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District Heating/Cogeneration Application Studies for the Minneapolis–St. Paul Area

Summary of Twin Cities Case Study and the St. Paul Project

M. A. Karnitz
J. O. Kolb

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DISTRICT HEATING/COGENERATION APPLICATION STUDIES FOR THE MINNEAPOLIS-ST. PAUL AREA

SUMMARY OF TWIN CITIES CASE STUDY AND THE ST. PAUL PROJECT*

M. A. Karnitz
J. O. Kolb

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ABSTRACT

A site-specific study was conducted to evaluate the feasibility of a large, cogeneration/district heating system for U.S. cities. The Minneapolis-St. Paul area was chosen as the site for a case study of a modern hot water district heating system. The first phase of the work was a conceptual feasibility study for the entire metropolitan region. The effort concentrated on assessing the heat loads and heat sources that could be connected over a 20-year period. This study phase set the framework for the overall potential for district heating in the region and was the stimulus for the second phase, the St. Paul district heating demonstration project. The St. Paul District Heating Development Company is planning to build the first modern hot water district heating system in a major U.S. city.

The assessment for the entire metropolitan region analyzed two levels of district heating: 2600 MW(t) — which limited the analysis of district heating to the downtown and commercial areas, and 4000 MW(t) — which, in addition to the downtown and commercial areas, expanded the analysis to medium density residential districts. The results indicate that district heating, on a regional basis in the Twin Cities, is technically feasible, and that large quantities of potentially scarce fuels (oil and natural gas) can be saved. The economics are judged to be viable, providing a suitable method of financing is used for the transmission and distribution system.

The St. Paul District Heating Project will have all the elements of a full-scale system: hot water transmission and distribution, conversion of the heating systems in existing buildings, and the potential for cogeneration. The core of St. Paul is the market area in which there are over 300

buildings. The estimated heat load for this service area is 270 MW(t). However, the project does not expect to connect all the buildings to the system in the initial 4-5 year period. The initial plan is to build a 165-MW(t) system at an estimated cost of $77 million. Analysis of this system shows that during the first 10 years of the project, the energy rates are projected to be below rates for full cost recovery, which results in a cost deferral of $12.1 million. This cost deferral is expected to be recovered during the second 10 years of the project. Despite the difficulties involved in finalizing the project, the City of St. Paul is expediting the development because of steadily rising fuel prices. It is anticipated that this district heating system will enable the City to keep thermal energy costs from rising as rapidly as the price of other fuels, thus making the city more attractive for business growth.

1. INTRODUCTION

1.1 Background

Currently, space heating and water heating account for 20% of the total U.S. energy demand. Over 90% of these requirements are supplied by oil and natural gas, fuels that are subject to rapid price escalation. In addition, our dependence on foreign oil threatens our national security and economic stability and adds significantly to the U.S. international trade deficit. District heating, which can use alternative domestic fuels, can result in more stable prices and greater national self-sufficiency.

District heating is a process in which thermal energy from a central source is distributed to commercial, industrial, and residential consumers for space heating and domestic hot water needs. The heat energy is distributed from a central plant to individual buildings by either steam or hot water pipelines. Buildings connected to the district heating system extract energy from the system rather than use fuel directly in boilers or furnaces located in each building. Plants that can use a variety of available domestic fuels, including coal, nuclear energy, and municipal refuse, can be built for district heating. Existing electric-only power plants can also be converted to supply both electricity and thermal energy to the district heating system. Thermal energy can also be supplied from industrial waste heat, solar energy, and geothermal sources.

District heating is a technology that originated in the United States in the late 1800s and that more recently has been successfully implemented in many European countries through the use of a different technology. As originally conceived, thermal energy in the form of steam was produced at a

central plant and distributed through underground piping networks to consumers. During the early part of the twentieth century, the first small cogeneration district heating plants came into existence. These systems used the exhaust steam from dual purpose power plants to heat buildings in the nearby business districts. As a result, district heating combined with cogeneration was widely accepted. During the late 1940s, the situation changed when the introduction of inexpensive oil and natural gas for space heating reduced the rapid growth of district heating. Many of the U.S. steam district heating businesses were not profitable because of inadequate rates or the lack of proper metering devices. A large number of systems went out of business, and many of the remaining systems are marginal businesses.

The history of district heating in Europe is somewhat different from that in the United States. The development of district heating networks in northern and eastern Europe started in the late 1940s. Hot water rather than steam was used predominantly as the transport medium, and these systems have proven to be economical. The reasons for the European systems' success are that (1) inexpensive domestic natural gas has not been available and (2) low-cost piping materials and installation techniques were developed. The hot water systems allow service to lower heat load density regions and the use of remotely located cogeneration plants. The annual growth rate of district heating in the northern European countries is about 20%/year. From a business point of view, European hot water systems look more like the a U.S. natural gas distribution business than U.S. steam district heating business. European systems serve much lower heat load densities than do U.S. steam systems. Another constraint on steam district heating systems is that steam cannot be repressurized and

extended into new areas as readily as hot water. As a result, hot water systems are more adaptable to meeting the changing needs of a community.

Modern hot water district heating systems have the potential to offer consumers many major advantages over operating their own building boilers: (1) competitive space heating energy costs, (2) lower maintenance costs and higher reliability, (3) improved air quality in the community, (4) improved safety (compared with fossil fuel fired systems), (5) smaller space requirements, and (6) lower initial capital costs for new buildings. Of these advantages, the most important one to the consumer is the cost of the heat energy. In numerous U.S. cities, natural gas is the alternative to district heating. The only way that a district heating system can compete is through the fuel flexibility feature, which implies the use of comparatively inexpensive fuels such as coal.

1.2 Purpose

The primary objective of this study was to determine the feasibility of a modern hot water district heating system for a U.S. city. The idea for such a study was the result of the large number of successful systems designed and built in northern Europe over the past 25 years. Many of the systems serve large segments of the city, and a significant number of them serve single-family residential consumers. Based on the success of the European systems, these studies were initiated to evaluate the European concept as it applied to a northern U.S. city.

The analysis was directed at determining both the technical and economic viability of a city-wide district heating system. The analysis of both the technical and economic factors was to be based upon the northern

European philosophy of design. Variations are expected because of differences between northern European and U.S. cities. The technical analysis addresses such issues as suitability of the European thin-wall piping design, the various aspects of building retrofit to a district heating system, and the various types of energy sources that could supply heat to a distribution system. The economic analysis looks at the system on a life-cycle cost basis. In addition, for various types of consumers, there is a separate economic analysis which includes initial retrofit costs and annual heating costs.

1.3 Approach

A site specific case study was selected as the approach to evaluate the feasiblity of a cogeneration/district heating system for U.S. cities. The intent was to do a cooperative study with a city and utility so as to incorporate their respective needs. The Minneapolis-St. Paul area was chosen as the site because it met the technical criteria, such as high number of heating degree days (>8000°F), large potential load, and the possibility for considering a variety of potential energy sources. However, the main reason for selecting the Twin Cities was the commitments by a number of local companies and agencies to participate in the effort. The local participants include, from the beginning of the study, the Northern States Power Company (NSP); the Minnesota Energy Agency (MEA); the City of St. Paul; the City of Minneapolis; the University of Minnesota; and then, later, the St. Paul District Heating Development Company (DHDC). They all agreed to actively participate and support the program. It was intended that the results of such a case study would servce as a model for other U.S. cities, particularly northern cities with at least 4000°F heating degree days.

The first assessment was a conceptual feasibility study for the entire metropolitan region. The "Overall Feasibility Study"[1] was performed by Studsvik Energiteknik, a Swedish laboratory that has performed similar studies in other countries. The objective of the study was to outline the general features of a new city-wide hot water district heating system, assumed to develop over a 20-year period. The major efforts were concentrated in four areas: assessment of the heating loads that could be connected over a 20-year period, determination of a feasible implementation schedule to connect the loads and to bring cogeneration plants and peaking and backup boilers on line, examination of the overall economic basis with alternative methods of financing, and estimation of the potential displacement of oil and natural gas fuels. This work stimulated several other studies in the evaluation of a city-wide district heating system. A list of the various studies is given in Table 1.1. Encouraging results of the overall feasibility study, along with the other studies, led to the formation by the City of St. Paul of the St. Paul DHDC. This company, formed in 1979, is charged with developing and implementing a hot water district heating system for the City of St. Paul.

1.4 Description of Studies

The overall feasiblity study was initiated in mid-1977 and completed in 1979. Chapter 2 of this report summarizes this study as it relates to the concept of a hot water district heating system for the whole metropolitan region. The results of the overall feasibility study were presented to the participants through the means of interim reports at frequencies of every three to six months. At each interval more interest was generated by the participants, and, in turn, they asked more questions about the concept.

Table 1.1. Minneapolis-St. Paul district heating studies

General description	Lead investigator
Distribution and building systems	
District heating study (overall feasibility study outlining 20-year development)	Studsvik Energitiknik
Building conversion study (description of conversion techniques and estimation of costs)	Minnesota Energy Agency
Energy sources studies	
Retrofitting an existing coal plant (description of conversion techniques and costs for High Bridge Power Plant in St. Paul)	United Engineers & Constructors
New coal/cogeneration plant assessment (investigation of the possibility of locating a new coal-cogenerating unit near or in the Twin Cities	United Engineers & Constructors
Institutional issues	
Ownership option and barriers (identification and evaluation of nontechnical issues: ownership, financing, regulation, and marketability)	Minnesota Energy Agency
Environmental	
Air quality modeling (prediction of the effect of cogeneration/district heating on the Twin Cities' air quality)	Oak Ridge National Laboratory

Some of the questions were answered by the overall feasibility study through the iterative process of the participants' supplying more data at each step of the analysis. However, there were many questions that the overall feasibility study did not address. For example, the participants wanted to know more detail about marketing, building conversion, energy sources, and ownership options. Consequently, other studies were initiated in an attempt to address these concerns.

A study on building conversion was initiated midway into the overall feasibility study. The Building Owners and Managers Association (BOMA) was concerned about the cost of converting a building so that it could

connect to a hot water district heating system. The MEA conducted the study primarily to determine the cost of converting the building heating systems to make them compatible with the new hot water district heating system.[2] This study used both a micro- and macroscopic approach. The first step was a survey of 280 buildings in the Minneapolis-St. Paul downtown areas. The buildings were categorized according to their use and their type of heating system. The other part of the study was a detailed analysis of five typical buildings. Different conversion methods were studied for these five buildings, and a cost estimate was made for the most suitable method. Correction factors were then applied to the results of the detail study of five buildings for other buildings as a function of peak thermal demand. This procedure allowed one to estimate the total cost of building conversion for the entire Twin Cities.

Several studies that involved a variety of alternative energy sources for the district heating system were conducted. The NSP owns and operates coal-fired electric generating plants in both Minneapolis and St. Paul. (The location of the existing plants in and around the Twin Cities is given in Fig. 1.1.) Because many existing electric-only units in northern Europe have been modified and are now cogenerating electricity and thermal energy, NSP initiated two studies to determine the feasibility of modifying their own existing units in the Twin Cities. They first hired ECONO, a Finnish consulting engineering firm, to perform a preliminary study to determine the amount of thermal energy that could be extracted from both the Riverside and the High Bridge Power Plants. The second study, which was conducted by United Engineers & Constructors, was a much more comprehensive investigation of options on how to retrofit the High Bridge Power Plant.[3]

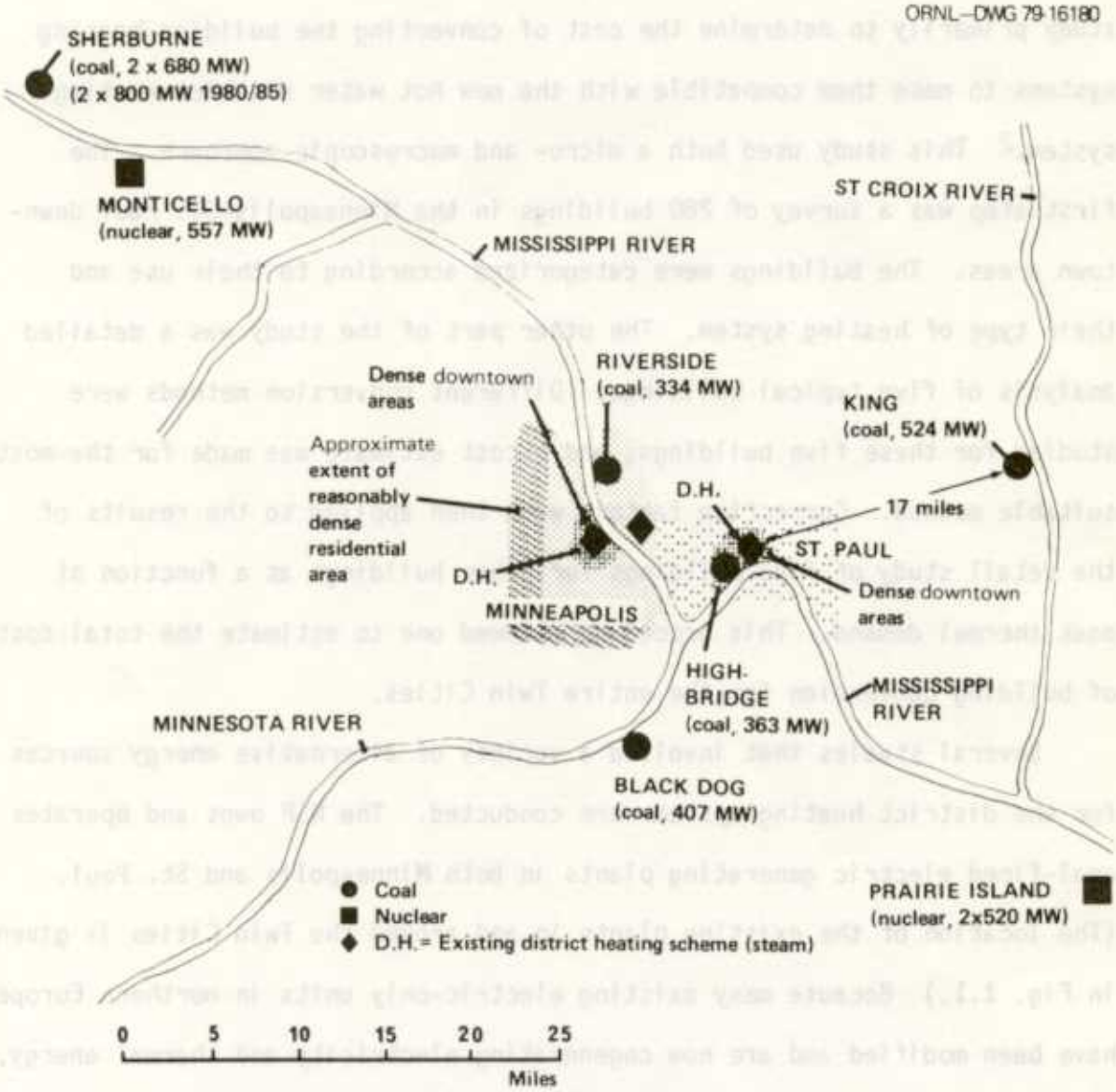

Fig. 1.1. Area map of existing steam-electric power plants.

The company also performed a detailed cost analysis on the turbine modification, the addition of heat exchangers, and the piping within the plant. The work determined that it was economically and practically feasible to retrofit an existing unit so that it could cogenerate electricity and thermal energy for a hot water district heating system.

The NSP also had United Engineers & Constructors perform an economic analysis on the cost allocation of cogeneration.[4] The report reviewed and compared several different procedures as to how to share the cost between the two products. Cogeneration has the potential for improving the fuel utilization efficiency and can thereby produce an economic benefit. There are a number of ways in which the cost of savings from increased productivity can be split. This cost allocation report recommends an equal sharing of the benefits with the electric customer, thermal customer, and the electric utility.

The NSP and the U.S. Department of Energy (DOE) also investigated the feasibility of a new cogeneration unit that would serve the electric demand and the new district heating system.[5] This analysis, which was done by United Engineers & Constructors, consisted of a conceptual design, a cost estimate, and an economic comparison of cogeneration plants at one existing metropolitan site and a newly selected site. Conceptual designs were done for pulverized-coal boilers, fluidized-bed boilers, and a closed-cycle air turbine with heat supplied in an atmospheric fluidized-bed combustor using closed-cycle air heaters. Two size ranges were considered: a 200-MW(e)—300-MW(t) cogeneration plant and 400-MW(e)—700-MW(t) plant. The parametric study compared different size ranges and conventional units with advanced concepts. This study concludes that a cogeneration plant operating at its assigned capacity factor will provide heat and electricity at

the plant boundary at a cost significantly less than the respective cost of comparable heat-only or electric-only plants. Again, this benefit results from better fuel utilization, common use of facilities, and the sale of two products -- heat energy and electricity.

Air quality considerations are obviously critical to the implementation of a district heating system. For example, one stack, used in the production of electricity and thermal energy, would replace emissions from the stacks of many low-level space heating furnaces. Oak Ridge National Laboratory (ORNL), in coordination with the MEA and the Minnesota Pollution Control Agency, performed an assessment on the annual average SO_2 air quality.[6] The analysis compared three scenarios: current environmental conditions, environmental conditions projected into the future without a district heating systems, and environmental conditions projected into the future with a district heating cogeneration system. The effect that district heating can have on air quality depends, to a large extent, on the type of fuel being replaced in the individual heating units. For the Twin Cities, approximately 90% of the heating requirements is currently supplied by natural gas. The results indicated that there was a significant overall benefit in ground level air quality of SO_2; however, there was a slight increase in total emissions of SO_2.

Another assessment was the examination of a nuclear/cogeneration plant for district heating.[7] The improvement in air quality using a nuclear power plant in comparison with a coal power plant was a major reason to include this option. Nuclear reactors have been used for district heating in Sweden and the Union of Soviet Socialist Republics (USSR). Beginning in 1964, the Swedish Agesta reactor provided 70 MW(t) to the suburbs of

Stockholm.[8] The plant also supplied electricity to the grid. It was shut down in 1974 because the economics of such a small plant were unfavorable. This study focused on an intermediate size [1200-MW(t)] Babcock and Wilcox pressurized water reactor (PWR), which is known as a consolidated nuclear steam system (CNSS). The capacity of this CNSS plant, when generating only electricity, is 400 MW(e). The CNSS concept stems from the nuclear merchant ship propulsion steam system but is designed to operate at a higher power level. Compared to conventional loop-type PWRs, the CNSS has additional inherent safety features. This aspect, along with the other characteristics of the reactor, such as size and compact design, may provide the basis for the possibility of obtaining new regulatory approval for a plant siting near to centers of population.

An institutional issue study was another of the series of studies relating to the development of a cogeneration/district heating system for the Twin Cities.[9] For this study, it was assumed that the technical basis for such a system was transferable from Europe to the United States. However, because answers to institutional issues of marketing, financing, ownership, regulation, taxes, and other concerns were not as readily transferable, these were the issues of this extensive investigation.

The objective of the institutional issue study was to identify and evaluate nontechnical, business-related issues affecting the creation, ownership, and operation of a new cogeneration hot water district heating system in the Twin Cities. Most of the principal participants were involved in the study. A number of issue papers were prepared that described and evaluated the consequence of each institutional issue. The technical model used as a basis was the one proposed in the overall feasibility study.[1] The MEA took the lead as the overall project coordinator.

A Steering and Advisory Committee made up of the other participants provided direction and review. In addition, public meetings identified a number of local concerns. The following recommendations were made as a result of the study.

1. Problems in the development of a Twin Cities metropolitan district heating system should be approached by first concentrating on projects of small scale.
2. A not-for-profit development corporation should be formed to complete the economic and technical feasibility studies necessary to select an owner/operator and a development strategy for a specific project.

It was recommended that a demonstration project be designed to heat a significant portion of the central business district of either Minneapolis or St. Paul and that use be made of the cogenerated thermal energy of existing plants. The perceived risk of such a project is less because the project does not depend on adding new generating units that require extensive capital outlay. St. Paul was recommended as the site for this project because the High Bridge Power Plant is near the central business district and the cities' existing steam system needs replacing.

As a result of this recommendation the St. Paul DHDC was incorporated on July 1, 1979, by the Mayor of St. Paul, the Director of the MEA, and the Executive Director of the St. Paul BOMA. The St. Paul DHDC Board of Directors represents business, government, energy users and suppliers. It was anticipated that this company or another owner/operator would complete the demonstration project. It was the intent of the Board of Directors that this company would not only provide service to the initial central business district but also have the intent of expansion of the district heating system to the remainder of the metropolitan area.

The St. Paul DHDC established an office in the St. Paul central business district on September 1, 1979. The demonstration project that the company has designed contains all of the elements of a full-scale system (i.e., hot water transmission and distribution, conversion of heating systems in existing buildings, and the potential for cogeneration).[10] Chapters 3, 4, and 5 of this study describe the demonstration project as proposed by the St. Paul DHDC. The St. Paul project has led to the detailed design and financing of the first modern hot water district heating system in a large U.S. city.

2. DESCRIPTION OF HOT WATER DISTRICT HEATING SCHEME FOR THE TWIN CITIES

The overall feasibility study[1] was done by Studsvik Energiteknik in coordination with the local participants in the Twin Cities. The objective of the analysis was to determine conceptual engineering and economic feasibility for the entire metropolitan region. The analysis concentrated on assessing the heating loads that could be connected over a 20-year period, outlining an implementation schedule to connect the loads and bring on cogeneration plants, and presenting a preliminary examination of the overall economics. The results presented in this chapter are excerpts from the overall feasibility study.

2.1 Potential District Heating Zones

The Twin Cities area contains two urban cores, Minneapolis and St. Paul which are about seven miles apart (Fig. 2.1). The commercial center cities are surrounded by regions of industrial sites and residential housing that link the two areas into one continuous metropolitan region. About 800,000 people live within the two city boundaries, but, when adding in nearby suburbs, the population exceeds 1 million people. The dense population, coupled with the cold climate, gives rise to a large space heating demand.

The vast majority of the heat demand is presently satisfied by natural gas. However, for industrial and large commercial customers, natural gas supplies are interrupted, and the customers are required to use oil during the winter months. Three small, steam-based district heating systems exist in the area: an old steam system in downtown St. Paul, a fairly new one in

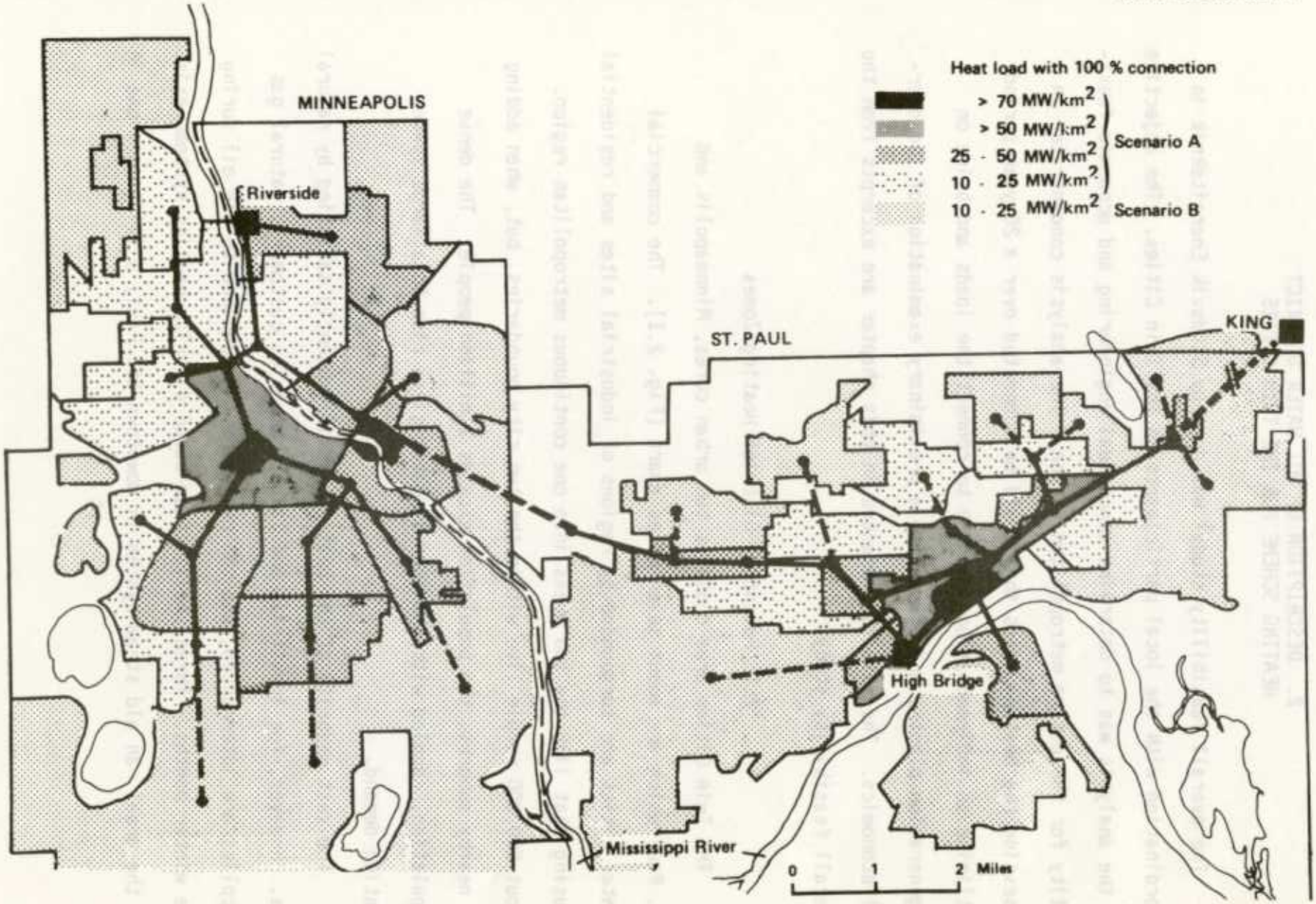

Fig. 2.1. Heat load densities in the Twin Cities area and possible regional piping systems.

downtown Minneapolis, and another one at the University of Minnesota. The latter two also include some district cooling.

Within the cities' boundaries there are two medium-sized, coal-fueled, electric generating stations -- High Bridge for St. Paul and Riverside for Minneapolis (Fig. 1.1). A third station, Blackdog, is located south of Minneapolis, and several newer coal-fired and nuclear plants are at various distances outside the metropolitan area. The closest of these is King, which is 17 miles from downtown St. Paul.

The Twin Cities area is a prime candidate for a regional district heating system because of the following attributes:

1. a cold climate and a city structure with a large potential heat load well adapted to district heating,
2. the present use of fuels that will become increasingly expensive and scarce (natural gas and oil),
3. the existence of coal-fired generation stations near the city with units suitable for conversion to cogeneration,
4. some existing tradition of district heating, and
5. interest and cooperative local authorities and utilities with a desire to improve efficiency of fuel usage.

2.2 Potential for District Heating and Development Strategy

Two levels for district heating were analyzed: Scenario A, which restricts district heating to the downtown and nearby residential districts, and Scenario B, which covers also medium density residential districts with one- and two-family housing outside the central parts of the city (Fig. 2.1). For these scenarios, the estimated thermal load over a

total 20-year development period is approximately 2600 MW(t) for Scenario A and 4000 MW(t) for Scenario B (Fig. 2.2).

The 2600 MW(t) for Scenario A excludes the loads of the existing district heating systems in downtown Minneapolis and at the University of Minnesota. Scenario A also excludes the loads of some large industries and all the loads for future establishment within the area. To compensate for the conservatism of these assumptions, it was assumed for the base case that all remaining customers within the area would subscribe to the service. The influence of a lower effective subscription rate was evaluated separately with a sensitivity analysis. For Scenario B, 70% of the potential additional customers over and above those in Scenario A were assumed to use the service.

The study was done with an assumed starting date for the development of 1980. This date was known to be totally impractical since the study was completed in 1979, and it was known that solving the institutional questions would require at least several more years. The basic technology assumed is that used in modern Swedish systems, which is now supplying Sweden with an increasingly large part of its national demand for space heating and domestic hot water by hot water distribution systems. About 75 district heating systems exist in Sweden, and three million of its eight million people are now served by district heating systems.

2.3 Principal Features of the Proposed Concept

The proposed district heating concept functions as follows.

1. The base load is supplied by cogeneration plants that provide about half the total peak load capacity but nearly 90% of the annual thermal energy (Fig. 2.3). Most of the thermal energy is provided from the

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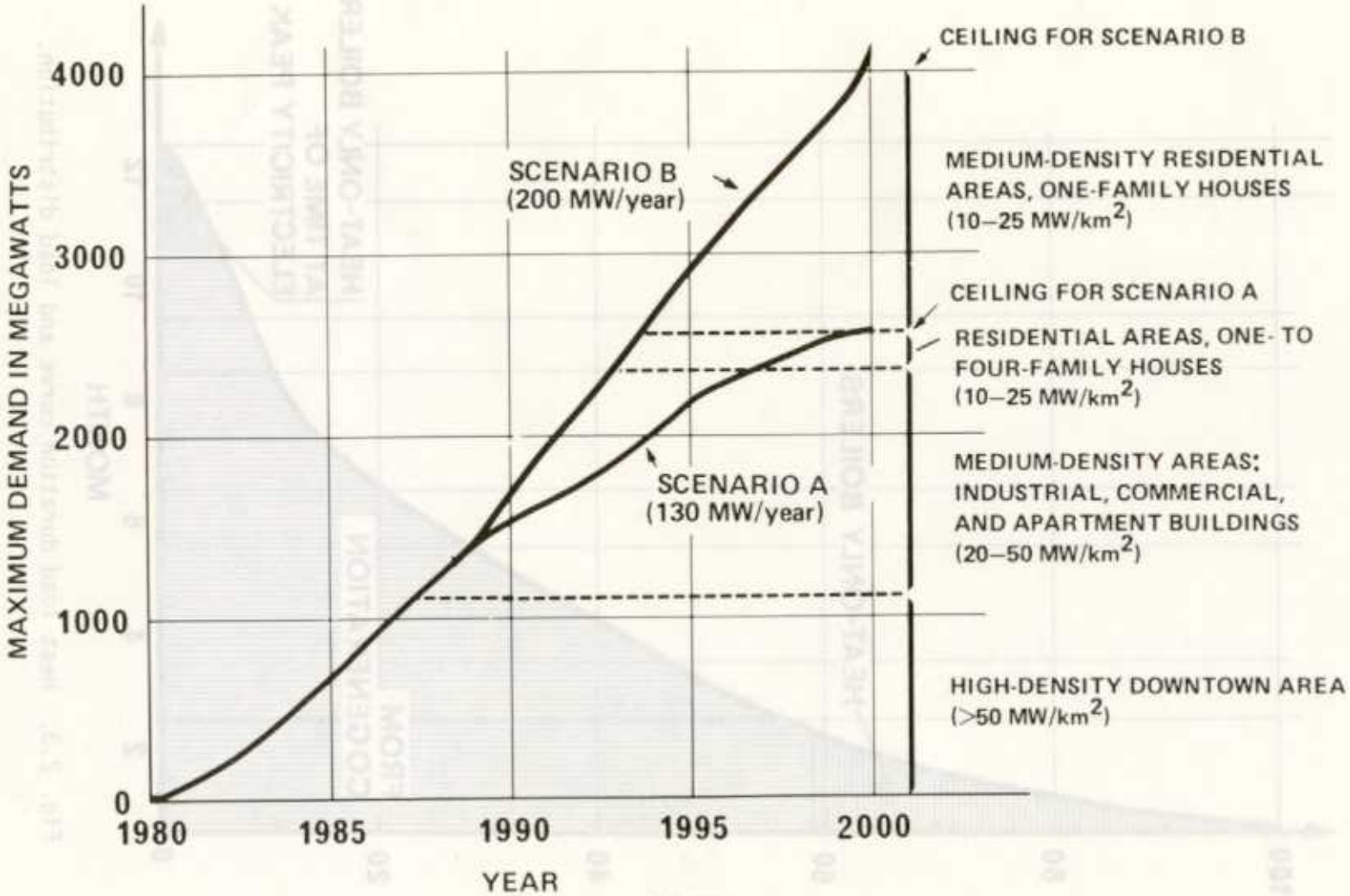

Fig. 2.2. Assumed thermal load connection rates for Scenarios A and B.

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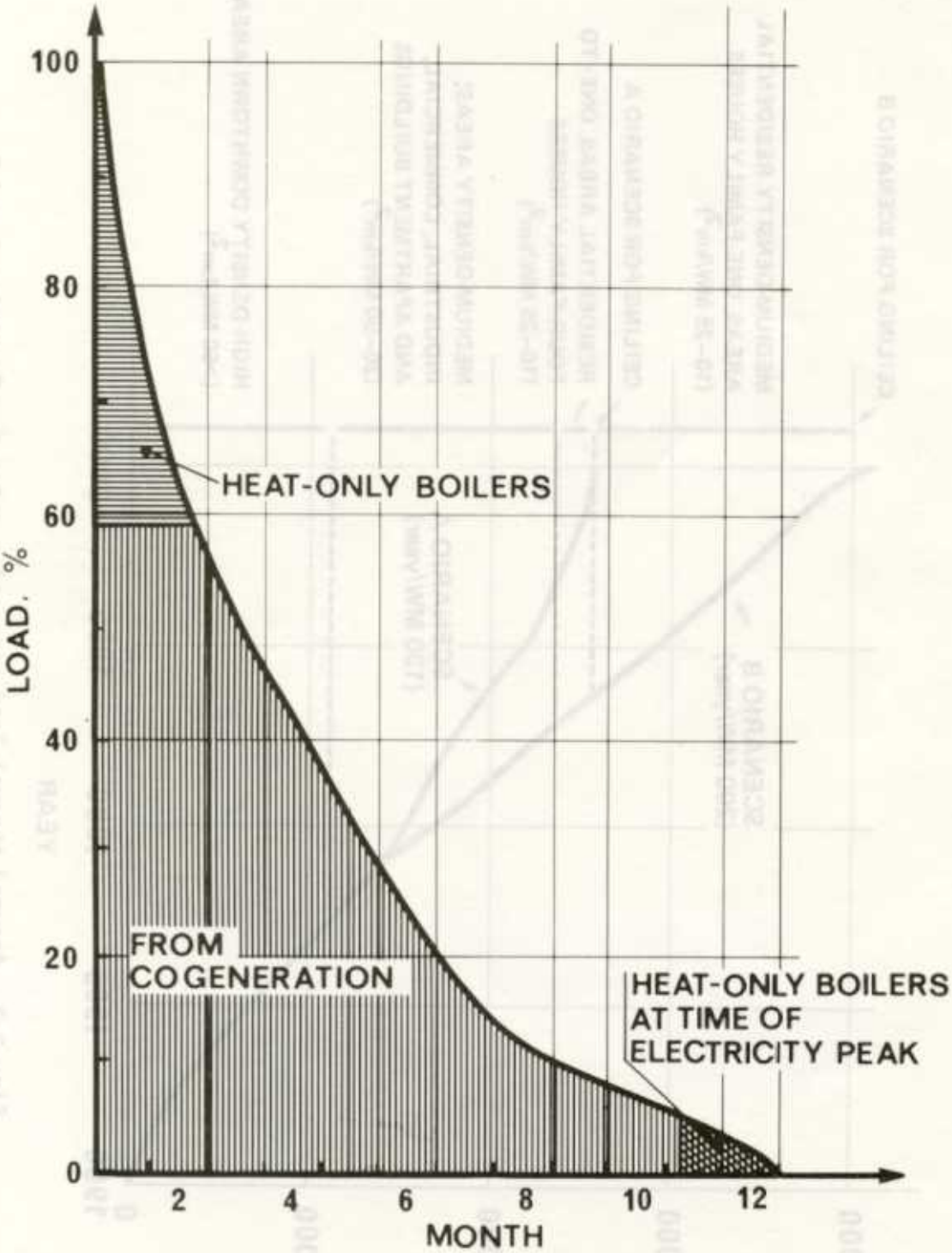

Fig. 2.3. Heat load duration curve and load distribution.

cogeneration units which are retrofitted turbogenerators at two existing stations--Riverside in Minneapolis and High Bridge in St. Paul. The fuel utilization efficiency of these units is greatly improved by operating in a cogeneration mode (Fig. 2.4). More specifically, a substantial improvement can be achieved in heat rates of the retrofitted turbine as shown for the High Bridge unit in Table 2.1.

Toward the end of the 20-year development period, these units would be complemented by new units. A new unit at Riverside is assumed for Scenario A. For Scenario B, two large units are proposed because it is impractical to use the city power plants exclusively. The two units are assumed to be located 17 miles east of the Twin Cities. The concept of cogeneration is to replace the large quantities of energy of oil and gas that are used for space heating with smaller quantities of coal.

2. The peak load and reserve capacity requirements are supplied by oil-fired, heat-only boilers. They have a large total capacity but only supply a small percentage of the annual heat energy. The boilers are located at various points of the heat load demand area, thus reducing the size of pipes necessary between the central cogeneration plants and the demand areas.
3. The heat is transported from the production plants to the various parts of the demand area by hot water mains in accordance with modern European district heating technology. Some of the large pipes are placed in tunnels in areas having adequate rock structures. Elsewhere, pipes are buried underground with 2 to 3 ft of cover.

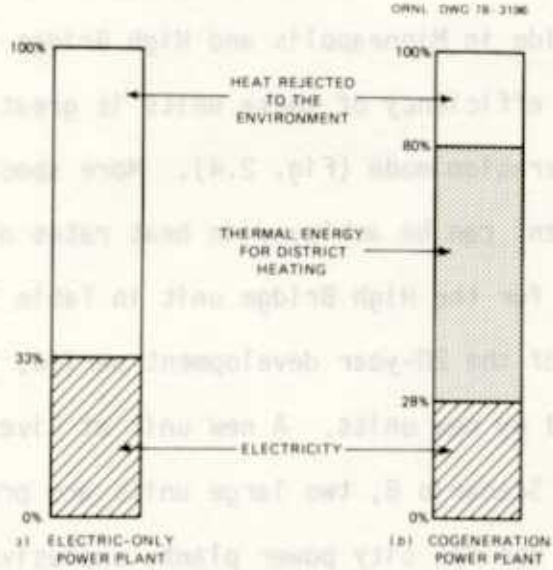

Fig. 2.4. Comparison of fuel utilization of electric-only and cogeneration power plants.

Table 2.1. Cogeneration performance of the High Bridge Power Plant

Unit	Original electrical generating capacity (MW)	Original electrical turbine heat rate Btu/kWh	Maximum heat energy (X 10^5 MJ/h)	Maximum simultaneous electrical generation (MW)	Lost electrical generating capacity (MW)	Turbine heat rate at maximum extraction (Btu/kWh)
3	62.	9340	4.095	48	13	3649
5	102.	8161	4.72	65	0	5616
6	156	7931	6.35	109	0	5635

4. Heat is distributed from the regional transmission system to individual buildings and houses by a pipe distribution system that runs under sidewalks, under streets, or through cellars. Prefabricated pipe, complete with insulation and protection ducts, are used. For Scenario B, in addition to the conventional piping system, a newer type of piping distribution system was examined for low heat load density residential areas.
5. The heating systems of existing buildings are adapted so that they can be connected to the district heating system through heat exchangers. Different conversion methods are necessary because of the different types of heating systems within the buildings.
6. The cooling loads are ignored in the analysis.
7. The system has built up progressively, starting with the densest heat load areas so as to start generating maximum revenue as soon as possible. The heat loads of the two existing district heating systems in central Minneapolis, as well as the heat loads for some large industries, have been ignored because more detailed studies are required before these loads could be integrated into an overall scheme.

2.4 Cost and Economics

The total incremental investment for the system and the building retrofit is estimated at $625 million in 1978 dollars for Scenario A. The total investment in 1978 dollars for Scenario B is $1235 million with conventional distribution technology and $1136 million with newer technology (Table 2.2). It is assumed in the study that the utility would finance the retrofit investment; however, in practice, the conversion cost would be borne by the consumer. As a result of this assumption, the rate charged

Table 2.2. Total investments in 1978 dollars for Scenarios A and B

	Investment ($ x 10^6)		Investment per simultaneous maximum demand[a] [$/kW(t)]	
Scenario A				
Cogeneration plants	55		21	
Peak load boilers	66		25	
Total production	121		46	
Hot water transport	104		40	
Hot water distribution	274		105	
Total transport and distribution	378		145	
Total production, transport, and distribution	499		191	
Building conversion	126		48	
Grand total	625		239	
Scenario B				
Cogeneration plants	98		24	
Peak load boilers	114		28	
Total production	212		52	
Hot water transport	221		54	
Hot water distribution	601	502[b]	149	124[b]
Total transport and distribution	822	723	203	178
Total production, transport, and distribution	1034	935	255	230
Building conversion	201	201	50	50
Grand total	1235	1136	305	280

[a]2621 MW(t), Scenario A; 4042 MW(t), Scenario B.
[b]New technology.

for heat is comparable to the value of fuel that is being replaced. To provide an incentive, the heat rate was set 10% below the cost of the cheapest alternative fuel. The method used to determine the district heating rate does not include any capital, operating, or maintenance costs of individual boilers. Thus, the incentive to connect to the district heating system is significantly greater than the 10% savings as estimated. If the cost of the consumer system connections and conversions is borne by the consumer, the utility can offer a lower rate for the heat. This rate gives the consumer additional savings that can be used to pay the capital charges on the investments.

The cheapest fuel, gas or oil, was used to determine the charge for the district heating energy. Initially, the cheapest fuel is gas, but from the mid-1980s on, the estimates were that oil would be cheaper than gas.

The utility's predictions on future inflation rates were used as were the fuel cost projections. These represent inflation rates of 5–6%/year at the beginning of the 20-year period and decrease to 4%/year by 2000 (Fig. 2.5). The inflation factor is applied in calculating investment and fuel costs in 1978 dollars.

Coal costs were assumed to increase throughout the period by 1.3%/year in terms of 1978 dollars. Oil costs were assumed to reach a world market price of $16/bbl by 1981* and to increase thereafter by about 2%/year in terms of 1978 dollars (slightly more rapidly than the rate of

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*Significant increases in world market prices have occurred since the completion of the study.

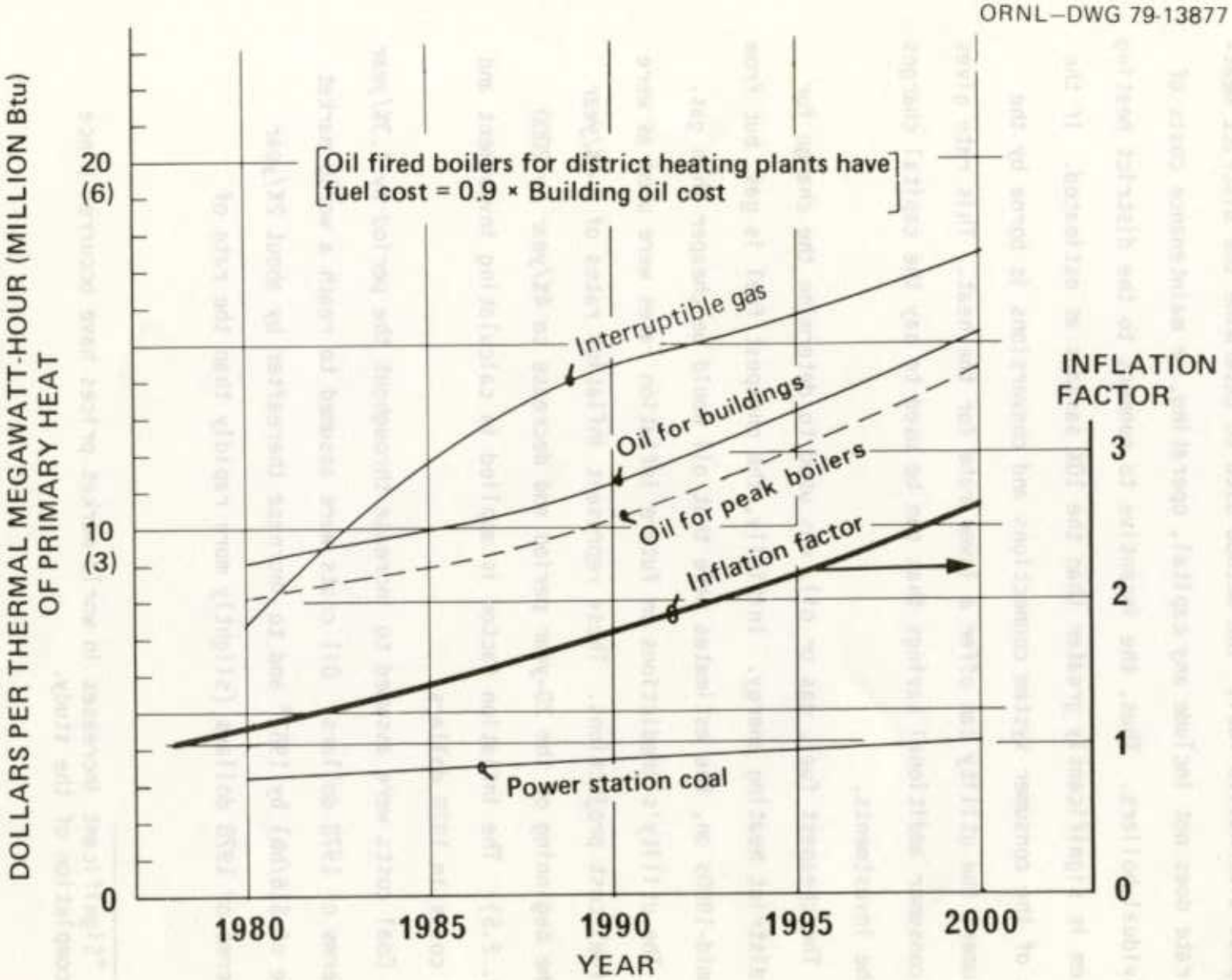


Fig. 2.5. Assumed costs of primary fuels over the period 1980-2000 in 1978 dollars (higher calorific value of fuel).

inflation). The average individual boiler efficiency is 70%, and the efficiency for the larger heat-only district heating boilers is 90%. The additional residential load for Scenario B is assumed to have a mean individual boiler efficiency of 58%.

Gas prices are assumed to increase by a factor of 2.4 over the 20-year period. By the mid-1980s, the gas prices to the consumers begin to exceed those for light oil and medium-grade oil. The utility estimators acknowledge that their oil price projections are on the low side for the long-term view. To compensate for this, an alternative case was covered for which gas and oil prices increase by an additional 1%/year.

The difference between a utility's income from sales of heat and the utility's annual operating cost and capital charges (including taxes) has been termed the "net savings". The economic calculation for Scenario A, with municipal financing, shows that that net savings are negative in the initial period but that they soon become positive (Fig. 2.6). Over the entire period there is an accumulated present-worth net savings equivalent to $183 million (Fig. 2.7). With private utility financing, capital charges are higher, and the accumulated present-worth net savings at the end of the 20-year period is a negative $77 million. However, the accumulative present worth has an upward slope at the end of 20 years and will be zero at the end of 33 years. The distribution piping system has a life of 30-35 years; therefore, this life is equivalent to the life-cycle economics of other utility-type investments. The sensitivity of the results to changes and assumptions is also illustrated. With an intermediate financing system, private utility financing for the production plant and municipal financing for the piping system, the net accumulative savings

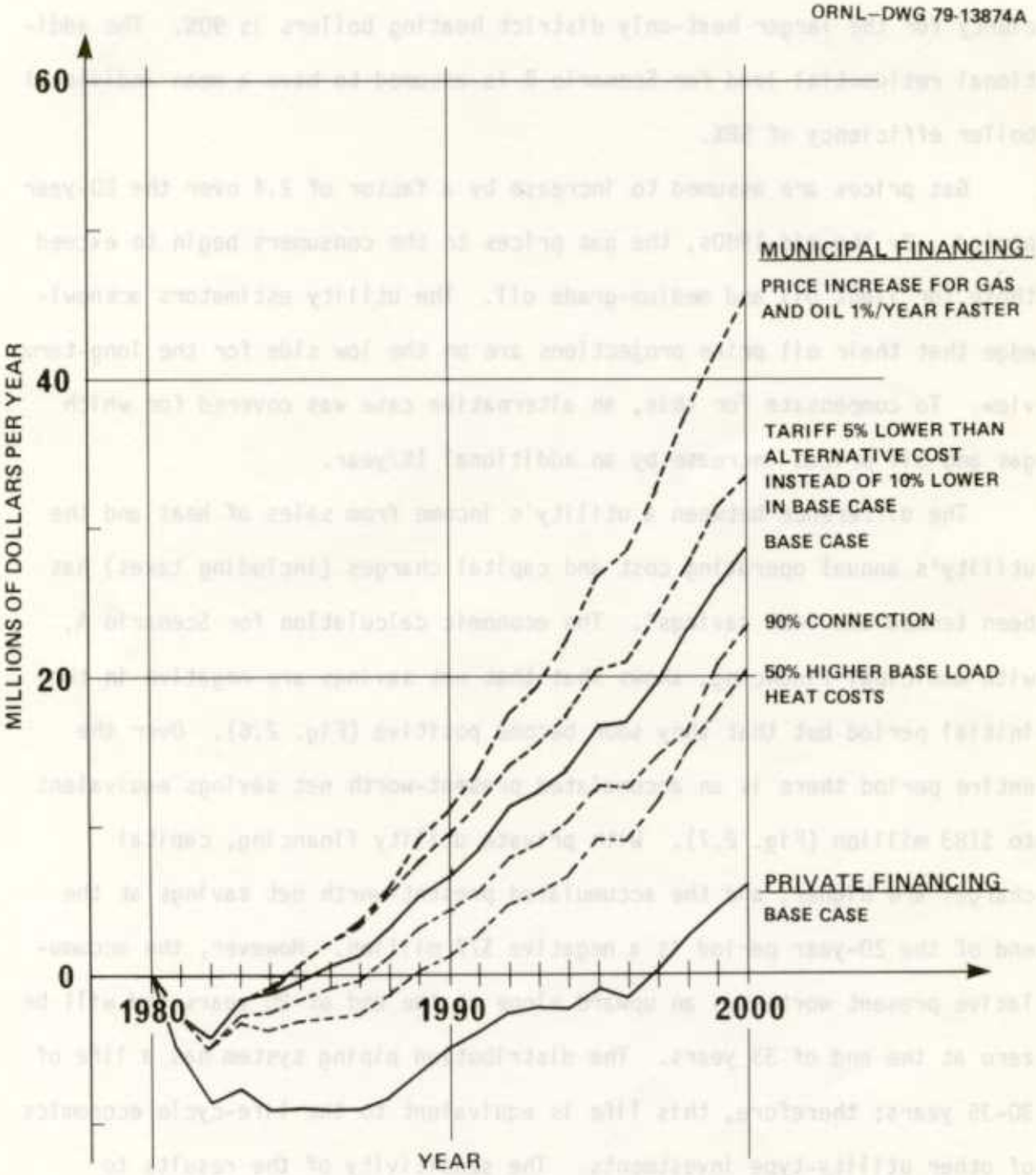


Fig. 2.6. Annual net savings in 1978 dollars, Scenario A.

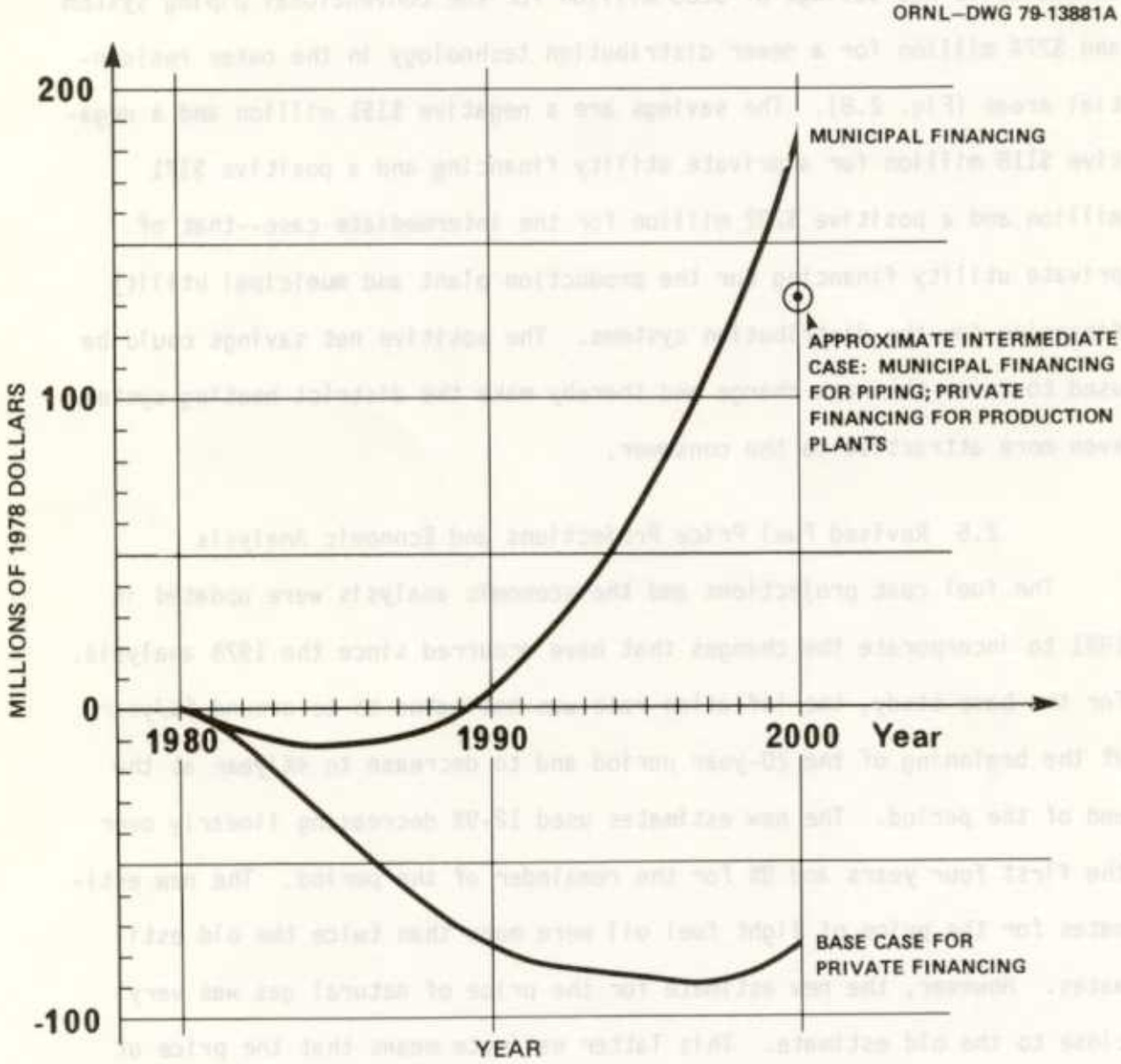


Fig. 2.7. Accumulated present worth of net savings of base case, Scenario A.

would be about $132 million. For Scenario B, muncipal financing gives an accumulative net savings of $238 million for the conventional piping system and $274 million for a newer distribution technology in the outer residential areas (Fig. 2.8). The savings are a negative $151 million and a negative $118 million for a private utility financing and a positive $171 million and a positive $202 million for the intermediate case--that of private utility financing for the production plant and municipal utility financing for the distribution systems. The positive net savings could be used to lower the rate charge and thereby make the district heating system even more attractive to the consumer.

2.5 Revised Fuel Price Projections and Economic Analysis

The fuel cost projections and the economic analysis were updated in 1981 to incorporate the changes that have occurred since the 1978 analysis. For the base study, the inflation rate was estimated to be around 5%/year at the beginning of the 20-year period and to decrease to 4%/year at the end of the period. The new estimates used 12-9% decreasing linearly over the first four years and 8% for the remainder of the period. The new estimates for the price of light fuel oil were more than twice the old estimates. However, the new estimate for the price of natural gas was very close to the old estimate. This latter estimate means that the price of natural gas is lower than the price of light oil over the entire period; this is contrary to the situation in the base study when, except for the very first years, light oil was the cheapest alternative consumer fuel. The district heating heat price is tied to the lowest alternative, and when calculated under these new conditions, they are roughly the same as the old rates. The new estimates for the price of heavy oil are significantly

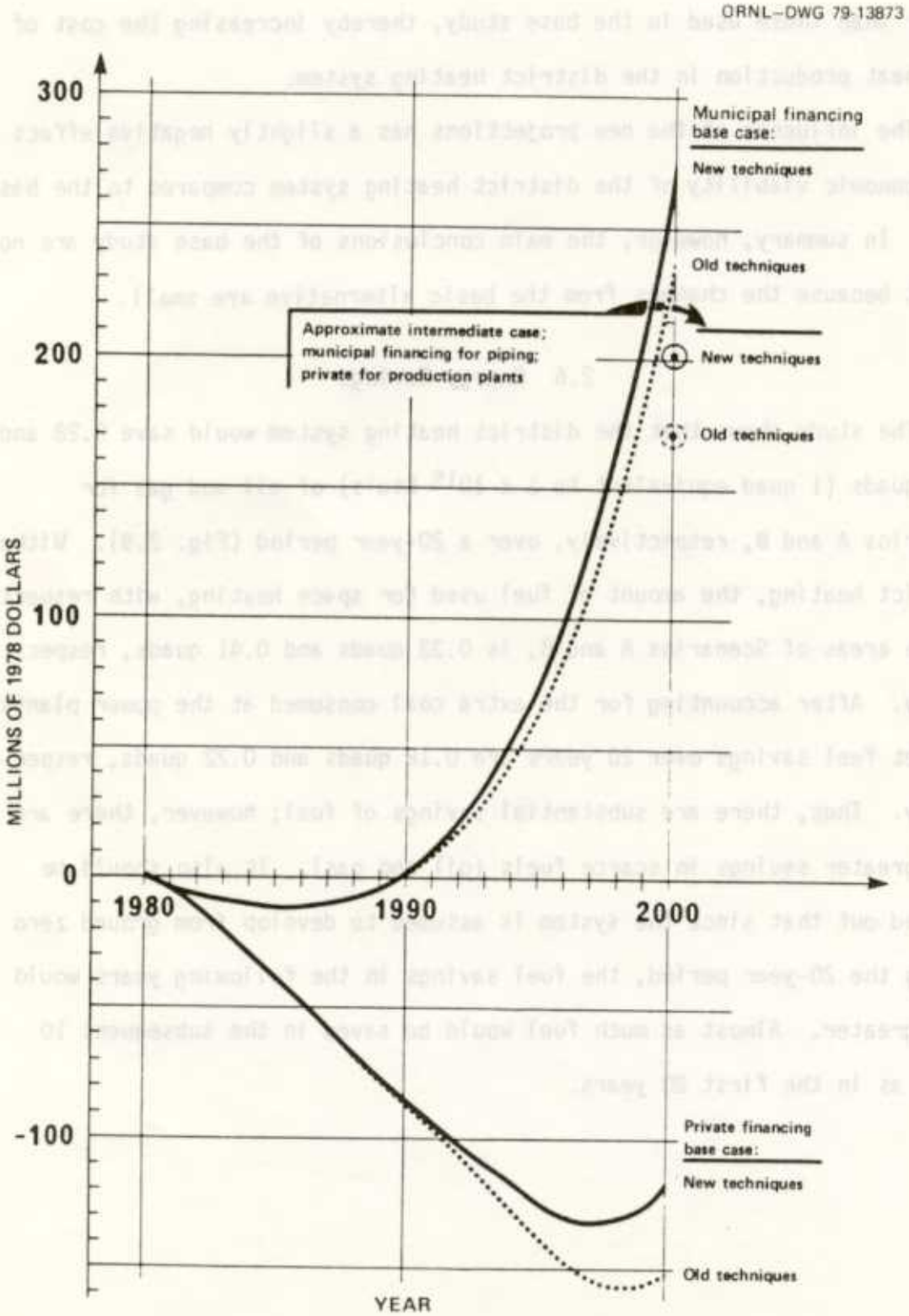


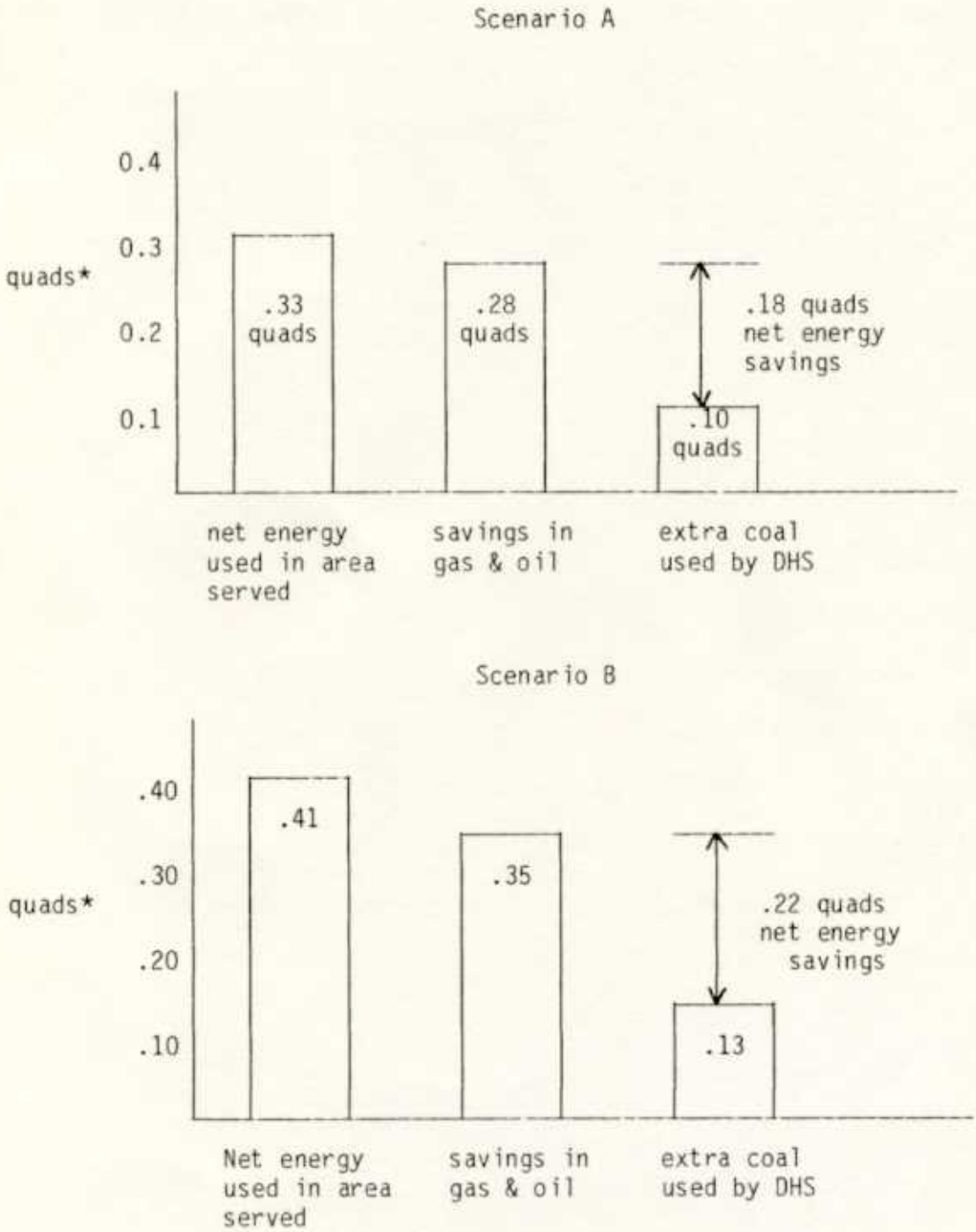
Fig. 2.8. Accumulated present worth of net savings for Scenario B.

higher than those used in the base study, thereby increasing the cost of peak heat production in the district heating system.

The influence of the new projections has a slightly negative effect on the economic viability of the district heating system compared to the base case. In summary, however, the main conclusions of the base study are not offset because the changes from the basic alternative are small.

2.6 Energy Savings

The study shows that the district heating system would save 0.28 and 0.35 quads (1 quad equivalent to 1×10^{15} Btu's) of oil and gas for Scenarios A and B, respectively, over a 20-year period (Fig. 2.9). Without district heating, the amount of fuel used for space heating, with respect to the areas of Scenarios A and B, is 0.33 quads and 0.41 quads, respectively. After accounting for the extra coal consumed at the power plants, the net fuel savings over 20 years are 0.18 quads and 0.22 quads, respectively. Thus, there are substantial savings of fuel; however, there are even greater savings in scarce fuels (oil and gas). It also should be pointed out that since the system is assumed to develop from ground zero during the 20-year period, the fuel savings in the following years would be even greater. Almost as much fuel would be saved in the subsequent 10 years as in the first 20 years.



*1 quad equivalent to 1 x 10^{15} Btus.

Fig. 2.9. Fuel savings realized with district heating 1980–2000.

3. DESCRIPTION OF THE ST. PAUL HOT WATER DISTRICT HEATING PROJECT

In July 1979, the District Heating Development Company, Inc. (DHDC) was formed to develop a hot water district heating system that is economically feasible for the City of St. Paul, Minnesota. For the first phase of the project, the goals were (1) to assess the detailed economic feasibility of a hot water district heating system serving the commercial core area of St. Paul and (2) to develop an implementation plan for financing and construction of the first segment of the system to be built over a 4-5 year time span. Excerpts from the study (reported in detail in ref. 10) are presented in this chapter. This study established a business plan which is anticipated to result in a viable hot water district heating project.

Through the studies performed in the project's first phase, the DHDC has developed a general description of each of the system's three main components: the heat loads and market definition, heat sources, and the piping distribution system. Details on the building conversion studies will be given in Chapter 4.

3.1 St. Paul Building Heat Loads

The first task undertaken by the DHDC in late 1979 was to define the St. Paul building heat loads. The objective was to gather through telephone and in-person surveys technical information and data on the heating systems and energy consumption of over 300 buildings in the hot water district heating market area (Fig. 3.1).

The heat load and the market definition results are summarized in Tables 3.1 and 3.2. One of the most important parts of the definition is shown in Table 3.1, which details the market by energy source and building

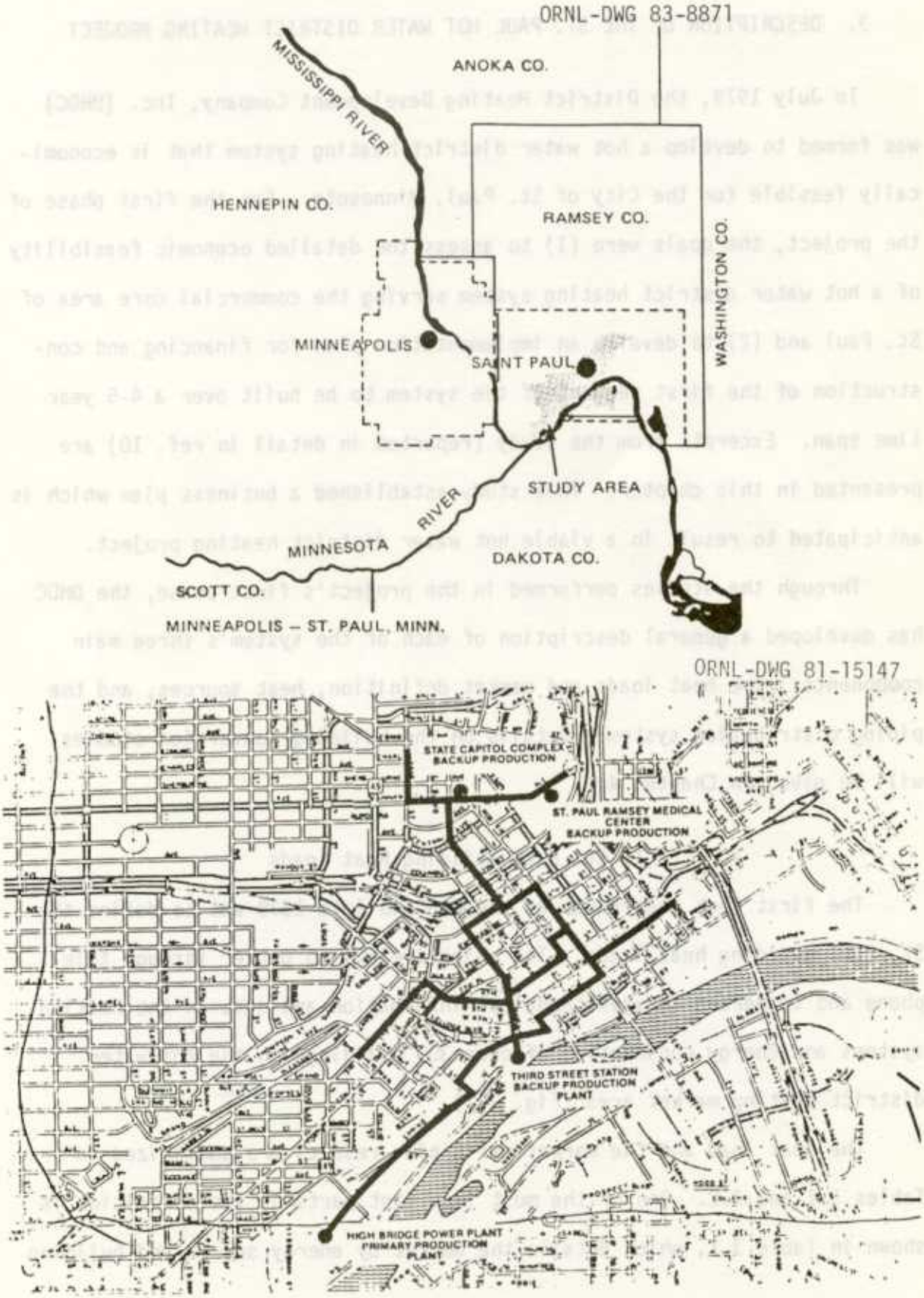


Fig. 3.1. St. Paul hot water district heating market area and study area.

Table 3.1. Market survey results for existing energy sources and building heating systems (1980) in the St. Paul central business district

Energy source	Percent of load	Heating system medium	Percent of load
Interruptible gas	49	Steam	43
Firm gas	12	Steam + hot water	43
District steam	31	Hot water	12
Oil	1	Air	2
Electricity	1		
Unknown	6		

Table 3.2. Summary of building types in St. Paul central business district

Markets	Peak demand [MW(t)]	No. of buildings
Identified markets		
Government buildings and hospitals	90	30
Large buildings [>500 kW(t)]	91	55
Small buildings [<500 kW(t)]	4	21
Planned development (1980–85)	40	14
Subtotal	225	120
Unspecific market		
Small buildings [<500 kW(t)]	20	140
Large buildings	40	
Total	285	

heating system. The heat load market within the project area is diverse and represents a typical downtown region. The downtown area does not represent a definite pattern of fuel-type use. Interruptible gas customers comprise 49% of the heat load market area. Steam district heating customers are the next largest at 31%. Firm gas customers comprise the third largest portion of the downtown heat load at 12%. Electricity and firm oil customers make up a very low percentage of the total heat load.

Although only 32% of the total buildings surveyed are considered large buildings [>0.5 MW(t)], these buildings comprise over 85% of the current heat load in the market area. Buildings with peak heat load demands below [0.5 MW(t)] are considered more difficult to connect to the system because of the higher conversion cost per peak demand. Within the core downtown market area are four hospitals and a large manufacturing company. Each of the hospitals represents a load of approximately 10 MW(t). Also, on the outskirt of the project are two other major heat loads, the Minnesota State Capitol Complex at 15 MW(t) and a major housing complex at 6 MW(t).

Heating load growth, through new development and construction in the downtown area, is expected to be 5-6 MW(t) annually. This accounts for a total of 30-40 MW(t) of growth over the next 7 years in downtown St. Paul. Including this growth, the estimated total heat load for the service area is 285 MW(t) in the central business district. The target market for hot water district heating is summarized in Table 3.2.

3.2 Heat Production Plants

Various existing types of heat sources are located within or near the project area. These include two coal-fueled plants, the NSP's High Bridge

Power Plant and the Third Street District Heating Plant, which is now owned by the St. Paul Steam Company, a subsidiary of the DHDC. In addition, there are several large boiler installations at the State Capitol and the hospitals (Fig. 3.1). The 140-MW(t) Third Street plant would be utilized during the early stages of the system growth and would also be used to supply steam to the existing steam district heating system until the latter system is phased out of service about 1985. Existing High Bridge turbine units and heat-only boilers can be retrofitted for use in the hot water district heating system. Depending on the heating load growth, the turbine units at High Bridge could be converted to cogeneration possibly in the mid-1980s to utilize heat rejected from the cogeneration of electric power. A detailed study by United Engineers & Constructors of the High Bridge turbine units concluded that three units could be converted to cogeneration operation, two units to extraction, and one unit to back pressure, as shown in Table 3.3, and provide up to 444 MW(t)* of thermal energy.[3] The heat-only boilers of the Third Street plant would then be used to supply energy for peak periods and also provide emergency back up capacity. The oil- and gas-fueled boilers at the State Capitol Complex and the St. Paul Ramsey Hospital can be connected to the system to provide additional thermal capacity and reliability.

3.3 Piping Distribution System

During 1980, a conceptual design study was conducted by a team of U.S. and European design consultants. Medium temperature (<250°F) hot water district heating has been used extensively in northern European cities for

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*All three units would not be converted to provide thermal energy for the heat load during the first five years.

Table 3.3. Cogeneration performance of the High Bridge Power Plant

Unit	Original electrical generating capacity [kW(e)]	Maximum heat energy [MW(t)]	Maximum simultaneous electrical generation [kW(e)]	Lost electrical generating capacity [kW(e)]
3	62,265	120	48,909	13.356
5	90,900	138	65,873	0
6	156,232	186	109,314	0

nearly 30 years. Because of this extensive experience, the Europeans have refined the hot water technology for increased reliability and cost effectiveness compared with high temperature water or steam piping systems. The St. Paul project has therefore been structured to utilize the knowledge from the European experience.

The conceptual design study[11] had as its major objectives:

1. to develop a conceptual system design that minimizes construction costs while ensuring a high degree of system reliability and flexibility,
2. to develop a system implementation schedule that will provide sufficient revenue return on invested capital during the system's development,
3. to prepare cost estimates and an expenditure schedule suitable for inclusion in an underwriter's bond prospectus, and
4. to develop a conceptual design of the distribution system in sufficient detail to serve as a basis for the preparation of detailed engineering design and construction bid specifications at a later date.

The district heating water will be pumped through large-diameter transmission pipelines from the High Bridge Power Plant to the Third Street Plant and from there through the downtown area to the State Capitol Complex. A conceptual piping route for a 270-MW(t) system is shown in

Fig. 3.2. Smaller-diameter-supply and return-distribution pipelines will be routed from the transmission lines through the streets to the buildings.

The pressure in the pipes will be a maximum of 250 psig. The temperature of the water will vary as a function of the outside temperature (Fig. 3.3). During the summer, when there are small heating loads, the temperature would be about 180°F. The district heating load generally increases as the outside temperature decreases, and the system temperature reaches a maximum of 250°F. The 250°F temperature selection for the system has been optimized for use of waste heat through cogeneration. Since the piping technology for these specificiatons have been proven, the piping is generally available in various designs and configurations. The St. Paul system will most likely use a direct, prefabricated system with a steel pipe insulated with polyurethane and encased in a polyethylene jacket.

The piping system will be constructed in sections. As each section is completed, it will become operational and produce revenue for the system. The distribution piping will be constructed and connected initially to the largest heat load areas, the State Capitol Complex and the four major hospitals. As many connections as possible will be made to other buildings along these routes. The system is anticipated to grow beyond this initial phase over several multiyear construction periods. During the latter growth stages, piping loops will be constructed to increase the system reliability.

3.4 Piping System Cost

The conceptual design outlines a hot water piping system to serve all the existing and future heat demands in the initial area. The piping

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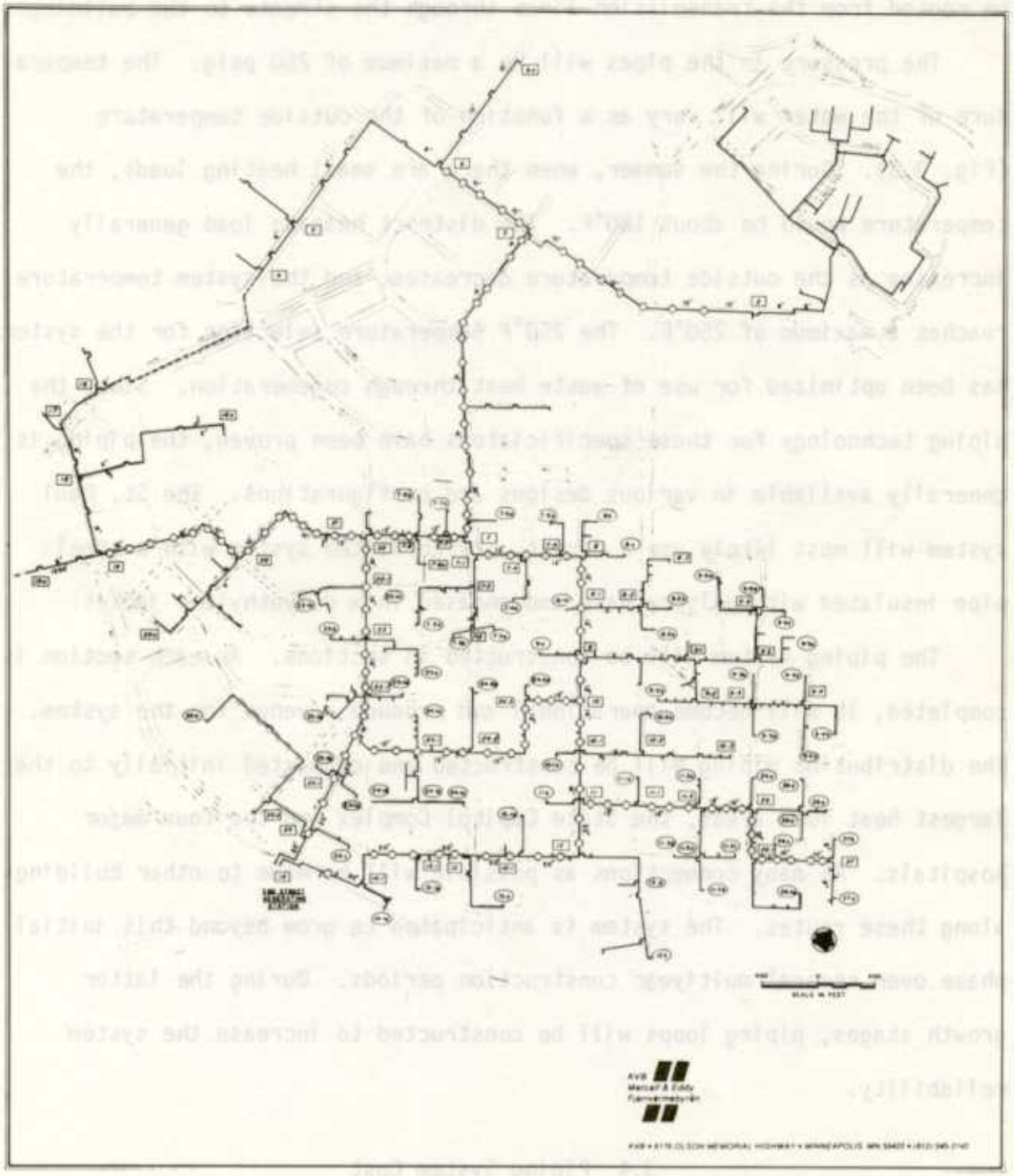

Fig. 3.2. St. Paul conceptual piping route for 270 MW(t) system.

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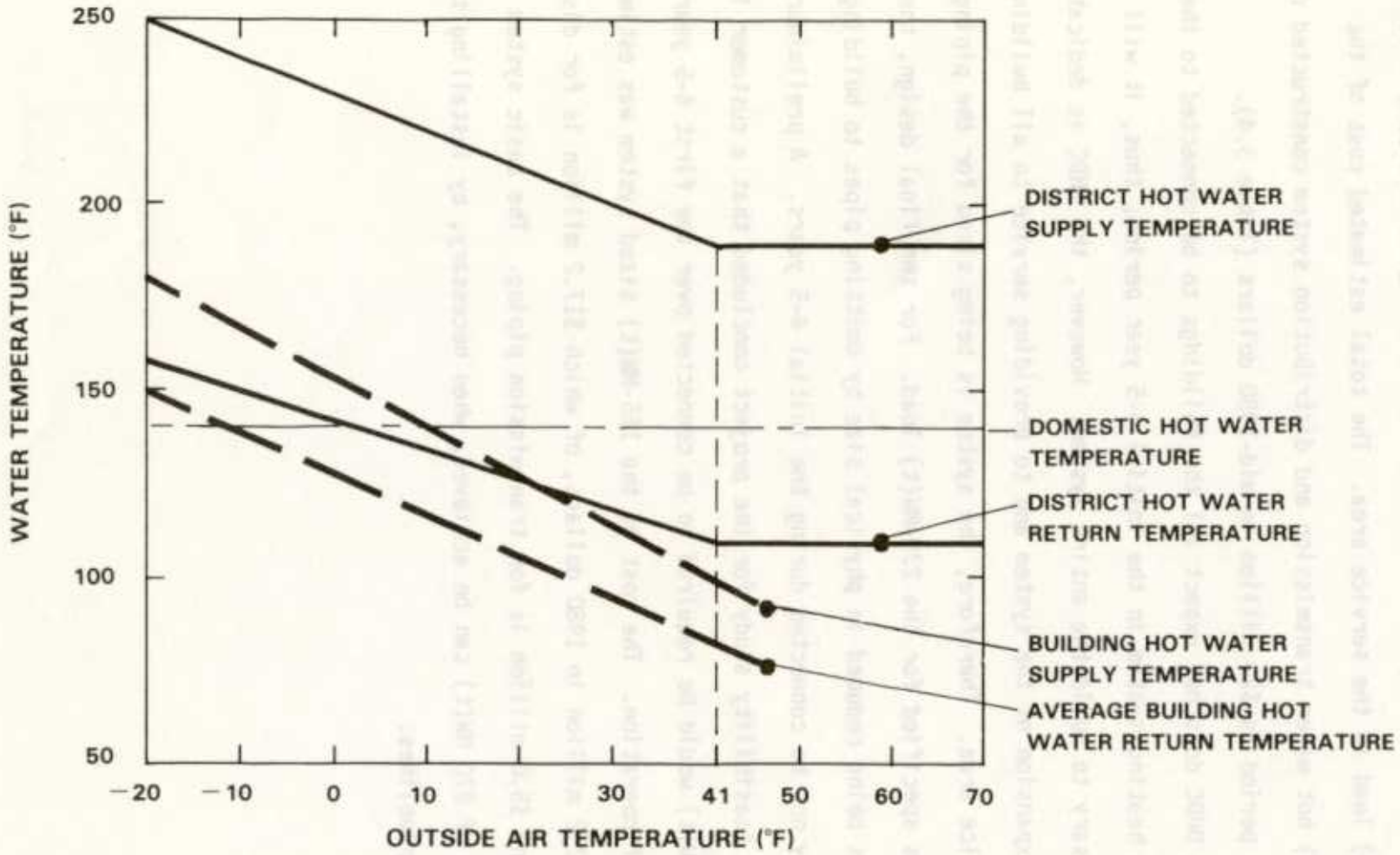

Fig. 3.3. Hot water temperatures for district heating system and hydronic building heating system as a function of outside air temperature.

diameters and flow capacities were therefore designed to supply a full 270-MW(t) load in the service area. The total estimated cost of the 270-MW(t) hot water transmission and distribution system constructed over a 4-5 year period is $29 million in mid-1980 dollars (Table 3.4).

The DHDC does not expect all the buildings to be connected to the district heating system in the initial 4-5 year period; thus, it will not be necessary to build the entire system. However, the DHDC is dedicated to future expansion of the system and to providing service to all buildings in the service area. Therefore, the system is being sized for the piping diameters specified for the 270-MW(t) load. For the final design, the system is being reduced in physical size by omitting pipes to buildings which may not be connected during the initial 4-5 years. A preliminary economic feasibility study for the project concluded that a customer load of 165 MW(t) would be required to be connected over the first 4-5 year period of operation. The cost of the 165-MW(t) sized system was estimated to be $22.2 million in 1980 dollars, of which $17.2 million is for distribution and $5.0 million is for transmission piping. The basic system capacity of 270 MW(t) can be achieved, when necessary, by installing the omitted pipelines.

Table 3.4. St. Paul district heating project cost

Year	Amount of pipe[a] (ft)	Estimated cost[a]
1	17,080	$ 3,450,000
2	22,820	4,500,000
3	32,510[b]	7,450,000[b]
4	58,760	5,500,000
Beyond 4	21,350	2,100,000
Totals	152,520	23,000,000
Engineering and contingencies		6,000,000
Total project cost		$29,000,000

[a]The total estimated project cost of the 270-MW(t) hot water transmission and distribution network, over a five-year construction period, in mid-1980 prices (ENR index = 3200).

[b]Transmission main between the Third Street and High Bridge generating plants include 10,000 ft of pipe at a cost of $4,000,000.

4. CONVERSION OF BUILDING HEATING SYSTEMS

As a part of the St. Paul district heating project, several studies were performed on the feasibility and the cost of converting building heating systems to be compatible with a 250°F (121°C) hot water district heating system. One of the main concerns in supplying building heating systems from a medium-temperature hot water district heating system is the diversity of building heating systems found in the St. Paul central business district. This diversity results basically from the wide range in sizes and ages of the buildings — from essentially new buildings to buildings as old as 90 years. During this 90-year period, a tremendous evolution from (1) one-pipe steam perimeter radiation to (2) modern heating, ventilating, and air conditioning (HVAC) systems utilizing air and/or water distribution media has occurred in the design of building heating systems. Therefore, building conversion cost becomes one of the key economic and marketing issues for implementing a medium-temperature hot water district heating system in St. Paul, Minnesota.

The building conversion study conducted by the DHDC supplements and expands on an earlier one conducted by the MEA for the Twin Cities feasibility study. In that study, the maximum hot water supply temperature was assumed to be 300°F so that buildings with low-pressure, steam heating systems would not be required to replace any in-building piping. The conversion cost results for buildings with steam heating systems from the MEA study are therefore significantly less than that calculated for the St. Paul DHDC project because these later estimates included costs for extensive system modernization and upgrading.

The modernization and upgrading of the building system are especially important in the St. Paul business district because a significant fraction (30%) of the buildings are more than 50 years old. The overriding philosophy of the conversion design was to optimize the life-cycle cost rather than to minimize the first cost of connection to the hot water system. The minimum first cost strategy would require a year-round hot water supply temperature in the range of 300–350°F. Such a high temperature hot water system could be used to heat buildings with existing steam distribution systems. This strategy leads to the lowest initial cost for adapting a building system but leaves the older steam distribution buildings with a system that is less efficient and more difficult to control, and with higher maintenance costs than for the medium temperature hot water district heating system

Therefore, the strategy followed in the DHDC project was based on the following principles: (1) the hot water supply temperature would be limited to 250°F to reduce the construction and operating cost of the district heating system; (2) building steam distribution systems would be converted to hot water (hydronic) systems in an economical fashion; (3) degraded or outmoded equipment would be replaced, and an overall system modernization would be included with the connection to the hot water district heating supply.

The DHDC building conversion cost study and economic analysis are presented in detail in ref. 12; also, studies of energy savings from converting steam distribution building systems to hydronic (hot water) systems are summarized in ref. 11. A summary of the building conversion cost study is presented in this section because of its importance to the implementation of the overall St. Paul project.

4.1 Description of the Building Conversion Study

A two-phase "Building Conversion Study" was performed by the Minneapolis engineering consulting firm, Michaud, Cooley, Hallberg, Erickson and Associates (MCHE). The overall objective of the MCHE study was to determine the feasibility and representative cost of connection and conversion of commercial, institutional, and multifamily residential buildings in the St. Paul central business district. The first phase of the study was an in-depth investigation of conversion methods and cost for seven buildings which was intended to provide the basis for estimating the conversion cost of all the buildings in the market area. However, after completing the first phase, the cost results proved to be too diverse to generalize for the entire market area. Therefore, a second phase was conducted to provide a quick conversion estimate for 106 buildings of different specific heating types. The second study provides information on the range and variability of conversion cost for ten types of building heating systems. All conversion costs in this report are in mid-1980 dollars and include only direct costs for material and labor; design fees or contingencies are not included. Only the phase-two study results are presented in this chapter; details on the phase-one study are included in ref. 12.

4.2 Building Heating Systems and Conversion Cost

The phase-two study was organized on the basis of ten types of building heating systems in accordance the types of perimeter and air- handling ventilation heating subsystems. The ten types of heating systems are described in Table 4.1.

The characteristics of the building heating systems are summarized in Table 4.2 for the 106 buildings surveyed; the conversion costs determined are based on a system age relative to 1980. There are a wide range of

Table 4.1. Description of building heating systems

System group No.	Description
1	Hot water radiation — hot air side Hot water is delivered to radiators and/or induction units within the heated space. In addition, hot water is supplied to heating coils in air handling units, which pass air over the coils and deliver warm air to the space.
2	Steam (two pipe) radiation — no air side Steam in a two-pipe configuration is supplied to radiators and/or induction units within the heated space.
3	Hot water radiation — no air side Hot water is supplied to radiators and/or induction units within the heated space.
4	Steam (one pipe) radiation — no air side Steam in a one-pipe configuration is supplied to radiators and/or induction units within the heated space.
5	Steam (two pipe) radiation — steam air side Steam in a two-pipe configuration is supplied to radiators and/or induction units within the heated space. Steam is also supplied to heating coils in air-handling units, which pass air over the coils and deliver warm air to the space.
6	No radiation — gas-fired air side Gas is burned to directly heat air, which is delivered to the space.
7	Steam (one pipe) radiation — steam air side Steam in a one-pipe configuration is supplied to radiators and/or induction units within the heated space. In addition, steam is supplied to heating coils in air-handling units, which pass air over the coils and deliver warm air to the space.
8	No radiation — steam air side Steam is supplied to air handling units, which pass air over the coils and deliver warm air to the space.
9	No radiation — hot water air side Hot water is supplied to heating coils in air handling units which pass air over the coils and deliver warm air to the space.
10	Hot water radiation — steam air side Hot water is delivered to radiators and/or induction units within the heated space. In addition, steam is supplied to heating coils in air-handling units which pass air over the coils and deliver warm air to the space.

Table 4.2. Summary of building heating system characteristics[a]

System Group No.	Number of buildings	Average peak demand [kW(t)]	Average system age (Years)[d]	Average demand/ unit area (W/ft^2)
1[b]	24	1,650	11	8.35
2[c]	10	1,222	43	8.13
3[b]	5	1,248	27	7.03
4[c]	10	405	58	9.89
5[c]	24	1,343	41	7.29
6	6	235	13	17.3
7[c]	8	722	60	11.5
8[c]	7	85	17	8.79
9[b]	5	607	22	7.92
10	7	2,067	10	10.0

[a]Total peak demand of surveyed buildings = 119.6 MW(t).
[b]Use hot water piping.
[c]Use steam piping.
[d]System age relative to 1980.

types of heating systems which include practically all combinations of perimeter radiation units and air-handling units. The energy source for these buildings is predominately gas, oil, or steam district heating. Electric heat and heat pumps are used in only a few buildings in the St. Paul market area. The average peak demand varies widely between the groups. The groups with the highest average age — numbers 2, 4, 5, and 7 — all have steam distribution piping. Groups 6 and 8 have the lowest average peak demands. Both groups use only air-handling systems and no perimeter radiation.

The conversion cost estimates are presented in two forms. First, Table 4.3 presents the conversion cost for buildings over a range that includes the maximum, the average, and the minimum values. The range covers the unit conversion cost in dollars per kW(t) of peak demand and the conversion cost per unit area of heated space. Secondly, recommended unit conversion costs were selected for each of the ten types of heating systems (see Table 4.4). These unit costs were selected as typical values to represent all buildings having a specific type of heating system over the size range of the buildings surveyed in the MCHE study. These cost values were then used to estimate the conversion costs for the remainder of the DHDC initial market area. For groups 2, 3, 6, 7, and 9, the average unit cost in Table 4.4 is essentially the same as the average value in Table 4.3. However, in groups 1, 4, and 8, the average value is reduced by removing several abnormally high-cost buildings from the group data base; conversely, the average values for groups 5 and 10 are increased slightly to reduce the influence of several buildings with relatively low conversion costs.

Table 4.3. Summary of building conversion costs for 250°F (121°C) hot water supply

Group No.	Average conversion cost ($)	Unit conversion[a,b] costs [$/kW(t)]			Conversion cost/unit area ($/ft^2)		
		Maximum	Average	Minimum	Maximum	Average	Minimum
1	94,040	219.2	57.0	22.6	2.33	0.476	0.032
2	171,200	318	140.1	62.4	2.35	1.14	0.56
3	59,220	148	47.4	27.6	1.72	0.333	0.28
4[c]	241,400	1301	596.2	216.4	10.59	5.89	2.38
5	209,800	462.2	156.3	31.9	6.65	1.14	0.21
6	25,980	300.4	110.6	52.8	2.84	1.92	1.37
7	159,900	891.6	221.6	89.1	8.92	2.56	0.84
8	20,290	708	240.1	172.4	24.5	2.10	0.97
9	33,720	105	55.6	27.6	1.05	0.440	0.19
10	151,300	216.7	73.2	24.0	2.11	0.733	0.45

[a]Costs include modernization of systems.
[b]All costs are in 1980 dollars.
[c]Group 4, nine of ten buildings require complete system replacement.

Table 4.4. Recommended building conversion costs

System group No.	Heating system type	No. of buildings	Average peak demand [kW(t)]	Unit cost $/KW(t)
1	Hot water radiation — hot water air side	22	1826	40
2	Steam (2-pipe) radiation — no air side	10	1223	140
3	Hot water radiation — air side	4	1517	44
4	Steam (one-pipe) radiation — no air side	7	392	403
5	Steam (2-pipe) radiation — steam air side	21	1351	181
6	No radiation — gas-fired air side	6	235	110
7	Steam (one-pipe) radiation — steam air side	7	823	220
8	No radiation — steam air side	3	172	198
9	No radiation — hot water air side	5	607	56
10	Hot water radiation — steam air side	7	2067	107
Total		92		

4.3 Conclusions of Building Conversion Studies

The MCHE conversion cost study covered a broad range of building types in terms of (1) function, (2) building ages, and (3) building size and heat demand. Also included in the treatment of cost are both the conversion and the modernization of the building heating system. The modernization usually makes the systems more efficient. Doing both the modernization and conversion simultaneously adds a great degree of complexity to establishing the building conversion cost.

The conversion cost study indicates that buildings having hot water supplied to the perimeter heating system, air side systems, or both are the most economical to convert to a medium-temperature, hot water district heating system. The average unit conversion cost for such systems is \$40/kW(t) with the lowest cost in the \$15-30/kW(t) range for newer systems, which require little or no upgrading. In contrast, heating systems with steam supplied to the perimeter — groups 2, 4, 5, and 7 — have the highest unit conversion cost, ranging from \$140-400/kW(t). The uncertainty of the conversion costs for such buildings, as evidenced by the range of costs found in the survey, indicate that an individual building survey and cost estimate is necessary to establish the conversion cost for a specific building or potential customer. Therefore, design assistance to potential customers should be considered as a part of the marketing phase of implementing a district heating system.

The investment to modernize some of the existing heating systems may require incentives to encourage the building owner to make such an investment. However, the owner benefits from this investment in modernizing

existing steam heating systems because of the resulting reduced energy consumption of the more efficient hydronic system. Information on converted buildings and studies of potential conversions from steam to hydronic system operation document that 10-20% energy savings from heating result. Additional energy savings of 20% can also be realized when conservation features such as "night setback" controls are included in the building system conversion and modernization.

As a part of its marketing program, the DHDC developed a computer program to analyze the annual cash flows for current customers of steam district heating and natural gas. The program calculates the cumulative cash flow after a customer hooks up to the DHDC system. A 5-6 year payback period, based on the time for a positive cumulative cash flow to occur, is considered the target for positive customer acceptance of the investment risk for the building conversion cost.

The results of the payback-period analysis show that 5-6 year payback period criteria are met for all current natural gas customers even if unit conversion costs are as high as $275/kW(t) of demand (1980 dollars). For current steam customers, the payback period criteria are met if (1) a high unit conversion cost of $275/kW(t) of demand results in 25% or greater energy savings or (2) a medium cost of $175/kW(t) results in a 5% or greater energy savings.[12]

Finally, the primary emphasis in converting a building heating system is to produce a system that is energy efficient and operationally effective for the minimum capital cost. Therefore, the reuse of existing equipment, such as steam-to-steam converter units for water-to-water converter units, is often an effective measure to reduce the conversion capital cost if the equipment is judged to be in good condition.

5. ECONOMIC FEASIBILITY OF THE ST. PAUL HOT WATER DISTRICT HEATING PROJECT

The preliminary economic feasibility study was based on the results from all the previous engineering and marketing investigations. As a basis for the economic feasibility analysis, the St. Paul DHDC developed a scenario for thermal energy production which was compatible with the planned construction and connection of the consumers. The economic feasibility analysis that is presented was completed in November 1980, during the early phases of the marketing; it is anticipated that as the project evolves changes will have to be incorporated. Therefore, this is not the final economic analysis that will be used for financing the system.

The pricing policy and the cost of thermal energy are areas which have substantial influence on the economics of the system. The district heating pricing policy and the cost of thermal energy are described in Sect. 5.1 and 5.2, respectively.

5.1 District Heating Pricing Policy

The first step in developing a pricing policy for district heating thermal energy was to analyze the alternative energy prices in the market area. Table 5.1 presents the alternative energy and fuel prices in St. Paul in 1980 and also end-use unit prices for assumed annual conversion efficiencies. The assumed annual average conversion efficiencies are 65% for No. 2 and No. 6 oil and for natural gas and 100% for steam. Individual boiler efficiencies vary with the age and the condition of equipment. Therefore, comparison of specific customer alternative energy costs requires adjustment for actual conditions.

Table 5.1. St. Paul heating energy prices for 1980

Alternate heating energy source	Energy price	End-use price[a] ($/10^6 Btu)
Steam, firm	$8.15/10^6 Btu	8.15
Steam, interruptible	$5.22/10^6 Btu	5.22
Natural gas, firm	$2.90/10^3 ft^3	4.85
Natural gas, interruptible	$2.15/10^3 ft^3	3.60
No. 2 Fuel oil	$1.04/gal	12.50
No. 6 Fuel oil	$0.55/gal	6.04

[a]Includes 8.7% city franchise fee.

The two principal alternatives considered for pricing district heating service were cost base rates and competitive service base rates. Cost base rates are generally superior to market base rates in achieving the objectives of (1) revenue equal to cost, (2) ease of administration, (3) customer acceptance, and (4) minimizing subsidization of customers. Cost base rates are based on the concept that a utility is entitled to recover all costs of operation and capital investment. In comparison, market base rates are set by substitute prices. A significant characteristics of market base rates is that, assuming high fuel price projections in the future, such rates would result in lower revenues earned in early years and higher revenues in later years. Cost base rates appear to have the opposite affect.

The DHDC decided to base the initial thermal energy price on the end-use price of firm natural gas. It was also decided that the district heating revenue requirements be determined based on the cost expected to be incurred in each year adjusted for a forecast level of facilities utilization. Customers would initially be charged prices which reflect current

utilization of the system, and all other costs would be deferred. At such time that the market constraint is in excess of the actual operating and capital costs, accumulated deferred cost would be amortized and recovered from the increase-customer base.

The initial average price of thermal energy in 1981 is $7.28/10^6$ Btu and is inflated at an assumed general inflation rate through 1988.[a] Figure 5.1 shows the average thermal energy price in current dollars per 10^6 Btu through the year 2000, along with alternative, end-use energy prices for natural gas, fuel oil, and district steam. After the year 1989, prices are projected using a cost base rate formula. At that time, the market based prices are projected to be higher than cost based prices.

5.2 Cost of Thermal Energy

The base scenario was evaluated assuming that all thermal energy would be purchased from the NSP High Bridge Plant or produced at the Third Street Plant. Initially hot water and steam were assumed to be produced from High Bridge boiler units B9 and B10 and transmitted to the Third Street Plant through new hot water and steam transmission lines completed in FY 1982.[b] Cogenerated thermal energy from High Bridge turbine unit T6 was assumed to be available in 1984. Backup production plants were assumed to be at the Third Street Plant, the state capitol, and St. Paul's Ramsey County Hospital. These are required because the High Bridge plant heat source is

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[a]The general inflation rate was assumed to be 12% for 1981 and 1982, 10% for 1983 and 1984, and 8% for 1985 through 2000.

[b]In July 1981, it was determined that only hot water transmission lines will be constructed between the Third Street Plant and the High Bridge plant.

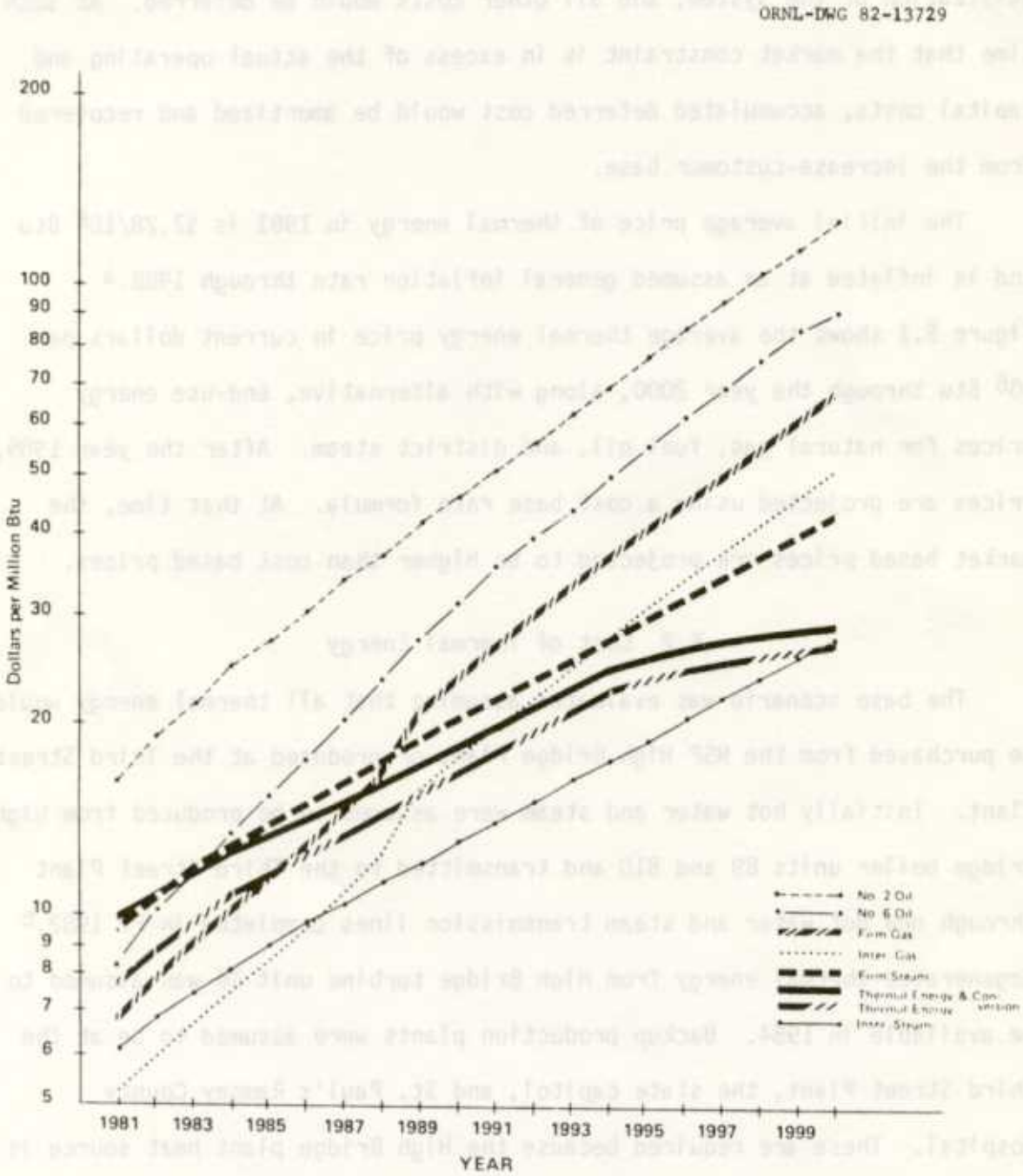

Fig. 5.1. Projected prices for hot water thermal energy and alternatives in St. Paul in current $/MBtu.

subject to interruption based on the NSP electric system requirements. It was assumed that 10% of the thermal energy would be provided by the backup plants and 90% by the the High Bridge plant.

Cost of thermal energy production by NSP represents an estimate of a cost-plus contract which is anticipated to be entered into between the St. Paul DHDC and NSP. Average production costs for the hot water were estimated by NSP for the High Bridge plant and by the DHDC for the Third Street Plant and Ramsey County Hospital plant. The costs in current dollars are presented in Table 5.2.

These cost estimates for hot water produced at the High Bridge plant are to be considered as preliminary because they include essentially no allowance for electric system related costs — specifically, replacement electric energy and excess electric energy. More recent cost estimates by NSP indicate that the electric system costs could contribute significantly to the hot water costs over the next decade. This situation would result if the electric dispatch of the T-6 turbine and B-9 and B-10 boilers were increased well above current levels and if the electric system peak demand were met by expensive, oil-fueled peaking plants. Therefore the DHDC and NSP are continuing negotiations for High Bridge thermal energy on an interruptible basis rather than a firm-supply basis.

5.3 St. Paul District Heating Project Cost and Development Plan

The economic feasibility study resulted in a business plan based on costs relating to project construction and financing and the price of thermal energy and the task of maintaining a debt service coverage requirement for an "A"-rated bond offering. Specific study results are as follows:

Table 5.2. Projected thermal production quantities and costs[a]

Year	Third Street Plant		High Bridge B-9 and B-10		High Bridge T-6		Total	
	Quantity (MBtu)	Cost ($/MBtu)	Quantity (MBtu)	Cost[b] ($/MBtu)	Quantity (MBtu)	Cost[b] ($/MBtu)	Quantity (MBtu)	Average Price ($/MBtu)
1981	-	-	-	-	-	-	-	-
1982	-	-	94,600	3.87	-	-	94,600	3.87
1983	-	-	430,000	4.43	-	-	430,000	4.43
1984	80,000	17.43	545,000	3.93	173,000	3.79	798,000	5.25
1985	100,000	18.77	201,260	4.90	704,410	3.79	1,006,300	5.23
1986	104,330	20.90	208,660	5.09	730,310	3.43	1,043,300	5.49
1987	104,650	23.09	209,300	5.28	732,550	3.49	1,046,500	5.81
1988	104,650	23.41	209,300	6.59	732,550	3.63	1,046,500	5.94
1989	104,650	25.85	209,300	6.84	732,550	3.80	1,046,500	6.61
1990	104,650	28.56	209,300	7.07	732,550	3.99	1,046,500	7.06
1991	104,650	33.38	209,300	7.36	732,550	4.19	1,046,500	7.74
1992	104,650	34.49	209,300	7.68	732,550	4.41	1,046,500	8.07
1993	104,650	37.90	209,300	8.05	732,550	4.69	1,046,500	8.68
1994	104,650	41.65	209,300	8.47	732,550	4.94	1,046,500	9.32
1995	104,650	45.78	209,300	8.93	732,550	5.24	1,046,500	10.03
1996	104,650	50.32	209,300	9.44	732,550	5.57	1,046,500	10.82
1997	104,650	55.31	209,300	10.01	732,550	5.95	1,046,500	11.70
1998	104,650	60.81	209,300	10.59	732,550	6.35	1,046,500	12.64
1999	104,650	66.85	209,300	11.26	732,550	6.77	1,046,500	13.68
2000	104,650	73.50	209,300	12.01	732,550	7.25	1,046,500	14.83

[a]In current dollars. M = million.
[b]8% escalation assumed for fuel cost.

1. The St. Paul DHDC needs a customer base of 165-MW(t) peak demand to have an economically feasible project.
2. A debt service coverage of 1.5 or greater is projected in the first years for the customer load of 165 MW(t). This coverage ratio is required by the bond rating agency. A load of 180 MW(t) increases the cash flow available in the early years by more than a million dollars. Every effort must be made to surpass the 165-MW(t) load.
3. Based on alternative fuel price projections, long-term customer economic benefits support district heating. However, short-term customer economics will likely make customer hookup commitments difficult to obtain.

The total cost of the system including those incurred by NSP and the customers is estimated at $77 million. Table 5.3 presents a breakdown of cost and financing. Direct construction costs are estimated to be $34.7 million; an additional $9 million will be required by NSP for conversion of the High Bridge plant. Customer heating system conversion costs are estimated at $23.5 million; an amount which is assumed to be financed by a sale of bonds through the St. Paul Authority. This debt is expected to be an obligation of the users, not the St. Paul DHDC. The company is obligated to secure $44.4 million and the financing sources include (1) bonding debt, (2) HUD/Urban Development Action Grant (UDAG) loan, and (3) City loan.

The economic analysis concludes that, during the first ten years of the project period, thermal energy rates are projected to fall below full cost, thus resulting in a cost deferral of $12.1 million. This cost deferral is projected to be recovered during the second ten years of the project period when full, cost-based rates are projected. Projected thermal revenues are shown in Table 5.4. These projections were based on

Table 5.3. Financing sources and project uses (in current dollars) for DHDC, NSP, and building owners

DHDC	
Sources:	
Debt financing	$34,600,000
HUD/UDAG loan	7,500,000
City loan	2,300,000
Total	$44,400,000
Uses	
Construction cost	$34,709,000
Debt service reserve and financing costs	4,729,000
Working capital, construction interest, and cash operating losses	4,962,000
Total	$44,400,000
NSP	
High Bridge conversion	$ 9,000,000
Building Owners	
Building conversion	$23,600,000
Total of all projected expenditures	$77,000,000

Table 5.4. Projected thermal revenues, sales quantities and prices

Year	Purchase requirement (MBtu)	Average system line loss	Quantity sold (MBtu)	Average price[a] ($/MBtu)	Gross revenues[b]	Large customer hookup incentive allowances	Net thermal revenues[b]
1981	-	-	-	-	-	-	-
1982	94,600	9%	86,025	8.15	701,000	86,000	616,000
1983	430,000	8%	394,553	8.97	3,539,000	413,000	3,126,000
1984	798,000	7%	738,943	9.87	7,294,000	783,000	6,511,000
1985	1,006,300	7%	940,491	10.66	10,026,000	923,000	9,104,000
1986	1,043,300	7%	974,858	11.51	11,220,000	692,000	10,528,000
1987	1,046,500	7%	978,242	12.43	12,159,000	461,000	11,698,000
1988	1,046,500	7%	978,242	13.42	13,127,000	231,000	12,896,000
1989	1,046,500	7%	978,242	14.49	14,176,000	-	14,176,000
1990	1,046,500	7%	978,242	14.97	14,644,000	-	14,644,000
1991	1,046,500	7%	978,242	15.78	15,441,000	-	15,441,000
1992	1,046,500	7%	978,242	17.56	17,177,000	-	17,177,000
1993	1,046,500	7%	978,242	18.11	17,718,000	-	17,718,000
1994	1,046,500	7%	978,242	18.68	18,279,000	-	18,279,000
1995	1,046,500	7%	978,242	19.36	18,937,000	-	18,937,000
1996	1,046,500	7%	978,242	20.25	19,813,000	-	19,813,000
1997	1,046,500	7%	978,242	21.19	20,730,000	-	20,730,000
1998	1,046,500	7%	978,242	22.16	21,677,000	-	21,677,000
1999	1,046,500	7%	978,242	23.24	22,737,000	-	22,737,000
2000	1,046,500	7%	978,242	24.47	23,942,000	-	23,942,000

[a]Excluding large customer hookup incentive allowances.
[b]Totals may not agree exactly with detail due to rounding.

an initial market based rate of $7.28/10^6$ Btus in 1981 and escalated through 1988 at the assumed general inflation rate. The cost-based rate begins in 1989.

5.4 District Heating Market Penetration

The ability of the St. Paul DHDC to develop the 165-MW(t) system in downtown St. Paul depends significantly on the market's building characteristics and economics. Some buildings have old one-pipe steam heating systems which are rapidly deteriorating, while other buildings have relatively new hot water systems which are readily compatible with the hot water district heating. The conversion of the older buildings will require substantial customer investment; therefore, the economic incentive for the customer conversion is diminished. It is expected to be more difficult to penetrate this market compared to those buildings which require a much smaller conversion investment. It is also expected to be difficult to acquire customers who are presently using natural gas. Gas is still relatively inexpensive, but its cost is expected to increase rapidly in the next three to five years as deregulation occurs. Customers already using the more costly energy sources, fuel oil and steam heat, are the most likely to be willing to convert to district heating.

The district heating company developed an ongoing three phase marketing plan: phase one — market awareness, phase two — customer contacts, and phase three — contract negotiation. All three of these phases are extremely important to the success in DHDC's signing customers to 30-year service contracts.

6. SUMMARY AND CONCLUSIONS

An analysis was made to determine the technical and economic feasibility of a modern hot water district heating system for U.S. cities. The Twin Cities of Minneapolis-St. Paul were chosen as the site for the district heating case studies. It met all the criteria, such as high number of degree days, large potential loads, existing electric generating stations near the cities, and interested and cooperatative local and state authorities. The idea for such a case study resulted from the large number of successful European, modern hot water district heating systems. The studies were initiated to evaluate the European concept as it applied to a northern U.S. city.

The first assessment was an overall feasibility study for the entire metropolitan region. The effort concentrated on assessing the heat loads and the heat sources that could be connected over a 20-year period. This work stimulated several other studies on evaluating the city wide district heating system. The overall feasibility study, along with the other studies, led to the formation of the St. Paul DHDC by the City of St. Paul. The St. Paul DHDC is proceeding with a demonstration project that would be the first modern hot water district heating system built in a major U.S. city.

6.1 Summary of the Twin Cities District Heating Overall Feasibility Study

Two levels of district heating were analyzed: Scenario A, which assessed district heating in the downtown and commercial areas, and Scenario B, which, in addition to "A", assessed medium density residential districts with one- and two-family houses outside the central parts of the cities. The estimated thermal load over a 20-year development period is

approximately 2600 MW(t) for Scenario A and 4000 MW(t) for Scenario B. The principal feature of the concept includes a transmission system that transports heat from production plants to various part of the market area by hot water mains in accordance with modern European district heating technology. The heat is then distributed from the transmission system to individual buildings and houses by a hot water distribution system that runs under sidewalks and streets and, where possible, through basements. The base load is supplied by cogeneration plants that provide about half of the total peak load capacity, but nearly 90% of the annual heat energy. Most of the thermal energy from cogeneration units could be provided by turbine generators converted to extraction operation at two existing stations, Riverside in Minneapolis and High Bridge in St. Paul. A new cogeneration unit at Riverside is assumed for Scenario A; for Scenario B, two large units, about 17 miles from the cities, are proposed because it seems impractical to use the power plants in the cities exclusively. The cogeneration plants replace large quantities of oil and gas used for space heating by using reject heat from the power plants and small quantities of additional coal and oil.

A modern hot water district heating system in the Twin Cities would save 0.28 and 0.35 quads of oil and gas for Scenario A and B, respectively, over a 20-year period. The percentage savings of these fuels is 85% of the total amount of fuel used for space heating in the district heating service area. Thus, there are extensive savings of premium fuels. It should also be noted that since the system is being developed during the first 20-year period, fuel savings in the following years would even be greater. Almost as much fuel would be saved in the subsequent 10 years as in the first 20 years.

The total investment in the piping system, production plants and building conversions is estimated to be $625 million (1978 dollars) for Scenario A and $1235 million for Scenario B. The economic results for Scenario A show that, with municipal financing, there is a large net savings of $183 million at the end of the 20-year period. With private utility financing, where capital charges are higher, the accumulative present net-worth savings is – $77 million at the end of the 20-year period. However, the accumulative present worth has a positive slope at the end of 20 years and will intersect zero at the end of 33 years. The distribution piping system has a life of 30–35 years, and which is equivalent to a life cycle economics of other utility investments.

For Scenario B, with municipal financing there is an accumulated net annual savings of $238 million and $274 million for conventional and newer distribution technologies, respectively, used in the residential areas. For private utility financing, the savings are -$151 million and -$118 million. For an intermediate case of private utility financing for the production plants and municipal utility financing for the distribution system, the net savings are $171 million and $202 million. The positive net savings, as in the municipal financing case, could be used to lower the rates and thereby make the district heating system more attractive to the consumer.

The overall conclusions of the study are that district heating on a regional basis in the Twin Cities is technically feasible and that large quantities of the primary fuels, natural gas and oil, can be saved. The economics are judged to be viable, providing a suitable method of financing is used for the transmission and distribution systems.

6.2 Summary of the St. Paul District Heating Project

The primary objective of the St. Paul DHDC is to build an economically viable hot water district heating system for the commercial downtown area of St. Paul. The goals for the first phase of the project were (1) to assess the economic feasibility of a hot water district heating system serving the commercial core of St. Paul, and (2) to develop an implementation plan for financing construction of the first segment of the system to be built over a 4-5 year time span.

Of the more than 300 buildings in the St. Paul hot water district heating market area, 32% are considered large buildings [i.e., thermal demand greater than 0.5 MW(t)]. The large buildings comprise over 85% of the heat load in the market area. The estimated total heat load for the service area is 270 MW(t), which includes 30-40 MW(t) of new growth over the next seven years.

The conceptual design includes a hot water piping system with a maximum temperature of 250°F to serve all the existing and future heat demands in the service area. The design includes a large transmission pipeline from the High Bridge Power Plant to the Third Street heat-only plant. The pipeline could be constructed when the heating system justifies the investment. There would also be a transmission line through the downtown area to the State Capitol Complex. Smaller-diameter supply and return distribution pipes would be routed from the transmission line. The piping diameters and flow capacities are designed to supply the full 270-MW(t) load in the service area. All the buildings are not expected to be connected to the district heating system in the initial 4-5 year period. Therefore it will not be necessary initially to extend the system over the entire area. The

system will be reduced by omitting pipes to buildings which are not connected to the system during the initial construction period. The omitted pipes merely reduce the number of buildings that would be served and in this manner reduce the system to a customer load of approximately 165 MW(t). The 165-MW(t) load was selected on the basis of a preliminary economic feasibility analysis.

The total cost of the 165-MW(t) system, in current-year (1982-1987) dollars, is estimated at $77 million, an amount which includes (1) $44.4 million, financed by the DHDC, for the transmission and distribution system and backup boiler plant conversion, (2) $9 million by NSP for the conversion of the High Bridge Power Plant, and (3) $23.6 million by the building owners for building conversions. The building conversion debt will be obligated by the users, not the DHDC. The sources for the DHDC financing included 30-year, tax-exempt, revenue bonds, a 20-year HUD-UDAG loan, and a city loan.

Depending on the type of internal building heating system, the cost of building conversion can vary significantly. Buildings that have hot water supplied to perimeter heating systems, air-side systems, or both are the most economical to convert to the hot water district heating system. The average unit conversion cost for such a system is $40/kW(t) of demand. In contrast, buildings with internal steam systems have the highest unit conversion cost, ranging from $140-400/kW(t). These high conversion costs are caused by significant upgrading and modernization required to provide for a hydronic heating system. The additional investment to modernize some of the older existing systems requires incentives to encourage the building owners to make such an investment. However, this investment in modernizing

an existing heating system will benefit the owner through reduced energy consumption of the more efficient hydronic system.

Because natural gas is the most competitive alternate energy source, the pricing policy for the district heating energy was based on the end-use natural gas price. The initial average price of thermal energy is $7.28/10^6$ Btu in 1981 and is inflated at the assumed general inflation rate through 1988. The financial analysis concludes that during the first ten years of the project, the thermal energy rates are projected to fall below full cost-based rates which results in a cost deferral of $12.1 million. This cost deferral is projected to be recovered during the second ten years of the project period when cost-based rates are projected instead of market based rates. The cost-based rates will start in 1989.

6.3 Conclusions from the St. Paul Project

The St. Paul project has demonstrated several important issues with regard to development of a new district heating system serving a northern urban market.

1. Transfer of European, medium temperature (250°F maximum) hot water piping technology to U.S. design and construction practices is possible; however, development of U.S. codes covering design and construction methods is needed to standardize products, stimulate U.S. vendors, and minimize the construction cost for medium-temperature transmission and distribution systems.

2. The types of existing building heating systems are an important factor in the market penetration for a medium-temperature, hot water district heating system. The most expensive buildings to convert are buildings with all-electric heating. Older buildings with one- or two-pipe

steam perimeter heating systems may also be expensive to convert, but, when converted, they can benefit the most from increased operational efficiency. A detailed survey of the building systems in the market area is therefore an important component in the system design and the ultimate customer marketing program.

3. In order to utilize cogenerated thermal energy from existing, coal-fueled utility power plants, the electric system-related costs must be considered in detail. These additional costs can exceed the cogeneration cost savings.

4. The ownership structure has an important relationship to the types of debt financing available to a new district heating utility service. Debt financing with long-term revenue bonds requires long-term (30-year) customer commitments to a service contract, thus adding difficulties in marketing the utility service. However, 30-year customer contracts have been successfully marketed in St. Paul after the concerns of the customers were addressed in the contract provisions.

5. The overall system development process has required about five years in the Twin Cities and St. Paul because of the extensive background studies needed. The experience from the St. Paul project and other potential projects should lead to reduced development periods for future district heating projects. As an example, a municipal-owned district heating utility in Wilmar, Minnesota, designed, financed, and installed a new, 8-MW(t) hot water system within 18 months in 1981 and 1982.

Despite the difficulties involved in finalizing a district heating project, the City of St. Paul is expediting development of the coal-based system because of steadily rising alternative energy prices. The energy

dependence of the City will play a critical role in its ability to revitalize and redevelop. The district heating system will enable the city to keep energy costs more reasonable, thus making the City more attractive for business growth.

6.4 Potential for Other U.S. Cities

Modern hot water district heating systems have the potential to offer consumers in their respective communities four major advantages: competitive space heating energy cost, lower maintenance cost and higher reliability, improved air quality in the community, and lower initial capital cost for new buildings. The most important advantage to the consumer is clearly the economic advantage. This advantage is usually achieved through the fuel flexibility of district heating and the conservation potential of cogeneration. Lower maintenance cost and higher reliability are achieved due to the simplicity of the consumer equipment. The main component of this equipment is a series of heat exchangers which seldom need maintenance and do not require a boiler operator for small- or medium-sized buildings. The developers of new buildings that connect directly to a district heating system have lower capital costs because the costs of the heat exchanger is much lower than that of a boiler.

The district heating system also has the potential to improve air quality in the community. Emissions from one stack at a central power plant replaces emissions from many low-level stacks. More effective controls can be put on large, central stacks than on many low-level stacks. However, the overall effect of district heating on air quality depends, to a large extent, on the type of fuel being replaced in the individual units.

Currently, the United States has approximately 10,000 MW(t) of city district heating consisting mainly of steam district heating systems. Sweden, a country with a population of 8.1 million, currently has an installed capacity of about 15,000 MW(t). By the year 2000, Sweden expects to have achieved an installed capacity of 30,000 MW(t). A rough estimation of the potential for district heating in the United States can be made by multiplying the Swedish number by a factor of 10. This factor is based on segmenting our northern areas into ten population regions roughly the size of Sweden. Therefore, the United States has an estimated capacity of 300,000 MW(t).

Modern hot water district heating systems in Europe have proven to be economical because they tend to have larger service areas and thereby serve more customers than the steam systems in the United States. The hot water technology allows them to serve a lower heat load density and use remotely located cogeneration plants. The annual growth rate of district heating in northern European countries is about 20%/year. With the hot water technology, the energy can be repumped and extended into new areas. As a result, the hot water systems are adaptable to meeting the changing needs of the community.

Cogenerated hot water district heating can provide significant public benefits at the local, state, and national levels in the United States. The technology of cogeneration hot water district heating has been proven throughout Europe to be capable of providing electrical and thermal energy in a manner which is safe, reliable, fuel efficient, cost effective, and environmentally compatible. In this country, we have the added advantage of being able to cogenerate much of our heat and power requirements using

domestic coal supplies. Cogenerated district heating can replace natural gas and oil used for space heating. This replacement has the potential to extend for a much longer time the availability of domestic natural gas and fuel oil supplies for use in the low-density areas of our nation's towns and cities.

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