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

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ABSTRACT

The Department of Energy, Minnesota Energy Agency, Northern States Power Company, and other local government and private organizations are cooperatively performing an in-depth application study to determine the feasibility of district heating for a large northern U.S. city. A Swedish firm, Studsvik, has developed an overall scenario and has attemped to show the potential of a fully implemented system. The proposed system would be about 2600 MW(t) and cover a significant portion of both Minneapolis and St. Paul. This study has proceeded in parallel with more in-depth studies of particular issues, such as detailed piping network plans in central St. Paul and cogeneration plant conversion cost study — both sponsored by Northern States Power Company. The overall conclusions that can be drawn at the present time are: (1) the concept is technically feasible, (2) it has great value from the fuel conservation aspect, and (3) the economics are viable with an appropriate financing system.

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INTRODUCTION

District heating is a process in which thermal energy from a central source (either a heat-only unit or a cogeneration plant that produces both electricity and thermal energy) is distributed to commercial, industrial and residential consumers for space heating and domestic hot water needs. From an historical standpoint, district heating was first implemented in the United States over 100 years ago. After a period of rapid growth, the expansion of steam district heating systems slowed in the late 1940's when inexpensive oil and natural gas became available for heating purposes. District heating technology is now being reassessed because of rapidly escalating energy prices and our country's increasing dependence on imported oil. Large hot water district heating systems have the potential of providing consumers with space heating at competitive prices while substituting more plentiful domestic fuels, such as coal and uranium, for heating needs currently supplied by oil and natural gas. Hot water district heating technology is available and has been widely utilized in many European countries with a great deal of success. Northern States Power Company (NSP), the U. S. Department of Energy (DOE), the Minnesota Energy Agency (MEA), and other local government and private organizations are cooperatively performing an in-depth application study to determine the feasibility of hot water district heating for a large U. S. metropolitan area -- namely, Minneapolis-St. Paul, Minnesota.

The program to assess district heating for the Twin Cities area consists of a number of coordinated studies focusing on technical, economic, environmental, and institutional issues. A list of the various studies is given in Table I. The reader is referred to an earlier paper[1] for a more detailed description of these studies. This paper will present the status and results of several phases of the program that have been completed or are near completion -- these include the Studsvik district heating, power plant retrofit, and St. Paul district heating studies. The remaining tasks are currently in progress and will be reported on when the work is completed.

STUDSVIK DISTRICT HEATING STUDY

This study is a joint effort based on current Swedish district heating technology and experience, adopted where necessary to U. S. conditions. U. S. participants supplied the basic data and economic criteria while Studsvik carried out the analysis. The results to date which are presented in this paper are based on a recent draft report.[2] It should be pointed out that some of this information is preliminary in nature and subject to minor changes when the work is completed. It is not expected, however, that any of the major conclusions will be significantly different than reported here.

The objective of Studsvik's analysis was to determine the feasibility of district heating for the Twin Cities and not to develop a detailed step-by-step plan for the network nor do detailed engineering and economic calculations. The major efforts were concentrated in three areas: a) Assessment of the heating loads which could be connected over a 20-year period; b) Determination of a feasible implementation schedule to connect the loads and bring cogeneration plants and peak load boilers on line; c) Examination of the overall economics based on alternative methods of financing.

HEAT LOAD

The cold climate (more than 8,000 heating degree days) combined with the large population of the Minneapolis-St. Paul area give rise to a fairly large concentrated heat load. The metropolitan area contains two separate downtown areas about seven miles apart (Figure 1). Around these core areas are industrial sites and residential housing which practically makes the area one continuous metropolitan region having a population of more than one million people.

Natural gas presently supplies the majority of the heat load in the region. Current heat demands within the entire region were forecast from records of gas consumption, existing district heating system heat demands, and consumer heating oil requirements. This analysis was carried out for 32 subareas in the Twin Cities and surroundings. The subareas were classified into five types of relatively homogeneous areas as indicated in Table II and the corresponding map in Figure 2. Table II shows that the dense downtown type 1 and 2 areas (>70 and >50 MWt/km^2) together represent 1,114 MWt of maximum heat demand; the medium density commercial and apartment house areas (25 to 50 MWt/km^2) represent 1,286 MWt and the nearby residential areas with two- and four-family houses (10 to 25 MWt/km^2) represent 565 MWt. The four areas together have a maximum heat demand of 2,965 MWt. Due to the complication of integrating the existing steam district heating systems in Minneapolis and the University of Minnesota into a hot water system within the time frame and work scope of the study, these areas were excluded. Also some large industries for which insufficient data were available were excluded. This case is referred to as Scenario A with a heat load of 2,600 MWt.

A potential heat load of 2000 MWt was estimated for outlying residential areas. Scenario B assumes that this load with a 70% connection would also be supplied by the regional district heating system giving a maximum demand of 4,000 MWt (2,600 + 1,400).

IMPLEMENTATION SCHEDULE

The heat load connection rate for Scenarios A and B are assumed to be approximately 130 MWt and 200 MWt per year respectively, over a 20-year period

(See Figure 3). This growth rate is consistent with modern Swedish experience. Initially, the main system would develop in the high-density downtown areas which have a heat density of more than 50 MWt/km^2. The system would spread to the medium-density industrial and commercial apartment buildings and to high density residential multiple-family houses having heat densities of 25 to 50 MWt/km^2. Initially the Minneapolis and St. Paul systems would develop independently. Eventually, when the systems become sufficiently large, an interconnecting pipeline would connect the two regions.

For Scenario A it has been assumed that all cogeneration capacity could be located at existing sites within the metropolitan area, i.e., at High Bridge for St. Paul and Riverside for Minneapolis with some energy interchange after the construction of the interconnecting pipeline. For Scenario B new units were assumed at an out-of-town site. This site was assumed to be King, located about 17 miles from downtown St. Paul (See Figure 1).

Table III tabulates the assumed cogeneration plants. The largest and most modern existing turbines would be converted first, i.e., High Bridge No. 6, Riverside No. 8 and High Bridge No. 5. The last cogeneration plant to be introduced for Scenario A is a new boiler turbine unit with a rating of 335 MWt and 190 MWe during cogeneration operation and 240 MWe for electric only operation. This unit should be located at Riverside to be near the load, but may have to be located at High Bridge due to site conditions.

The total heat from the cogeneration units summarized in Table III is 1,516 out of a maximum 2,600 MWt demand for Scenario A. The cogeneration units would provide about 60% of the peak capacity of the system and supply almost 90% of the annual thermal energy demand. The remaining load would be provided by peak-load oil-fired boilers.

PIPING COSTS

A distinction is made between large regional pipes transporting heat from the production plants to various areas of the city and distribution pipes delivering heat from the transport system to individual buildings. Good tunneling rock exists in the form of the St. Peter Sandstone under large parts of the metropolitan area. Risers from the tunnel to the surface would be used to connect the transmission lines to the distribution lines. The eastern part of St. Paul and the western part of Minneapolis do not have favorable tunneling conditions. All pipes in those areas would be installed in surface trenches.

The cost of main metropolitan area tunnel system was based on tunneling cost data for the Twin Cities and Swedish pipe material costs (see curve 1 on Figure 4). Curve 3 shows typical cost levels applicable in Swedish cities of 100,000 inhabitants. Figure 4 also shows costs for downtown and residential Stockholm. Downtown Stockholm has considerably higher costs than the smaller cities due to congestion, traffic, and high labor rates. The costs for residential Stockholm districts are close to those of smaller cities. Investigations by Swedish and U. S. consultants suggest that cost levels for covered surface piping in small cities are very similar in Sweden and the U. S. for civil engineering work, installation, etc.

Based on the comparison for smaller cities, curve 2a, which lies somewhat above downtown Stockhom costs, was used to determine piping costs for downtown Minneapolis and St. Paul; curve 2b, which is considerably higher than residential Stockholm costs, was used for the residential regions of the two cities. These assumptions on piping costs are believed to be conservative. Nevertheless, in order to confirm this assumption, accurate cost estimates for the Twin Cities piping should be determined based on detailed estimating procedures.

For planning studies of this type covering large areas, it is the practice in Sweden not to do street-by-street surveys of the whole area to determine local distribution system cost, but rather to find other cities with comparable conditions for which cost data are available from actual network construction. For this study Stockholm was selected as a city with a similar degree of congestion and with a mixture of rock excavation and surface construction.

Figure 5 shows data on Stockholm system distribution costs (excluding the Stockholm regional transport system) for districts with various load densities and average consumer size. The costs have been updated to reflect 1978 dollars. As many of the pipes were installed before some new methods were developed (such as the application of prefabricated techniques to larger pipes and prestressing pipes by bellows), the costs should be conservative in relation to new systems built in the future.

COST OF CONVERTING BUILDING HEATING SYSTEMS

The Minnesota Energy Agency conducted a study on the cost of converting building heating systems to make them compatible with a new hot water district heating system[3]. A survey was conducted of 280 buildings in the Minneapolis-St. Paul downtown areas to categorize them according to the type of heating system used and building type. Different conversion methods were studied, each giving different return water temperatures. It was found that, considering the entire system, the most economical conversion was the one with the lowest return water temperature.

Detailed estimates were made for five buildings, typical of broad building groups. Correction factors were applied to other buildings as a function of capacity. The results are shown in Figure 6. The average cost of building and house system conversions evaluated in this manner was $64/kw for Scenario A. This assumes that all existing heating systems would require conversion. In practice, over the twenty-year development period, there would be some new buildings and houses requiring no conversion at all, and some old existing heating systems would have to be replaced anyway. Therefore, the net additional investment due to connection of buildings and houses to district heating system is only some fraction of the full conversion cost derived above. It is estimated that this fraction would be about 0.6 over the period concerned, and this value has been used in the analysis for the reference case.

ECONOMIC ANALYSIS

The determination of the rates charged for thermal energy was not part of the scope of work for this study because of the uncertainty as to how the cost allocation between thermal and electric energy from a cogeneration plant would actually be determined. (This question has been considered in the institutional study which was conducted by the MEA). For the purposes of this analysis, rates for the sale of district heat were set to give consumers an economic advantage compared to alternative forms of heat supplies. It was assumed that district heat would cost 10 percent less than the cheapest alternative (either gas or oil). It was considered that this would provide sufficient incentive for consumers to hook up to the district heating system.

Based on these rates and the total energy sold, the district heating company would obtain an annual income, I_n, in the Nth year. The company would also have to meet various fuel and operating costs, capital charges on its investments and taxes in the case of a private utility. The difference between the annual income and the annual costs, K_n, has been termed the "net annual saving", $S_n = I_n - K_n$ which can be negative in the initial years when revenue is insufficient to meet costs, and positive thereafter. The sum of the values of this annual saving in various years can be referenced to the year 1978 by the application of an appropriate interest rate, r, and inflation factor, F_n.

Over the 20-year period this sum, $\sum_{n=1}^{20} S_n (1 + r)^{-n}/F_n$, is then a measure of the overall viability of the system.

Predictions by NSP on future inflation rate and fuel costs were used for the base cases. The inflation rate assumed was 5 to 6% per year initially and then 4% per year to the year 2000. Coal costs were assumed to increase by about 1.3% per year above the rate of inflation throughout the period. Oil costs were assumed to reach world market prices by 1981, and to increase thereafter at about 2% per annum in terms of 1978 dollars, i.e., slightly more rapidly than inflation. Mean individual boiler efficiency is 70% and efficiency for large heat-only district heating boilers is 90%.

Gas prices are assumed to increase by a factor of 2.4 over the 20-year period. By the mid-1980's, gas prices begin to exceed those for light and medium grade oil. In light of current rapidly escalating world oil prices, a second case has been run in which gas and oil prices are assumed to increase at an additional 1% per annum (i.e., 3% over the rate of inflation).

Table IV summarizes the total investments needed for Scenario A for the entire 20-year period in terms of 1978 dollars. The total cost includes the transmission and distribution system, cogeneration and peak load plants, and building heating system conversions. It can be seen that the system is highly capital intensive with over 50% of the investment in transmission and distribution lines. For this reason it is important that as the system develops, consumers must be connected early to start generating revenues as soon as possible. Out of a total investment of $596 million, about 80% would normally be financed by the utility and the rest by building owners.

Figure 7 shows the calculated net saving in 1978 dollars for the reference cases (solid lines) for both municipal and private utility financing. Variations from the reference cases, which indicate sensitivities to different assumptions, are shown by dashed lines. Figure 8 shows the accumulated net savings on a year-by-year basis expressed in 1978 dollars.

The results for the municipal financing case show accumulated net savings become positive in about 9 years, and the present worth of accumulated net savings at the end of the 20-year period of $209 million. With private utility financing it takes much longer to obtain a break-even of annual costs. The accumulated net savings does not become positive during the period considered, but the net negative value is small, about -$55 million. With a combined form of financing, i.e., private utility for production plants and municipal for transport and distribution piping, there would be a net accumulated saving estimated to be $150 million after 20 years.

The curves clearly show the importance the method of financing has on the overall economics. Strong incentives exist for attempting to obtain at least some of the capital for district heating systems at terms more favorable than those applicable for private utility financing - e.g., by municipal bonds.

The economic results for Scenario B are not available at the present time.

SENSITIVITY ANALYSIS

Table V shows the sensitivity of the present worth of the accumulated net savings to changes in various assumptions. Some of these cases are also shown in Figure 7.

One significant parameter is the cost of the transport and distribution system. The cost assumed for the base case is somewhat higher than that experienced in the Stockholm area, which in turn is considerably more expensive than other regions in Sweden. If actual costs were 20% lower than assumed, the accumulated net savings would increase by about $35 million as shown by case 2.

For the base case it was assumed that 100 percent of all present consumers within the supply area would connect to the district heating system. The actual connection rate will be somewhat lower. Case 3 shows the influence of a 10% lower connection rate. However, for this analysis the cost of the transport and distribution system is assumed to be the same as that for the system with the full 100% connection despite the lower heat demand associated with the lower connection. With these assumptions, the accumulated net savings are reduced by $46 and 15 million for municipal and private financing respectively. It should be pointed out that additional loads from new establishments within the area were neglected as were some big industries and two of the existing steam district heating systems. The influence of additional loads from such sources would tend to compensate in part for the optimistic assumption of a 100 percent connection.

If the cost of building conversions charged to the district heating system is reduced from 60 to 50 percent of the total cost of converting every building, the net accumulated savings would increase by $16 to 12 million.

One of the most critical assumptions indicated by case 5, is the influence of a one percent per annum higher rate of increase in consumer gas and oil prices. This increases the net accumulated savings by substantial amounts - $125 and $53 million for municipal and private financing respectively. At this higher fuel price escalation rate, a system financed by private utilities essentially breaks even after 20 years.

Case 6 illustrates the influence of a 50% higher cost of coal, which could be the case, for example, in Eastern regions of the country. This reduces net savings by $101 and 47 million respectively.

Case 7 shows the effect of assuming a district heat price of 5 percent below the lowest cost alternative instead of 10 percent as assumed in the base case. This significantly increases the accumulated net saving achieved by the utility by $51 and 24 million respectively, assuming that all consumers still connect.

FUEL SAVINGS

Figure 9 shows the fuel consumed for district heating. This includes additional coal that is needed to generate electricity sacrificed through conversion of electric-only plants to cogeneration units. The figure also shows the fuel that would be required to supply thermal energy to the same consumers by individual oil- and/or gas-fired boilers. For Scenario A, the net result over the period 1980 - 2000 is a savings equivalent to 31 million barrels of oil -- and an additional replacement of gas and oil by coal equal to 18 million barrels of oil equivalent. Thus a total of 49 million barrels of the most limited fuel types is replaced. For Scenario B the total net fuel saving over the period is about 30% greater than for Scenario A.

ST. PAUL DISTRICT HEATING STUDY

NSP is an active participant in the Studsvik study of the Minneapolis-St. Paul area. During the course of its initial involvement, NSP determined that it must do an independent analysis of its own. All previous thinking and attitudes at NSP were a result of experience with steam district heating systems. There are major differences in a steam system as compared to a hot water system as shown by the Swedish experience.

The purpose of the NSP study of the St. Paul area was to provide NSP management with a decision document concerning district heating. The major objective of the study was a comprehensive assessment of the physical and financial impact of installing an expanded district heating system in St. Paul. The size of the study area was kept small relative to the Swedish work so as to be manageable for detailed evaluation. The downtown area of St. Paul was chosen because it incorporated the present NSP system, and the high heat load density would provide the greatest chance of success for the system. The Chas.

T. Main Engineering Company of Boston, Massachusetts, was selected by NSP to perform this study. The study is not yet completed, but some preliminary information is available at this time and is presented in this paper. Final results and conclusions are expected in approximately three months.

PHASE I HEATING MEDIUM SELECTION

An evaluation was performed to select a suitable heat transport medium for a large expanded district heating system. The basis for this evaluation was an extensive literature search of U. S. and European technical papers for steam and hot water district heating system experience. A quantitative methodology consisting of weighted suitability indices and a decision matrix system was used to evaluate hot water and steam. A draft copy of the evaluation was distributed to the local technical, governmental and business community, and a public meeting and discussion were held to provide input to the selection process. The consensus was that 300^{0} F hot water was the preferred heating medium.

PHASE II MARKET SURVEY AND ANALYSIS

The objective of this phase was to estimate the potential size of the district heating system and the revenues that could be returned from this market in the years 1980-2000. The methodology used was based on a free market choice using a comparative payback analysis for each customer. This assumes that the difference in energy price between the thermal energy from the district heating system and the alternative energy sources such as gas and oil can be a basis for an economic choice for the conversion. The customer finances and pays for the conversion at his cost of capital. The payback period and investment in existing building heating systems were customer specific. The conversion costs for building heating and cooling systems were developed in a separate study performed by the Minnesota Energy Agency[3].

The market survey was based on a detailed questionnaire and interviews with nearly all of the energy users in the study area. The study area shown in Figure 10 represents the commercial and industrial core of the City of St. Paul. Single-family residential areas were not included. The survey information included building type, size, age, type and age of heating and cooling systems, and annual and peak energy use. Three years of NSP billing information for electricity, gas, and steam sales for customers in the study area was also used. The survey data were combined with economic data, including fuel costs, and inflation rates (shown in Table VI), payback periods, interest rates, years to retirement of existing heating and cooling systems, conversion opportunity costs, and depreciation life. A computer program was used to perform a financial assessment for each customer to determine whether or not the customer would hook up, and if he did, when and at what price. Based on this analysis district heating demand curves were developed for the study area for the years 1985, 1990, 1995 and 2000. For the year 2000 the total district heating load for this area is approximately 350 MWt (thermal). This includes heating, cooling and process heat loads based on a 300^{0} F hot water district heating system.

PHASE III SYSTEM DESIGN AND COST

The third phase of the study consisted of an engineering conceptual design for a 300^{0} F hot water distribution system and the estimation of capital and operating costs. The design of the piping distribution system was based on the heat demand as projected by the market study. A conceptual design study for the conversion of the High Bridge Generating Plant to cogeneration was performed by United Engineers and Constructors of Philadelphia. The capital and operating costs of the cogeneration plant are discussed separately in this paper. These costs will be incorporated into the district heating system cost estimate.

The district heating system is shown on Figure 11. Hot water from the cogeneration unit at High Bridge is delivered to the area distribution center at Third Street. Supply and return headers proceed from the Third Street Steam Plant to Zone 1, 3a and 3b. Zone 2 is supplied from Zone 3a, and Zone 4 is supplied from Zone 3b. Zone 5 has been omitted due to marginal heat demand.

The district heating system is designed as a closed system. At the generating plant a heat exchanger is used to separate steam from the district heating water; at the customer end another heat exchanger is used to separate the building heating system from the district heating water. The district heating water is chemically treated to prevent internal piping corrosion.

The geology of the specific area determined whether the main headers would be installed in existing or new tunnels or in culverts for surface trench burial. The distribution piping can be installed in the streets and through the basements of buildings. Distribution piping buried directly in the ground is enclosed in factory-fabricated asphalt wrapped steel conduit for corrosion protection. Calcium silicate was selected for pipe insulation.

The maximum water flow rate is 17,000 gpm based on a 150° F temperature difference between supply and return water. Line velocities of up to 7 feet per second are used in smaller distribution piping and 10 feet per second in the large main headers. The piping is all welded steel construction. All pipes, valves and fittings are selected for design temperature and pressure of 325° F and 300 psig respectively in accordance with ANSI Standards. Piping material is seamless steel A-53 Grade B. Schedule 40 wall thickness is used for piping diameters of 2 1/2" to 10". Piping diameters of 12" to 24" use a .375 inch wall thickness.

Capital cost estimates for the total project, including the High Bridge conversion costs to achieve cogeneration capability and the installation of the hot water distribution system, will be determined. A construction and implementation schedule will also be developed for the study area.

PHASE IV FINANCIAL ANALYSIS

The above information will provide a basis to determine the financial feasibility of the St. Paul district heating system. Two costs of money will be considered - one at 6.25% for municipal financing and the other at 10.3% which is NSP's composite cost of money. The financial analysis will use a cash flow computer program to calculate the revenues required to support the project's financial carrying charges and operating costs through the study period. From this analysis, the payback period will be determined by computing the time required for the sum of the present value of costs to equal the sum of the present value of the revenues.

RETROFIT OF HIGH BRIDGE GENERATING PLANT TO COGENERATION

Northern States Power Company's existing power plants are the designated heat sources for both the Studsvik and the St. Paul District Heating Studies. The power plants are ideally located close to the heat load and use coal as the basic fuel. Conversion of existing power plant turbine units to cogeneration is used wherever possible in district heating applications as the conversion of an existing unit is lower in cost than building new units or installing new heat-only boilers. The technical feasibility of converting the existing units to cogeneration is therefore important to the development of the district heating system.

TECHNICAL FEASIBILITY

An initial study to assess the technical feasibility of converting the existing turbine units at the Riverside and High Bridge Generating Plants was performed by Ekono Inc. The study was based on turbine technical manual data and Ekono's European experience in turbine conversion to cogeneration-district heating operation.

The feasibility of modifying each unit to permit condensing tail (extraction) or back pressure operation was analyzed, and the available district heating power for each type of conversion was calculated. The thermal and electrical output for the High Bridge units is shown in Table VII. The table illustrates the relationship between the district heating supply water temperature and the electrical derate of the units. The electrical derate of units 5 and 6 at 190^{0} F is one half of the derate at 300^{0} F at approximately the same thermal output. For a 300^{0} F hot water system, 4 MW_t power can be gained for each MWe derate of the units. The potential district heating power available from the converted units is sufficient for a large hot water district heating system.

The next phase of the turbine retrofit program required additional technical detail to be developed. Economic data was also required to support the C. T. Main Inc. study of the St. Paul area. United Engineers and Constructors developed a conceptual design for retrofitting the High Bridge Generating Plant as the heat source for the St. Paul thermal load. The development of the heat source concept required an assessment of the physical condition of the High Bridge Units and their suitability for conversion. The concept was then developed in sufficient detail to guarantee the feasibility of the plant retrofit and the accuracy of the cost estimates. This included arrangement drawings, process and instrument diagrams, heat balance diagrams and a detailed major equipment list. A capital and operating cost estimate was also prepared.

ASSESSMENT OF THE HIGH BRIDGE PLANT

The units were assessed to determine their suitability for conversion to cogeneration. The equipment was inspected and the operating reports were evaluated. Discussions were held with NSP operating and maintenance staff. Meetings were held with the major plant equipment manufacturers. The turbine manufacturers verified the feasibility of modifying the units to cogeneration.

Units 3, 4, and 6 were selected for conversion to cogeneration. The selection is based on the high availability of these units and the projected low maintenance cost to maintain the high availability. Unit 4 is similar to Unit 3 but was not recommended for conversion due to its lower availability and the high cost projected to improve its availability. In addition, the base loaded thermal capacity of the Unit 4 was not required to meet system thermal demand.

COGENERATION SYSTEM DESIGN

The conceptual system design is shown schematically in Figure 12. Unit 3 is converted to a back pressure operation by removal of a portion of the low pressure blading. It is not amenable to steam extraction due to the single casing turbine design. Unit 3 will be operated in a thermal base loaded condition to heat the return water from 150° F to 190° F. Units 5 and 6 are converted to condensing tail operation by the installation of a variable steam by-pass in the external crossover piping between the high pressure and low pressure casings. Condensing tail operation permits the unit to be operated in the summer in the "Electric Generation" mode without loss of electrical capacity. These units will operate in series with Unit 3 to heat the water to a maximum of 300° F for the peak thermal demand of the system. An emergency heat exchanger supplied with boiler steam is used when a cogeneration unit is not available.

OPERATION AND PERFORMANCE

Three thermal load conditions have been defined for operation at various ambient temperature conditions: 1) During "low heating demand" conditions, (48^{o} F or above) Unit 3 can carry the load. Units 5 and 6 operate in the electric only mode, without an electrical derate. 2) During "intermediate heating demand" conditions (11^{o} F to 48^{o} F), Unit 3 must be supported with heat from either Units 5 or 6. 3) During "high heating demand" conditions (less than 11^{o} F), all three units are required to satisfy the heating demand.

When Unit 3 operates at a maximum heating load of 120 MW_t, the maximum electric capacity is 42 MWe; Unit 5 will generate 138 MW_t and 66 MWe, and Unit 6, 186 MW_t and 109 MWe. These figures vary slightly from the initial Ekono estimates due to boiler capacity limitations and additional cooling flow to the LP turbines recommended by the turbine manufacturers.

CONTROL STRATEGY

The turbine control system is designed to maintain normal operating temperature and pressure conditions within the turbine, for both the "Cogeneration" or "Electric Generation" modes of operation. The proposed control stategy is acceptable to the turbine manufacturers. It is designed to protect the equipment during upset conditions and to provide reliable district heating service.

When LP steam is extracted at the LP crossover for district water heating, the steam flow to the LP stages of the turbine is decreased by an equal amount. Thus, the pressure and temperature conditions within the IP and LP sections of the turbine are not altered when changing the amount of LP steam extracted as the temperature and pressure conditions within the IP and LP stages depend only upon the total steam flow through these stages.

The steam flow to the LP section is permitted to decrease to the minimum required for adequate cooling of the LP stages. The steam flow to the district heating heat exchanger is not permitted to increase when the steam flow to the LP section of the turbine reaches the 22% minimum value of LP turbine normal flow.

CAPITAL AND OPERATING COSTS

A detailed capital cost estimate is shown in Table VIII. The costs are based on 1978 equipment prices and labor rates and include indirect costs such as engineering and construction management. Included in the estimate are costs required to convert Units 3, 5, and 6 and also the estimated costs for major repairs or maintenance required to extend the life of these units. The costs are production costs at the High Bridge Station and do not include amortization costs of the distribution system or other distribution costs such as pumping power.

Based on the system thermal cogeneration output of 444 MWe and the $9,000,000 conversion costs, the unit cost of cogeneration is approximately $20/KWt. When the $3,000,000 maintenance cost required to extend the life of the units is added, the unit cost of cogeneration is $27/KWt.

The operating costs for electrical and thermal energy were developed using a cost allocation method that maintains electrical costs equal to separate electrical generation costs and develops thermal costs that are less than half those obtained from separate heat-only boiler thermal generation. The cost of electricity produced at the High Bridge Plant is defined from its historic base, and this value is subtracted from the overall cost of operating the cogeneration station. The remaining costs, including amortization of the retrofit costs, represent the cost of producing thermal energy. This allocation method encourages conversion to district heating but does not penalize electric customers. Annual thermal energy costs at the plant for Units 3, 5, and 6 are $1.04 per million Btu. This includes $0.58 in fixed costs and $0.46 in operating costs.

CONCLUSIONS

Studsvik has developed an implementation scenario for a large regional hot water district heating system. The analysis concluded that the concept is technically feasible, has great value from a fuel conservation aspect, and can achieve viable economics with an appropriate financing system. The 2600 MWt system servicing a significant portion of the two cities would be economically viable with joint municipal-private financing. Typical utility financing alone may not be a viable option for such a large system. However, a possible scenario using utility financing could service the more attractive high heat load density regions, but not the lower heat load density areas.

Northern States Power Company has examined retrofitting the existing High Bridge Power Plant to serve as a heat source for district heating. The results indicate that 300° F hot water can be supplied without a substantial loss in generating capacity at an estimated capital cost of $\$20/KW_t$. This is less than the capital cost of a new oil or gas fired boiler at approximately $\$40/KW_t$.

Northern States Power Company is involved in a study looking at the initial development of a hot water district heating system for the central portion of the city of St. Paul. This system is a subset of the overall scenario outlined by Studsvik. The goal of this study is to supply the details not provided in the Studsvik work to enable the utility to make a decision concerning the implementation of a hot water district heating system. The financial analysis for this work is not complete at the present time, and meaningful conclusions cannot be drawn.

In summary, the preliminary analysis of the feasibility of a district heating system for the Minneapolis-St. Paul area is nearing completion, and the results show that significant savings in oil and natural gas are possible. It is uncertain, however, as to what type of financing (i.e., utility, municipal, or some combination of these) would be most suitable to implement such a system. This question and others need to be resolved in order to bring about the successful development and growth of cogeneration/district heating systems which can be a significant benefit to both local and national interests.

REFERENCES

1. J. Pearce, M. Karnitz, M. Barnes, and A. Rubin, "Large-Scale District Heating and Cogeneration - Twin Cities Studies", presented at American Power Conference, April 24-26, 1978, Chicago, Illinois.
2. Studsvik Energiteknik AB, Minneapolis/St. Paul District Heating Study, Draft of Final Report, February 1979.
3. Minnesota Energy Agency, District Heating Conversion Methods and Costs for Existing Buildings, Draft of Final Report, 1978.

TABLE I MINNEAPOLIS - ST. PAUL DISTRICT HEATING STUDIES

I.	DISTRIBUTION AND BUILDING SYSTEMS	SPONSOR
	Studsvik District Heating Study	DOE
	St. Paul - District Heating Study	NSP
	Building Conversion Study	DOE
II.	ENERGY SOURCES STUDIES	
	Retrofiting an Existing Coal Plant	NSP
	New Coal/Cogeneration Plant Assessment	NSP & DOE
	Nuclear Cogeneration Plant Assessment	DOE
III.	INSTITUTIONAL ISSUES	
	Ownership Option and Barriers	DOE
IV.	ENVIRONMENTAL	
	Air Quality Modeling	DOE

TABLE II AREA TYPES AND HEAT DEMAND

Type of Area		Minneapolis (MW_t)	St. Paul (MW_t)	Total (MW_t)
1.	Very dense downtown areas with existing DH systems (>70 MW/km^2)	206	60	266
2.	Other large customers needing special consideration	100	191	291
3.	Dense downtown area (>50 MW/km^2)	313	244	557
4.	Medium density districts with commercial buildings and multi-family apartment buildings (25-50 MW/km^2)	1000	286	1286
5.	Residential areas with two-family and four family houses (10-25 MW/km^2)	370	195	565
6.	Total load, including special customers	1989	976	2965
7.	SCENARIO A TOTAL	1781	840	2621
	<u>Additions for Scenario B</u>			
8.	Large customers needing special consideration	48	51	99
9.	Residental areas (10-25 MW/km^2)	1105	826	1931
10.	Total additions	1153	877	2030
11.	SCENARIO B (potential)	2934	1717	4651
12.	SCENARIO B with 70% connection of item 10	2588	1454	4042

TABLE III COGENERATION PLANTS

Power Plant Unit	Original Electrical Output MW_e	Cogeneration Output 1) MW_e	MW_t	Conversion Cost ($ Million)	Start of Operation (year) 4)
Existing Units					
High Bridge No. 3	62	48	117	3.3	10
High Bridge No. 4	62	48	117	3.3	6
High Bridge No. 5	102	64	157	4.0	3
High Bridge No. 6	156	98	240	4.5	2
Riverside No. 6	62	48	110	3.3	2
Riverside No. 7 2)	55	52	110	0.0	7
Riverside No. 8	216	127.5	330	5.5	2
Total	716	485.5	1181	23.9	
New Units	Maximum Electric Output MW_e			Extra Cost 3) ($ Million)	
High Bridge 9 or Riverside No. 9 (Scenario A)	240	190	335	29	12
King (Scenario B)	900	2 x 400	2 x 350	72	18
TOTAL, SCENARIO A	956	675.5	1 516	53	
TOTAL, SCENARIO B	1616	885.5	1 881	96	

1) Simultaneous maximum electrical and maximum thermal power output.

2) New back pressure turbine installed in existing building to match existing boiler. Value of additional electrical power gained is estimated to equal cost, therefore no charge to district heating system.

3) Additional cost due to economy of scale as compared to normal large capacity units at remote sites.

4) Assuming start of distribution system construction in year 0

TABLE IV DISTRICT HEATING SYSTEM INVESTMENTS, SCENARIO A. (1978 DOLLARS)

	Total Cost (Million $)	Unit Cost * ($ per KW)
Cogeneration plants	55	21
Peak load boilers	79	30
Production plant total	134	51
Hot water transport	81	31
Hot water distribution	256	98
Transport and distribution total	337	129
Production, transport, distribution	471	180
Building conversion	125	50
System total	596	230

* Based on 2621 MW_t Maximum System Demand

TABLE V SENSITIVITY OF NET ACCUMULATED SAVINGS TO CHANGES IN ASSUMPTION (MILLION 1978 DOLLARS)

	Net Accumulated Saving		Change From Base Case	
	Municipal Financing	Private Utility Financing	Municipal Financing	Private Utility Financing
1. Base case	208.60	-54.56	-	-
2. 20% lower transmission and distribution costs	246.87	20.29	+35.27	+34.27
3. 90% connection without change in transmission and distribution cost	162.74	-69.58	-45.86	-15.03
4. Building conversion costs charged to district heating reduced from 60% to 50%	224.37	-42.54	+15.77	+12.03
5. 1% per year faster oil and gas price increases	333.86	-1.39	+125.26	+53.17
6. 50% higher coal costs	107.90	-101.90	-100.70	-47.36
7. District heating price at 5% below lowest alternative fuel instead of 10% below	260.09	-30.58	+51.49	+23.98

TABLE VI PRICE OF ALTERNATE FUELS
(1978 $/MILLION BTU OF DIRECT HEAT)

Year	Oil	Natural Gas	Electricity
1978	3.25	2.08	8.33
1985	5.21	6.25	12.80
1990	7.28	9.28	15.84
1995	10.41	12.54	19.37
2000	14.70	16.92	23.67

NOTES:
1) Inflation is 5.3% 1978 to 1985 and 4.2% 1985 to 2000
2) Oil cost is 2.8% above inflation
3) Gas cost is 2.6% above inflation
4) Boiler conversion efficiency is 80%

TABLE VII HIGH BRIDGE TURBINE CONVERSION DATA

Unit - Conversion (1) Supply/return temp. °F	Original Rating MWe	Simultaneous Cogeneration MWe	Simultaneous Cogeneration MWt	Derate MWe
Unit 3 & 4 - C. T. 131/190° F	62	50	118	12
Unit 3 & 4 - B. P. 131/190° F	62	50	119	12
Unit 5 - C. T. 190/300° F	102	59	154	43
Unit 5 - B. P. 131/190° F	102	83	157	19
Unit 6 - C. T. 190/300° F	156	97	218	59
Unit 6 - B. P. 131/190° F	156	127	227	29

1) CT - condensing tail; BP = back pressure

TABLE VIII CAPITAL CONVERSION COSTS

Equipment	Retrofit Cost	Maintenance Cost
Structures and Improvements	$ 30,000	--
Boiler Plant Equipment	4,105,000	$2,450,000
Turbine-Generator Units	2,880,000	--
Accessory Electric Equipment	315,000	--
Total Direct Costs	7,330,000	2,450,000
Indirect Costs	620,000	200,000
	7,950,000	2,650,000
Contingency	1,050,000	350,000
Total	$ 9,000,000	$3,000,000

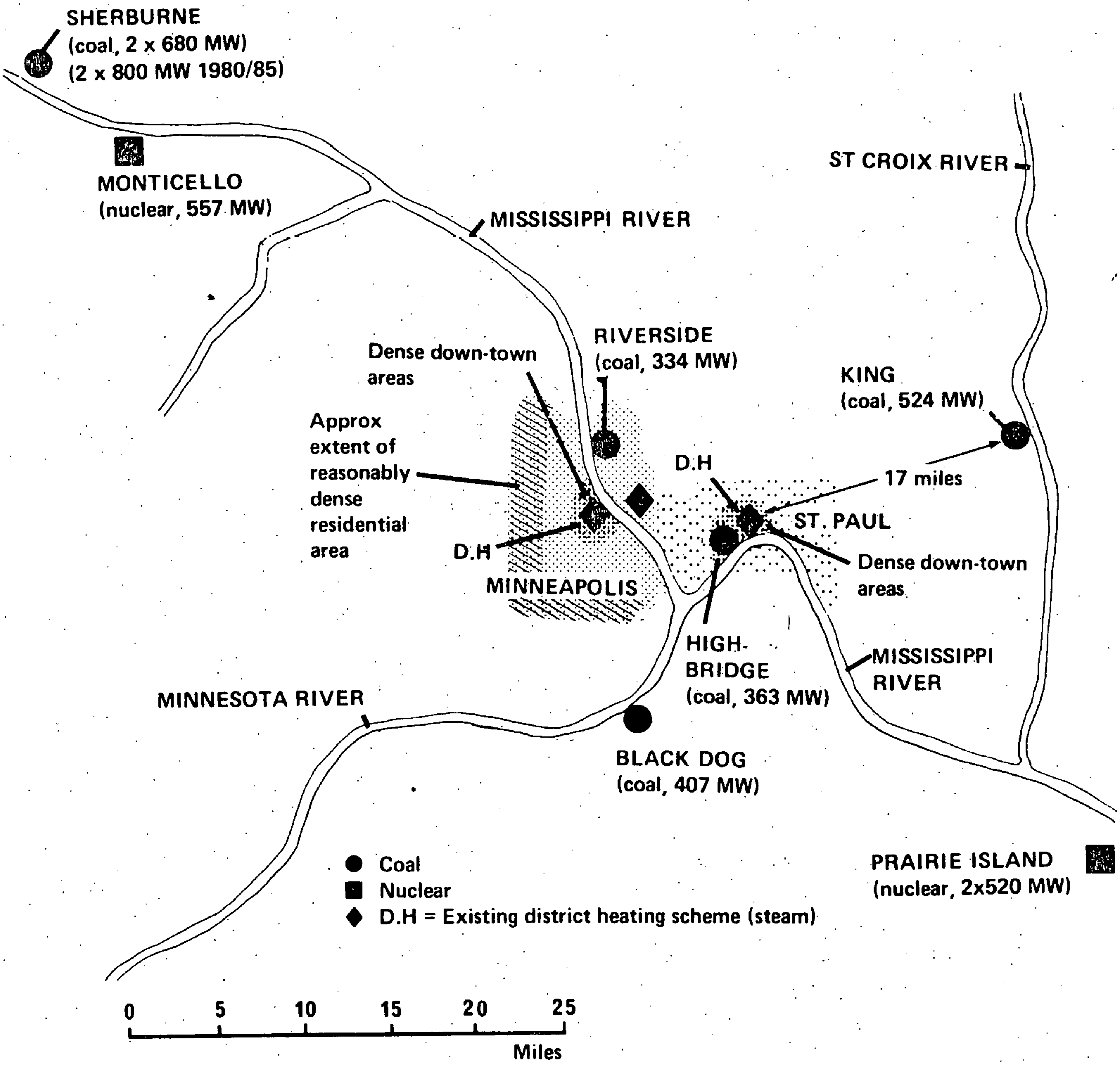
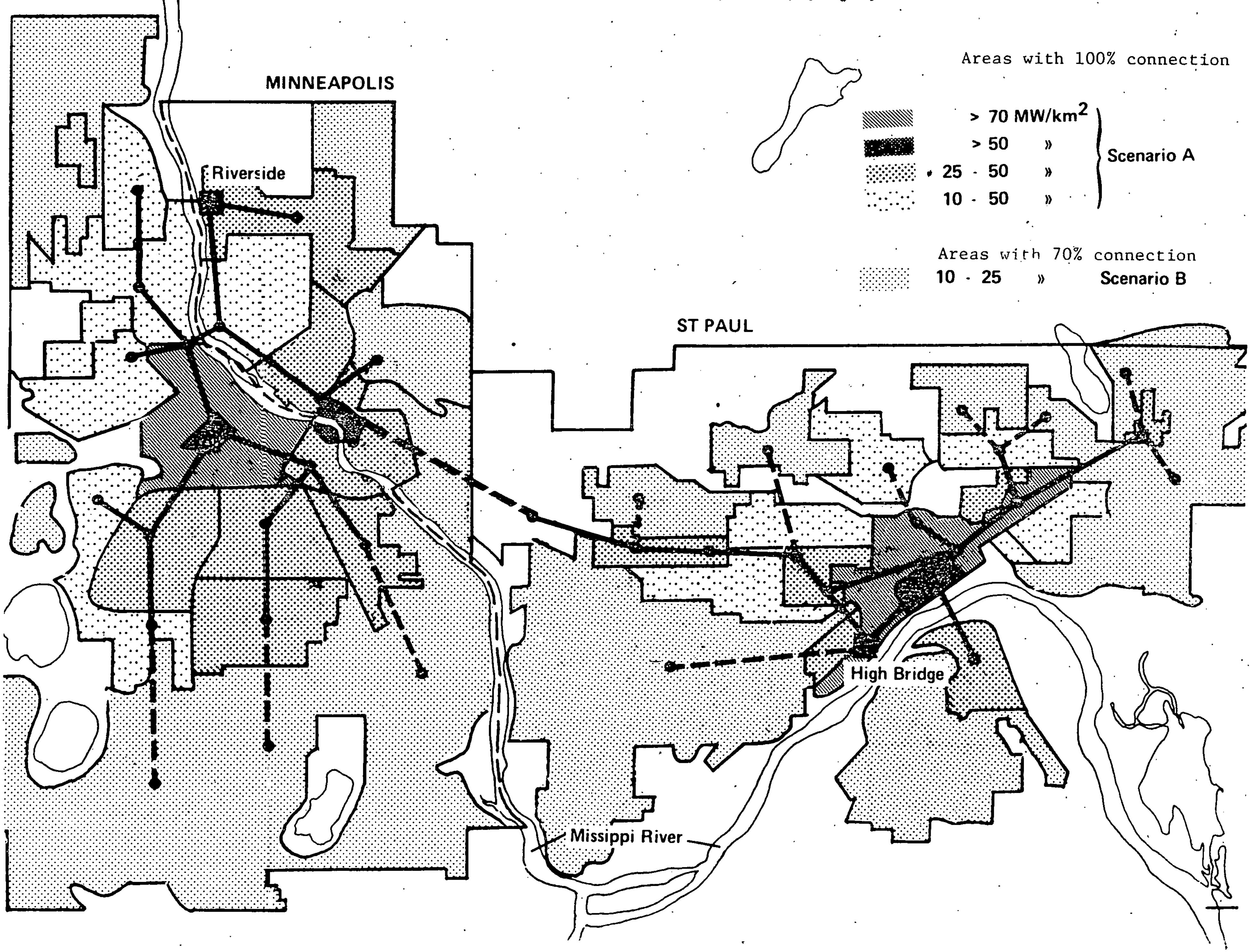


Fig. 1. Area map with main thermal power plants.

Fig. 2. Heat load densities and possible regional piping systems.



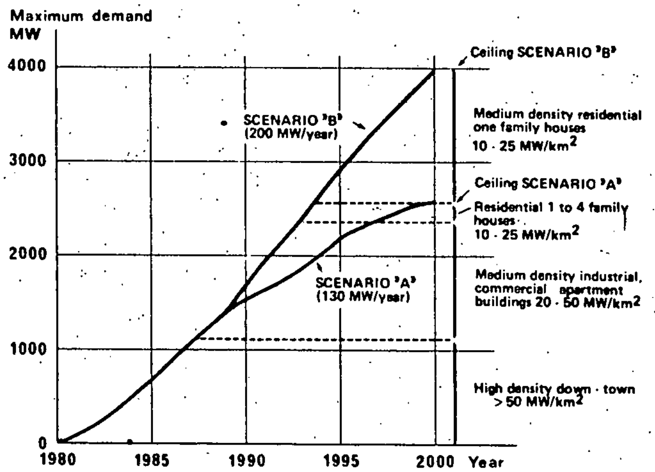


Fig. 3. Assumed load connection rates for Scenarios A and B.

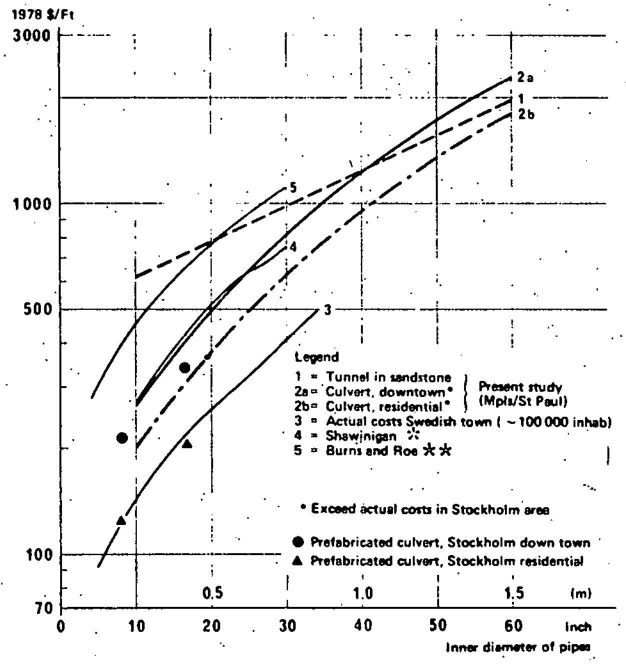


Fig. 4. Total installed cost of two-way hot water line (urban).

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*"District Heating, Cooling and Solid Waste Conversion" The Shawinigan Engineering Company Limited, Ottawa, Canada, March 1977, (Costs are presented in 1977 dollars).

**I. Oliker and J. Phillip, "Technical and Economic Aspects of District Heating Systems Supplied from Cogeneration Power Plants", American Power Conference, Chicago, IL, April 1978, (Costs are presented in 1977 dollars).

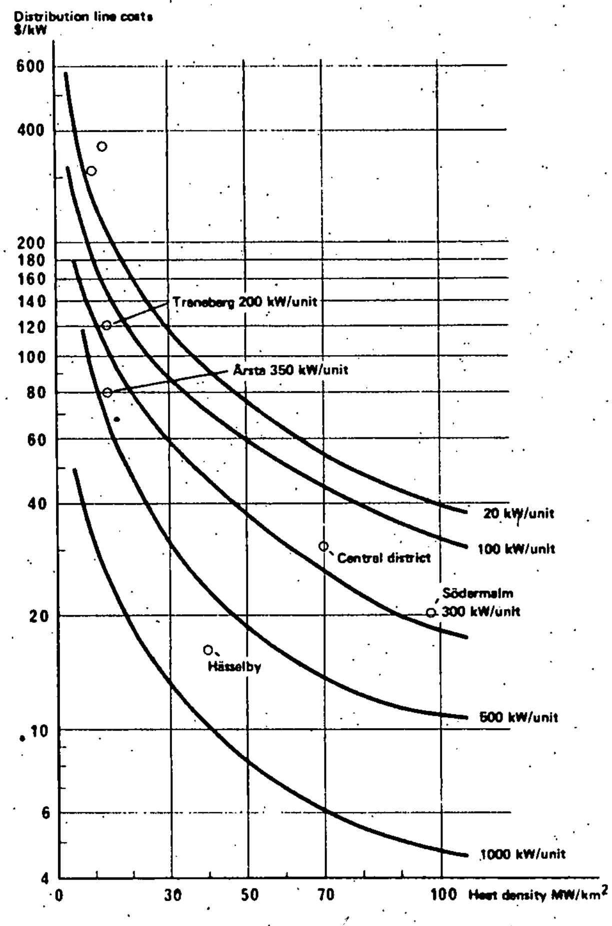

Fig. 5. Distribution network cost as a function of heat density (Stockholm's cost figures).

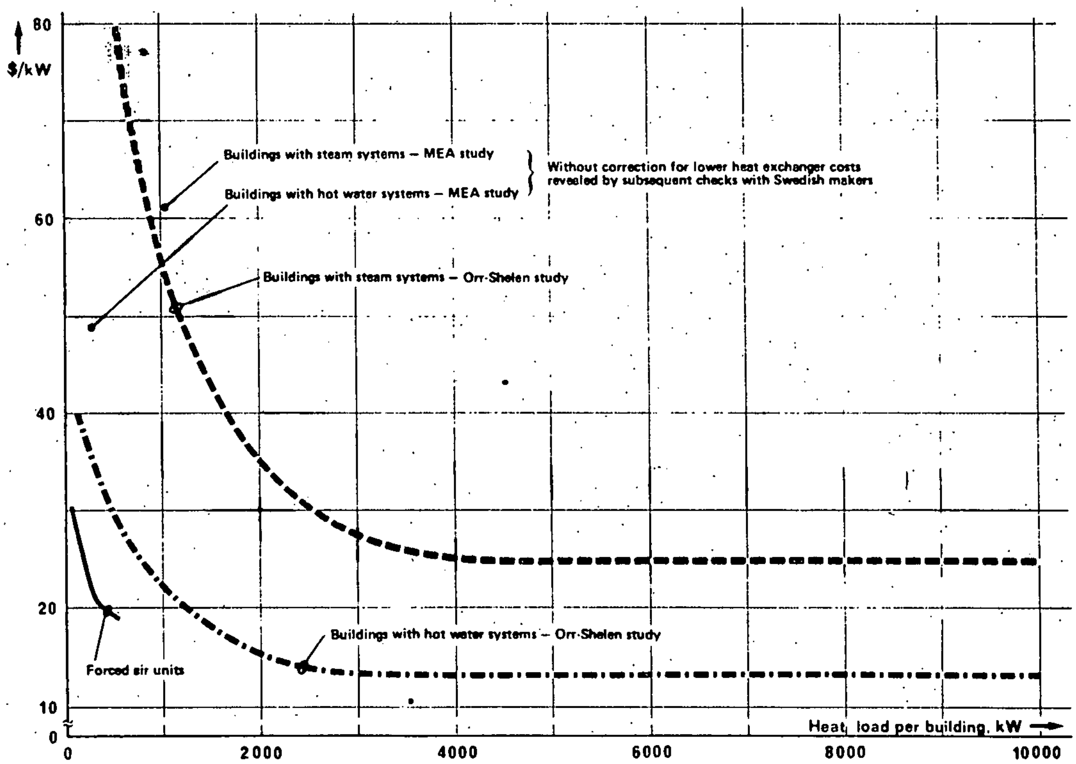

Fig. 6. Cost of building heating systems conversions. (See Reference 3).

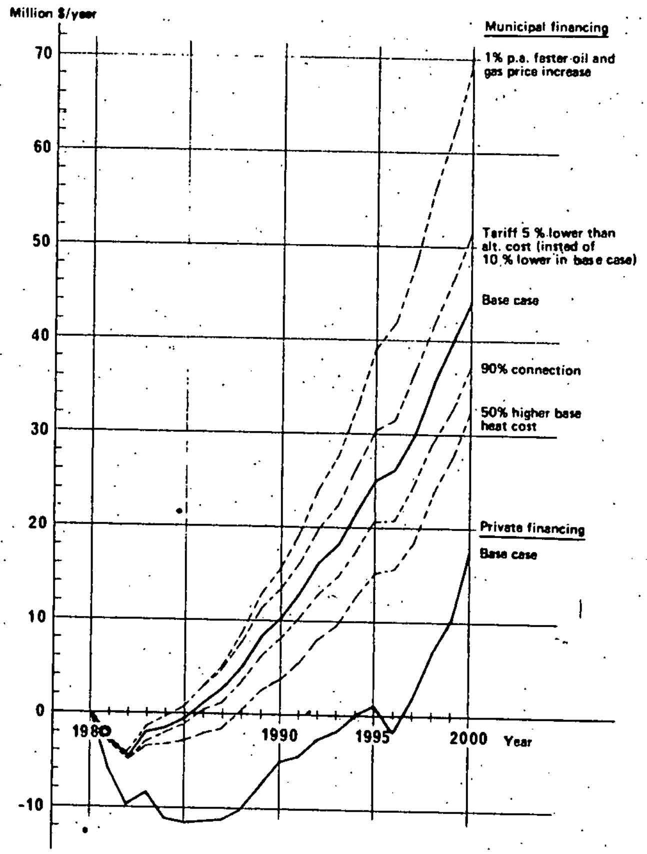

Fig. 7. Annual net savings in 1978 dollars.

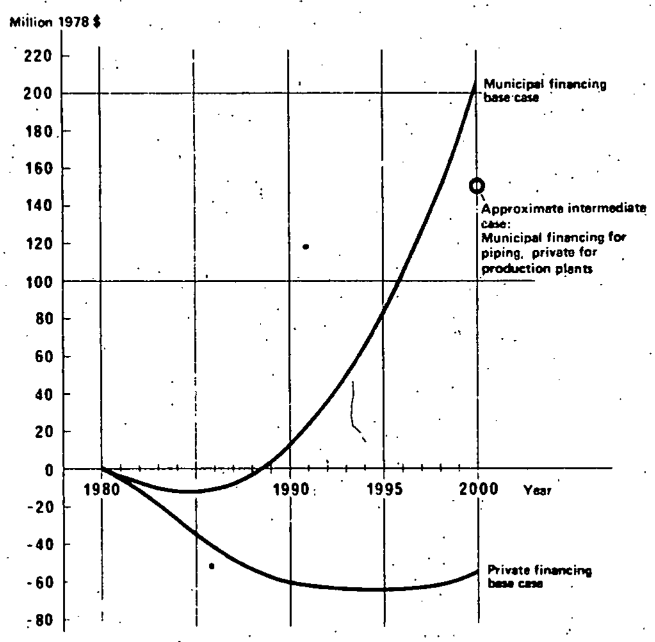

Fig. 8. Accumulated present worth of net savings for base case.

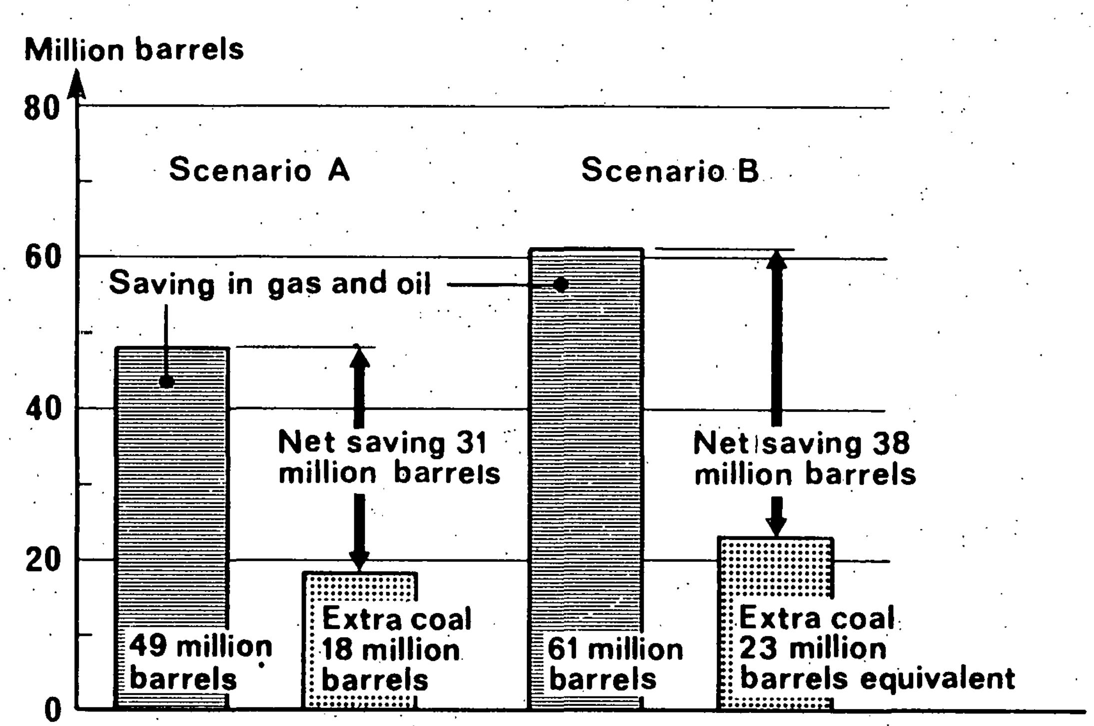

Fig. 9. Fuel savings due to district heating, 1980 to 2000, Scenario A and B.

ZONE 1: LARGE INSTITUTIONS

ZONE 2: STATE CAPITOL COMPLEX

ZONE 3: COMMERCIAL BUILDINGS

ZONE 4: INDUSTRIAL AREA

ZONE 5: MIXED BUSINESS AND LARGE INDUSTRY

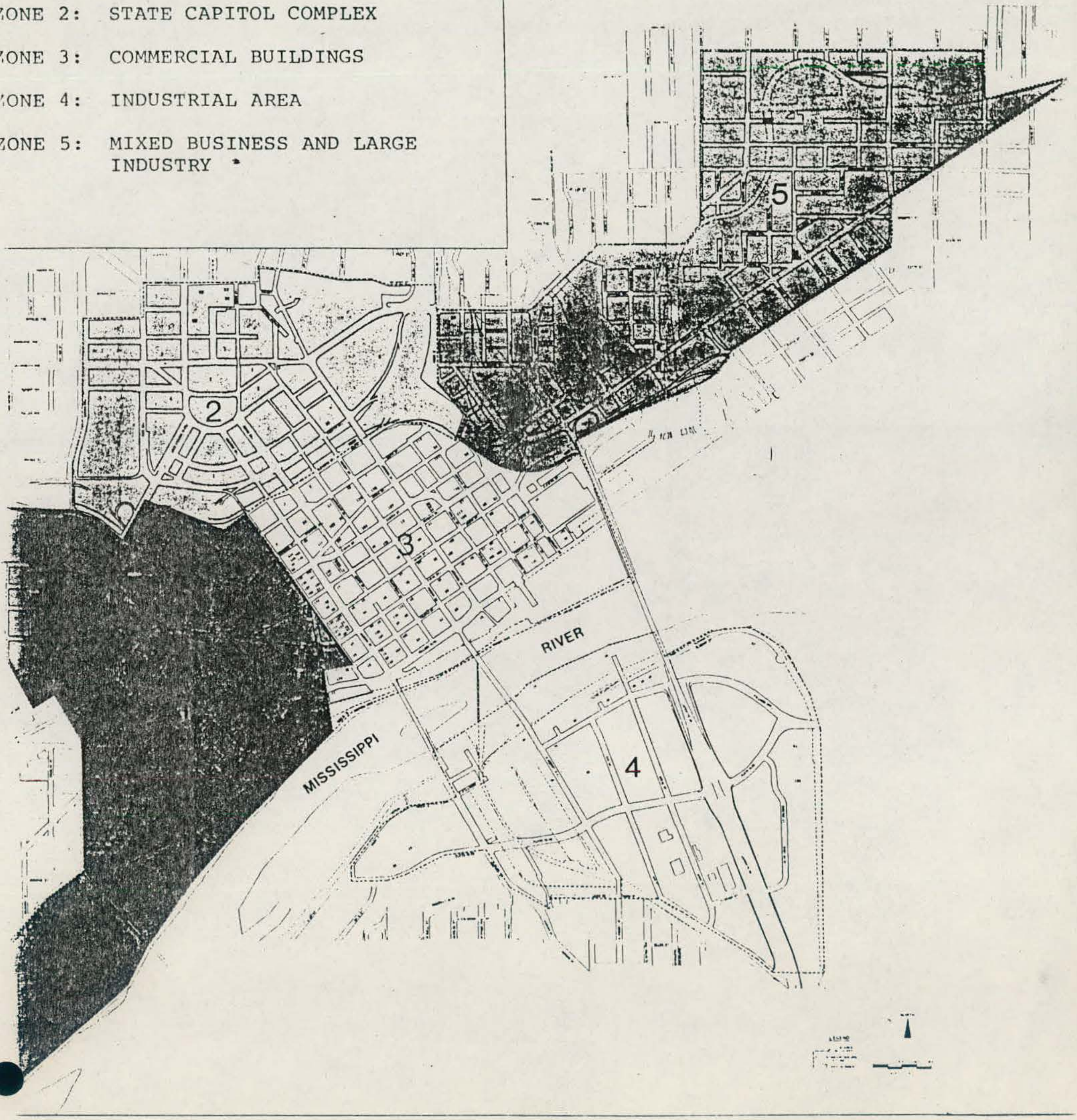

FIGURE 10 ST. PAUL STUDY AREA

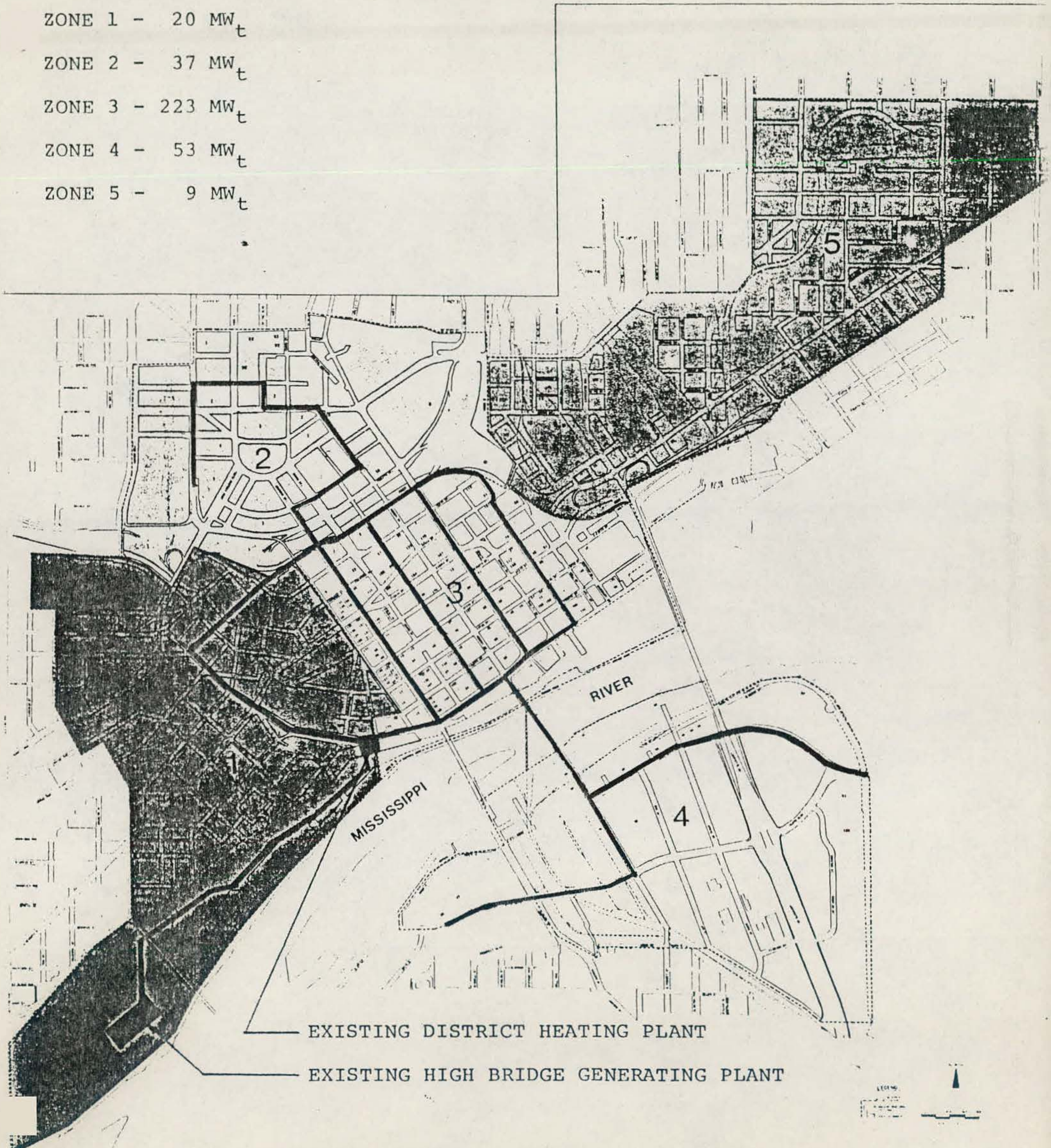

FIGURE 11 ST. PAUL DISTRICT HEATING SYSTEM