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ENERGY
CONSERVATION

DISTRICT HEATING AND COOLING SYSTEMS FOR COMMUNITIES THROUGH POWER PLANT RETROFIT AND DISTRIBUTION NETWORKS

Final Report, Phase I—Identification and Assessment

September 1979

Work Performed Under Contract No. EM-78-C-02-4981

Wisconsin State Energy Office
Madison, Wisconsin

U. S. DEPARTMENT OF ENERGY

Division of Buildings and Community Systems

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PHASE I - IDENTIFICATION AND ASSESSMENT

FINAL REPORT

VOLUME I - EXECUTIVE SUMMARY

SEPTEMBER 1979

WISCONSIN STATE ENERGY OFFICE

PREPARED FOR:
U.S. DEPARTMENT OF ENERGY
CHICAGO OPERATIONS OFFICE
UNDER CONTRACT EM-78-C-02-4981

3.0 OBJECTIVES

The Phase I Identification and Assessment Study was aimed at surveying the State of Wisconsin to identify potential sites for a district heating system and evaluating these sites in terms of their technical, institutional and economic merits. Specific objectives of the study were to:

- Identify candidate plants and service areas,
- Perform an energy market analysis for selected areas,
- Identify and evaluate plant retrofit and distribution alternatives for the selected service areas,
- Identify and evaluate institutional problems within the infrastructure,
- Perform an economic analysis for the candidate sites, and
- Select the most promising site for further study.

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1.0 INTRODUCTION

Two functions of the Department of Energy are to investigate and disseminate information on efficient use of energy. As part of this effort, DOE sponsored the District Heating and Cooling System (DHCS) for Communities through Power Plant Retrofit and Distribution Networks, Phase I Identification and Assessment Study. The study assesses the preliminary technical, economic and institutional feasibility of district heating systems achieved by retrofitting existing utility power plants in three Wisconsin cities: Green Bay, Janesville/Beloit and Madison.

District heating is the use of one or more central heat sources to supply the low to moderate thermal needs of a community through a distribution system. The central heat source can be a heat-only boiler or a cogeneration (e.g., power plant producing both electric and thermal energy) facility. This type of system is becoming the dominant mode of operation in urban areas of the Scandinavian and Soviet Bloc countries.

The results of this study, which was performed over a nine-month period, are contained in this report. The Phase I study was performed by the following team of state agencies, industries and utilities:

Contractor: Wisconsin Office of State Planning and Energy
Madison, Wisconsin

Subcontractors: Honeywell Inc.
Energy Resources Center
Minneapolis, Minnesota

American Hydrotherm Corporation
New York, New York

Wisconsin Public Service Commission
Madison, Wisconsin

Madison Gas and Electric Co.
Madison, Wisconsin

Wisconsin Power and Light Co.
Madison, Wisconsin

Wisconsin Public Service Corporation
Green Bay, Wisconsin

Manitowoc Public Utilities
Manitowoc, Wisconsin

Wisconsin Electric Power Co.
Milwaukee, Wisconsin

Results of the study are published in three volumes:

- Volume I - Executive Summary,
- Volume II - Detailed Results,
- Volume III - Appendices.

Volume I is a brief synopsis of the project and its results. Volume II contains the assumptions that were used, a description of the approach and detailed results. Volume III, the Appendices, contains detailed background information used during the study.

2.0 STATEMENT OF THE PROBLEM

In a conventional utility power plant, about 35 percent of the usable energy derived from fuel burned is transformed into electricity. In a typical cogeneration facility, such as one found in Sweden, 20 to 25 percent of the fuel burned is transformed into electricity and 45 to 55 percent is transformed into thermal energy. Thus, in a cogeneration facility 65 to 80 percent of the fuel burned is transformed into usable energy forms compared with 35 percent from a conventional (electric only) power plant.

The energy conservation potential of a cogeneration facility is obvious. Space and water heating needs supplied through more efficient cogeneration district heating systems will free considerable supplies of scarce fossil fuels (natural gas and/or fuel oil) for other uses. The long-term economic benefits include more stable costs for space and water heating needs, since these costs would be tied to the price of coal at the electric generating station rather than to the more rapidly escalating prices of natural gas and fuel oil. In an area with air pollution problems (such as a nonattainment area), a cogeneration district heating system might well enhance that area's ability to attract new industry. At present, an industry that depends on burning coal to supply its heat energy needs probably would not be allowed to locate in a nonattainment area. However, if these heat needs could be supplied by a district heating system, the industry would not have to burn coal and could locate in the nonattainment area.

To examine the feasibility of the district heating concept, the Department of Energy initiated a seven-phase program entitled "District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks." The initial phases of the program are aimed at identifying and evaluating potential sites, institutional problems and financial arrangements.

Later phases are aimed at detailed design and construction of promising projects. Final phases are aimed at initial testing, start-up and operational evaluation of the demonstration project.

This project contains the results of the Phase I Identification and Assessment Study for the State of Wisconsin.

4.0 APPROACH

The overall methodology employed on the Phase I study is illustrated in Figure 1. Team members responsible for each task/subtask are also identified.

The overall approach consisted of surveying the State of Wisconsin to identify all existing intermediate and base-loaded electric generating facilities. Once identified, screening criteria were developed to narrow the list to the three most promising sites. For each of the three sites, an extensive market analysis was performed to identify and characterize thermal loads and survey potential users on their views and concerns regarding the concept. Parallel to this effort, each of the three sites was evaluated on its technical and institutional merits. The technical evaluation centered on identifying and evaluating utility plant retrofit schemes and distribution system alternatives to service the identified thermal market. The institutional analysis evaluated potential barriers such as environmental, distribution system right-of-way, and legal issues within the infrastructure of the state, city and community. Finally, all previous aspects of the analysis were combined to determine the economic viability of each site.

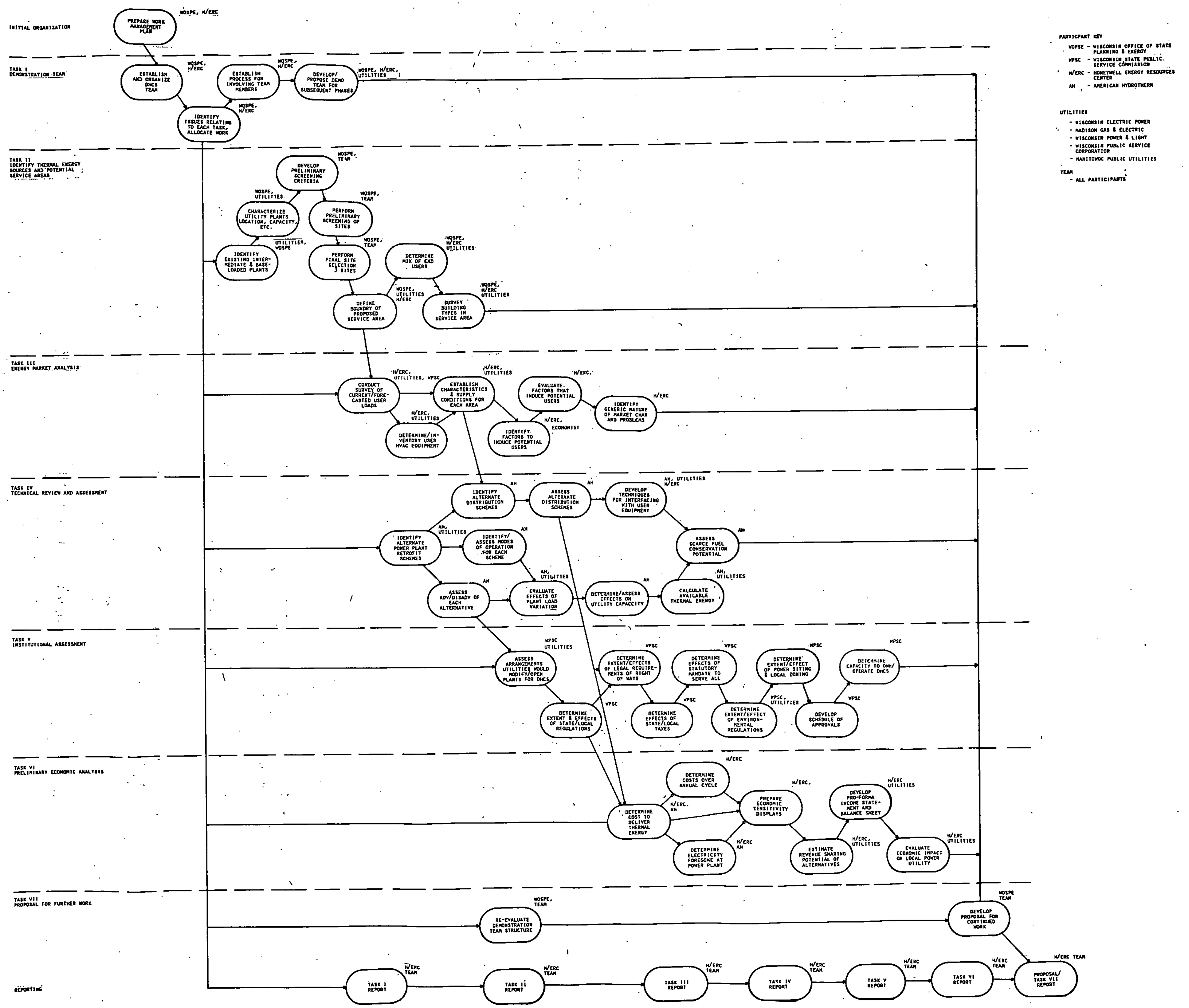

Figure 1. Phase 1 Study Approach, District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks

5.0 RESULTS

5.1 SITE SELECTION

Eighteen existing intermediate/base-loaded generating plants were identified and characterized by location, capacity, ownership, fuel type and capacity factor. To select the most promising sites, the following criteria were developed:

- Thermal density of the potential heat load and its characterization,
- Remaining expected lifetime of the generating units,
- Potential environmental benefits accruing to the area through cogeneration,
- Reliability and/or backup capability for the DHCS,
- Facility load factor.

After two levels of screening, three sites were determined to have the greatest potential for DHCS retrofit modifications:

- Green Bay--served by the Pulliam Plant,
- Janesville/Beloit--served by the Rock River and Black Hawk Plants,
- Madison--served by the Blount Street Plant.

5.1.1 Green Bay

The geographical areas selected (Figure 2) include the Central Business District (CBD) and the Industrial Area (three paper mills) located across the Fox River from the power plant. The CBD offers a concentration of multistory retail stores, office buildings, hotels and city-county buildings. The area is currently being renovated and offers great potential for future markets for a DHCS. The three paper mills are concentrated in a small area

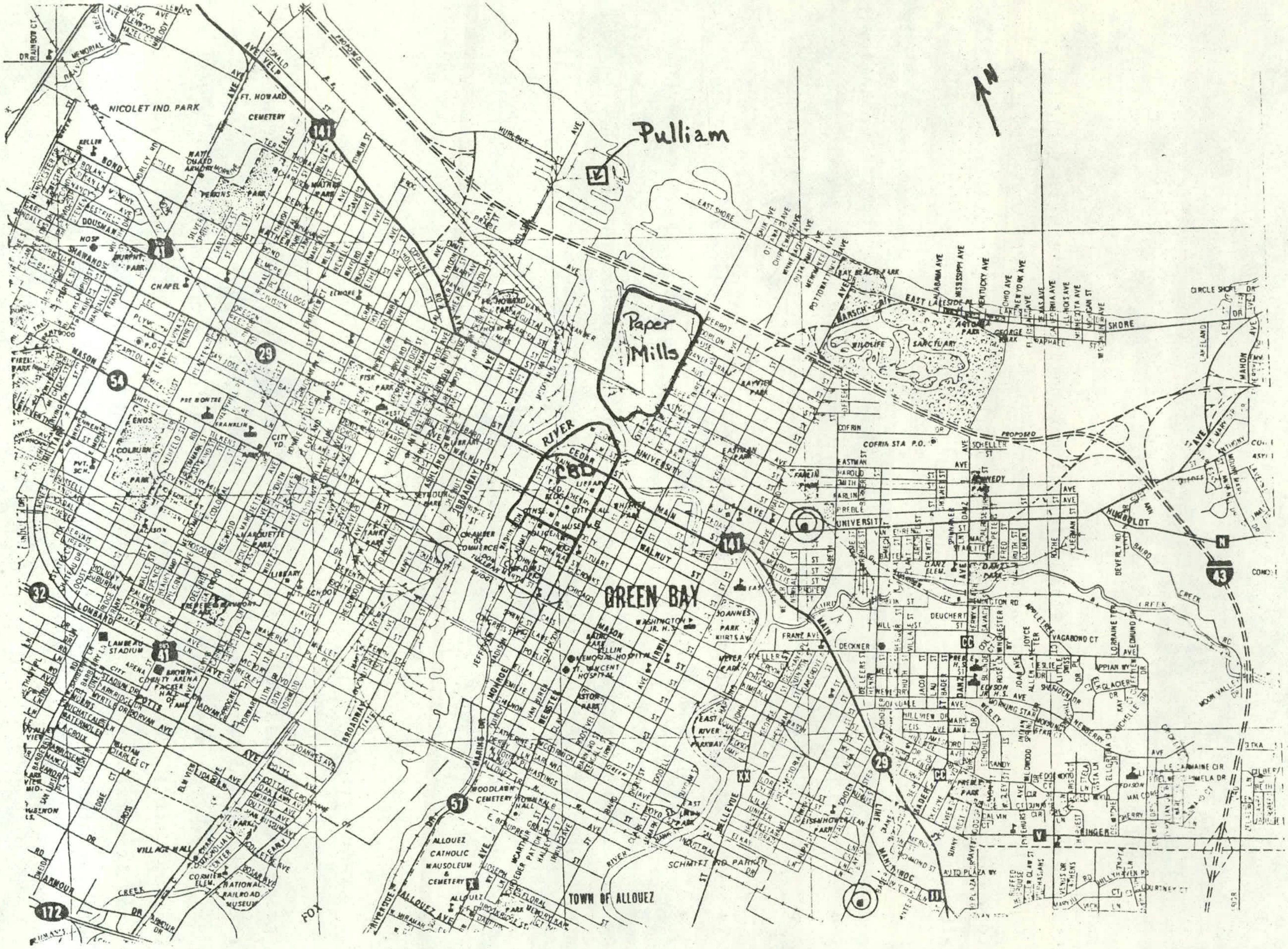

Figure 2. Green Bay Area

and use a large amount of process steam and process hot water. Boiler makeup water is extracted from the city water system and process water from the Fox River.

Thermal requirements for this service area were derived using actual gas consumption data (1977-1978) obtained from the Wisconsin Public Service Corporation and from discussions with representatives of the paper mills.

Consumption data were converted to load data by using an efficiency factor of 75 percent.

The thermal loads (Btu x 10^9/year) for Green Bay are:

Current		Future	
CBD	238.7	CBD	64.0
Industrial	3465.0		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
CBD	89.0	CBD	38.0
Industrial	401.00		

The types and percentages of fuel currently consumed are:

Area	Fuel	Percentage
CBD	Natural Gas	100
Industrial	Natural Gas	17
	No. 6 Fuel Oil	17
	Coal	66

In the vast majority (82 percent) of the buildings, natural gas-fired boilers are the source of space heating. Of those, about 66 percent use steam for distribution and 34 percent use hot water.

Gas-fired hot water heaters are used in a majority of the buildings. In buildings that have a large hot water requirement (i.e., hotel/motels), steam or hot water heat exchangers are used.

The majority of the air conditioning equipment consists of small window units, which is indicative of the general age of the buildings. Larger department stores and the shopping plaza have central electric chillers. One building had a central absorption unit, but it was scheduled to be taken out because of operational problems.

5.1.2 Janesville/Beloit

The cities of Janesville and Beloit were analyzed together because of the close geographical locations of both the communities and power plants.

The areas selected for detailed analyses are illustrated in Figure 3 and include the Janesville CBD and areas to the south of it, the Beloit CBD and areas near it, and the industrial area east of Beloit.

The thermal market in this selected area can be described as:

- Beloit thermal loads that are very close to the Black Hawk Power Plant--these loads include the Beloit CBD, industry and Beloit College, and are appropriate for consideration of a very compact distribution network.

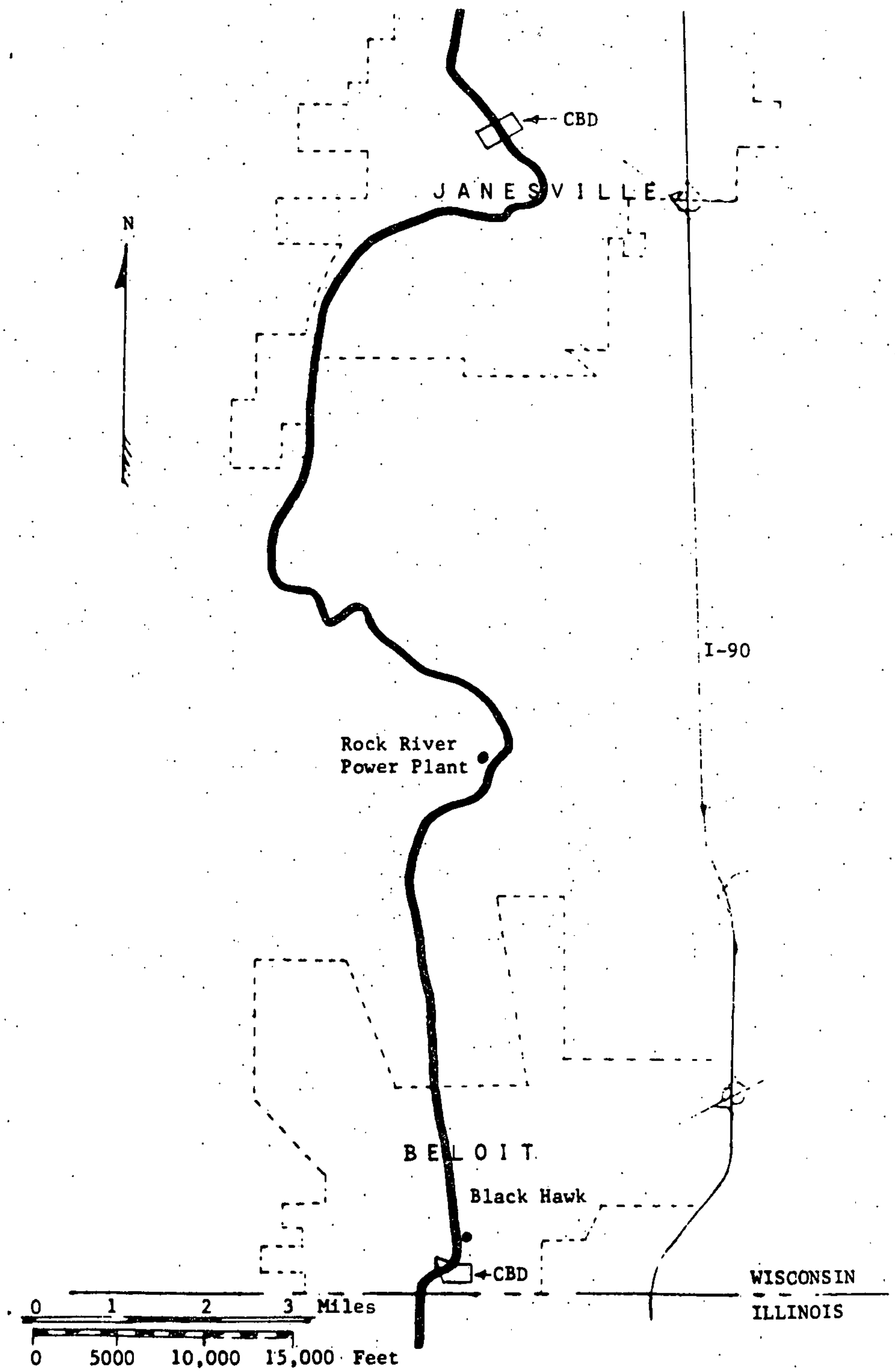

Figure 3. Janesville/Beloit Service Area

- South-of-Janesville thermal loads that are applicable to a network off a pipe from the Rock River Power Plant, with or without a connection to Black Hawk--these loads include the Janesville CBD, industry, and schools.
- Additional thermal loads north and east of Beloit (called Beloit "other")--these loads include industry, schools and a hospital.

The thermal loads (Btu x 10^9/year) for Janesville/Beloit are:

Current		Future	
Janesville CBD	31.9	Janesville Industry	1010.0
Janesville Industry	1192.6		
Beloit CBD	27.6		
Beloit Industry	1131.4		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
Janesville CBD	12.0	Janesville Industry	250.0
Janesville Industry	295.0		
Beloit CBD	11.0		
Beloit Industry	416.0		

The types and percentages of fuel currently consumed are:

Fuel	Percentage
Coal	35
Natural Gas	65

Space and process heating in 90 percent of the "blocks" (i.e., CBD block, industrial plant, or school, etc.) is provided by natural gas-fired boilers. Five percent use natural gas-fired space heaters and five percent use coal boilers plus gas space heaters. Oil is the predominant backup fuel for the boilers (50 percent of the blocks), LP gas is used as backup in 14 percent of the cases, coal is used as backup in five percent of the cases, and 27 "blocks" have no backup.

Hot water is provided by gas hot water heaters and steam-to-water heat exchangers on a 50/50 ratio.

The majority of the air conditioning equipment consists of small window units. Larger businesses have central electric chillers. Two "blocks" use central absorption units.

5.1.3 Madison--Served by the Blount Street Plant

The areas selected for detailed analysis (Figure 4) include the Central Business District (plus those buildings heated by the Capitol Heating Plant) and the University of Wisconsin campus. The CBD area encompasses about 100 city blocks of multistory commercial retail and hotel/motel buildings and includes those buidlilngs (i.e., office) served by the Capitol Heating Plant. The University of Wisconsin occupies an area about the size of the CBD. The campus contains about a 150 multistory classroom, office and dormitory buildings.

The current thermal load was derived using natural gas consumption data and steam supply data (1977-1978) supplied by Madison Gas and Electric Company. Load data for the Capitol Heating Plant and the University of Wisconsin were derived by assuming that 1000 pounds of steam equals 10^6 Btu. Almost 100 percent of the buildings in the central business district have natural gas-fired boilers. Of these, about 80 percent have steam distribution systems; the remainder have hot water.

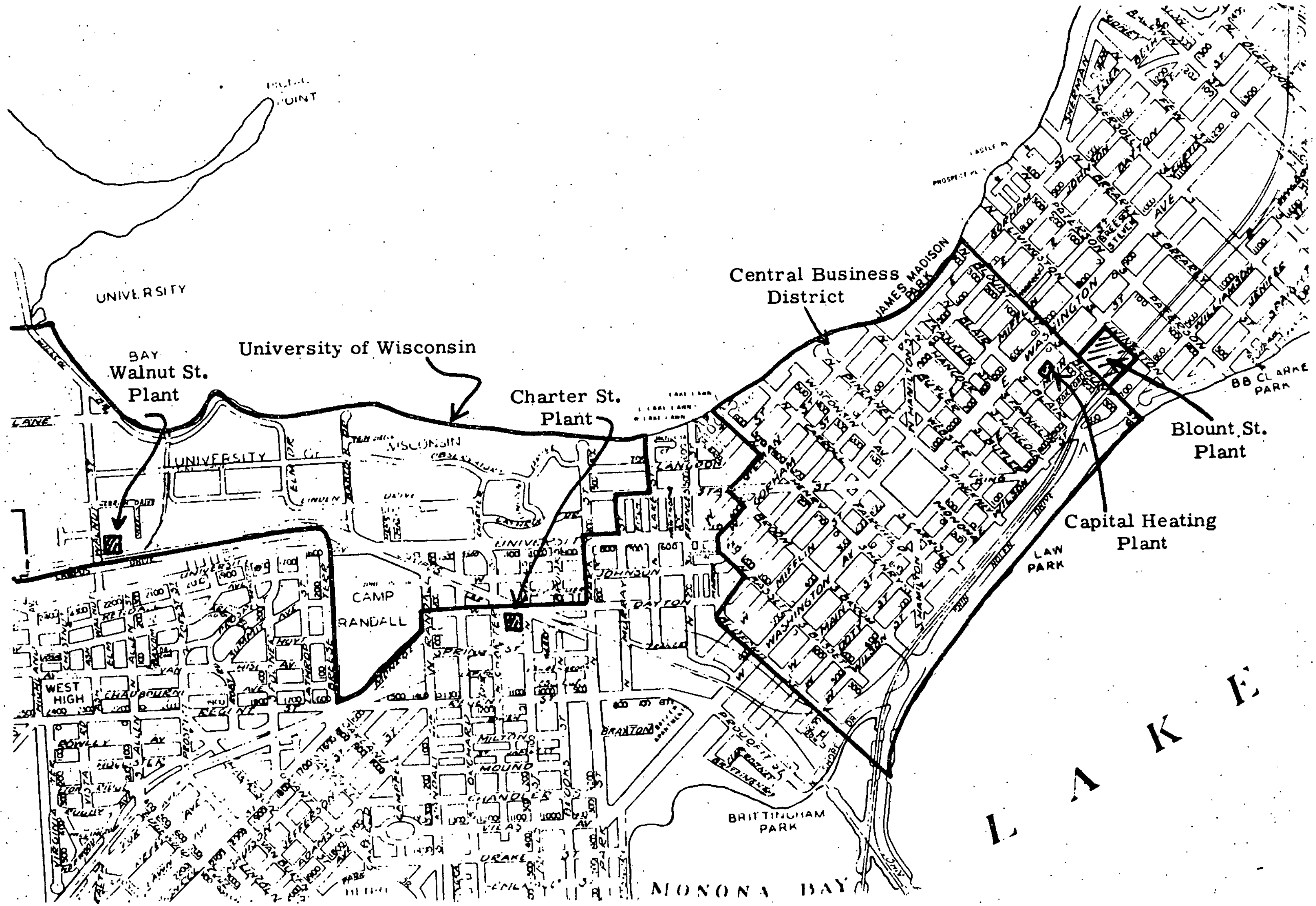

Figure 4. Madison Service Area

The thermal loads (Btu x 10^9/year) for Madison are:

Current		Future	
CBD (includes Capitol Heating Plant)	609.1	CBD	27.8
University	1637.0		

The peak hour demand (Btu x 10^6/hour) is:

Current		Future	
CBD (includes Capitol Heating Plant)	281.2	CBD	8.8
University	580.0		

The types and percentages of fuel currently consumed are:

Area	Fuel	Percentage
CBD	Natural Gas	100
Capitol	Natural Gas	65
	No. 6 Fuel Oil	7
	Coal	28
University of Wisconsin	Natural Gas	39
	Coal	38
	No. 5 Fuel Oil	6.5
	No. 2 Fuel Oil	16.5

Gas-fired hot water heaters are used in the majority of buildings. In buildings having a large hot water requirement (i.e., hotel/motel), steam or hot water heat exchangers are used.

The majority of the air conditioning equipment consists of electric window units or central chillers. One building, a hospital, contained a central absorption unit.

5.2 FACTORS TO INDUCE POTENTIAL SUBSCRIBERS

To determine what factors would induce potential users to subscribe to the DHCS, interviews were conducted in the communities of Green Bay, Janesville/Beloit, and Madison with building owners, managers, operators and directors.

Economics was the consideration most often mentioned that would induce potential users to subscribe to the DHCS. Capital expenditures for building conversions should be projected to produce a payback ranging from three to five years. Financial expenditures with paybacks longer than this period would receive less attention. Factors that would help to achieve this payback criteria for a DHCS and circumstances where it would be relaxed included:

- Tax Credits were often mentioned by private businesses/corporations as a means to help offset initial retrofit costs.
- Low interest loans were often mentioned as a method to help achieve the financing objective. As opposed to tax credits, this vehicle would also benefit nonprofit organizations.
- The Federal Government should consider financing a portion of the DHCS installation.
- Because of the bleak outlook for energy, energy-related expenditures appear to be receiving higher priority in business decisions. Because of this factor, most people would be willing to relax payback criteria from three to five years.
- The better the business climate at the time, the more relaxed the economic payback.
- Those persons who lived in the community and owned/operated businesses in the community appeared more inclined to support the DHCS concept because of possible benefits to the community.
- Reduced pollution was a welcomed benefit; however, those interviewed seemed unable to place a value on this benefit because it was intangible and difficult to quantify.

Additional information about DHCS--hot it works, what it would cost, what current users think about it--would greatly add to the general public's acceptance of the DHCS concept. Based on the small sample of people interviewed, this would be a significant factor in inducing potential users to subscribe to the DHCS system.

Reliability was not deemed to be a significant factor as perceived by the users. This is not to say that they are not concerned, but rather that they would view a project such as this to be reliable because the system will be designed as such. They also view the thermal energy as coming from the utility, which they generally consider to be as reliable as possible.

Having the streets torn up for installation of the DHCS distribution system was determined not to be a significant factor that would deter potential users. Businessmen commented that ripped up streets make it inconvenient for customers, thus business tends to suffer. Industry views this potential problem even less signficantly. As long as supplies can be received and products shipped, there is no problem.

5.3 INSTITUTIONAL ASSESSMENT

An institutional assessment was accomplished by analyzing the impact of all statutes, codes, ordinances, regulations and other external factors that may impact the establishment of a DHCS in Wisconsin. Conclusions reached are:

- The reform-minded utility regulatory climate in Wisconsin ensures that a DHCS system will be supported. Institutional impediments can be expected, however, when a multitude of agencies are to give approvals before the DHCS can proceed. An example is intervention of the Federal Highway Administration, which is expected to oppose a river bridging in Green Bay using the existing bridge.

- The State regulations often override local regulations, as in the case of siting and taxes due to the existing State laws and the support of the utility customers.
- It appears that institutional problems would be minimized if the DHCS were owned/operated by an existing utility. However, eventual rules of PURPA may favor setting up an independent DHCS that purchases heat from the electric utility.
- State-backed utility bonds are an option that opens the way financially for an independently owned DHCS system, should this alternative prove preferable.
- The Public Service Commission of Wisconsin believes the main test of DHCS viability is economic, not institutional. If energy can be delivered at a cost that is competitive with that of No. 6 fuel oil, success appears likely. If it cannot be competitive with No. 6 fuel oil, but only with No. 2 oil, the risks are greater but reduced by the effects of marginal cost-based pricing for natural gas.

5.4 DISTRICT HEATING SYSTEM ALTERNATIVES

Seven district heating system alternatives were developed by designing preliminary power plant retrofit schemes and distribution/transmission networks to serve the identified loads. Similar retrofit modifications were proposed for the Pulliam, Rock River and Blount Street Power Plants. The major portion of extracted energy was obtained at the crossover point just before the low-pressure condensing turbine. Additional smaller energy inputs extracted from the high- or intermediate-pressure turbine were used to bring the DHCS distribution system temperature up to the desired operating temperature. The modification proposed for the Black Hawk Power Plant, with no existing condensing turbine, was to extract all the required DHCS energy directly from the single turbine used. Backup heat-only peaking boilers were suggested or proposed in each modification.

A medium-temperature (250°F to 350°F) or high-temperature (above 350°F) hot water distribution system (operating pressures between 150 and 300 psig) was proposed as the DHCS distribution system in each instance. Such a hot water distribution system has many advantages:

- It is a completely closed circuit, with supply and return mains maintained under pressure. There are no losses due to flashing, and very little makeup water is required. Corrosion within the system is minimized. Because the system is closed circuit, the heat not utilized in the terminal heat transfer equipment is returned to the high-temperature water boilers or heat exchangers.
- Such a system can be designed for large temperature drops; thus smaller pipe sizes and less pumping capacity can be employed.
- Operation and temperature control are easily maintained. Uniform temperature is easily maintained, not only for normal operation, but also during peak loads, abnormal operating schedules, and for long periods of banked loads such as overnight or on weekends.
- Piping may slope up or down to suit the terrain, reducing the amount of excavation required and eliminating all drip points and return pump locations, as compared to steam.
- There are lower distribution piping costs since pipe sizes are generally smaller than in a steam system or low-temperature water system of the same capacity. Fewer specialties are required with elimination of steam traps, pressure-reducing valves, separators, flash tanks, condensate receivers and return pumps, as compared to steam.
- Lower operating costs result from better utilization of heat and reduced maintenance.
- Such a system can be considered a safer heat transfer agent then high-pressure steam.
- There is a tremendous "flywheel" effect in the heat storage in such a system, which acts to even out fluctuations in the load.

No technical problems with any of the designs are foreseen. A brief description of each of the alternatives is given below along with the amount of heat being supplied to the selected service area, estimated installed costs and the potential scarce fuel (natural gas, oil) savings. The distribution system costs do not include costs for user modifications to his building or plant, nor for supply and return piping between the building and the distribution system. Both proposed Green Bay distribution systems include the cost ($1,000,000) of a separate pipe bridge across the Fox River.

5.4.1 Green Bay

5.4.1.1 CBD and Three-Mill Alternative--Includes three paper mills (located across the Fox River from the power plant) and the Central Business District, which is located immediately south of the paper mills (Figure 5). The distance from the Green Bay Pulliam Plant to the southern boundary of the CBD is approximately two miles.

● Heat Supplies	3540.85×10^9 Btu/year
● System Costs	
- Plant Retrofit	$3,000,000
- Distribution System	$8,000,000
● Scarce Fuel Savings	1418.3×10^9 Btu/year

The difference between the heat supplied and the thermal loads (page 5-3) is due to the 158 hours that the heat supply is interrupted since full power is needed and the 22 days of holidays and planned shutdowns. Capital costs for a 100 million Btu/hour standby oil- or gas-fired water heater to provide enough heat for the downtown area during the interruption hours are included. The quantity of heat that would be sold from the standby-fired water heater is not included since this would be replacing oil- or gas-fired building boilers.

Heat was taken from the Pulliam 8 unit by removing steam from one extraction point (183 psia) and the crossover point (89.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal varied throughout the year from a February average of 478 million Btu/hour to an August average of 409 million Btu/hour. The corresponding rate of power lost varied from 37.3 to 31.1 MW.

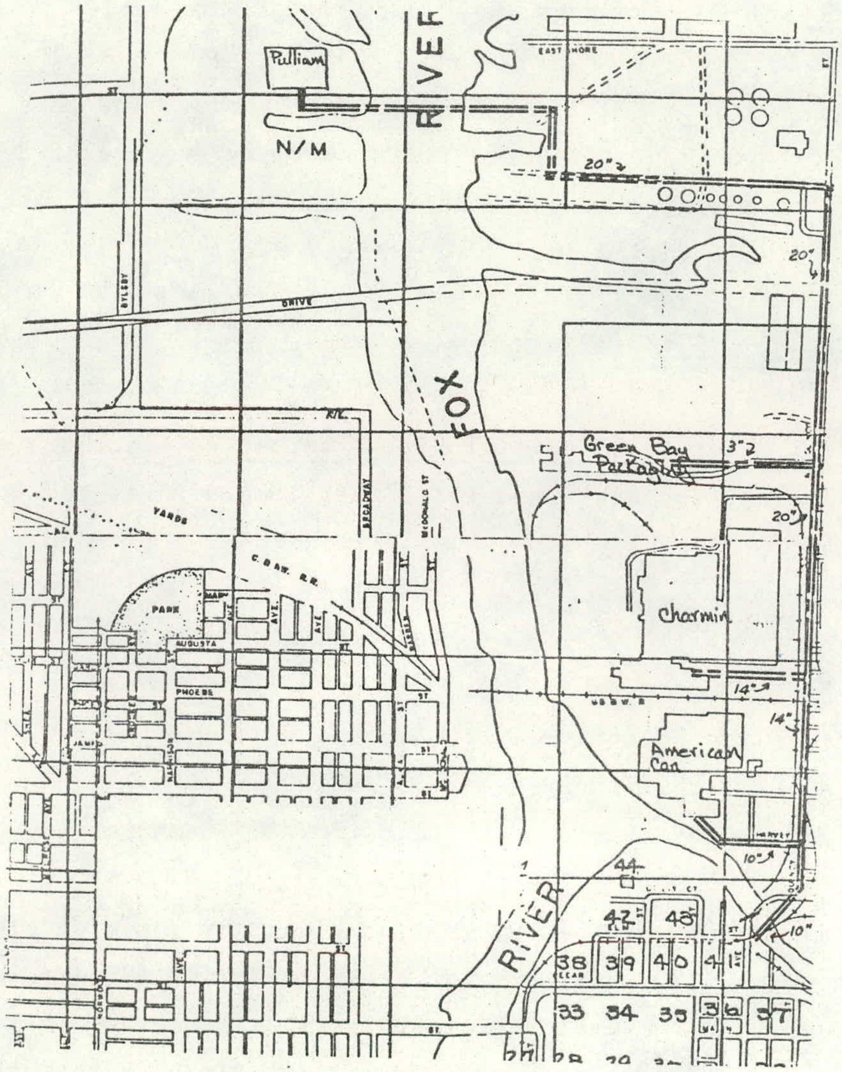

Figure 5. Green Bay Distribution System with Northern River Crossing

5.4.1.2 CBD and Two-Mill Alternative--Includes the two smaller paper mills and the CBD. The largest paper mill was omitted.

● Heat Supplied	1418.33×10^9 Btu/year
● System Costs	
- Plant Retrofit	\$2,200,000
- Distribution System	\$6,500,000
● Scarce Fuel Savings	1418.3×10^9 Btu/year

Heat was removed from Pulliam 8 as described above. The rate of heat removal varied throughout the year from a February average of 215 million Btu/hour to an August average of 146 million Btu/hour. The corresponding rate of power lost varied from 17.2 to 11.7 MW.

5.4.2 Janesville/Beloit

5.4.2.1 Rock River to Industrial Park Alternative--Includes a proposed (i.e., no current tenants) industrial park located near the Rock River Power Plant.

● Heat Supplied	1234.80×10^9 Btu/year
● System Costs	
- Plant Retrofit	\$1,500,000
- Distribution System	\$5,200,000
● Scarce Fuel Savings	1481.8×10^9 Btu/year

Heat was taken from the Rock River 1 or 2 unit by removing steam from one extraction point (183 psia) and the crossover point (89.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal averaged 150 million Btu/hour throughout the year with a power loss of 10.36 MW.

5.4.2.2 Black Hawk to Beloit Alternative--Includes large industrial users in and near Beloit, Wisconsin.

- Heat Supplied 670.41 x 10^9 Btu/year
- System Costs
  - Plant Retrofit $1,500,000
  - Distribution System $14,300,000
- Scarce Fuel Savings 84.0 x 10^9 Btu/year

Heat was taken from the Black Hawk 3 and 4 units by removing steam from three extraction points (298 psia, 123 psia, and 42.7 psia) and condensing it in high-temperature water distribution system heat exchangers. The rate of heat removal varied from a February average of 93.7 million Btu/hour to an August average of 62.9 million Btu/hour. The corresponding rate of power lost varied from 6.23 to 4.18 MW.

5.4.2.3 Rock River to Janesville and Beloit Alternative--Includes heavy users near Janesville and Beloit, with all energy extracted from the Rock River Power Plant.

- Heat Supplied 1928.61 x 10^9 Btu/year
- System Costs
  - Plant Retrofit $2,500,000
  - Distribution System $67,200,000
- Scarce Fuel Savings 2314.3 x 10^9 Btu/year

Heat was removed from the Rock River 1 or 2 unit by removing steam from two extraction points (201 psia and 89.7 psia) and the crossover point (28.0 psia). The rate of heat removal varied from a February average of 362 million Btu/hour to an August average of 139.7 million Btu/hour. The corresponding rate of power lost varied from 24.9 to 9.8 MW.

5.4.3 Madison

5.4.3.1 CBD and Capitol Heating Complex--Includes portions of the Central Business District and the buildings heated by the Capitol Heating Plant.

- Heat Supplied — 215.10×10^9 Btu/year
- System Costs
  - Plant Retrofit — \$1,000,000
  - Distribution System — \$3,500,000
- Scarce Fuel Savings — 258.1×10^9 Btu/year

Heat was removed from the Blount Street 6 or 7 unit by removing steam from two extraction points (305 psia and 150 psia) and the crossover point (59.2 psia). The rate of heat removal varied from a February average of 61.5 million Btu/hour to an August average of 4.7 million Btu/hour. The corresponding rate of power lost varied from 4.92 to 0.38 MW.

5.4.3.2 University of Wisconsin--Includes complex of buildings (approximately 150) at the University of Wisconsin.

- Heat Supplied — 1176.05×10^9 Btu/year
- System Costs
  - Plant Retrofit — \$2,400,000
  - Distrubtion System — \$14,200,000
- Scarce Fuel Savings — 1411.3×10^9 Btu/year

Heat was taken from the Blount Street 6 or 7 unit as described above. The rate of heat removal varied from a January average of 252 million Btu/hour to an August average of 26.5 million Btu/hour. The corresponding rate of power lost varied from 20.2 to 2.1 MW.

5.5 EFFECT ON UTILITIES CURRENT AND FUTURE OPERATION

For all of the alternatives considered, the cogeneration turbine was a "must run" turbine, and the electrical output from that unit was fully dependent on the amount of heat that was taken off to the district heating system.

During cogeneration operation, the power output from the retrofitted turbine is reduced and the lost power must be made up by other units.

The peak power demand cogeneration operation is considered an "interruptible" operation. Therefore, there would be no effect on the reserve capacity of the utility. As an example, the Green Bay operation would have a range of "interruption" hours per year from 42 (year 1980) to 329 (year 1990).

5.6 ECONOMIC ANALYSIS

With the background information developed during the study, the economic analysis was structured to assess the viability of each alternative from a viewpoint that would economically induce building owners to convert to the DHCS. This was accomplished by selecting a customer base rate for thermal energy that was lower than competitive fuels in each of the three areas. The analysis centered on either the local utility or municipality financing the plant retrofit and distribution networks. For two alternatives, joint financing between the utility and municipality was analyzed.

For each of the three sites and each of the alternatives analyzed, yearly fixed revenue requirements necessary to retire the cost of the capital investment were determined. Yearly fuel costs at the power plant, based on coal escalating at a real rate of 4.0 percent and oil at 4.1 percent, were calculated. These were added to yearly operation and maintenance costs of the system to determine total revenue requirements.

Gross income for each of the three sites was determined by selecting a customer rate structure and escalating it at a rate equal to that expected for the fuel that would be displaced. In each of the three sites, the fuel that would be displaced is natural gas. The customer rate for thermal energy from the DHCS was selected by taking 90 percent of the current charge per Btu for natural gas at each site. This 10 percent reduction was selected as a means of providing an incentive for customers to convert their buildings to DHCS. The customer rate was escalated at the real rate expected for natural gas (7.0 percent), and the gross yearly income was determined.

Annual savings were then determined by subtracting total yearly revenue requirements from gross income. Accumulated annual savings (in 1979 dollars) were then plotted on a yearly basis. Thus the results obtained depict the economic viability of the DHCS for each alternative while considering:

- Capitalization structure of the utility or municipality,
- Installed cost of the DHCS,
- Thermal load supplied,
- Fuel, operation and maintenance costs,
- Income based on a competitive energy charge rate, and
- Income based on a charge rate that provides incentive for owners to convert their buildings.

A summary of the results for each of the three sites and each of the alternatives analyzed is illustrated in Figures 6 through 12. The summary results depict the accumulated net present worth or annual savings as a function of the year of operation for each financing alternative considered. Table I summarizes the major assumptions used in the economic analysis.

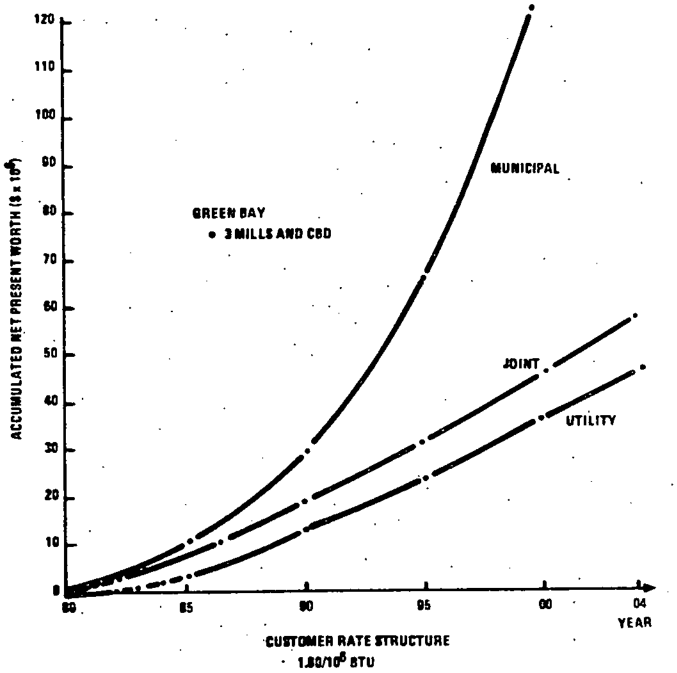

Figure 6. Accumulated Net Present Worth versus Year, Green Bay, Three Mills and CBD

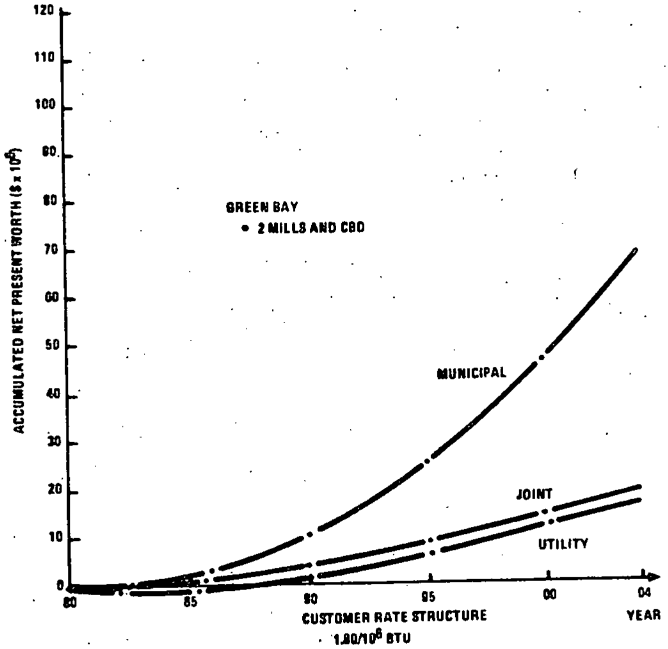

Figure 7. Accumulated Net Present Worth versus Year, Green Bay, Two Mills and CBD

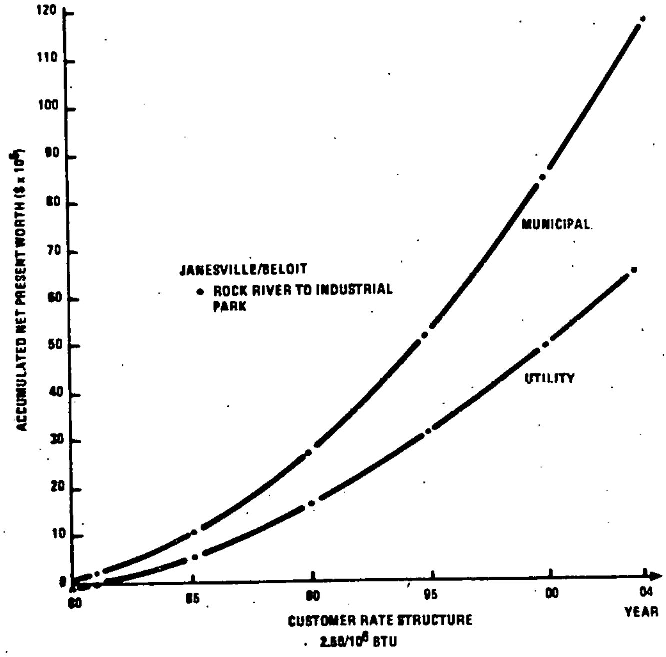

Figure 8. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Industrial Park

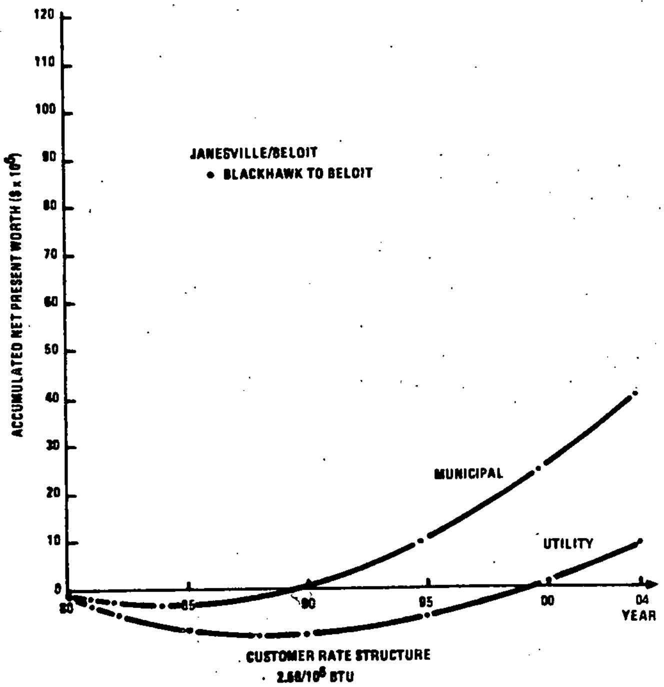

Figure 9. Accumulated Net Present Worth versus Year, Janesville/Beloit, Black Hawk to Beloit

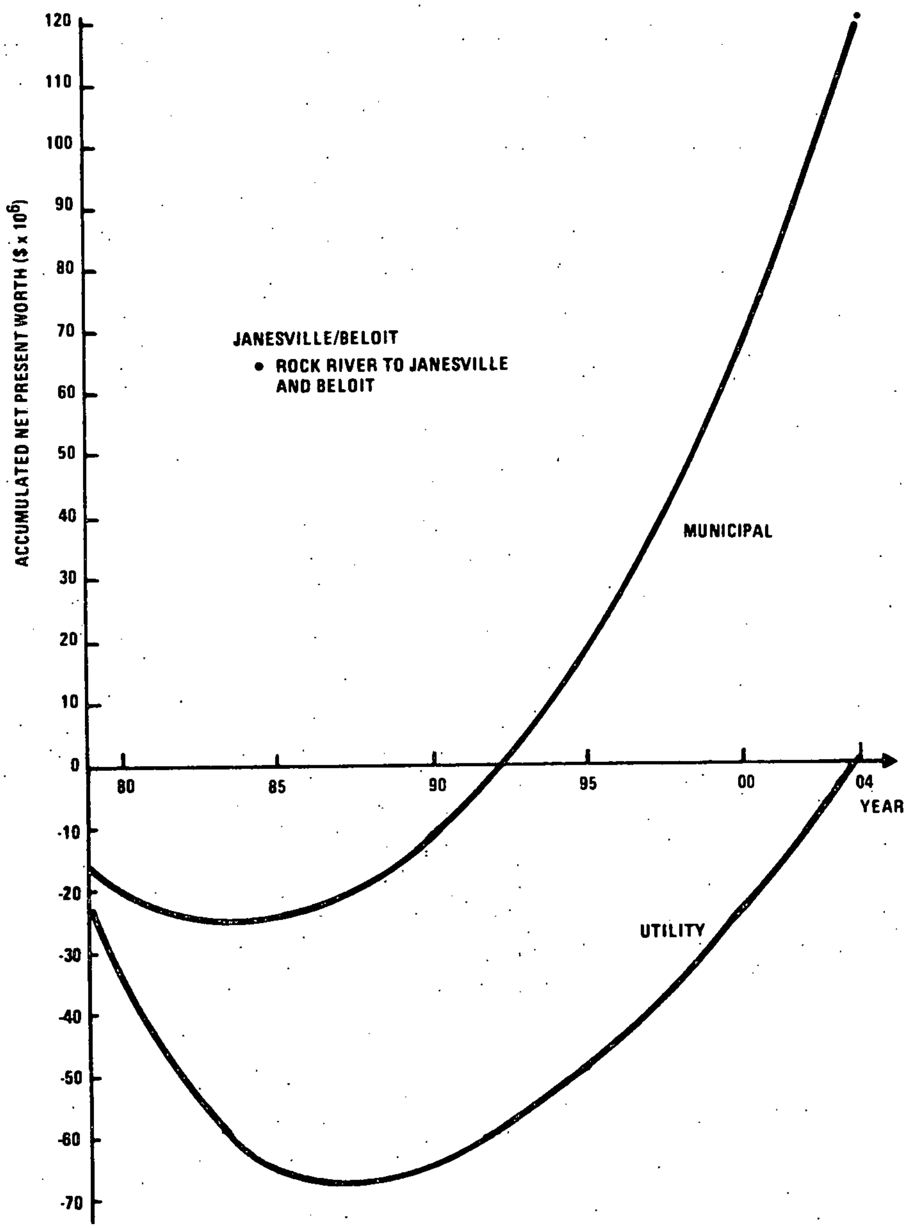

Figure 10. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Janesville and Beloit

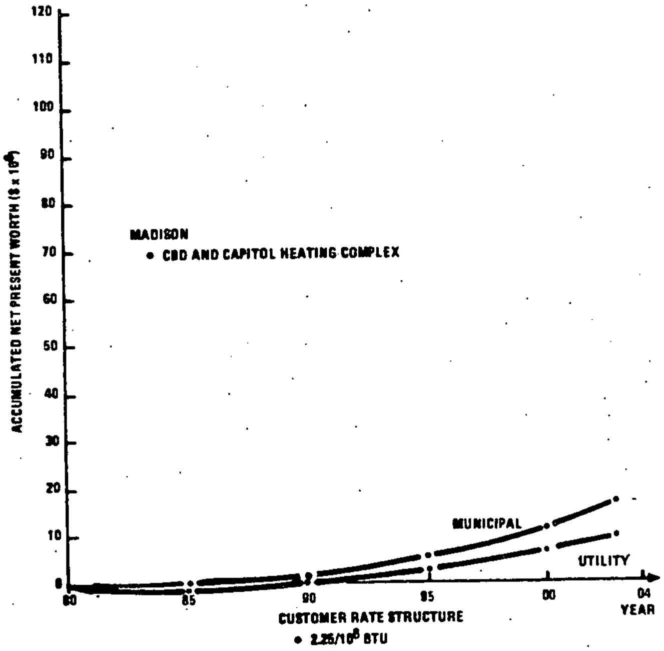

Figure 11. Accumulated Net Present Worth versus Year, Madison, CBD and Capitol Heating Complex

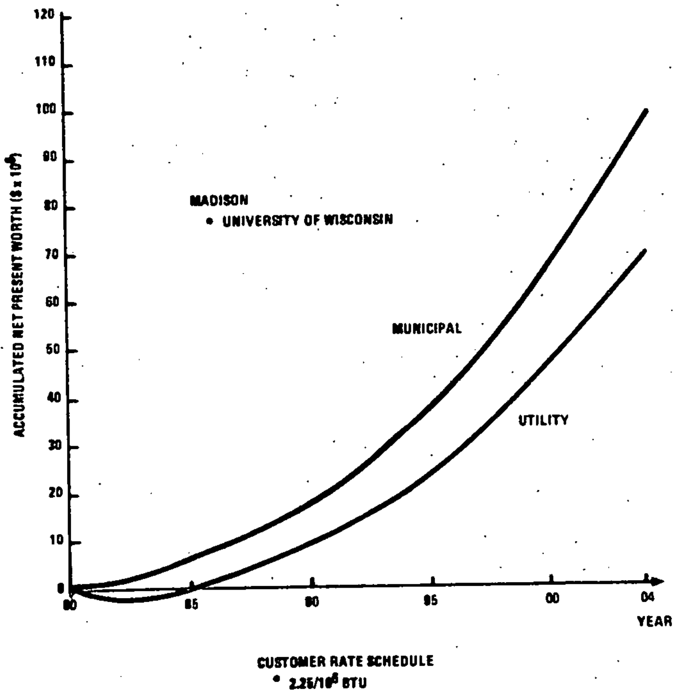

Figure 12. Accumulated Net Present Worth versus Year, Madison, University of Wisconsin

Table I. Major Assumptions in Economic Analysis

PERIOD OF ANALYSIS	25 YEARS
INFLATION RATE	7.0 PERCENT PER YEAR
ANNUAL INVESTMENTS FOR CAPITAL EQUIPMENT	OCCUR IN FIRST YEAR
MAINTENANCE, DISTRIBUTION SYSTEM	1.0 PERCENT OF COST
INSURANCE, DISTRIBUTION SYSTEM	0.2 PERCENT OF COST
OPERATION, DISTRIBUTION SYSTEM	BASED ON PUMP SIZED TO PUMP FLUID
OPERATION/MAINTENANCE - TURBINE RETROFIT	UTILITY SIMULATION MODEL
CAPITALIZATION INPUTS	EACH UTILITY
INCOME FROM SALE OF HEAT	BASE RATE 90 PERCENT OF RATE FOR NATURAL GAS IN AREA
CAPACITY CHARGES FOR LOST ELECTRICAL GENERATION CAPACITY	CUSTOMERS TREATED AS INTERRUPTIBLE LOADS
LOSS OF REVENUE FROM GAS SALES	NOT CONSIDERED IN OVERALL ECONOMICS
BUILDING CONVERSION COSTS	NOT CONSIDERED IN OVERALL ECONOMICS

The most promising site is Green Bay, where a large industrial process load as well as a commercial building heat and hot water load are all located within two miles of the Pulliam Power Plant. The large industrial load and low capital investment resulting from a small DHCS size combine to make the economics attractive. Positive net annual savings would be realized in two years (three-mill alternative) and seven years (two-mill alternative), based on highly competitive thermal rates, and would provide incentive for building owners to convert. This period could be reduced even further by considering municipal or joint financing mechanisms, although this would increase the institutional problems encountered.

Because of the concentration of estimated loads and the short distribution system, the most economically attractive alternative analyzed was the industrial park to be located near the Rock River Power Plant in the Janesville/Beloit area. At present, no industries have been identified as park occupants.

The next most promising site analyzed was Madison. The two alternatives included (1) a portion of the CBD and buildings heated by the Capitol Heating Plant and (2) the University of Wisconsin complex of buildings. Both analyses assumed that all customers would come on line during the first year of system operation. This would be an optimistic assumption for the CBD. In reality, the buildings would come on line over a time-phased period. Combined with the lack of any large industrial loads, this would tend to make the economics less desirable than illustrated.

The University of Wisconsin currently has two central boiler plants and a steam distribution system. Because of its distance from the Blount Street Power Plant, a substantial investment ($16,600,000) would be required to transport hot water to the central plants for distribution to the buildings. Costs for converting each building would also be substantial. These costs were not included in the economic analysis performed. Combined with a time-phased building conversion plan, these costs would represent a less desirable economic outlook.

The two remaining alternatives analyzed for the Janesville/Beloit have scattered concentrations of loads requiring extensive and costly distribution systems. The results of the economic analysis illustrate this situation, depicting long periods where the system would have negative accumulated savings.

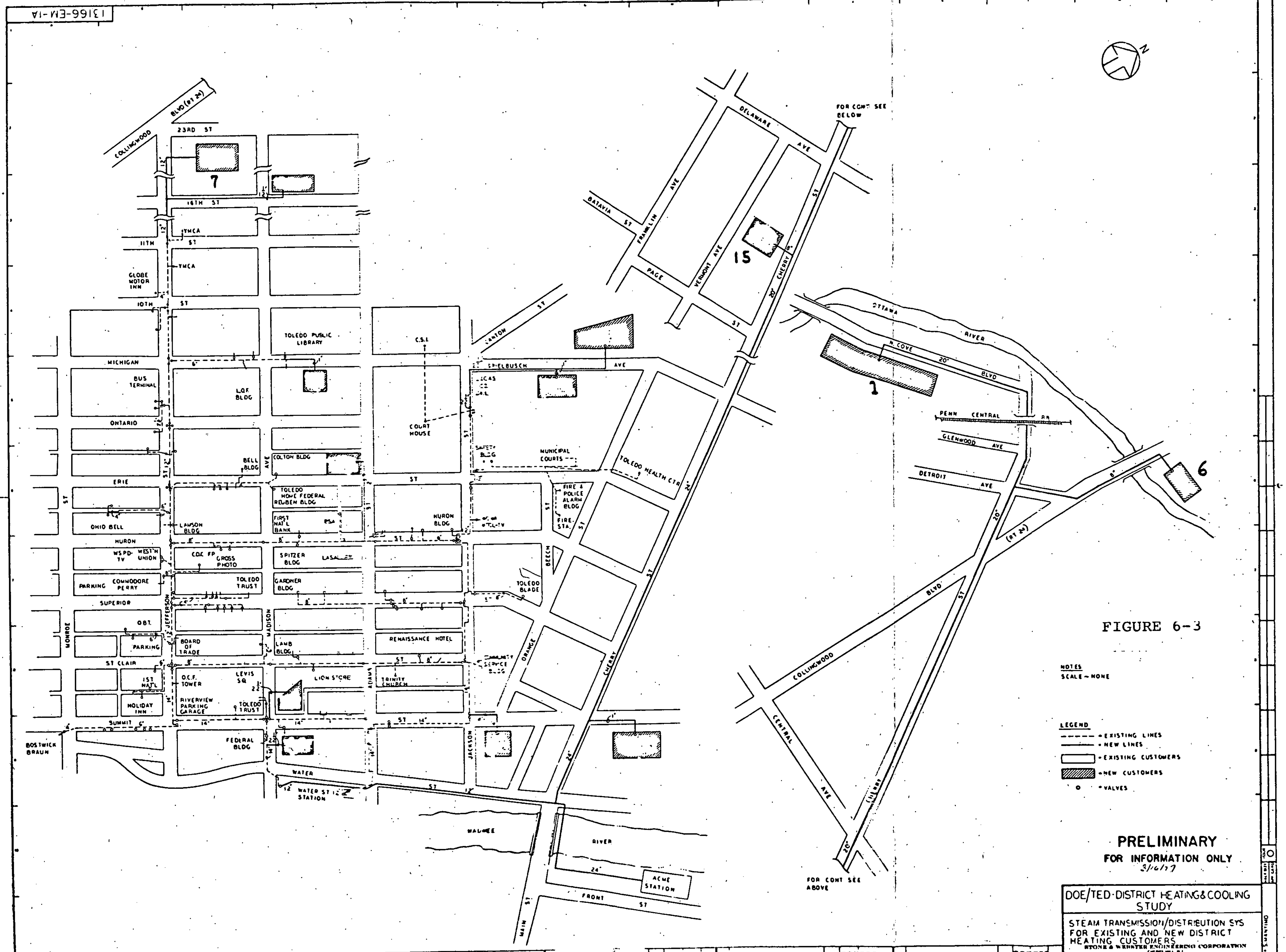

FIGURE 6-3

NOTES
SCALE – NONE

LEGEND
- - - - - = EXISTING LINES
——— = NEW LINES
☐ = EXISTING CUSTOMERS
▨ = NEW CUSTOMERS
○ = VALVES

PRELIMINARY
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DOE/TED·DISTRICT HEATING & COOLING STUDY

STEAM TRANSMISSION/DISTRIBUTION SYS
FOR EXISTING AND NEW DISTRICT
HEATING CUSTOMERS

STONE & WEBSTER ENGINEERING CORPORATION
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