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CONVERSION

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

Final Report. Phase 1—Identification and Assessment
Volume 2—Detailed Results

MASTER

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

PHASE 1 - IDENTIFICATION AND ASSESSMENT

FINAL REPORT

VOLUME II - DETAILED RESULTS

SEPTEMBER 1979

WISCONSIN STATE ENERGY OFFICE

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

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FOREWORD

District heating is the use of one or more central heat sources to supply the low to moderate temperature energy needs (space and water heating) of an area through a distribution system. The central heat source can be either a heat-only boiler or an electric cogeneration (i.e., production of electric and thermal energy at a single site) facility. The heat is usually distributed through a system of underground insulated pipes to buildings that require the energy. The energy is delivered in the form of steam or high temperature, high pressure hot water and transferred to the buildings through one or more heat exchangers.

In many places in Europe, cogeneration facilities are used to produce both heat and electrical energy. In fact, this is becoming the dominant mode of space and domestic hot water heating in the urban areas of West Germany and the Scandinavian and Soviet bloc countries.

A cogeneration facility uses fuel much more efficiently than a conventional, electric generating facility, which produces only electricity. In a typical Swedish cogeneration facility, between 20 and 25 percent of the fuel energy is transformed into electricity and 45 to 55 percent of the fuel energy is delivered to the district heating system. Thus, in a cogeneration facility about 70 to 75 percent of the input fuel energy can be transformed into usable energy forms (electricity and hot water for space and/or water heating) compared with 30 to 35 percent usable energy (electricity) from a conventional 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 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, startup and operation evaluation of the demonstration project.

This report contains the results of the Phase I Identification and Assessment Study for the State of Wisconsin. Study results are presented in three volumes:

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

The Phase I study was performed by the following team of state agencies, industries and utilities:

Contractor: Wisconsin Office of State Planning & 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 & Light Co.
Madison, Wisconsin

Wisconsin Public Service Corporation
Green Bay, Wisconsin

Manitowoc Public Utilities
Manitowoc, Wisconsin

Wisconsin Electric Power Co.
Milwaukee, Wisconsin

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TABLE OF CONTENTS

	<u>Page</u>
SECTION 1.0 INTRODUCTION	1-1
1.1 OBJECTIVES	1-1
1.2 APPROACH	1-1
SECTION 2.0 SITE SELECTION	2-1
2.1 INTRODUCTION	2-1
2.2 SPECIFIC OBJECTIVES	2-1
2.3 APPROACH	2-2
2.4 IDENTIFICATION OF EXISTING INTERMEDIATE/ BASE-LOADED PLANTS	2-2
2.5 SCREENING CRITERIA	2-5
2.6 PRELIMINARY SITE SELECTION	2-5
2.7 FINAL SITE SELECTION	2-8
Green Bay--Served by the Pulliam Plant	2-10
Madison--Served by the Blount Street Plant	2-10
Janesville/Beloit--Served by the Rock River and Black Hawk Plants	2-10
2.8 CONCLUSIONS	2-11
SECTION 3.0 ENERGY MARKET ANALYSIS	3-1
3.1 INTRODUCTION	3-1
3.2 GREEN BAY	3-1
Potential Service Areas	3-1
Areas Selected for Detailed Analysis	3-4
Industrial Area	3-8
3.3 JANESVILLE/BELOIT	3-17
Potential Service Areas	3-17
Areas Selected for Detailed Analysis	3-26
3.4 MADISON	3-32
Potential Service Area	3-33

TABLE OF CONTENTS (continued)

	<u>Page</u>
Areas Selected for Detailed Analysis	3-40
3.5 FACTORS TO INDUCE POTENTIAL USERS	3-44
Evaluation of Factors	3-47
SECTION 4.0 TECHNICAL REVIEW AND ASSESSMENT	4-1
ALTERNATE POWER PLANT RETROFIT SCHEMES	4-1
ADVANTAGES/DISADVANTAGES OF PLANT RETROFIT SCHEMES	4-2
MODES OF OPERATION FOR TURBINE RETROFIT SCHEME	4-16
EFFECTS OF UTILITY PLANT LOAD VARIATION	4-21
EFFECT ON UTILITY'S GENERATION CAPACITY	4-22
AVAILABLE THERMAL ENERGY FROM POWER PLANT	4-22
SYSTEM CHARACTERISTICS	4-23
General	4-23
Steam Systems	4-23
Hot Water Systems	4-25
Distributive Systems	4-30
Distribution System Characteristics	4-32
ADVANTAGES OF HIGH-TEMPERATURE WATER versus STEAM	4-42
Safety Considerations	4-49
Capital Costs	4-50
TECHNIQUES FOR INTERFACING WITH END USER	4-51
SCARCE FUEL CONSERVATION POTENTIAL	4-58
CONCLUSIONS	4-59
SECTION 5.0 INSTITUTIONAL ASSESSMENT	5-1
5.1 STATE COMMITMENT	5-1
5.2 FEDERAL COMMITMENT	5-3
5.3 OBJECTIVE	5-6

TABLE OF CONTENTS (continued)

	<u>Page</u>
5.4 APPROACH	5-6
Extent and Effects of State and/or Local Utility Commission Regulation	5-7
Arrangements Under Which Electric Utilities Would Modify and Operate Power Plants as Part of a District Heating and Cooling System	5-9
Extent and Effects of Legal Requirements to Obtain Easements, Franchises to Occupy the Public Right-of-Way, Land Acquisition and to Obtain Certificates of Convenience and Necessity	5-10
Effect of State and Local Tax Laws	5-12
Effects of a Statutory Mandate to Serve All	5-13
Extent and Effects of Environmental Regulations	5-14
Extent and Effects of Power Siting Laws and Local Zoning Laws on Ability to Retrofit an Existing Power Plant and Build a District Heating and Cooling System	5-17
Review of the Corporate Charters of Each Participating Utility Company and All Applicable Statutes, Codes and Ordinances, to Confirm the Legal Capacity to Construct, Own and Operate the District Heating and Cooling Demonstration Projects	5-17
Detailed Schedules of Approvals, Both Internal and External, That Have to be Obtained in Order to Reach a Decision on the Construction of the Project	5-17
5.5 CONCLUSIONS	5-18
SECTION 6.0 PRELIMINARY ECONOMIC ANALYSIS	6-1
APPROACH	6-1
ASSUMPTIONS	6-1

TABLE OF CONTENTS (Concluded)

	<u>Page</u>
Operation and Maintenance Costs/Distribution and Transportation System	6-3
Operation and Maintenance Costs--Plant Retrofit Components	6-3
Results and Fuel Escalation Rates	6-5
Financing Options	6-7
Capitalization Inputs	6-8
District Heating Alternatives Analyzed	6-8
CONCLUSIONS	6-11

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LIST OF FIGURES

<u>Figure</u>		<u>Page</u>
1	Phase I Study Approach, District Heating and Cooling Systems for Communities through Power Plant Retrofit and Distribution Networks	1-3
2	Major Power Plants in Wisconsin (Net Capacity, MW)	2-3
3a	Preliminary Service Area, Madison, Wisconsin	2-12
3b	Preliminary Service Area, Green Bay, Wisconsin	2-13
4	Green Bay Area	3-2
5	Green Bay Selected Service Area	3-7
6	Building Age, Green Bay CBD	3-16
7	Janesville/Beloit Area	3-18
8	Selected Subareas	3-19
9	Location of 47 Blocks of Data, Janesville/Beloit	3-22
10	Detail of Janesville Central Business District	3-23
11	Detail of Downtown Beloit Subarea	3-24
12	Detail of Beloit Central Business District	3-25
13	Madison Service Area	3-34
14	Madison Central Business District	3-35
15	Topical Questions	3-48
16	Pulliam 8 Heat Balance Diagram with District Heating System Retrofit for Three- and Five-Mill Heat Loads and Downtown Green Bay Loads	4-17
17	Black Hawk 3 and 4 Heat Balance Diagram with District Heating System Retrofit for Ten Largest Beloit Users	4-18

LIST OF FIGURES (Continued)

<u>Figure</u>		<u>Page</u>
18	Rock River 1 or 2 Heat Balance Diagram with Turbine Retrofit for District Heating System or Future Industrial Park	4-19
19	Blount Street 6 or 7 Heat Balance Diagram with District Heating System Retrofit for the University and Downtown Madison	4-20
20	Insulated Pipe in Steel Conduit and Reinforced Concrete	4-39
21	Insulated Pipe in Plastic Conduit and Poured Concrete	4-43
22	Green Bay, Separate Pipe Bridge	4-44
23	Green Bay, Cross-Section and Details of Proposed Tower Drive Bridge	4-45
24	Green Bay Distribution System with Northern River Crossing	4-46
25	Green Bay Distribution System with Southern River Crossing	4-47
26	Typical Converter Room for Multiservice Use of High Temperature Water	4-52
27	Typical Arrangement of High Temperature Water Converter Room	4-53
28	Sample Results, Life-Cycle Savings	6-5
29	Sample Results, Accumulated Net Present Worth	6-6
30	Accumulated Net Worth versus Year, Green Bay, Three Mills and CBD	6-12
31	Accumulated Net Worth versus Year, Green Bay, Two Mills and CBD	6-13

LIST OF FIGURES (Concluded)

<u>Figure</u>		<u>Page</u>
32	Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Industrial Park	6-14
33	Accumulated Net Present Worth versus Year, Janesville/Beloit, Blackhawk to Beloit	6-15
34	Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Janesville and Beloit	6-16
35	Accumulated Net Present Worth versus Year, Madison, CBD and Capitol Heating Complex	6-17
36	Accumulated Net Present Worth versus Year, Madison, University of Wisconsin	6-18

LIST OF TABLES

<u>Table</u>		<u>Page</u>
I	Existing Intermediate/Base-Loaded Electric Generating Plants in Wisconsin	2-4
II	Site Screening and Selection Criteria	2-6
III	Information about Existing Wisconsin Electric Generating Plants Relating to DHCS Screening Criteria	2-7
IV	Current Load (Btu x 10 ⁹)	3-5
V	Future Load Data (Btu x 10 ⁹)	3-11
VI	Load Summary, Green Bay	3-13
VII	HVAC Inventory Summary	3-15
VIII	Heating System Age Summary	3-15
IX	Current Load at Janesville/Beloit (Btu x 10 ⁹)	3-20
X	Peak Hourly Load Summary	3-28
XI	Janesville/Beloit Load Distribution	3-30
XII	Janesville/Beloit Load Summary	3-31
XIII	Madison - Current Load Data (Btu x 10 ⁹) 1977-1978	3-36
XIV	Future Loads, Madison (Btu x 10 ⁹)	3-43
XV	Load Summary, Madison	3-45
XVI	HVAC Inventory Summary	3-46
XVII	Age Distribution	3-46
XVIII	Simulated Monthly Pulliam Cogeneration Operation	4-4
XIX	Commercial Green Bay Heating Load	4-5
XX	Green Bay Commercial Space Heating and Domestic Hot Water Monthly Loads	4-6
XXI	Simulated Monthly Cogeneration Operation **Heavy Beloit Heat Users (27, 28, 34-40) Blackhawk Power Plant)	4-7

LIST OF TABLES (continued)

<u>Table</u>		<u>Page</u>
XXII	Simulated Monthly Cogeneration Operation Heavy Beloit Heat Users and Heavy Janesville Heat Users (11, 13*, 14, 17, 18, 19) (Rock River Power Plant)	4-8
XXIII	Future Industrial Park West of Rock River Power Plant	4-9
XXIV	Simulated Monthly Blount Street Cogeneration Operation (Madison Downtown Heat Users)	4-10
XXV	Capitol Heating Plant Data	4-11
XXVI	Madison Ten Largest Downtown Blocks (Excluding 000, 85 and 86 Served by Capitol System)	4-12
XXVII	Simulated Monthly Blount Street Cogeneration Operation When Supplying Heat Only to University of Wisconsin Buildings for Space Heat and Domestic Hot Water	4-13
XXVIII	Green Bay District Heating System (Three Paper Mills) 1985 Operation	4-14
XXIX	Green Bay District Heating System (Two Paper Mills)	4-15
XXX	Capital Costs of Primary Piping Systems per Foot of Piping (1979 Dollars)	4-40
XXXI	Heat Exchanger Costs, Customer System Retrofit (1979 Dollars)	4-54
XXXII	Customer Retrofit Costs (1979 Dollars)	4-55
XXXIII	Typical Building Costs (Note 1) Customer System Retrofit (1979 Dollars)	4-56
XXXIV	Typical Costs for Absorption Cooling*	4-57
XXXV	Summary of Capital Costs and Technical Data, Green Bay, Pulliam Plant	4-61
XXXVI	O & M Costs (x 1000), Green Bay, Three Mill and CBD Alternative	6-4

SECTION 1.0 INTRODUCTION

1.1 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, and
- Perform an economic analysis for the candidate sites.

1.2 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 on the concept. Parallel to this effort, each of the three sites was evaluated on its technical

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

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.

SECTION 2.0 SITE SELECTION

2.1 INTRODUCTION

This section describes the process by which the team members selected existing intermediate/base-loaded electric generating stations with the greatest potential as heat sources for a District Heating and Cooling System (DHCS) as well as the results of this process.

2.2 SPECIFIC OBJECTIVES

The specific subtasks to be accomplished included:

- Identify all existing intermediate/base-loaded electric generating plants in Wisconsin.
- Develop preliminary screening criteria to prescreen these candidate sites.
- Perform the preliminary screening of these candidate sites.
- Characterize each site surviving the preliminary screening as to location, ownership, size, equipment, etc.
- Perform the final site selection using more detailed data.
- Define the proposed DHCS service area for each remaining final site.
- Determine the mix of end users within each service area.
- Survey the building types within each service area.

These subtasks were reviewed by team members during a review meeting and performed during two working meetings and the period between those meetings.

2.3 APPROACH

Task II objectives were primarily accomplished through the cooperative efforts of all team members during two working meetings. The team was comprised of members of the Wisconsin Office of State Planning and Energy, the Honeywell Energy Resources Center, American Hydrotherm Corporation, the Wisconsin Public Service Commission, and the five participating Wisconsin utilities: Wisconsin Power & Light Company, Wisconsin Public Service Corporation, Wisconsin Electric Power Company, Madison Gas & Electric Company, and Manitowoc Public Utilities. Team decisions were made by consensus. During discussion prior to consensus, development objections and/or reservations were addressed as directly and clearly as possible. The perspectives and information of every member of the team were also shared during the discussion.

2.4 IDENTIFICATION OF EXISTING INTERMEDIATE/BASE-LOADED PLANTS

The Wisconsin Office of State Planning and Energy (WOSPE) identified all existing intermediate/base-loaded electric generating plants in Wisconsin. The approximate location of each of these plants is shown in Figure 2. A summary of the operating characteristics of these plants is shown in Table I. No electric generating plants owned and operated by Northern States Power Company--a Minnesota-based utility that serves a small portion of northwestern Wisconsin--were included in this list. Northern States Power had indicated to WOSPE that they were presently investigating district heating potential in Minnesota and were not interested in participating in the Wisconsin program at this time.

Figure 2. Major Power Plants in Wisconsin (Net Capacity, MW)

Table I. Existing Intermediate/Base-Loaded Electric Generating Plants in Wisconsin

FOSSIL-FUELED STEAM GENERATING PLANTS				
NAME OF PLANT	OPERATING UTILITY	CAPACITY (mW) 12/31/77	mW HR. GEN. 1977	CAPACITY FACTOR (PERCENT)
SOUTH OAK CREEK	WEPCO	1,170	4,852,453	47
NORTH OAK CREEK	WEPCO	550	1,717,044	39
COLUMBIA	*	556	2,952,208	61
EDGEWATER UNITS 1, 2, 3	WP&L	126	345,893	31
EDGEWATER UNIT 4	**	351	1,886,841	61
PORT WASHINGTON	WEPCO	400	1,355,956	39
PULLIAM	WPSC	392.5	1,764,971	51
LAKE SIDE	WEPCO	310.8	243,544	9
VALLEY	WEPCO	269.7	1,126,692	48
NELSON DEWEY	WP&L	227.2	1,186,913	60
BLOUNT STREET	MG&E	194	427,389	25
ROCK RIVER	WP&L	150	546,870	42
WESTON	WPSC	135	608,460	51
BAY FRONT	LSDP	82.2	109,615	15
BLACK HAWK	WP&L	50	133,856	31
MANITOWOC	MUNICIPAL	69	207,994	34
NUCLEAR-FUELED STEAM GENERATING PLANTS				
†POINT BEACH		1,006	7,309,147	83
††KEWAUNEE		535	3,546,342	76

WEPCO - WISCONSIN ELECTRIC POWER COMPANY
 WP&L - WISCONSIN POWER AND LIGHT COMPANY
 WPSC - WISCONSIN PUBLIC SERVICE COMMISSION
 MG&E - MADISON GAS & ELECTRIC COMPANY
 LSDP - LAKE SUPERIOR DISTRICT POWER COMPANY

*JOINTLY OWNED BY WP&L (39.3%), WPSC (38.9%) AND MG&E (21.8%)

**JOINTLY OWNED BY WP&L (68.2%) AND WPSC (31.8%)

†JOINTLY OWNED BY WEPCO (50%) AND WISCONSIN MICHIGAN POWER COMPANY (50%)

††JOINTLY OWNED BY WPSC (41.2%), WP&L (41.0%) AND MG&E (17.8%)

2.5 SCREENING CRITERIA

Preliminary screening criteria were developed prior to an initial organizational and team working meeting. These criteria were discussed and supplemented during a subsequent team meeting. The resulting list of selection criteria was divided into two categories: primary criteria and secondary criteria. The primary criteria were those judged to be of greatest importance in the selection of a potential cogeneration facility for a DHCS. The secondary criteria were those of either secondary importance in the selection process or of such a detailed nature as to be more useful in the technical analysis. The selection criteria are shown in Table II, which also indicates the criteria of greatest importance in the final site selection process.

2.6 PRELIMINARY SITE SELECTION

Using the selection criteria listed in Table II and the available information about the existing intermediate/base-loaded electric generating plants in Wisconsin, summarized in Table III, the team identified the existing plants having the highest potential for retrofit modification to serve a DHCS. The last five plants in Table III are sited in rural or small town (Bay Front in Ashland, population about 9,000) areas and were immediately eliminated from consideration because of low thermal density. Four generating plants--Weston, Lakeside, Port Washington, and North and South Oak Creek--all showed some promise as DHCS sites, but were eliminated because of special considerations. The Weston Plant, south of Wausau, has a new unit scheduled to begin operation in 1982 as a cogeneration unit, supplying steam to industrial customers nearby. The consensus was that our efforts would be more fruitfully applied to other sites where cogeneration benefits could be higher. The Lakeside Plant was eliminated from further consideration because of its age and resulting high costs of operation as well as

Table II. Site Screening and Selection Criteria

<u>PRIMARY CRITERIA</u>	FINAL SITE SELECTION	TOO DETAILED	SECONDARY IMPORTANCE
THERMAL DENSITY--DISTANCE OF THE LOAD FROM THE GENERATING PLANT, TYPES OF EXISTING HEATING SYSTEMS, FUELS USED, ETC.	X		
REMAINING LIFETIME OF EXISTING GENERATING UNITS--AT LEAST 10 YEARS DESIRABLE	X		
ENVIRONMENTAL CONCERNS--POTENTIAL ENVIRONMENTAL BENEFITS THAT COULD BE DERIVED FROM COGENERATION	X		
UTILITY COMMITMENT TO COGENERATION	X		
RELIABILITY FACTOR--AT LEAST TWO EXISTING UNITS THAT COULD BE MODIFIED (BACKUP CAPABILITY)	X		
LOAD FACTOR--DOES THE PLANT QUALIFY OR COULD A DHCS MODIFIED PLANT QUALIFY UNDER THE DOE CRITERIA AS AN INTERMEDIATE/BASE-LOADED PLANT?	X		
CHANGES IN ECONOMICS CAUSED BY SUCH A PROPOSED MODIFICATION			
<u>SECONDARY CRITERIA</u>			
PLANT CAPACITY			X
PLANT OWNERSHIP			X
HOURLY ELECTRICAL DEMAND ON A WEDNESDAY NEAREST THE 15TH OF THE MONTH FOR EACH WINTER MONTH AND FOR A REPRESENTATIVE MONTH FOR FALL, SPRING AND SUMMER CONDITIONS	X		
TRADEOFF CURVES OF ELECTRICAL OUTPUT VERSUS POTENTIAL HEAT DELIVERY FOR EXISTING TURBINES	X		
MINIMUM TURBINE CHARACTERISTICS THAT WOULD ALLOW A REASONABLE RETROFIT MODIFICATION	X		

Table III. Information about Existing Wisconsin Electric Generating Plants
Relating to DHCS Screening Criteria

	DISTANCE TO LOAD (MILES)	TYPE OF LOAD WITHIN 5 MILES	REMAINING LIFETIME (YEARS)	POTENTIAL ENVIRONMENTAL BENEFITS**	UTILITY COMMIT- MENT†	RELI- ABILITY (NO. UNITS)	1977 LOAD FACTOR (PERCENT)
BLOUNT STREET	<1	COMMERCIAL(HD)* RESIDENTIAL(MD)* INSTITUTIONAL(HD)	5-25	YES	YES	5	25
PULLIAM	<2	INDUSTRIAL(HD) COMMERCIAL(HD)	5-25	YES	YES	4	51
BLACK HAWK	<1	INSTITUTIONAL(HD) COMMERCIAL(MD)	5-10	YES	YES	2	31
ROCK RIVER	2-7	INSTITUTIONAL(HD) COMMERCIAL(MD)	10-20	?	YES	2	42
EDGEWATER	1-3	INDUSTRIAL(MD) COMMERCIAL(MD)	5-30	?	YES	2	53
VALLEY	<1	INDUSTRIAL(HD) COMMERCIAL(HD) RESIDENTIAL(HD)	20-25	YES	YES	2	48
MANITOWOC	<2	INDUSTRIAL(MD) COMMERCIAL(MD)	5-15	?	YES	4	34
N&S OAK CREEK	5-7	COMMERCIAL(MD) RESIDENTIAL(LD)*	5-20	YES	YES	4	45
PORT WASHINGTON	1-2	COMMERCIAL(MD) RESIDENTIAL(LD)	5-10	?	YES	2	39
LAKE SIDE	2-5	INDUSTRIAL(HD) COMMERCIAL(HD) RESIDENTIAL(MD)	5	YES	YES	-	9
WESTON††	2-4	INDUSTRIAL(MD) COMMERCIAL(MD)	10-15	?	YES	-	51
NELSON DEWEY	-	RURAL	10-20	NO	-	-	60
COLUMBIA	-	RURAL	30	NO	-	-	61
BAY FRONT	1-3	COMMERCIAL(LD) RESIDENTIAL(LD)	5-15	NO	-	-	15
POINT BEACH	-	RURAL	30	NO	-	-	83
KEWAUNEE	-	RURAL	30	NO	-	-	76

*HD -- HIGH DENSITY; MD -- MEDIUM DENSITY; LD -- LOW DENSITY.

**IS THERE POTENTIAL FOR REDUCING OTHER AIR POLLUTION EMISSIONS IN THE AREA BY SUPPLYING THE
POLLUTION SOURCES WITH AN ALTERNATE ENERGY SOURCE THROUGH A DHCS?

†FOR THOSE GENERATING PLANTS WHICH DEMONSTRATE SOME POTENTIAL AS A DHCS HEAT SUPPLIER, IS
THERE A COMMITMENT BY THE UTILITY OWNER TO THE IDEA OF COGENERATION?

††ONE UNIT AT WESTON, PLANNED FOR OPERATION IN 1982, IS TO BE A COGENERATION UNIT.

its short expected remaining lifetime. The low thermal density near the Port Washington Plant (population of Port Washington about 9,500) resulted in its elimination. Likewise, the North and South Oak Creek Plants, sited in a predominantly residential area, were quite far from the high density thermal demand centers of Racine (about 7 miles) and downtown Milwaukee (about 10 miles), and they were also eliminated from consideration.

The remaining seven intermediate/base-loaded electric generating plants--Blount Street in Madison, Pulliam in Green Bay, Black Hawk in Beloit, Rock River between Beloit and Janesville, Edgewater in Sheboygan, Valley in Milwaukee and Manitowoc in Manitowoc--were considered to have the highest potential for retrofit modification to serve a DHCS. The utilities were asked to supply additional data on these seven plants at a team meeting for use in the final site selection process.

2.7 FINAL SITE SELECTION

Additional data were obtained from the utilities on each of these seven generating plants and are included in Appendix A. These data, along with maps of the area surrounding each generating plant, were used by team members to perform the final site selection. The team was able to reach a consensus on each decision. The most important criteria used in the final selection process were:

- Load factor--does the plant qualify or would a DHCS modified plant qualify under the DOE criteria as an intermediate/base-loaded plant?
- Thermal density in the surrounding area--residential, commercial and industrial.

- Expected remaining lifetime for the plant.
- Potential environmental advantages--is the plant presently in a nonattainment area?
- Degree of utility commitment.

Two generating plants were eliminated from further consideration during the initial discussion--the Valley Plant in Milwaukee and the Manitowoc Plant. Both of these plants presently supply to their customers heat in the form of steam as well as electricity. The Manitowoc Plant supplies steam to a nearby brewery, and the Valley Plant supplies steam to a district heating system in downtown Milwaukee. Since each plant already supplied the maximum amount of steam to its heat customers, the only feasible retrofit would have been to increase the boiler capacity at each plant in order to increase the steam supply. In the case of Manitowoc, this was not possible because of physical limitations. The Valley Plant was prevented from adding boiler capacity because of air pollution restrictions in the Milwaukee area. However, team members agreed that continuing participation of the Manitowoc Municipal Utility and the Wisconsin Electric Power Company in the Wisconsin DHCS Program was imperative. Their experience with existing district heating or heat delivery systems would be very beneficial to our future analysis.

The suggestion was made that the Rock River Plant and the Black Hawk Plant be considered together as potential heat sources for a DHCS, which would serve both Janesville and Beloit as well as an industrial park between the two cities. The consensus was that this idea made a lot of sense since the heat transmission line between the two cities would represent only a small portion of the entire distribution system. The number of potential customers would be larger since both cities would be involved.

With this modification the task of final site selection became relatively straightforward. The three sites with highest potential were selected immediately.

Green Bay--Served by the Pulliam Plant

Much of the potential demand in the Green Bay service area would be represented by industries that would use the heat for process heating as well as space/hot water heating needs. In addition, some commercial and high-density residential users exist in downtown Green Bay, which is in the early stages of a renovation and revitalization effort. Most of the residential housing in Green Bay is scattered single-family units--difficult and expensive to serve with a district heating system.

Madison--Served by the Blount Street Plant

This area probably contains the most diverse mix of potential users of the three service areas. Industrial users would be a relatively small component. There are a number of potential institutional users. The state government buildings in downtown Madison are served by a steam distribution system fed by head-only boilers located less than two blocks from the Blount Street Plant. The University of Wisconsin-Madison campus is less than two miles from the Blount Street Plant. The Madison Area Technical College (MATC) has not made final selection of a site for its new combined campus, which might be a potential user. Like Green Bay, the downtown Madison area is undergoing revitalization, with the State Street Mall, the Capitol Concourse and the Madison Civic Center being the most prominent changes. In addition to the commercial users that could be served, downtown Madison has some high-density residential development as well.

Janesville/Beloit--Served by the Rock River and Black Hawk Plants

As in Green Bay, the Janesville/Beloit area has little high-density residential development. Commercial demand is comparable to Green Bay, and the industrial demand is probably much less. The industrial concerns of Janesville

and Beloit, generally much smaller than the large paper mills of Green Bay, may be more willing to use a district heating system since their capital investment in in-plant heat delivery systems would be significantly less than that of a major paper mill. In addition, there is an institutional customer, Beloit College, with an existing low pressure steam heating system. Beloit College has already indicated to Wisconsin Power & Light Company that they would be interested in using heat from any potential district heating system.

The Sheboygan area (Edgewater Plant) has the smallest potential heat demand of the final four areas considered and was identified as the first alternate in case an insurmountable difficulty was encountered at an early stage of analysis of the three primary sites.

The team members agreed that no reliable comparative ranking among the three primary sites could be done in the absence of market, technical, institutional and economic analyses. The only meaningful ranking that could be accomplished during the site selection task was what has been done--selection of the three best sites from all the potential sites in Wisconsin.

Preliminary boundaries were developed for the DHCS service areas in Madison and Green Bay. These preliminary service areas are shown in Figures 3a and 3b. Final delineations of these service areas, as well as the more complex Janesville/Beloit service area, will result from the Energy Market Analysis and the Technical Review and Assessment.

2.8 CONCLUSIONS

In summary, three areas in Wisconsin have been identified as having high potential for a DHCS served by heat from an existing electrical generating

79130

2-12

Figure 3a. Preliminary Service Area, Madison, Wisconsin

Figure 3b. Preliminary Service Area, Green Bay, Wisconsin

plant. They are Madison, Green Bay and Janesville/Beloit. An additional encouraging factor in each instance is that the utility serving the area is strongly committed to this concept if it can be demonstrated that it is economically and institutionally acceptable.

SECTION 3.0 ENERGY MARKET ANALYSIS

3.1 INTRODUCTION

The results of the energy market analysis are presented in this section and described separately for each of the three selected sites--Green Bay, Janesville/Beloit and Madison. Potential service areas identified are characterized by present and future thermal loads, types of heating, hot water and air conditioning equipment, types of buildings and supply conditions for thermal energy. Finally, all three sites are analyzed with respect to factors that would induce potential users to subscribe to the DHCS.

3.2 GREEN BAY

Green Bay is located in Brown County in northeastern Wisconsin at the junction of the Fox and East Rivers, which empty into Green Bay on Lake Michigan (Figure 4). The city covers 44 square miles and has a population of 89,154 (1977 estimate), which is expected to increase to 92,000 by 1980.

The principal industry of Green Bay is paper making, with 11 mills of various sizes located in the area. In addition, there are some 25 plants in which food and kindred products are processed for national and foreign markets.

Potential Service Areas

The Pulliam Power Plant is located on the west bank of the Fox River at the point where it flows into Lake Michigan (Figure 4). Because the river is navigable by ships that ply the Great Lakes and the world's seaways, bridges

Figure 4. Green Bay Area

that are not high enough to permit their passage are either lift or swing-out bridges. This is an important consideration in regard to piping for a DHCS. All bridges on the East River are stationary.

The thermal market in the immediate area of the power plant can be described as follows:

- A few large industries are located on the west bank of the Fox River (the same side as the power plant). These industries are scattered along a six-mile stretch of the river rather than concentrated in one location. Further, the industries are of various types (i.e., steel fabricating, vegetable canning, a paper mill and a cement plant). Some, such as the cement plant, have requirements for high temperature process heat.
- The area adjacent to the power plant and along Lake Michigan has been set aside for a future industrial park. Currently, the area is vacant, but represents a significant future load.
- The area beyond the river bank contains scattered small commercial buildings and some single-family residences. The area further to the west contains primarily single-family residences.
- Immediately across the river from the power plant are three large paper mills concentrated in an Industrial Area that is 3/4 mile long by 1/2 mile wide.
- The area beyond the paper mills and on the same side of the East River contains scattered commercial building and single-family residences.
- The Central Business District (CBD) is located on the northern tip of land between the Fox and East Rivers.
- The area south of the CBD contains scattered small commercial buildings, multifamily and single-family residences.

Areas Selected for Detailed Analysis

The areas selected for detailed analysis are illustrated in Figure 4 and include the Industrial Area (three paper mills) located across the Fox River from the power plant and the Central Business District.

The three paper mills are concentrated in a small 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.

The Central Business District offers a concentration of multistory retail stores, office buildings, hotel and city-county buildings. The area is currently being renovated (see future loads) and offers even greater potential for future markets for a DHCS.

The remaining areas briefly surveyed were rejected for further detailed analysis at the present time because of their low thermal densities. The two areas in Green Bay that have a substantial thermal demand are the Central Business District and the paper mills.

Central Business District--Buildings within the Central Business District almost exclusively use natural gas for space and hot water heating. Thermal requirements for this area were derived using actual gas consumption data (1977-1978) supplied by Wisconsin Public Service Corporation of Green Bay.

Load data for the area were computed using an efficiency factor of 75 percent and are summarized by block and month in Table IV. Block numbers correspond to the block numbers on Figure 5.

Table IV. Current Load (Btu x 10⁹)

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1	1.347	1.264	1.024	.897	.476	.311	.316	.327	.389	.545	.626	1.104	8.628
2	1.425	1.156	.874	.550	.168	.012	.004	.007	.019	.130	.251	.372	4.969
3	Vacant Block												
4	.748	.706	.637	.459	.194	.116	.067	.053	.077	.182	.292	.613	4.141
5	.363	.257	.253	.290	.106	.032	.002	.005	.004	.010	.034	.193	1.548
6	.029	.030	.030	.021	.015	.007	.003	.004	.004	.005	.010	.023	.179
7	1.055	1.078	1.181	.851	.623	.526	.389	.161	.234	.426	.537	.962	8.024
8	Load Null												
9	1.420	1.252	.988	.625	.384	.129	.107	.084	.116	.328	.580	1.124	7.140
10	2.923	2.782	2.354	1.968	.932	.523	.467	.530	.569	.674	1.880	2.037	17.641
11	1.701	1.753	1.883	1.237	.800	.296	.060	.048	.056	.208	.575	1.263	9.881
12	1.588	1.660	1.747	1.119	.737	.377	.053	.046	.053	.124	.448	1.334	9.286
13	.807	.672	.638	.416	.278	.113	.018	.009	.009	.061	.178	.352	3.623
14	.929	.563	.592	.410	.223	.148	.017	.010	.022	.025	.257	.535	3.814
15	.411	.530	.316	.215	.074	.019	.025	.012	.018	.090	.155	.350	2.207
16	3.276	2.781	2.071	1.560	.503	.090	.099	.101	.164	.820	1.168	2.317	14.952
17	2.297	2.064	1.640	1.201	.456	.081	.045	.048	.139	.495	.942	2.015	11.467
18	1.513	1.500	1.192	.918	.524	.550	.751	.588	.544	.365	.491	1.030	10.064
19	.540	.677	.499	.445	.341	.135	.066	.059	.073	.124	.289	.563	3.773
20	.310	.366	.265	.263	.134	.047	.046	.018	.020	.081	.114	.296	1.962
21	.268	.262	.181	.122	.044	.027	.022	.032	.038	.051	.053	.220	1.319
22	1.892	1.766	1.367	.976	.521	.329	.338	.347	.410	.620	.853	1.484	10.904

Table IV. Current Load (Btu x 10⁹) concluded

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
23	3.859	3.099	2.581	2.017	1.301	1.092	.860	.846	.797	1.432	1.886	2.459	22.230
24	.365	.386	.330	.268	.177	.060	.025	.022	.025	.026	.215	.341	2.241
25	.426	.476	.325	.233	.178	.065	.035	.028	.026	.070	.164	.348	2.372
26	Load Null												
27	.706	.651	.570	.501	.309	.278	.248	.251	.256	.242	.332	.393	5.041
28	1.078	1.054	.724	.486	.098	.229	.086	.087	.082	.198	.381	.751	5.328
29	1.836	1.589	1.301	1.064	.594	.335	.236	.308	.405	.629	.935	1.584	10.841
30	1.082	1.255	.813	.775	.348	.019	.006	.004	.010	.017	.206	.765	5.300
31	.813	.583	.620	.475	.314	.058	.011	.005	.274	.402	.300	.423	4.279
32	.467	.508	.449	.189	.095	.018	.011	.010	.012	.062	.119	.407	2.347
33	.706	.651	.570	.501	.309	.241	.248	.251	.256	.243	.332	.393	5.041
34	.706	.651	.570	.501	.309	.241	.248	.251	.256	.243	.332	.393	5.041
35	Vacant Block												
36	.904	.858	.712	.614	.428	.211	.199	.176	.226	.421	.510	.785	6.044
37	.624	.386	.355	.269	.116	.026	.028	.026	.036	.189	.065	.147	2.277
38	1.150	1.058	.918	.794	.490	.382	.404	.397	.404	.384	.531	.668	7.581
39	.565	.422	.242	.307	.046	.051	.009	.009	.017	.104	.173	.292	2.234
40	.439	.413	.301	.217	.050	.023	.025	.023	.030	.072	.137	.335	2.065
41	.452	.343	.486	.212	.055	.033	.007	.006	.015	.060	.119	.415	2.199
42	2.790	2.460	2.130	1.215	.630	.180	.045	.090	.330	.900	1.725	2.490	15.000
43	.694	.705	.524	.425	.144	.022	.002	.002	.028	.093	.216	.436	3.290
44	1.350	1.230	1.065	.608	.315	.090	.023	.045	.165	.450	.863	1.245	7.500
Totals	45.041	41.897	35.318	26.214	13.839	7.522	5.651	5.426	6.608	11.601	19.274	33.257	238.773

Figure 5. Green Bay Selected Service Area

Peak Hour Demand--Peak hour demand was estimated by determining the peak day load and then calculating the maximum hourly load based on the minimum temperature. During January 1978, the following conditions prevailed for Green Bay.

• Degree-day hours for month	1658
• Maximum degree-day hours for day	66
• Minimum temperature, January 30	-14°

The maximum daily load was determined to be:

$$= \frac{\text{Max. degree-day hours for day}}{\text{degree-day hours for month}} \times \text{monthly load}$$

$$= \frac{66}{1658} \times 45.041 \times 10^9 \frac{\text{Btu}}{\text{day}}$$

The peak hour load can then be estimated:

$$\frac{\text{degree-day hours (based on min. temp.)}}{\text{degree-day hours (max. day for month)}} \times \frac{\text{max. daily load}}{24}$$

$$= \left(\frac{79}{66} \right) \frac{\text{DD}}{\text{DD}} \left(\frac{1 \text{ day}}{24 \text{ hours}} \right) (1.79295 \times 10^9 \frac{\text{Btu}}{\text{day}}) = 0.0894 \times 10^9 \frac{\text{Btu}}{\text{hour}}$$

Industrial Area

Three paper mills, Green Bay Packing, Inc., Charmin Paper, Inc., and American Can Company, are located in a concentrated area immediately north of the downtown business district (Figure 5).

Each of the three plants operate 24 hours per day, seven days per week, with shutdown occurring only on scheduled maintenance days and during holidays. Plant shutdown time is approximately 22 days per year.

The mills require a substantial amount of steam and hot water for process use. Since a substantial amount of the steam is used in processes where the condensate is not returned, there is a large requirement for boiler makeup water. Currently, makeup water is taken from the city water system at an average yearly temperature of 50°F.

There also is a large requirement for hot water for process use. Water for this use is taken from the Fox River at an average yearly temperature of 45°F and heated to 140°F.

Water requirements for the paper mills were obtained from data available at Wisconsin Public Service Corporation and conversations with paper mill representatives. Because individual data is proprietary, only totals are given. Water consumption includes:

- Boiler makup - 1.20×10^6 gallons/day
- Process water - 9.00×10^6 gallons/day

Based on boiler makeup water being heated to 300°F and process water to 140°F, the water consumption can be translated into the following thermal loads:

- Boiler makeup - 2.5×10^9 Btu/day
- Process water - 7.125×10^9 Btu/day

The load is constant with respect to months, except for holidays and scheduled plant shutdown periods.

Peak Hour Demand--Since the paper mills operate continuously except for holidays and scheduled plant shutdown period, the peak hour demand is the average load over the day:

- Boiler makeup - 0.104×10^9 Btu/hour
- Process water - 0.297×10^9 Btu/hour

Cooling Load--Little emphasis was initially placed on the potential cooling load for two reasons. First, it was estimated to be low in comparison to the space heating and hot water load. Second, the majority of the space cooling load was estimated to be supplied by small electric window units and central electric chillers (a fact later borne out by the HVAC analysis). In this case, a sizable retrofit cost would be experienced in switching to absorption cooling equipment.

Rather than expending time and effort identifying all cooling loads, only large loads in buildings amenable to central absorption systems were identified. For Green Bay, this consisted of one large shopping plaza having:

- Cooling load - 25×10^6 Btu/hour
- Operational schedule - April 15 to September 30,
10:00 a.m. to 9:00 p.m., Monday-Saturday;
11:00 a.m. to 5:00 p.m., Sunday

Forecasted Future Load--A substantial future load exists for the Green Bay Central Business District. Appendix B contains a detailed analysis of this load, its magnitude and distribution. A summary of the additional load, on a block by block, month by month basis, is contained in Table V. The peak hourly load is estimated to be 0.038×10^9 Btu/hour.

Load Summary--A summary of the current and forecasted loads and peak hour loads are summarized in Table VI.

Table V. Future Load Data (Btu x 10⁹)

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1													
2													
3													
4													
5													
6													
7	1.621	1.417	1.249	.734	.400	.149	.076	.099	.228	.557	1.019	1.451	9.242
8													
9	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
10	.783	.688	.602	.354	.191	.070	.034	.045	.108	.267	.490	.700	4.326
11													
12													
13													
14													
15	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
16	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
17	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
18													
19													
20													
21	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
22	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289

79130

3-11

Table V. Future Load Data (Btu x 10⁹) concluded

Block	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
23	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
24	.246	.246	.189	.111	.060	.022	.011	.014	.034	.084	.154	.220	1.358
25	.246	.246	.189	.111	.060	.022	.011	.014	.034	.084	.154	.220	1.358
26													
27	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
28	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
29													
30													
31	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
32	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
33													
34													
35	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
36													
37	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
38													
39	.429	.377	.330	.194	.106	.040	.020	.026	.061	.147	.270	.384	2.443
40	.429	.377	.330	.194	.106	.040	.020	.026	.061	.147	.270	.384	2.443
41	.414	.364	.318	.187	.101	.037	.018	.024	.057	.141	.259	.370	2.289
42													
43	.369	.324	.284	.167	.090	.033	.016	.021	.051	.126	.231	.330	2.037
44	1.621	1.417	1.249	.734	.400	.149	.076	.099	.228	.557	1.019	1.451	9.242
Totals	11.450	10.108	8.806	5.177	2.805	1.035	0.512	0.674	1.591	3.913	7.177	10.240	63.991

79130

3-12

Table VI. Load Summary, Green Bay

Load	BTU x 10 ⁹												Total
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	
CBD	45.04	41.90	35.32	26.21	13.84	7.52	5.65	5.43	6.61	11.60	19.27	33.26	238.77
Industrial	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	288.75	3465.00
TOTAL	333.79	330.65	324.07	314.96	302.59	296.27	294.40	294.18	295.36	300.35	308.02	322.01	3703.77
Future CBD	11.45	10.11	8.81	5.18	2.81	1.04	.51	.67	1.59	3.91	7.18	10.24	63.99

Peak Hour Demand

Current

- CBD 089. x 10⁶ BTU/Hr
- Industrial 401. x 10⁶ BTU/Hr

Future

- CBD 038. x 10⁶ BTU/Hr

Fuel Used

CBD	Natural Gas	100%
Industrial	Natural Gas	17%
	#6 Fuel Oil	17%
	Coal	66%

The building types within the CBD are nearly all commercial (retail store, the shopping plaza, office buildings, etc.). A small number (4 out of 140) are hotels/motels. Currently there is only one high-rise residential building in the service area.

Future additional loads within the CBD (projected by 1985) will be a mixture of commercial, hotel/motel and multifamily. No future loads are specified for the industrial park area. Currently, there is no construction in this area. Projections for the near future (by 1985) would be speculative since no tenants have been identified.

HVAC Inventory--Data characterizing the type and age of heating, hot water and air conditioning equipment were collected and analyzed for 28 buildings (approximately 20 percent of total) in the Central Business District. Detailed data are contained in Appendix C. A summary of the types of HVAC equipment is contained in Table VII; the age distribution in Table V.

The vast majority (82 percent) of the buildings have natural gas-fired boilers as a source of space heating. Of these, about 66 percent use steam for distribution and 34 percent use hot water. These results seem to correlate with the general age of the buildings in the Central Business District. Many of the buildings date back to the early 1900s (Figure 6). Steam was used in most large buildings built before 1960. Since then many new buildings have been designed for hot water space heating.

Gas-fired hot water heaters are used in a majority of the buildings. In buildings having a large hot water requirement (i.e., hotels/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

Table VII. HVAC Inventory Summary

	<u>Number</u>	<u>Percentage</u>
● Heat Source		
Boiler	23	82
Gas Forced Air	4	14
Electric	1	4
● Distribution		
Steam	14	50
Hot Water	9	32
Air	5	18
● Hot Water		
Steam Exchanger	5	18
Hot Water Exchanger	8	29
Gas	15	54
● Air Conditioning		
Electric	27	96
Absorption	1	4

Table VIII. Heating System Age Summary

Age	Number	Percent
0-5	7	23
6-10	5	17
11-15	2	7
16-20	5	17
21-25	4	13
26-30	5	17
31	4	13

department stores and the shopping plaza have central electric chillers. One building contains a central absorption unit, but it is scheduled to be removed because of operational problems.

3.3 JANESVILLE/BELOIT

The Janesville/Beloit area is located in southern Wisconsin along the Rock River which flows southward into Illinois. The cities are in Rock County, population 132,000 (1970), and are separated by 10 miles. The 1977 population of Janesville is 49,656 and Beloit, 36,208.

Potential Service Areas

Two power plants exist in the service area, the Black Hawk Plant in Beloit and the Rock River Plant midway between the two cities. Figure 7 shows the location of the two cities in relation to each other, the Central Business Districts (CBDs) and the power plants.

The thermal market in this area can be described as:

- Industry in the vicinity of Janesville,
- Industry in Beloit,
- Industry along the freeway east of Beloit,
- Janesville CBD,
- Beloit CBD,
- Schools,
- Residential areas.

3-18

Figure 7. Janesville/Beloit Area

Figure 8. Selected Subareas

Table IX. Current Load at Janesville/Beloit (Btu x 10⁹)

Block	J	F	M	A	M	J	J	A	S	O	N	D	Total	Remarks
1	0.62	0.50	0.26	0.14	0.02	0.02	0.01	0.01	0.03	0.13	0.38	0.48	2.6	J-CBD
2	0.33	0.26	0.15	0.09	0.02	0.03	0.02	0.02	0.04	0.11	0.27	0.29	1.6	J-CBD
3	0.59	0.50	0.27	0.18	0.08	0.03	0.04	0.04	0.07	0.17	0.50	0.50	3.0	J-CBD
4	0.75	0.68	0.37	0.20	0.06	0.02	0.02	0.03	0.07	0.20	0.65	0.62	3.7	J-CBD
5	1.04	0.96	0.65	0.47	0.26	0.17	0.17	0.20	0.23	0.41	0.98	0.95	6.5	J-CBD
6	0.47	0.61	0.32	0.20	0.10	0.06	0.08	0.08	0.11	0.21	0.50	0.49	3.2	J-CBD
7	0.91	0.64	0.11	0.53	0.06	0.02	0.02	0.02	0.05	0.21	0.68	0.73	4.0	J-CBD
8	1.07	0.86	0.52	0.35	0.16	0.14	0.14	0.12	0.18	0.32	0.83	0.90	5.6	J-CBD
9	0.33	0.26	0.17	0.12	0.02	0.01	0.01	0.01	0.02	0.11	0.28	0.32	1.6	J-CBD
10	0.4	0.4	0.3	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.2	0.4	2.0	
11	4.7	3.6	0.8	0.8	0.6	0.8	0.8	0.3	0.8	0.7	3.8	5.7	23.2	
12	0.7	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0	0.1	0.4	0.7	3.4	
13	102.7	91.5	81.4	76.3	58.0	46.8	36.6	36.6	39.7	75.3	85.4	100.7	831.0	
14	2.6	3.2	2.4	1.4	1.1	0.8	0.8	0.8	0.8	1.0	1.8	2.4	19.0	
15	1.5	1.6	1.5	1.3	0.8	0.5	0.2	0.2	0.2	0.4	0.7	1.1	9.8	
16	1.6	1.7	1.2	0.9	0.4	0.1	0.1	0.1	0.2	0.5	1.1	1.6	9.2	
17	2.9	3.5	3.2	2.3	0.9	0.5	0.3	0.4	0.5	0.5	0.7	2.0	17.4	
18	15	15	15	15	15	15	15	15	15	15	15	15	180	
19	6.3	6.5	6.6	5.4	4.7	4.6	4.1	4.0	5.8	4.9	6.5	6.2	65.4	
20	0.8	1.0	0.8	0.6	0.3	0.1	0.0	0.0	0.0	0.1	0.3	0.7	4.6	
21	0.7	0.7	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.1	0.4	0.6	3.4	
22	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.9	

NOTE: J-CBD = Janesville Central Business District

Table IX. Current Load at Janesville/Beloit (Btu x 10⁹) concluded

Block	J	F	M	A	M	J	J	A	S	O	N	D	Total	Remarks
23	1.6	1.4	1.2	0.8	0.7	0.5	0.4	0.4	0.8	1.0	1.4	1.6	11.7	
24	2.1	2.0	1.6	0.7	0.4	0.0	0.0	0.0	0.0	0.5	1.2	1.6	10.0	
25	1.9	1.7	1.5	0.9	0.5	0.0	0.0	0.0	0.0	0.7	1.1	1.6	9.8	
26	1.2	1.0	0.9	0.7	0.6	0.5	0.4	0.5	0.6	0.5	1.1	1.0	8.8	
27	9.1	8.9	6.5	4.7	5.7	5.9	7.0	6.7	6.5	4.7	4.4	7.1	77.0	
28	5.0	2.7	2.4	1.4	1.0	0.6	0.5	0.8	2.0	2.6	3.2	4.7	26.9	
29	1.7	1.3	1.0	0.6	0.4	0.2	0.2	0.2	0.4	0.5	0.5	1.6	8.5	
30	0.8	0.8	0.5	0.6	0.3	0.2	0.1	0.2	0.2	0.2	0.2	0.4	4.4	
31	0.8	0.6	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.5	2.6	
32	0.2	0.5	0.7	0.5	0.6	4.5	3.4	4.4	0.1	0.0	0.4	0.2	15.4	
33	1.0	1.2	1.7	0.5	0.1	0.0	0.0	0.0	0.0	2.3	1.1	2.0	9.6	
34	10.1	11.3	10.7	9.4	9.8	8.0	8.8	8.0	6.3	7.1	8.7	10.1	108.1	
35	4.1	3.8	2.9	1.8	0.9	0.2	0.0	0.1	0.3	1.1	1.8	3.5	17.1	
36	44.1	68.7	38.9	15.3	14.7	12.3	4.5	4.5	6.5	4.9	9.2	10.7	234.2	
37	6.8	7.3	5.7	7.7	6.8	6.3	4.7	6.2	6.2	6.4	6.7	6.5	75.8	
38	18.0	19.7	9.8	22.8	15.7	19.4	19.9	18.1	14.0	19.7	17.3	18.3	212.6	
39	42.2	41.5	36.7	20.7	14.0	9.0	4.4	4.4	9.5	11.3	19.4	35.3	248.4	
40	17.3	16.5	7.0	6.4	1.8	3.2	3.5	3.9	3.5	7.1	11.8	16.5	98.5	
41	0.42	0.41	0.29	0.19	0.11	0.01	0.01	0.01	0.01	0.08	0.16	0.32	2.0	B-CBD
42	0.21	0.27	0.20	0.09	0.02	0.01	0.01	0.01	0.01	0.04	0.08	0.23	1.2	B-CBD
43	1.04	0.95	0.74	0.43	0.19	0.02	0.03	0.02	0.02	0.19	0.41	0.85	4.9	B-CBD
44	0.34	0.22	0.32	0.12	0.05	0.02	0.02	0.02	0.02	0.06	0.09	0.26	1.5	B-CBD
45	1.48	1.38	1.01	0.50	0.20	0.03	0.03	0.03	0.03	0.21	0.44	1.11	6.5	B-CBD
46	1.68	1.34	1.20	0.79	0.44	0.17	0.17	0.17	0.16	0.56	0.65	1.34	8.7	B-CBD
47	0.51	0.44	0.41	0.21	0.09	0.01	0.01	0.01	0.01	0.20	0.21	0.41	2.5	B-CBD

NOTE: B-CBD = Beloit Central Business District

Figure 9. Location of 47 Blocks of Data, Janesville/Beloit

ILLUSTRATION

Not To Scale

3-23

Figure 10. Detail of Janesville Central Business District

79130

Figure 11. Detail of Downtown Beloit Subarea

ILLUSTRATION

Not To Scale

79130

3-25

Figure 12. Detail of Beloit Central Business District

Areas Selected for Detailed Analysis

The areas selected for detailed analysis are shown in Figure 8. They include the Janesville CBD and areas to the south of it, the Beloit CBD and areas nearby, and an area of industry east of Beloit.

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

- Beloit thermal loads which 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.
- Thermal loads south of Janesville, which are applicable to a network off of 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. These loads include industry, schools and a hospital (called Beloit "other").

The area north of the Janesville CBD is not included in the detailed analysis because it is mostly residential and scattered commercial of a low thermal density and too far from the power plant for efficient delivery of thermal energy. The residential areas in both cities are of too low a thermal density for consideration. A great deal of open farmland exists in the area between Beloit and Janesville.

Current Thermal Load--The thermal demand for the selected Janesville/Beloit area is delineated in Table IX. This demand is characterized by 47 "blocks" of data, which include CBD blocks, industries, schools and other entities. The location of each "block" is defined by Figure 9 and detail Figures 10, 11 and 12. The thermal demand was derived using natural gas consumption (1977-78) supplied by Wisconsin Power and Light (WP&L) Company. The load data was calculated using an efficiency factor of 75 percent.

Peak Hour Demand--Peak hour demand was estimated by determining the peak day load (from weather data) and calculating the maximum hourly load based on ASHRAE design recommendations. For the selected area, the peak loads occurred in February 1978. The peak days in February were the 2nd and 3rd. The following degree-day data was used:

- Degree days for February (base 65°F) - 1466
- Maximum degree days for 2nd and 3rd - 62
- ASHRAE design temperature - -13°F

Therefore, the maximum daily load was

$$(\text{February load}) \times \left(\frac{62}{1466}\right)$$

and the average hourly load (maximum day) was

$$(\text{February load}) \times \left(\frac{62}{1466}\right) \times \left(\frac{1}{24}\right)$$

and the peak hourly load would be

$$\left(\frac{78}{62}\right) \times \text{average hourly load (max. day)} =$$

$$\left(\frac{78}{62}\right) \times (\text{February load}) \times \left(\frac{62}{1466}\right) \times \left(\frac{1}{24}\right) =$$

$$(0.00222)$$

Table X summarizes the peak hourly load from the selected service areas.

Load Distribution--Because the building types in the Janesville/Beloit service area range from small commercial buildings to large manufacturing facilities,

Table X. Peak Hourly Load Summary

Block	Total Feb. Load (BTU x 10 ⁹)	Peak Hour (BTU x 10 ⁶)	Subtotals BTU x 10 ⁶
1	0.5	1	
2	0.3	1	
3	0.5	1	
4	0.7	2	
5	1.0	2	
6	0.6	1	
7	0.6	1	
8	0.9	2	
9	0.3	1	
10	0.4	1	
11	3.6	8	
12	0.6	1	
13	91.5	203	
14	3.2	7	
15	1.6	4	
16	1.7	4	
17	3.5	8	
18	15	33	
19	6.5	14	
20	1.0	2	
21	0.7	2	
22	0.2	0	
23	1.9	4	
24	2.0	4	307 (Janesville)
25	1.7	4	
26	1.0	2	
27	8.9	20	
28	2.7	6	
29	1.3	3	
30	0.8	2	
31	0.6	1	
32	0.5	1	
33	1.2	3	
34	11.3	25	75
35	3.8	8	75 (Beloit "Other")
36	68.7	152	
37	7.3	16	
38	19.7	44	
39	41.5	92	
40	16.5	37	
41	0.4	1	
42	0.3	1	
43	1.0	2	
44	0.2	0	
45	1.4	3	
46	1.3	3	
47	0.4	1	352 (Beloit Downtown)

the thermal loads vary greatly and are not uniformly distributed. Thirty-four of the "blocks" represent single point loads (i.e., one manufacturing facility). Even the CBD blocks (13) are characterized by widely varying loads. Table XI illustrates the load distribution; the total yearly load by block, the rank of the block with respect to size of load, the total number of customers per block and, in the case of multiple customers, a distribution by major customers.

Cooling Load--Little emphasis was placed on the potential cooling load unless large loads were discovered. The HVAC analysis indicates very minimal use of absorption chillers and a high preponderance of small electrical window air conditioners. Thus, the cost of retrofit to absorption cooling equipment would probably be prohibitive, and the cooling load is therefore not evaluated.

Future Loads--Neither Janesville or Beloit are expected to experience commercial growth that would significantly influence the thermal demand analysis. However, due to the large amount of available land, some potential does exist for industrial parks between the two cities. One planned industrial park will be located west of Rock River Power Plant (Figure 9). Forecast loads for that park are estimated to be over 10^{12} Btu/year with a peak of 250×10^6 Btu/hour based on Wisconsin Power & Light discussions with potential tenants. Thus, the potential load would rank first in the service area and represent over 40 percent of the existing load.

Load Summary--Table XII summarizes the loads for the Janesville/Beloit area. The data is presented for:

- Janesville CBD,
- Janesville industry,

Table XI. Janesville/Beloit Load Distribution

Block	Total Load BTU/Yr. x 10 ⁹	Rank	Total Number of Customers	Distribution
1	2.6	38	6	1 = 69%
2	1.6	43	5	1 = 59%
3	3.0	37	12	1 = 43%, 2 = 57%
4	3.7	33	3	1 = 47%
5	6.5	26	5	1 = 90%
6	3.2	36	9	1 = 57%
7	4.0	32	5	1 = 69%
8	5.6	28	16	3 = 57%
9	1.6	44	1	
10	2.0	41	1	
11	23.2	12	1	
12	3.4	32	1	
13	831.0	1	1	(35% of total, i. e. of 2408)
14	19.0	13	1	
15	9.8	20	1	
16	9.2	22	1	
17	17.4	14	1	
18	180	5	1	
19	65.4	10	1	
20	4.6	30	1	
21	3.4	35	1	
22	0.9	47	1	
23	11.7	17	1	
24	10.0	18	1	
25	9.8	19	1	
26	8.8	23	1	
27	77.0	8	1	
28	26.9	11	1	
29	8.5	25	1	
30	4.4	31	1	
31	2.6	39	1	
32	15.4	16	1	
33	9.6	21	1	
34	108.1	6	1	
35	17.1	5	1	
36	234.2	3	1	(-10 of total)
37	75.8	9	1	
38	212.6	4	1	(9% of total)
39	248.4	2	1	(10% of total)
40	98.5	7	1	
41	2.0	42	5	1 = 51%
42	1.2	46	4	1 = 36%
43	4.9	29	18	3 = 53%
44	1.5	45	1	
45	6.5	27	12	1 = 36%, 2 = 57%
46	8.7	24	21	1 = 44%, 2 = 63%
47	2.5	40	1	
Total		2408		

Table XII. Janesville/Beloit Load Summary

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Janesville CBD	6.1	5.3	2.8	2.3	0.8	0.5	0.5	0.5	0.8	1.9	5.1	5.3	31.9
Janesville Industry	143.7	132.9	117.1	106.2	83.4	69.7	58.3	57.7	63.9	100.3	119.0	140.4	1192.6
Beloit CBD	5.7	5.0	4.2	2.5	1.1	0.3	0.3	0.3	0.3	1.3	2.0	4.6	27.6
Beloit Industry	164.3	160.5	127.3	94.2	73.0	70.3	57.4	52.0	56.1	69.2	87.1	120.0	1131.4
Totals	319.8	303.7	251.4	205.2	158.3	140.8	116.5	110.5	121.1	172.7	213.2	270.3	2383.5
Future Ind. Pk.	120	110	100	90	70	60	50	50	50	90	100	120	1010
Peak Hr. Loads													
Janesville CBD	12 x 10 ⁶ BTU/hr												
Janesville Ind.	295 x 10 ⁶ BTU/hr												
Beloit CBD	11 x 10 ⁶ BTU/hr												
Beloit Ind.	416 x 10 ⁶ BTU/hr												
Totals	734 x 10 ⁶ BTU/hr												
Future Ind. Pk.	250 x 10 ⁶ BTU/hr												

FUEL USAGE

Coal	35%
Gas	65%

- Beloit CBD,
- Beloit industry,
- Totals,
- Future loads,
- Peak hour loads.

The fuel usage breakout is also included in the table.

HVAC Inventory--Data characterizing the types of heating, hot water, process heat and air conditioning equipment were collected and analyzed for 21 blocks (approximately 45 percent of total) of the Janesville/Beloit service area. Detailed data is contained in Appendix C.

The vast majority (90 percent of the "blocks" use natural gas-fired boilers as a source of space and process heating. Five percent use natural gas-fired space heaters and 5 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 5 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" (27 and 40) use central absorption units.

3.4 MADISON

Madison is located in Dane County in central Wisconsin. Prominent in the topography of Madison are Lake Mendota and Lake Monona, between which the city is situated. The 1970 census population of Madison is 173,285.

Potential Service Area

Madison Gas and Electric Company supplies electric power and natural gas to the metropolitan area of Madison. The Blount Street Power Plant is located just off the downtown loop, between the two lakes (Figure 13).

The thermal market in the immediate area of the Blount Street Plant can be described as follows:

- The Central Business District (CBD) contains office, retail store, and hotel/motel buildings. This area is bounded on the northeast by Blount Street and the southwest by Bedford Street. Lake Mendota and Lake Monona provide the boundaries to the northwest and southeast.

Within the CBD are a number of state/country buildings that are heated and some of which are cooled by a separate, state-operated coal-, gas-and oil-fired steam (125 psig) generating plant (Capitol Heating Plant). The buildings currently heated by this network include the State Capitol Building, State Office Building, City/County Building and General Executive Facility (GEF) No. 1. GEF No. 2 and GEF No. 3, currently under construction, will also be supplied by this network. The buildings that are and will be supplied chilled water from a 2500-ton, steam-turbine-driven central chiller are the three newer General Executive Facility buildings. The location of the Capitol Heating Plant and building served by the plant are identified in Figure 14. (i.e., those blocks with "///" around them.)

- The University of Wisconsin occupies a large area along Lake Mendota and west of the CBD (Figure 13). This area contains about 150 buildings. The university operates two, (coal, oil and

Figure 13. Madison Service Area

Figure 14. Madison Central Business District

Table XIII. Madison - Current Load Data (Btu x 10⁹) 1977-1978

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
00	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
29	.096	.105	.098	.081	.047	.082	.160	.058	.045	.062	.079	.098	.867
30	.782	.842	.690	.649	.298	.380	.077	.281	.236	.466	.645	.748	6.093
31	.229	.230	.197	.144	.048	.043	.009	.035	.036	.096	.146	.199	1.411
32	.613	.562	.450	.266	.158	.068	.066	.058	.863	.189	.277	.460	3.252
33	.704	.635	.553	.288	.138	.015	.016	.014	.160	.127	.271	.498	3.274
34													0
35													0
40	.369	.464	.304	.262	.111	.091	.016	.063	.064	.189	.312	.364	2.609
41	1.427	1.268	.868	.638	.497	.177	.173	.157	.184	.399	.735	1.280	7.801
42	.090	.082	.065	.039	.024	.007	.007	.004	.005	.028	.082	.082	0.596
43	.231	.231	.167	.069	.032	.008	.007	.008	.011	.046	.125	.202	1.136
44	1.013	.889	.702	.399	.198	.114	.133	.067	.113	.287	.456	.802	5.191
45	.075	.068	.052	.033	.010	.014	.003	.011	.010	.026	.046	.070	0.417
46	.179	.179	.135	.092	.029	.008	.001	.001	.010	.102	.116	.176	1.025
47	.443	.458	.352	.246	.088	.083	.016	.054	.056	.116	.027	.416	2.642
48	.086	.086	.065	.051	.020	.016	.003	.007	.012	.041	.064	.091	0.541
49													0
50	.652	.609	.507	.414	.171	.288	.062	.214	.184	.340	.474	.619	4.533
51	1.747	1.317	1.077	.735	.254	.024	.024	.023	.050	.370	.678	1.140	7.437
52	3.819	3.442	2.812	1.292	.418	.215	.192	.197	.451	.451	1.867	2.379	17.302
53													0
54	1.267	.900	.672	.440	.258	.176	.145	.129	.182	.351	.665	.977	6.160
55	.244	.238	.181	.126	.057	.097	.020	.080	.065	.106	.150	.206	1.569
56	.552	.509	.347	.205	.065	.078	.018	.069	.048	.164	.314	.484	2.852
57	.147	.134	.104	.071	.029	.024	.001	.001	.005	.039	.091	.135	0.779
58	.313	.302	.229	.157	.145	.022	.005	.013	.021	.103	.204	.292	1.704
60	3.962	3.761	2.948	1.839	1.078	.268	.268	.223	.302	1.240	2.076	3.545	21.510
61	1.529	1.595	1.294	.822	.592	.281	.300	.292	.383	.581	.958	1.379	10.010

Table XIII. Madison - Current Load Data (Btu x 10⁹) 1977-1978 (continued)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
62	.930	.845	.699	.442	.241	.138	.096	.112	.135	.332	.509	.753	5.201
63	.932	.932	.671	.425	.145	.131	.029	.111	.109	.311	.528	.797	5.154
64	.725	.747	.516	.220	.094	.010	.007	.007	.007	.135	.382	.511	3.360
65	.659	.617	.362	.135	.048	.024	.025	.029	.051	.051	.025	.524	2.753
66	2.078	1.900	1.143	.438	.057	.005	.005	.005	.005	.266	.809	1.462	8.174
67	2.173	1.944	1.633	.963	.461	.157	.188	.220	.366	1.026	1.422	2.034	12.585
68	.155	.112	.086	.023	.006	.003	.003	.003	.003	.008	.036	.081	.517
69													0
70	1.039	1.065	.829	.611	.210	.192	.037	.133	.142	.432	.732	1.043	6.464
71	.764	.748	.538	.367	.133	.083	.017	.062	.077	.280	.463	.684	4.195
72	.295	.290	.227	.154	.047	.075	.017	.051	.035	.108	.168	.278	1.746
73	.650	.650	.547	.293	.078	.056	.015	.040	.054	.231	.390	.570	3.573
74	4.841	4.335	2.175	1.267	.886	.773	.704	.670	.746	1.121	1.927	3.641	23.112
75	2.451	2.148	2.119	.796	.271	.061	.051	.045	.053	.534	1.466	2.374	12.369
76	.589	.884	.460	.234	.147	.113	.108	.114	.103	.165	.341	.699	3.957
77	.111	.106	.069	.012	.005	.001	.001	.001	.001	.026	.060	.090	.484
78													0
79	1.103	1.011	.794	.593	.235	.222	.046	.145	.157	.462	.726	1.003	6.497
80	.433	.414	.289	.194	.060	.023	.004	.016	.017	.076	.212	.350	2.088
81	.662	.621	.509	.326	.076	.022	.005	.016	.036	.211	.462	.711	3.656
82	3.800	4.408	3.215	.563	.418	.008	.008	.008	.032	1.148	2.432	2.545	18.583
83	1.386	1.985	1.187	.582	.187	.108	.095	.081	.086	.305	.989	1.417	8.409
84	1.751	1.768	1.360	.745	.159	.132	.026	.094	.109	.373	.894	1.496	8.906
85	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
86	4.500	3.780	3.150	2.430	2.120	2.300	1.750	1.670	1.710	2.340	3.110	4.460	33.320
87	1.251	1.293	1.076	.855	.316	.292	.054	.201	.218	.631	.967	1.279	8.430
88	1.079	.884	.672	.395	.087	.016	.017	.017	.017	.019	.383	.927	4.514
89	1.150	1.144	.824	.504	.167	.163	.034	.129	.109	.282	.611	1.083	6.201
90	2.037	1.965	1.477	.572	.161	.010	.007	.007	.011	.354	1.005	2.226	9.831

79130

3-37

Table XIII. Madison - Current Load Data (Btu x 10⁹) 1977-1978 (continued)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
91	.883	.936	.654	.384	.173	.057	.048	.046	.051	.311	.518	.803	4.865
92	1.902	1.103	.849	.554	.094	.136	.032	.032	.047	.373	.750	.207	6.077
93	1.2839	1.135	.847	1.098	.326	.118	.116	.126	.134	.420	.781	1.034	7.419
94	3.486	3.476	2.910	1.786	1.271	.567	.405	.468	.512	1.155	2.239	3.403	21.680
95	3.050	2.521	1.804	1.016	.501	.181	.163	.161	.171	.566	1.528	2.296	13.957
96	.319	.282	.211	.119	.077	.134	.031	.029	.032	.095	.178	.245	1.652
97	.360	.309	.246	.158	.096	.051	.043	.036	.036	.117	.210	.291	1.953
98	.390	.371	.292	.172	.082	.026	.026	.023	.026	.010	.242	.454	2.204
99	.200	.205	.148	.084	.041	.011	.024	.024	.026	.040	.084	.121	1.008
100	.308	.306	.268	.171	.115	.070	.075	.053	.053	.123	.224	.297	2.064
101	2.144	1.919	1.511	.934	.699	.148	.219	.248	.299	.748	1.148	1.937	11.954
102	3.000	2.651	1.923	1.347	.396	.089	.019	.076	.087	.516	1.551	2.435	14.093
103	.091	.084	.066	.044	.006	.018	.000	.001	.007	.031	.052	.077	.476
104	.934	.926	.612	.365	.087	.013	.002	.008	.035	.247	.560	.920	4.713
105	.099	.110	.112	.127	.076	.154	.030	.112	.084	.110	1.189	2.100	4.303
106	.775	.756	.512	.269	.067	.040	.008	.030	.039	.174	.397	.699	3.766
107													0
108	6.500	5.460	4.550	3.510	3.070	3.330	2.520	2.420	2.470	3.380	4.500	6.450	48.160
109	.554	.480	.372	.199	.137	.073	.068	.075	.089	.164	.236	.433	2.883
110	.140	.149	.109	.063	.044	.033	.029	.017	.023	.060	.099	.128	.895
111	.266	.269	.206	.103	.059	.032	.034	.029	.033	.083	.152	.231	1.496
112	1.029	.977	.729	.280	.159	.033	.041	.041	.049	.190	.397	.575	4.502
113	.282	.272	.201	.109	.028	.022	.005	.018	.123	.086	.137	.239	1.422
114	.255	.226	.174	.110	.033	.018	.003	.014	.021	.099	.176	.237	1.366
115	.378	.354	.246	.130	.048	.037	.016	.023	.015	.095	.194	.338	1.873
116	.167	.156	.123	.079	.039	.022	.010	.015	.016	.046	.089	.140	.902
117													0
118													0
119	.107	.104	.078	.049	.029	.009	.008	.009	.008	.034	.063	.091	.591

79130

3-38

Table XIII. Madison - Current Load Data (Btu x 10⁹) 1977-1978 (concluded)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
120	.085	.087	.066	.041	.031	.024	.009	.007	.009	.028	.047	.073	.508
121	.720	.666	.511	.349	.117	.026	.005	.020	.039	.191	.324	.585	3.553
122	1.023	.915	.641	.337	.080	.039	.007	.028	.041	.196	.521	.905	4.734
123	.497	.424	.292	.139	.055	0	.006	.016	.007	.009	.131	.334	1.913
124	.590	.438	.468	.243	.429	.648	.714	.663	.547	.183	.312	.424	5.659
125	.187	.193	.135	.076	.018	.009	.002	.007	.012	.040	.100	.184	.965
126													0
257													0
258	.085	.081	.062	.040	.024	.027	.020	.025	.027	.039	.052	.072	.555
260													0
264	.722	.616	.514	.340	.105	.001	.002	.000	.022	.050	.374	.592	3.340
265	.185	.183	.135	.067	.032	.016	.013	.011	.015	.040	.084	.145	.927
266	.761	.487	.462	.301	.270	.225	.220	.224	.265	.279	.311	.441	4.047
267	.357	.347	.260	.167	.046	.016	.004	.017	.021	.109	.223	.332	1.899
268	.791	.777	.538	.367	.137	.160	.031	.104	.119	.262	.487	.739	4.512
Total (CBD)	113.574	104.032	71.603	44.084	24.797	18.810	13.433	14.642	16.815	32.525	52.567	89.607	609.071
UW	225	201	171	119	106	103	94	88	89	106	141	194	1637
TOTALS	338.574	305.032	242.603	163.084	130.797	121.810	107.433	102.642	105.815	138.525	193.567	283.314	2246.071

79130

3-39

natural gas) steam heating plants (Walnut St. and Charter St. plants) that produce (150-175 psig) steam to heat all of and cool some of these building. Cooling is accomplished by steam-turbine-driven chillers (one 7000-ton unit and four 3500-ton units). The majority of the buildings contain steam distribution systems. Buildings constructed since 1960 have hot water distribution systems.

- The area west of the CBD and south of the university contains scattered commercial buildings, some multifamily (two to three units) and single-family residences.
- The area to the northeast of the CBD contains scattered commercial buildings, multifamily (two to three units) and single-family residences.

Areas Selected for Detailed Analysis

The areas selected for detailed analysis include the Central Business District and those building heated by the Capitol Heating Plant and the University of Wisconsin campus. The CBD encompasses about 100 city blocks of multistory commercial retail and hotel/motel buildings, and includes those buildings (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 150 multistory classroom, office and dormitory buildings.

The remaining areas on either side of the CBD were rejected for the present time because of the low thermal density and extended distribution system that would be required to serve them.

Current Thermal Load--The current thermal load was derived using natural gas consumption and steam supply data (1977-78, reference 4) supplied by Madison Gas and Electric. Load data for natural gas consumption were

converted using an efficiency factor of 75 percent. Load data computed from steam supply data for the Capitol Heating Plant and the University of Wisconsin (Appendix D) were derived by assuming 1000 pounds steam equals 10^6 Btu.

Table XIII summarizes the load data by block and month. The block numbers used correspond to those in Figure 14 and also to city numbers. For this reason, the block numbers do not run consecutively. The State Capitol was arbitrarily assigned a block number of 0.

Peak Hour Demand--Peak hour demand for the CBD (excluding the buildings served by the Capitol Heating Plant) was estimated by determining the peak day load and then calculating the maximum hourly load based on the minimum temperature. For Madison during January 1978, the following conditions prevailed:

• Degree-days for January (base 65°F)	1688
• Maximum degree-day (9th)	71
• Minimum temperature (30th)	-12°F
• ASHRAE design temperature	-13°F

Therefore, the maximum daily load was

$$(\text{January load}) \times \left(\frac{71}{1688}\right)$$

and the average hourly load (maximum day) was

$$(\text{January load}) \times \left(\frac{71}{1688}\right) \times \left(\frac{1}{24}\right)$$

and the peak hourly load would be (ASHRAE)

$$\left(\frac{78}{71}\right) \times \text{average hourly load (maximum day)} =$$

$$\left(\frac{78}{71}\right) \times (\text{January load}) \times \left(\frac{71}{1688}\right) \times \left(\frac{1}{24}\right) =$$

$$(0.00193) \times (\text{January load})$$

The total peak hourly load for the CBD is 219.198×10^6 Btu/hour.

Peak hour loads for the buildings occupied by the capitol heating plant and the University of Wisconsin were determined (Appendix D) to be 62×10^6 Btu/hour and 580×10^6 Btu/hour, respectively.

Future Thermal Loads--Appendix B contains a detailed analysis of additional future loads within the CBD, their magnitude, location and distribution. These have been summarized on a block-by-block, month-by-month basis in Table XIV. The peak hourly load for this future load is estimated to be 8.8×10^6 Btu/hour.

Cooling Loads--No cooling load data was collected for Madison. The CBD contains a number of commercial buildings that are cooled during portion of the summer months. As indicated by the sample HVAC data collected, the vast majority of the buildings that do contain air conditioning equipment have electric window units and central chillers. Only one absorption air conditioning unit was identified.

Converting to absorption air conditioning equipment would be expensive, especially in light of the fact that there would be conversion costs for the heating systems. The cooling loads are currently viewed as a potential add-on to a DHCS, once the system becomes operational.

Table XIV. Future Loads, Madison (Btu x 10⁹)

Block	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
53	.50	.40	.40	.20	.10	-	-	-	.10	.20	.30	.40	2.60
65	2.01	1.68	1.45	.79	.40	.10	.02	.05	.23	.64	1.22	1.80	10.39
107	1.80	1.40	1.40	1.00	1.00	1.20	1.20	1.20	1.00	1.00	1.20	1.40	14.80
Totals	4.31	3.48	3.25	1.99	1.50	1.30	1.22	1.25	1.33	1.84	2.72	3.60	27.79

Load Summary--Table XV contains a summary of the load data for Madison: monthly and total loads, peak hour demands and types of fuels used for the Madison service area.

HVAC Inventory Analysis--Data characterizing the type and age of heating, hot water and air conditioning equipment were collected and analyzed for 25 buildings (approximately 10 percent of total) in the Central Business District. Detailed data are contained in Appendix C. A summary of types and age distributions is contained in Tables XVI and XVII.

The vast majority of 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. This appears to correlate with the general age of the buildings. The majority were built before 1960 when steam was the common distribution media.

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

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

3.5 FACTORS TO INDUCE POTENTIAL USERS

To determine what factors would induce potential users to subscribe to the DHCS, 13 interviews (representing 23 people) were conducted in the communities of Green Bay, Janesville/Beloit and Madison. Owners, managers, operators and directors representing a cross-section of building types were interviewed. Applicable comments from each interview are summarized in Appendix E. The

79130

3-45

Table XVI. HVAC Inventory Summary

	Number	Percentage
Heat Source		
• Boiler	25	100
Distribution		
• Steam	21	81
• Hot Water	5*	19
Hot Water		
• Steam Exchanger	5*	19
• Hot Water Exchanger	1	4
• Gas Fired	20*	77
Air Conditioning		
• Electric	22	88
• Absorption	1	4
• None	2	8

Table XVII. Age Distribution

Age	Number	Percentage
0-5	1	4
6-10	3	12
11-15	2	8
16-20	1	4
> 20	18	72

remaining paragraphs of this section describe the approach used to determine what factors would induce potential users to subscribe and an evaluation of these factors.

During a monthly working session, the study team identified a number of factors that might induce potential users to subscribe to a DHCS. These were used to develop a list of topical questions (Figure 15) that would be used to solicit views and comments from prospective users.

Interviews were arranged through the utilities serving each of three communities. Each actual interview was conducted by a Honeywell and a utility representative.

Evaluation of Factors

As determined from the interviews, factors that would induce potential users to subscribe to the DHCS fall into the following categories:

- Economics
- Additional Information
- Reliability
- Pollution
- Disruption
- Safety

Economics--Economics are the consideration most often mentioned. During the interviews, it was determined that capital expenditures within a business should be projected to produce a payback ranging from three to five years. Financial expenditures longer than this period would receive less attention.

- Q - AS A POTENTIAL CUSTOMER OF A DISTRICT HEATING AND COOLING SYSTEM, WHAT ARE SOME OF YOUR CONCERNS ABOUT BECOMING A SUBSCRIBER AND WHAT ARE SOME INDUCEMENTS THAT YOU WOULD CONSIDER?

TOPICS

- Rates
 - Less than competitive fuels
 - Amount less (5 percent, 10 percent, etc.)
 - Regulated rates (PSC Commission)
- Conversion Costs
 - Discount for early subscribers
 - Tax rebate for initial conversion costs
 - ROI target for conversion
 - Payback time
 - Low Interest Loans
 - Less manpower requirements in building
- Reliability/Service
 - Multiple paths to customer
 - Downtime $\leq$ 1 hour
 - Service organization
- Conversion Time
 - Customer organization
- Disruptive Time
 - Ripped up streets
- Air pollution
 - 50 percent less
- Safety
- Others

Figure 15. Topical Questions

Once this was determined, factors that would help achieve this payback criteria for a DHCS and circumstances where it would be realized were examined.

Achieve Payback Criteria

- Tax Credits--Tax credits were often mentioned by private businesses/corporations as a means to help offset initial retrofit costs. Tax credits would not help some of the people interviewed (e.g., school, YMCA) because of their nonprofit status.
- Low Interest Loads--Low interest loans were the next most often mentioned method to help achieve the financing objective. As opposed to tax credits, this vehicle would also benefit nonprofit organization.
- Government Financial Participation in Construction--The Federal Government should consider financing a portion of the DHCS installation. Private business was quick to point out that the Government funds many social welfare programs, hydro dams and nuclear power plants.

Relaxed Payback Criteria

- Energy Outlook--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. Ranges cited include an extension from three to five years.
- Business Climate--The better the business climate at the time, the more relaxed the economic payback. This was expressed during interviews by people who were residents of the community. Some people interviewed (e.g., manager of a shopping plaza) suggested that the owners, who were not residents of the community, would not be swayed by this argument. They would examine the investment in light of alternative investments only.

- Community Involvement--Those persons who lived in and also owned/operated businesses in the community appeared more inclined to support the DHCS concept because of possible benefits to the community. This sentiment was also expressed by persons at the State Bureau of Engineering, who suggested that the State of Wisconsin might succumb to community pressure to participate as a building owner within the community.
- Reduced Pollution--Reduced pollution was a welcomed benefit. However, those interviewed seemed unable to place a value on pollution because it was an intangible benefit and difficult to quantify.

The interviews were conducted early in the DHCS program. At the time, little concrete information was available on costs involved, what the system would entail, how it would work and the advantages of the DHCS concept. A frequent comment expressed by numerous people, especially those with no technical background, was the desire to obtain additional (written, verbal) information. When this was available, they would feel more comfortable with the DHCS concept and better able to make decisions on becoming a potential user.

In contrast to those who expressed comments about the lack of information were people who were familiar with steam district heating systems and those who had an engineering background. While these people were in the minority (about 4 out of 23), they seemed to grasp and relate to the DHCS concept more readily. Those who were familiar with steam district heating systems in Milwaukee and St. Louis and who worked in buildings heated by the system knew that the DHCS system is a viable and reliable concept. They would have no qualms about eliminating their own boiler after the DHCS system was checked out and working. This was in contrast to the majority of the

people who expressed that they would keep their present boilers, etc., as backup.

People with technical backgrounds, even though they were not familiar with the DHCS concept, were quick to grasp the concept and relate to it. They could foresee the benefits, such as increased plant efficiency, less pollution and no on-site boilers to maintain, as being beneficial to their business.

Additional information about DHCS systems--how it works, what current users think about it and costs--would greatly add to the general public 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--Reliability was not deemed a significant factor as perceived by the user. This is not to say that they are not concerned. Rather, 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 regard as reliable.

The reliability of the in-building components, such as heat exchangers, controls, etc., was not broached.

The reliability concern was expressed mainly by those that did not understand the DHCS concept. Those familiar with steam DHCSs knew them to be highly reliable over extended periods of operation. This implies that general education of the public would help greatly to eliminate reliability as a factor that might preclude subscription.

Pollution--Reduced pollution within the area was seen as a desirable benefit of the DHCS. Those that lived in the community would welcome an improved environment.

However, when probed about what they would be willing to pay for improved air quality, the responses ranged from vague generalities to very little. Hence, reduced pollution is seen as a factor that would tend to relax economic considerations rather than being a determining factor on whether or not to subscribe to the DHCS program.

Disruption--Having 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 torn up streets make it inconvenient for customers, thus business tends to suffer.

Industry views this potential problem even less significantly. As long as supplies can be received and products shipped, there is no problem.

Safety--Few comments on the safety of the system were received. Those that did comment viewed the safety of the system as good or better than natural gas systems.

The question of safety may be associated more with the general education (additional information) of the subscribers. Known and unknown safety advantages to the DHCS could be pointed out.

SECTION 4.0 TECHNICAL REVIEW AND ASSESSMENT

The stated objective of the technical review and assessment is to define and evaluate power plant retrofit schemes and distribution networks and determine their effect on the utilities' current and future operation and ability to conserve scarce fuels.

The heat market data that was correlated during Task 3 was refined, tabulated and sent to the three participating utilities. Using an in-house simulation model, yearly fuel, operation and maintenance costs and hours of interruption were calculated. The heating system was considered to be an interruptible load (when maximum power is needed, the heating system would be cut off).

From analysis of the site description and load data developed during Tasks 2 and 3, it was determined that four power plants and seven alternate retrofit schemes would be considered.

The alternate retrofit schemes that were evaluated were those that could supply the quantity of heat necessary without major turbine changes, corresponding downtime and turbine retrofit costs.

ALTERNATE POWER PLANT RETROFIT SCHEMES

Generally power plant steam turbine can be retrofitted in the following ways:

- (1) multistage uncontrolled extraction in parallel to existing feedwater extraction;
- (2) convert a straight condensing turbine to a pack-pressure turbine;
- (3) add automatic extraction valve gear to an existing straight condensing turbine; and
- (4) add valves and piping in the crossover piping to remove a portion of the medium pressure steam that went to the low pressure turbine.

The turbine retrofit details of the first three choices are discussed in the attached letter from General Electric, dated 2/17/77 (Appendix F). The first, second and fourth schemes are relatively easy.

Also contained in Appendix F are the flow diagram and Mollier diagram of a single case turbine with extractions and the flow diagram and Mollier diagram of a cross-compound turbine.

The seven alternate power plant retrofit schemes that were reviewed are:

- Green Bay Central Business District (CBD) with three paper mills--Pulliam 8 unit with one medium pressure extraction and crossover extraction steam.
- Green Bay CBD with two paper mills--same as above.
- Heavy Beloit heat users--Black Hawk Units 3 or 4 with three extraction points.
- Heavy Beloit and Janesville heat users--Rock River Unit 1 or 2 with two medium pressure extractions and crossover extraction.
- Future Rock River Industrial Park--same as above.
- Madison Heat for University--Blount Street Unit 6 or 7 by using the existing one automatic extraction point on each machine.
- Madison Downtown Heat--Blount Street Unit 6 or 7 by using existing automatic extraction.

ADVANTAGES/DISADVANTAGES OF PLANT RETROFIT SCHEMES

The analysis of each alternative is based on fuel cost, operating and maintenance cost, number of interruptible hours, capital cost, and the losses in the distribution system.

The fuel cost, operating and maintenance cost, and number of interruptible hours were calculated by a utility simulation model based on the tables of "power lost" and loads that were submitted to them (Tables XVIII through XXVII).

The results from the Wisconsin Public Service Corporation's analysis are summarized in Tables XXVIII and XXIX. The 1985 operation (three paper mills) is given in Table XXVIII. The heat losses and pumping losses are summarized in Table XXXV. The heat gained to power lost ratio for the Pulliam 8 Plant is 12.8 MM Btu/hour per MW.

Table XVIII on page 4-4 shows the average reduction of electrical capacity after retrofit for the largest (three paper mills) case and smaller (two paper mills) case. The reduction of electrical capacity for the three-paper-mills case varies from 37.3 to 31.1 MW, and for the two-paper-mills case varies from 17.2 to 11.7 MW. The heat balance, shown on Figure 16 on page 4-17, is based on the average hourly January heat loads and power lost values from Table XVIII (476.9 million Btu/hour: 37.3 MW and 213.9 million Btu/hour: 17.2 MW).

The following tables were sent to the Wisconsin Power and Light Company for their analysis of the three Beloit and Janesville schemes:

Table XXI. Heavy Beloit Heat Users (27, 28, 34-40)
(Black Hawk Power Plant)

Table XXII. Heavy Beloit Heat Users and Heavy Janesville Users
(11, 13, 14, 17, 18, 19)

Table XXIII. Future Industrial Park West of Rock River

The heat gained to power lost ratio for the first scheme is 15.0 MM Btu/hour per MW. The ratio for the other two schemes is 14.5 MM Btu/hour per MW.

The following tables were sent to the Madison Gas and Electric Company for their analysis of the two Madison schemes:

Table XXIV. Simulated Monthly Blount Street Cogeneration Operation

Table XXV. Capitol Heating Plant Data

Table XXVI. Madison Ten Largest Downtown Blocks

Table XVIII. Simulated Monthly Pulliam Cogeneration Operation

	*	**	***	****
	LARGEST	LARGEST		
	HOURLY	MW POWER LOST	SMALLER	SMALLER
	HEAT LOAD	USING	HEAT LOAD	MW POWER LOST
MONTH	BTU X 10 ⁶	PULLIAM 8	BTU X 10 ⁶ /HR	USING PULLIAM 8
Jan.	476.929	37.3	213.9	17.2
Feb.	478.389	37.3	215.4	17.2
Mar.	460.306	35.7	197.3	15.8
Apr.	444.598	32.5	181.6	14.6
May	423.371	32.3	160.4	12.8
June	412.885	31.5	149.9	12.0
July	409.283	31.1	146.3	11.7
Aug.	409.199	31.1	146.3	11.7
Sept.	412.388	31.4	149.4	12.0
Oct.	421.852	32.3	148.9	12.8
Nov.	437.737	33.7	174.7	14.0
Dec.	459.463	35.6	196.5	15.7

* Including 401 MM Btu/hour for the three paper mills (the word "largest" means the three-paper-mill alternate).

** Power lost using Pulliam 8 is based on $\frac{476.9}{37.269} = 12.80$ $\frac{\text{MM Btu/hour}}{\text{MW}}$

*** Including 138 MM Btu/hour for two paper mills (the word "smaller" means the two-paper-mill alternate).

**** Power lost using Pulliam 8 is based on $\frac{215.4}{17.254} = 12.48$ $\frac{\text{MM Btu/hour}}{\text{MW}}$

Table XIX. Commercial Green Bay Heating Load

<u>MONTH</u>	<u>CURRENT MONTHLY LOAD BTU x 10⁹</u>	<u>CURRENT HOURLY LOAD BTU x 10⁶</u>	<u>ADDITIONAL FORECASTED MONTHLY LOAD BTU x 10⁹</u>	<u>ADDITIONAL HOURLY LOAD BTU x 10⁶</u>	<u>FUTURE TOTAL HOURLY LOAD BTU x 10⁶</u>
Jan.	45.041	60.539	11.450	15.390	75.929
Feb.	41.897	62.347	10.108	15.042	77.389
Mar.	35.318	47.470	8.806	11.836	59.306
Apr.	26.214	36.408	5.177	7.190	43.598
May	13.839	18.601	2.805	3.770	22.371
June	7.522	10.447	1.035	1.438	11.885
July	5.651	7.595	0.512	0.688	8.283
Aug.	5.426	7.293	0.674	0.906	8.199
Sept.	6.608	9.178	1.591	2.210	11.388
Oct.	11.601	15.593	3.913	5.259	20.852
Nov.	19.274	26.769	7.177	9.968	36.737
Dec.	33.257	44.700	10.240	13.763	58.463

Table XX. Green Bay Commercial Space Heating and Domestic Hot Water Monthly Loads

<u>MONTH</u>	<u>FUTURE TOTAL HOURLY LOAD BTU X 10⁶</u>	<u>* SPACE HEATING HOURLY LOAD BTU X 10⁶</u>	<u>AVERAGE DEGREE DAYS</u>	<u>AVERAGE TEMP. (F)</u>
JAN.	75.929	67.7	1494	16.9
FEB.	77.389	69.1	1313	18.1
MAR.	59.306	51.0	1141	28.2
APR.	43.598	35.3	654	43.2
MAY	22.371	14.1	335	54.2
JUNE	11.885	3.6	99	61.7
JULY	8.283	- -	28	64.1
AUG.	8.199	- -	50	63.4
SEPT.	11.388	3.1	174	59.2
OCT.	20.852	12.6	484	49.4
NOV.	36.737	28.4	924	34.2
DEC.	58.463	50.2	1333	22.0

* Domestic hot water is assumed to be an average of 8.3 BTU X 10⁶/hr based on the July and August total heat load.

Based on 1494 degree days for January, the average degree day is $\frac{1494}{31} = 48.2$.

Maximum degree day is based on the minimum temperature of - 14 F on January 30 which corresponds to a 79 degree day.

Maximum hourly space heating load is $\frac{79}{48.2} (67.6) = 110.8$ MM Btu/hr.

Maximum hourly space heating and domestic hot water load is $110.8 + 8.3 = 119.1$ MM Btu/hr.

Table XXI. Simulated Monthly Cogeneration Opeartion
 **Heavy Beloit Heat Users (27, 28, 34-40)
 (Blackhawk Power Plant)

<u>Month</u>	<u>Aver. Heat From Boiler Btu X 10⁶/hr</u>	<u>Aver. Heat From Turbine Btu X 10⁶/hr</u>	<u>MW Power Lost Using Black Hawk *</u>
January	111.4	93.7	6.23
February	165.5	93.7	6.23
March	62.9	93.7	6.23
April	27.0	93.7	6.23
May	0	88.3	5.86
June	0	82.8	5.49
July	0	62.9	4.18
August	0	62.9	4.18
September	0	69.9	4.69
October	0	84.4	5.64
November	19.0	93.7	6.23
December	54.6	93.7	6.23

* Power lost using Black Hawk is $\frac{46.87}{3.124} = \frac{15.0 \text{ MM Btu/hr}}{\text{MW}}$

** Only heat users of 2 MM Btu X 10³ or larger for the month of January were included.

Table XXII. Simulated Monthly Cogeneration Operation
Heavy Beloit Heat Users and Heavy Janesville
Heat Users (11, 13*, 14, 17, 18, 19) (Rock
River Power Plant)

<u>Month</u>	<u>Aver. Heat From Boiler Btu X 10⁶/hr</u>	<u>Aver. Heat From Turbine Btu X 10⁶/hr</u>	<u>MW Power Lost Using Rock River **</u>
January	23.5	362.	24.9
February	80.7	362.	24.9
March	0	303.6	20.9
April	0	261.3	18.1
May	0	196.2	13.5
June	0	177.9	12.3
July	0	140.3	9.7
August	0	139.7	9.6
September	0	156.8	10.8
October	0	215.3	14.9
November	0	270.1	18.7
December	0	325.7	22.5

* Only coal fired boilers are replaced in Block 13.

** Power lost using Rock River is $\frac{362}{25.007} = \frac{14.48 \text{ MM Btu/hr}}{\text{MW}}$

Table XXIII. Future Industrial Park West of Rock River Power Plant

Estimated load is over 1×10^{12} Btu/yr with a peak of 250 MM Btu/hr.

Assuming 343 days per year operation at 150 MM Btu/hr the yearly load is $343 \times 24 \times 150 = 1,234,800$ MM Btu.

Power lost using Rock River is $\frac{362}{25.007} = \frac{14.48 \text{ MM Btu/hr}}{\text{MW}}$

Average power lost is $\frac{150}{14.48} = 10.36 \text{ MW}$.

For purposes of the "power lost" replacement fuel cost, O & M cost, and hours of interruption, the assumed power lost is 10.36 MW for every hour of the year.

Table XXIV. Simulated Monthly Blount Street Cogeneration
Operation (Madison Downtown Heat Users)

<u>MONTH</u>	<u>* HOURLY HEAT LOAD BTU X 10⁶</u>	<u>** MW POWER LOST USING #4</u>	<u>*** MW POWER LOST USING #6 or #7</u>
Jan.	57.9	6.36	4.63
Feb.	61.5	6.76	4.92
Mar.	45.9	5.04	3.67
Apr.	27.0	2.97	2.16
May	15.7	1.73	1.26
June	5.5	0.60	0.44
July	5.8	0.64	0.46
Aug.	4.7	0.52	0.38
Sept.	8.7	0.96	0.70
Oct.	20.3	2.23	1.62
Nov.	31.1	3.42	2.49
Dec.	45.0	4.95	3.60

* Included are the Capitol Heating Plant potential cogeneration steam sale and the 10 largest downtown heat users (74, 94, 60, 82, 52, 102, 95, 67, 75 and 101).

** Power lost using #4 is based on $\frac{94.94}{10.43} = \frac{9.099 \text{ MM Btu/hr}}{\text{MW}}$

*** Power lost using #6 or #7 is based on $\frac{248.65}{19.90} = \frac{12.49 \text{ MM Btu/hr}}{\text{MW}}$

Table XXV. Capitol Heating Plant Data

<u>MONTH</u>	<u>MEGAWATT-HR</u>	<u>EXHAUST STEAM LB/HR AVER. *</u>	<u>HEATING STEAM LB/HR AVER. **</u>	<u>POTENTIAL SALE COGENERATION STM. LB/HR AVER. ***</u>
Jan.	669	20,448	34,300	13,852
Feb.	446	15,092	31,100	16,008
Mar.	317	9,689	24,700	15,011
Apr.	249	7,864	18,500	10,636
May	228	6,969	14,030	7,061
June	217	6,854	9,000	2,146
July	200	6,113	9,000	2,887
Aug.	242	7,397	9,000	1,603
Sept.	234	7,391	11,930	4,539
Oct.	359	10,973	19,900	8,927
Nov.	528	16,676	23,300	6,624
Dec.	604	18,461	27,800	9,339

* 1977 Data based on a steam rate of 22.74

** 1976 Data May thru Sept. corrected based on some of the Capitol plant boiler generation being used for chiller steam turbine drive at 9.85 lb/ton.

*** Potential is the difference of the heating steam (sum of blocks 000, 85, and 86) and the exhaust steam production. Even though this is the difference of data from 2 different years the answer should be approximately correct.

Table XXVI. Madison Ten Largest Downtown Blocks (Excluding
000, 85 and 86 Served by Capitol System)

<u>BLOCK</u>	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	
74	4.841	4.335	2.175	1.267	.886	.773	.704	.670	.746	1.121	1.927	3.641	
94	3.486	3.476	2.910	1.786	1.271	.567	.405	.468	.512	1.155	2.239	3.403	
60	3.962	3.761	2.948	1.839	1.078	.268	.268	.223	.302	1.240	2.076	3.545	
82	3.800	4.408	3.215	.563	.418	.008	.008	.008	.032	1.148	2.432	2.545	
52	3.819	3.442	2.812	1.292	.418	.215	.192	.197	.451	.451	1.867	2.379	
102	3.000	2.651	1.923	1.347	.396	.089	.019	.076	.087	.516	1.551	2.435	
95	3.050	2.521	1.804	1.016	.501	.181	.163	.161	.171	.566	1.528	2.296	4-12
67	2.173	1.944	1.633	.963	.461	.157	.188	.220	.366	1.026	1.422	2.034	
75	2.451	2.148	2.119	.796	.271	.061	.051	.045	.053	.534	1.466	2.374	
101	2.144	1.919	1.511	.934	.699	.148	.219	.248	.299	.748	1.148	1.937	
TOTAL	32.726	30.605	23.050	11.803	6.399	2.467	2.217	2.316	3.019	8.505	17.656	26.589	Monthly X 10 ⁹ Btu
	44.0	45.5	30.9	16.39	8.60	3.43	2.90	3.10	4.19-11.4	24.52	35.74		Average X 10 ⁶ Btu/hr

79130

Table XXVII. Simulated Monthly Blount Street Cogeneration Operation When Supplying Heat Only to University of Wisconsin Buildings for Space Heat and Domestic Hot Water

<u>MONTH</u>	* <u>HOURLY HEAT LOAD BTU X 10⁶</u>	** <u>MW POWER LOST USING #6 or #7</u>
Jan.	252	20.2
Feb.	214	17.1
Mar.	214	17.1
Apr.	201	16.1
May	123	9.8
June	79	6.3
July	26.5	2.1
Aug.	26.5	2.1
Sept.	94.5	7.6
Oct.	154	12.3
Nov.	176	14.1
Dec.	198	15.9

* Not included is the heat to generate high pressure steam for electric generation and steam turbine driven chillers.

** Power lost using #6 or #7 is based on

$$\frac{248.65}{19.90} = \frac{12.49 \text{ MM Btu/hr}}{\text{MW}}$$

Table XXVIII. Green Bay District Heating System
(Three Paper Mills) 1985 Operation

<u>MONTH</u>	<u>OPERATING HOURS</u>	<u>FUTURE TOTAL HOURLY BTU X 10⁶</u>	<u>MONTHLY BTU X 10⁶</u>
Jan.	744	477	354,888
Feb.	593	478	283,454
Mar.	744	460	342,240
Apr.	720	445	320,400
May	744	423	314,712
June	720	413	297,360
July	744	409	304,296
Aug.	137	409	56,033
Sept.	720	412	296,640
Oct.	744	422	313,968
Nov.	720	438	315,360
Dec.	744	459	341,496
			<u>3,540,847</u>

NOTES:

- (a) August operating hours are low because 79 of the interruptible hours and the 22 days of holidays and planned shutdowns are assumed to occur then. February hours are low because 79 of the interruptible hours are assumed to occur then.
- (b) The difference between the heat supplied (3,540,847) and the thermal loads (page 3-13) is due to the 158 hours that 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 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.

Table XXIX. Green Bay District Heating System
(Two Paper Mills)

1985 OPERATION

<u>MONTH</u>	<u>OPERATING HOURS</u>	<u>FUTURE TOTAL HOURLY BTU X 10⁶</u>	<u>MONTHLY BTU X 10⁶</u>
Jan.	744	213.9	159,142
Feb.	593	215.4	127,732
Mar.	744	197.3	146,791
Apr.	720	181.6	130,752
May	744	160.4	119,338
June	720	149.9	107,928
July	744	146.3	108,847
Aug.	137	146.2	20,029
Sept.	720	149.4	107,568
Oct.	744	158.9	118,222
Nov.	720	174.7	125,784
Dec.	744	196.5	<u>146,196</u>
			1,418,329

NOTES:

- (a) August operating hours are low because 79 of the interruptible hours and the 22 days of holidays and planned shutdowns are assumed to occur then. February hours are low because 79 of the interruptible hours are assumed to occur then.

The heat gained to power lost ratio for the cogeneration designs that use Blount Street Unit 4 is 9.099 MM Btu/hour per MW. The ratio when using Unit 6 or 7 is 12.49 MM Btu/hour per MW.

MODES OF OPERATION FOR TURBINE RETROFIT SCHEME

The Green Bay scheme for three and two paper mills is illustrated in Figure 16. Medium pressure steam flow to DHS heater 2 is flow controlled to eliminate any turbine upsets due to any district heating system upset. Because of the large heat capacity of the water in the district heating system, the possibility of a district heating system upset is slight. During a peaking operation, control valve FIC-1 CV will automatically close.

The minimum steam flow to the low pressure turbine is indirectly controlled by control valve FIV-2CV, which controls the flow of steam to DHS heater 1. The pressure of the steam to DHS heater 1 is controlled by PIC-1CV. During a peaking operation, FIC-2CV closes and PIC-1CV opens.

The basic operation continues the original design throttle and reheat steam flows and pressures.

At intermediate heat loads, FIC-2 and FIC-1 are reset to adjust the steam flows to DHS heaters 1 and 2. Determination of the priority of steam to either DHS heater 1 or 2 will be made during Phase 2 of this project.

The operation of the Black Hawk (Figure 17), Rock River (Figure 18), and Blount Street (Figure 19) cogeneration schemes is similar to that described above for Pulliam 8.

Figure 16. Pulliam 8 Heat Balance Diagram with District Heating System Retrofit for Three- and Two-Mill Heat Loads and Downtown Green Bay Loads

NOTES:

1. MASS FLOWS ARE IN #/HR. (SMALL FLOWS ARE NOT SHOWN FOR CLARITY)
2. PRESSURES ARE IN P. S. I. A.
3. ENTHALPIES ARE IN BTU/#.
4. TEMPERATURES ARE °F

Figure 17. Black Hawk 3 and 4 Heat Balance Diagram with District Heating System Retrofit for Ten Largest Beloit Users

Figure 18. Rock River 1 or 2 Heat Balance Diagram with Turbine Retrofit for District Heating System or Future Industrial Park

49130

Figure 19. Blount Street 6 or 7 Heat Balance Diagram with District Heating System Retrofit for the University and Downtown Madison

EFFECTS OF UTILITY PLANT LOAD VARIATION

The effects of variation of heat demand on the total cogeneration operation will be considered for the following expected range of operation:

- Average winter operation,
- Peak winter operation,
- Spring and fall operation,
- Summer operation.

For all of the designs 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.

The throttle steam flow and pressure would normally be at design conditions. The extraction steam and crossover steam flows would be controlled to meet the heating system loads, but not in excess of the requirements for the safe operation of the turbine.

If the heat demand is greater than that available from the turbine, either a peaking boiler must be used, some heat loads must be interrupted, or excess high pressure steam from other power plant boilers must be used.

During peak winter operation, thermal storage of the water in the distribution piping will average out the turbine heat drain during peak hourly loads.

During summer, spring, or fall operation the district heating system can operate with lower temperatures if the heat is used only for space heating and domestic hot water.

EFFECT ON UTILITY'S GENERATION CAPACITY

During cogeneration, the power output from the retrofitted turbine is reduced. The lost power must be made up by generating additional power from other units in the utility's complete system.

If the cogeneration operation is considered an "interruptible" operation, during times of peak power demand in either the winter or summer seasons the cogeneration heat from the turbine could be shut off. For this operation there would be no effect on the total 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).

Wisconsin Public Service Corporation's analysis of the Green Bay operation considered the district heating system in their dispatching order in a position just after the combustion turbines, but before their other interruptible loads (large electric interruptible loads and electric domestic hot water heaters).

AVAILABLE THERMAL ENERGY FROM POWER PLANT

The peak theoretical thermal energy and the corresponding highest temperature level of the energy when it is transmitted by high temperature water is:

- Pulliam 8 - 674 MM Btu/hour at 313°F;
- Pulliam 7 - 364 MM Btu/hour at 330°F;
- Black Hawk 3 - 46.9 MM Btu/hour at 407°F;
- Rock River - 362 MM Btu/hour at 246°F;
- Blount Street 4 - 118 MM Btu/hour at 386°F;
- Blount Street 5 - 116 MM Btu/hour at 386°F;
- Blount Street 6, 7 - 249 MM Btu/hour at 304°F.

The actual thermal energy that was considered to be available is shown on Tables XVIII, XXI, XXII, XXIII, XXIV, and XXVII.

SYSTEM CHARACTERISTICS

General

The most common media used for generating and distributing heat for space heating and industrial heating are steam and hot water. In indirect or secondary heating systems, heat from the combustion of fuel or from electric energy is transferred to a liquid or a gas and distributed through pipes or ducts to the area or process where a second heat transfer takes place. This method makes it possible to obtain close control of temperatures, to supply heat to a number of processes or areas from one primary heating unit, and to locate that unit in the most convenient place. The most common example of indirect heating is that used for building heat where water, steam, or air is used as the heat-transfer medium. Among the heat-transfer fluids used in industry, aside from steam, water, and air, are the special petroleum-based heat-transfer oils, various chemical fluids, and inorganic salt mixtures.

Steam Systems

A steam heating system uses the vapor phase of water to supply heat to a conditioned space or a process. In the steam heating system, the heat transfer medium moves through successive changes of state. Basically, the cycle is as follows: heat from a suitable source is supplied to water (in a steam boiler), causing it to boil and continuously vaporize. The vapor is transported to terminal equipment through a system of piping. In the terminal equipment, the flow of heat is transferred, and condensation takes place (again changes state). The cycle is completed by the return of condensate to the boiler where heat is reapplied to reconvert it into steam.

In some installations, the cycle is only partially completed. The vapor is transported to the terminal equipment where its energy is transferred; the condensate is subcooled as far as practicable, and then released to the sewer

instead of being returned to be recycled. Such disposal of condensate usually occurs in large district heating systems or process work where it may be contaminated or may be considered more economical to discard it than to provide piping for its return; this waste of water increases the feedwater makeup and chemical treatment requirements, and increases the possibility of corrosion.

Steam heating systems may be classified according to their operating pressure ranges as follows:

- Low-pressure system when the operating pressures vary from 0 to 15 psig;
- Medium-pressure system when the operating pressures vary from 15 to 155 psig;
- High-pressure system when the operating pressures are above 155 psig.

Low-pressure systems range from small residences to large commercial or industrial buildings where the main load consists of comfort heating and domestic hot water requirements.

Medium-pressure systems are most commonly used in industrial plants, institutional buildings, for process applications, and to supply steam to widespread loads.

High-pressure systems are used in those industrial plants where higher process temperatures are required and for large area distribution, as well as for district heating where the heat energy is to be transported over long distances. In all large systems where steam is generated and transmitted at high pressures, the high pressures are reduced to medium pressures and subsequently to low pressures to suit local requirements for process heating and space heating. Pressure reducing valves are installed at convenient locations in each building or area where the reduced pressure are required.

The return of condensate to the boiler is a guiding factor in successful steam system design. In gravity return systems, the condensate returns to the boiler solely by gravity, but the steam flows by the effect of the steam to pressure. Gravity systems are usually limited to small loads or package processing equipment, in which operation at various pressures is not required. When conditions are such that the condensate cannot be returned to the boiler by the action of gravity, either traps or pumps (or both) must be employed, and these systems are known as mechanical return systems. Such return systems are employed in large installations and multibuilding complexes where many changes in elevation of steam mains occur and where long condensate return mains make it impractical to use a gravity return system.

An important consideration in the design of a steam system is to provide for proper drainage of the condensate that separates out in the steam piping. The steam mains must be uniformly graded and free from places where condensate can collect, except those provided for its collection and drainage. The distribution of steam should be rapid, uniform and without noise. The condensate which collects in steam piping must be drained to prevent interference with the ready flow of steam. This dictates that the steam piping should always pitch downward in the direction of flow. Also, the system should be designed and installed so that the steam piping can drain completely by gravity whenever the steam is shut off. If condensate runs against the steam flow (counter flow of condensate and steam), the steam piping must be oversized to reduce the steam velocity and prevent picking up of the condensate by the steam, which would cause turbulence, noise, water hammer and severe shocks to the piping system.

Hot Water Systems

A water heating system is one in which hot water is used to convey heat to or from a conditioned space or process through piping connecting a boiler or water heater, with suitable terminal heat transfer units located at the space

or process. Hot water systems handle only a liquid, not a liquid and its vapor as do steam systems.

Hot water systems are usually classified according to their operating temperature ranges, as follows:

- Low-temperature water system (LTW) - A hot water heating system operating at a temperature below 250°F, with a maximum working pressure of 30 psig;
- Medium-temperature water system (MTW) - A hot water heating system operating at a design supply temperature between 250° and 350°F, with a working pressure not exceeding 150 psig;
- High-temperature water system (HWT) - A hot water heating system operating at temperatures over 350°F and a usual pressure rating of 300 psig for the system.

Low-temperature water systems have replaced steam systems for residential heating applications. Many commercial, institutional and residential buildings have been successfully and economically designed using low-temperature water. Where loads consist primarily of space and domestic water heating and do not exceed 5 to 10 million Btu per hour total, low-temperature water is generally used.

Medium-temperature water systems are most commonly used in industrial process applications and in heating systems in large commercial and institutional buildings. Medium-temperature water is generally used for industrial applications with process loads and for space heating or district heating applications having total loads of from 5 to 20 million Btu per hour.

High-temperature water systems are generally used in large district heating installations, such as: military bases, campuses, shopping center, airports, and in applications having process heating requirements in excess of 325°F.

High-temperature water is generally used for space heating applications where loads are in excess of 20 million Btu per hour.

High-Temperature Water Systems--High-temperature water systems are basically similar to the conventional forced circulation hot water heating system. Basic components are: HTW generator or boiler, expansion vessel, boiler circulating pump, system circulating pump, distribution piping, and heat utilization equipment. In operation, the HTW generator receives low-temperature return water from the system and adds required heat to bring the water up to the system circulating pump, which circulates the water through the distribution pipelines to the points of application in the various buildings. The system water return to the generator at a lower temperature to complete the cycle. For this study, the HTW generator will be a heat exchanger with HTW on one side and turbine extraction steam on the other side.

At certain times, the simultaneous closing of many control valves in the system will reduce the quantity of HTW returning to the generator. Should the flow of the system return water to the generator become less than the minimum design flow requirements, high-temperature water from the generator discharge will flow through the bypass connection to combine with the system return water and maintain minimum flow to the HTW generator.

System circulating pumps are used to overcome the frictional resistance to fluid flow within the distribution pipes. HTW permits the transportation of thermal energy over long distances with a very slight drop in temperature. For example, in a properly insulated 6-inch diameter pipe, the loss in temperature is generally less than 3°F per mile of conduit.

Vents are installed at the high points and drains at the low points of the system. The system is vented at these points mainly when starting. The drains are used when additions or repairs to the system require the draining

and subsequent filling of the sections.

Heat is extracted throughout the system by user equipment. As the system is completely closed, no water is consumed in satisfying the heating requirements. All unused heat remaining in the water is returned to the source. Changes in volume in the system water due to temperature fluctuations in the system are taken up in the expansion vessel, which at the same time is used for pressurizing the system.

HTW Flexibility--High-temperature water is suitable for both space and process heating in a wide range of applications. Where high temperatures are required, HTW can be applied directly to space or process heating coils. For normal baseboard or radiator heating, domestic hot water, and lower temperature process jobs, closed-circuit heat exchangers are employed at desired locations. Medium and low pressure process steam can be generated, where needed, by HTW-to-steam heat exchangers.

In summary, high-temperature water is capable of producing any or all of the following:

- Direct heating with high-temperature water;
- Indirect heating by use of high to low-temperature water heat exchangers for localized space heating with low-temperature water;
- Domestic hot water for local use;
- Low-pressure steam for space heating;
- Steam used for process or for power;
- Medium-temperature water or low-pressure steam for absorption air conditioning systems.

Flow Generation--In terms of flow generation, hot water heating systems are of two types; (1) the gravity system, in which circulation of the water is due to the difference in weight between the supply and return water columns

of any circuit or system, and (2) the forced system in which a pump, usually driven by an electric motor, maintains the necessary flow.

Gravity systems are no longer used in the United States. In the past they were used for single dwellings and small to moderate size commercial installations. The forced circulation system gives better control, quicker response, positive circulation, and lower first cost due to the much smaller pipe sizes and smaller terminal heating units.

Pressurization--In a hot water heating system, an expansion tank must be provided to take care of changes in water volume resulting from changes in water temperature. Expansion tanks may be open or closed. The open tank is vented to the atmosphere and must be located above the highest point in the system. Open tanks are limited to small installations having operating temperatures of 180°F or less, and thus have very limited use.

By far, the largest number of installations are furnished with closed expansion tanks, which provide a means of pressurization over a wide range of operating conditions. In addition to accommodating changes in water volume, the closed expansion tank controls the pressure of the system above the saturation temperature of the water to prevent boiling of the water, which can lead to serious operational difficulties.

There are two methods of pressurization in common use: (1) inert gas pressurization and (2) steam pressurization. In a gas pressurized system, the expansion space in the expansion vessel is filled with an inert gas, usually nitrogen, which varies in pressure as the water level rises and falls. In a steam pressurized system, the expansion vessel is located above the boilers and connected in the supply water line from the boilers. Water in the expansion vessel flashes into steam and maintains system pressure above the saturation point of the cooler water in the balance of the system.

Distributive Systems

The central heating plant will comprise one or more heat exchangers and their related pumps, receivers and auxiliary equipment. The heat exchangers will receive extraction steam from the steam-driven turbine generators and generate high temperature water for distribution to surrounding buildings for heating purposes and industrial uses.

It is usually preferable that groups of buildings be supplied with heat from a central plant rather than from individual plants to permit design for better combustion efficiency with less expensive fuel and reduction of labor per unit of output. The central plant justifies use of more competent personnel and often decreases the investment required.

There are other advantages such as confining noises, odors, and debris to a single location where it is more convenient for handling.

The term district heating refers to the supplying of heat from a central plant to a group of buildings in a city, institution, housing development, or industrial or commercial area. District heating systems may serve a wide variety of heating and cooling loads in a large area. Loads commonly encountered are comfort heating and cooling, and steam generation for process or power use. The proportion and duration of these loads can be a major factor in determining the type of district heating system which is best for a given area.

Distribution Piping--Distribution piping in district heating systems may be run through buildings, through the air on poles or other structures, or underground in conduits or tunnels. Local conditions and investment will be governing factors in establishing the route of the pipes. Important points in laying out distribution piping are:

- Piping within buildings or basements is normally least expensive to install and to maintain.
- Underground installations involve excavation, which represents a substantial portion of the total cost. The depth of such excavations should be kept to a minimum after due consideration has been given to the possible damaging effect of the operating-line heat on lawns and shrubbery and the possible damage to the underground structure due to heavy traffic, etc.
- Walking tunnels usually are not provided for distribution mains in the district heating industry because of their relatively high first cost as compared with smaller conduits, unless they are required to accomodate miscellaneous other services or to provide underground passage between buildings.
- Overhead piping on poles or structures is generally less expensive than underground lines, especially in some institutional and industrial areas, and may be a means of eliminating buried conduit in areas where underground installations would be expensive or undesirable. Thin corrugated aluminum sheets are available for covering the insulation on lines exposed to the weather. Such lines may introduce freeze-up problems, higher heat losses and, in many locations, would be considered unsightly. For purposes of this study, overhead piping was not considered.
- Piping routed in loops, with suitable valves to provide alternate feeds for major loads, allows service to be maintained despite trouble in any one feeder.
- It is desirable to estimate as far as possible the probable growth and change in load centers. Since the character of the district served is almost certain to change with time, the distribution system must be planned to accommodate changes. It is helpful to provide a master distribution plan, that can be revised from time to time to suit conditions as the system grows.

Distribution System Characteristics--

Steam Systems--

Steam distribution pressure: The pressure at which the steam is distributed depends upon the requirements of the building served by the system, the size of the load, and the length of the distribution piping. Large steam distribution systems usually operate at send-out pressures between 125 and 250 psig. Steam pressure higher than 250 psig are usually not justified because the increased cost for heavier system components, such as piping, valves, and pressure-reducing stations, exceed the benefits derived from operating at higher pressure.

Depending on its use, steam can be used either at line pressure or by passing it through a pressure-reducing valve. Steam at line pressure is used in industrial process applications; for steam supply to laundries; and for other high-pressure equipment such as steam-driven turbines for water chillers in air conditioning systems. The upper limit of 250 psig, which is equivalent to 405°F, restricts the usefulness of a steam system for general industrial applications since many industries require higher temperatures.

For comfort heating applications, the high pressure district steam is reduced in pressure by passing the steam through one or two pressure-reducing valves. Most building heating systems, such as apartment houses, office and commercial systems, such as apartment houses, office and commercial buildings, operate at pressures from 2 to 15 psig. The reasons for operating at the lower pressure are mainly: (1) less danger to the building occupants should there be a break in the piping or failure in a piece of equipment; (2) more comfortable environment when terminal heating equipment such as radiators, convectors and baseboard heaters operate at lower surface temperatures; and (3) lower cost of terminal heating equipment when designed for low pressures.

Two-Pipe System: A two-pipe steam distribution system consists of one large-diameter pipe for steam distribution and a relatively small-diameter pipe for condensate return. Steam piping in distribution systems is normally subject to very little corrosion, and carbon steel pipe is used with satisfactory results. Condensate return on the other hand is subject to rapid, and in some cases severe, corrosion. For condensate return lines, wrought iron pipe is often used because of its slower rate of corrosion; however its cost is greater than that of steel pipe. Brass or copper, which have much longer life than steel or wrought iron, are seldom used today because of their high cost.

One-Pipe System: Some large steam distribution systems eliminate condensate return piping because of high initial cost for a corrosion resistant system, or because of high replacement costs if steel pipe material is used. However, if the condensate is wasted instead of being returned to the plant, there is a total loss of the heat energy available in the condensate. This loss of heat energy alone can reduce the overall thermal efficiency by 10 to 15 percent, not to mention the additional installation cost for equipment and operating costs of a water treatment system to handle 100 percent makeup water for boiler feed. In addition, this type of system wastes a valuable natural resource. For these reasons a one-pipe system was not considered for this study.

Pitch: Steam piping should be pitched downward in the direction of flow. If conditions make it necessary to pitch pipe in the opposite (counterflow) direction, the pipe size must be increased to reduce turbulence. Gravity-condensate piping must be pitched to the collection point; pumped-condensate piping is pitched only for drainage purposes. The direction and amount of pitch for all underground piping are governed by ground profile and/or the location of interferences.

Drip Points: All steam piping must be dripped at the low points through a suitable steam trap. The trap discharge can be connected to the gravity-condensate return main, if available, or to the pumped-condensate return main. The least desirable method is to discharge the trap to waste.

Condensate Return: As much condensate as possible should be returned to the steam generating plant to save heat and the cost of treating water for boiler feed. It may be returned by gravity or pumping. If site contour and boiler plant location with respect to the buildings are favorable, the gravity system can be used; otherwise, a condensate return pump is necessary in each building. It is sometimes possible to group several favorably located buildings so that one pump can be used for the group.

A regular schedule of inspection and maintenance must be set up for the outlying receiving tanks and pumps. Tanks must be kept clear of sludge and corrosion accumulations. Air vents must be kept clear, but must be arranged so that any mixture of free air with the water in the tank is retarded.

Float-switch mechanisms must be kept free and in proper operating condition to maintain a proper level in the tanks. Condensate pumps and motors must be lubricated according to a schedule, and packing must be adjusted and/or renewed periodically to prevent excessive leakage or shaft damage from too tight or hardened packing. Strainer must be kept in proper repair and cleaned periodically.

Insulation and Waterproofing: All piping must be insulated to conserve heat, and underground piping must be waterproofed to protect ferrous materials against corrosion.

Pipe Expansion: Under operating conditions, pipe is increased in length by the difference between its installed and final temperatures. Expansion is controlled by using loops or bends; various types of corrugated

packless-type expansion joints; flexible ball-type joints; or slip, packed-type joints.

Two-Pipe High-Temperature Water Systems--

Design Considerations--The choice of a hot water system should be based on a careful analysis of a number of factors; the nature of the loads involved; the characteristics and layout of the buildings; the comfort and control requirements; and analysis of the economics of the complete system.

The principal economic consideration in any water system design is the balance of first cost and operating cost. First cost includes generating and terminal equipment and distribution system. Generally speaking, the cost of the generators and terminals will be determined by the load requirements and temperature range selected, and the cost of the distribution system at design conditions, the more economical the distribution system will be.

As a general rule, for a specific system both first cost and operating costs will be reduced with reductions in water quantity circulated. First-cost reductions result from the smaller and less expensive piping system, reduced requirement for secondary building space, smaller pumps, etc. Reduced operating costs result from lower pump horsepower. Much depends upon the techniques employed to make smaller flow rates possible.

Water Temperature and Flow Rate--The design water temperature and flow rates are interrelated, as are the system piping layout and pump selections. Also, the type and control of the heat exchangers employed in the system affect the flow rate and pump selection, and the pump selection and distribution system affect the controllability. These are examples of the major interrelationships which exist.

In small residential buildings or small commercial structures, flow rates to all heat transfer elements are based on an assumed single overall system temperature difference. For example, a 20-degree temperature drop is commonly selected for such applications. This has led to certain rules of thumb that simplify design procedure and afford sound economy with satisfactory performance.

However, for large systems, determination of the minimum system flow rate is recommended as it usually results in the least overall cost and best performing system. The minimum system flow rate is determined by summation of the flow rates to individual users. The most satisfactory method of determining the minimum system flow rate is to assume that the leaving water temperature (primary system) at each heat exchanger is higher than the final temperature of the heated medium (secondary system) by a constant value. Thus, the lower the final temperature of the heated medium, the larger the temperature drop through the exchanger. For example, with a 20-degree difference, the following temperatures result:

	<u>Final Secondary</u> <u>Temperature</u>	<u>Leaving Primary</u> <u>Temperature</u>
Air-Handling Coil	120°F	140°F
Domestic Water Heater	140°F	160°F
Steam Generator at 7 psig	235°F	255°F

This method is particularly useful in the design of large systems having a wide variety of comfort and process loads.

The system design temperature depends on the requirements of the buildings served by the system, the size of the load, and the length of the distribution piping. Temperatures vary between 350°F for medium size systems to 420°F for large systems. The usual practical limit of temperature is about

450°F due to the rapid rate of pressure higher pressure-rated components required.

In large systems, then, a large temperature drop can be taken; at a generated temperature of 420°F, the normal drop can be about 160°F, but may be as high as 200°F. In small systems a drop of 60°F is sufficient.

Heat Exchangers--The most widely used method for converting the heat in high-temperature water to a medium adaptable for use in buildings is to pass it through a heat exchanger in which either lower temperature hot water or steam is generated. The converted heat can be used for space heating and process work, with one heat exchanger required for each service. Process heat exchangers can also be used to heat or cool some other process fluid.

Heat in the form of low-pressure steam or medium-temperature water can be used as the operating force of an absorption refrigeration machine to produce chilled water for air conditioning. The absorption refrigeration machine is a water chilling package that uses heat directly without the use of a prime mover, thus utilizing the central heating facilities on a full-time, year-round basis.

Piping--The selection of piping materials for a high-temperature water system is greatly simplified since the supply and return pipes are of the same material; and with proper water treatment, very little corrosion takes place in the system. Schedule 40 steel pipe, with welded steel fittings and steel valves, is applicable to most HTW systems.

Pitch--Piping for high-temperature water can be laid to follow ground contours. Piping need not be dripped at each low point, but should have provisions for emptying sections of piping for shutdown. The elevation of hot water pipes in buildings may be changed as often as required to suit the installation.

Insulation and Waterproofing--The provisions for insulating and waterproofing of high-temperature water piping are generally similar to those for steam piping.

Expansion of high-temperature water piping is similar to that described for steam systems.

Storage--High-temperature water systems may be operated to even out the peak loads and low loads within 24-hour cycles by using storage. Storage is usually accomplished by bypassing water from the flow to the return mains and, thereby storing heat in the return main for future use or storing heat in accumulators. Systems that experience normal peaks may obtain as much as 15 percent added capacity through such heat storage.

Two-Pipe Medium and Low Temperature Water Systems--The design and characteristics of two-pipe medium and low temperature water systems are similar to high temperature water systems.

Piping Systems--Various pipe and insulation methods are used for underground distribution of high temperature hot water. Some typical systems are described below.

Insulated Pipe in Steel Conduit (Figure 20)--This system consists of an inner, fluid-carrying pipe with four inches of rigid calcium silicate insulation. The outer covering is a 10-gage steel casing coated with waterproofing material. Using specially designed spacers, the inner pipe and insulation is supported in a manner that provides a 1-inch air space between the insulation and outer steel covering. The system is prefabricated in 40-foot lengths.

Temperature range of the insulation is up to 1200°F. All fittings, such as tees, angles and reducing plates, required for a complete system are available. Installation is direct burial with anchors supporting the conduit assembly every 400 feet. Costs are summarized in Table XXX.

INSULATED PIPE IN REINFORCED CONCRETE ENCLOSURE

TYPICAL CONSTRUCTION BASED ON DETAILS
SUPPLIED BY PERMADUC INTERNATIONAL, MINNEAPOLIS, MINN.

INSULATED PIPE IN STEEL CONDUIT

TYPICAL CONSTRUCTION BASED ON DETAILS SUPPLIED
BY PERMANENT PIPING SYSTEMS OF CHICAGO, ILL.

Figure 20. Insulated Pipe in Steel Conduit and Reinforced Concrete

Table XXX. Capital Costs of Primary Piping Systems per Foot of Piping (1979 Dollars)

AREA	PIPE DIAMETER	POURED CONCRETE (Notes 1 & 4)	STEEL CONDUIT (Note 2)	REINFORCED CONCRETE (Note 3)	REFERENCE (Note 5)
URBAN	12"	\$ 629	\$ 638	\$ 588	\$ 582
	16"		800	707	
	20"	945	1,033	826	892
	24"	1,048	1,236	868	
	30"	1,285	1,460	1,089	1,248
	36"		2,071	1,258	
SUBURBAN	12"	256	511	550	
	16"		640	668	
	20"	385	827	786	
	24"	427	989	830	443
	30"	524	1,168	1,053	515
	36"		1,657	1,228	612
RURAL	12"	233	425	520	
	16"		533	635	
	20"	350	689	750	
	24"	388	824	794	405
	30"	476	973	1,005	474
	36"		1,381	1,183	572

Note 1. Costs estimated using "Means Mechanical & Electrical Cost Data 1979" - Published by Means.

Note 2. Costs based on manufacturers data (Permanent Piping Systems) including estimate of escalation for suburban and urban areas.

Note 3. Costs are based on data from "Permaduc".

Note 4. Rural costs were calculated. Suburban costs were obtained by multiplying by 1.1 and urban costs by multiplying by 2.7. These escalation factors were derived from the Olikier and Philipp report referenced in Note 5.

Note 5. Reference report is "Technical and Economic Aspects of District Heating Systems Supplied From Cogeneration of Power Plants" by Olikier and Philipp for poured concrete fill design. Reference costs in 1977 dollars were increased by 16% to obtain 1979 dollars.

Insulated Pipe in Reinforced Concrete Enclosures (Figure 20)--This is a patented system with the trade name "Permaduc" consisting of steel piping with mineral fiber insulation contained in an enclosure constructed of reinforced monolithic concrete covered with a waterproof barrier. The insulation is four to six inches thick and is rated up to 600°F. The system is assembled in the field and is suitable for direct burial. Because of its strength it need not be buried below the frost line. Costs are shown in Table XXX.

Insulated Pipe in Plastic Conduit (Figure 21)--This system consists of a steel pipe with polyurethane foam and a polyethylene protecting sleeve. The pipe is prefabricated at the factory and shipped in 20- or 40-foot lengths. Standard units are suitable for service temperatures up to 120°C (248°F), with special units available up to 170°C (338°F). The system is designed for direct burial, and fittings are available for bends, branch takeoffs, adapters and couplings required for a complete system. Cost data is not available at this time.

Insulated Pipe in Poured Concrete (Figure 20)--This system consists of steel pipe with four inches of thermobestos insulation (or equivalent) encased in a poured concrete bank. Insulation for service rating up to 1200°F is available. The entire system is field fabricated and suitable for direct burial. Cost data is shown in Table XXX.

An alternate type of poured concrete construction uses an insulating cement in place of insulation around the pipe. To allow pipe expansion, an air gap is created around the pipe with a parting medium such as asphaltic-lined corrugated cardboard. Service temperature of this system is 800°F.

River Crossings--An important design consideration in distribution systems is the method used to cross rivers. We will describe two possible methods.

Figure 22 illustrates a typical design whereby a separate bridge is constructed to cross the Fox River in Green Bay. The design shows a 20-inch supply and return pipe with 4 inches of insulation which is encased in a steel conduit. The cost for this application is approximately \$1,000,000 and is the recommended method for crossing the Fox River.

Figure 23 illustrates a typical design whereby the piping is installed under the roadway and inside openings in the transverse floor girders. This design can only be considered if the piping details are known when the bridge is being designed. For the Green Bay application, it is probably too late to add the piping since the bridge is under construction.

Typical Distribution Piping Network Configurations--Figures 24 and 25 show two different distribution configurations for the Green Bay application.

The first network crosses the river near the power plant and follows the routing of the roads east of the paper mills. For the three-mill design, there is approximately 9700 feet of 20-inch pipe, 2600 feet of 14-inch pipe, 2100 feet of 10-inch pipe, and 1900 feet of 3-inch pipe.

The second network crosses the narrowest part of river near the paper mills and runs along the shore west of the power plants. For the three-mill design, there is approximately 9900 feet of 20-inch pipe, 2700 feet of 14-inch pipe, 660 feet of 10-inch pipe, and 640 feet of 3-inch pipe.

ADVANTAGES OF HIGH-TEMPERATURE WATER VERSUS STEAM

The following are among the outstanding advantages of HTW systems as compared to steam distribution systems or low-temperature water systems:

- The HTW system is 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

INSULATED PIPE
IN PLASTIC CONDUIT

TYPICAL CONSTRUCTION BASED ON DETAILS
SUPPLIED BY M. L. SHELDON PLASTICS CO.

INSULATED PIPE
IN POURED CONCRETE

(SEE NOTE 1)

NOTE 1

AN ALTERNATE CONFIGURATION WOULD REPLACE
THE INSULATION AND AIR SPACE WITH A PARTING
MEDIUM SUCH AS ASPHALTIC LINED CORRUGATED
CARDBOARD AND THE CONCRETE WOULD BE AN
INSULATING TYPE SUCH AS "Z-CRETE."

Figure 21. Insulated Pipe in Plastic Conduit and Poured Concrete

Figure 22. Green Bay, Separate Pipe Bridge

NOTES:

TYPICAL DESIGN (NOT FOR CONSTRUCTION)
 THIS FIGURE IS REVISED BY AMERICAN
 HYDROTHERM FROM PLATE 3 OF CONSOER
 TOWNSEND & ASSOCIATES REPORT "PROPOSED
 STEAM DISTRIBUTION SYSTEM WISCONSIN
 PUBLIC SERVICE CORP."

Figure 23. Green Bay, Cross-Section and Details of
 Proposed Tower Drive Bridge

Figure 24. Green Bay Distribution System with Northern River Crossing

Figure 25. Green Bay Distribution System with Southern River Crossing

the system is minimized. Because the HTW system is closed circuit, the heat not utilized in the terminal heat transfer equipment is returned to the high-temperature water boilers.

- There is ability in a HTW system to design 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 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.
- There is a tremendous "flywheel" effect in the heat storage in the HTW system, which acts to even out fluctuations in the load.

Of all the factors favoring the HTW heating system, the "flywheel" effect in heat storage is the most important. The available heat storage of a water system operating at 400°F compared to 400°F steam is many times as great for the water system, assuming equal volume for the two systems.

Thermal storage is a function of the heat capacity per unit volume (Btu/cubic foot). In one cubic foot of 400°F water we have the following energy:

- Water Density x Enthalpy (Btu/lb) = Total Heat Content.
- $53.65 \times 375 \text{ Btu/lb} = 20,119 \text{ Btu}$ in 1 cubic foot of water at 400°F .
- Steam Density x Enthalpy of Steam = Total Heat Content.
- $0.537 \times 1201 = 645 \text{ Btu}$ in one cubic foot of steam at 400°F .

Thus, the stored energy in a HTW system is about 30 times greater than that in a comparable steam system.

Safety Considerations

A question often arises regarding the safety features of high-temperature water compared with steam systems operating at the same temperatures and pressures. Events in which a sudden rupture or large leak may have developed in a HTW line are very rare, and little is known about the damages which result. However, from practical tests of the flow of HTW from an open pipe into the atmosphere, and also from reports of the few accidents that have occurred, some knowledge has been obtained regarding the behavior of the sudden discharge of HTW into the atmosphere. Two characteristic features accompany the sudden expansion of high-temperature water upon a release of pressure to atmosphere:

- A very high rate of increase in volume;
- A very low rate of energy release during expansion.

Flashing into steam and expansion will absorb the potential energy stored in the fluid. The expanding high-temperature water will transform into a very wet fog. The expansion will reduce the temperature of the fluid to 212°F . A further reduction below 212°F is caused by the turbulent mixing of the fluid with the room air. The exact reduction below 212°F depends on many factors; the temperature of the system; the discharge area; the distance from the point of discharge; and the room temperature. Under ordinary conditions, the temperature in the discharge falls to about 125° to 140°F .

within a short distance as compared to the temperature of the discharge of a low-temperature water system, which remains essentially the same as the temperature of the working fluid. Thus, the temperature in the discharge of an LTW system will normally be higher than the temperature developed in the discharge of an HTW system.

It is well known that accidental breaks in high pressure steam lines have caused serious damages to persons and property since:

- The heat transmitted to a closed space by escaping steam is very high in a short interval of time.
- The steam exit velocity and kinetic energy are about five times that of escaping water.
- Escaping steam will rapidly displace the air in a closed space causing suffocation to persons trapped in the space.
- High pressure steam striking the skin will cause severe burns.

High-temperature water can be considered a safer heat transfer agent than high-pressure steam.

In view of the distinct advantages of distributing high temperature water over distances associated with a project of this complexity, steam systems will not be given further consideration.

Capital Costs

Capital costs have been established for the primary hot water distribution system on a linear foot basis. They were based on 12-inch through 36-inch pipe to give a range of costs. A summary of primary distribution costs is shown in Table XXX. Detailed costs (i.e., excavation, pipe bedding, back-fill, etc.) are tabulated in Appendix F.

TECHNIQUES FOR INTERFACING WITH END USER

Where an existing process or plant is using HTW for process or space heating, the direct interface of distribution fluid to user equipment is simple and inexpensive. If, however, an attempt were made to convert an existing steam system to HTW, the changes are complex and expensive, and each system would have to be evaluated on its own merits for its cost effectiveness. In addition, a break or problem in the end user's equipment could severely affect the distribution system and the central plant. In view of this, and since each system conversion from steam to HTW is unique, no attempt was made to establish costs for direct interface.

Indirect interface of user's equipment with the district HTW using heat exchangers is an effective way of adapting existing facilities to an HTW distribution system. Heat exchangers can be sized to generate domestic hot water (DHW), process steam, or space heating hot water. The basic design of a converter system would be similar for all buildings. Basically, equipment sizes and quantities would vary. Two typical conversion schemes are illustrated in Figures 26 and 27.

Costs have been developed for heat exchangers, interior and exterior plumbing, excavation and controls. Costs have not been included for the customer's internal distribution. These costs are tabulated in detail in Appendix F and summarized in Tables XXXI and XXXII.

Table XXXIII shows total annual cost for a building assuming piping distances and thermal loads as indicated. In addition, we have assumed operating, maintenance and insurance costs of 2.75 percent of the capital costs.

Table XXXIV shows total capital cost for an absorption chilled water system using HTW as the heat source.

Figure 26. Typical Converter Room for Multiservice Use of High Temperature Water

Figure 27. Typical Arrangement of High Temperature Water Converter Room

Table XXXI. Heat Exchanger Costs, Customer System Retrofit
(1979 Dollars)

<u>LOAD</u> <u>MMBH</u>	<u>SERVICE</u>	<u>HEAT</u> <u>EXCHANGER</u> <u>AREA - ft²</u>	<u>COST</u> <u>INCLUDING</u> <u>INSTALLATION</u>
2	HOT WATER TO LOW PRESSURE STEAM	22.1	1216
4		41	1882
6		68	2678
8		98	3532
10		143	5896
12		143	5896
14		195	7402
16		195	7402
18		195	7402
20		251	9322
2	HOT WATER TO HOT WATER	58	2236
4		110	3450
6		138	3960
8		200	5438
10		258	7778

Table XXXII. Customer Retrofit Costs (1979 Dollars)

INTERIOR PLUMBING		EXTERIOR PLUMBING		EXTERIOR EXCAVATION	CONTROL SYSTEMS	
SPACE HEATING & DHW	PROCESS HEAT	SPACE HEATING & DHW	PROCESS HEAT		SPACE HEATING & DHW	PROCESS HEAT
\$34.28 LF	\$50.43 LF	\$37.65 LF	\$47.46 LF	\$154.29 LF	\$8,896	\$10,627

LF = Linear Foot

Table XXXIII. Typical Building Costs (Note 1)
Customer System Retrofit (1979 Dollars)

	<u>DHW</u>	<u>PROCESS OR SPACE HEATING</u>	<u>TOTAL</u>
Interior Plumbing	\$3,428	\$ 5,043	\$ 8,471
Exterior Plumbing	3,765	4,747	8,512
Excavation	---	15,428	15,428
Heat Exchanger	3,960	3,532	7,492
Controls	8,896	10,627	19,523
TOTAL	\$20,049	\$39,377	\$59,426

(NOTE 1) ASSUMPTIONS: 100' Interior and exterior runs
6 MMBH for DHW
8 MMBH for Low Pressure Steam
- Process or Space Heating

A 200-unit high-rise apartment building would require approximately the above heat for domestic hot water and space heating.

Table XXXIV. Typical Costs for Absorption Cooling*

<u>TONS OF REFRIGERATION</u>	<u>ABSORPTION UNIT #/TON</u>	<u>INSTALLATION \$/TON</u>	<u>PUMPS & MOTORS \$/TON</u>	<u>COOLING TOWER \$/TON</u>	<u>PLUMBING \$/TON</u>	<u>WIRING \$/TON</u>	<u>TOTAL \$/TON</u>
60	180	25	100	214	55	55	629
90	180	20	100	186	55	55	596
125	160	18	100	173	55	55	561
150	160	18	100	172	55	55	560
300	160	17	100	163	55	55	550
400	160	15	100	156	55	55	541
1000	140	14	100	149	55	55	293

* Does not include cost of distribution within the building

SCARCE FUEL CONSERVATION POTENTIAL

Scarce fuel is understood to mean fuel gas or fuel oil. The scarce fuel conservation potential depends on the following factors:

- Turbine retrofit effectiveness, which could be expressed as the ratio of heat gained to power lost.
- The fuel that the utility fires to replace the power lost due to cogeneration.
- The heat losses in the distribution system (normally less than one percent of heat sold, so this is ignored).
- Distribution pumping charges (the equivalent fuel to be fired to generate the electricity to drive the pumps was shown as a cost item, not as a subtraction from the potential scarce fuel that would be saved).
- The type of fuel fired as an alternate by the heat user if he did not use heat from the cogeneration system and the efficiency of his boiler.

For the Green Bay applications, the approximate scarce fuel saved per year is 1,418,000 MMBtu. The three-mill and two-mill designs are the same since the heat that would be sold to the larger paper mill is now generated by firing coal. The downtown Green Bay business district is now using gas to supply its heat. The two smaller paper mills are also using 100 percent scarce fuel now. The fuel that the utility fires to replace the power lost due to cogeneration is approximately 75 percent coal and 25 percent oil.

For the Beloit (Black Hawk Plant) application, the approximate scarce fuel saved per year is 840,252 MMBtu. It is assumed that all of the heat users are using either gas or oil and have a 75 percent boiler efficiency. The fuel that the utility fires to replace the power lost due to cogeneration is approximately 94 percent coal and 6 percent oil.

For the Janesville and Beloit (Rock River Plant) application, the approximate scarce fuel saved per year is 2,314,000 MMBtu. It is assumed that all heat users are firing scarce fuel at 75 percent efficiency. The fuel that the utility fires to replace the power lost due to cogeneration is 90 percent coal and 10 percent oil.

For the future industrial park (Rock River Plant) application, the approximate scarce fuel saved per year is 1,482,000 MMBtu. It is assumed again that the industrial park might be firing 100 percent scarce fuel at 75 percent efficiency. The replacement fuel that the utility fired is 90 percent coal and 10 percent oil.

Data was not fully available on the Madison applications so the operation was assumed to be similar to the Rock River applications. On this basis the downtown Madison design would save approximately 258,000 MMBtu of scarce fuel, and the University design would save approximately 1,176,000 MMBtu.

CONCLUSIONS

There are no technical problems with any of the seven retrofit schemes that were assessed in detail and summarized in Table XXXV.

The most promising project would be one in which a major amount of the heat would be removed from the turbine from relatively high pressure crossover piping, the power plant is near to the heat consumers to reduce the distribution piping and pumping cost, the heat load throughout the year is relatively constant due to the sale of heat to low temperature level industrial consumers, and a high proportion of scarce fuel will be saved.

The Green Bay site appears to fit well into the above criteria. The crossover piping is at 89.7 psia, the Pulliam Plant is approximately two miles from the

paper mills and three miles from downtown Green Bay (about 25 percent of the downtown area is being renovated), and approximately 1,400,000 MMBtu of scarce fuel will be saved.

The capital cost of the Green Bay three-mill design is approximately \$11,000,000 and of the two-mill design is approximately \$8,700,000. A major factor in these capital costs is the distribution system portions, which are \$8,000,000 and \$6,500,000, respectively.

It is finally concluded that the Green Bay site is technically promising, and that work should be continued in Phase 2 of this project.

Table XXXV. Summary of Capital Costs and Technical Data,
Green Bay, Pulliam Plant

	THREE MILLS	TWO MILLS
Distribution System	\$8,000,000	\$5,500,000
Power Plant	3,000,000	2,200,000
Aver. Pumping KWH/MM Btu	1.6	1.6
Yearly Heat Sold (MM Btu)	3,540,847	1,418,329
Yearly KWH for Pumping	5,665,355	2,269,326
Heat Losses (MM Btu/hr)	2.86	2.07
Scarce Fuel Saved (MM Btu)	1,418,329	1,418,329

JANESVILLE/BELOIT (BLACK HAWK AND ROCK RIVER PLANTS)

	<u>Black Hawk & Beloit</u>	<u>Rock River & Both</u>	<u>Rock River & Park</u>
Distribution System	\$14,300,000	\$67,200,000	\$5,200,000
Power Plant	1,500,000	2,500,000	1,500,000
Aver. Pumping KWH/MM Btu	.339	2.05	1.57
Yearly Heat Sold (MM Btu)	670,414	1,928,614	1,234,800
Yearly KWH for Pumping	227,270	3,953,659	1,938,636
Heat Losses (MM Btu/hr)	3.2	17.4	1.2
Scarce Fuel Saved (MM Btu)	840,252	2,314,337	1,481,760

MADISON (BLOUNT ST. PLANT)

	<u>Downtown</u>	<u>University</u>
Distribution System	\$3,500,000	\$14,200,000
Power Plant	1,000,000	2,400,000
Aver. Pumping KWH/MM Btu	.34	.25
Yearly Heat Sold (MM Btu)	215,101	1,176,048
Yearly KWH for Pumping	73,135	293,937
Scarce Fuel Saved (MM Btu)	258,121	1,411,258

SECTION 5.0

INSTITUTIONAL ASSESSMENT

This section analyzes the institutional problems of establishing a District Heating and Cooling System (DHCS) in Wisconsin. Before elaborating on the findings, both the Public Service Commission of Wisconsin (PSCW) commitment and the Federal Government commitment to the concept of cogeneration should be outlined.

5.1 STATE COMMITMENT

Every two years, the major Wisconsin utilities are required by Wisconsin Statute (196,491) to submit Advance Plans--reports of their long-range power facility need projections and their plans to meet those needs. The PSCW, in turn, is required to assess the utilities' projections and plans. The first such assessment was issued in December 1976 and discussed the issue of cogeneration as an alternative to building larger utility plants:

Power plants operate most efficiently when they approach maximum output. When the power generating system has smaller plants, the plants are more likely to be operating at maximum output more of the time. This leads to more efficient operation of the plants, and less use of fuel. The resulting fuel cost savings offsets still more of the additional cost of smaller units.

Smaller plants can be used as dual-purpose plants more easily than larger plants. A dual-purpose plant provides steam or hot water in addition to electricity. Because generation of electricity is inherently inefficient--typically at least two-thirds of the energy content of the fuel is lost as waste heat--dual purpose use of the plant can recover some of the energy that would be lost as waste heat. The steam or hot water can be sold to replace natural gas and oil.

For dual-purpose operation to succeed, the power plant has to be located fairly close to the steam and hot water customers. This type of siting would be more feasible with smaller plants. Very large plants are almost always located away from population and load centers. Such siting makes it much more difficult to sell steam and hot water economically.

The use of dual-purpose plants is presently the subject of much study. It is not yet clear how the costs and benefits of this dual approach balance, but it does appear that, given the dwindling supplies of oil and gas, dual-purpose plants are very promising. (Pg. 23)

In the order analyzing the submittal of these reports (05-EP-1), the Commission stipulated that, "The utilities shall develop incentive rate structures for the sale of electrical energy to, and the purchase of electrical energy from, industrial or commercial firms which cogenerate" (PSC 05-EP-1, 8/78). Furthermore, the Commission repeatedly emphasized its desire for increased efforts in the areas of conservation, efficient energy use and the utilization of alternative energy sources:

In this advanced plan, the Commission directed the utilities to consider several prospective changes. Specifically, the Commission directed quantifications of the effects on future load growth of 1) conservation, 2) conversion from natural gas, 3) load management, 4) rate structure reform, and 5) improvements in end-use efficiency (Pg. 11).

Cogeneration has potential for increasing the efficiency of energy use in Wisconsin. The industrial cogeneration of electric energy appears to provide more potential for improving energy efficiency than utility cogeneration of steam. Process steam appears to be economical if sold on an interruptible basis. Economic usage of utility cogeneration seems to depend on the simultaneous availability of a high load factor plant and a nearby high load factor, high volume user of low-temperature energy. The utilization of waste heat is another provision of option (Pg. 23)

Programs designed to explore utilization of alternative energy sources and fuels, utilization of waste products and waste heat, and methods of controlling load are also appropriate and should be pursued. The Commission recommends that funds planned to be used on breeder research be diverted to these and similar ends. (Pg. 24)

The Commission finds that alternative sources of energy are potentially valuable and that it is in the public interest for the utilities to become more involved in the development and implementation of such sources. (Pg. 27)

All utilities filing plans for the next planning period shall also include an analysis of the projected effect, year by year, of their proposed and alternative generation plans. (Pg. 30)

The utilities shall investigate and adopt reasonable alternative generating strategies. (Pg. 31)

In addition, the Commission has authorized cogeneration rates in the most recent Madison Gas & Electric rate case (4220-UR-4/5, January 22, 1979). This order clearly states the Commission's commitment to encouraging the cogeneration of electricity. "MG&E is encouraged to pursue cogeneration contracts with other customers." MG&E is ordered to increase its credit to the cogenerator from an off-peak rate for energy to a full-time differentiated rate. It is further ordered to give a generation capacity credit for displaced KW's.

5.2 FEDERAL COMMITMENT

On November 9, 1978, President Carter signed into law the Public Utility Regulatory Policies Act (PURPA). The purposes of the act are to encourage conservation of electrical energy, optimum efficiency of use of facilities and resources by electric utilities, and equitable rates for electric customers.

Among the provisions of the act is a discussion of Federal requirements for the sale or purchase of electrical energy to cogeneration or small power production facilities (section 210).

TITLE II--CERTAIN FEDERAL ENERGY
REGULATORY COMMISSION AND
DEPARTMENT OF ENERGY AUTHORITIES

Sec. 201. DEFINITIONS

Section 3 of the Federal Power Act is amended by inserting the following before the period at the end thereof:

"(17)(A) 'small power production facility' means a facility which--

"(i) produces electric energy solely by the use, as a primary energy source, or biomass, waste, renewable resources, or any combination thereof; and

"(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts:

"(B) 'primary energy source' means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy--

"(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

"(ii) the minimum amounts of fuel required to alleviate or prevent--

"(I) unanticipated equipment outages, and

"(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electrical power outages;

"(C) 'qualifying small power production facility' means a small power production facility--

"(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe: and

"(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(D) 'qualifying small power producer' means the owner or operator of a qualifying small power production facility;

"(1S)(A) 'cogeneration facility' means a facility which produces--

"(i) electric energy, and

"(ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes;

"(B) 'qualifying cogeneration facility' means a cogeneration facility which--

"(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency as the Commission may, by rule, prescribe; and

"(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(C) 'qualifying cogenerator' means the owner or operator of a qualifying cogeneration facility.

Although the rules for cogeneration and small power production are still being developed, section 210 of PURPA provides that such rules be prescribed that encourage the sale and purchase of electric energy to cogenerators or small power production facilities.

One of the outstanding features of section 210 is the provision exempting cogenerators from the regulations typically associated with electric energy sales or purchases. Some of these exemptions include the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations respecting rates. Any small power production facility that has a power production capacity, combined with any other facilities at the same site, of less than 30 MW qualifies for these exemptions.

One of the more attractive regulatory exemptions is the laxed rate-making procedure. Unlike an electric utility, a private cogeneration facility is not authorized a rate of return on its operation. To compensate for the greater risk associated with establishing a cogeneration facility, Congress has deemed it reasonable to exempt cogenerators and small power production facilities from the type of examination that is traditionally given to electric utility rate applications (section 210, subsection B). Relieving cogenerators of the burdensome examination typically associated with electric rate-making will be a major incentive for the development of more cogeneration facilities.

The Act is specifically aimed at nonutility-owned systems of cogenerating facilities over utility-owned cogenerating systems. For reasons important to the Wisconsin project, this is an issue of interest. We have basically limited our research to a utility-owned system. However, some of the utility companies are wary about the risks associated with a cogeneration system and feel financing may be difficult to get without affecting bond ratings and their other utility operations. A viable alternative is for an independent agent to own the cogenerator and possibly lease or buy equipment (generation capacity) and space from the utility.

5.3 OBJECTIVE

The objective of this task is to provide an analysis of the impacts of all statutes, codes, ordinances, regulations and other external factors which may impact the establishment of a DHCS in Wisconsin. In short, the task was to identify the legal, financial and regulatory problems that might be met by the District Heating and Cooling Demonstration Project.

5.4 APPROACH

The approach consisted of examining the subtasks outlined in the contract and expanding on them when necessary. To do a thorough analysis, it was necessary for us to contact other State agencies and recruit the assistance of the utilities involved. The State agencies contacted were: the Department of Natural Resources (DNR), Department of Transportation (DOT), and Department of Revenue (DOR), and the Secretary of State's Office.

Extent and Effects of State and/or Local Utility Commission Regulation

Wisconsin Statute 196.01 defines a Public Utility as the following:

Public Utility means and embraces every corporation, company, individual, association, their lessees, trustees, or receivers appointed by any court, and every sanitary district, town, village or city that may own, operate, manage or control any toll bridge or any plant or equipment or any part of a plant or equipment, within the state, for the conveyance of telephone messages or for the production, transmission, delivery of furnishing of heat, light, water or power either directly or indirectly to or for the public.

Thus, a District Heating and Cooling System would necessarily have to conform to the regulations of the PSCW that guide all utilities; however, none of these seem to impede the feasibility of a DHCS in Wisconsin.

The principal areas of regulation are:

- Construction,
- Rate of Return,
- Rate Level and Structure,
- Safety.

Construction--Regulations involving construction, installation, or operation of any new plant, equipment, property or facility or the improvement or addition to existing equipment, property, apparatus, or facilities, state that no work shall occur until the utility complies with any applicable general or special order of the Commission. The specifics that must be included in the application are in PSC 112.06 of the Administrative Code. Simply put, the applicant must show the need for the work and show that the work does not impair the efficiency of the service or add to the cost of service without proportionately adding to the value or available quantity thereof.

Rate of Return--After reviewing a utility's accounting books and records, the PSCW determines the rate of return it feels will enable the utility to attract sufficient capital from investors to continue providing adequate service. In the case of the proposed DHCS, the PSCW will have to determine a rate of return that will attract investors to a new utility service. The utility companies have indicated that a DHCS is a greater risk than their other services and will require, perhaps a rate of return slightly higher than is established for their other services. However, this state has encouraged conservation and efficient energy use--Department of Industry, Labor and Human Relations codes, PSC conservation program, Office of State Planning and Energy efforts. Since the PSC sets different rates of return for different services, one may expect that a just and appropriate rate would be set for DHCS services.

An additional option to help reduce the risk of a DHCS is for the State to guarantee utility bonds. Something like this has been provided for in Ontario. If similar arrangement can be made in Wisconsin, an additional organizational and financial option may be an independently owned cogeneration system that sells the by-product, electric energy, to utilities and other power-producing industries at a reasonable and just rate or that leases generation capacity from an electric utility.

Rate Level and Structure--It is within the power of the PSCW to assure that utility rates be just, reasonable, sufficient and nondiscriminatory. If it appears to the Commission that these provisions are not met, the Commission can require the utility to establish new tariffs, or it can determine, and by order fix, reasonable rates to be imposed in lieu of those found to be unlawful or unreasonable.

The PSCW believes in the appropriateness of marginal cost pricing for energy. It is therefore appropriate to expect the DHCS system, when regulated

by the PSCW, would have to present rate schedules based on marginal cost analysis. If the electrical generation capacity is owned by the electric utility, the capacity costs charged to the DHCS would be on a diurnal and seasonal time differentiated basis. Most, if not all, generating capacity costs may be avoided if the DHCS can operate under an interruptible rate from the electric utility. This will depend on the length of interruption that can be tolerated in relation to the maximum number of hours of interruption that the electric utility requires during the heating season. Since the improved natural gas supply concomitant with the DHCS would serve to reduce projected winter electric heating loads, it is reasonable to expect that most Wisconsin electric utilities would remain summer peaking with relatively few interruptions needed in the winter. At the national level, the effects of the incremental cost pass-through clause for natural gas pricing to large industrial customers will make any DHCS that is competitive with No. 2 oil also competitive with natural gas.

Safety--Wisconsin Statute 196.745 reads: "Every public utility which owns, operates, manages or controls facilities for the production, transmission or distribution of gas shall construct, operate and maintain such facilities in a reasonably adequate and safe manner." After holding hearings, the Commission is to issue orders or rules requiring that the construction or operation of the facility in question be safe.

Arrangements Under Which Electric Utilities Would Modify and Operate Power Plants as Part of a District Heating and Cooling System

The basic assumption used for determining a feasible site for a DHCS in Wisconsin is that an existing power plant be retrofit. The specific engineering and technical modifications necessary were covered under the previous task.

An issue that cannot be overlooked is the near certainty of increasing the hours of operation of the Blount Street (Madison) and Black Hawk/Rock River (Janesville/Beloit) plants. To provide the amount of steam needed to operate a DHCS, the plants will have to increase their hours of operation. The Pulliam (Green Bay) plant is unlike these in that it already operates much like a base-load plant and will not have to increase its operating hours.

Extent and Effects of Legal Requirements to Obtain Easements, Franchises to occupy the Public Right-of-Way, Land Acquisition and to Obtain Certificates of Convenience and Necessity

Wisconsin Statute 32.02 outlines the rights of eminent domain. In subsection 5, the right of condemnation is extended to any Wisconsin corporation furnishing heat, power or electric light for the public, and for additions or extensions to its part and for the purpose of conducting tests or valid studies to determine the suitability of a site for the placement of a facility. Once a utility receives a certificate of approval from the PSCW, it has the power of condemnation of all land excluding that owned by another utility, railroad, river crossing, or highway department. To obtain right-of-way in a wetlands area, the utility will have to comply with section 404 of the Federal Water Pollution Control Act of 1972 requiring permits from the Army Corps of Engineers. In addition to this Federal regulation, the utility will have to comply with Chapter 10 of the River and Harbor Act of 1899 and Chapter 30 of the State DNR statutes. If the utility does not need to lay the pipes in a riverbed or cross a navigable river, Wisconsin Statute 182.017 states that it is exempt from the normal permit procedure.

The utility is required by Wisconsin Statute 196.58 to obtain municipal approval for the furnishing of service in the municipalities in which it operates. This approval should be obtained prior to applying to the PSCW for authorization.

Applications for authorization from the PSCW must follow the guidelines in Chapter 112.06 of the PSC Administration Code. The utility is required to furnish information describing the project, the proposed method of financing the project, the purpose and need of the project, the effect on the cost of operation and quality and reliability of service, a description and cost of alternatives that were considered, Environmental Impact Statement (EIS) screening information, and the designation of public utilities, municipalities and others principally affected by the project.

For a DHCS in Green Bay, the distribution system will have to cross the Fox River to reach the customers. There are three proposed alternatives for the river crossing:

- Via a utility-owned and -built bridge,
- Via an existing interstate highway bridge,
- Via the riverbed.

The first requires permits from the Department of Natural Resources (DNR), Brown County and, depending on the design, the Army Corps of Engineers. Section 10 of the Harbor Act of 1899 and Section 404 of the 1972 Federal Water Pollution Control Act are the regulations that will determine if the Corps enters the picture. Simply put, if the proposed bridge alters the navigability or quality of the river at all, the Army Corps of Engineers will probably require permits.

The second proposal is to hang the distribution pipes under the interstate highway bridge. This poses even more obstacles in the form of permits. The Federal Highway Administration has regulations that guide interference with any of its structures. In addition to this, the State Department of Transportation (DOT) has established strict standards with which utilities must comply when crossing public highway rights-of-way. Design approval

must be obtained from the DOT as well as compliance with section 3.301 of the policy statement, Provisions For Bridge Attachments (as stated below). Our discussions with the DOT have led us to believe they will contest our placing pipes at the proposed site.

3.301 Provisions for Bridge Attachments

Generally, acceptable utility installations are those which will occupy a position beneath the structure's floor, inside the outer girders or beams or within a cell, and at an elevation above low superstructure steel or masonry.

Communication and electric power line attachments shall be suitably insulated, grounded, and preferably carried in protective conduit or pipe from the point of exit from the ground to re-entry. Carrier pipe shall be suitably insulated from electric power line attachments.

Pipelines to be attached to a highway structure shall not exceed a maximum internal pressure of 150 P.S.I.G.

A utility proposing to occupy a highway structure with its lines must have an acceptable method of suspending the facility, allowing for expansion and contraction and going through or around the bridge abutments.

Alternative three is to lay the pipes in the riverbed. This will require the same approval from the Corps of Engineers as stated above and compliance with Chapter 30 of the DNR codes. This alternative appears to necessitate the most burdensome channels of approval.

Effect of State and Local Tax Laws

In Wisconsin the local tax is replaced by the State Ad Valorem property tax. The formula used to determine the tax dollars to be collected is as follows:

Original cost (cost to put in service)
 - depreciation cost
 net book value
 x full value average tax rate $\frac{\text{(amt. of property taxes collected)}}{\text{(value of property taxed)}}$

 gross tax dollars
 x .10 (investment credit appropriated from the general fund)
 net tax

The implementation of a district heating and cooling system will increase the net book value since the company will have to invest in retrofitting an existing plant and establishing a distribution system (piping). Although the PSC may decide to adjust the depreciation rates--an old plant is being materially improved rather than a new plant being added--the cost of putting in the DHCS will change the net book value.

The resulting change in net book value will correspondingly change the amount of net tax dollars. All else remaining constant, the utility can expect to have its AD VALOREM taxes increase if its net book value increases.

Effects of a Statutory Mandate to Serve All

Wisconsin Statute 196.37 provides that customers within a utility's service area have a right to receive service, i.e., upon reasonable request the utility has a duty to service all customers in its established service territory. This provision should have no significant impact on the proposed DHCS. Each utility already has an established service territory within the state.

Within the territory the utility offers different services to different customers. Once a utility decides to whom it wants to make the service available and has the PSCW authorization, it is obligated to serve all who request it; however, not everyone is required to take the service that is offered. It should be pointed out that in the 1940s Northern States Power Company faced the unusual situation of having a customer who wished to connect to its steam heating system at a location that previously did not have service. The company claimed it would cost a great deal of money to hook up this customer. The court ordered the utility to serve that customer, despite the financial burden it placed on the utility, because the utility had an obligation to serve.

Extent and Effects of Environmental Regulations

The DHCS projects that are described in this report involve the retrofitting of existing turbine facilities. Due to the fact that no new boilers would be constructed, no air quality permits would have to be issued for such a project to be built. In fact, one of the advantages of a DHCS that is often cited is that such a system may lead to an improvement in air quality. Therefore, regulations covering air quality standards do not seem to be a barrier to these systems.

There are two facets of any DHCS project that would fall under the environmental review procedures of the Public Service Commission. These would be the retrofitting of the power plant steam turbine equipment and the construction of the steam transmission and distribution facilities.

Under Section PSC 2.90 of the Wisconsin Administrative Code, construction of steam production facilities is an action that requires an individual screening to determine whether an environmental impact statement (EIS) is required. It is unclear whether the retrofitting of turbine equipment would fall into this

category. Construction of utility facilities not otherwise specified in PSC 2.90 are classified as Type 3 actions: no EIS is required. Consequently, a classificatory determination would have to be made by the Commission before the need for an EIS could be determined with certainty. The approval for the construction of steam transmission and distribution facilities is also classified as a Type 3 action. It should be noted that the Commission can consider any action brought to its attention and determine that an EIS is required.

The Green Bay DHCS project would require environmental review from other state and federal agencies. The particular agencies involved would depend upon the river crossing option chosen for the final design. The available alternatives are: (1) a bridge constructed specifically for that purpose; (2) the I-43 highway bridge now under construction; and (3) a submarine crossing on the riverbed.

The State of Wisconsin Department of Natural Resources would have the general state jurisdiction for the river crossing. To make a determination as to whether an EIS would have to be filed before DNR permits were granted, detailed engineering plans would have to be submitted. Field personnel would also visit the site of the crossing and from this information a decision would be made concerning the need for a more formalized environmental review. In a telephone conversation, a DNR employee in the Bureau of Environmental Impact gave an informal opinion that no EIS would be required for such a project.

The United States Coast Guard would have to issue a permit for any overhead crossing. This would involve options 1 and 2. If the distribution pipes are attached to the highway bridge but are above the low point of steel, no permit would be required from the Coast Guard. However, a permit would still be required from the State of Wisconsin Department of Transportation. If the pipes were tucked up under the steel substructure of the bridge so there would

be no visual impact, it is most probable that the Department of Transportation would not require that an EIS be filed before granting a permit.

The Coast Guard would definitely require a permit if a separate bridge is constructed. Whoever files the permit application would be required to file a general environmental analysis for the bridge. The Coast Guard would review the impact of the bridge on wetlands, wildlife habitat and the human environment, including the effects on commercial and industrial activity. From this information, they would make a determination as to whether or not an EIS would be required. However, due to the predominantly industrial character of the Fox River in the project area, it is doubtful that the Coast Guard would require a more detailed environmental review.

For a submarine crossing, the U. S. Army Corps of Engineers would have to issue a permit. The Corps would consider the chemical makeup of the bottom sediments and might require that any contaminated sediments be removed from the site as a condition of the permit. They would also need to evaluate final engineering plans before a permit could be issued, and thus would also need these plans to determine the need for an EIS. Once again, a telephone conversation with an employee in the Permit Section of the Corps' Chicago office gave the impression that no EIS would be required by the Corps for a crossing permit to be issued.

It is difficult to state categorically whether or not detailed environmental review of DHCS projects would be needed without at least preliminary engineering plans. However, it can be stated that environmental restrictions are probably not great barriers to project construction.

Extent and Effects of Power Siting Laws and Local Zoning Laws on Ability to Retrofit an Existing Power Plant and Build a District Heating and Cooling System

The power plant siting law, Wisconsin Statute 196.491, places no direct obstacles in the way of retrofitting a power plant for cogeneration. PSC 111.12, Administrative Code, states that the inefficient use of energy should be discouraged; a DHCS improves the efficiency of energy use.

Local zoning laws do not create obstacles. Because no new plants are being constructed, there is no problem with the zoning ordinances. The location of each plant is already in a properly zoned area, and a change in the operation will not pose any problems.

Review of the Corporate Charters of Each Participating Utility Company and All Applicable Statutes, Codes and Ordinances, to Confirm the Legal Capacity to Construct, Own and Operate the District Heating and Cooling Demonstration Projects

The corporate charters of the three eligible utilities clearly allow each to own, operate and maintain steam heating utilities. However, there are two requirements that will have to be met before the demonstration project can proceed. The utility must apply to the local government council for franchise rights to establish a heating system within the municipality. Once this is approved, the utility must apply to the Commission for authority to implement the project. When these two provisions are met, the utility may proceed with constructing a DHCS.

Detailed Schedules of Approvals, Both Internal and External, That Have to be Obtained in Order to Reach a Decision on the Construction of the Project

The following will be required:

- Apply to municipality to operate a steam heating utility;
- Apply to PSC for construction approval;
- Obtain licensing approval from
 - DNR,
 - DOT,
 - Army Corps of Engineers;
- Obtain financial guarantees;
- Obtain engineering approvals;
- Obtain customer contracts.

5.5 CONCLUSIONS

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 which purchases heat from the electric utility.

State-backed utility bonds are an option that opens the financial way for an independtly owned DHCS system should this alternative prove preferable.

The PSCW 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 oil but only with No. 2 oil, the risks are greater but reduced by the effects of marginal cost-based pricing for natural gas.

SECTION 6.0 PRELIMINARY ECONOMIC ANALYSIS

This section examines the economic viability of the district heating system alternatives for Green Bay, Janesville/Beloit and Madison. An approach is outlined and basic assumptions delineated. Summary results for each alternative are illustrated. Detailed results, including fuel escalation sensitivity analysis, income statements, balance sheets and specific examples illustrating how the economic results were determined, are contained in Appendix G.

APPROACH

From the rate structure charged to the customer, an annual or gross income (I_N) would be realized. In providing heat, yearly operational, maintenance and fuel expenses (OM_N) would be incurred. Expenses would also be incurred from yearly revenue requirements (R_N) that are necessary to recover capital investments and taxes. The difference between income and expenses is the annual savings (AS_N); that is,

$$AS_N = I_N - OM_N - R_N$$

For each of the three sites and for each district heating system alternative analyzed, these cost components were determined, annual savings calculated and results discounted to present (1979) dollars. Since the economic results are particularly sensitive to future fuel costs, a number of alternatives were generated to examine the sensitivity of real fuel escalation rates. Finally, a single fuel escalation scenario was selected and the resultant calculations examined to determine the sensitivity of other cost parameters.

ASSUMPTIONS

Major assumptions used for the economic analysis include:

- Period of Analysis--A 25-year period was selected.
- Inflation Rate--A constant rate of seven percent per year was used over the analysis period. This rate was applied to all fuel, operation and maintenance expenses.
- Annual Investments for Capital Equipment--All expenditures for plant retrofit and the distribution network were assumed to occur in the first year, except where system costs were high. These are specifically noted.
- Income from the Sale of Thermal Energy--The determination of income from the sale of thermal energy depends on the amount charged and the fuel escalation rate over the analysis period. For purposes of this analysis, it was assumed that the customer would need an economic incentive to switch to the district heating system that would defray costs associated with conversion of his building. Therefore, as a starting point, a thermal energy base rate of 90 percent of the cost of the least expensive fuel used by building owners in the area was selected. This cost then was escalated over a range of different rates (2 to 10 percent) for that fuel to test the sensitivity of the economics. The other major assumption applied to income from the sale of thermal energy was to assume that all potential customers are connected to the system immediately rather than having a gradual customer buildup over a period of time.
- Capacity Charges--Capacity charges to reflect the loss of electrical generation capability at the power plant were not considered since customers were treated as interruptible loads.
- Lost Revenue from Sale of Gas--Loss revenue from the sale of natural gas and its economic impact on the utility was not considered in this analysis.

Operation and Maintenance Costs/Distribution and Transportation System

Operation and maintenance costs for each system alternative analyzed are detailed in Appendix G. An example for Green Bay is illustrated in Table XXXVI and includes:

- Maintenance on Distribution/Transportation System--This cost was assumed to be one percent of the annual distribution system cost, an amount experienced by Swedish District Heating Systems.
- Insurance Cost on Distribution/Transportation System--A figure of 0.2 percent of the total cost per year was used.
- Operational Costs for Distribution/Transportation System--Pumping costs were based on the size required to pump the necessary amount of water through the system. The total yearly KWH required (e.g., 5,500,000) were multiplied by the industrial electric rate (e.g., \$.022/KWH) for that area.

Operation and Maintenance Costs--Plant Retrofit Components

Operation and maintenance costs for utility plant retrofit were determined using a simulation model that considers the district heat required and the characteristics of the unit(s) selected to provide the heat. The model determines fuel and operation/maintenance costs for energy extracted from that unit (e.g., electricity foregone) and fuel and O&M costs of other units that have to be fired to make up that lost electrical generation. The two costs combined are the total O&M costs for plant retrofit (Table XXXVI). Costs per year vary because the projected hours of interruption and projected generation requirements vary over the years.

Year	Distribution			Plant		Total O&M Costs
	Maintenance 1% of Cost (8x10 ⁶)	Insurance .2% of Cost (8x10 ⁶)	Pump Power 5.5x10 ⁶ kWh/yr @ 022/kWh	District Heating Portion	Cost of Shifting to less Efficient Boilers	
1980	80	16	122	260	117	595
1981	86	17	131	295	140	669
1982	92	18	140	315	239	804
1983	98	20	149	337	223	827
1984	105	21	160	359	199	844
1985	112	22	171	384	276	966
1986	120	24	183	408	330	1066
1987	128	26	196	432	427	1209
1988	137	27	210	464	443	1282
1989	147	29	224	495	316	1212
1990	157	31	240	472	329	1230
1991	168	34	257	456	286	1233
1992	180	36	275	488	306	1320
1993	193	39	294	522	328	1412
1994	206	41	315	559	351	1511
1995	221	44	337	598	375	1617
1996	236	47	360	640	401	1730
1997	253	51	385	684	430	1851
1998	270	54	412	732	460	1981
1999	289	58	441	783	492	2120
2000	310	62	472	838	526	2268
2001	331	66	505	897	563	2426
2002	354	71	541	960	603	2596
2003	379	76	578	1027	645	2778
2004	406	81	619	1099	690	2972

Table XXXVI. O & M Costs (x 1000), Green Bay, Three Mill and CBD Alternative

Results and Fuel Escalation Rates

A parametric analysis was performed for the following range of fuel escalation rates:

<u>Fuel</u>	<u>Real Rate</u>	<u>Rate with Inflation</u>
Coal	0 to 7 percent	7 to 14 percent
Oil	3 to 10 percent	10 to 17 percent
Natural Gas	2 to 10 percent	9 to 17 percent

The results consisted of a number of curves representing life-cycle savings versus real fuel escalation rates for natural gas, as shown in Figure 28.

Figure 28. Sample Results, Life-Cycle Savings

Natural gas is the dominant fuel used in Green Bay, Janesville/Beloit and Madison. Therefore, income from the sale of thermal energy to the consumer was tied to the current price of natural gas and the expected escalation rates.

The results depicted represent life-cycle savings that could be achieved using a base rate and range of escalation rates. Using these results, the economic viability of the district heating system can be determined as a function of:

- Costs and escalation rates for fuel burned (coal and oil) at the utility,
- Income escalation at different rates.

To examine the year-by-year flow of funds into the district heating system, the accumulated net present value for each year was determined (Figure 29).

Figure 29. Sample Results, Accumulated Net Present Worth

The cost of determining the accumulated net present worth of the district heating system for all fuel escalation rates would be prohibitive. Therefore a single escalation rate was selected for each fuel. Real fuel escalation

rates selected (i.e. those in excess of inflation) include:

- Natural Gas 7.0 percent
- Distillate Fuel Oil 4.1 percent
- Coal 4.0 percent

These real escalation rates were extracted from, "Historic and Forecasted Energy Prices by DOE Region and Fuel Type for Three Macroeconomic Scenarios and One Imported Oil Price Scenario," Office of Energy Use Analysis, November 1978. The rates are based on the Trendlong scenario, which depicts a situation of relatively stable long-term economic growth.

The results illustrated depict the accumulated net present worth of the district heating system assuming:

- Coal and oil used by the utility is escalating at 4.0 percent and 4.1 percent, respectively.
- Income from the sale of thermal energy on a base rate for that area and escalating at 7 percent.

Financing Options

Three financing options were considered for each alternative investigated. These include:

- Utility Financing--The entire cost of the project (i.e., plant retrofit equipment and distribution system) is financed by the utility using its capitalization structure. The entire system is operated and maintained by the utility.
- Utility/Municipal--The cost of the plant retrofit equipment is financed by the utility, whereas the cost of the distribution system is financed by a municipal utility. The cost of operating and

maintaining the plant portion of the system is borne by the utility. The municipal utility operates and maintains the distribution system.

- Municipal--The entire cost of the project (including operation and maintenance) is financed by a municipal utility.

Capitalization Inputs

The preliminary economic analysis performed for each of the three sites was based on the capitalization structure of each utility. For the municipal financing option, a return rate of 8 percent was used for all three sites. Inputs are summarized in Table XXXVII.

District Heating Alternatives Analyzed

The district heating alternatives analyzed were described in detail in Section 3.0. A brief summary of these alternatives follows.

Green Bay--

- Three Mills and CBD--Includes three paper mills (located across the Fox River from the power plant) and the Central Business District (CBD), which is located immediately south of the paper mills. The distance from the Green Bay Pullium Plant to the southern boundary of the CBD is approximately two miles. Distribution costs include \$1,000,000 for a pipe bridge across the Fox River.
▲ Heat Supplies	3540.85 X 10 ⁹ Btu/year
▲ System Costs	
Plant Retrofit	\$3,000,000
Distribution System	\$8,000,000

Table XXXVII. Economic Analysis Input Summary

	Green Bay Wisconsin Public Service Corporation	Janesville/Beloit Wisconsin Power & Light	Madison Madison Gas & Electric
Capitalization	Bonds 47% @ 9% Preferred 12% @ 9% Common 41% @ 13%	Bonds 48% @ 9.75% Preferred 12% @ 9.5% Common 40% @ 14.5%	Bonds 51% @ 8.0% Preferred 14% @ 9.0% Common 35% @ 12.0%
Income Tax Rate (State/Fed)	49.95%	50%	49.95%
Advalorem Tax Rate	\$30 per \$1000 Assessed Valuation	\$25 per 1000 Assessed Valuation	\$30 per 1000 Assessed Valuation
Investment Tax Credit Rate	10%	10%	10%
Utility Discount Rate Employed	17%	11.62%	9.54%
Book Life	27 years	31 years	27 years
Depreciation Method	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining - 1st two years Sum of Digits - Remaining years	Double Declining + 1st two years Sum of Digits - Remaining years
Municipal Financing Rate	Bonds 100% @ 8%	Bonds 100% @ 8%	Bonds 100% @ 8%
Municipal Discount Rate Employed	8%	8%	8%

- Two Mills and CBD--Includes the two smaller paper mills and the CBD. The largest paper mill was omitted. Distribution costs include \$1,000,000 for a pipe bridge across the Fox River.

▲	Heat Supplied	1418.33 X 10 ⁹ Btu/year
▲	System Costs	
	Plant Retrofit	\$2,200,000
	Distribution System	\$6,500,000

Janesville/Beloit--

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

▲	Heat Supplied (Estimate)	1234.80 X 10 ⁹ Btu/year
▲	System Costs	
	Plant Retrofit	\$1,500,000
	Distribution System	\$5,200,000

- Blackhawk to Beloit--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

- Rock River to Janesville and Beloit--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

Madison--

- 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 \$3,500,000
- 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
 - Distribution \$14,200,000

CONCLUSIONS

Detailed results of the economic analysis are contained in Appendix G.

A summary of the results for each of the three sites and each of the alternatives analyzed is illustrated in Figures 30 through 36. 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.

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 percent and oil at 4.1 percent, were calculated. These were added to yearly operations and maintenance costs of the system (based on a yearly average inflation rate of 7 percent) to determine total revenue requirements.

Figure 30. Accumulated Net Worth versus Year,
Green Bay, Three Mills and CBD

Figure 31. Accumulated Net Worth versus Year
Green Bay, Two Mills and CBD

Figure 32. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Industrial Park

Figure 33. Accumulated Net Present Worth versus Year,
Janesville/Beloit, Blackhawk to Beloit

Figure 34. Accumulated Net Present Worth versus Year, Janesville/Beloit, Rock River to Janesville and Beloit

Figure 35. Accumulated Net Present Worth versus Year, Madison, CBD and Capitol Heating Complex.

Figure 36: Accumulated Net Present Worth versus Year, Madison, University of Wisconsin

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 was selected by taking 90 percent of the current charge for natural gas at each site. This would become the rate charged for thermal energy from the DHCS. A 10 percent reduction was selected as a means of providing an incentive for customers to convert their building to the DHCS. The customer rate was escalated at a rate expected for natural gas (7 percent) and the gross yearly income was determined.

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

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

A comparative summary of the sites and alternatives considered is given in Table XXXVIII. For each alternative, total fixed revenue requirements (in 1979 dollars) are tabulated. Also tabulated and illustrated in Figures 30 through 36 are the number of years required until accumulated net present worth of savings equals fixed revenue requirements.

Table XXXVIII. Comparative Summary of DHCS Alternatives

DISTRICT HEATING SYSTEM ALTERNATIVE	TOTAL FIXED REVENUE REQUIREMENTS FOR DHCS SYSTEM (\$1979 x 1000)		YEARS UNTIL TOTAL ANNUAL SAVINGS EQUAL REVENUE REQ.	
	UTILITY	MUNICIPAL	UTILITY	MUNICIPAL
GREEN BAY				
3 MILLS & CBD	11,137	10,881	10	6
2 MILLS & CBD	8,808	8,606	18	10
JANESVILLE/BELOIT				
ROCK RIVER TO INDUSTRIAL PARK	9,720	6,511	7	3
BLACKHAWK TO BELOIT	22,920	15,353	> 25	17
ROCK RIVER TO JANESVILLE/ BELOIT	117,744	77,683	> 25	21
MADISON				
CBD & CAPITOL HEATING COMPLEX	6,065	4,451	19	14
UNIVERSITY OF WISCONSIN	22,373	16,420	14	9

The most promising site is Green Bay, where a large industrial process load as well as a commercial building heating and hot water load are located close to the Pulliam Power Plant. The industrial process load from the three paper mills represents about 90 percent of the total load in the defined service area. If these loads come on line immediately, as assumed in the economic analysis, positive net annual savings can be realized within two years. This would provide a large steady source of income for the DHCS while the downtown business area is brought on line over a time-phased period.

For the other alternative considered for Green Bay, consisting of the two smallest paper mills and the Central Business District, the total load is 40 percent of the three-mill alternative while the costs are 80 percent. These proportionate loads and costs combine to make the economics slightly less desirable, with positive net annual saving realized in seven years. The large industrial base load would provide the same benefit as with the three-mill alternative, providing a steady income while the CBD is gradually brought on line.

The most economically attractive alternative analyzed is the industrial park to be located near the Rock River Power Plant in the Janesville/Beloit area. The concentration of estimated loads and the short distribution system could make this site economically attractive at a future date. 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 Complex 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-phase period. Hence, the economics would tend to be less desirable than portrayed.

The University of Wisconsin currently has two central boiler plants and a steam distribution system. Because of the 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 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.

A sensitivity analysis was performed that related fuel escalation rates to life-cycle savings (Appendix G, Volume III). The analysis illustrates how life-cycle savings over a 25-year period vary as a function of fuel escalation rates for fuels (coal and oil) consumed by the power plant and district heating fuel costs to the consumer. The latter is represented by escalation rates for natural gas, for which the cost of district heating energy was assumed to follow. This analysis was conducted for utility, municipal and joint financing.

The results of the analysis indicate that the economic viability of the project is very sensitive to fuel escalation rates. Given the uncertainty of future fuel escalation rates, this would indicate that district heating systems with lengthy payback periods should be carefully analyzed. Those with shorter payback periods or those that do not operate at a large deficit for a long period of time can be viewed more favorably. The Green Bay, Wisconsin, site appears to fall into the latter category.