF = 0:	= (0.876 · CFE) <u>E</u>	+ 0
HEF = 1:	= (0.768 · CFB) <u>E</u>	+ (0.615 · CFB) <u>H</u>

SOURCE: United Engineers & Constructors, Inc., Capital Cost: Pressurized Water Reactor Plant, Volumes 1 and 2, NUREG-0241 (Philadelphia, PA: June 1977).

portion of the nuclear steam supply can be diverted when HTW is to be produced, as discussed in connection with Figure 3.13. The added cost, based on the United Engineers & Constructors source document cited, includes turbines and generator with no cooling tower and with the normal condenser replaced with two smaller condensers (feedwater heaters).

Table 3.8, with cost equations similar to those for the coal-fired steam-extraction turbine system of Table 3.6, reflects the operating conditions for the LWR plant. When steam is diverted from the main turbogenerator to the separate cogeneration system, the electric output decreases as heat output increases. As before, the cost equations assume that dependence of electric output on heat extracted is linear, and that the nuclear steam supply is sized to deliver steam required by the main turbogenerator to produce 1140 MW_e . The terms CFB, for boiler capacity factor, and HEF, for heat extraction factor, appear in the equations to express the interdependence of heat and electric production. At zero heat production, $\text{HEF} = 0$; at full production, 800 MW_t , $\text{HEF} = 1$. In the reference case and cost equation, when no HTW is produced, $\text{CFB} = \text{CFE}$; the same is true for the district heating (DH) case when $\text{HEF} = 0$. With the separate cogeneration system in operation at $\text{HEF} = 1$, the maximum amount of electricity produced is reduced from 1140 MW to 1000 MW, which reduces the factor 0.876 in the electric revenue term of the cost equation by the ratio $1000/1140$, to 0.768--the number of electric terawatt-hours per year per 100 MW_e of boiler capacity that could be produced if the system operated at full nameplate rating during the entire year. Similarly, 0.615 terawatt-hours of heat could be produced under these conditions because the factor 0.876 is multiplied by $800/1140$, or 0.702.

All costs having been normalized to a 100 MW_e reference, estimates of the costs for the various cogeneration configurations described may be compared directly.

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4. PRIVATE-SECTOR ANALYSIS

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INTRODUCTION

The private-sector venture analysis conducted in this study follows the outline of a venture analysis given in Chapter 2. The first step, a detailed product description, is presented in the first section of this chapter. It is followed by the detailed market consideration. First the potential market, the market for which HTW would be competing, was defined. Then the decision process of electric utilities and regulators was investigated. Cost calculations were performed next in order to determine the minimum selling price for HTW that would still earn an acceptable rate of return for the electric utilities. This information, combined with the size of the potential market and information on likely competing systems, was used to determine the likely market for HTW and, also, for the HTW products. Finally, the corporate decisionmaking process of the innovator supplying the equipment was investigated. This chapter concludes with an analysis of the likely private-sector decision on the integrated energy utility venture.

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NEW VENTURE PRODUCTS

The Role of Equipment Suppliers

While it is recognized that the financial investment, the operating responsibility, and the major risk of loss for the venture, "The Integrated Energy Utility," will fall on the electric or heat utility that undertakes this innovation, there are innovations required on the part of equipment suppliers as well. Part of the investigation of the attitude of the private sector in this venture analysis was the selection of several product opportunities that could become significant if the Integrated Energy Utility achieved a high penetration, and exploring these with industry to see how they could react to initiating work on such products as ventures.

For convenience in access and free discussion, products of potential interest to and within the perceived scope of the General Electric Company were selected. In the systems described earlier, in Chapter 3, there are components that are manufactured by General Electric and many or most that are not. There is a surprisingly large number of vendors whose products must be combined to make these systems. Customarily the utility or an architect-engineer firm acts as the integrator, to bring all the necessary pieces together and see that they are assembled, installed, and tested.

Flexible HRSG

In the case of the gas turbine system and the combined cycle system, General Electric assembles and makes most components, but on-site installation work including foundations and support services are supplied by others. In the case of these two systems most of the parts--the gas turbine, generator, stack, instrumentation and control, the combined-cycle steam turbine-

generator, and cooling system--are not new products nor would they be modified significantly for the Integrated Energy Utility.

The component that is the key to adding the capability to generate and supply heat as HTW, as well as electricity, is the Heat Recovery Steam Generator (HRSG), now used to extract waste heat from the stack gases and convert it to steam suitable to drive the turbogenerator. This product is illustrated in Figures 3.6 and 3.7. For the introduction stages of the Integrated Energy Utility, thermal energy may be needed at industrial sites as process steam at lower temperatures and pressures than the approximately 900 psig, 935°F steam supplied to the steam turbine. High temperature water at various temperatures may also be needed for processes. For off-site purposes, as has been previously described, HTW at temperatures up to 200°C (400°F) is the preferred means of distribution.

As a potential new venture product, a flexible HRSG capable of providing several output streams to different processes was suggested. Steam could be diverted from the live steam supply to the turbine and throttled to lower pressures and/or reduced in temperature by desuperheating, i.e., injecting sprays of feedwater. Also extraction steam could be taken from the turbine, and HTW could be diverted from several points in the HRSG and adjusted to the desired temperature by mixing with feedwater. Such a system would primarily add controls and instrumentation rather than major new equipment. Potential advantages would be the ability to meet specific industrial process heat needs rapidly without a design, tooling, and production delay; flexibility in changing the output mix with time, as an off-site need for HTW is expanded; and perhaps some production economies in producing multiple units of a standard module rather than custom-made products.

As with the other new venture products to be described, the changes in the concept and the ultimate conclusions on its desirability as a new venture will be described in the section of Chapter 4 on Corporate Decision-making.

Backpressure Turbine Generator for Small Coal Plant

Industrial steam-turbine generators are established products in the Medium Steam Turbine Department of General Electric, in Lynn, Massachusetts. These products have been made in condensing versions with one or more steam extraction points between stages, in backpressure or noncondensing versions where the steam outflow from the turbine is at the pressure and temperature wanted by industry, and in versions with both extraction and back-end steam outputs. Steam has been the output in all of these; no turbine generators producing HTW for district heating have been made by this Department.

The new venture product suggested was a backpressure turbine with several extraction points, similar to that shown in Figure 3.8, which is designed for thermodynamic efficiency in generating HTW (i.e., with minimum reduction in electric output for a given level of HTW generation).

The generator and electrical equipment would not change from current technology, and GE does not customarily make the feedwater heaters, the pumps, the coal-fired boiler, and most of the auxiliaries. Emphasis would be on the turbine. Little new technology is involved, but designing the unit and offering it for sale might stimulate the market.

Backpressure Turbine for Nuclear Reactor Plant

Modifications of large nuclear plants take much time and money and are approached cautiously by industry because of long, tedious review and approval processes and safety and reliability analyses. District heating cogeneration with an LWR could be done in several ways with different degrees of innovation and hence of technical risk. These could be called a first-, second-, and third-generation modification of the current turbine generation system, embodied in the reference system of Table 3.8.

The first-generation change is to leave the main turbogenerator unchanged and add a small backpressure turbine to provide electricity and heat flexibly, to an 800 MW_t heat output. This is described on pages 3.83 to 3.89.

A second-generation approach is a condensing extraction turbine that would be similar in configuration to Figure 3.8, i.e., multiple steam extraction points heat not only the feedwater loop but also the district heating loop. Extending this concept to the LWR turbine is simple in principle but would require redesign of many of the turbine parts over a long development period to qualify for nuclear service.

The third approach, suggested in some foreign literature, is an all-backpressure nuclear turbine system as illustrated in Figure 4.1. In this configuration, what is normally a six-flow low pressure turbine, as shown by the dotted lines, can be reduced to a four-flow, with four different backpressures obtained by truncating each low pressure turbine at a different pressure. The backpressure steam from each of these turbines heats the feedwater loop and the district heating loop to successively higher temperatures.

The third generation has the capital cost advantage of not requiring as much turbine capacity, not needing the large condensers and cooling towers used with the first and second generations, and will reject no waste heat to the environment. It can also produce more usable heat, e.g., 2000 MW_t, while putting out 800 MW_e. Nothing like this in such large sizes has been done in this country, nor do we know that it has been actually built in Europe. It would require much component development and solution of system integration problems to meet nuclear plant requirements. It would be expensive and a great engineering challenge that might not be solved.

Since the reference plant is the same for all three generations, the principal economic difference in Table 3.6 is in the "Incremental Capital Cost per 100 MW_e."

For the three generations of LWR cogeneration, the value of this increment is shown in the first column in millions of 1976\$ per 100 MW_e, as in Table 3.8, and in the second column in millions of 1985\$ for a 1200 MW_e plant, as is later used in Table 4.11.

	<u>1976\$</u>	<u>1985\$</u>
	(in millions of dollars)	
1. Separate DH Turbine	+23.0	466
2. Extraction Turbine	+ 2.9	59
3. Backpressure Turbine	-18.2	-369

DESCRIPTION: 800 MW_e, 540°F/R540°F/1000 psig; backpressure
10 psia; approximately 3000 MW_t (350°F, 150° return).

Functional Diagram:

Figure 4.1. Nuclear Backpressure Plant

If the IEU successfully penetrates the market, it can be expected that in the course of time the form of LWR that is purchased will progress from generation 1 to generation 3 because of the significant capital cost savings. However, generation 3 could not be expected to be operational much before AD 2000, and later if not expedited. To be conservative, Table 4.11 uses an incremental capital cost between that for generations 1 and 2 over the whole time period.

Because of the long lead time, the new product venture suggested for the first GE management review was generation 3. This would be a significant advance and require considerable investment, in contrast to the other new product ventures that are considerably shorter term.

Heat Metering System

Another suggested potential General Electric new venture product for the Integrated Energy Utility is the means of measuring the thermal energy delivered to the end user, as the familiar watt-hour meter measures electric energy consumed. If district heating with HTW becomes a significant part of the U.S. energy consumption, millions of these will be required.

General Electric manufactures watt-hour meters and has had a major market share of this product for many years. The reliability and accuracy of its product are recognized by the utilities, and a product of similar reliability and accuracy would be required by them for measuring the use of heat by district heating customers.

In the United States, where present district heating systems are suppliers of steam, the prevailing means of measuring energy delivered is measurement of the volume of condensate formed. With an HTW system the measurement of the water flow is not enough; the inlet and outlet temperature of the water, or in particular the temperature difference between them, must be considered. The product of the flow and the temperature difference is a first-order measure of the value of the heat delivered.

In European countries there are existing HTW district heating systems that incorporate heat meters integrating flow and temperature difference. R.M.E. Diamant* illustrates and describes a number of devices in operation in 1968. Some are mechanical, combining a rotating vane type meter for water flow and cams or levers activated by the temperature difference to control the rate of rotation of an integrating gear-train register. Some are thermoelectric. There would appear to be considerable room for ingenuity and improvement over 1968 technology.

The evolution of the above potential products and the conclusions thereon are further discussed under Corporate Decisionmaking in this chapter.

*R.M.E. Diamant, and J. McGarry, Space and District Heating (London, England: Iliffe Books Ltd., 1968).

MARKET ANALYSIS

Potential Markets

High temperature water cannot be a substitute for all forms of energy; there are certain uses for which it is suitable and others for which it is not. The suitable uses comprise the potential market for HTW--that is, the market for which it will compete. This potential market has been determined in the residential, commercial, and industrial sector.

Residential Sector

U.S. Bureau of Census Series II, used by DOE in the MOPPS studies, was accepted as a given in developing the demand forecasts. Dividing this population series by the average household size yields a time series for the number of households in the United States. In its projections of households, the Census Bureau postulated four alternate household series using the Series II population data.* Series C was selected by the study team as the most likely of the series presented. In this series the average household size decreases from 2.93 persons per household in 1975 to 2.67 in 1990. Since the Census Bureau does not forecast this series beyond 1990, the 1990 figure of 2.67 is then assumed to be constant to 2020. However, households and housing units are not identical because of vacancy rates and the multiplicity of home ownership. There were 77.553 million year-round housing units in 1975 and only 71.514 million households, yielding a ratio of 1.08 housing units per household.

*U.S. Bureau of the Census, Current Population Reports, Series P-25, No. 607, "Projections of the Number of Households and Families: 1975 to 1990" (Washington, DC: U.S. Government Printing Office, 1975).

Assuming this ratio constant, a time series of the number of U.S. housing units compatible with the Series II population projections was developed.

Since the analysis of demand on a regional basis is an important element of this study, it is necessary to apportion the U.S. growth in housing units on a regional basis. The National Planning Association issued regional growth forecasts* that served as a basis for apportioning the national population regionally. While these forecasts deal with population shifts in the near term (1977-1982), they are useful in formulating the long-term forecasts. A growth percentage was developed apportioning a percentage of the total national growth to each of the four regions. That is, for each region:

Housing Units_T =

$$\frac{\text{US Population}_T}{\text{Average Household Size}_T} \times \frac{\text{Housing Units}}{\text{Household Ratio}_T} \times \text{Regional Growth Percentage}_T$$

Where T = time

Two assumptions shaped the demand forecasts: 1) only new units--built after 1975--were considered as potential candidates for district space heating (since the retrofit costs could run as high as several thousand dollars for residential space heating) and 2) the housing unit had to be within the boundaries of an SMSA in order to meet minimum population-density criteria. Thus, the summation of all new housing units in an area that fell within an SMSA were candidates for demand. The total new housing units for any time is as follows:

Housing Stock T+1 - Housing Stock T, plus the number of demolitions.

*The National Planning Association, Regional Economic and Demographic Projections (Washington DC: National Planning Association, 1975).

This figure is then multiplied, for each region, by the percentage of housing in each region that is within an SMSA.*

Since the average energy used for space and water heating is dependent upon housing type, it is necessary to disaggregate each region's housing units. A three-tiered disaggregation was used--single-family detached, multifamily (this includes low-density, attached housing and 5+ unit structures), and mobile homes. The percentage of new housing of a given type varied by region and was based upon historical trends and expectations about the future.

Next, average energy usages for space heating and water heating were developed based on data from a report to the President's Council on Environmental Quality and The Federal Energy Administration.** Numbers were developed, by housing unit type in each region, for the average energy usage for space heating. These numbers represented 1970 data which were then assumed to hold for 1975. A conservation factor was included in each average in order to project more realistically average energy levels to 2020. The 1975 level was assumed to decrease 1 percent per year for space heating and 1/2 percent per year for water heating until 1990. The average levels were then assumed to remain constant until 2020.

Commercial Sector

Perhaps the most difficult task involved in projecting the energy usage of new commercial construction is to determine the amount of new commercial construction that will be put in place. As was the case in projecting demand figures for residential usage, it is assumed that only new construction would

*The percentage of housing units within an SMSA was determined by the study team from historical trends and anticipated saturation levels.

**A. D. Little, Residential and Commercial Energy Use Patterns, Report to The President's Council on Environmental Quality and The Federal Energy Administration (Cambridge, MA: A. D. Little, 1974).

be included in the demand calculations. However, unlike the residential sector where the number of housing units could be correlated to households and population, the commercial square footage put in place is almost impossible to correlate with any readily predictable variables. Regressions of the commercial square footage put in place with population, gross national product, housing put in place, etc., yield particularly low R^2 s.* In fact, the only good correlation demonstrated by this variable was with itself: that is, the moving average of commercial square footage put in place demonstrated an exponential curve associated with a time trend. Therefore, it is assumed that commercial square footage will grow over the next 45 years at the same 2.224 percent per year as it did over the last 45 years.

The development of demand projections for commercial space heating and water heating follows the same logic flow as for the residential sector. The national growth within SMSA is apportioned on the same percentage basis regionally as residential, and average usage figures are developed the same way. The major differences are in the level of disaggregation and the conservation attained. Because of new radical construction techniques and architectural design patterns, it is assumed that conservation in new buildings for commercial construction will be double that of residential. That is, average energy use would decrease two to one percent per year for space and water heating respectively, over the 1975-1990 time frame. Then, as in the case for residential, average commercial energy usage remains constant to 2020.

*The overall R^2 may not be low, but that is because of a strong degree of autocorrelation in the dependent variable and cross correlations between the dependent and independent variables with time. When the partial derivatives are taken or first differences are used, the correlation is extremely low--the R^2 is typically below .20. The same poor correlations were also found when the variables were lagged.

Industrial Sector

Unlike the residential and commercial sectors where a retrofit market was not considered, retrofit is included in the potential industrial market. Furthermore, industrial demand was not limited to SMSAs since the industry itself can be a focal point for district heating.

The basic forecasts of industrial demand for energy were taken from the Phase II Industrial Sector Service Demands (ERDA, MOPPS, 6/3/77), and Phase III Industrial Sector Energy Service Demands. Table 4.1 shows fossil-fuel uses for the industrial sector. As shown in this table, 14.8 percent of heat used in industrial processing is 230°F, 16.5 percent is between 231°F and 400°F, and 68.7 percent is above 400°F. We have assumed that HTW would be supplied at a temperature of about 175°C (350°F). Thus, it was assumed that 25 percent of the indirect heat needs potentially could be filled by a district heat type scheme. It was also assumed that an additional 5 percent of the indirect energy demand would be for industrial space heating.

Some of the users of heat at 400°F and above might conceivably buy heat at 350°F and upgrade it to the temperature they require. We did not consider this market because of lack of information on the number of users who might be able to perform upgrading. Nonetheless it could lead to a larger HTW market than assumed here.

Some industrial plants are extremely large users of energy. For these users the economics are expected to favor operation of large in-plant generating equipment, probably producing both electricity and heat. Since district heating is not likely to compete for this portion of the market, it was subtracted from the potential market. Users of more than 350M lbs/hr of steam, representing around 15 percent of the market, are excluded.

Table 4.1

FOSSIL FUEL USES INDUSTRIAL SECTOR - 1972
(10¹² Btu)

Industry Sector	230°F	231-400°F	400°F & Steam Drive	In-Plant Generation	Space Heat	Total
Food and Kindred Products	542	191	50	7	103	803
Textile Mill Products	161	28	-	3	91	283
Apparel & Other Textile Products	9	-	-	-	37	46
Lumber & Wood Products	19	31	58	3	61	172
Paper & Allied Products	272	698	110	110	78	1,268
Chemical & Allied Products	399	825	1,197	106	133	2,660
Petroleum & Coal Products	50	-	2,446	152	15	2,663
Rubber & Plastic Products	10	151	-	2	17	180
Stone, Clay & Glass Products	-	12	1,161	13	62	1,248
Primary Metal Products	-	-	3,663	153	-	3,816
Fabricated Metal Products	113	57	54	3	57	284
Machinery Except Electrical	88	29	100	3	73	293
Electrical Equipment & Supplies	78	29	46	2	39	194
Transportation Equipment	59	191	-	-	44	294
Natural Gas Processing	-	-	1,504	-	-	1,504
All Other	539	359	449	18	430	1,795
Total	2,339	2,601	10,838	575	1,240	17,593

SOURCE: "The Templifier for Process Heat," P. N. Ross, Westinghouse Electric Corporation; Paper Presented at EEI Conservation & Energy Management Division, Annual Conference.

Finally it was assumed that in the future industrial plants would make maximum use of waste heat within the plant. Not all waste heat can be used, of course. We assumed that two thirds of usable waste heat would be used and reduced the potential market for this accordingly.

The numbers were then regionalized for 1975 by using The Annual Survey of Manufacturers 1974, Fuels and Electric Energy Consumed, Standard Metropolitan Statistical Areas (U.S. Department of Commerce, Bureau of the Census). Each of the 263 SMSAs listed were assigned to a region and then the regional energy figures were totaled. Although only 2654.4×10^9 KWH equivalent of 3924.7×10^9 were in these 263 SMSAs, it was assumed that the regional percentages for 1975 (1974) were: Northeast = 20.1 percent, Northcentral = 30.3 percent, South = 39.3 percent, West = 10.3 percent. A forecasted industrial time series was then developed using the same regional proportions of growth that were applied in the residential sector.

Availability of Aquifer Storage

Since the proposed district heating systems include the use of aquifer storage as an integral part, the potential market must be further restricted to those areas of the country where suitable storage sites are available. There is little hard knowledge about the geographic distribution of such sites. Based on estimates by several geologists we estimated that about 60 percent of the country would be suitable but this figure could be as low as 30 percent or as high as 90 percent. Thus the potential market was further reduced to 60 percent to exclude those areas where storage would not be possible.

Total Market

Table 4.2 shows the final potential market for district heating. The estimation of this market used very conservative assumptions; thus this is likely to be a lower bound on the actual potential market. The most crucial assumption is the restriction of the residential and commercial market to new demand only. If retrofit in existing structures becomes economically feasible, or is mandated by government action, the market could easily be two or three times as large. The availability of aquifer storage is also important. It could easily be 50 percent larger or smaller than we have assumed. The potential market would change accordingly. Some of these variations can be taken into account during the probabilistic phase of analysis but others, such as retrofit, which could change the result by over 100 percent would make the probabilistic result virtually meaningless. It should, therefore, be noted that the potential market is based on conservative assumptions.

Table 4.2

NEW POTENTIAL MARKET FOR DISTRICT HEATING
($\times 10^{12}$ Btu)

YEAR	INDUSTRIAL				RESIDENTIAL AND COMMERCIAL			
	NE	NC	SOUTH	WEST	NE	NC	SOUTH	WEST
1980--1985	100	160	230	80	300	410	320	210
1985--1990	110	190	265	95	435	610	476	310
1990--1995	120	200	300	115	575	805	635	410
1995--2000	135	235	345	135	710	990	785	510
2000--2005	145	260	380	150	840	1180	940	610
2005--2010	155	280	415	170	980	1375	1105	715
2010--2015	175	325	480	200	1125	1580	1275	825
2015--2020	200	370	560	235	1270	1785	1445	935

Utility Decision Analysis

Interviews were conducted with people from electric utilities and from regulatory commissions to learn of attitudes toward current district-heating systems and to understand the factors that may be important in decisions concerning adoption of any of the HTW systems described in this study. The results of the interviews with the utilities are presented below; discussion of the interviews with the regulators is found later in this section.

A list of the participants in the interviews is given in Table 4.3. The study team expresses its appreciation to all of these people for their cooperation.

Utility Interviews

Summary. To obtain insight into the receptivity of utilities for the concept of an integrated energy system, a series of telephone interviews was conducted during the last week of November and the first week of December of 1977. Advance questionnaires were mailed to 25 utilities, and 21 of these utilities cooperated in setting up the interviews. Table 4.4 shows the distribution of the utilities in respect to their type of service and their geographic location.

The interview protocol that was sent to each of the utilities is reproduced in Appendix A. The protocol consisted of four parts; the first part was directed primarily to the utilities having district heating systems and sought to elicit understanding on current attitudes towards the steam business as well as the reasons for why the steam business represents so small a part of total energy sales in this country. Part two of the

Table 4.3

INTERVIEW RESPONDENTS

J. Agosta	Senior Engineer, Commonwealth Edison
Thomas Baejems	Assistant Director of Technical Services Long Beach Gas Co.
Hasso Bhatia	Office of Tariff Analysis Michigan Public Services Commission
V. S. Boyer	Vice President, Engineering and Research Philadelphia Electric Co.
Elwood Clymer	Senior Engineer, Philadelphia Electric Co.
Richard Cooper	Executive Vice President Indianapolis Power and Light Co.
Nolan Daines	Vice President, Planning & Research Pacific Gas & Electric Co.
Tom Darte	Superintendent of Distribution Springfield, IL Water, Light, and Power Dept.
Robert Ellis	Senior Financial Analyst, Florida Power and Light Co.
J. S. Filbert	Vice President for Operations Connecticut Natural Gas Corp.
Paul Hodiak	General Manager of Applied Energy San Diego Gas and Electric Co.
Joe Jenkins	Engineering Department, Florida Public Service Commission
Wayne Johnson	Manager of Production, Kansas City Power and Light Co.
Sidney Law	Director of Research, Northeast Utilities Service Co.
Ted Lehrer	Senior Engineer, Philadelphia Electric Co.
James Liles	Operations Research Analyst, Office of Regulatory Analysis, Federal Regulatory Commission
L. F. Lischer	Vice President for Research and Development Commonwealth Edison

Table 4.3 (Cont.)

Robert Lloyd	Director of Consumer Services Florida Power and Light Co.
Steven Mallard	Vice President for System Planning Public Service Gas and Electric Co. of New Jersey
Parker Mathusa	Office of Research, New York Public Service Commission
Jerome Matosec	Resources Development Engineer Los Angeles Department of Water and Power
James McKenna	Manager of Commercial and Industrial Sales The Brooklyn Union Gas Co.
H. H. Miller	Vice President, Distribution Baltimore Gas and Electric Co.
H. Nexon	Vice President for Rates and Regulations Commonwealth Edison
Helge Nurmi	Supt. of CENT-CON Energy Complex, Detroit Edison Co.
Keith Parks	General Manager, Eugene Water & Electric Board
John Pearce	Assistant Director of Research Northern States Power
Thomas Rockey	Civil Engineer, Seattle Department of Lighting
Harold Sipe	Head, Electrical Branch California Public Utilities Commission
Tom Torre	Steam Engineer Consolidated Edison of New York
Lawrence Tuck	Division Head, Steam Sales and Service Boston Edison
James Waldon	Project Manager Florida Power and Light Co.

Table 4.4

DISTRIBUTION OF UTILITIES

<u>Type of Utility</u>	<u>Number</u>
Electric and Gas Service	8
Electric Service	10
Gas Service	3
<u>Utility Characteristics*</u>	
Municipal Utility	5
Over 1 Million Customers	10
With a District Heating System	13
<u>Geographic Location</u>	
Northeast	8
Midwest	6
Southeast	1
Northwest	3
Southwest	3

*Categories are not exclusive--a utility may be in more than one or in none.

interview protocol was designed to reveal the principal factors that would enter utility decisionmaking with respect to whether or not the utility might look favorably upon going into or expanding the sales of heat through any of the integrated energy systems under consideration in this study. In the third part of the interview protocol, implementation of a decision to provide high-temperature water for district heating was examined in relation to regulatory problems and government incentives. The last part of the interview protocol suggested a number of scenarios by which integrated power systems could develop and examined the attractiveness and likelihood of each of them.

The interviews generally supported the observation that utility sale of steam and district heating in the United States today is a quasi-static business. Most of the district heating systems were installed many years ago. While urban renewal of the 1960s encouraged some profitable expansion, current difficulties and costs of laying new distribution piping in urban areas all but restrict new customers to commercial buildings proximate to existing distribution lines. The limited load diversity of the downtown area of most urban environments results in poor heat load factors and makes the economics of competing with fossil-fired individual heating plants difficult. Out of 13 utilities having district heating systems, 10 singled out these two factors (cost of installation of distribution and poor heat load factor) as being the most important reasons limiting the expansion of the sale of steam. The third most important factor selected by 7 of the 13 utilities was the difficulty of finding new steam-plant sites from which to serve their urban district heating systems.

In general, the utilities expressed little enthusiasm for the prospects of HTW systems or for the large-scale expansion of district heating served

by such systems. While the potential for lower total energy costs was singled out as the most important of the positive attributes of the proposed HTW systems, skepticism was expressed as to whether this indeed would be true. It was clear in the interviews that primary consideration for any venture by the utilities was the need to be able to show a profitable rate of return on equity of at least 15 percent.

Among the potentially positive attributes of the HTW systems, increased energy efficiency was given the second highest rating, although many commented that increased energy efficiency was important only if it could lower a total energy cost. It was generally agreed that the demonstration of the system was a prerequisite to consideration by any utility for adopting a HTW system, but the difficulty of installing distribution of hot-water pipes in settled areas was still seen to be a major drawback for the widespread expansion of such systems.

Of the 21 utilities interviewed only 5 agreed that the HTW system was feasible in their areas, and here it has to be noted that the feasibility was generally qualified to apply to limited applications. Among the incentives that might be helpful, about half the utilities expressed interest in increased investment tax credit although none felt that this would be a determining incentive. There was almost no enthusiasm for federally guaranteed loans. In general the utilities felt demonstrating that the venture could provide a sufficient rate of return would be the primary incentive.

About one third of the utilities indicated that regulatory problems might be associated with the development of HTW district heating systems. Many of the utilities pointed out that the principal difficulty with regulation was the time required for regulatory action in response to utility request for rate increases and plant siting.

Among the possible implementation scenarios for HTW systems, only beginning service to relatively large industrial loads was seen as a possible scenario by as many as half the utilities. While eight of the utilities agreed that starting with small boilers in new areas was a possible development, it was felt that this would be practical for large consolidated loads and not for residential areas. Both in the scenario where waste heat is taken from gas turbines located in substations and in the scenarios using small boilers, it was felt that there would be problems siting in urban areas because of air-quality standards and noise standards.

A fuller discussion of each of the parts of the interview and excerpts of the interview comments are presented in Appendix A.

The Market for HTW Products

This section will present the detailed cost and market analysis associated with the proposed systems and available alternatives. The costs and required utility revenues needed to provide high temperature water to space and process heat customers is presented first, followed by the market penetration analysis and a discussion of the potential market for equipment to provide high temperature water.

Cost Calculations for HTW

The general methodology used for the calculations in this section is discussed in Chapter 2, and a description of the computer model is presented in Appendix C. The next several paragraphs provide system and calculational assumptions.

System Assumptions for the Economic Analysis

Cost allocation (steam extraction, backpressure plants). The heating customer pays for the loss in electric revenues that accompanies the reduction in electric generation efficiency when salable heat is produced. The heating customer carries the total burden of plant modification costs. No benefits from heat sales are assigned to the electric customer, whose electric charges remain unchanged. (When the steam extraction plant is not producing salable heat--that is, when the plant operates at full-capacity electric production--no plant charges other than the annualized heating modification costs are born by the heating customer.)

Cost allocation (gas turbine). When the gas turbine is operated to

generate heat, electricity is assumed to be sold to the grid at base-load cost. To be conservative, this cost is computed for a nuclear plant. The sale of electricity reduces the total plant charges carried by the heating customer. (When the gas turbine is not being used to produce salable heat, it is assumed it is being used as a peaking unit, and that electric revenues just offset plant costs except for the annualized waste heat boiler and modification costs.)

Total heating system energy output (gas turbine, steam extraction plants).

Two extreme cases are considered: (1) heat is produced all year round at a given plant capacity factor, being either delivered to load or stored, and the load is supplied both from storage and from the plant; (2) heat is produced at a given capacity factor only for storage; heat to load is then supplied entirely from storage. In Case 2, when heat is being taken from storage, the extraction plant is used for full electric production and the gas turbine for electric peaking power (or they may follow the electric load); they are, however, assumed to be available to compensate for the outage of any heat storage modules. In Case 1 there is no specific back-up. It is assumed that the system can tolerate the loss of turbine heat, or the loss of several of the storage well modules. For each plant the system output is taken to be the average of these two cases.

Total heating system energy output (backpressure plant). A sufficient degree of heating system inter-connection is assumed to be in place to provide security for Case 1.

Storage aquifers. All storage is assumed to be located at the end of the transmission line and proximate to the load center.* Storage heat recovery

*The market analysis assumes that availability of aquifers in desired locations is normally distributed with a mean of 60 percent and standard deviation equal to 10 percent.

factors are assumed to be normally distributed about a mean of 75 percent, with upper and lower bounds of 100 and 50 percent. (The recovery factor applies to the energy capacity of the well, not to its rated power.)

Transmission. The transmission line is sized to the heating power output of the plant. A heat exchanger is assumed to separate the transmission and distribution systems. Transmission costs are distributed about the mode with an upper limit equal to twice the modal cost, and the lower limit equal to two thirds of the modal cost.

Gas turbine plants are assumed to be located proximate to load centers and have no long-distance transmission costs; steam extraction and backpressure plants are assumed to be 20 miles distant from distribution load centers.

Distribution. The distribution system is assumed to serve the needs for both space heat and hot water. Distribution system costs are based on the work on district heating systems done by Brookhaven.* Costs per delivered Btu for distribution for urban configurations given by the Brookhaven report have been increased by 30 percent to bring the installed piping costs closer to values given by Olszewski.** Distribution system costs are distributed about the mode with an upper limit equal to twice the modal cost and a lower limit of two thirds the modal cost. Load factors in the Brookhaven study for urban distribution systems serving residential and commercial users were around .45; a load factor of .4 is assumed for all the systems of this study.

*J. Karheck et al., "The Technical and Economic Feasibility of U.S. District Heating Systems Using Waste Heat from Fusion Reactors" (Upton NY: Brookhaven National Laboratory, February 1976).

**M. Olszewski, "Preliminary Investigations of the Thermal Energy Grid Concept" (Oak Ridge TN: Oak Ridge National Laboratory, October 1977).

Total system losses for distribution and transmission are assumed to be equal to 5 percent of the system output.

Distribution costs are associated with mixed loads of commercial and residential customers. For service from heat plant to industrial customers, heat is assumed to be delivered directly from a heating plant that is proximate to the industrial load or from the end of a transmission line; in either case there are no distribution costs.

Miscellaneous assumptions. The costs for delivered heat derived from the calculations in this section assume that all of the heat available from the plant is sold. This assumption leads to the lowest cost of heat with respect to possible heat sales and raises questions concerning available markets and their development. These questions are discussed in the sections on market penetration and government incentives.

All prices reported in this section are in current dollars over the 30 years (the assumed life of the venture) from 1985 to 2014. The assumed inflation rate was 6 percent. These assumptions are in concert with the use of the factor 0.15 for calculating the annual capital charges (discussed in Chapter 2) and allow the display of dynamic economic relationships between capital-intensive and fuel-intensive heat delivery systems over the life of the venture.

There was some attempt to regionalize the study on a macro basis by varying the fuel and distribution costs. All fuel costs are taken from the MOPPS study,* which provides regional prices for coal. All other fuel prices are assumed to be the same on a national basis. Coal prices used by region are as follows (1975 dollars per million Btu): Northeast = \$2.20, North Central = \$1.10, South = \$1.50, West = \$1.10. All fuel prices are

assumed to escalate 1 percent per year over the inflation rate, which is generally consistent with the MOPPS forecasts. The exception is coal prices that are for the most part assumed in MOPPS to rise in step with general inflation. Therefore our delivered heat prices from coal plants will be somewhat higher than suggested by MOPPS but differences will be small.

The costs of the distribution system needed to sell all the heat from a given size plant are highly region-dependent. This is primarily because individual customers use differing amounts of heat in the various regions. For example, residential customers in the South may only require half the Btu's for space heating as a comparable northern customer. Therefore the distribution system to serve southern residential customers must be approximately twice as large (and costly) as its northern counterpart to sell all the heat from a given plant. Regional distribution costs have been taken from the Brookhaven report discussed above.

All costs associated with implementing a district heating system have been included in our analysis with the exception of the heat exchanger and associated equipment needed by each customer to receive the heat from the distribution system. In the industrial case the assumption has been made that equivalent equipment is needed whether a boiler or a district heating system is used. Therefore we have compared our proposed systems to boilers using residual fuel oil and have included the capital costs of the boilers in the comparisons. In the residential/commercial case it has been assumed that the heat exchanger and associated equipment is similar in price to an oil or gas furnace and therefore this cost has been removed from the analysis. In fact, however, the furnace is likely to be more

expensive than the heat exchanger so that any error here is conservative, i.e., favors the alternatives over the district heating systems. The above assumptions are supported in the report by Olszewski.

Finally, the assumed efficiencies for existing heat sources are as follows: oil furnace, 60 percent; gas furnace, 70 percent; boiler, 85 percent. The heat pump is assumed to have a coefficient of performance of 2.5. Due to the use of independent sources, these values for the alternative systems are slightly different from those used in the market penetration analysis described in a later section. The comparisons and conclusions in this section are intermediate in nature and the calculations for the proposed systems have been passed to the market penetration model for the final analysis. Fuel costs for the proposed systems have been standardized in both analyses.

Cost Data. Tables 4.5-4.8 exhibit all of the cost and selected operational data used for calculating the price the utility must charge to supply heat. All costs are given in 1985 dollars in 1985. Capital and operating costs are escalated at 6 percent over the life of the venture while fuel costs are escalated at 7 percent. The plant capital and O&M costs, and the fuel costs are those for full electrical operation of the plant. The charges for the heat customer are calculated from these and the remaining costs directly attributable to the heat customer in the manner discussed earlier.

The capital and fuel costs include upper and lower values which are used for the probabilistic analysis. The operation and maintenance costs were not varied in the probabilistic phase since they are generally quite small in magnitude in relation to the capital costs. As indicated previously, the philosophy used for pricing heat from the gas turbine is different from

Table 4.5

GAS TURBINE PLANT
COST INFORMATION

\$1985 x 10 ⁶ In 1985	INDUSTRIAL			RESIDENTIAL/COMMERCIAL		
	Lower Value	Most Likely Value	Upper Value	Lower Value	Most Likely Value	Upper Value
<u>Capital Costs</u>						
Plant/Equipment	23.30	25.30	27.70	23.30	25.30	27.70
Incremental Heat Equipment	7.03	7.80	9.37	7.03	7.80	9.37
Aquifer	7.43	14.86	20.50	7.43	14.86	20.50
Transmission	-	-	-	-	-	-
<u>Distribution</u>						
Northeast	-	-	-	37.50	56.20	112.50
North Central	-	-	-	35.60	53.40	106.90
West	-	-	-	46.40	69.80	139.50
South	-	-	-	55.60	83.30	166.50
<u>O&M Costs</u>						
Plant (Fixed/Variable)		1.18			1.18	
Incremental Heat Equipment		.27			.27	
Aquifer		.07			.07	
Transmission		-			-	
<u>Distribution</u>						
Northeast		-			.49	
North Central		-			.49	
West		-			.49	
South		-			.49	
<u>Fuel</u>						
Northeast	33.10	37.90	42.60	33.10	37.90	42.60
North Central	33.10	37.90	42.60	33.10	37.90	42.60
West	33.10	37.90	42.60	33.10	37.90	42.60
South	33.10	37.90	42.60	33.10	37.90	42.60
Electric Generation		100 MW			100 MW	
Reduction in Electric Generation for Heat Output	Sell electricity back to grid at nuclear rates. Approximated by a 32.8% reduction in electrical generation in 1985 escalating to a 62.4% reduction in 2014.					
Available Heat	2.93x10 ¹² Btu			2.93x10 ⁶ Btu		

Table 4.6

COAL EXTRACTION PLANT
COST INFORMATION

\$1985 x 10 ⁶ In 1985	INDUSTRIAL			RESIDENTIAL/COMMERCIAL		
	Lower Value	Most Likely Value	Upper Value	Lower Value	Most Likely Value	Upper Value
<u>Capital Costs</u>						
Plant/Equipment	682.40	744.80	812.60	682.40	744.80	812.60
Incremental Heat Equipment	50.70	56.35	67.61	50.70	56.35	67.61
Aquifer	38.00	76.00	104.90	38.00	76.00	104.90
Transmission	82.00	123.00	246.00	82.00	123.00	246.00
<u>Distribution</u>						
Northeast	-	-	-	200.00	299.00	598.00
North Central	-	-	-	189.00	284.00	568.00
West	-	-	-	247.00	371.00	741.00
South	-	-	-	295.00	443.00	885.00
<u>O&M Costs</u>						
Plant (Fixed/Variable)		6.08			6.08	
Incremental Heat Equipment		1.22			1.22	
Aquifer		.35			.35	
Transmission		1.03			1.03	
<u>Distribution</u>						
Northeast		-			2.63	
North Central		-			2.63	
West		-			2.63	
South		-			2.63	
<u>Fuel</u>						
Northeast	125.90	143.90	161.90	125.90	143.90	161.90
North Central	63.00	72.00	81.00	63.00	72.00	81.00
West	63.00	72.00	81.00	63.00	72.00	81.00
South	85.90	98.10	110.30	85.90	98.10	110.30
Electric Generation		600MW			600MW	
Reduction in Electric Generation for Heat Output		20%			20%	
Available Heat	15.6x10 ¹² Btu			15.6x10 ⁶ Btu		

Table 4.7

COAL BACKPRESSURE PLANT
COST INFORMATION

\$1985 x 10 ⁶ In 1985	INDUSTRIAL			RESIDENTIAL/COMMERCIAL		
	Lower Value	Most Likely Value	Upper Value	Lower Value	Most Likely Value	Upper Value
<u>Capital Costs</u>						
Plant/Equipment	276.30	301.70	329.20	276.30	301.70	329.20
Incremental Heat	-45.80	-38.20	-28.70	-45.80	-38.20	-28.70
Aquifer	18.90	37.80	52.20	18.90	37.80	52.20
Transmission	59.10	88.70	177.40	59.10	88.70	177.40
<u>Distribution</u>						
Northeast	-	-	-	98.40	147.60	295.20
North Central	-	-	-	93.50	140.20	280.40
West	-	-	-	122.10	183.10	366.20
South	-	-	-	145.70	218.60	437.20
<u>O&M Costs</u>						
Plant (Fixed Variable)		2.09			2.09	
Incremental Heat Equipment		.35			.35	
Aquifer		.17			.17	
Transmission		.74			.74	
<u>Distribution</u>						
Northeast		-			1.30	
North Central		-			1.30	
West		-			1.30	
South		-			1.30	
<u>Fuel</u>						
Northeast	38.30	43.80	49.30	38.30	43.80	49.30
North Central	19.20	21.90	24.60	19.20	21.90	24.60
West	19.20	21.90	24.60	19.20	21.90	24.60
South	26.10	29.80	33.50	26.10	29.80	33.50
Electric Generation		200MW			200MW	
Reduction in Electric Generation for Heat Output		40%			40%	
Available Heat	7.7x10 ¹² Btu			7.7x10 ⁶ Btu		

Table 4.8

NUCLEAR EXTRACTION PLANT
COST INFORMATION

\$1985 x 10 ⁶ In 1985	INDUSTRIAL			RESIDENTIAL/COMMERCIAL		
	Lower Value	Most Likely Value	Upper Value	Lower Value	Most Likely Value	Upper Value
<u>Capital Costs</u>						
Plant/Equipment	1485.00	1621.00	1768.00	1485.00	1621.00	1768.00
Incremental Heat Equipment	97.80	108.60	130.40	97.80	108.60	130.40
Aquifer	73.00	145.90	201.30	73.00	145.90	201.30
Transmission	112.70	168.90	337.80	112.70	168.90	337.80
<u>Distribution</u>						
Northeast	-	-	-	385.00	578.00	1156.00
North Central	-	-	-	367.00	549.00	1098.00
West	-	-	-	478.00	716.00	1432.00
South	-	-	-	569.00	855.00	1710.00
<u>O&M Costs</u>						
Plant (Fixed Variable)		7.41			7.41	
Incremental Heat Equipment		1.08			1.08	
Aquifer		.68			.68	
Transmission		1.42			1.42	
<u>Distribution</u>						
Northeast		-			5.10	
North Central		-			5.10	
West		-			5.10	
South		-			5.10	
<u>Fuel</u>						
Northeast	60.00	68.60	77.20	60.00	68.60	77.20
North Central	60.00	68.60	77.20	60.00	68.60	77.20
West	60.00	68.60	77.20	60.00	68.60	77.20
South	60.00	68.60	77.20	60.00	68.60	77.20
Electric Generation		1200MW				
Reduction in Electric Generation for Heat Output		16%			16%	
Available Heat	30.1x10 ¹² Btu			30.1x10 ⁶ Btu		

the other systems. However, it was possible to translate this philosophy into the electric reduction approach used for the other systems by calculating an equivalent reduction percentage as a result of selling electricity back to the grid. These percentages are indicated at the bottom of each table and reflect the average between Case 1 and Case 2 discussed earlier in the systems assumptions section.

Deterministic Computational Results

Industrial case. Table 4.9 displays the final computations in the industrial case for all of the proposed systems, along with a boiler using residual fuel oil. The values in the table reflect the cost of heat from a newly built plant in the year indicated. The coal plants have regional prices associated with them due to the regional prices for coal. However, the remaining systems have national fuel prices and all systems are free of distribution networks. The prices in Table 4.9 thus provide the basic inputs to the deterministic market penetration study discussed later in this report.

An examination of the prices in 1985 indicates that relative to the boiler, the gas turbine and the coal extraction plant in the Northeast and South regions do not compete economically. All other systems are cheaper, with the nuclear extraction plant being significantly so.

Figures 4.2 and 4.3 present selected values from Tables 4.8 to 4.11 in graphical form. Figure 4.2 indicates that the gas turbine is more costly than the boiler over the 30 years considered here, while the nuclear plant stays competitive. Figure 4.3 shows that both coal plants in the North Central and West regions remain competitive during the same time span.

Figure 4.4 presents an additional calculation for the nuclear plant for comparison purposes. The lowest curve shows the cost of heat from a nuclear plant built in 1985 and operated for 30 years. Since all utility commissions

Table 4.9

REQUIRED UTILITY REVENUES FOR DISTRICT HEATING
INDUSTRIAL ALL REGIONS
CURRENT DOLLARS PER MILLION BTU
INFLATION AT 6%
SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	9.33	13.27	18.89	26.94	38.45	54.91	77.51
Nuclear Extraction	6.41	8.62	11.58	15.57	20.94	28.17	35.72
Built in 1985	6.41	6.82	7.36	7.98	8.84	10.04	11.32
Coal Extraction							
Northeast	9.80	13.31	18.07	24.56	33.41	45.43	59.63
North Central	8.32	11.22	15.15	20.45	27.65	37.36	48.30
West	8.32	11.22	15.15	20.45	27.65	37.36	48.30
South	8.85	11.98	16.21	21.94	29.75	40.30	52.45
Coal Backpressure							
Northeast	8.32	11.31	15.40	20.96	28.55	38.89	49.83
North Central	6.92	9.36	12.65	17.10	23.13	31.29	39.87
West	6.92	9.36	12.65	17.10	23.13	31.29	39.87
South	7.43	10.06	13.65	18.50	25.10	34.05	43.49
Boiler with							
Residual Fuel Oil*	8.70	12.21	16.32	24.87	33.27	47.26	59.64

*Includes capital costs of \$1.11/MBTU in 1985 in 1985 dollars. This value is escalated at 6% per year for all subsequent years.

Figure 4.2. Required Utility Revenues for District Heating in Industrial Case for All Regions. Values Reflect Cost of System Built in Current Year.

Figure 4.3. Required Utility Revenues for District Heating in Industrial Case for North Central/West Regions. Values Reflect Cost of System Built in Current Year.

Figure 4.4. Required Utility Revenues for District Heating in Industrial Case for All Regions.

use average cost pricing, the cost of providing heat from nuclear plants will be somewhere between these two curves. The cost of heat from a boiler built in 1985 will be only slightly less than that shown in the figure since the capital costs of the boiler are small relative to the fuel costs.

The divergence of the boiler curve and the curve for the nuclear plant built in 1985 highlights the cost implications of fuel-intensive versus capital-intensive heat systems. Once the nuclear plant is built, it can provide heat for 30 years at very slowly rising costs relative to the boiler. This is due to the fact that most of the nuclear plant costs arise from loan repayments that are constant, while most of the boiler costs are fuel-related. Therefore, capital-intensive systems should provide progressively cheaper and more predictably priced* heat relative to fuel-intensive systems, and if they are cost competitive or nearly so at the time of construction, should be given careful consideration from a cost standpoint. This point is enhanced further if the system uses coal or nuclear fuel, which is under greater domestic control than oil.

Residential/commercial case. Tables 4.10 through 4.13 display the results in the residential/commercial case for all regions. Regional differences occur in this case because of coal prices and the variations in the extent of the distribution systems as discussed earlier. All systems in this case have distribution systems and all except the gas turbine have transmission lines. The proposed system prices are compared to three alternatives--home heating oil, natural gas, and a heat pump.

The most favorable region for the proposed systems is the North Central region. Here all of the proposed systems are cheaper than the heat pump in

*The predictability feature is very important from the standpoint of business long-range planning. Certainly one barrier to capital investment is the uncertainty of energy supplies and costs. Systems that substantially remove these uncertainties should have beneficial impacts throughout the economy.

Table 4.10

REQUIRED UTILITY REVENUES FOR DISTRICT HEATING
 RESIDENTIAL/COMMERCIAL NORTHEAST
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	13.15	18.41	25.83	36.30	51.08	71.98	99.42
Coal Backpressure	11.64	15.75	21.34	28.91	39.19	53.14	67.81
Coal Extraction	13.23	17.91	24.22	32.80	44.42	60.17	78.24
Nuclear Extraction	9.80	13.15	17.65	23.69	31.81	42.71	54.08
Nuclear Extraction Built in 1985	9.80	10.39	11.10	11.89	12.97	14.47	16.06
Heating Oil	10.45	14.78	20.35	26.47	33.50	49.96	63.07
Natural Gas	6.40	11.30	15.85	20.85	26.75	39.53	49.91
Heat Pump	13.05	17.80	24.40	32.09	42.94	58.20	73.48

Table 4.11

REQUIRED UTILITY REVENUES FOR DISTRICT HEATING
RESIDENTIAL/COMMERCIAL NORTH CENTRAL
CURRENT DOLLARS PER MILLION BTU
INFLATION AT 6%
SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	12.99	18.21	25.55	35.93	50.58	71.31	98.58
Coal Backpressure	10.08	13.58	18.31	24.68	33.27	44.87	57.01
Coal Extraction	11.60	15.62	21.04	28.33	38.18	51.47	66.11
Nuclear Extraction	9.64	12.94	17.37	23.32	31.30	42.04	53.24
Heating Oil	10.45	14.78	20.35	26.47	33.50	49.96	63.07
Natural Gas	6.40	11.30	15.85	20.85	26.75	39.53	49.91
Heat Pump	13.05	17.80	24.40	32.09	42.94	58.20	73.48

Table 4.12

REQUIRED UTILITY REVENUES FOR DISTRICT HEATING
 RESIDENTIAL/COMMERCIAL WEST
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	13.89	19.42	27.17	38.11	53.49	75.21	103.50
Coal Backpressure	10.98	14.79	19.93	26.85	36.17	48.75	61.90
Coal Extraction	12.46	16.77	22.58	30.39	40.94	55.16	70.76
Nuclear Extraction	10.54	14.14	18.98	25.48	34.20	45.90	58.11
Heating Oil	10.45	14.78	20.35	26.47	33.50	49.96	63.07
Natural Gas	6.40	11.30	15.85	20.85	26.75	39.53	49.91
Heat Pump	13.05	17.80	24.40	32.09	42.94	58.20	73.48

Table 4.13

REQUIRED UTILITY REVENUES FOR DISTRICT HEATING
RESIDENTIAL/COMMERCIAL SOUTH
CURRENT DOLLARS PER MILLION BTU
INFLATION AT 6%
SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	14.64	20.42	28.41	39.90	55.89	78.42	107.55
Coal Backpressure	12.25	16.50	22.27	30.04	40.54	54.72	69.58
Coal Extraction	13.72	18.48	24.91	33.59	45.32	61.15	78.74
Nuclear Extraction	11.28	15.15	20.32	27.27	36.59	49.12	62.17
Heating Oil	10.45	14.78	20.35	26.47	33.50	49.96	63.07
Natural Gas	6.40	11.30	15.85	20.85	26.75	39.53	49.91
Heat Pump	13.05	17.80	24.40	32.09	42.94	58.20	73.48

1985, although the gas turbine becomes more expensive in later years. The coal backpressure and nuclear extraction plants compete favorably with heating oil over the 30 years of interest. However, none of the proposed systems compete with natural gas although the nuclear extraction plant narrows the gap considerably over the study period. In addition, the prices shown are for plants built in the year indicated--average prices would show more favorable comparisons.

The relationship between the proposed systems and the alternatives deteriorates as one moves to the South and West regions because of the more extensive distribution systems needed to sell all the heat output. For example, in the South none of the proposed systems are cheaper than natural gas or heating oil, and only the coal backpressure and nuclear plants compete with the heat pump. Further graphical comparisons are displayed in Figures 4.5 through 4.8 for the North Central and South regions.

Summarizing the results of this section, it is clear there is a gradient from favorable to unfavorable cost comparisons as one moves from the Northeast-industrial case to the South-residential/commercial case. The favorable results for the industrial case and the residential/commercial case in the Northeast and North Central regions suggest that district heating systems could be commercially viable and should be given further consideration. The results for the residential/commercial case in the South and West regions indicate that district heating systems here will be difficult to justify unless fuel prices rise much more sharply than is currently anticipated.

Probabilistic Computational Results. The probabilistic phase of the economic analysis was carried out in accordance with the methods discussed in Chapter 2 and Appendix C. In each case of interest, 100 runs were made and appropriate statistics calculated. Since all output distributions were

Figure 4.5. Required Utility Revenues for District Heating in Residential/Commercial Case for North Central Region. Values Reflect Cost of System Built in Current Year.

Figure 4.6. Required Utility Revenues for District Heating in Residential/Commercial Case for North Central Region. Values Reflect Cost of System Built in Current Year.

Figure 4.7. Required Utility Revenues for District Heating in Residential/ Commercial Case for South Region. Values Reflect Cost of System Built in Current Year.

Figure 4.8. Required Utility Revenues for District Heating in Residential/Commercial Case for South Region. Values Reflect Cost of System Built in Current Year.

approximately normally distributed, the means and standard deviations completely characterize these distributions.

The means have been displayed previously in Tables 4.9-4.13, and the standard deviations are displayed in the same format in Tables 4.14-4.18. Limits on all alternative fuels have been taken to be ± 12.5 percent of the mean.* With the use of these two sets of tables, the reader can construct any set of appropriate limits, i.e., one, two or three sigma** limits.

Figures 4.9 and 4.10 present graphically the use of two sigma limits for the nuclear plant for both the industrial and residential/commercial cases and illustrate two uses of risk analysis. In Figure 4.9 the lower limit for the boiler and the upper limit for the nuclear plant built in 1985 barely intersect in 1985 and diverge rapidly after 1985. Therefore, if one has reasonable confidence concerning the input distributions, one can conclude that the nuclear plant will almost surely compete with the boiler in 1985 and beyond. Figure 4.10 is a time-expanded graph showing the probabilistic behavior of the nuclear plant built in 1985 for the residential/commercial case and natural gas. An examination of the mean values for the nuclear plant and natural gas indicate that the nuclear plant is more expensive than natural gas in 1985, but that this relationship reverses itself before 1990. This suggests, for example, that some government subsidy might be appropriate to build and operate the plant in the early years in order to get less expensive heat relative to natural gas in later years. The question then arises as to how long the subsidy would have to be in force. This question can be answered probabilistically by an examination of the limits in both cases. If the nuclear plant cost were to occur at its lower limit and natural gas were

*Technical Assessment Guide, EPRI, June 1977.

**The word "sigma" refers to the Greek letter Σ , which is often used to represent the standard deviation.

Table 4.14

STANDARD DEVIATIONS FOR PROPOSED DISTRICT HEATING SYSTEMS
 INDUSTRIAL ALL REGIONS - CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6% - SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	.65	.93	1.32	1.89	2.69	3.84	5.60
Nuclear Extraction	.62	.83	1.11	1.49	2.01	2.70	3.40
Coal Extraction							
Northeast	.77	1.01	1.37	1.87	2.54	3.45	4.38
North Central	.74	.97	1.31	1.77	2.39	3.23	4.04
West	.74	.97	1.31	1.77	2.39	3.23	4.04
South	.75	.98	1.32	1.79	2.42	3.28	4.13
Coal Backpressure							
Northeast	.70	.93	1.26	1.71	2.34	3.18	4.01
North Central	.65	.84	1.14	1.54	2.08	2.82	3.56
West	.65	.84	1.14	1.54	2.08	2.82	3.56
South	.66	.86	1.17	1.58	2.15	2.91	3.70
Nuclear Extraction Built in 1985	.66	.65	.68	.73	.80	.89	.99

Table 4.15

STANDARD DEVIATIONS FOR PROPOSED DISTRICT HEATING SYSTEMS
 RESIDENTIAL/COMMERCIAL NORTHEAST
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	.92	1.27	1.78	2.50	3.52	4.97	6.74
Coal Backpressure	1.19	1.58	2.13	2.89	3.92	5.31	6.61
Coal Extraction	1.20	1.58	2.13	2.89	3.91	5.29	6.63
Nuclear Extraction	1.07	1.42	1.91	2.56	3.44	4.61	5.82
Nuclear Extraction Built in 1985	1.07	1.18	1.21	1.25	1.31	1.40	1.50

Table 4.16

STANDARD DEVIATIONS FOR PROPOSED DISTRICT HEATING SYSTEMS
 RESIDENTIAL/COMMERCIAL NORTH CENTRAL
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	.91	1.25	1.76	2.48	3.49	4.92	6.66
Coal Backpressure	1.13	1.49	2.01	2.71	3.66	4.94	6.19
Coal Extraction	1.16	1.52	2.05	2.76	3.72	5.02	6.28
Nuclear Extraction	1.05	1.39	1.88	2.52	3.38	4.54	5.68

Table 4.17

STANDARD DEVIATIONS FOR PROPOSED DISTRICT HEATING SYSTEMS
 RESIDENTIAL/COMMERCIAL SOUTH
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	1.15	1.53	2.14	2.99	4.19	5.88	7.65
Coal Backpressure	1.44	1.90	2.56	3.45	4.66	6.29	7.88
Coal Extraction	1.42	1.85	2.49	3.36	4.53	6.12	7.74
Nuclear Extraction	1.33	1.77	2.38	3.19	4.28	5.74	7.21

Table 4.18

STANDARD DEVIATIONS FOR PROPOSED DISTRICT HEATING SYSTEMS
 RESIDENTIAL/COMMERCIAL WEST
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Gas Turbine	1.04	1.40	1.96	2.74	3.85	5.42	7.17
Coal Backpressure	1.29	1.72	2.31	3.11	4.20	5.66	7.08
Coal Extraction	1.29	1.68	2.26	3.04	4.09	5.51	7.03
Nuclear Extraction	1.20	1.60	2.14	2.88	3.87	5.19	6.50

Figure 4.9. Required Utility Revenues for District Heating in Industrial Case for All Regions. Dashed Lines Define Distributional Ranges Calculated Using the Mean $\pm$ Two Standard Deviations.

Figure 4.10. Required Utility Revenues for District Heating in Residential/Commercial Case for Northeast Region. Dashed Lines Define Distributional Ranges Calculated Using the Mean $\pm$ Two Standard Deviations.

to be priced at its upper limit, this reversal would take place around 1986 (point A in Figure 4.10). On the other hand, if the nuclear plant cost were to occur at its upper limit and natural gas were priced at its lower limit, this reversal would not take place until around 1994 (point B in Figure 4.10). Therefore, one could conclude that the subsidy would need to be applied for one to nine years with a mean of four years. Clearly the extreme values of one and nine years are very unlikely, being the product of two small probabilities.* The two continuous sets of distributions with a price variable induce a single distribution with a time variable that can then be used to answer questions similar to the one posed above.

The probabilistic analysis discussed here does not change any of the general conclusions reached in the deterministic phase, but provides data and methods for conducting much richer analyses in terms of questions that can be answered and examination of potential risks.

Sensitivity Analysis. Sensitivity testing was performed on the two variables that were judged to have the most uncertainty concerning their ultimate costs--fuels and the transmission/distribution system. Table 4.19 shows two computations of interest. The coal price for a coal backpressure plant has been increased by 50 percent, yielding a 16.8 percent increase in total costs in 1985 rising to 19.8 percent in 2014. The rising percentage difference is due to the fact that the coal price is rising faster than the remaining costs of generating heat.

*For normally distributed random variables, the probability that the value of the variable exceeds two standard deviations in a given direction is 0.0228. Assuming independence of the two variables in question, the probability of both variables exceeding two standard deviations in specified directions is $(0.0228)^2 = 0.00052$.

Table 4.19

SENSITIVITY ANALYSIS FOR SELECTED DISTRICT HEATING SYSTEMS
 CURRENT DOLLARS PER MILLION BTU
 INFLATION AT 6%
 SYSTEM BUILT IN CURRENT YEAR

SYSTEM	1985	1990	1995	2000	2005	2010	2014
Coal Backpressure							
Industrial Northeast							
Base Case	8.32	11.31	15.40	20.96	28.55	38.89	49.83
Fuel Cost Increased by 50%	9.72	13.27	18.13	24.80	33.92	46.44	59.72
Difference in %	16.8	17.3	17.7	18.3	18.9	19.4	19.8
Nuclear Extraction							
Residential/Commercial							
Northeast							
Base Case	9.80	13.15	17.65	23.69	31.81	42.71	54.08
Trans/Dist System Cost Increased by 50%	12.12	16.26	21.82	29.27	39.27	52.70	66.68
Difference in %	23.7	23.7	23.6	23.5	23.5	23.4	23.3

The coal plant is therefore relatively insensitive to large fuel cost increases and again highlights the benefits of a capital-intensive energy source. Since all fuel prices would tend to rise together, and alternative fuel-intensive system costs would rise the full 50 percent, such an event would greatly enhance the desirability of district heating using a coal backpressure plant.

The nuclear extraction plant is somewhat more sensitive to large increases in the costs for the transmission/distribution system, having a 23.7 percent increase in total costs in 1985 as a result of a 50 percent increase in the cost of transmission/distribution. In the residential/commercial case the transmission/distribution system is a major cost, and fuel costs for the nuclear plant are relatively small. Therefore it will be important to reduce the uncertainty surrounding the transmission/distribution costs so that utilities can better judge the total costs and potential markets for heat sales.

Summary. The costs, calculations, and analysis tools presented in this section represent a comprehensive economic analysis of currently available central waste heat systems. If desired, the reader can undertake additional analyses using, for example, the tables of standard deviations provided in the section on risk analysis or by making complete deterministic or probabilistic runs using the model as described in Appendix C.

The preliminary conclusions of this section indicate that district heating can be economically viable in the industrial sector and in the residential/commercial sector in the North. A more complete analysis using additional market variables is presented in the next section.

Development Paths

Given the number of different plants that could be used to produce HTW and the different markets that might be served, the development of district heating could proceed along a number of different paths. We begin with six possible development paths. These were presented to utility executives during the interview (see Appendix A). The respondents in the interviews generally indicated that, in the absence of governmental action to legislate implementation in a large area, the system would probably start small, with gas turbine plants near industrial load centers, and build up as demand grew. In order to study the effects of the buildup of the integrated energy utility, and in response to the interview comments we have defined three development paths. The development paths define only the sequence in which new plants are added. The market penetration model determines the rate at which plants are constructed.

Development Path A.

The first development path, like the other two, assumes that, without government intervention, the first year in which a district heating system based on the IEU concept would begin serving a market is in 1995. This means that by about 1990 the aquifer storage concept would be demonstrated on a large scale and demonstration projects to determine load characteristics and pipeline design also would be completed. The first customers would be served with gas turbine plants located close by. As the market grows, these gas turbine plants would be interconnected to provide improved reliability and larger coal extraction plants would be added to the system.

This development path assumes a somewhat disperse development of HTW district heating. Thus, within each of the four regions of the country, the market would be served by gas turbine plants until at least six plants were in operation. After that, both gas turbines and coal extraction plants would be added to serve new customers. Seventy percent of new demand would be

served by new coal extraction plants and 30 percent by new gas turbines.

Thus, the construction ratio would be about two gas turbine plants for every one coal extraction plant.

Development Path B.

In this development path new load is served first by gas turbines, then by coal backpressure plants, and finally, by nuclear extraction plants. Here, an even more disperse development is assumed. New load is served by gas turbine plants until 15 such plants have been constructed. After that, 50 percent of new load is served by gas turbines and 50 percent by coal backpressure plants. Thus about $2\frac{1}{2}$ gas turbine plants are built for every coal backpressure plant. After 35 plants are on-line new load is served by a 20-30-50 combination of gas turbines, coal backpressure, and nuclear extraction plants. Thus, for every nuclear plant built there are $2\frac{1}{3}$ coal backpressure plants and 4 gas turbines.

Development Path C.

This development uses the same sequence as Path B (gas turbine, coal backpressure, nuclear extraction), however it assumes a much more concentrated development. Here the system begins only in a few areas in each region and expands mainly in those areas without beginning in many new areas as well. Thus the greater degree of interconnectedness in the transmission and distribution grid allows the use of more large plants.

In this path two gas turbines are used to start development in each region. Then, market growth is met by adding gas turbines and coal backpressure plants in about an equal ratio. Thus 70 percent of the new demand is supplied by coal backpressure plants. After six plants are in operation in each region new demand is met in a 10-40-50 ratio of gas turbines, coal backpressure plants, and nuclear extraction plants. Thus nuclear plants are connected to the grid much earlier than in Path B.

Market Penetration

Introduction. Once the costs and other characteristics of the Integrated Energy Utility system have been determined, it is necessary to project the penetration of high temperature water into the residential, commercial and industrial market. Substitution theory is one approach often used to generate such projections. A simple model of the process of technological substitution was developed by Fisher and Pry in the early 1970s.* They described the process as an S-shaped curve of the form:

$$f = 1/2 [1 + \tanh a(t-t_0)]$$

where f is the fractional substitution at any time, a is half the annual fractional growth rate in the early years and t_0 is the time at which half the substitution is complete.

More complex approaches to substitution analysis have been developed by others, including Mansfield,** Blackman,*** and Stern.****

Most of these approaches suffer from a number of restrictions on their application. Among these are

- the consideration of only two-body substitutions, that is, one item substituting for a second.

*J. C. Fisher and R. H. Pry, "A Simple Substitution Model of Technological Change," Technological Forecasting and Social Change, Vol. 3 (1971), pp. 75-88.

**E. Mansfield, "Technical Change and the Rate of Imitation," Econometrica, Vol. 29 (October 1961).

***A. W. Blackman, E. J. Seligman, and G. C. Sogliero, "An Innovation Index Based on Factor Analysis," Technological Forecasting and Social Change, Vol. 4 (1973), pp. 301-316.

****M. O. Stern, R. U. Ayres, and A. Shapanka, "A Model for Forecasting the Substitution of One Technology for Another," Technological Forecasting and Social Change, Vol. 7 (1975), pp. 57-79.

- the assumption that once the substitution starts it will proceed unidirectionally to the final level of saturation. The substitution will not reverse itself at some future time.
- a certain amount of historical data must be available from the early stages of the substitution. A substitution that has not yet started can be considered only by analogy.

In many cases these restrictions rule out the use of traditional substitutional analysis for many applications because: they are multi-body substitutions, involving more than two items; the substitution may reverse itself over time in response to external changes; and the start of the substitution may be many years in the future. In these instances the approach is usually to assume that the substitution dynamics are determined solely by the prices of the competing technologies.* Unfortunately, this assumption also is often invalid. Additional characteristics, such as ease of use, flexibility of use, prestige, marketing support, etc., may be important in the substitution.

The approach to market penetration used in this study solves these problems by describing the actual driving force of the substitution: the decision process of the people or organizations who will purchase the technology. Decision modeling is used to simulate the decisionmaking of the important actors in a substitution. By developing this simulation it is possible to consider a number of technologies competing for the same market, substitutions that may proceed at uneven rates or even reverse, and substitutions that have not yet begun.

*The Mansfield approach, however, considers profitability as well, and the Stern approach considers a range of noncost variables.

Decision modeling has been used as a market research tool for some time, and has been widely used during the past seven years.* Generally it is used in market research to describe the dynamics of an existing market and the attributes of a particular product that determine its market share. In the application described here a variation of decision modeling is used to describe the decision process of the important actors in the market. The simulated decision process is then used to forecast the future penetration of new technologies into the market.

The decision modeling approach assumes that decisionmakers consider a number of different factors in comparing the various alternatives available to them and that some of these factors are more important than others. Although a decisionmaker may not actually list these decision factors or consciously weigh them, they are implicit in his perception of the value of the different alternatives. In order to choose the "best" alternative, it is necessary for the decisionmaker to make a value judgment about what constitutes high value and low value. A technology that has low cost may be considered more valuable than one with higher cost, while one with higher reliability may be more valuable than one with low reliability. How does a high-cost, high-reliability technology compare with a low-cost, low-reliability alternative, though? To answer this question the decisionmaker must specify how important cost and reliability are to him. The low-cost, low-reliability

*Milton J. Rosenberg, "Cognitive Structure and Attitudinal Effect," Journal of Abnormal and Social Psychology, Vol. 53 (1956), pp. 367-72; Martin Fishbein, "A Behavior Theory Approach to the Relations between Beliefs about and Object and Attitude toward the Object," in Readings in Attitude Theory and Measurement, M. Fishbein, Ed., Wiley, New York, 1967; William L. Wilkie and Edgar A. Pessemier, "Issues in Marketing's Use of Multi-Attribute Attitude Models," Journal of Marketing Research, Vol. 10 (1973), pp. 428-41.

alternative may be perceived to be the "better" alternative if cost is much more important than reliability, or the reverse may be true if reliability is more important. It is assumed here that this process of assigning values to alternatives can be replicated by defining the relevant decision criteria and combining this information with perceptions of the importance of each criterion and the degree to which each alternative meets each criterion.

The first step in such an approach is to list the decision criteria used to judge the alternatives. Relative importance weights are then assigned to each criterion. The degree to which each alternative choice meets each of the criterion is then estimated. The result is a matrix like the one shown below.

DECISION CRITERIA	DECISION WEIGHTS	ALTERNATIVE RATINGS				
		A ₁	A ₂	A ₃	A ₄	A ₅
C ₁	W ₁	A ₁₁	A ₂₁	A ₃₁	A ₄₁	A ₅₁
C ₂	W ₂	A ₁₂	A ₂₂	A ₃₂	A ₄₂	A ₅₂
C ₃	W ₃	A ₁₃	A ₂₃	A ₃₃	A ₄₃	A ₅₃
C ₄	W ₄	A ₁₄	A ₂₄	A ₃₄	A ₄₄	A ₅₄

C_1 through C_4 represent the decision criteria. W_1 through W_4 are the importance weights for those criteria, A_1 through A_5 are the available alternatives, and A_{11} through A_{54} indicate the degree to which a particular alternative meets a particular criterion.

Once these entries have been specified, the value of each alternative to the decisionmaker is computed by summing the products of the weights and ratings. Thus,

$$V_i = \sum_n W_n \times A_{in}$$

where: V_i = perceived value of alternative i

W_n = importance weight of criterion n

A_{in} = degree to which alternative i satisfies criterion n

Since the value, V_i , calculated in this manner is dependent on the scales used for weighting the criteria and rating the alternatives, these values are converted to relative numbers by dividing by the average value.

$$RV_i = V_i / AV$$

$$AV = (\sum_i V_i) / NOAA$$

where: RV_i = relative value of alternative i

AV = average value of all alternatives

$NOAA$ = number of alternatives available

The alternative that has the highest relative value would be the expected choice for a given decisionmaker. When using this method to simulate the outcomes of a large number of decisions, however, the highest valued alternative is not likely to be the choice in every case. In this case the importance weights and alternative ratings represent average values perceived by the decisionmakers. Thus while the highest valued alternative should be chosen in more decisions than any other alternative, it may not

be chosen in all decisions. (Because of differences in regional or individual perceptions an alternative may have the highest value for a particular individual but not for the group as a whole when average weights and ratings are used.)

It is necessary, therefore, to convert the relative perceived values calculated for each alternative into market penetrations. This step is accomplished by plotting relative perceived value versus penetration for some historical period for which data are available. The result is a function similar to that shown below.

Once this relationship has been developed from past data, it can be used with future values of perceived value to determine penetration. Since there is no guarantee that the penetrations thus calculated will sum to 100 percent of the market, they must be normalized to sum to 100.

When new alternatives that were not available historically become available to the decisionmaker, it is necessary only to describe these alternatives in terms of the decision criteria in order to introduce them into the model. For most of these new alternatives, however, there is a learning period involved. Decisionmakers often are reluctant to choose a new alternative with which they have no experience. They also may be

uncertain of cost and other figures and thus be hesitant to consider fully a new alternative. As experience with the new alternative begins to accumulate, however, these problems disappear. In order to take this learning behavior into account, it is necessary to introduce a learning curve adjustment that reduces the perceived value of a new alternative in the first years after introduction. This learning curve usually affects the new alternative only in the first few years after its introduction.

Residential Decision Model. In the residential sector high temperature water will be competing in the market for home space heating and hot water heating. Since 1950 there have been essentially three fuels competing for the residential space heating market--oil, gas, and electricity. In the future not only high temperature water but also solar and electric heat pumps may be competing for that market. Figure 4.11 shows the historical experience for gas, oil, and electric resistance heating since 1950. In Figure 4.12 penetration of these three fuels is shown on a regional basis in the same time period. The decision model of penetration in the residential space heating market constructed for this study simulates the decision process of home buyers and builders. This model assumes that decisions on space heating systems are based on five system characteristics:

- Initial cost
- Operating costs
- Cleanliness
- Safety
- Fuel Availability

These criteria are based on judgments by the other study team. In some instances it may be possible to use market survey information on special interview to determine the criteria, but the information was not available for this study. The initial cost represents the cost of installing the heating system. Operating costs are the recurring cost of operating the system, which are essentially the fuel cost.

SOURCE: Petroleum Facts and Figures, 1971, p. 328.

Figure 4.11. Penetration for U.S. Sales of Automatic Domestic Central-Heating Equipment

SOURCE: The Futures Group, based on reports of the U.S. Census of Housing for 1950, 1960, 1970, 1973, 1974.

Figure 4.12. Automatic Space Heating Penetration

Cleanliness represents the user's perception about the amount of dirt or smoke involved with the operation of the system. Safety is simply the user's perception about the likelihood of serious accident while operating the system. Finally, fuel availability is the user's perception of his ability to purchase fuel for his heating system throughout the lifetime of the system.

Each of these factors enters into the decision, but they are not all equally important. Importance weights have been assigned to each of these decision criteria. These weights are shown in Table 4.20. As this table shows, it was assumed that for the Northeast initial costs and operating costs were the most important decision factors in 1960, while fuel availability was relatively unimportant. By 1975 operating costs and fuel availability had become the most important factors.

In some regions such as the North Central region, the severe winters cause operating costs to be the most important decision factor, while in other regions--the South for example--the relatively warmer climates cause greater emphasis to be placed on initial cost.

In all regions it is assumed that while cleanliness and safety are taken into account in the decision they are relatively less important than initial cost, operating costs, and fuel availability.

The values of the weights were based on the judgment of study team members. These judgments were checked for the historical time span by checking the model results with history. The future weights, however, are simply our best judgment.

The next step in constructing the residential space heating decision model was to determine actual perceived value for the decision criteria for each of the three systems, gas, oil, and electric resistance heating. These values were determined by historical data where it was available, and were estimated by the study team where data were not available. Since much less data on such items as fuel costs and initial costs were available on a

Table 4.20

IMPORTANCE WEIGHTS FOR
RESIDENTIAL SPACE HEATING DECISION MODEL

	1960	1975	2000
NORTHEAST			
Initial Cost	90	90	90
Operating Cost	80	115	105
Cleanliness	30	30	30
Safety	20	20	20
Fuel Availability	10	120	100
NORTH CENTRAL			
Initial Cost	70	70	70
Operating Cost	110	135	125
Cleanliness	30	30	30
Safety	20	20	20
Fuel Availability	10	50	80
SOUTH			
Initial Cost	130	130	130
Operating Cost	50	85	75
Cleanliness	30	30	30
Safety	20	20	20
Fuel Availability	10	120	100
WEST			
Initial Cost	100	100	100
Operating Cost	80	115	105
Cleanliness	30	30	30
Safety	20	20	20
Fuel Availability	10	50	80

NOTE: Higher weights represent greater importance.

SOURCE: The Futures Group.

regional basis than on a national basis, the model was originally calibrated using national data.

By combining the estimates of initial costs, operating costs, safety, cleanliness, and fuel availability for oil, gas, and electric resistance systems with the estimated decision weights for each of these criteria, figures of merit were developed for each of the three heating systems for the period 1950-1975. These figures of merit were converted to relative figures of merit by dividing each by the average figure of merit for all three systems. A calibration curve was then developed by plotting these relative figures of merit versus the actual penetrations for each of the systems over the period 1950-1975. This calibration curve is shown in Figure 4.13. The fact that the points defined relatively well an S-shaped conversion curve tends to support the estimates of decision criteria weights and heating system values made in the construction of the model. This conversion curve, developed using national data, was assumed to apply to each of the four regions.

In order to use the model in projecting future penetrations for heating systems, it is necessary only to specify those systems that will be competing for the space heating market, and the characteristics of those systems in terms of initial costs, operating costs, safety, cleanliness, and fuel availability. The relative figures of merit then can be calculated and the penetration determined from the calibration curve. For this study, it was assumed that, in addition to gas, oil, and electric resistance heating, three new systems would be available for residential space heating: high temperature water, solar heating, and electric heat pumps. For the solar system, it was assumed that 40 percent of the energy would come from the sun, and the other 60 percent would be supplied by a backup system fueled by oil. The heat pump was assumed to be an advance electric heat pump supplying 2.5 Btu's of output for each Btu of electric input. Future fuel prices were taken from the

SOURCE: The Futures Group.

Figure 4.13. Calibrations Curve for Residential Decision Model

MOPPS study. These figures and the estimates of the other system characteristics for the six systems used are shown in Table 4.21. Complete details of the residential decision model are given in an appendix.

For the commercial sector, lack of data prohibited us from developing a separate commercial space heating decision model. Therefore, the residential space heating decision model was also used for the commercial sector.

Industrial Decision Model. The industrial decision model was developed following the same procedures already outlined for the residential decision model. Here, however, lack of data prevented us from performing the same detailed calibration of the model for the historical period as we performed for the residential model. Therefore, we developed the calibration curve using what data was available and assuming that only two decision criteria were important: cost and ease of use. In the industrial sector, there is a wider range of future technology available to industries for providing processed heat. The technologies considered in the industrial decision model are shown in Table 4.22, along with the characteristics of those technologies as described in the MOPPS industrial working group report. The figures shown in Table 4.22 were used along with the MOPPS projections of future fuel prices to calculate expected costs for energy delivered from each of those systems. It should be noted that some of the systems such as the advanced external combustion engine, the open cycle brayton engine, and the backpressure turbine are co-generation systems. In these cases, a credit for the electricity generated was taken in calculating the cost of delivered heat.

Combined Models. In order to compare the system shown in Table 4.22 with district heating providing energy to an industrial user, it is, of course, necessary to know the cost of high temperature water from the district heating

Table 4.21

HEATING SYSTEM CHARACTERISTICS
NORTHEAST REGION
YEAR 2000

	OIL	GAS	ELECTRIC RESISTANCE	SOLAR (OIL BACKUP)	ELECTRIC HEAT PUMP	HIGH TEMPERATURE WATER
Initial Cost	.65	.85	1	.25	.55	.9
Operating Cost	1	.85	.35	1.67	.90	*
Cleanliness	.4	1	1	1	1	1
Safety	.8	.5	1	1	1	.9
Fuel Availability	.75	.30	1	1	1	1

NOTE: Higher numbers indicate more favorable characteristics.

*This figure is calculated during the model run. It depends on the total capacity installed for generating high temperature water.

SOURCE: The Futures Group.

Table 4.22

ENERGY TECHNOLOGY ALTERNATIVES IN THE INDUSTRIAL DECISION MODEL

TECHNOLOGY	FUEL	1ST YEAR MKT PENE	CAPITAL COSTS (\$)	OUTPUT (Btu/HR)	CAPACITY HRS/YEAR	EFFI- CIENCY	O+M (\$/MM Btu)
1. Atmospheric Fluidized Bed	Coal	1980	6.32×10^6	120×10^6	4000	.70	.165
2. Pressurized Fluidized Bed	Coal	1990	7.385×10^6	120×10^6	6000	.75	.183
3. Conventional Coal with FGD	Coal	Past 1975	8.3×10^6	120×10^6	4000	.6	.205
4. Low Btu Gas with Boiler	Coal	1987	15.5×10^6	120×10^6	4000	.50	.44
5. Solar Planar Collector	Solar	1980	1.35×10^6 NE 1.08×10^6 NC $.81 \times 10^6$ S $.54 \times 10^6$ W	10×10^6 *	4380	1.00	.59 NE .47 NC .35 S .23 W
6. Advanced Internal Combustion (Diesel Cogeneration)	Oil	1985	5×10^6	(160×10^6) (10 Mwe) 125×10^6_t	7000	.80	.312
7. Advanced External Combustion (Cogeneration)	Coal	1987	9.5×10^6	(160×10^6) (10 Mwe) 125×10^6_t	7000	.76	.312
8. Open Cycle Brayton Engine (Cogeneration)	Oil	1985	3.5×10^6	(160×10^6) (10 Mwe) 125×10^6_t	7000	.78	.312
9. Electric Industrial Heat Pump	Elec.	1980	$.35 \times 10^6$	10×10^6 *	7000	3.2	.58
10. Backpressure Turbine (Cogeneration)	50% Oil 50% Coal	1979	5×10^6	300×10^6_t 34×10^6	7000	.83	.58
11. Conventional Oil	Oil	Past	6×10^6	120×10^6	4000	.67	.15
12. Conventional Gas	Gas	Past	6×10^6	120×10^6	4000	.67	.15

*Numbers adjusted from MOPPS study to add costs for a gas-fired boiler.

SOURCE: Information based on the MOPPS Industrial Working Group, June 1977.

scheme. The cost of high temperature water from each of the different plants considered in this study were calculated as presented in the preceding section. However, the costs of high temperature water to a residential or an industrial user may not depend simply on the cost of high temperature water from one plant, but will be average costs reflecting the costs of using high temperature water from a number of different plants built in different years and using different technologies. It is therefore necessary to calculate the average cost of hot water to each user. In order to make this calculation it is first assumed that high temperature water to the first few users in each area will be generated by gas turbine plants. The costs of high temperature water for these initial users are therefore simply the cost of high temperature water generated by gas turbine plants. As the system grows, however, and larger capacity plants such as combined cycle or coal extraction plants come on line, the average cost of the hot water to a user will drop, because the cost of high temperature water generation for the larger plants is less than for the gas turbine plants.

The sequence of plant construction is determined by the development paths discussed in the preceding section. For Path A it was assumed that the first six plants to be equipped to produce high temperature water would be gas turbine plants. After the market had expanded beyond the capacity of those six plants, additional capacity would be added by building coal extraction plants equal to 70 percent of the new demand, and gas turbine plants equal to the remaining 30 percent.

For Path B gas turbines are constructed until 15 plants have been built. The next group of plants is split 50-50 between gas turbine and coal backpressure. Finally, after 35 plants are on line new additions proceed with 20 percent gas turbine, 30 percent coal backpressure, and 50 percent nuclear.

Path C is similar to Path B except that only two gas turbines are required to start the system. Next additions are 70 percent coal backpressure and 30 percent gas turbine. After six plants have been installed new additions are 50 percent nuclear, 40 percent coal backpressure, and 10 percent gas turbine.

The model, then, keeps track of the number of plants built of each type in each year. The average cost of hot water is calculated by weighing the cost of producing hot water for each of the three types of plants in each of the years in which those plants were built by the capacity of those plants. In this way the average cost of hot water to the industrial and the residential user depends on the size of the market at any given time. As the market grows, larger and more efficient plants can be brought on line to serve that market and the average costs of high temperature water are kept lower than they would be otherwise. The total market is the sum of the markets for the industrial, residential, and commercial markets. Thus, growth in one market benefits the other market as well by tending to keep costs of high temperature water low.

Total Market for HTW Products

Deterministic Analysis. Results of the decision model runs for development Path A are shown in Tables 4.23 and 4.24. Table 4.23 shows penetration of high temperature water, that is, the percentage of new demands that is captured by the high temperature water technology. As Table 4.23 shows, penetration in the industrial sector begins in 2000, shortly after the availability of high temperature water in 1995. It increases to final levels around 10 percent in all regions. Penetration into the residential and commercial sectors reaches somewhat higher levels, attaining 14 percent in the Northeast by 2020.

Table 4.23

HTW PENETRATION - DEVELOPMENT PATH A

	PENETRATION					
	YEAR					
	1995	2000	2005	2010	2015	2020
NORTHEAST						
Industrial		.02	.08	.09	.09	.09
Residential & Commercial		.11	.10	.12	.14	.14
NORTH CENTRAL						
Industrial		.02	.08	.08	.09	.09
Residential & Commercial		.08	.06	.08	.10	.11
SOUTH						
Industrial		.02	.07	.08	.09	.08
Residential & Commercial		.10	.10	.11	.12	.12
WEST						
Industrial		.02	.07	.07	.07	.07
Residential & Commercial		.08	.08	.08	.10	.10

SOURCE: The Futures Group

Table 4.24
HTW MARKET DEVELOPMENT PATH A

	PENETRATION				
	YEAR				
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020
GROWTH IN HTW OUTPUT BTU x 10 ¹² /YR					
Gas Turbines	3	60	80	105	130
Coal Extraction			30	85	145
NUMBER OF PLANTS ADDED					
Gas Turbine (100 MWe)	2	20	28	35	44
Coal Extraction (600 MWe)			3	6	10
PERCENT OF NEW BASELOAD ELECTRICAL GENERATION	-	3%	6%	10%	14%
APPROXIMATE NUMBER OF ESTABLISHMENTS ADDED (Thousands)					
Industrial	1	10	15	25	55
Commercial	2	130	230	400	525
Residential	8	390	610	1150	1385

SOURCE: The Futures Group

Table 4.24 shows the consequences for high temperature water generation of penetration levels shown in Table 4.23. Initially, most of the high temperature water output is supplied by gas turbine plants. As demand grows, much of the new output of high temperature water is supplied by coal extraction plants. Gas turbine plants are first brought on line around 2000 and reach a construction rate of about nine per year by 2020. Coal extraction plants do not begin to come on line until the 2000-2005 period and reach a level of around two plants per year by the end of the model run. This construction represents about 10-15 percent of new base load construction for electrical generation by the end of the new period. An approximate number of industrial, commercial, and residential establishments using high temperature water also is shown in Table 4.24. The number of residential and commercial establishments using high temperature water is, of course, much greater than the number of industrial establishments because the average use of industrial establishments is much greater than for residential and commercial. By 2020 the demand for high temperature water shown in Table 4.24, although reaching high enough levels to be installed on 10-15 percent of all new base load electrical generation, still represents a rather small percentage of total demand in each of the three sectors. It represents about 4 percent of all space heating demand in the residential sector and only 1 percent of all industrial demand for indirect heat.

Tables 4.25 and 4.26 show similar information for Path B. The penetration figures are practically identical with Path A although, of course, the plants that serve that market are different. By 2020 about two gas turbine plants, one coal backpressure plant, and less than one nuclear plant per year are being constructed with HTW capability.

Table 4.25

HTW PENETRATION - PATH B

	PENETRATION					
	YEAR					
	1995	2000	2005	2010	2015	2020
NORTHEAST						
Industrial		.02	.08	.09	.09	.10
Residential & Commercial		.11	.10	.12	.14	.15
NORTH CENTRAL						
Industrial		.02	.08	.08	.09	.09
Residential & Commercial		.08	.06	.08	.12	.10
SOUTH						
Industrial		.02	.07	.08	.09	.10
Residential & Commercial		.10	.10	.11	.12	.13
WEST						
Industrial		.02	.07	.07	.07	.07
Residential & Commercial		.08	.08	.08	.10	.10

SOURCE: The Futures Group

Table 4.26
HTW MARKET PATH B

	PENETRATION				
	YEAR				
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020
GROWTH IN HTW OUTPUT BTU x 10 ¹² /YR					
Gas Turbine	3	33	24	30	20
Coal Backpressure		20	30	30	30
Nuclear Extraction				27	47
NUMBER OF PLANTS ADDED					
Gas Turbine	2	12	8	11	7
Coal Backpressure		3	4	4	4
Nuclear Extraction				1	2

SOURCE: The Futures Group

Path C, shown in Tables 4.27 and 4.28, has considerably higher penetrations because of lower costs due to a larger contribution of coal backpressure and nuclear plants. In this path by 2020 the addition of gas turbines reaches 2 by 2020, coal backpressure reaches about 3 plants, and nuclear about 1 per year.

Probabilistic Analysis. The decision model used to determine the future market for HTW products can be used in a Monte Carlo procedure to determine the uncertainty of the forecasts as well. The Monte Carlo procedure uses probability distributions for each of the important inputs to the model and, by randomly selecting from these distributions, performs a large number of model runs. These runs correspond to different futures that might arise. By determining the variation in market size for these runs the uncertainty in the mean forecast is found.

Unfortunately, this procedure gives a distorted view of the real uncertainties involved. The only parameters that can be varied in the Monte Carlo runs are those that are a part of the model. In this case the largest sources of uncertainty are exogenous to the model. Thus, the model does not display the uncertainty involved with whether retrofit will take place in the residential and commercial market, whether the aquifer storage concept will actually work, whether the implementation scenarios selected are the right ones, whether air conditioning might become part of the load, or whether regulations will allow utilities to operate HTW systems in all areas. These are the major uncertainties. How they are ultimately resolved will make more difference in the size of the final market than small variations in most of the model parameters.

Table 4.27

HTW PENETRATION PATH C

		PENETRATION					
		YEAR					
		1995	2000	2005	2010	2015	2020
NORTHEAST							
Industrial Residential & Commercial	Industrial		.02	.16	.29	.37	.40
	Residential & Commercial		.11	.21	.29	.32	.34
NORTH CENTRAL							
Industrial Residential & Commercial	Industrial		.02	.17	.32	.40	.43
	Residential & Commercial		.08	.19	.29	.32	.34
SOUTH							
Industrial Residential & Commercial	Industrial		.02	.15	.27	.34	.38
	Residential & Commercial		.10	.14	.18	.21	.22
WEST							
Industrial Residential & Commercial	Industrial		.02	.14	.23	.30	.32
	Residential & Commercial		.08	.15	.22	.25	.27

SOURCE: The Futures Group

Table 4.28
HTW MARKET PATH C

	PENETRATION				
	YEAR				
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020
GROWTH IN HTW OUTPUT BTU x 10 ¹² /YR					
Gas Turbine	3	15	10	20	25
Coal Backpressure		40	50	75	100
Nuclear Extraction			60	95	125
NUMBER OF PLANTS ADDED					
Gas Turbine	2	5	4	7	9
Coal Backpressure		5	7	10	13
Nuclear Extraction			2	3	4

SOURCE: The Futures Group

For illustrative purposes, however, Monte Carlo runs have been performed for Paths A and B. Ranges of uncertainty for HTW costs are displayed in earlier sections of this chapter. Estimated uncertainty ranges for other parameters included standard deviations of 4 percent for fuel prices, 6 percent for capital costs, 5 percent for decision weights, and 10 percent for the percentage of the country that has suitable aquifer storage sites.

The results of the runs are shown in Table 4.29. They show standard deviations for the total market of about 12 percent and 22 percent for Paths A and B respectively by 2020. Thus the 95 percent confidence limits for the total market would be ± 24 percent for Part A and ± 44 percent for Path B.

Conclusion. Based on the preceding analysis it appears that there is likely to be a small but significant market for HTW products. Table 4.30 shows the likely range of the market size for each of the products. These figures are predicated on the following major assumptions:

1. The aquifer storage system will work well and suitable aquifer storage sites will be available throughout 40-80 percent of the country.
2. The residential and commercial market will consist solely of new construction; no retrofit of existing structures will take place.
3. The residential and commercial market will consist solely of space heating and water heating; air conditioning with HTW will not take place.
4. The HTW will develop based on its ability to compete with other technologies on the basis of cost and performance. The government will not mandate HTW installations on a large scale.

Then assumptions are crucial since the different assumptions could change the market drastically. If the aquifer storage system does not work well, for example, there would be no market. On the other hand, if the government mandated the retrofitting of large areas, the market would be enormous.

Table 4.29

UNCERTAINTY RANGES FOR HTW MARKET

Market for HTW
Mean $\pm$ Two Standard Deviations
(1012 Btu/yr)

	PENETRATION				
	YEAR				
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020
PATH A					
Gas Turbine	3 $\pm$ 1	60 $\pm$ 10	80 $\pm$ 16	105 $\pm$ 16	130 $\pm$ 28
Coal Extraction			30 $\pm$ 30	85 $\pm$ 13	145 $\pm$ 39
PATH B					
Gas Turbine	3 $\pm$ 1	33 $\pm$ 10	24 $\pm$ 8	30 $\pm$ 17	20 $\pm$ 8
Coal Backpressure		20 $\pm$ 20	30 $\pm$ 14	30 $\pm$ 9	30 $\pm$ 10
Nuclear Extraction				27 $\pm$ 27	47 $\pm$ 23

Table 4.30
MARKET FOR HTW PRODUCTS

	PENETRATION				
	YEAR				
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020
Gas Turbine Plants	0-2	5-24	3-34	5-40	5-55
Coal Backpressure Plants	-	0-7	2-9	2-13	2-17
Coal Extraction Plants	-	-	0-4	4-7	7-13
Nuclear Extraction Plants	-	-	0-2	0-5	1-7
Meters (thousands)	0-22	320-730	500-1200	520- 2630	1100- 2830

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CORPORATE DECISIONMAKING

The Decisionmakers

In the private sector, the commercialization of the "Integrated Energy Utility" as a venture involves a number of corporate bodies. The electric utility that decides to offer to distribute and sell thermal energy in the form of high temperature water (HTW), as well as electricity, bears the lion's share of the capital investment and the risk of gain or loss. Its decisionmaking processes and criteria must be given careful attention, as was done through the intensive interview process reported.

Other decisionmakers are the suppliers of the many equipments and services used in a complete cogeneration plant and of the complete system of generation, transmission, and distribution. Each must decide whether to invest in a product line or product line modifications that will meet the requirements of the Integrated Energy Utility, and whether to bid when a purchase is planned by a utility. These decisions will be affected not only by desire to capture a new market but also by need to maintain a product line that will enable the supplier to retain his share of the market he supplies.

Other private-sector decisionmakers, whose decision plays a key role in the commercial success of the Integrated Energy Utility, are the large customers (industrial and commercial users of heat) who must decide between the offered HTW service and conventional methods of heat supply through their own investment.

While favorable decisions must be made by all of these corporate entities, and the many individual customers for heat as well, it is clear that the leading or driving decision is that of the utility.

No one equipment supplier, such as General Electric, supplies enough of the equipment needed to be a strong driving force. For example, in a large coal-fired power plant, which might be designed for conventional or cogeneration use, the factory equipment cost of the turbine-generator, which is the principal component GE would supply, is only 10.1 percent of the total direct cost of the plant.* It is a still smaller fraction, 4.7 percent, of the total investment made by the utility before the start of plant operation.

In order to examine the corporate decisionmaking of equipment suppliers, and the role they might play in stimulating or inhibiting the "Integrated Energy Utility" as a venture, provision was made in the organization of this project to consider a number of new product ventures that a supplier might consider. The cooperation of representatives of several levels of decisionmaking in the General Electric Company was promised for the purpose of reviewing the suggested new product ventures and providing reactions and discussion on the criteria and probable decision process if these ventures were formally presented for corporate decisions.

General Decision Criteria

This section is solely concerned with General Electric decisionmaking, as discussed with GE managers; no comparable exploration of other equipment suppliers has been attempted. However, General Electric is a highly decentralized company with great diversity of types of products, markets served, and management styles. There are probably counterparts someplace in the GE

*United Engineers & Constructors, Inc., Capital Cost: Low and High Sulfur Coal Plants - 800 MWe, NUREG-0244 (Philadelphia, PA: June 1977), Volume 3, pp. 9-4 to 9-7.

structure to almost any type of business and management style found in U.S. industry.

Management styles do differ widely, so it is difficult to find categorical principles and criteria that apply universally. Management styles depend of course in large part on the personality of the man in charge of a business. They are encouraged or inhibited by many other considerations. A business that is currently healthy, with high profitability on sales and return on investment, good market share, and quality products in a growing market, can afford to commit more resources to new products that are long range and high risk than can a business that is faltering and failing to meet its goals.

The manager responsible for a business or profit center has considerable freedom in his operating decisions. Quite large commitments of labor and materials can be made in manufacturing improvements or new product development without higher management approval other than that implicit in his annual budget and goals for sales and earnings. However, investment decisions in equipment, structures, and land have traditionally had much tighter controls, with appropriations above certain amounts requiring successive approval by management levels up to the Board of Directors. Thus, the new-product decisionmaking process may be quickly responsive to perceived trends in its early stages but require searching review when capital appropriations for a new factory or production line are required.

General Electric's view of itself is as a high-technology producer: To be attractive a new business should involve creative ideas, patentable or proprietary, that cannot quickly be matched by many other companies. GE regards itself as an equipment supplier rather than a systems integrator.

Continuing production of a product line with continuing improvements is preferred to one-of-a-kind custom products with very high design content.

Profitability and the meeting of earnings goals are of course the important considerations in judging the health and survival of a business and its management. The earnings goal set may involve many things such as percent of sales, of value added, return on investment, and the growth plans for the business that may trade off current earnings for future prospects. A new project or business opportunity considered by itself may be judged by the estimated return on investment, discounted or net, compared to the ROI on other uses of the same resources. It was found difficult to get any single number as "the required return on investment"; the diversity of business situations is too great, and historic results range from very high to very much negative (not planned that way of course). One manager was willing to say that 15 to 20 percent was perhaps an average expected return on investment.

The use or non-use of the more sophisticated analytic tools for decision making is definitely a matter of management style. Some upper echelon managers make common use of decision trees and are interested in probabilistic upper and lower bounds on the budgetary estimates and appropriation requests submitted to them. Others want only a best estimate and a downside risk of loss. A single-point budget (expected value) is still the most common in usage. In making venture decisions that must go upward to Group, Sector, or Board of Directors, use of DCRR (discounted cash rate of return) formulation of the expected return is customary, with 10 to 40 percent being the acceptability limit depending on other factors important in each case.

Generic History of a Venture. A number of phases, often overlapping, characterize a proposed venture for a new product or other innovation. They

can be characterized as Initiation, Exploration, Product Planning, and Implementation.

Initiation

The project may originate in several ways:

- What do customers want? Multiple specific customer inquiries, corporate or industry surveys, suggest potential new products.
- Identify a need. Trends create needs and early recognition of a potential product before customers and competitors identify the need is advantageous.
- Fill a hole in the product line. Recognition of an unserved market that is related to the current product technology, such as intermediate or larger sizes, is important.
- New application for a technologic advance. This kind of spinoff: what can be done rather than what is wanted requires both judgment and vision. New businesses can originate.
- Advocacy. A convinced and persuasive advocate of a new venture concept is often a catalyst that is far quicker and surer than rational analyses and surveys.

Exploration

Early, low budget steps in the decisionmaking course of the venture include:

- How big is the need? Identifying the size and composition of the potential market, threats to the need such as other ways to satisfy it, or trends that can eliminate it, are the roles of market analysis.
- Technical and economic feasibility. Analysis and small R&D investments test whether the concept is sound and merits the next stage of development.

Product Planning

For survivors of the early phases, more detailed planning and resource allocation are performed.

- Product line options. One model or several; modular units; what sizes? Facilities required for development, test, and production.
- More detailed market analyses. How many can be sold, over time? What is the market share pattern? If high at first, is market share unduly subject to attrition as others enter the field?
- Allocation of resources. In order to meet earnings goals and to stay within budget allocations for engineering, marketing, and manufacturing, consideration must be given to the other demands on the same resources that may have higher priority, better payoff, less risk, be committed by previous agreements with other parts of the company, etc. A valid, desirable venture may be delayed or foregone if available resources are not compatible with the need and timing.

Implementation

This phase may be simple if a hole in the product line is to be filled, requiring no new technology or facilities. Planning for engineering design, production, and marketing can be a routine part of the business. If new facilities, machines, buildings, or a whole new plant are required, extensive analysis of the justification for the venture must be made and be subject to approval reviews by successive levels of management to the Board of Directors. In these reviews it is competing for resources with an increasingly large spectrum of other opportunities and current requirements.

In all of the above phases, the role of advocacy continues. That someone is willing to bet his career on a venture is a persuasive argument, although not always conclusive. The original advocate must persuade, for the necessary higher levels of review, a suitable group of higher management levels who in turn become the advocates.

In the simulated management review meetings arranged for this project, TEMPO has played the advocate role, proposing potential products in an initial review meeting at GE's executive offices in Fairfield, Connecticut on October 10, 1977. From the discussion and suggestions received at that

meeting, modifications and additional justification of the proposed ventures were prepared. A second meeting was held at the same location on February 28, 1978. The following sections describe the attitudes and conclusions generated by the proposed new product ventures.

Flexible Heat Recovery Steam Generator

The concept was defined as a version of the Heat Recovery Steam Generator (HRSG) now used with the MS7000 Gas Turbine to provide combined cycle, or STAG, operation. It is capable of generating 274,000 lb/hr of steam at 900 psig and 935°F from feedwater at 110°F.

For industrial applications this would be the maximum temperature, pressure, and thermal power output deliverable. Lesser temperatures and pressures needed for specific processes could be obtained by throttling and/or desuperheating the steam. By mixing steam with pressurized feedwater, HTW at desired temperatures could be obtained. By retaining the basic HRSG as the interface with the turbine, considerable flexibility would be available for meeting different industrial needs, even changing industrial needs, and gradual transition to HTW as the market for it developed. The basic module could be made repetitively without need for custom design. Specific customer needs would be handled by added minor components.

At the first review meeting in October, the reaction by a staff executive suggested that GE is not primarily interested in custom designing, with high engineering content, heat exchangers tailored to one-of-a-kind market. Others can do that better than we can. However, if a modular design can easily meet a variety of applications and a market for it is shown, it would be interesting. The added cost penalty of having the unit flexible was questioned. Additional information was promised for the second meeting.

While the cost of minor components to degrade the steam from the HRSG might not be excessive, it was likely that a HTSG specifically designed for the extreme case of generating HTW only might be considerably simpler and cheaper. The design engineers were asked to compare the two cases: production of steam at 901 psig (6.3 MPa) and 935°F (502°C), and production of HTW with a sendout temperature of 404°F (207°C) and a return temperature of 110°F (43°C). Figure 4.14 shows that for the same energy input (115 MW), 274,000 pounds per hour of steam or 1,300,000 pounds per hour of HTW could be produced. For steam, two economizers (air to water), an evaporator, and a superheater are used. The area of heat exchanger tubes required to generate HTW is only 60 percent as great as that needed to generate the steam. In fact, the two economizers alone could be just about adequate. This difference in the area required, as well as the lower pressure for HTW, which permits thinner tube walls, makes quite a difference in HRSG cost. The steam generator costs about 30 \$/kW while the HTW generator costs about 16 \$/kW.

This would provide a strong motivation to design for HTW where HTW was known to be the principal product wanted. The product planner for this component indicated that each customer generally has different requirements, and the factory is prepared to synthesize a large range of output combinations from standard parts with little component engineering. He would not call this custom design. No development is needed. He would recommend that each HRSG be made for the specific output(s) required rather than designing a universal module.

The conclusion is that this product is considered a routine part of a going business rather than a new business opportunity. Accordingly, no action is needed to be ready to supply utilities as soon as their decision making indicates the need for a gas turbine with heat recovery to HTW.

	<u>HRSG</u>	<u>HTW ONLY</u>
A	38%	45%
B	19%	15%
C	31%	
D	12%	
	<u>100%</u>	<u>60%</u>
	274 000 #/HR	1 300 000 #/HR
	901 PSIG	300 PSIG
	935°F	404°F
	125 MW(TH)	125 MW(TH)

Figure 4.14. New Product Opportunity, Flexible HRSG

Backpressure Turbine for Coal Plant

The concept was to design a 140 MW_e backpressure turbine with 400 MW thermal output at HTW at 350°F. The backpressure condenser and two extraction points heat district heating return at 150°F up to the final temperature in "feedwater heaters." No cooling towers or other waste-heat disposal system is needed. Since the electric output and heat output must stay in step, the preferred dispatch mode is base load operation at full load, with thermal storage to match heat supply to the heat demand cycle.

A size smaller than the backpressure turbine shown in Figure 3.8 was selected as the new product venture for two reasons. The product is put within the scope of the Medium Steam Turbine Department, which has experience with noncondensing turbines; and in small sizes it is more likely to find an early market in Integrated Energy Utilities, while the demand for district heating is being developed. The configuration suggested is shown in Figure 4.15. The smaller capacity makes it simpler; the turbine has a single high-pressure section and a single low-pressure section, three feedwater heaters, and two stages for district heating.

The product planner for Medium Steam Turbine examined the proposed product and indicated that no part of the turbine generator required development or investment. Only normal component engineering, as expected in most of their business, is necessary. They are ready when utilities are ready to buy. Again, it appears that no advance action is necessary.

District Heating Turbine for Light Water Reactor

In the first management review, those concerned with the turbine generators for nuclear reactors commented that the new product venture illustrated in Figure 4.1 was too extreme. The large turbines currently used are carefully engineered to the requirements of the LWR steam supply. There would be a very long and expensive development cycle to bring backpressure turbine

Thermal Input 629 MW
 136 + 413 = 549 MW or 87% Eff.
 H.R. Chargeable to Power 4000 Btu/kWh

Figure 4.15. Backpressure TG for Coal Plant

equivalents to the same level of reliability. Utilities are not likely to purchase such a radical departure, considering the difficult approval cycle on nuclear plants, before less radical intermediate steps have been demonstrated. In other words, what was proposed was third generation, not the first-generation product for nuclear district heating. Designers recommended that for a first-generation product the main turbine generator should be left unchanged and that a district heating turbine on a separate shaft be provided for backpressure district heating.

This is the configuration depicted in Figure 3.13. The main turbine generator can run at rated load as before, or some portion of the live steam from the reactor can be diverted to the district heating turbine, capable of putting out 800 MW_t. There is relatively little loss of electricity with maximum heat output, about one MW_e lost for 5.7 MW_t of district heating, but the electricity generation capacity is partially duplicated. The system of Figure 3.13 is likely to be less economic than that shown in Figure 4.1 because of the added turbine costs and the need for a heat rejection system, which could be omitted with the latter configuration.

The design of the backpressure turbine for nuclear reactor steam conditions, saturated steam at 965°F (520°C), would require development. The size indicated could be made as a two-flow low-pressure section at 1800 RPM, as is done in the main turbine, but the standard parts used in backpressure turbines by Medium Steam Turbine Department are 3600 RPM technology. A four-flow low-pressure turbine at 3600 RPM would be one approach. The valves are shown separately, to the two halves of the low pressure turbine. Flexibility in controlling the flow to the low pressure turbines separately is desirable to achieve part load heat and electricity operation and still maintain the district heating output at the desired temperature.

Heat Metering System

In an Integrated Energy Utility a measure of the amount of product used by the customer is essential for proper billing. It was suggested at the first management review meeting that this be one of the venture products examined, in addition to the turbines and HRSG suggested. A staff executive indicated that a high-technology, high-reliability product that is superior to anything else on the market could be a very desirable product for GE, by analogy to the watt-hour meter business.

At the second management review meeting a short report was made on the potential requirements for such a heat metering system, and on a preliminary expression of interest by one GE component.

Figure 4.16 presents some aspects of the requirements. For safety of the consumer, and to prevent mixing of the water quality used in HTW distribution with the tap water on consumers' premises, isolation by a heat exchanger is desirable. The distribution system may use a higher temperature and pressure than would be safe in the home. As shown, water inlet at 350-300°F might leave the premises at a temperature as high as 300°F or as low as 100°F. On the consumer side the outlet temperature would be kept below 210°F; the inlet temperature may be tap water at 60°F. To prevent excessive temperatures on the consumers side and high temperature return to the distribution system, valve set V_1 is needed to control flow. Valve set V_2 on the consumer side is safety shutoff valves energized by unsafe temperatures or pressure. Valves V_1 can also be used as safety valves. The sensor system must recognize unsafe temperature as well as measure the heat delivered. Three temperature sensors, T_1 , T_2 , T_3 , are indicated.

The amount of heat delivered to the consumer is measured by the product of the flow rate Q and the temperature difference $T_1 - T_2$. The cumulative

- REQUIREMENTS

- OUTPUT
 - CUMULATIVE ENERGY
 - PEAK DEMAND INFORMATION
 - TIME-OF-DAY INFORMATION
 - ENERGY QUALITY INFORMATION
 - SAFETY FUNCTIONS
- CONCEPTS
 - MECHANICAL SENSORS
 - ELECTROMECHANICAL
 - ELECTRONIC
 - MICROPROCESSOR
- COMPONENTS
 - FLOW SENSOR
 - TEMP. SENSORS
 - INTEGRATOR
 - DISPLAYS
 - HEAT EXCHANGER

Figure 4.16. Heat Metering System

register of this energy delivered over time is the primary measure of value to the customer. However, as is found increasingly important today with electric energy, the cost to the utility may be a function of the peak demand and the time of day of the peak demand as well as the quantity of energy delivered. The quality of the energy delivered also affects costs and operating procedures. If a customer uses a large flow and a small temperature difference $T_1 - T_2$, he is returning water at a high temperature (say, 300°F) to the return lines where it is mixed with lower temperature water and returned to the district heating plant. Another customer may use a small flow and a large $T_1 - T_2$, returning water at say 100°F, because he is heating tap water from 60° to say 180°F. The product $Q_1(T_1 - T_2)$ may be the same in both cases but the first customer has gotten a thermodynamically more valuable product and should pay more, if equitable rates can be determined.

The Heat Metering System comprises not only the delivery system, the heat exchanger, the valves and sensors for T and Q , but a measurement and control box into which inputs T_1 , T_2 , T_3 , and Q_1 go, generating control signals for V_1 and V_2 as well as a record of the various measures of energy used.

For this complex of functions a mechanical sensor and recording system could be very expensive. Other alternatives may prove superior. The recent rapid development of microprocessor components and their dramatic drop in cost suggest that if compatible low cost sensors can be developed, microprocessor technology may be appropriate.

The GE division with the greatest experience in electric utility energy consumption and peak demand measurement is the Meter Business Department. Discussions with the manager of their Strategic Planning Operation indicated that this Department could potentially be interested if the utility interest

and need were apparent and it was perceived to be a growth market in which GE could make a suitably high return on investment. Their experience is in electromechanical devices; there is no expertise in their component on flow measurement or temperature sensors.

They are currently faced with utility and regulatory agency interest and concern with alternative rate structures that may depend on the time of day of electric usage, the coincidence of electric usage with peak demand, reduced rates for offpeak usage, and special rates when utility control of demand by remote control of air conditioning, water heating, and other major loads is permitted. Implementation of any of these on a widespread basis would provide markets for very different energy and power meters than are currently manufactured. The Strategic Planning Operation must assess which alternatives are likely so that resources can be committed to the most important development programs. These potential markets are believed to be near term, and use of resources to meet them is considered more urgent than the Integrated Energy Utility and the need for heat metering systems.

In the case of this new venture product there is a very different situation from that in the other three products considered, which were found to be well within the product scope and capability of the responsible component without commitment of resources until the market develops. In this case there is not a clear "home" for the product. The Department serving the utility energy meter market does not have the technology or responsibility for the sensors, heat exchangers, and other parts of the heat metering system. Their resources are fully committed to more immediate needs. A decision that such a meter should be developed and the assignment of responsibility would have to come from higher corporate echelons.

This case is certainly not a purely financial decision of market analysis and expected rate of return on investment. The market is not clear until utility decisionmakers signal by their actions that a market will develop. A concept to be evaluated, innovative sensors and an integration of controls and components, has not been formulated. GE would not be likely to use existing metering technology in which European or domestic firms are already entrenched.

This particular need, a small but necessary part of the Integrated Energy Utility as a system, is not likely to be initiated in advance of market development unless a strong advocate appears. In the above department, in some other part of the Company, or elsewhere in industry, this must be someone who persuades the Company or one of the Company's utility customers that a development should be initiated.

General

It became clear from the discussion accompanying the above product reviews that the introduction of innovation into the power generation business is generally through a close working relationship between Company components and specific utilities. Sometimes the Company is the originator; by analyses or research and development a potential improvement is recognized. Through marketing contacts with utilities, and through technical contacts at industry conferences and elsewhere, interest is indicated. Sometimes a utility, recognizing a problem, requests help, requests an estimate of what an improved product would cost, or announces its interest through industry meetings. When both the Company and a utility agree on interest, a series of cooperative steps may follow: analyses, cost estimates, tradeoffs on requirements versus cost, and an agreement to purchase a first unit.

THE PRIVATE-SECTOR DECISION

The private sector decision involves two separate decisionmakers, electric utilities and equipment suppliers. The likely electric utility decision appears in the results of the utility interviews. In general, utilities seem willing to consider the venture if they can be convinced that the system will work as described. Thus, if they are reasonably certain that the system will function well and they can earn their allowed rate of return, they would be willing to proceed. None of the utilities are currently convinced, however, that this is the case. Some have had bad experience with steam systems, others question whether the economics, indeed, will be favorable. The aquifer storage system concept is interesting to most, but, of course, remains to be proved on a large scale.

Thus the utilities are interested but the system must be demonstrated. None of them expressed any willingness to be the prime mover behind the required development effort, investing their own funds in development projects. However, some expressed an interest in being involved in any effort funded by someone else, such as the federal government.

General Electric, representing the supplier industry, also took a wait-and-see attitude. They are interested in the venture and generally willing to produce the turbines. However, they feel that the required R&D for small turbines is not very large. There is no need to invest in the development of the turbines until a firm interest is expressed by a utility. At that point they would be willing to spend several months of effort to investigate the development required. If the results seemed favorable they would be willing to work with the utility to establish requirements and price and agree to offer for sale. Upon mutual agreement, they would begin design and production of the turbine-generator.

Thus General Electric sees no need for investing funds in development until a firm expression of interest develops. At that time the development of the first few turbines would not be much different from the custom turbine design that is involved with many orders today. The larger turbines, such as the nuclear extraction turbine, would involve considerably more effort, of course, but is sufficiently far in the future to wait for the initial market development before proceeding with investment decisions. The meters might also be of interest to General Electric but, again, they see no need to begin the development effort now.

Thus, both the utilities and the equipment suppliers see the Integrated Energy Utility as a promising idea, but are not willing to take upon themselves the task of developing and demonstrating the system initially. If it were demonstrated to be profitable, however, they would probably be willing to adopt the venture.

5. PUBLIC-SECTOR ANALYSIS

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INTRODUCTION

The objective of this phase of the study is to analyze the implementation of district heating from society's point of view. What social costs and benefits are incurred as a result of the introduction of the system? What are the costs to a community in terms of environmental changes? Will there be employment impacts? What businesses will be created and which established businesses will suffer? How will the political system react? Can the existing regulatory framework supply the necessary public direction for this form of heating? Is there an impact on supplies of scarce energy raw materials? On balance, is this a technological innovation that should be encouraged, if necessary, with public support?

This chapter contains two forms of analysis: 1) an attempt to assess net social benefits based on a concept developed by Mansfield and his associates,^{*} and 2) an evaluation of political, social, and economic issues and impacts that are not readily quantified. Overall, the analysis presents a review and definition of the areas of socioeconomic impact that can result from the implementation of district heating. The weight of the evidence leads to conclusions regarding the benefits to the public sector: a significant argument is made for a federally assisted demonstration project to prove the economic feasibility of the system.

^{*} Edwin Mansfield et al., Social and Private Rates of Return from Industrial Innovations (Philadelphia, PA: University of Pennsylvania, September 1975).

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PUBLIC IMPACTS OF THE INTEGRATED ENERGY UTILITY

Net Social Benefits - Quantitative CalculationsIntroduction

A model was constructed to calculate the quantifiable social benefits that would accrue from the introduction of HTW district heating systems using energy produced by an IEU.* The quantifiable social benefits referred to are those calculated using consumer surplus and resource savings. That is

$$\begin{aligned} \text{Net social social benefits} &= \text{consumers surplus} \\ &+ \text{resource savings.} \end{aligned}$$

The consumers' surplus is the real increase in consumer income, including increased benefits, caused by the innovation. Resource savings are the increased output (or decreased, if the resource savings are negative) which occur elsewhere in the economy as a result of the innovation. Since the retained profits caused by the innovation are in fact the monetary measure of the resource savings, the resource savings also can be defined as the profits accrued by the innovation minus the profits that otherwise would have been accrued by competitors had the innovation not occurred. For the HTW system,

$$\begin{aligned} \text{resource savings} &= \text{HTW profits gained} \\ &- \text{competitive profits lost.} \end{aligned}$$

The IEU social benefits model was constructed on a regional basis for 4 regions--the Northeast, North Central, South and West. The model also is divided by end-use sectors--industrial, residential and commercial.

*See Appendix B for a description of the equations used in the modeling.

The Industrial Sector

Thirteen different technologies were included as potential alternatives for fulfilling industrial low temperature process heat and space heating requirements. The alternate technologies considered were

- atmospheric fluidized bed
- pressurized fluidized bed
- conventional coal with FGD
- low Btu gas from coal
- solar planar collector
- advanced internal combustion
- advanced external combustion
- open cycle Brayton engine
- electric industrial heat pump
- backpressure steam turbine
- conventional oil
- conventional gas
- high temperature water

The characteristics of these systems are given in Chapter 4.

Using decision model techniques described elsewhere, penetrations for these alternative fuels were calculated under two alternative assumptions--one with the presence of HTW, the other without. The consumers' delivered heat costs were calculated for each of the systems, both with and without HTW, by multiplying the amount of heat demanded by the cost per million Btu's for each of the systems. This calculation is somewhat complicated because the heat is generated in a variety of plants built in different times, with different efficiencies and costs. Nevertheless, the consumer surplus was the difference of the total price paid by the consumer with and without HTW. The consumer surplus was positive in all three development paths.

However, the consumer surplus is only a part of the net social benefits. It is necessary to include the resource savings in the calculations. Profits earned by the competing systems are calculated by multiplying the cost of heat delivered by the percentage of the cost that represents profit. Subtracting the profits earned by these systems when HTW is available from the profits when HTW is not available yields the profits lost to HTW. HTW profits are calculated by multiplying the HTW profit rate by the value of HTW supplied.

Subtracting the change in profits for competing systems from the gain in profits for HTW yields the net resource savings. Net social benefits are the sum of resource savings and consumer surplus.

The Residential and Commercial Sector

The residential and commercial model is similar to the industrial sector. Here six systems are competing for the market: oil, gas, electric resistance, solar, electric heat pump, and HTW. The assumed efficiencies of these systems were as follows: oil = 65 percent; gas = 70 percent; electric resistance = 100 percent; solar = 65 percent for oil backup; electric heat pumps = 250 percent. As in the industrial sector, penetrations were determined for each system assuming the presence and absence of the HTW alternative. Calculations then proceeded as before to determine the consumers' surplus and resource savings.

The Combined Model

The two sectors were combined to determine total social benefits. For both sectors the assumed percentages of delivered heat cost that constituted profit were 9 percent for oil-, coal-, and gas-based systems, 14 percent for electricity-based systems, and 10 percent for solar systems.

The analysis described to this point assumes that consumer surplus is solely dependent on a reduction in price caused by the switch to HTW. The decision model used to calculate market penetration (described in Chapter 4) includes factors other than price, however. It is assumed that in the residential and commercial sector new heating systems are selected on the basis of two cost attributes (initial capital cost and operating cost) and three

noncost attributes (cleanliness, safety, and perceived fuel availability). The cost and noncost attributes are combined into one measure of perceived value by assigning appropriate decision weights to each of the attributes and then summing these weighted values for each heating system. These same weights can be used to calculate an approximate monetary value of the three noncost attributes.

For example, for 2020 in the residential and commercial sector in the Northeast the decision weights are as follows:

<u>Attribute</u>	<u>Weight</u>
Initial capital cost	90
Operating cost	105
Cleanliness	30
Safety	20
Fuel Availability	100

Thus, the two cost attributes have a combined weight of 195. If the least expensive alternative in 2020 is the electric heat pump with a cost of \$85/million Btu (in 2020 dollars), the value of each point in the weighted value of an attribute is approximately $\$85 \div 195$ or \$.43. Thus, if an alternative is perceived to have a safety rating of 1 (on a scale of 0 to 1), a consumer would be willing to pay \$8.60/million Btu more (\$.43 x rating of 1 x decision weight of 20) for it than for a comparable system with a cleanliness rating of 0.

This approach was applied to calculate the dollar value of the noncost attributes for each of the available systems in each year. These values were then subtracted from the actual cost to yield a measure of the total value to the consumer, although because differences among systems were not large for noncost attributes, the final benefit calculations were not affected greatly by this calculation.

In calculating social benefits, the use of aggregate numbers for an entire region to determine the consumer surplus leads to some problems. On an individual basis it is obvious that a consumer would normally only choose HTW over

another system if the HTW either costs less or in some other way provides additional benefits. Consumers must have a reason to choose HTW, and that reason will usually be that HTW appears to offer more benefits than any other system. The decision model used to calculate market penetration operates on this principle. However, in this study the decision model is applied to an entire region of the country, involving millions of consumers. The use of average values for decision weights and perceived system attributes allows the calculation of average perceived values for each system. Since these values are averages, they cannot be expected to be true for every individual consumer. Thus, although one system has a higher average value than all other systems it is not expected that only that system will be purchased. A system with a lower average value also will be purchased by some consumers because, for those consumers, it actually has a higher perceived value. Due to local differences in preference, one system will not have the same value to all consumers. Therefore, when average values are used, the system with the highest average value is expected to capture the largest share of the market, but not all of it. Other systems, which have lower average values, will be chosen by some consumers because those other systems actually have greater value for them.

In order to account for this effect, the decision model uses a conversion curve that relates the amount of penetration into the market to the relative value of a system. This curve appears as follows:

Relative value, in this case, is a ratio of the value of a particular system to the average value of all available systems. This curve indicates that even a system with a relatively low perceived value will capture some of the market. This happens because that system really is best for some small share of the total market. Thus, the conversion curve is a kind of probability curve, expressing the percent of the market that will find a given alternative to be the best as a function of the relative perceived value of that system. The curve itself is derived from historical data and should, therefore, express the true distribution of perceived system values around the average values.

When HTW water becomes a new alternative system in the marketplace, its market penetration is calculated using the conversion curve just as the penetrations of all the other systems are. One result of this calculation is that some systems that have higher values, on the average, than HTW will lose market share to HTW. Thus, using only average values it appears that some consumers have opted for a system with lower benefits, leading to a negative consumer surplus when HTW is introduced. However, these are simply those consumers who do, in fact, receive higher value from HTW (since no one will choose a system providing less value). For other consumers, who stay with the alternative system instead of going to HTW, the benefits of the alternative system are actually higher than the averages indicate. Thus, the introduction of HTW can cause only an increase in benefits, but it is possible, when using average values, to calculate a reduction in benefits for some segments of the market.

Unfortunately, there is no precise way to calculate the actual increase in benefits in such a situation. Therefore, we have made the most conservat.

assumption possible--that those people who appear to be switching to a lower valued system are actually receiving positive benefits, but that their increase in benefits is small and can be approximated by assuming no increase in benefits. This approach obviously will understate the total benefits; thus the calculated increase in benefits represents a lower bound on the consumer surplus due to the introduction of HTW.

The net social benefits derived from the innovations are expressed in current terms on a cumulative basis. They were also discounted to present value, using an 8 percent discount rate and the following formula:

$$PV = B(t) + \frac{B(t+1)}{1+i} + \frac{B(t+2)}{(1+i)^2} + \dots + \frac{B(t+n)}{(1+i)^n}$$

where

- PV is present value of net social benefits
- B(t) is the net social benefit in year t
- i is the discount rate (8%)
- n is the number of years from the present to 2020 (42 years)

Results

Net Social Benefits

The primary outputs of the IEU social benefits model are consumer surplus, resource savings, and net social benefits. Tables 5.1, 5.2, and 5.3 present those outputs for Development Paths A, B and C, respectively. With the exception of the discounted present value for the net social benefits, all numbers are in millions of current dollars. The discounted present value is in 1978 dollars and assumes a discount rate of 8 percent. The discounted present values of the net social benefits of the IEU are \$586 x 10⁶ million for Development Path A, \$681 x 10⁶ million for Path B, and \$4712 x 10⁶ million for Path C.

Development Paths B and C experienced negative resource savings (negative resource savings occurred in Path A, but only for one time period). Negative

Table 5.1

CUMULATIVE CONSUMER SURPLUS, RESOURCE SAVINGS
AND NET SOCIAL BENEFITS FOR DEVELOPMENT PATH A

Year	Cumulative Consumer Surplus (x10 ⁶ current dollars)	Cumulative Resource Savings (x10 ⁶ current dollars)	Cumulative Net Social Benefits (x10 ⁶ current dollars)
1990	0	0	0
1995	40	-9	31
2000	303	108	411
2005	683	304	987
2010	1802	400	2202
2015	4430	318	4748
2020	8539	883	9422

Discounted present value of net social benefits = $\$586 \times 10^6$ (1978 dollars).

SOURCE: The Futures Group

Table 5.2

CUMULATIVE CONSUMER SURPLUS, RESOURCE SAVINGS
AND NET SOCIAL BENEFITS FOR DEVELOPMENT PATH B

Year	Cumulative Consumer Surplus (x10 ⁶ current dollars)	Cumulative Resource Savings (x10 ⁶ current dollars)	Cumulative Net Social Benefits (x10 ⁶ current dollars)
1990	0	0	0
1995	40	-38	2
2000	325	28	353
2005	719	156	875
2010	1963	121	2084
2015	4932	-148	4784
2020	12632	-453	12179

Discounted present value of net social benefits = $\$681 \times 10^6$ (1978 dollars)

SOURCE: The Futures Group

Table 5.3

CUMULATIVE CONSUMER SURPLUS, RESOURCE SAVINGS
AND NET SOCIAL BENEFITS FOR DEVELOPMENT PATH C

Year	Cumulative Consumer Surplus (x10 ⁶ current dollars)	Cumulative Resource Savings (x10 ⁶ current dollars)	Cumulative Net Social Benefits (x10 ⁶ current dollars)
1990	0	0	0
1995	40	-38	2
2000	324	39	363
2005	4295	-449	3846
2010	18742	-2073	16669
2015	45183	-5220	39963
2020	94528	-9804	84724

Discounted present value of net social benefits = $\$4712 \times 10^6$ (1978 dollars)

SOURCE: The Futures Group

resource savings means that the resource savings gained from the implementation of high temperature water was less than those lost by competing systems. In other words, the competitive profits lost were greater than the profits gained from the implementation of HTW systems. However, these negative resource savings were of insufficient magnitude to offset the consumer surplus. That is, the net social benefits are positive in all three development paths.

Social Rate of Return

This procedure determines the net social benefits expected from the HTW innovation through 2020. However, it cannot be used to determine a rate of return. Each plant requires a large initial investment for construction and equipment. Only after years of operation is this investment recovered in terms of social benefits. Thus, each plant has negative benefits for the first years of operation. When taking an entire region of the country, at any time some plants built years ago will have recovered their initial investment while others built recently will not have done so. Since the market is continually growing there are more new plants being added each year than were added at any year in the past. The result is that, for most of the period 1990-2020, there are more plants that have not yet recovered their initial investment and, therefore, show negative social benefits. These plants will eventually show positive benefits but not by 2020.

A social rate of return can be calculated by following the procedures outlined above but limiting the analysis to a single generating plant. In this case all of the benefits accruing from a single investment can be calculated and a rate of return determined. The rate of return will vary depending on the type of plant considered, the region of the country, the market served, and the date of installation. Calculations for a few representative

plants, however, should indicate the range of rates of return to be expected.

Table 5.4 shows the calculations for a coal extraction plant of 600 MWe constructed in the Northeast in 2005. The capital cost of the plant is the sum of the part of the generating plant attributable to HTW production, the aquifer storage system, the transmission pipeline, and the distribution pipeline. This represents the entire investment cost since General Electric has indicated that essentially no R&D expenditures would be required to produce the turbines. Some costs for pilot plants and demonstration of aquifer storage probably will be required, but these costs would be small when spread over all HTW plants.

It is assumed that the plant serves a representative residential and commercial market. Thus, the penetration of HTW into the markets previously served by gas, oil, electric resistance, solar, and electric heat pump is the same as the penetration calculated for the entire Northeast region in Development Path A. The consumer surplus, therefore, is found by multiplying the total output of the plant by the fraction of that output that is replacing each of the other systems, and by the price differential between HTW and the competing system. These products are summed for all systems.

Resource savings is the difference between the profits earned by the HTW operation and the profits that would have been earned by the competing systems if HTW were not available. This difference is negative since HTW generally sells for a lower price and, because of regulation, does not have a higher profit rate. Net social benefits are the sum of initial investment, consumer surplus, and resource savings.

The result is a social rate of return of 13 percent, less than the private rate of return of 15 percent. Tables 5.5, 5.6 and 5.7 show similar calculations for gas turbine, coal backpressure, and nuclear extraction plants. The social

Table 5.4

NET SOCIAL BENEFITS
COAL EXTRACTION PLANT - 600 MWe
NORTHEAST REGION - RESIDENTIAL AND COMMERCIAL LOAD
(Millions of current dollars)

YEAR	COST OF PLANT	CONSUMER SURPLUS	RESOURCE SAVINGS	NET SOCIAL BENEFITS
2005	-2254	-	-	-2254
2010	-	1052	-197	855
2015	-	1959	-343	1616
2020	-	3161	-538	2623
2025	-	5026	-801	4225
2030	-	7529	-1152	6377
2035	-	10716	-1607	9109

Social rate of return = 13 percent.

Table 5.5

NET SOCIAL BENEFITS
GAS TURBINE - 100 MWe
NORTHEAST REGION - RESIDENTIAL AND COMMERCIAL LOAD
(Millions of current dollars)

YEAR	COST OF PLANT	CONSUMER SURPLUS	RESOURCE SAVINGS	NET SOCIAL BENEFITS
2005	-91	-	-	-91
2010	-	97	-18	79
2015	-	160	-31	129
2020	-	299	-48	251
2025	-	640	-70	570
2030	-	995	-97	898
2035	-	1170	-128	1042

Social rate of return = 21 percent.

Table 5.6

NET SOCIAL BENEFITS
 COAL BACKPRESSURE - 200 MWe
 NORTHEAST REGION - RESIDENTIAL AND COMMERCIAL LOAD
 (Millions of current dollars)

YEAR	COST OF PLANT	CONSUMER SURPLUS	RESOURCE SAVINGS	NET SOCIAL BENEFITS
2005	-1143	-	-	-1143
2010	-	673	-116	557
2015	-	1169	-194	975
2020	-	1884	-295	1589
2025	-	2864	-429	2435
2030	-	4182	-610	3572
2035	-	5873	-846	5072

Social rate of return = 14 percent.

Table 5.7

NET SOCIAL BENEFITS
 NUCLEAR EXTRACTION - 1200 MWe
 NORTHEAST REGION - RESIDENTIAL AND COMMERCIAL LOAD
 (Millions of current dollars)

YEAR	COST OF PLANT	CONSUMER SURPLUS	RESOURCE SAVINGS	NET SOCIAL BENEFITS
2005	-4043	-	-	-4043
2010	-	3892	-603	3289
2015	-	6717	-958	5759
2020	-	10568	-1440	9128
2025	-	15815	-2095	13720
2030	-	22972	-2983	19989
2035	-	32411	-4157	28254

Social rate of return = 19 percent.

rates of return vary from a low of 13 percent for the coal extraction to a high of about 21 percent for the gas turbine. These rates of return are lower than most of those found by Mansfield in his study of industrial innovations, but are generally somewhat higher than the private rate of return.

These calculations use actual prices for fuel and equipment in calculating consumers' surplus. (Note that since the prices used here include the assumption that by 2005 all prices essentially reached equilibrium with imported oil, marginal and average prices are equal.) The costs were not adjusted for the value of other system attributes as discussed earlier in this chapter. Including these benefits as well increases the social rate of return for the coal extraction from 13 percent to 15 percent, the same as the private rate of return.

The uncertainty of these rate-of-return calculations also can be calculated. The major uncertainties involved with the innovation are not shown here, however, since it is assumed that the whole output of the plant is used, the aquifer storage system is functioning, and only one plant is being considered. With this in mind, the uncertainties in the rate of return result from uncertainties in the capital cost of the generating plant and storage and distribution systems, and the fuel prices. Using distributions for these components developed earlier in this report in a Monte Carlo model of social benefits yields a mean rate of return for the nuclear extraction plant of 19 percent with a standard deviation of 2. Thus, the 95 percent confidence range for the social rate of return on the nuclear extraction plant is 15-23 percent. The range is similar for the other plants studied here.

Socioeconomic Issues

Introduction

District heating has failed to realize its potential in the United States due to a variety of factors, most important of which are technological limitations, institutional resistance, and economic conditions. Among the economic problems that have inhibited the spread of district heating, one of the most serious is the unsatisfactory rate of return on utilities' investment in district heating plants. Tight money markets, regulatory policies, environmental requirements and the lag in recovering increased fuel costs are also factors affecting the wholesale market for district heating.

In recent years consumers have been able generally to meet their space-heating and hot water needs more cheaply with individual heating systems. However the increasing cost of fuel, its scarcity, and environmental considerations have made district heating systems more attractive since district heating promises to effect some reduction in fossil fuel consumption and pollutants. In this discussion we focus on the socioeconomic issues related to district heating that may act as constraints or as positive forces on the development of district heating in the United States.

Aside from the direct economic stimulus of investment in district heating plants, what are the implications for economic development for the region or area in which the facilities are located? Are these implications related to size and type of generating plant? Would the total energy concept in any community act as a growth pole, and would this be a desirable impact in an

existing low-population area? This study does not attempt to resolve these questions because it has focused on a national model that does not readily permit local and regional analysis. However, an intrinsic component of a decision on the national policy toward district heating depends on the results of analysis that does answer these questions.

The analysis in this chapter attempts to consider some of the requirements for a district heating experiment. For example, to be a success it will be necessary for other industries to colocate in the area of the district heating plant. A number of factors are likely to affect colocation: proximity to markets, raw materials, transportation and related businesses; availability and cost of financial services; quality, cost, and quantity of labor; local taxes and local social services (including health, recreation and cultural opportunities).

In the development path that includes a nuclear facility, considerations of security and safety become significant factors. Nuclear-related industries might find such areas attractive because of proximity to primary markets. Isolation of nuclear sites as a security and safety measure would work against colocation of industry.

Local taxes may not play a dominant role in industrial relocation, but they could be decisive if other factors were roughly equal. Pressure on local taxes would likely be upward in the initial construction phase, particularly so in the construction of nuclear facilities that are of a large size. The larger the facilities, however, the more likely they will be to force planning; this may stimulate legislation to encourage financing of public services. Licensing procedures, required for many aspects of the electric utility business, increasingly are requiring planning.

Evaluation of these factors and the feedback relationships they engender is subject to value judgments. Some see growth as good, others as bad. This analysis has largely ignored the value issues. However, they should be an essential component of further analysis. An in-depth study will have to take into account the complicated network of local, state, regional, and federal impacts including the value orientation of each of the competing interests.

The political and regulatory environment within which the impacts are judged and policies will have to be designed is given in Appendix F. The institutional impacts on district heating are discussed in Appendix G.

Socioeconomic Impacts

The purpose of this section is to analyze selected socioeconomic impacts attendant to the proposed development paths that would be followed to implement district heating. In policy development these issues, raw materials, availability, the attitudes and impacts on business and industry, community response, the response of utilities and other energy suppliers, environmental considerations, and international implications would be considered--not in that order, but at several stages of the development path. We have isolated these impact areas to simplify the analyses.

Effect on Electric Utility Fuel Mix

A forecast of the demand for fuel with respect to both fuel type and total quantity is central to the planning of a district heating system. Such a forecast conventionally extends forward for at least 20 years, in order to provide minimal support for economic analysis. Previous policy decisions on fuel have been based on the economics of fuel availability, storage and handling factors, and the suitability for use in the class of fuel-burning equipment available. However, recent developments and concern with environmental factors has resulted in the need to control emission of pollutants into the atmosphere, and these factors have grown greatly in importance and have been given high priority by government. There is also a growing awareness of ecological implications in the continued use of fossil fuels against the background of depleting world reserves and the cost of imported oil in the United States. Apart from fissionable materials for nuclear reactor fuels, the basic choice lies between coal and gas. Each part of the fuel cycle has effects of varying degree

on environment, raw materials supply and the health and safety of workers and the general public. Other studies of electric power generation have presented cost-benefit analysis of the impact of land disturbance, land commitment for waste, the health and safety of workers, and on emissions to the environment. These analyses of the nuclear and fuel cycles also have quantified occupational injury and fatality rates.* For purposes of this study, we have narrowed the analysis of environmental impacts to a consideration of the amount of fuel that would be used, the amount of each fuel that would be saved, and the amounts of particulates SO_x and NO_x that would be discharged into the atmosphere.

The specific IEU to be analyzed is one that produces and distributes electricity and HTW. Electricity can be generated by a hydroelectric plant, by a steam turbine fueled by oil or natural gas. Future options that may become significant are solar energy, geothermal fission, MHD, and fuel cells. In this simulation of private-sector considerations of an innovation, the modes of generation that are used are those for which most of the technology and cost factors are well understood. (See Table 5.8.) One of the systems is fueled by oil--the gas turbine; and two involve coal-fired boilers--a coal extraction and coal backpressure system. It is also feasible to use a light water reactor backpressure plant, although political constraints may delay the use of nuclear power. Nuclear plants that produce both steam and electricity involve many environmental and social problems that require technological solutions not yet perfected.

*For detailed analysis of these factors see: Argonne National Laboratory Social Costs for Alternate Means for Electrical Power Generation for 1980 and 1990. Reference Report, Chapter 2. Description of Energy Systems, March 1973. See also Temple, Barker and Sloan, Inc. Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry, May 1976.

Table 5.8

VENTURE ANALYSIS
Systems Defined

<u>System</u>		<u>MW_E</u>	<u>W/ Storage</u>	<u>Trans- mission</u>	<u>Distri- bution</u>
Gas Turbine	(GT)	70	X		X
Coal/Extraction	(CE)	600	X	X	X
Coal/Backpressure	(CB)	200	X	X	X
LWR/Extraction	(BS)	1200	X	X	X

Coal

In 1974 generation capacity in the United States totaled 476 million kilowatts, 71.3 percent of which was accounted for by fossil-fueled units. Hydroelectric capacity was second in importance with 11.6 percent of the total, while nuclear and peaking capacity represented 6.6 percent and 8.7 percent respectively. Table 5.9 summarizes the installed capacity by fuel type as it existed in 1974.

A variety of factors suggest a swing to coal as the dominant source of generating capacity. Temple Barker and Sloan (TBS) project that the overall trend for fossil additions will peak by 1979 with additions of 19.2 and 16.7 million kilowatts in 1979 and 1980. In 1980 the total fossil additions will decline slightly as gas and oil additions cease entirely. This trend is expected due to the DOE policy to encourage decreased reliance on oil and gas. The projected capacity mix is presented in Table 5.10.

Conversion of some gas units to coal or oil and some oil units to coal also will affect the capacity projections for 1980. Table 5.11 summarizes these conversions. The Clean Air Act and its amendments may have some impact on these conversions.

Table 5.9
1974 UNITED STATES
INSTALLED GENERATION CAPACITY

Generator Type	Installed Capacity (million kw)	Percentage of Total Capacity
	1974	1974
Fossil	339.4	71.3
Coal	185.8	54.7
Oil	66.3	19.5
Gas	87.4	25.7
Nuclear	31.6	6.6
Hydroelectric	55.4	11.6
Pumped Storage	8.3	1.7
Peaking Units	<u>41.3</u>	<u>8.7</u>
	476.0	99.9%

SOURCE: Temple, Barker and Sloane, May 1976, p. II-19

Table 5.10

NATIONAL BASELINE SUMMARY
CAPACITY MIX BY PRIME MOVER: SELECTED YEARS

(millions of kilowatts)

<u>PRIME MOVER</u>	<u>1975</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Coal	196.2	276.8	332.9	434.6
Oil	72.3	96.1	91.2	85.5
Gas	89.2	48.2	41.0	33.0
Nuclear	40.7	79.7	132.0	219.8
Hydro	57.6	66.4	73.5	85.7
Pumped	8.5	11.8	16.3	23.8
Peaker	<u>44.8</u>	<u>52.0</u>	<u>64.1</u>	<u>85.6</u>
TOTAL	509.4	631.0	751.0	968.0

SOURCE: Temple, Barker and Sloan, May 1976, p. II-20

Table 5.11

GAS AND OIL CAPACITY CONVERSIONS
SINCE 1975

(million kilowatts, cumulative)

	<u>Gas to Coal</u>	<u>Gas to Oil</u>	<u>Oil to Coal</u>
1975	0.1	0.5	0.4
1976	1.8	5.3	1.1
1977	3.7	10.5	3.4
1978	5.5	15.8	4.9
1979	7.9	21.0	6.4
1980	9.2	26.3	11.1

SOURCE: Foster Associates, Impact of Natural Gas
Curtailments on Electric Utility Plants
(August 1975), Exhibit II-21

By 1980, after electricity capacity additions, conversions, retirements, and capacity factors are integrated, the amount of electricity that will be generated by coal will account for 49.2 percent of the fuel mix. By 1985 nuclear generation will account for about 22 percent of total generation but will increase to about 28 percent by 1990. Coal is expected to maintain its 50-percent share. Table 5.12 provides the annual generation by fuel type.

Table 5.12

NATIONAL BASELINE SUMMARY
GENERATION MIX BY PRIME MOVER

(billions kwh)

	<u>1975</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Coal	857.2	1261.4	1644.9	2135.6
Oil	275.5	361.3	334.4	276.8
Gas	262.5	142.4	122.4	90.1
Nuclear	192.3	404.1	726.7	1201.1
Hydro	250.0	301.8	359.1	410.0
Pumped	34.1	49.4	73.4	105.8
Peaking	<u>36.6</u>	<u>45.1</u>	<u>60.5</u>	<u>80.5</u>
TOTAL	1908.2	2565.6	3321.4	4300.0

SOURCE: Temple, Barker and Sloane, May 1976, p. II-31

Fuel requirements are based on two types of information: the heat rates of units and the Btu content of the fuel. Heat rates vary for old and new units. In addition, several other factors affect the assumptions used to calculate heat rates, fuel prices, and quantities. According to a recent study coal is projected to decline in Btu content by 1980 as a result of increased

use of western low-sulfur coal. (See Table 5.13.) TBS estimates that about 30 percent of coal used in 1985 will be the western low-Btu type. The amount of coal projected to be burned for electric generation is summarized below:

Table 5.13

COAL CONSUMED FOR GENERATION OF
ELECTRICITY: SELECTED YEARS

(mm tons)

<u>1975</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
387.8	610.8	807.0	1022.9

SOURCE: Temple, Barker and Sloan, May 1976,
p. II-32

Gas

Due to federal policy, natural gas is projected to undergo a significant drop in the share of total capacity of electric generating plants from about 18.4 percent in 1974 to 3.4 percent in 1990. This drop is the result of both conversions to other fossil fuels and slowed rate of new additions. The impact of legislation to partially deregulate natural gas has not yet been calculated, but it is expected that the rising cost would add to the factors that act as a deterrent for the use of gas for generating fuel.

Conversions from gas to coal are expected to reach 9.2 million kilowatts by 1980 and from gas to oil, 26.3 million kilowatts by the same year. Gas, which represented 262.2 kilowatt hours in 1975, is expected to drop to 90.1 kilowatt hours by 1990.

Electric consumption of natural gas for baseload generation is concentrated mainly in the gas-producing states. However, gas used for peaking operations is widespread. Total electric utility consumption has increased dramatically. For the period 1940 to 1970, it climbed from little or nothing to four thousand cubic feet per year (Figure 5.1). In 1970 gas-powered generating stations accounted for 1.7 trillion cubic feet or 16 percent of market for domestic output of natural gas.

SOURCE: Argonne National Laboratory. Social costs for Alternate Means of Electrical Power Generation for 1980 and 1990. Reference Report, Chapter II-128.

Figure 5.1. Electric Utility Consumption of Natural Gas

Oil

Oil-fired generating stations supplied approximately 12 percent of the electricity generated in the United States in 1971. Most of this capacity is concentrated on the East and West Coasts, where access to low-cost foreign oil has favored this energy form. Most of the oils used in generating electricity are blended from the heavy residuum and gas oil products of refinery operations. Although number six fuel oil is the most commonly used fuel oil under market conditions, utilities may arrange to burn lighter oils. Studies as late as 1973 suggested that oil's advantages over coal, such as lower environmental health costs and the lower rate of residuals, would result in shifts from coal to oil. However, the 1973 embargo altered the significance of these perceived benefits. Over 90 percent of electric utility demand for residual fuel oil is supplied by foreign refineries. The structure of domestic demand for other refinery ends, coupled with the effects of the U.S. oil import quota programs, effectively discouraged domestic production of residual fuel oil until the recent energy crisis. As of 1973 the residual fuel oil output of the U.S. refineries was 7 percent of crude oil import. From 1944 until 1964 total domestic consumption of residual fuel oil remained nearly constant at 500 million barrels per year. Electric utility demand during this period was also fairly stable, accounting for 15-20 percent of total demand. When government regulations limited the sulfur contents of fuel, the demand for residual fuel oil increased dramatically and many utilities were forced to switch from coal to oil firing. Supply problems on the East Coast resulted. In 1966 the federal government eased the supply problem by decontrolling residual fuel oil imports. Figure 5.2 shows the trend in electric utility

consumption and total domestic consumption of residual fuel oils from 1935 until recent years.

SOURCE: Argonne National Laboratory. Social Costs for Alternate Means of Electrical Power Generation for 1980 and 1990. Reference Report, Chapter II-128.

Figure 5.2. Residual Fuel Oil Consumption

The peacetime demand categories for residual fuel oil by electric utilities consist of the following:

1. Replacement fuel for power plants converted from coal-firing to oil-firing. Although increasingly stringent emission control regulations formerly required the conversion of existing coal-fired burners, the increased dependence on foreign oil has resulted in shifts from oil-fired to coal-fired boilers in many areas of the country.

2. Fuel for new intermediate-sized boilers in the 300-600 MWe/capacity range. These boilers will be utilized for peaking duty in the utility system. Coal-fired boilers are usually more expensive than oil-fired units for this type of operation. Unavailability of gas will leave much of this market to residual fuel oil.
3. Fuel for 300-1299 MWe capacity boilers designed for baseload operations. Residual fuel oil will compete with large coal- and nuclear-fired units for this part of the electric utility market.
4. Alternate fuel for gas turbines designed for peaking service. Package size of these units will be in the 40-100 MWe range.

Nuclear Power

Total free-world uranium recoverable at less than \$15 per pound of U308 was estimated in 1970 to be about 3.4 million tons of U308, which includes the U.S. reserves of 1.45 million tons. The world and U.S. estimates have increased somewhat since that time.*

Electric utilities' experience in financing new nuclear plants has been characterized by major delays and increases in costs due to overlapping regulations in state, federal and regional jurisdictions, lack of standardization in nuclear plants, and inflation. States have expressed concern over radiological health and safety hazards associated with nuclear generating facilities. However, novel state actions raise significant constitutional issues regarding the role of federal and state governments in developing peacetime nuclear power. There are potential federal and state conflicts posed by state efforts to regulate privately owned federally licensed power

*Argonne National Laboratory, op. cit. II-164.

plants engaged in the commercial production of electricity. A recent Supreme Court decision* has sharply limited the ability of environmentalists to get help from the federal courts in their attempts to block nuclear power plants. The Court decision is expected to improve the outlook for nuclear power. Representatives of the nuclear industry have been hoping for such an outcome. New confidence that the Nuclear Regulatory Commission's actions in cases such as the Vermont Yankee Nuclear Power Corporation would be upheld will reduce the uncertainty of planning for plant construction.

Impact of District Heating

The consumption of primary fuels for the generation of electricity was about 25 percent of the total national energy input in 1970. It may reach 30-50 percent by the year 2000. Consequently this study of the implementation of district heating focused on the potential savings of scarce fuels. The savings shown by the year 2020 are nominal. However, this was a macroanalysis. In any given region or specific locality, savings could be more significant. It is difficult to estimate the national value of fuel saved that might have been used had the community not switched to district heating. The results of our analysis indicate that by the year 2020 following Development Path A, the United States would be using an extra 42 million barrels of oil, 10 million less tons of coal, and 130 tons less uranium oxide. The cost in oil amounts to only two days of current usage; in coal, less than a 1-percent savings; and in uranium oxide, about 2-percent savings. The saving in gas is also fractional. Even in Path C, the savings are marginal. However it is important to note that these figures are based on conservative estimates of penetration at a relatively slow rate. In addition, marginal savings are

*April 4, 1978, as reported in the Wall Street Journal.

exacerbated by a loss of heat in storage through the use of underground aquifers. If there were more rapid market penetration, there would be greater fuel savings, and if there is more certainty about the use of aquifers, or if perfections in the process of using aquifers can be achieved, this would help increase the amount of fuel savings. Current projections are for the loss of 25 percent of the energy in storage. It is significant that despite the conservative estimate, our figures suggest that there will be some savings.*

Impacts on Business and Industry

District heating involves the transmission of medium temperature hot water through piping that could be above ground, such as in median strips of multi-laned highways and in industrial areas or underground. Based on European experience pipes are most commonly laid in precast or side cast concrete ducts. The pipes are encased in preformed pipe insulation or the ducts are filled with concrete. Walk-through ducts are used beneath major roads in the USSR, but in the majority of cases, the ducts are too small for access. The ideal underground distribution system combines good insulating properties with high mechanical strength and complete imperviousness to moisture penetration. There is room for innovative technology in this area since no technology has been found that will satisfy the ideal.

By the year 2020, our study concludes that between 6,200 (Path A) and 12,500 (Path B) miles of piping will be required in the United States. Based on data in another study, an average city the size of Jersey City or Newark requires approximately 350 miles of pipe for the installation of district heating. Consequently, by the year 2020 our study suggests that somewhere

*Argonne National Lab. "Potential for Scarce Fuel Savings in the Residential/Commercial Sector through the Application of District Heating Systems," Nov. 1977.

between 17 (Path A) and 36 (Path C) cities will have installed district heating. The total number of individuals employed in laying transmission pipes on a national basis will be approximately 1500 by the year 2020. If this study is localized, the impact on any given labor force could conceivably be significant in terms of new jobs, but not such as to create a drain on other similar work categories.

In addition the demand for improved heat distribution pipes could stimulate innovations in technology and result in new ventures. Other products expected to develop new markets are heat exchangers to transfer heat from the district hot water to the building heating system, and special meters that can measure the amount of heat, water, and electricity received. A large variety of additional industries would be involved if distribution bids were requested by utilities within any given community. Based on experience in a city such as Akron, bids were requested on plumbing, heating and air conditioning, electrical equipment, pollution abatement equipment, steam blow-off condensers, steam distribution extensions, instrument air compressors, maintenance and machine shop equipment, and oil-spill prevention equipment. In addition, employment would be increased within engineering firms and design and construction firms. If construction involves tunnelling and piping to existing structures as for example in a retrofit situation, those markets would be affected. If metering is conducted by a private outfit this would create an additional small-business venture. However, the likelihood is that the metering would be carried out by a municipal or state agency because of the labor and cost savings involved. Similarly maintenance would be conducted either by the utility responsible for the district heating or as contracted out to a private firm. In previous studies, as for example in Toronto, it was recommended that all maintenance be carried out by one agency with some labor and cost savings.

Because our study deals with new construction only and does not include a retrofit example, it is not possible to include the numerous businesses and small industries that would be impacted if a retrofit application were considered. Laying pipes in a highly urbanized area is obviously much more difficult. In New York City for example there is concern about subsurface street congestion and well-organized opposition causing construction delays, union demands, and work restrictions that have placed a heavy burden on the economics of the Con-Ed Steam System operation. It is unlikely that these problems would be encountered in new construction to the same degree. The impact of union demands, environmental concerns, and business economics are somewhat unknown with new construction.

Utilities and Other Energy Suppliers

Based on results of interviews with regulatory authorities discussed in Chapter 4 and the extensive analysis of the political and regulatory environment affecting utilities and localities discussed earlier in this chapter, utilities would not welcome district heating as an innovation. Evidence from earlier studies (in particular the Toronto analysis) suggests that a system of incentives and restrictions are necessary in order to add customers to the district heating system and satisfy the basic needs of an economic development plan. In the Toronto study incentives are recommended for owners of buildings, in the form of a subsidy by the city to reduce the expense of converting building heating systems to district heat. Similarly a restriction was recommended that would prohibit, within the area served by district heat, combustion of all solid fuels and of any fuel having a sulfur content greater than 0.5 percent by weight in any installation other than a designated district

heating plant. This restriction would become effective within two years of the completion of the integration and expansion of the district heating system.

A variety of issues have been raised by utilities interested in the district heating concept. Many of these pose problems for resolution by the regulatory agencies:

- How would the utilities calculate the costs to be allocated to electrical generation and hot water generation? Certainly some of the fuel costs should be allocated to hot water generation. Would some of the plant costs--aside from the equipment directly used for handling hot water--also be charged to hot water production?
- Would utilities be able to raise money for the hot water system at the same interest rate that they get for the electrical system?
- Would utilities be reluctant to take on the additional problems of administration, maintenance, training, etc. associated with getting into the hot water business?
- Would the utilities own the heat exchanger and other equipment in a residence and rent them to the user or would the user own the equipment?
- If the hot water is used for new space heating this could cut into the market for electric space heating and thus cut future electric load growth.
- Retrofit is possible but the capacity of the plant will be reduced by 1 MWe for every 6 to 10 MW of heat. Thus a utility would have to be in a capacity excess condition in order to do extensive retrofitting. Many utilities have excess capacity now--but within ten years the situation could be just the reverse.

Environmental Impacts

Aquifers

The use of underground storage in aquifers will impact primarily on the drilling industry. Expansion of the heat storage well concept can be expected

to stimulate developments among equipment manufacturers producing pump installations as well as acting as a stimulus to further geological research on the conservation benefits of aquifer storage.

Our study is based on an assumption that 60 percent of the market could take advantage of the use of aquifers due to siting problems. It is presumed, based on earlier studies, that there would be no serious impacts on ground water, no seismic effects, and no change in the saline content of existing aquifers since the water would be pumped in and out in a relatively pure state. One criticism of the case of aquifers at 500 feet has been the fact that high temperature water may enter the drinking supply. This can be remedied by using saline aquifers that are generally available at 1000 feet and are not used for drinking water.

The number of wells required in each development path does not represent a significant percent of the total number of wells in the United States. (See Table 5.14.) However, they would constitute a small and steadily growing market for pumping and drilling equipment and a source of employment for related categories of drillers, mechanics, engineers.

Other studies have suggested that aquifers could also be used for the reverse process, storing cold water for use in air conditioning.* The Commerce Department recently reported that plans are being developed for a system to store the chill from the harsh Long Island winters to air condition buildings at New York's JFK International Airport. Several wells will be drilled into the aquifer and during the winter months ground water will be pumped from the aquifer and passed through cooling towers where it would absorb chill from

*Commerce America, September 26, 1977, p. 16.

Table 5.14

NUMBER OF WELLS REQUIRED FOR DISTRICT HEATING
WITH AQUIFER STORAGE

	<u>Year</u>					Total
	1995- 2000	2000- 2005	2005- 2010	2010- 2015	2015- 2020	
	<u># WELLS PATH A</u>					
Gas Turbine	22	220	308	385	484	1419
Coal Extraction	0	0	171	342	570	1083
Total	22	220	479	727	1054	2502
	<u># WELLS PATH B</u>					
Gas Turbine	22	132	88	121	77	440
Coal Backpressure	0	84	112	112	112	420
Nuc Extraction	0	0	0	108	216	324
Total	22	216	200	341	405	1184
	<u># WELLS PATH C</u>					
Gas Turbine	22	55	44	77	99	297
Coal Backpressure	0	140	196	280	364	980
Nuc Extraction	0	0	216	324	432	972
Total	22	195	456	681	895	2249

Note: Number of wells required for each plant:

Gas Turbine = 11
 Nuclear Extraction = 108
 Coal Extraction = 57
 Coal Backpressure = 28

the air. The cold water then would be returned to the aquifer for storage. During the summer this cold water will be pumped from the aquifer and used to chill the circulatory fluid in the airport's air conditioning system. Researchers estimate that the system could reduce the amount of electricity needed to cool the terminal complex by as much as 90 percent.

Air Pollution

Based on the analysis of Path C, we have found that one of the environmental impacts of district heating represents a small improvement in air quality by the year 2020. Because the nature of the study was national, it is difficult to draw conclusions about the environmental impact on a local level. Some greater environmental benefits would accrue than are suggested by the national figures presented in Table 5.15. If Path C is followed there would be net savings on all fuels and therefore net environmental impact savings that would grow proportional to changes in some of the basic assumptions of the study. For example, if some of the implementation is done in existing markets, the amount of environmental savings would increase considerably as the number of individual home heaters was reduced in favor of a centralized plant. According to the results of this study, Path C represents a modest decrease in particulates, SO_x and NO_x by the year 2020. In Path A, which represents a slower penetration of markets and also makes heavier reliance on nuclear generators, the decrease in particulates is smaller and there is a slight increase in pollution from SO_x and NO_x .

Table 5.15

IMPACT ON AIR POLLUTION BY DISTRICT HEATING (TONS)

Year: 2020	Path A	Path C
Particulates	-14.3 mill.	-41.4 mill.
SO ₂	9.2 mill.	-393.9 mill.
NO ₂	20.9 mill.	-90.0 mill.

The essential design of district heating with aquifer storage avoids the necessity of rejecting excess heat to the environment. Cooling towers and dumping excess heat into the streams or rivers would only be used during the summer when the demand for heating would be low.

International Impacts

There is not sufficient impact on the quantity of imported oil to affect trade balances based on the development pacts outlined for this study. Our analysis of European experience with district heating suggests that a most profitable approach for American energy interests would be to encourage the maximum U.S. participation in international committees concerned with an exchange of information on district heating. Based on European experience that district heating saves fuel as well as reduces air pollution, government task forces in England and Sweden, as well as in parts of Eastern Europe, have encouraged the implementation of district heating. Most European experience is based on new construction, installed after the Second World War. However, the Japanese have done considerable work retrofitting existing cities. The international exchange of information would facilitate the diffusion of technologies. It would also allow U.S. developers to keep abreast

of technological developments abroad. Since it is likely that any expansion of district heating in the United States would turn to equipment manufacturers with experience in the field, European invasion of U.S. markets is a distinct possibility.

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THE PUBLIC-SECTOR DECISION

The public sector analysis has been conducted in an effort to evaluate the public return on the implementation of district heating. This analysis was conducted in a fashion similar to the private sector venture analysis, internalizing a different set of benefits and costs, and quantifying risk and uncertainty where appropriate. The private sector analysis revealed that the private sector would commercialize the venture if it could be shown to be financially and technologically profitable.

We have studied the public sector assessing the net social benefits of district heating, an analysis based on the work of Edwin Mansfield. In addition, the study included an extensive investigation of other issues and impacts. Our objective was to evaluate both the direct and indirect costs and benefits that accrue from the commercialization of district heating. The analysis of net social benefits concludes that the consumer surplus would be positive in all three development paths; the sum of resource savings is negative but these negative resource savings were not enough to offset the consumer surplus. The net social benefits, which are the sum of initial investment resource savings and consumer surplus, are positive in all three development paths. A social rate of return was calculated, by limiting the analysis to a single generating plant, and was found to be about the level that would be acceptable to the private sector.

The issue analysis covered political/regulatory factors, institutional issues, and the environmental components of district heating implementation.

Based on a review of the political/regulatory analysis, government assistance will be necessary to overcome the political barriers to implementation of district heating. There is no strong evidence to support regulation of the sale of heat on the local level. Rather, federal regulation could be a positive force to stimulate private and public sector applications, research, and development of supporting technology.

Institutional barriers to the implementation of district heating have been cited in European reports and other studies done in the United States. A review of these obstacles confirms the evidence that major conflicts could arise among and between conflicting interests such as: distributors and producers of electricity, agencies and interest groups with vested interests in existing heating systems or a reluctance to experiment with a new system, building and zoning agencies required to develop new codes and techniques for inspection. Additional obstacles include financial institutions unwilling to fund private ventures, reluctance of all parties to attempt heat storage in aquifers, and resistance in public acceptance.

The impact of district heating on population and employment is not apt to result in a serious constraint to implementation if the development path chosen involves gradual penetration of the market.

The evaluation of environmental issues was based on several specific impacts that we could measure. In terms of fuel savings, it was found that although the system would use somewhat more oil but less coal, the overall effect on raw materials is probably beneficial. The number of wells needed for aquifer storage was minimal and did not pose problems related to seismicity and salinity. The air pollution level would drop with district heating, although our figures are not conclusive since they are based on a national

analysis. The reduction of air pollution in individual communities could be significant.

In sum, we found few negative social benefits and the net benefits, while not overwhelming, are within the acceptable range to warrant public investment in a government demonstration project to permit assessment of impacts on a local level.

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ADDENDUM

Federal Agencies With Jurisdiction by Law or Special Expertise
on Various Types of Environmental Impacts Which Might Be
Encountered in Electric Power Generation

(Excerpted From Federal Register 36, 7727-29), April 23, 1971

AIR

Air Quality and Air Pollution Control

- ° Department of Agriculture
 - Forest Service (effects on vegetation)
- ° Department of Health, Education, and Welfare
 - (Health aspects)
- ° Environmental Protection Agency
 - Air Pollution Control Office
- ° Department of the Interior
 - Bureau of Mines (fossil and gaseous fuel combustion)
 - Bureau of Sport Fisheries and Wildlife (wildlife)
- ° Department of Transportation
 - Assistant Secretary for Systems Development and Technology (auto emissions)
 - Coast Guard (vessel emissions)
 - Federal Aviation Administration (aircraft emissions)

ENERGY

Environmental Aspects of Electric Energy Generation and Transmissions

- ° Nuclear Regulatory Commission (nuclear power)
- ° Environmental Protection Agency
 - Water Quality Office
 - Air Pollution Control Office
- ° Department of Agriculture
 - Rural Electrification Administration (rural areas)
- ° Department of Defense
 - Army Corps of Engineers (hydro-facilities)
- ° Federal Power Commission (hydro-facilities and transmission lines)
- ° Department of Housing and Urban Development (urban areas)
- ° Department of the Interior (facilities on Government lands)

Natural Gas Energy Development, Transmission and Generation

- ° Federal Power Commission (natural gas production, transmission, and supply)

- ° Department of the Interior
 - Geological Survey
 - Bureau of Mines

HAZARDOUS SUBSTANCES

Transportation and Handling of Hazardous Materials

- ° Department of Commerce
 - Maritime Administration
 - National Marine Fisheries Service
 - National Oceanic and Atmospheric Administration
(impact on marine life)
- ° Department of Defense
 - Armed Services Explosive Safety Board
 - Army Corps of Engineers (navigable waterways)
- ° Department of Health, Education, and Welfare
 - Office of the Surgeon General (health aspects)
- ° Department of Transportation
 - Federal Highway Administration Bureau of Motor Carrier Safety
 - Coast Guard
 - Federal Railroad Administration
 - Federal Aviation Administration
 - Assistant Secretary for Systems Development and Technology
 - Office of Hazardous Materials
 - Office of Pipeline Safety
- ° Environmental Protection Agency (hazardous substances)
- ° Nuclear Regulatory Commission (radioactive substances)

LAND USE AND MANAGEMENT

Coastal Areas: Wetlands, Estuaries, Waterfowl Refuges, and Beaches

- ° Department of Agriculture
 - Forest Service
- ° Department of Commerce
 - National Marine Fisheries Service (impact on marine life)
 - National Oceanic and Atmospheric Administration
(impact on marine life)
- ° Department of Transportation
 - Coast Guard (bridges, navigation)
- ° Department of Defense
 - Army Corps of Engineers (beaches, dredge and fill permits, Refuse Act permits)
- ° Department of the Interior
 - Bureau of Sport Fisheries and Wildlife
 - National Park Service
 - U.S. Geological Survey (coastal geology)
 - Bureau of Outdoor Recreation (beaches)
- ° Department of Agriculture
 - Soil Conservation Service (soil stability, hydrology)

- ° Environmental Protection Agency
Water Quality Office

Historic and Archeological Sites

- ° Department of the Interior
National Park Service
- ° Advisory Council on Historic Preservation
- ° Department of Housing and Urban Development (urban areas)

Flood Plains and Watersheds

- ° Department of Agriculture
Agricultural Stabilization and Research Service
Soil Conservation Service
Forest Service
- ° Department of the Interior
Bureau of Outdoor Recreation
Bureau of Reclamation
Bureau of Sport Fisheries and Wildlife
Bureau of Land Measurement
U.S. Geological Survey
- ° Department of Housing and Urban Development (urban areas)
- ° Department of Defense
Army Corps of Engineers

Mineral Land Reclamation

- ° Appalachian Regional Commission
- ° Department of Agriculture
Forest Service
- ° Department of the Interior
Bureau of Mines
Bureau of Outdoor Recreation
Bureau of Sport Fisheries and Wildlife
Bureau of Land Management
U.S. Geological Survey
- ° Tennessee Valley Authority

Parks, Forests, and Outdoor Recreation

- ° Department of Agriculture
Forest Service
Soil Conservation Service
- ° Department of the Interior
Bureau of Land Management
National Park Service
Bureau of Outdoor Recreation
Bureau of Sport Fisheries and Wildlife
- ° Department of Defense
Army Corps of Engineers
- ° Department of Housing and Urban Development (urban areas)

Soil and Plant Life Sedimentation, Erosion and Hydrologic Conditions

- ° Department of Agriculture
 - Soil Conservation Service
 - Agricultural Research Service
 - Forest Service
- ° Department of Defense
 - Army Corps of Engineers (dredging, aquatic plants)
- ° Department of Commerce
 - National Oceanic and Atmospheric Administration
- ° Department of the Interior
 - Bureau of Land Management
 - Bureau of Sport Fisheries and Wildlife
 - Geological Survey
 - Bureau of Reclamation

NOISE

Noise Control and Abatement

- ° Department of Health, Education, and Welfare (health aspects)
- ° Department of Commerce
 - National Bureau of Standards
- ° Department of Transportation
 - Assistant Secretary for Systems Development and Technology
 - Federal Aviation Administration (Office of Noise Abatement)
- ° Environmental Protection Agency (Office of Noise)
- ° Department of Housing and Urban Development (urban land use aspects, building material standards)

RADIATION AND RADIOLOGICAL HEALTH

- ° Department of Commerce
 - National Bureau of Standards
- ° Nuclear Regulatory Commission
- ° Environmental Protection Agency
 - Office of Radiation
- ° Department of the Interior
 - Bureau of Mines (uranium mines)

TRANSPORTATION

Air Quality

- ° Environmental Protection Agency
 - Air Pollution Control Office
- ° Department of Transportation
 - Federal Aviation Administration
- ° Department of the Interior
 - Bureau of Outdoor Recreation
 - Bureau of Sport Fisheries and Wildlife
- ° Department of Commerce
 - National Oceanic and Atmospheric Administration (meteorological conditions)

Water Quality

- Environmental Protection Agency
 - Office of Water Quality
- Department of the Interior
 - Bureau of Sport Fisheries and Wildlife
- Department of Commerce
 - National Oceanic and Atmospheric Administration (impact on marine life and ocean monitoring)
- Department of Defense
 - Army Corps of Engineers
- Department of Transportation
 - Coast Guard

URBAN

Congestion in Urban Areas, Housing, and Building Displacement

- Department of Transportation
 - Federal Highway Administration
- Office of Economic Opportunity
- Department of Housing and Urban Development
- Department of the Interior
 - Bureau of Outdoor Recreation

Environmental Effects With Special Impact in Low-Income Neighborhoods

- Department of the Interior
 - National Park Service
- Office of Economic Opportunity
- Department of Housing and Urban Development (urban areas)
- Department of Commerce (economic development areas)
 - Economic Development Administration
- Department of Transportation
 - Urban Mass Transportation Administration

Urban Planning

- Department of Transportation
 - Federal Highway Administration
- Department of Housing and Urban Development
- Environmental Protection Agency
- Department of the Interior
 - Geological Survey
 - Bureau of Outdoor Recreation
- Department of Commerce
 - Economic Development Administration

WATER

Water Quality and Water Pollution Control

- ° Department of Agriculture
 - Soil Conservation Service
 - Forest Service
- ° Department of the Interior
 - Bureau of Reclamation
 - Bureau of Land Management
 - Bureau of Sports Fisheries and Wildlife
 - Bureau of Outdoor Recreation
 - Geological Survey
 - Office of Saline Water
- ° Environmental Protection Agency
 - Water Quality Office
- ° Department of Health, Education, and Welfare (health aspects)
- ° Department of Defense
 - Army Corps of Engineers
 - Department of the Navy (ship pollution control)
- ° Department of Transportation
 - Coast Guard (oil spills, ship sanitation)
- ° Department of Commerce
 - National Oceanic and Atmospheric Administration

Marine Pollution

- ° Department of Commerce
 - National Oceanic and Atmospheric Administration
- ° Department of Transportation
 - Coast Guard
- ° Department of Defense
 - Army Corps of Engineers
 - Office of Oceanographer of the Navy

River and Canal Regulation and Stream Channelization

- ° Department of Agriculture
 - Soil Conservation Service
- ° Department of Defense
 - Army Corps of Engineers
- ° Department of the Interior
 - Bureau of Reclamation
 - Geological Survey
 - Bureau of Sport Fisheries and Wildlife
- ° Department of Transportation
 - Coast Guard

WILDLIFE

- ° Environmental Protection Agency
- ° Department of Agriculture
 - Forest Service
 - Soil Conservation Service
- ° Department of the Interior
 - Bureau of Sport Fisheries and Wildlife
 - Bureau of Land Management
 - Bureau of Outdoor Recreation

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6. GOVERNMENT INCENTIVES

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INTRODUCTION

A recent investigation of federal research and development expenditures, conducted by the House Committee on Science and Technology, concludes that there is a need for incentives to bring about the performance of additional research and development in the private sector.* However, the development of a policy to stimulate innovation in technology should proceed only after a "careful in-depth assessment of past and present effects of the incentives to technological innovation."

Intervention by the government in cases where the market mechanism is perceived to have failed in bringing about the desired results or to have led to undesirable consequences, should be made only after careful assessment of both the primary and secondary effects of such intervention. The combined effects of tax, regulatory, patent, antitrust, government procurement and trade policies should be studied with due regard for sectoral differences.**

This study of the integrated energy utility concludes with a review of the technology policy that the Congress is so seriously questioning, a summary of the conclusions of this study that point to a need for a demonstration project, an analysis of various types of government incentives, a review of the proposals of other studies of district heating and cogeneration, and some policy recommendations based on the foregoing analysis.

*Subcommittee on Domestic and International Scientific Planning and Analysis. Special Oversight Report No. 7, Review of Federal Research and Development Expenditures and the National Economics. 94th Cong. 2nd sess., 1976.

**Ibid., p. 2.

We recognize that value judgments and political decisions play a significant role in policymaking on technological innovation and energy conservation, and that therefore this study has provided only partial, tentative findings. It is the conclusion of the study team that the role of government should be to establish an environment where business and government can work together, and that government's role should be to develop a consistent policy favorable to private investment and the minimization of uncertainty.

The Congress is searching for an identifiable national policy dealing with research and development. This chapter outlines the status of current policy and makes several concrete proposals to delineate the respective roles of government and private enterprise concerning commercial undertakings such as the development of a long-term venture in district heating.

FEDERAL TECHNOLOGY POLICY

Current federal technology policy is the sum of actions taken by the federal government affecting 1) the production of technological innovation significant to the national economy, 2) the diffusion and/or exploitation of technology throughout the domestic economy, and 3) the diffusion and exploitation of technology for international advantage.

There is no broadly based federal program for promoting general technology developed in the private sector. Each federal agency promotes the creation and development of new technology related to its subject mission. There is considerable disagreement about the national policy, and in particular federal programs for diffusing and exploiting specific manufacturing technology and innovations. In some areas the policy has been carefully conceived and executed. However, in others policy apparently has developed without planning. In particular, the policies that are designed to create incentives for diffusion and exploitation of technology have come under serious attack. A recent Rand study suggests that too much federal involvement at the demonstration and commercialization stage makes the success of innovations less likely.* The larger the private sector role in demonstrating and commercializing the technological process, according to this study of federally funded demonstration projects, the more likely the success in implementing the process.

Most technological innovation needs no government intervention to encourage commercial adoption if an appropriate market exists. Government action to commercialize a technology becomes necessary when two conditions exist

* Rand Corporation, Analysis of Federally Funded Demonstration Projects (April 1976).

simultaneously: 1) if there is a special benefit to the nation or society from that technology, and 2) if the market environment does not encourage its adoption.

There are a variety of government roles and instruments that can be used to reduce one type of obstacle or another towards the successful commercialization of the technology. However, little is known about the impact of fiscal policies upon the diffusion of innovations. Donald Schon, the author of a critical analysis of technological change in America, writes:

For good or evil, the effects of government policy on technological innovation are poorly understood. We understand only in primitive terms how fiscal policy affects incentive in investment in industry. We understand far less how anti-trust policy affects willingness to invest in innovation. Still less do we understand the interlocking effects of tax and anti-trust policy. A tax policy aimed at encouraging investment in new capital equipment (and consequently at encouraging investment and new technology) may run head on into an anti-trust policy administered in such a way as to discourage such investment, or a patent policy which deprives corporations of the incentive to be first among competitors in development.*

Schon suggests that a government policy to encourage innovation must look at the interaction of government and industry as though it were a complex servomechanism. Government, according to many critics, needs sensors to detect the impact of policy upon innovation.

- What are the effects of tax policy on corporate capital investment?
- What are the effects of manpower adjustment policy on the match between workers and jobs?
- What is the structure of the unemployed population?
- What is the rate of reemployment, corporate profitability, productivity?

*Donald A. Schon, Technology and Change, The Impact of Invention and Innovation on American Social and Economic Development (New York: Dell Publishing Company, 1967), p. 185.

Nor have American businessmen agreed on the best public policy to stimulate innovation and encourage the rate of diffusion of technology. Some government functions are accepted as legitimate by business groups:

- Collecting and publishing statistics about the industrial process.
- Exercising control of tariff and quota regulations to protect American business from certain forms of foreign competition.
- Employing monetary and fiscal policy to encourage economic growth and discourage depressions.
- Subsidizing certain industries.
- Undertaking major technical innovations requiring capital investment in the public interest.

However, industry leaders are not sure as to the best course of action to pursue because of uncertainties and problems. A recent study by the Government Accounting Office (GAO) identified the issues in government energy policy that concern industry: 1) the lack of federal and state coordination results in conflicting requirements, fragmented policies and procedures, and jurisdictional differences, 2) inadequate and different demands of forecasting methodologies, 3) lack of standardized reserve levels or reliability criteria, 4) inadequate financing for operations and expansion, 5) possible imposition of load management and pricing alternatives with concomitant socioeconomic implications, 6) uncertain effects and costs of new technologies, and 7) the potential conflict of environmental and conservation requirements with industry objectives.*

In a specific reference to the utility industry, the GAO study expressed concern as to whether the nation's 3600 municipal cooperative, state, federal,

*Government Accounting Office, "Energy: Issues Facing The 95th Congress," April 28, 1977, p. 24.

and private utilities can cooperate sufficiently to build the kinds of systems needed for the future or whether further federal planning and intervention is needed. The government is currently examining the problems and issues confronting the electric utility industry to identify and assess the factors affecting the industry's future, their interrelationship, and the pros and cons of alternative courses of action.

REQUIREMENTS FOR INCENTIVES TO PROMOTE DISTRICT HEATING

When we began this study it was recognized that a private-sector venture analysis of the integrated energy utility concept might not paint a rosy picture for private investment. There were several reasons for this skepticism. Since there was no experience with aquifer storage in conjunction with district heating in the United States, all of the calculations and projections in this area would be viewed as experimental. In addition, all previous U.S. utility experience with district heating had been limited to the transmission of steam heat with its concomitant technological and economic problems. Further, earlier studies had documented the institutional obstacles to innovation by the private investor-owned utilities, which were the primary focus of the utility segment of this study. Since our presentation on the viability of district heating required a frank assessment of the attitudes of utility executives, their resistance might weigh heavily against the venture.

Nevertheless, European experience with district heating had been successful and provided evidence of important fuel savings and a reduction in water and air pollution. These facts warranted an investigation of the feasibility and the marketability of the system in the United States. If our research demonstrated similar public-sector benefits in the United States, we were prepared to recommend government incentives to provide a satisfactory environment for private investment in district heating.

The results of our analysis appear in Chapters 4 and 5. To summarize our conclusions, we have found a small but important market for district heating with hot water using aquifer storage. But the manufacturer of the power

plants whom we involved in our study did not feel that the market was large enough to warrant its entry or investment. Further, the manufacturer expressed concern about utility company resistance. It was felt that there was little likelihood that changes in government regulatory policy would alter utility company attitudes in the near future. In addition, we learned in the process of the research that the manufacturers of the power plant had no interest or experience in serving as system contractors, and a systems contractor appeared to be a prerequisite for the success of the venture.

The public-sector analysis of the venture proceeded along two lines. The first was to evaluate the net social benefits of implementing the integrated energy utility, using a model based on studies by Edwin Mansfield. The best social rate of return occurred in the model using a nuclear extraction plant. For the overall picture of the net social benefits accruing to the nation by implementation of district heating, it was found that the system would show positive benefits, but not by the end year of this analysis, 2020.

The second part of the public-sector analysis involved a discussion of the socioeconomic impacts of the system. In general it was found that the system would result in fuel savings, would reduce air pollution significantly, could be implemented in new communities without significant employment impacts, would not disrupt local land-use regulations or adversely impact riparian right. However, institutional constraints and the cumbersome structure of the political regulatory environment posed significant obstacles to the implementation of district heating.

The analyses of both the private and public sectors were conducted with extremely conservative figures because there were many factors about which definite information was not available. In addition, the study was national

in scope and could not show benefits and impacts on local communities except as extrapolated from the larger analysis. Benefits that looked infinitesimal on a national scale could represent significant factors in a community decision.

The end result of both the private- and public-sector conclusions was a decision to consider the nature of government incentives which would improve the economic, social, political, and institutional environment for district heating. The next section is a review of the arguments for government intervention and the nature of that intervention in other energy conservation projects.

ALTERNATIVE GOVERNMENTAL ACTIONS

Since the oil embargo of 1973-74, national attention has been focused on the need to develop a new energy policy. One of the most important aspects of this policy is the development and implementation of new energy technologies. The potential federal role has been the subject of several studies and specific attention has been directed at the process by which energy technologies are developed to the point of being accepted in the marketplace.* In designing the federal research, development, demonstration, and commercialization process, a series of choices must be made involving many technical regulatory and institutional decisions.

The Argument for Government Intervention

Economists concerned with technological change have concluded that monetary and fiscal measures that will assure a sustained high level of economic activity will strengthen the incentive of business to introduce interventions as well as the willingness of workers to make the necessary accommodations involved in their introduction. It is felt that new technologies exercise their impact on the productivity growth of the economy, not as a function of the volume of resources committed to the search process or even the actual achievement of new inventions. Rather, that impact, given the productivity differential between the new technology and the one it displaces, is a function of the speed with which the new technology is diffused throughout the economy.**

*Congressional Budget Office, Energy Research, Development, Demonstration, and Commercialization (January 1977), identified earlier studies and defines several commercialization strategies.

**Nathan Rosenberg, "Factors Affecting the Diffusion of Technology," Chapter 11 in Nathan Rosenberg, Perspectives on Technology (Cambridge MA: Cambridge University Press, 1976).

Rosenberg points out that new technologies generate productivity growth only to the extent that they are actually incorporated into the economic life of the society. Decisions to adopt are highly sensitive to expectations of market conditions and to expectations concerning the adequacy of the demand for the product. He concludes, therefore, that government intervention can be a useful incentive for the industry decisionmaking process.

I believe that one possibly fruitful route through which technological improvements of the desired kind can be produced is by government measures to reduce the uncertainty over the size of the future demand for certain classes of products. Governments, federal, state, and local, can shape the direction of technological change in such areas of increasing concern as environmental pollution and energy by offering contractual guarantees which will assure the existence of markets for technologies which will meet certain performance specifications and pollution-reducing requirements, or by commitments which will provide certain minimum price guarantees or other financial assurances for firms undertaking to develop the technology for the exploitation of new energy sources. The willingness of private industry to undertake such commitments can be vastly strengthened by the assurance of some minimum demand for the eventual product if it meets appropriate performance specifications. Needless to say, the potential elements of waste misallocation in such arrangements are great, and our past experience with government price supports in agriculture identify some of the pitfalls. Nevertheless, if the right combination of assurances and incentives can be contrived over the relevant time horizons, the social payoff may also be very high. Alternatively, subsidies by a tax reduction or more direct means are worth considering in the case of the development of new technologies which are regarded as fulfilling certain peculiarly urgent social needs.*

Another view regarding the need for strong government intervention was suggested in a study by M.I.T. on energy conservation. The proposed policy

*Nathan Rosenberg, "Thinking about Technology Policy for the Coming Decade in U.S. Congress," Joint Economic Committee, U.S. Economic Growth from 1976 to 1986: Prospect, Problems, and Patterns, Vol. 9. Technological Change. 94th Congress, 2nd Session (1977), p. 21.

for accelerated energy conservation, according to M.I.T. researchers, must depend heavily on mandatory measures to improve end-use efficiency. This approach raises arguments about tampering with the free enterprise system.

Direct intervention must be considered, however, because price alone cannot provide sufficiently strong motivation for accelerated conservation. Price increases are limited as a conservation stimulus, even for the industrial sector because energy costs still average well below 10 percent of value added for all manufacturing. Thus, even large additional rises in fuel prices will not necessarily place overwhelming conservation pressures upon manufacturers.*

The consensus of most critics of current energy policy is that a transition to a conservation plan requires a massive restructuring for deployment of resources, capital, and technology

Among the factors that have fostered growth of district heating outside the United States are

- maximum fee agreements which guarantee that the cost for district heating will not exceed the cost for other forms of central heating.
- long-term, low-interest guaranteed loans made at interest rates of 5-6 percent for time periods of up to 30 years.
- district heating being classified as an energy-saving procedure, thereby qualifying the system subscribers for grants of up to 35 percent.
- high-density-load apartment blocks, built on green-field sites, belonging to municipalities that required the installation of a district heating system as a condition of development.
- the absence of natural gas and discouragement of oil-fired central heating on environmental grounds. The only real alternative to district heating is electrical space heating, and district heating is more economical at housing densities above 14 dwellings per hectare (5-1/2 dwellings per acre).
- historical patterns of evolution where collaboration of municipal works and major power producers has been well developed.

*Thomas F. Widmer and Elias P. Gyftopoulos, "Energy Conservation and a Healthy Economy," Technology Review (June 1977), pp. 38-39.

- the design and insulation of buildings and heating systems within the buildings that are compatible with district heating.
- long-term contractual agreements of up to 30 years, which protect both the consumers and suppliers of heat.
- the perception that district heating assures the continuity of supply of energy and helps fulfill national goals of fuel independence through increased efficiency.
- R&D into standardization and prefabrication of distribution and transmission equipment.
- a political and legal atmosphere in Sweden that promotes proactive planning.
- a structure where all district heating systems are owned and operated by the local town councils. In Sweden, it is legal for local authorities to generate, distribute, and sell both heat and electricity; however, local authorities are prohibited from engaging in the purpose of making any significant profit. Therefore, they resell the heat for a price that represents their actual cost and tends to minimize rates.
- industrial cooperation with local government. For example, the Swedish Wine and Spirit Monopoly sells waste heat to the Stockholm Energy Authority for space heating. This results in costs savings for both the Swedish Wine and Spirit Monopoly and district heat consumers because the otherwise waste heat can be used.

Some of the federal policies and their implementations that bear on the diffusion or exploitation of technology include the following.

Tax Credit for Investment in Plant and Equipment. The rationale of this policy is the assumption that new technological know-how is continuously incorporated in newly designed plants and equipment and that the utilization of the new technology will be faster with tax credits. There is little if any quantitative evidence regarding the degree to which new technology is exploited faster with this mechanism than without it or with another.*

Compulsory Licensing of Privately Held Patents to Other Domestic and Foreign Potential Users. This policy action is demanded by the Department

*Betsy Ancker-Johnson, "National Science and Technology Policy: Current Policies and Options for the Future," Research Management (January 1977), p. 9.

of Justice in the name of antitrust regulation. Surveys of the literature have found that the antitrust remedy of compulsory licensing has not been especially successful in generating widespread licensing and utilization of the technologies in question. In some cases companies subject to compulsory licensing and antitrust decrees have reduced their patenting activities.

Federal Procurement Policy as a Means for Speeding the Innovation Process Including Diffusion Exploitation of New Technology. This policy was followed in the National Bureau of Standards Experimental Technology Incentives Program started four years ago. It is not yet clear whether the federal procurement policy can be used as a lever to accelerate technological diffusion in producing nonmilitary items. The government's technology policy is summarized briefly in Table 6.1, Possible Federal Technology Policy Options.

Federal financing incentives can be classified as indirect or direct.* Indirect actions operate through the market mechanism to affect the price of products thereby influencing consumer behavior. They are particularly well suited to new energy supply technologies and conservation actions.

Direct actions bypass ordinary market mechanisms by involving the government as a commercial agent allocating resources directly.

Indirect actions operate through the market mechanism to affect the price of products and possibly modify energy supply and use patterns. The steps involved seek to modify the decision of energy users and energy producers. Such action generally results in only moderate shifts in cost-benefit ratios, they are not normally suited to assist technologies which require large advances to become economically competitive. The principal types of direct and indirect action are shown in Table 6.2.

*The following analysis is drawn from the Government Accounting Office study, An Evaluation of Proposed Federal Assistance for Financing Commercialization of Emerging Energy Technologies, August 24, 1976.

Table 6.1

POSSIBLE FEDERAL TECHNOLOGY POLICY OPTIONS

A. ANALYSIS AND PLANNING	14. Social cost/benefit analysis of proposed regulations 15. Manpower retraining, relocation and pension program 16. SEC study of the effect of corporate remuneration policies on innovation.
B. PRODUCTION OF TECHNOLOGY	<i>Creation of new technical enterprises and aid to independent inventors:</i> (a) <i>Direct financial aid</i> 17. National Research and Development Corporation to finance innovative activity of individual inventors 18. Preferential treatment to new technology enterprises in government contracts 19. University small technical enterprise associates 20. Free patent protection <i>Creation of new technical enterprises and aid to independent inventors:</i> (b) <i>Indirect financial aid</i> 21. Assurance of venture capital availability for new technical enterprises 22. Government guarantee on SBIC loans to new technical enterprises 23. More generous capital gains tax treatment 24. SBIC's incorporation under Subchapter S or as partnerships 25. Increased liquidity through SEC and IRS modifications 26. More favorable founder stock option incentives 27. Tax deductibility of investments in new technical enterprises 28. Graduated corporate income tax rate structure 29. Use of government infrastructure services
Resource assurance 1. Skilled S&T manpower development 2. Stable and adequate basic R&D support <i>Provision of proprietary rights</i> 3. Patent law revision <i>Federal support of industrial R&D: direct</i> 4. Interest-free or low-interest government loans for industrial R&D 5. Grants for generic industrial R&D <i>Federal support of industrial R&D: tax measures</i> 6. Increase in investment credit for R&D plant 7. Increase in depreciation allowances for R&D plant 8. New tax credits or equivalent cash payments for industrial R&D 9. Tax credits or cash payments for industrial R&D expenditures, not plant 10. Tax credits or cash payments for incremental industrial R&D 11. Tax credits or cash payments for incremental industrial R&D in chemical and capital goods industries	
C. DIFFUSION AND EXPLOITATION OF TECHNOLOGY DOMESTICALLY	D. DIFFUSION AND EXPLOITATION OF TECHNOLOGY FOR INTERNATIONAL ADVANTAGE
<i>Information diffusion</i> 1. Gathering, organizing, and disseminating scientific and engineering information 2. Educational publications on consequences of major technology changes 3. Science court to establish credibility of scientific information 4. Provision of information to state and local governments 5. Consumer technology information services 6. Enhanced NBS voluntary performance standard effort <i>Federal support of commercialization</i> 7. Funding for commercialization of selected government inventions 8. Funding for commercialization of socially desirable private inventions 9. Stimulation of innovation through Federal procurement policy <i>Reduction of barriers to innovation</i> 10. Patent law revision 11. Federal patent policy 12. Modification of antitrust laws to allow cooperative R&D 13. Determination and modification of regulations inhibiting innovation	<i>Improvement of U.S. competitiveness in international trade</i> 1. Policy statement on free flow of publicly available data 2. Limit of decrees on compulsory licensing to domestic availability 3. Increase of U.S. effectiveness in international standards-setting 4. Improved control of design and manufacturing technology 5. National benefit equalization tax 6. Disallowance period of seven years for export of technology, per se, developed with Federal funds 7. Transfer of technology, per se, to Eastern bloc only through "Techport" 8. Expansion of export promotion programs <i>Technological support of lesser developed countries</i> 9. Business code of behavior 10. Establishment of bilateral commissions 11. Organization of multilateral commissions 12. Expansion of World Bank activities 13. Expansion of foreign aid programs <i>International Cooperation</i> 14. Promotion of cooperative industrial R&D

SOURCE: Betsy Ancker-Johnson, "National Science and Technology Policy: Current Policies and Options for the Future," Research Management, January 1977, p. 11.

Table 6.2

MAJOR GOVERNMENT ACTIONS AVAILABLE FOR STIMULATING
NEW ENERGY TECHNOLOGIES AND CONSERVATION ACTIONS

INDIRECT	DIRECT
1. Tax Action	1. Specific Regulation
2. Price Regulation	2. Contracts
3. Credit Assistance	3. Grants
4. Subsidy	4. Government Ownership

Indirect Government Actions

Tax actions can be used to stimulate conservation actions and accelerate the commercialization of emerging energy-supply technologies. Tax incentives, tax credits, and disincentives such as excise taxes on gasoline are most effective when applied to conservation actions and energy technologies that are currently economical or nearly so. The major advantages of tax action over other types of federal incentives are that tax actions are relatively easy to administer, provide for public visibility, and can be precisely tailored to reach the targeted population. Tax incentives, however, have the disadvantage of reducing tax revenue, and of assuming permanent status.

Price regulation is most useful in emergency situations. However, price controls may induce waste, often require a large bureaucracy to administer, and reduce or render more costly the effectiveness of other initiatives, such as price supports. Price controls may be imposed in the context of regulation such as setting a "fair rate of return" on utility profits. In that case, price controls on one fuel may be set so as to affect the use of another fuel.

Credit assistance such as loans and loan guarantees are most effective in making investment decisions in which fixed costs are a major component of total

costs, and investor choices are sensitive to relatively small variations in the cost of capital. A loan guarantee in this situation can eliminate or reduce any risk premium demanded by investors. Loan guarantees have disadvantages, however: 1) they are unlikely to increase the total supply of investment funds, and 2) they are apt to divert such funds to insured areas and away from others. If loan guarantees are issued for energy projects they might divert investment funds away from home mortgages or state and local bond issues. In addition, stimulus to investment in certain energy projects may come at the expense of investment in oil or gas or other areas.

Loan guarantees may be ineffective despite the lower interest rate they would generate; firms may be unwilling to undertake the activity if a higher rate of return on capital is available elsewhere. If the loan guarantee is for an unprofitable activity, the reduction in interest rates may not reduce total cost by enough to make the venture look attractive and to warrant participation by firms with alternate investment possibilities. Loan guarantees frustrate budgetary discipline because they do not compete for federal tax moneys in the same manner as other programs.

Subsidies in the form of price guarantees would involve a commitment by the federal government to pay the difference between market prices at the time of production and any cost of production above those prices. The cost of price guarantees would depend on several factors such as the expected volume of the fuel whose price was being guaranteed for the technologies. A price guarantee system may lead to large expenditures if there is significant growth in the industry being subsidized. These expenditures can also present a problem if economies of scale necessitate production of the subsidized product by one or a few firms. In such a situation lack of adequate competition and/or inefficiency could result in excess cost to the government.

Direct Government Actions

Direct actions are best suited to situations when 1) an action is required to deal with an emergency, or 2) effective action of the type desired in a pre-determined time frame by private enterprise seems unlikely, 3) the action is deterred principally by cost and effectiveness together with uncertainty regarding the future and the size of necessary capital requirements or 4) the action requires attention to goals such as developing environmental and socioeconomic data that industry may be unwilling or unable to pursue. Direct actions tend to provide more specific visibility and control than some indirect actions; however, there are some disadvantages. A tariff on imported crude oil or a quota may create equity problems by producing large windfall gains to favored domestic producers. Contracts are related to price guarantees, procurement contracts and grants. Unless a firm price is agreed to beforehand, such contracts tend to be costly in nature and share all the advantages and disadvantages of similar government involvements. The disadvantages include complexity, incentives for inefficiency, and the need for sustained monitoring. Advantages of this option include more control of project efficiency and progress, and greater visibility of financing as compared to indirect methods. Grants could be provided for specific development work or construction.

There is conflicting evidence on the effect of government regulation. Experiments are necessary to determine the effective approach in any new field such as district heating.* Incentives such as allowed profits and tax relief attract investment just as taxes, price control, and regulatory action may deter investment.

*A. Gerstenfeld, "Government Regulation Effects on the Directions of Innovation: A Focus on Performance Standards," Engineering Management, Vol. 24, No. 3 (August 1977).

Industry is reticent about government intervention, and the general impression given at a recent workshop on the issue of the federal energy agency's role in the commercialization of energy technology was that government subsidies would replace rather than supplement private capital and that the net result would be less rather than more investment for commercialization. "The sentiment was widely shared that any government subsidies of energy technology commercialization should be limited in time and extent and that the instruments chosen to provide the subsidy should be designed to minimize direct government interference with prerogatives and decisionmaking of individual firms."*

The success of a venture such as district heating will require shaping new relationships between government and private research and technology groups. There are several examples of government/business relationships leading to successful development of large-scale commercial systems. In particular the catalytic cracking, synthetic rubber, and Bell Laboratories programs offer some useful insights and guidelines for government approaches that stimulate innovation.**

Several government strategies have been particularly successful.

1. Erecting or guaranteeing a demand. This approach was successful in the development of 100 octane gas, synthetic rubber, computers, and cargo aircraft. The success of this approach is dependent on whether the firm is inclined to invest its money and develop technical capability and support a marketing phase.

*U.S. Congress. House. Committee on Science and Technology. Joint Oversight Hearings. International Cooperation in Energy, Research, and Development, before the Subcommittee on Energy, Research, Development, and Demonstration, 94th Congress, 2nd Session (1976), p. 307.

**This discussion is based on the analysis of J. B. Quinn, "New Approaches for New Public Needs," Research Management, Vol. XX, No. 6 (November 1977).

2. Breaking down bottlenecks. Barriers of secrecy, anti-trust, transportation, or investment can be broken down effectively by government intervention. The government's capacity to provide data on aggregate resources and set priorities for use of scarce resources impacts significantly on development times.
3. Aggregate demand. The government has often aggregated and simplified market structures, making it easier or less risky for private parties to innovate for or produce more rapidly for those markets. Government intervention was responsible for standardizing aviation gas and assuring a demand for synthetic rubber. Standard setting such as building codes, waste disposal requirements, and air pollution regulation can have the same effect on the development of energy technologies.
4. Aggregate resources. EPRI is an example of aggregating research monies to serve the large-scale needs of the electric utilities. Other applications of this concept might be effective in fragmented industries.
5. Extend time horizon. Political pressures often compress time horizons to the 2-4 year frame of the election cycle. Through longer term standard setting and quasi public financing, government could actively stimulate innovation and the market for the innovation.
6. Take unusual risks. The government stimulated rapid advance in the state of the art of synthetic rubber, catalytic cracking, computers, and advanced communication systems. Once the characteristics of these systems were known the risk for private industry to carry them further became significantly reduced. Similar risk reduction is possible today. It would require that the government work with private industry by underwriting prototype technologies.

Cogeneration Legislation - A Potential Model

Legislation recently introduced in the U.S. Congress to encourage cogeneration and waste heat utilization may provide a model for the types of incentives that might stimulate the adoption of district heating.* The incentives and disincentives in this legislation are directed at the utility industry, the regulatory commissions, and industrial purchasers of generating equipment.

- To industry, an additional 10 percent investment tax credit for buying and installing cogeneration equipment
- To utilities, denial of their existing investment tax credit if they unreasonably refuse to exchange electricity with cogenerators at a fair price
- To utility commissions, grants to assist state regulators in modernizing their regulations and procedures to encourage cogeneration and waste-heat recovery.

Senator Hart's legislation assumes that the federal government's proper role should be a hands-off policy unless negotiation among the three parties involved result in an acceptable arrangement for government intervention. This approach is consistent with the consensus among business spokesmen that government intervention is least successful when used to stimulate the diffusion of new technologies.

However, response to the bill has not been overwhelmingly positive. According to the Senator's office, the private utility lobby opposed the bill and was unwilling to help change it.**

* S1363. Cogeneration and Waste Heat Utilization Act Introduced by Sen. Gary Hart (D-Col.) 95th Cong., 1st sess., 1977. For additional discussion of this legislation see: Congressional Record, Vol. 128 (April 25, 1977), No. 68 and (May 26, 1977), No. 91. Congressional Clearinghouse on the Future, What's Next? Vol. 2 (August 1977) No. 2 is the first "impact forecast" developed by the Library of Congress to evaluate effects of legislation being considered by the Congress. A companion bill (see H. R. 6661) was introduced in the House by Rep. Ottinger (D-NY).

**Telephone conversation with Ed MacIlwain, June 15, 1977.

Environmentalists preferred legislation that would contain more mandatory requirements for both industry and the utilities. Organized labor would support the conservation philosophy of the bill but opposed investment tax credits to businesses. Support for the legislation is strongest from the public power groups and rural electric cooperatives.

Energy Conservation Incentives and Disincentives

A variety of proposals to encourage energy conservation appear in legislation, magazines, research reports, and every forum concerned with the federal government's emerging energy policy. A brief summary is presented to serve as an introduction to consideration of specific proposals for encouraging the development of district heating.

Measures that could be implemented by regulatory commissions include the following:

1. Reduced standby demand charges to industry.
2. Peakload pricing as a policy tool to encourage waste heat recovery.
3. Evaluate rate structure (time-of-day pricing, lifeline costing, marginal pricing and constant industry and residence rates, effect on waste heat conservation and recovery practices).

Incentives and disincentives to industries and utilities include the following:

1. Employing waste heat charges as a waste heat conservation recovery and use strategy.
2. Tax incentives:
 - Increased investment tax credit
 - Accelerated depreciation for properties and equipment and recovery uses.
 - Increased taxes on enterprises wasting excess quantities of heat energy.
3. Regulatory disallowances in determining just and reasonable rates of capital costs for the construction of additional electric utility generating capacity.
4. Fuel taxes on enterprises requiring significant quantities of steam or heat energy that do not adopt measures to conserve, recover, and use that energy.

In addition, there are a variety of proposals to provide financial assistance to state regulatory authorities to aid them in studying means for 1) facilitating recovery and use of waste heat energy, and 2) encouraging electric utilities to adopt conservation-oriented regulation.

Specific proposals contained in earlier studies related to district heating are summarized briefly below.

GOVERNMENT INCENTIVES PROPOSED IN OTHER DISTRICT HEATING STUDIES

European Experience with District Heating

The typical district heating system in Europe is owned and operated by the municipality or state, or is a cooperative enterprise. Although district heating in the United States is most commonly supplied by private enterprise or public utilities there is much that can be learned from the European experience. In Denmark, the government encouraged district heating by guaranteeing loans and providing technical assistance. The objective of government intervention in Denmark was to reduce total foreign imports. District heating plants consume lower cost residual fuel oil whereas individual heating systems require expensive imported distillate fuel oil.

In the U.S.S.R. and other countries with planned economies, state control over energy distribution and urban construction lead to large-scale application of district heating. The motivation for government policy was economies of fuel, labor and building materials and reduction of air pollution.*

Toronto, Canada

The Toronto District Heating Study was initiated by city authorities who thought it was necessary to reduce or control the disposal to the atmosphere of waste gases that arise from the process of heating buildings in the high-density areas of the city. Hence the initial and primary consideration was to enhance social benefits. The policy recommendations that resulted from the study had several well-defined social goals: improved air quality, conservation of energy resources, and increased aesthetic and social benefits for the citizens of Toronto.**

*See this report, Chapter 3 and additional references cited in Toronto District Heating Study, Volume 2, p. 20.

**Toronto, Ontario, District Heating Study: Summary and Policy Report. 1976

To accomplish these objectives the city proposed to absorb half the costs of conversion of buildings to district heating and the city recommended that it pay for the interconnection and expansion of the integrated system in return for an annual rental fee equal to the associated debt service charges. It was proposed that legislation be enacted that would prohibit the installation, use, and maintenance of individual heating plants for the heating of new buildings exceeding 50,000 square feet. Many other proposals for government incentives and disincentives are contained in the Toronto report. The variety of proposals was designed to increase heat conservation (such as the removal of the sales tax on electric heat pump systems), to reduce air pollution, to integrate small private heating plants, and to provide for construction of a new refuse fired steam plant as a base load for the system.

Thermo Electron Study of In-Plant Generation

This study, conducted on in-plant electric power generation in the chemical, petroleum refining and paper and pulp industries, only considered power systems that generate electric power in conjunction with process steam. It excluded utility-type systems such as condensing steam turbines, gas turbines and steam turbine plants.

Although it is not a study of district heating, the Thermo Electron study is relevant because it pertains to a related system for utilizing waste heat. The study concludes that in-plant generation offers a valuable mix of public and private benefits worthy of government incentives to stimulate private investment:

*Thermo Electron Corp., A Study of Inplant Electric Power Generation in the Chemical, Petroleum, Refining and Paper and Pulp Industries. NTIS, June 1976 (PB 255 659).

Inplant electric power generation potentially has numerous national advantages besides energy conservation. The most important of these are lower cost of electricity to the consumer and/or greater profit potential for industry and utilities, assisting in the implementation of a fuel conversion strategy to coal through the use of steam turbine topping (which would further lessen dependence on foreign oil imports), less atmospheric pollution as a result of lower fuel consumption, and greater reliability and security of a multi-source electrical generation system versus a smaller number of larger systems.*

Some of the policies proposed in the study may be suggestive of a direction for government policy on district heating.

We suggest that a multi facet program to enhance the implementation of in-plant generation be initiated and coordinated by the energy agencies of the federal government.**

This program would consist of a demonstration program for planning, design, construction, and implementation, which is expected to trigger rulemaking changes and test cases in the regulatory and rate area. It is also proposed that rulings be obtained from the Federal Power Commission and State Public Utility Commissions to result in a more favorable regulatory climate for in-plant generation.

Despite the evidence that in-plant electric power can be generated at comparable or lower costs than fossil-fuel-fired central station power "in most situations,"*** the study found that there were strong forces to overcome in "industry's high required rate of return for ancillary investments" and "utilities' generally negative attitude toward inplant generation, and the present legal and regulatory environment which is not conducive to either industry or utility ownership of facilities for inplant generation."****

*Ibid., I-14.

**Ibid., I-11.

***Ibid., I-12.

****Ibid., I-12-13.

The government program proposed in the study calls for federally guarantee loans to industry and leasing companies at current market interest rates and up to 50 percent of the required investment. In addition the study suggests that traditional tax incentives such as investment tax credits could contribute significantly to in-plant power generation, and smaller incentives are recommended for utilities to induce them to invest in in-plant generation.

Finally it is proposed that federal government guaranteed loans offered at market rates would probably be viewed differently by the investment community than ordinary debt and could possibly be treated as an off-balance sheet entry allowing industry to borrow funds for its regular product-oriented investments.

It is assumed that 50-percent financing will tend to make industry invest in in-plant generation systems that are more attractive from a national viewpoint than utility power, while not substantially increasing investment in those systems for which the reverse is true.

Energy Industrial Center Study

This is a study of the technical, environmental, economic, and legal and regulatory aspects of generating by-product electrical power from steam generation by industry for use in manufacturing. No conclusions about policy are stated although the report does identify public benefits in terms of fuel saved, air pollution reduced, and decreased demands for capital investment on utility planning.

In the legal and regulatory analysis there is a small suggestion of the need for a government incentive:

If it were deemed to be a matter of national policy to encourage the ventures under discussion, perhaps industrial property dedicated to the generation of electric energy should qualify for greater investment tax credit than otherwise available.*

Heat Storage Well Study

A study of "The Role of the Heat Storage Well in Future U.S. Energy Systems" was conducted by GE TEMPO in 1976.** Among the governmental policies recommended to encourage implementation of the storage well concept, the TEMPO report urges***

- federal pressure on State Utility regulatory agencies to include energy conservation as an objective
- changes in the regulatory process to make financial capital available to investor owned utilities
- federal financing of demonstration projects "until risk has been shown to be low."*

*Energy Industrial Center Study, prepared by The Dow Chemical Company et al., June 1975, p. 20.

**Study was conducted by C. F. Meyer and W. Hausz for GE-TEMPO Center for Advanced Studies, Santa Barbara, CA, and Washington, DC, December 1976.

***Ibid., p. 7-1, 7.2, 7-3.

POLICY RECOMMENDATIONS

Due to the macro nature of this study, the description of public benefits is only suggestive of the positive conservation and health-related advantages that would accrue to any community implementing district heating. However, the study team is sufficiently impressed with the results of the analysis to propose that a demonstration project is worth government funding. As part of this demonstration particular attention should be given to a variety of possible approaches that would enhance the project from the private sector perspective and increase the public benefits.

The demonstration project should be conducted in an area in which the condition of underground aquifers is well known and where there would be a minimal possibility of problems relative to ground water contamination.

In addition to providing tax incentives to industry and permitting utilities a higher rate of return, both proposals made by other studies, it is suggested that the government consider chartering a private corporation as a systems contractor. In discussion with industry it is evident that the implementation process for district heating requires overall direction and coordination. Neither the power plant manufacturer nor private investor-owned utilities seem well suited to this job, and municipalities are likewise constrained by institutional and political factors.

The demonstration project could include a variety of federal, state and local incentives such as

- creating a public works project out of the laying of underground pipe for transmission of hot water

- stimulating industrial development in the area of a district heating demonstration project by offering free heat in return for a long-term lease
- experimenting with use of water utility as a possible agent for district heating
- encouraging public discussion and policy analysis to develop means for overcoming political and institutional constraints discussed in Chapter 5
- encouraging federal and local participation in international study commissions to facilitate the broadest exchange of information with European and Canadian experts on district heating.

A demonstration project undertaken in connection with a federal or municipal power authority would demonstrate the advantages and potential problems associated with aquifer storage, without the complications inherent in the involvement of a private investor-owned utility. However it is recommended that a full-scale demonstration project is the only means to developing a political and regulatory climate conducive to private investment.

It is a prerequisite of any demonstration project that evaluation be an integral part of the process. Evaluation of a district heating demonstration should be conducted at each stage of development and with the full cooperation of all affected interests.

The demonstration project could be a major factor in reducing or eliminating the major uncertainties cited throughout this report. Thus valuable information could be gained relating to the concept of aquifer storage, the use of retrofit, the possibility of air conditioning, the load densities required, and the need for government action to require use of district heat.

In addition to a demonstration project several site-specific studies should also be performed. The characteristics of this venture are such

that each system will have to be designed to meet the specific characteristics of each site. This study, with its natural focus, could not investigate site-specific considerations in detail. There are likely to be many sites where the system is much more attractive than shown here and others where it is less attractive. A number of site-specific studies is required to investigate these considerations fully.