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Development Options for Existing Municipal Steam District Heating Systems

May, 1980

DEVELOPMENT OPTIONS FOR EXISTING MUNICIPAL STEAM DISTRICT HEATING SYSTEMS

Touche Ross & Co.
Pfeifer & Shultz/HDR, Inc.
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I. EXECUTIVE SUMMARY

The primary objective of this study was to identify and analyze development options for three relatively small Minnesota municipal steam district heating systems currently experiencing economic and operating difficulties - Mountain Iron, Owatonna, and Worthington. Analysis included current physical systems, possible technical options, market situation, financial condition, and institutional considerations.

Although mentioned throughout this report, two factors relating to the analysis require that the results of this project be interpreted with care:

- There is a great deal of uncertainty about future fuel costs and availabilities.

- The economic analysis of several development options yields a total preliminary estimated cost which is very close to the total estimated cost of system shut down. Therefore, it is likely that the ultimate decisions concerning the future of these systems cannot be made solely upon economics. The institutional issues will have a very significant impact on the outcome.

Key findings and conclusions of the study include:

- There are no technical reasons preventing perpetuation and renovation of any of the three steam systems. Questions concerning the ability to arrest or reverse the erosion in the customer bases and the advisability of renovating a system which would need to price its product in excess of other market alternatives must still be resolved.

- The least expensive development option for the three systems appears to be a renovation of existing steam distribution systems. Although hot water technology is generally more efficient than steam, the rate impact of the added cost of converting end-user buildings from steam to hot water appears to exceed the benefits of increased efficiency. If construction grants could be obtained to offset higher conversion costs, hot water would be preferable from an energy efficiency standpoint.

- It is economically infeasible for small district heating systems to enjoy the fuel cost advantages of burning coal if they must bear the financial burden associated with pollution control equipment.

- The economics of electric generation at large coal-fired power plants have made it increasingly less attractive for municipalities to operate smaller, less efficient plants which cogenerate electricity and steam for a district heating system. Consequently, the energy conservation potential of cogeneration may be illusory due to the more forceful economics of electric production.

Although it may not appear economically attractive to perpetuate and renovate these systems when less expensive alternative heating means are available, other factors may argue strongly in favor of revitalization. Before a decision is made to terminate steam operations, serious consideration should be given to objectives such as:

- Displacement of imported fuels;

- Conservation of scarce gas and oil; and

- Community economic and social factors.

If these broader objectives are found to outweigh other economic factors, study/design grants, construction grants, or operating subsidization might reasonably be considered. This study did not attempt to make those judgements but, rather, defers them to community leaders and state policy makers. In addition, the study should not be viewed as a final analysis but as a means for provoking additional discussion, and possibly analysis, of specific development alternatives or of shutdown implications.

If, after reviewing the economic analysis, a community decides to pursue system renovation, they should pursue a course similar to the following:

1. Analyze, discuss, and resolve the respective institutional issues. If these are resolved in favor of renovation,

2. Select one or more specific scenarios and begin an in-depth analysis including:

   a. Survey the local market to determine how many new and existing customers can be expected on the system with the likely development options and projected rates. Obtain commitments if possible.

   b. Proceed with detailed engineering design and cost estimates.

None of the options identified in this study should necessarily be ruled out based upon preliminary estimates, but, rather, should be pursued based upon the community's needs. (For example, if the community wishes to take advantage of hot water technology, that scenario may be worth pursuing despite the increased cost.)

3. After detailed design and cost estimates are completed, the community will be in a position to fully assess its funding needs and options. Since many funding sources require detailed plans upon application, it will probably be difficult for the community to seriously pursue many options until this point in the project.

4. Pending final engineering and funding, the community would then be ready to commence system renovation.

II. BACKGROUND, SCOPE, AND OBJECTIVES OF STUDY

A. Background

At the present time, 15 municipal district heating systems are operating in Minnesota, or approximately half of the number which were once operated. Generally, these systems were installed during the first 30 years of this century and the termination of operations has occurred principally over the last five years.

In 1979 the State Legislature enacted into law a requirement that utilities notify the Minnesota Energy Agency two years prior to an intended abandonment of a municipal district heating system. Funds were appropriated to enable the Agency to investigate the notifying communities' situation and to identify short and long-term development options for the systems. This report is the result of the Agency funding the firm of Touche Ross & Co. and its subcontractor, Pfeifer and Shultz/HDR, Inc., to identify and develop options for the cities of Mountain Iron, Owatonna, and Worthington which had previously notified the Agency of economic difficulties and possible shutdown.

B. Scope and Objectives of Study

The team of Touche Ross and Pfeifer and Shultz/HDR was formed to provide an effective, efficient approach to the problem. Touche Ross has extensive experience in the areas of operations, management, marketing, finance and economic analysis including specific experience in cogeneration district heating feasibility analysis. Pfeifer Shultz/HDR, Inc. has extensive experience in the design and engineering of district heating systems and has experience with each of the community district heating sytems to be studied. The scope and objectives proposed were:

- To identify and analyze short and long-term development options for each of the systems;
- To identify and analyze potential market, technical, institutional and economic obstacles to revitalization;
- To develop recommendations for further study, as appropriate; and
- To identify viability issues and other factors which are relevant to the three study cities and which might be generic to municipal steam district heating systems.

An overall objective in conducting the study was to insure that no reasonable development alternative was overlooked. During the last two years a number of cogeneration district heating studies have either been completed or are currently underway in Minnesota. These studies suggest that hot water cogeneration district heating systems may be economically feasible, yet existing municipal steam district heating sytsems are experiencing financial difficulties. If central systems have a role in this state's energy future, it would be prudent to develop options and a plan for their perpetuation. Accordingly, care was taken to explore any reasonable alternative for improving operations or preserving the existing central systems.

C. Study Plan

The study consisted of four distinct phases:

Phase I - Background. Relevant background data, reports, and statistics were reviewed for the three sites; meetings with utility managers and the project team were held to discuss the market, technical, institutional, and financial condition of each system. Possible development alternatives were identified for further investigation by the project team.

Phase II - Analysis of preliminary alternatives. Possible alternatives were subjected to a preliminary analysis; capital and operating costs, efficiencies, and impact on rates to customers were estimated. Alternatives or combinations of alternatives were identified for further investigation in Phase III.

Phase III - Analysis of most promising alternatives. The reduced set of most promising alternatives was scrutinized in greater detail; site inspection of facilities and market were completed and a limited number of customers were interviewed; cost estimates, institutional assessment, and financial analysis were finalized; a single most promising alternative was isolated for the most in-depth analysis.

Phase IV - Report preparation. Final data was collected, analyses were completed, and a report was drafted.

III. GENERAL OBSERVATIONS AND FINDINGS

A. Current Status and Background

Physical System

The boiler and electric generating equipment operated by the three municipalities is generally in good working condition. Like most municipal electric plants in the state, the equipment was typically installed 15-30 years ago, has the capability to cogenerate electricity and steam for district heating, and is relatively small and inefficient by today's electric generation standards.

Distribution systems are generally the main problem for municipal utilities. The systems provide steam (as opposed to hot water) to customers and were originally installed in 1915, 1926, and 1935 for Worthington, Owatonna, and Mountain Iron, respectively. At such age, and given the technology available fifty years ago, these systems are understandably at or beyond the end of their useful lives. According to maintenance personnel the pipe is completely corroded away in places and the steam merely passes through the opening left in the earth. On cold days, steam can be seen escaping from the ground.

In places where piping remains intact, repair work will sometimes jar the line sufficiently to cause another break only a few feet away. Repair work in manholes is also hazardous due to the condition of the pipe: should a pipe fail while a repairman was working in a manhole, the worker would almost certainly be seriously injured. In addition, condensate returns are generally non-functional or functioning poorly.

Insulation covering the pipes is almost completely deteriorated, according to maintenance personnel, and this lack of insulation is a major cause for the low efficiencies of the distribution systems (e.g., from 26% in Mountain Iron to 75% in Owatonna). High radiation losses and condensate losses together make these systems costly and very poor vehicles for delivering energy.

Questions logically arise as to why the systems were allowed to deteriorate to such a decrepit state. The reason is most likely not mismanagement but, rather, simple economics. As less-expensive heating alternatives became available--natural gas, fuel oil, and electricity--the utilities likely found that they had to compete in price with the alternatives or face rapid erosion of the steam sales base. Consequently, steam was priced competitively and the lack of cash flow from revenues produced two significant results:

- Maintenance, replacements, and improvements were routinely deferred; and
- System replacement was not funded.

Only in retrospect do we now see some of the long-range implications of the temporary availability of inexpensive fuel.

Market

The municipal steam systems of Mountain Iron, Owatonna, and Worthington serve markets which appear to be somewhat less than optimal for economical steam district heating. All three systems serve principally space heating demands: Mountain Iron being primarily residential, Owatonna and Worthington being primarily commercial. Consequently, the market can be described as having very low load density with unfavorable seasonal load profiles (i.e., sales occur mostly in winter months with very little load during non-heating months). Compared to other municipal steam heat systems in the state, the three cities studies are among the lowest in terms of pounds of steam sold relative to length of distribution system. In other words, the potential revenues relative to capital base required for producing those revenues is low.

Faced with the competition offered by alternative fuels and the changing economics of electric production (to be discussed in more detail later), there was a real disincentive for utility managers to develop or expand the steam heating market. In fact, over the years, the utilities have tended to ignore the steam systems and have not attempted to stem the gradual withdrawals from the system. Expansion in the commercial, industrial and institutional sectors has tended to occur on the fringe of the cities and the systems were not expanded to offer service. Consequently, the customer bases have declined to very low levels and the trend continues even today.

One further complication of the municipal steam market is that customers don't necessarily understand the economics of purchasing steam vs. using their own gas or oil system, and there has likely been little marketing effort directed at insuring that customers are making valid comparisons. The tendency for a customer contemplating an alternate source may be to compare steam cost and fuel cost directly on a Btu basis without adjusting the fuel cost for efficiency of combustion or adding the amortization and maintenance cost of the new system. In addition, other considerations such as the risk of non-availability of fuels or the increased risk of building fire may be ignored or minimized. To the extent that this occurs, the steam customer base has eroded as a result of incomplete or inaccurate information or analysis.

In recent years the federal Department of Energy and the Minnesota Energy Agency have actively pursued the development of hot water cogeneration district heating in Minnesota, notably in Saint Paul, Moorhead, and Red Wing. The question arises as to why these systems would be viable when municipal systems are experiencing financial difficulties. Although favorable economics have not been conclusively demonstrated for any of these study sites, there is one salient market difference between them and the cities of Mountain Iron, Owatonna, and Worthington: load density. The potential heating load is considerably more concentrated--perhaps five to ten times as concentrated--in Saint Paul, Moorhead, and Redwing than in the three smaller municipal systems. Consequently, a comparably sized distribution system with a more dense load will generate more revenue for the same amount of capital base. Because fixed charges resulting from capital investment can be spread across a broader revenue base, overall economics improve greatly due to higher load density.

Economics

The economics of district heating in the three cities studied are significantly impacted by three energy-related factors:

- the cost of available fuels,
- system fuel efficiency, and
- the economics of electric production.

At the present time, coal is clearly less expensive per Btu than natural gas or oil. In addition, it is commonly believed that the prices of gas and oil will escalate much faster than coal because of diminishing supplies and ease and cleanliness of use. However, a utility must maintain certain federally mandated standards with respect to air quality and these standards can be met by a coal-burning utility only with the addition of rather costly pollution control devices. Consequently, the cost advantage afforded the small district heating system by burning coal may be more than offset by increased capital charges for those devices.

If the utility must burn gas or oil in order to meet air quality standards, there will likely be no fuel cost advantage of a central heating system over individual heating systems (see discussion of system fuel efficiency, below). This is significant because it implies that scarce fuel conservation potential (i.e., the fuel substitution potential) of district heating might not be applicable to low-density, remote municipal sites.

A second energy-related economic consideration is the fuel efficiency of a steam district heating system versus individual building heating systems. It is commonly believed that district heating is more fuel-efficient than individual systems, but that outcome also depends on circumstances. Heating and cooling engineers maintain that the efficiency of individual gas and oil systems is typically between 50% and 80% with 70-75% efficiency estimated for newer furnaces. Manufacturers of a new hot water boiler operating on the pulse combustion principle maintain that fuel efficiency in excess of 90% can be expected.

A typical boiler in a municipal utility might have a fuel efficiency of 80-85% and a distribution system in good repair might be 80-90% efficient. Assuming boiler efficiency of 85% and distribution system efficiency of 85%, overall efficiency would be 72% as compared to as much as 90% for a small individual system. This implies that small steam district heating systems may not, in fact, have a fuel-efficiency advantage over small individual heating systems primarily due to the inefficiencies inherent in the distribution network.

It can be argued, however, that it is erroneous to impute the inefficiency of a steam/electric system entirely to district heating if electricity is also being produced. To the extent that the primary purpose of the plant is to produce electricity and steam is extracted as a byproduct after some electricity has been produced, this argument has merit. If some electric production is foregone due to the steam extraction, then some amount of the inefficiency should be imputed to the steam system. If the plant is operated primarily to supply steam heat customers and electricity is the real byproduct, then all of the inefficiency might legitimately be imputed to the steam heat utility.

The third energy-related economic consideration is the changing economics of electric power production. Municipal electric plants were constructed during a period when there was a lack of other alternatives and turbine-generator systems were installed which matched the municipalities' current and projected electric needs. Gradually, it became more economical to build and operate huge coalfired and nuclear plants and to transmit power over long distances. One by one, municipal utilities terminated or greatly reduced electric production and began to rely on more economical power sources. Although it is still economical to operate some municipal generating units, the trend has been clear--smaller, less-efficient municipal electric generating plants have yielded to large, remotely located, efficient plants. Small municipal district heating systems are, in part, casualties of that trend.

B. Impediments to Perpetuation and Renovation of the Three Steam Systems

Physical System

The distribution systems of the three district heating utilities clearly must be replaced if operations are to continue for any period of time. Such a renovation is very costly and may be difficult to justify economically or on an energy-efficiency basis.

Although the boilers supplying steam to the systems are generally in good operating condition, they are not optimal. The boilers in Mountain Iron and Worthington are far too large for efficient supply to such small loads and smaller "package" boilers would need to be installed.

A major impediment to continued operation, therefore, is the degree of renovation and capital outlay required and the resultant implications for steam rates.

Market

Few attractive opportunities for expansion of the customer base were identified in any of the three cities. Most of the potential customers with significant heating needs were too distant from the plant to justify a line extension or presented other intractable problems.

In all three cities, the trend has clearly been for the customer base to shrink. The City of Worthington has already notified customers of an anticipated shutdown in the fall of 1981, and Owatonna has also notified customers of the possibility. These actions tend to hasten customers' withdrawal. In view of the declining market base and of the anticipated shutdowns, it may be impractical to expect to expand the systems.

Economics

Several significant economic factors may act as impediments to perpetuating and renovating the three systems:

- The capital cost of renovation may ultimately exceed the cost to install individual building heating systems.

- High debt service costs will be incurred for renovation and must be spread across an already small and diminishing customer base. Due to the current high interest costs and the difficulties experienced by municipalities in selling bonds, debt financing appears to be both expensive and difficult to obtain.

- Because of air quality requirements and the cost of emission control devices, it may be most economical for the three systems to burn gas. If gas can be burned for the principal heating season, the central heating system might be able to match overall fuel economics of available alternative individual systems. Over the longer term, however, the utility might be forced to burn oil, in which case it would likely be at a fuel price disadvantage to its customers.

- The high cost of a complete conversion to hot water district heating for a small customer base virtually dictates a least-cost renovation, i.e., renovation of the existing steam system. Although hot water district heating is more energy efficient than steam district heating, it may not be sufficiently better to justify the high costs associated with converting buildings to hot water.

- As energy becomes increasingly more expensive, the efficiencies of new individual building heating systems will likely continue to improve and central steam systems may become increasingly less economical relative to either individual systems or a hot water district heating system.

IV. UNCERTAINTIES ASSOCIATED WITH FUEL PRICE PROJECTIONS AND FUEL AVAILABILITIES

The most theoretically sound method for evaluating the economics of various investment alternatives is a discounted cash flow analysis. As applied to the situations of the three cities, a variation of this methodology--discounted life cycle costing--appears relevant because expenses over the life of the investment are related to the present time, the option with the lowest discounted cost being the most attractive. Discounted life cycle cost analysis would be appropriate in these circumstances were it not for the heavy dependence on future fuel prices.

A. Fuel Price Projections

At the current time there is a high degree of uncertainty associated with future fuel prices. This is due to extreme uncertainty about supply/demand relationship, world political events, and government policies and regulations. Consequently, little, if any, confidence can be placed in fuel price projections beyond a few years.

Discounted life cycle cost analysis is heavily dependent on future fuel prices because fuel costs are a significant expense for both the district heating utility and the customer utilizing an alternative heating system. This concept would be particularly useful in the analysis of the three systems because of the number of capital alternatives and potential fuels. However, the extreme uncertainty about a significant cost item casts doubt on the usefulness of the results for decision purposes. Accordingly, a simpler, more traditional approach which places the primary emphasis on immediate projected costs per unit sold appears more appropriate for this study.

An illustrative example of the results of a life cycle costing approach are included in Appendix A.

B. Fuel Availability

In addition to the uncertainty about future fuel prices, there is considerable uncertainty about the future availability of gas, and perhaps even oil, for utility usage. Natural gas is currently available for utility consumption during most of the year at relatively low cost. It also appears that gas will continue to be available for such uses for several more years, but beyond that the situation is less clear. There is conflicting information and projections relative to gas availability due to uncertainties about the amount of reserves, production and exploration levels, and the rate of growth or decline in usage for various purposes. The problem is compounded by the unpredictability of government actions and regulations relating to emphasis on usage of domestic and renewable fuels such as coal and wood; incentives to exploration and production; and air quality objectives.

It is impossible to determine at this time whether sufficient gas will be available for district heating needs in the future. The fact that abundant gas is available now and that gas companies are reassuring customers of supplies may suggest that it will continue to be made available.

V. SITE ANALYSIS

Each system was reviewed in order to obtain an understanding of the current problems and opportunities. Prior to site visits, available background information was reviewed, including financial statements, engineering studies, and other pertinent statistical information. The site visits and subsequent analysis focused on current and future problems and opportunities in the market, technical, financial, and institutional areas.

This section of the report consists of individual subsections for Mountain Iron, Owatonna, and Worthington. Each site-specific subsection is further organized as follows:

- Section A: System data--key facts and statistics about the system.

- Section B: State of the system--a discussion of the condition of the physical system and market.

- Section C: Preliminary alternatives--a listing and discussion of various options and components of broader options which were identified as having potential for improving the system; the alternatives, or alternative components, are summarized in each site-specific subsection and are organized according to the following criteria:

  - Plant--improvements/changes related to the plant equipment, operation, or fuel;
  - Distribution system--improvements/changes related only to the piping network outside the plant;
  - Customer systems--improvements/changes in customer heating systems or the market; and
  - Other--changes related to pricing, ownership or other operating and institutional arrangements.

  The objective of the identification and subsequent overview analysis of these preliminary alternatives was to insure that all reasonable options were considered. "Brainstorming" discussions were held with the utility managers and the project team so that every conceivable option could be identified. An option was dismissed at that point if there was a unanimous decision that it merited no further analysis due to obvious infeasibility. A list of all reasonable potential alternatives was then prepared. Limited research and a "back-of-the-envelope" analysis was performed in order to identify a reduced list of potentially feasible or "most promising" alternatives.

Exhibit 2 for each city presents the estimated capital cost, related increased operating cost (if applicable), estimated impact on rates, and a brief discussion of the alternatives. Basic simplifying assumptions of the analysis were:

- The sales base would remain approximately equal to current annual sales;
- System investment would be financed by debt at 8% per annum with level annual debt service payments;
- Customer conversions to hot water district heating would be paid by or financed by the utility so that, in either case, the impact on heating cost per unit sold would be equivalent;
- Customer conversions to alternate heating systems would be financed by individual customers by borrowing; the investment would be repaid over ten years with level installment payments at an interest rate of 10% per annum. Implicit in this assumption is that customers financing conversions with cash are imputed the same "opportunity" cost of money and that non-owning customers receive the impact via rental rates.

Finally, Exhibit 3 illustrates the impact of combining various alternatives.

- Section D: Most promising option--additional detail and discussion of the most attractive option. Preliminary options were eliminated from further study at such time that it became apparent that they were infeasible or clearly less attractive than other remaining options. The reduced list of potentially feasible alternatives was subjected to additional scrutiny and analysis. A final, most promising alternative was identified for each city and is discussed in Section D. Initial cost estimates and fuel prices used in the analysis of preliminary alternatives were revised and updated.

- Section E: Institutional considerations--a summary and discussion of potential non-technical barriers to perpetuation and renovation of the systems.

MOUNTAIN IRON

A. System data

Distribution system:

Length of distribution system	7,028 ft.
Age of distribution system	45 yrs.
Condensate return?	No
Condition of system	Very Poor
Approximate annual metered sales (in thousand pounds of steam)	30,000
Efficiency of distribution system (metered sales/ steam to system)	approx. 26%

Plant:

Boilers

Unit	#1	#2
Size (in lbs./hour)	30,000	20,000
Year installed	1951	1964
Fuel	Eastern Coal	Gas, #2 Oil
Air quality compliance?	No	Yes

Steam source for district heating	Header steam through PRV
Fuel cost ($ per million Btu)	
Gas	$3.50
Wood pellets	$2.18
Coal	$2.35
Current fuel use	Wood Pellets and Coal

Market:

Number of customers	129
Principal customer class	Residential
Current steam rate ($ per thousand pounds)	$13.50
Alternate fuel cost to customers ($ per million Btu)	
Gas	$4.21
Oil (#2)	approx. $7.00
Electricity	approx. $10.55

B. State of the System

Mountain Iron's steam system is one of the smallest (in terms of steam sales) of the remaining municipal steam systems in the state. The plant facilities no longer cogenerate steam heat and electricity (in fact, the turbines have been removed) but boilers are in relatively good working condition. The large boiler (unit #1) burns Eastern coal and is actually too large to serve the current market efficiently (which would be even more true if the distribution system were replaced and the total load declined). Boiler #2 operates on gas or oil.

The distribution system is completely worn out--the condensate return line has corroded away, the steam line leaks extensively, and the insulation is completely deteriorated in places. The condition of the system can be best illustrated by example:

- On a recent 42°F day the boiler was supplying 14,000 lbs. of steam per hour and the system peak on coldest days is only 18-20,000 lbs. per hour. This is due to extremely high losses.

- The boiler must supply nearly five times as much steam to the system as is recorded in metered sales.

It is questionable whether any resources should be devoted to the steam system without a complete replacement of the distribution system.

Customers purchase steam from the utility almost exclusively for space heating and domestic hot water needs. Consequently, the annual load curve for the system is unfavorable and requires that all capital costs be recovered during the heating season. There are 129 customers currently supplied by the system, most of which are residential customers. Relative to annual sales, the distribution system is rather extensive.

There has been a noticeable decline in the customer base in Mountain Iron in recent years. In 1977, for example, the City had nearly 160 customers. A visual survey of the market area failed to reveal any large potential customers within a reasonable proximity of the system.

Approximately one-third of all revenue is derived from the school district, one-fifth from the City, with the remainder from the other 127 customers. All customers are metered but the meters are old and require continual maintenance.

C. Preliminary Alternatives

Various alternatives were identified for Mountain Iron and are summarized on Exhibit M-1. Exhibit M-2 presents estimated capital costs, operating costs (if applicable), estimated impact on rates, and a brief discussion of the alternatives. Exhibit M-3 presents a summary of combinations of alternative components and the total rate impact per thousand pounds of steam sold, by scenario.

Exhibit M-1

MOUNTAIN IRON

- Preliminary Alternatives -

Plant

1. Hot water conversion
2. Install pollution control equipment for Unit #1
   a. burn coal
   b. burn wood chips
   c. burn wood pellets
3. Convert Unit #1 to gas/oil
4. Burn cardboard refuse
5. Install "package" boiler (gas/oil)--use in off-peak season
6. Utilize alternate heat source
   a. U.S. Steel (hot water or steam)
   b. School (hot water or steam)
7. Shut down system

Distribution System

8. Hot water conversion
   a. Steel pipe
   b. Fiberglass pipe
   c. Using existing steam line for return
9. Install new steam distribution system with condensate return
10. Add condensate return to present system

Customer Systems

11. Hot water conversion
12. Repair/replace meters
13. Hook up new customers
    - New housing development
    - Others

Other

14. Raise rates
15. Co-op of user to own/rehabilitate/operate system

Exhibit M-2
MOUNTAIN IRON

- Evaluation of Preliminary Alternatives -

Plant:

1. Hot water conversion of plant

• Capital cost of heat exchanger	$250,000
• Revenue requirement	
- Amortization of investment, per year	$ 25,000
- Amortization per M. lb. sold	$ 0.83

• Must be considered in conjunction with other system components
  - Distribution system conversion
  - Building conversions
• May require additional building space
• Overall impact of total system conversion is addressed under "customer systems," Alternative #11

2a. Install baghouse and burn coal

• Baghouse cost	$900,000
• Revenue requirement per annum	
- Amortization of investment	90,000
- Incremental operating costs (power, manpower, replacement bags, etc.)	75,000
TOTAL	$165,000
- Required additional revenue per M. lb. sold assuming 30,000 M. lb. annual sales	$ 5.50

• The primary advantage of burning coal is the fuel cost advantage over gas or oil; however, pollution control equipment such as a baghouse would be required to bring the plant into compliance with EPA quidelines. Based upon current and projected fuel prices for coal, gas, and oil, the estimated fuel cost savings would be less than the additional charge for amortizing and operating the baghouse.

2b. Install mechancial collector and burn wood chips

• Requires new boiler, silos, and handling equipment	$1,060,000
• Requires mechanical collector	150,000

Exhibit M-2
MOUNTAIN IRON

• Revenue requirement per annum	
- Amortization of investment	$121,000
- Incremental operating cost	75,000
TOTAL	$196,000
- Revenue requirement per M. lb.	$ 6.53
• Estimated fuel cost per million Btu ($15/ton, 16 million Btu/ton)	$ 0.94

- Supply of chips uncertain in long run, as is price; chips are likely to be priced on a Btu basis in the future as demand for chips for fuel increases
- Estimated fuel savings relative to gas insufficient to justify investment

2c. Install mechanical collector and burn wood pellets

• Capital cost for mechanical collector	$150,000
• Revenue requirement	
- Amortization of investment, per year	$ 15,000
- Amortization per M. lb.	$ 0.50
• Fuel cost per million Btu	$ 2.18

- Long term reliability of supply unverified at this time; there are currently only a few suppliers of wood pellets in the state, and the utility may be vulnerable to potential supply problems
- It has not been verified that a mechanical collector will meet EPA emissions requirements

3. Convert #1 boiler to gas/oil

• Capital cost, approx.	$150,000
• Revenue requirement	
- Amortization of investment, per year	$ 15,000
- Amortization per M. lb. sold	$ 0.50

- Only serves to add back-up to existing gas-fired capacity
- Eliminates potential for cost savings by switching to cheaper fuel (gas is 50% more expensive/million Btu than coal)
- Less efficient than a smaller "package" boiler used for off-peak needs

4. Burn cardboard refuse

- Capital cost
  - Shredder — $ 50,000
  - Burning system — 350,000
  - TOTAL — $400,000
- Revenue requirement, per annum
  - Amortization of investment — $ 40,000
  - Amortization per M. lb. sold — $ 1.33
- Fuel cost; assuming no cost of obtaining cardboard — $ 0
- Cardboard may need to be mixed with coal for proper burning
- Availability of needed quantity of cardboard and cost of delivery has not been verified

5. Install "package" gas/oil boiler for off-peak usage

- Capital cost at $20/# for a 10,000 #/hr. boiler — $200,000
- Revenue requirment
  - Amortization of investment, per year — $ 20,000
  - Amortization per M. lb. — $ 0.67
- Assumes no major building construction needed
- Could reduce fuel cost by:
  - Operating during low-demand months
  - Increased efficiency of new boiler (assume 80% efficient)

6a. Utilize alternate heat source -- U.S. Steel

- Capital cost for hot water supply line — $1,090,000
- Revenue requirement, per annum
  - Amortization of investment — $109,000
  - Amortization per M. lb. — $ 3.63
- May be more efficient than using existing boiler with converter
- Assumes U.S. Steel will sell hot water
- U.S. Steel may have reject heat available

6b. Utilize alternate heat source -- School

- Capital cost
  - Boiler ($20/# x 20,000 lb/hr) — $ 400,000
  - Misc. dist. system changes — 50,000
  - TOTAL — $450,000

Exhibit M-2
MOUNTAIN IRON

- Revenue requirement

- Amortization of investment, per annum	$ 45,000
- Amortization per M. lb.	$ 1.50

7. Shut down system

- Non-avoidable costs, per annum

- Salaries and benefits (50%)	$ 35,000
- Depreciation	4,000
TOTAL	$ 39,000

- New heating systems would be required for each customer

- 123 x average of $3,000/system	$369,000
- 6 commercial, school, and city buildings	500,000
TOTAL	$869,000

- Operating cost for new system, customer systems

- Amortization of investment in new systems, per year	$140,000
- Gas cost for 37,500 mcf (30,000 million Btu needed at 80% efficiency) at $4.21 MCF	158,000
- Non-avoidable utility cost from shut-down	39,000
- Elimination of operating losses	(40,000)
TOTAL ANNUAL COST	$297,000
- Annual cost per million Btu (exclusive of utility losses and non-avoidable costs)	$ 9.93

- Cost of providing 30,000 M. lb. steam with $3.55 gas

- Fuel (150,000 mcf)	$532,500
- Other	80,000
TOTAL	$612,500

- Net annual savings of shut down $315,500

Distribution system:

8a. Hot water conversion - steel pipe

- Capital cost $820,000
- Revenue requirement

- Amortization, per year	$ 82,000
- Amortization per million Btu	$ 2.73

- Assume 90% efficiency of dist. system

Exhibit M-2
MOUNTAIN IRON

8b. Hot water conversion - fiberglass

• Capital cost	$300,000
• Revenue requirement, per annum	
- Amortization of investment	$ 36,000
- Amortization per million BTU	$ 1.20
• Delivery temperature limited to 230°F	
• Operating systems using fiberglass pipe have not been identified	
• Assume 90% efficiency for distribution system	

9. New steam distribution system

• Capital costs	$600,000
• Revenue requirements	
- Amortization of investment, per annum	$ 60,000
- Amortization per M. lb.	$ 2.00
• Assume efficiency of 85%	

10. Add condensate return to present system

• Capital cost @ $20/foot	$150,000
• Revenue requirement	
- Amortization of investment, per annum	$ 15,000
- Amortization per m. lb.	$ 0.50
• Increased efficiency minor (1-2%)	
- 30 mil. lbs. x 75° temperature savings	
.. At $2.35/million Btu (coal)	$ 5,300
.. At $3.55/million Btu (gas)	$ 8,000
• Savings per M. lb.	
- Coal	($ 0.18)
- Gas	($ 0.27)
• Net impact per M. lb.	
- Coal ($0.50 - $0.18)	$ 0.32
- Gas ($0.50 - $0.27)	$ 0.23

10a. Hot water conversion using existing steam line for return

- Not practical or advisable
  - Low efficiency due to quality of insulation
  - System already in poor condition
  - Would only save on cost of pipe, not installation
  - Would likely involve higher annual maintenance costs

Exhibit M-2
MOUNTAIN IRON

Customer systems:

11. Convert buildings to hot water

• Capital cost				
- Meter and service	$2,650			
- Customer conversion	2,880			
	$5,530	x	123	$ 680,000
- School and other large buildings (6 @ $20,000 each)				120,000
				$ 800,000
• Revenue requirements				
- Amortization of investment, per annum				$ 80,000
- Amortization/million Btu				$ 2.67

- Overall efficiency of hot water district heating somewhat better than steam but increased efficiency insufficient to justify large increase in required capital expenditures for plant conversions, distribution system, and building conversions

12. Replace meters

• Capital/installation cost 129 x $300	$ 39,000
• Revenue requirement	
- Amortization, per year	$ 3,900
- Amortization per M. lb.	$ 0.13

- Will improve billing accuracy but will not improve efficiency

Other:

13. New customers

• Capital cost for 250 new residential customers in housing development	
- Customer conversion at $5,500 each	$1,375,000
- New distribution system	1,000,000
TOTAL	$2,375,000
• Estimated increased sales (in M. lbs.)	25,000
• Revenue requirement	
- Amortization of investment, per year	$237,500
- Amortization per M. lb. sold	$ 9.50

Exhibit M-2
MOUNTAIN IRON

- Many of "potential" customers have electric heat or other new heating systems and likely would not convert
- This alternative clearly is not economically viable under the circumstances
- No other possible customers with potentially significant loads were identified within a reasonable distance from the plant

14. Rate Increase

- Average rate was $8.69/M. lb. in 1979
- Customer rates currently $760 minimum ($10/M. lb. for the first eleven M. lbs. and excess at $7) plus fuel adjustment of about $3.50/M. lb. for gas; average rate currently about $14.00 - $14.50 when firing with gas
- Rates probably at upper limit of allowable range
- Although gas is about 50% Canadian, rate is still considerably lower than steam rate on Btu basis due to inefficiencies of steam distribution system
- Intercity Gas Co. reports numerous requests for gas service from customers currently served by steam

15. Co-op of users

- City could deed business over to users at no cost
- Users could jointly manage, make decisions to rebuild/rehabilitate
- Co-op would relieve city but would not help users without extensive renovation to system
- City and school district currently account for approximately 50% of sales

Exhibit M-3

MOUNTAIN IRON

- Alternative Scenarios -

Note: The following cost estimates are very preliminary; caution is recommended in comparing scenarios

	Cost per Million Btu
• Install baghouse	$ 5.50
New steam system	2.00
Fuel--coal [$2.35/(.80* x .85**)]	3.46
Other operating costs	2.65
TOTAL	$ 13.61
• Install mechanical collector	$ 0.50
New steam system	2.00
Fuel--wood pellet [$2.18/(.80 x .85)]	3.09
Other operating costs	2.65
TOTAL	$ 8.24
• Install "package" boiler	$ 0.67
New steam system	2.00
Fuel--gas*** [$3.55/(.85 x .85)]	4.84
Other operating costs	2.65
TOTAL	$ 10.16
• Hot water conversion	
- Plant	$ 0.83
- Distribution system (fiberglass)	1.20
- Customer	2.67
Fuel--gas*** [$3.50/(.80 x .90)]	4.86
Other operating costs	2.65
TOTAL	$ 12.21
• Convert unit #1 to gas/oil	$ 0.50
New steam system	2.00
Fuel--gas*** [$3.50/(.80 x .85)]	5.15
Other operating costs	2.65
TOTAL	$ 10.30
• Shut down system	
- New individual heating systems	$ 4.67
- Fuel (gas)	5.26
TOTAL	$ 9.93

* Assumed plant efficiency

** Assumed distribution system efficiency

*** There is no assurance that gas will be available for district heating usage in the future; if #2 oil is burned, fuel cost per million Btu will increase by 75-100% based upon current price differentials.

D. Most Promising Alternative

The most promising development alternative, from the standpoint of minimizing rate increases while simultaneously attempting to minimize capital requirements, is the following:

- Replace the existing distribution system without condensate return;
- Install a new 15,000 lb./hour, 15 psi, gas/oil "package" boiler for low load requirements; and
- Install a 20,000 gallon oil tank for fuel backup.

Tentative capital costs and fuel price estimates utilized in the analysis of preliminary alternatives were challenged and updated. The revised estimated cost for renovating and operating this system are:

	Capital Cost	Cost per 1000 lbs
Distribution system		
Material	$300,000	$ 1.00
Labor	180,000	0.60
Customer service connections	20,000	0.07
Plant		
Boiler	56,000	0.19
Fuel tank	12,000	0.04
Installation	100,000	0.33
Fuel (gas @ $3.50/mcf; 85% plant efficiency and 85% distribution system efficiency)		4.84
Engineering and contingencies	100,000	0.33
Other operating costs		2.65
TOTAL	$768,000	$ 10.05

If a condensate return and new meters are also installed, the following estimated costs result:

	Capital Cost	Cost per 1000 lbs
Base system	$768,000	$ 10.05
Condensate return		
Material	150,000	0.50
Labor	90,000	0.30
Savings due to condensate return		(0.27)
Meters	77,000	0.26
TOTAL	$1,085,000	$ 10.84

The above estimates are not based upon design but, rather, on vendor estimates and extrapolation from other recent experience. Consequently, the final estimate could vary by as much as 20%. The estimate for the distribution system is based upon an assumption that part of the old system would not be replaced due to alternate routing, etc.; the estimate for new meters assumes that the utility would provide installation at no additional cost.

Although the initial analysis indicated that installation of a mechanical collector and wood pellet fuel would result in considerable savings, this alternative was not pursued for the detail analysis for the following reasons:

- A test was performed on Mountain Iron when it was burning pellets and the particulate emissions far exceeded emissions from coal.

- It has not been adequately demonstrated that a mechanical collector can meet EPA emmissions standards; representatives of the Minnesota Pollution Control Agency indicate that they are not aware of any such facilities in the state which would meet EPA guidelines.

- There is no assurance that pellets will remain competitively priced with coal; although they are nominally less expensive at the current time, there can be no assurance that they will remain so if the demand for wood wastes for other uses continues to increase.

- At present there are few wood pellet producers within a reasonable distance of Mountain Iron and the utility may have inadequate backup supply opportunities.

These considerations do not completely rule out conversion to wood pellets, however. Since the first stack test at Mountain Iron, operating procedures have been revised and emissions have reportedly been greatly reduced. A new stack test should be taken, perhaps for a derated load, to determine if emissions requirements can be met without the addition of a mechanical collector. The uncertainties associated with long-term supply and price could also be investigated in greater detail. The risk of material consequences resulting from disruptions in supply or major price escalation could be evaluated in light of the cost of replacing the steam distribution system.

E. Institutional Considerations.

The following issues should also be considered in evaluating whether to perpetuate district heating in Mountain Iron:

- Most of the customers of the steam system are residential customers, many of which are elderly or living on fixed incomes. The utility superintendent estimates that 60% of the residential customers rely on fixed incomes and that many will have difficulty in financing or paying for installation of a new heating system. This factor tends to argue in favor of perpetuating the steam system.

- Approximately 50% of the gas supplied to Mountain Iron is of Canadian origin; a termination of district heating operations will place a greater dependence on this imported fuel at a time when the nation is encouraging domestic fuel consumption. This consideration also argues in favor of continuing steam service.

- Widespread conversion to electric heating may sharply increase electric charges for Mountain Iron due to the ratcheted demand charge on peak loads of the utility. Increased electric demand could also necessitate additional investment in the City's electric system. Analysis of this potential problem should be performed if the City decides to terminate steam service. Additional discussion of this concern is included in Appendix B.

- A new district heating system would be a substantial investment and the risk of continued market deterioration should be carefully considered. Many of the residences on the steam system are older homes and their useful lives may be less than that of a new distribution system. On the other hand, the City and school district are major customers and will need to install new heating systems at a cost to tax payers.

- If a decision is made to renovate the system, assurance should be obtained that further mine encroachment is not imminent. Should a renovated district heating system be affected, the mine would likely have to bear the cost.

- The Mountain Iron utility is currently under stipulation by the MPCA to bring particulate emmissions into compliance with regulations. A decision to continue operations, to renovate, or to shut down must be made relatively soon and must be coordinated with the MPCA. New stack tests while burning pellets might conceivably indicate that Mountain Iron is, in fact, in compliance.

- An agreement between the City of Mountain Iron and Intercity Gas Co. prohibits the gas company from supplying gas to any steam customer. This agreement will have to be voided if the City decides to terminate steam operations. If the steam system is perpetuated, this agreement should be continued.

OWATONNA

A. System Data

Distribution system:

Length of distribution	7292 ft.
Age of distribution system	50-55 yrs.
Condensate return?	No
Condition of system	Poor
Approximate annual metered sales (in thousand pounds of steam)	25,000
Efficiency of distribution system (metered sales ÷ steam to system)	approx. 75%

Plant:

Boilers

Unit	#4	#5	#6
Size (in lbs./hr)	80,000	100,000	200,000
Year installed	1941	1957	1969
Fuel	#6 Oil,Gas	#6 Oil,Gas	#6 Oil,Gas
Air quality compliance?	Yes	Yes	Yes

Steam source for district heating	Turbine Extraction
Fuel cost (per million Btu)	
Gas	$1.96
Oil (#6)	2.55
Current fuel use	Gas

Market:

Number of customers	120
Principal customer class	Commercial
Current steam rate (per thousand pounds)	$4.25
Alternative fuel cost to customers ($ per million Btu)	
Gas	$2.33
Oil (#2)	approx. $7.00
Electricity	approx. $14.65

B. State of the System

Of the three systems studied, Owatonna's is the smallest in terms of annual pounds of steam sold, but it is also probably in the best condition. Three gas and oil-fired boilers and turbine-generator units, all in good working condition, are capable of cogenerating electricity and steam for the district heating system.

Although the distribution system is perhaps in better condition than either Mountain Iron's or Worthington's, it is nevertheless in need of replacement. The insulation has completely deteriorated in places and maintenance personnel indicate that they are able to see long distances along the pipe due to absence of any insulation. Joints and expansion devices are sufficiently corroded that maintenance personnel are apprehensive of accidentally jarring or breaking pipes while working in manholes and risking serious injury.

Approximately 60% of the original distribution system was abandoned five years ago due to the poor condition and low load. Two residential lines were abandoned and system losses were reduced from 50% to the current 25%.

Steam is purchased by about 120 customers, approximately two-thirds of which are commercial, and used primarily for space heating and domestic hot water heating. As a result, the annual load factor is unfavorable. Two of the largest customers use steam only in low load periods--spring, summer, and fall--and rely on their own systems during the peak heating season.

Two additional considerations contribute to the system's problems. Some sections of the distribution system extend through customer basements and it is not unusual for these pipes to be uninsulated, thus providing some free heat to customers. Another problem relates to the unusual fact that meters are owned by customers rather than by the utility. Although not verified, it is unlikely that such an arrangement would result in accurate metering of sales due to the fact that maintenance and control would be less rigorous (and unadjusted steam meters tend to undermeter).

Like Mountain Iron and Worthington, Owatonna has experienced a gradual decline in the steam sales base over recent years. During the past five years only five customers have withdrawn from the system but they accounted for about 10% of current sales.

C. Preliminary Alternatives

Various development options were identified for Owatonna and are summarized on Exhibit O-1. Exhibit O-2 presents estimated capital costs, operating costs (as applicable), estimated impact on rates, and a brief discussion of the alternatives. Exhibit O-3 presents a summary of combinations of alternative components and the total rate impact per thousand pounds of steam sold, by scenario.

Exhibit O-1

OWATONNA

- Preliminary Alternatives -

Plant

1. Hot water conversion
2. Utilize alternative fuels
   a. Coal (#5 boiler)
   b. Refuse
   c. Crankcase oil
3. Slurry coal to plant with sewer effluent
4. Install a package boiler (gas/oil)
5. Utilize extraction from #6 turbine
6. Construct a new 45 MW electric plant
7. Supply system from industrial cogenerator
8. Shut down system

Distribution System

9. Hot water conversion
   a. Steel pipe
   b. Fiberglass pipe
10. Rehabilitate/rebuild existing distribution system with condensate return
11. Add condensate return to present system
12. Insert plastic pipe to existing mains and use existing mains for condensate return

Customer Systems

13. Hot water conversion

Other

14. Raise rates
15. Add customers e.g.:
    a. Midwest Foods
    b. OTC

Exhibit O-2
OWATONNA

- Evaluation of Preliminary Alternatives -

Plant:

1. Hot water conversion of plant

• Capital cost for heat exchanger	$ 250,000
• Revenue requirement	
- Amortization, per year	$ 25,000
- Amortization per M. lb. sold (assuming 25,000 M. lb.)	$ 1.00

- Must be considered in conjunction with other system components
  - Distribution system conversion
  - Building conversion
- Overall impact of total system conversion is addressed under "Customer Systems," Alt. #9

2a. Alternative fuels - coal for unit #5

- Infeasible -- inadequate plant space for coal supply systems and ash removal systems

2b. Alternative fuels - refuse

• Capital cost	
- Plant (75 tons/day capacity)	$2,010,000
- Hook-up to system	50,000
TOTAL	$2,060,000
• Revenue requirement	
- Amortization, per year	$ 206,000
- Labor, ash removal, electricity O&M, etc., net of tipping fee @ $6/ton	$ 145,000
TOTAL, per year	$ 351,000
• Revenue requirement per M. lb. sold	$ 14.04

- Refuse would have to be collected from Owatonna, Waseca, and surrounding area to supply enough energy input
- Infeasible as economic source of steam for district heating

Exhibit O-2
OWATONNA

2c. Alternative fuels - crankcase (drain) oil

• Capital cost	unknown
• Cost per gallon	$.25 - .35
• Fuel cost per million Btu (145,000 Btu/ gallon)	
- Assuming $0.25 oil	$1.72
- Assuming $0.30 oil	$2.07
- Assuming $0.35 oil	$2.41

- Does not offer any cost advantage over gas if priced over $0.28 per gallon
- Presents significant risks of damage to boiler and stack due to presence of contaminants
- Suppliers have not had any experience with burning the fuel in boilers as large as Owatonna's
- Drain oil is classified by MPCA as a "hazardous waste" and is not currently authorized for fuel use
- Likelihood of significant air emission problems exists
- Does not appear to be a viable alternative

3. Slurry coal to power plant

- Infeasible to burn coal (see Alternative 2a)

4. Install "Package" boiler

• Capital cost	$200,000
• Revenue requirement	
- Amortization, per year	$ 20,000
- Amortization per M. lb. sold	$ 0.80

- May be more efficient than existing boilers; however, current allocation of cost from electric utility to steam utility may not even recover cost of fuel, so this alternative appears to have little merit since it will increase fuel cost to steam customers

5. Extract from #6 turbine

• Turbine and piping modifications	none

- Could eliminate operation of less-efficient boiler (#4)

Exhibit O-2

OWATONNA

• Impact on allocation from electric utility to steam utility could be minor; if allocation was reduced by 5%, savings for the steam utility would be approximately, per year	($ 3,500)
• Reduction in allocation, per M. lb., if allocation were reduced by 5%	($ 0.12)
• Allocation unlikely to be reduced due to fact that current charge from electric utility to steam utility fails to recover cost of steam on a Btu basis	
• This alternative is actually being tried at the current time with favorable results	

6. New 45 MW electric plant

• Capital cost @ $2200/kw	$ 99.0 million
• Allocation to steam utility	
- If 10% (hypothetical)	$ 9.9 million
- Revenue requirement of 10% allocation, per year	$990,000
- Revenue requirement per M. lb. sold	$ 39.60
• Alternative clearly does not favor district heating	

7. Industrial cogeneration

• Cost of thermal energy would likely be determined by cost of alternative fuels; if equal to current gas cost, approximate cost per M. lb.	2.40
• Cost per M. lb. @ 75% efficiency	$ 3.20
• Capital cost to connect (assuming cogenerator is close to system)	$100,000
• Revenue requirement	
- Amortization, per annum	$ 10,000
- Amortization, per M. lb. sold	$ 0.40
• Other operating cost per M. lb	$ 0.75
• Total cost, per M. lb.	
- Steam from cogeneration	$ 3.20
- Amortization of hook-up cost	0.40
- Other op. costs	0.75
TOTAL	$ 4.35
• Current steam cost per M. lb.	$ 4.25

Exhibit O-2
OWATONNA

- Assuming $4.25 per M. lb. as price of steam to customer, maximum cost that could be paid for steam — $ 1.95
- Appears to be infeasible as an alternative under assumed conditions

8. Shut down system

- Non-avoidable costs, per annum (based on 1978 data)

- Production (50%)	$ 35,000
- Accounting and A&G @ 50%	2,000
TOTAL	$ 37,000

- New customer systems would be required
  - 120 x $3,000/system — $360,000
- Operating cost for new systems

- Amortization of new systems (at 10% interest over 10 years)	$ 58,000
- Gas cost for 31,250 MCF (25,000 mil. BTU needed @ 80% efficiency) @ $2.50	78,000
- Non-avoidable costs of shut down	37,000
TOTAL	$173,000

  - Annual cost per million Btu (excluding non-avoidable utility costs) — $ 5.44
- "Cost" of providing steam from utility dependent on allocation used, but likely exceeds cost of shut down

Distribution system:

9a. Hot water distribution system - steel pipe

- Capital cost — $850,000
- Revenue requirement
  - Amortization, per year — $ 85,000
  - Amortization per million Btu — $ 3.40
- Assume 90% efficiency

9b. Hot water distribution system - fiberglass

- Capital cost — $375,000
- Revenue requirement
  - Amortization, per year — $ 37,500
  - Amortization per million Btu — $ 1.50
- Delivery temperature limited to 230°F
- Operating systems using fiberglass pipe have not been identified
- Assume efficiency of 90%

Exhibit O-2
OWATONNA

10. New steam distribution system

• Capital cost	$625,000
• Revenue requirement	
- Amortization, per year	62,500
- Amortization, per M. lb.	2.50
• Assume efficiency of 85%	

11. Add condensate return

• Capital cost ($20 x 7300 ft.)	$146,000
• Revenue requirement	
- Amortization, per year	14,600
- Amortization, per M. lb.	0.58
• Potential savings due to increased efficiency (of 1-2%)	
- 25 million lbs. x 75° temperature savings @ $1.91/million Btu (gas)	$ 3,600
- Savings per M. lb. sold	(0.14)
• Net impact ($.58-.14)	0.44

12. Insert plastic pipe in existing mains

- Infeasible for steam
- Likely infeasible for hot water system due to
  - Cooling effect of condensate on hot water supply
  - Insufficient capacity in lines
  - Difficulty in making customer connections

Customer Systems:

13. Hot water conversion for customers

• Capital cost	
- 114 customers x $5500	$625,000
- 6 customers x $20,000	120,000
TOTAL	$745,000
• Revenue requirement	
- Amortization, per year	$ 74,500
- Amortization, per M. lb.	2.98

- Overall efficiency of hot water district heating somewhat better than steam but increased efficiency insufficient to justify large increase in required capital expenditures for plant conversions, distribution system, and building conversions

Exhibit O-2
OWATONNA

Other:

14. Rate Increase

• Rate currently, per M. lb.	$ 4.25
• Avg. gas rate per MCF	$ 2.53
• Avg. rate @ 80% efficiency	$ 3.16
• Avg. cost of new individual systems	$ 4,000
- Amortization over 10 years, per year	$ 640
- Amortization per million Btu	$ 3.46
• Upper limit to steam charge per M. lb. ($3.46 + $3.16)	$ 6.62
• Additional revenue which could be generated by $2.37 ($6.62 - 4.25) rate increase (assuming no lost customers)	$ 59,250
• Potential capital expenditure supported by increased revenue	$600,000
• Potential capital expenditure nearly sufficient for a replacement of steam distribution system	
• Customer base has been declining and the decline would likely accelerate with a 56% rate increase	

15. Add customers

• May be able to flatten annual load curve (Incremental cost of serving additional customers during low-load periods is low)	
• May be able to spread fixed costs	
• Annual revenue requirement per foot of line extension to amortize cost of line to servce new customers (assuming $100/ft)	$ 10
- Revenue requirement assuming 1,000 feet new line ($100,000 capital cost)	$ 10,000
- Revenue requirement per M. lb. sold to cover fuel cost (costed on Btu basis, using gas @ $1.90, and assuming 75% efficiency)	$ 2.61
- Required sales, in M. lbs., to cover cost of fuel and line (ignoring all other costs and assuming a price of $4.25 per M. lb.)	$ 6100
- Percent of current annual sales	25%
• Probably unrealistic to seek new customers in view of trend in customer base and fact that current customers have already been notified of possible shutdown	

Exhibit O-3
OWATONNA

- Alternative Scenarios -

Note: The following estimates are very preliminary; caution is recommended in comparing scenarios.

	Cost per Million Btu
• Extraction of steam from #6 turbine	$0.00
• New steam distribution system	$2.50
Current charge per M. lb. (to cover fuel**, maintenance, and other charges)*	4.25
TOTAL	$6.75
• Hot water conversion	
- Plant	$1.00
- Distribution system (fiberglass)	1.50
- Customer	2.98
Current charge per M. lb. (to cover fuel**, maintenance, and other charges)*	4.25
TOTAL	$9.73
• Shut down system	
- New individual heating systems	$2.32
- Fuel (gas)	3.12
	$5.44

*Assuming that this charge would not be reduced due to the fact that the utility is not currently recovering the cost of fuel on a Btu basis and overall efficiency would not be greatly improved.

**Assumes gas; there is no assurance that gas will be available for electric utility usage in the future; if oil is burned, fuel cost per million Btu would increase by approximately 30% based upon current price differentials.

D. Most Promising Alternative

From the standpoint of minimizing capital costs and the impact on steam rates, the development alternative which appears most attractive is the following:

- Extract steam from the #6 turbine, rather than the #4 unit, in order to eliminate the efficiencies of electrical production associated with #4, and
- Construct a new steam distribution system without condensate return.

Tentative capital costs and fuel price estimates utilized in the analysis of preliminary alternatives were challenged and updated. The revised estimated costs for renovating and operating this system, in phases, are:

	Capital Cost	Cost per 1000 lbs
1980 - 2000 feet of line on Cedar Street		
Material	$100,000	$0.40
Labor	70,000	0.28
1981 - 1500 feet of line, principally on Main St.		
Material	75,000	0.30
Labor	52,500	0.21
1982 - 500 feet of line on Oak Street		
Material	25,000	0.10
Labor	17,500	0.07
1983 - 1100 feet of line on Broadway		
Material	55,000	0.22
Labor	38,500	0.15
1984 - 1100 feet of line on Pearl Street plus 1300 feet of line on miscellaneous streets		
Material	120,000	0.48
Labor	84,000	0.34
Engineering and contingencies	96,000	0.19
Current charge		4.25
TOTAL	$ 733,500	$6.99

If a condensate return and new meters are also installed, the following estimated costs result:

	Capital Cost	Cost per 1000 lbs
Base system	$733,500	$6.99
Condensate return		
Material	182,500	0.73
Labor	91,000	0.37
Engineering and contingencies	41,000	0.08
Savings due to condensate return		(0.14)
Meters	72,000	0.29
TOTAL	$1,120,000	$8.32

It was assumed in making the above estimates, that the distribution system would be installed coincident with renovation of streets in the downtown area. Escalation in cost was assumed to be approximately offset by interest earnings on funds borrowed for the construction program and invested until disbursement to contractors. Estimates were not based upon design but, rather, on vendor estimates and extrapolation from other recent experience. Consequently, final estimates could vary by as much as 20%. The estimate for new meters assumes that the utility would provide installation at no additional cost.

E. Instititional Considerations

The following issues should also be considered in evaluating whether to perpetuate district heating in Owatonna:

- Although the distribution system is not in good physical condition, it is possible to perpetuate the service for several more years until such time that the losses become clearly intolerable. If, at the end of such a period, economic or fuel supply circumstances were changed such that there was renewed interest in renovating the system, there would likely be intense resistence and a heavy cost penalty to tearing up streets which would have been recently renovated. Consequently, if a decision to renovate (and, therefore, to operate the system over the long term) is to be made at any time, it likely has to be immediately.

- A fundamental constraint to renovating and perpetuating the Owatonna system is the cost of gas. Gas can currently be purchased from Owatonna Public Utilities for as low as $2.33 which equates to approximately $3.10 per million Btu for a conventional furnace or as low as $2.60 for a new boiler operating on the pulse combustion principle. Amortization of the estimated average cost of a new building system is from $1.40 to $1.60 per million Btu, implying that the total alternative cost to customers is in the $4.00 to $5.00 range. This would seem to indicate that the utility really has little price flexibility in the current environment and little additional revenue-generating capacity for supporting additional debt.

- In the fall of 1979, the Utility commissioned a study of economic power sources which suggested that, because of a cost advantage in purchasing power over producing power in Owatonna, the Utility consider the purchase of "Economy Energy" from Interstate Power Co. when it is available and when the risk of loss of service due to failure of the interconnection is low. Adoption of this policy would entail the occassional shutdown of the #6 generating unit, thus eliminating the source of steam for the district heating system. Should the steam system be perpetuated and trends in electric power production costs continue, the City will experience an increase in the electric generating cost penalty due to continued electric production for the sole purpose of supplying steam to the steam department customers.

- The steam customer base is declining in Owatonna and there appears to be little opportunity to add load at the current time. The fact that the Utility has recently recommended to customers that they seek other sources for their heating needs will likely exacerbate this problem. It may be unrealistic to assume that the trend can be halted, much less reversed, without a significant and, perhaps, costly effort.

- If the steam district heating is perpetuated, consideration should be given to eliminating some lines which have low customer density and likely do not generate sufficient revenues to cover costs.

- Owatonna is currently a member of the Southern Minnesota Municipal Power Agency (SMMPA) which is tentatively planning to construct a medium-sized coal-fired power plant to serve the member cities. If SMMPA does construct a new plant and Owatonna becomes a participant for total electric requirements, the municipal plant would be placed in standby and the district heating source would be eliminated. If the utility continued to generate for the purpose of supplying steam to district heating customers, an economic penalty would likely result.

WORTHINGTON

A. System Data

Distribution system:

Length of distribution system	12,000 ft.
Age of distribution system	20-75 yrs.
Condensate return?	Yes
Condition of system	Poor
Approximate annual metered sales (in thousand pounds of steam)	50,000
Efficiency of distribution system (metered sales/ steam to system)	69%

Plant:

Boilers		
Unit	#2	#3
Size (in lbs./hour)	75,000	115,000
Year installed	1946	1950
Fuel	Gas, #6 Oil	Gas, #6 Oil, Western Coal
Air quality compliance	Yes	No (on coal)
Steam source for district heating	#3 Turbine Extraction	
Fuel cost ($ per million Btu)		
Gas		$2.04
Oil (#6)		$2.94
Coal		$1.76
Current fuel use		Gas/Coal

Market:

Number of customers	142
Principal customer class	Commercial
Current steam rate ($ per thousand pounds)	$4.91
Alternate fuel cost to customers ($ per million Btu)	
Gas	$2.80
Oil (#2)	approx. $7.00
Electricity	approx. $11.74

B. State of the System

The Worthington district heating system is the largest of the three systems studied in terms of annual pounds of steam sold, length of distribution system, and number of customers. Relative to other municipal steam systems in Minnesota it is still rather small. The boilers and turbine-generator units are in good condition but are old and relatively inefficient by today's standards.

With parts of the distribution system being 50-75 years old, it is understandable that the pipes are in need of replacement. Corrosion is extensive and insulation has deteriorated badly. Plant records indicate distribution system efficiency of approximately 70% but these measures are considered unreliable due to problems with the plant steam flow meter. Evidence of inefficiency included steaming on virtually dry pavement in one section of street on a wet spring day and considerable heat loss from pipes extending through customer basements.

The steam system currently has 142 customers, a decline of 32 from the number reported in 1977. The customer base is basically downtown commercial and institutional/governmental customers. The potential for adding additional load is limited due to the fact that most large potential commercial/industrial customers or other possible customers are located at considerable distances from the system. Relative to annual sales, the distribution system is rather extensive.

C. Preliminary Alternatives

Various development options were identified for Worthington and are summarized on Exhibit W-1. Exhibit W-2 presents estimated capital costs, operating costs (as applicable), estimated impact on rates, and a brief discussion of the alternatives. Exhibit W-3 presents a summary of combinations of alternative components and the total rate impact per thousand pounds of steam sold, by scenario.

Exhibit W-1
<u>WORTHINGTON</u>

- Preliminary Alternatives -

Plant	Distribution System	Customer Systems	Other
1. Hot water conversion	10. Hot water conversion a. Steel pipe b. Fiberglass pipe	12. Hot water conversion	13. Rate increase
2. Install windmills and use electrode boilers to generate steam	11. Rehabilitate/replace steam system		14. Add customers - S.W. Minn. Comm. Col. - New school - Campbell's Soup - Northland Mall - Holiday Inn
3. Install baghouse and burn coal			
4. Add desuperheater			
5. Burn flax straw			15. Re-negotiate MBMPA contrac
6. Convert unit #2 to coal			16. Sell electric production
7. Supply system from SWMCC			
8. Install "package" boiler			
9. Shut down system			

Exhibit W-2
WORTHINGTON

- Evaluation of Preliminary Alternatives -

Plant:

1. Hot water conversion of plant

- Capital cost of heat exchanger $250,000
- Revenue requirement
  - Amortization of investment, per year $ 25,000
  - Amortization per M. lb. sold (assuming annual sales of 50,000 M. lbs) $ 0.50
- Must be considered in conjunction with other system components
  - Distribution system conversion
  - Building conversions
- Overall impact of total system conversion addressed under "customer systems", Alternative 10

2. Windmills and electrode boilers

- Capital cost for windmills (at $1,000 per KW x 5,800 KW) $5,800,000
- Does not include capital cost for site, switching gear, or transmission facilities
- Infeasible on capital cost alone
- Would still require backup system for times when wind was insufficient or too strong

3. Install baghouse and burn coal

- Capital cost $2,000,000
- Revenue requirement, per annum

- Amortization of investment	$200,000
- Incremental operating costs	$100,000
TOTAL	$300,000

  - Required additional revenue per M. lb. sold assuming 50,000 M. lb. annual sales $ 6.00
- The primary advantage of burning coal is the fuel cost advantage over gas or oil; however, pollution control equipment such as a baghouse would be required to bring the plant into compliance with EPA guidelines. Based upon current and projected fuel prices, for coal, gas, and oil, the estimated fuel cost savings would be less than additional charge for amortizing and operating the baghouse

Exhibit W-2

WORTHINGTON

4. Install desuperheater and use with #2 boiler

• Capital cost	$ 75,000
• Revenue requirement	
- Amortization of investment, per annum	$ 7,500
- Amortization per M. lb.	$ 0.15
• Purpose of adding desuperheater is to eliminate the necessity for reducing pressure of steam by operating turbines	
• Annual savings due to termination of electrical generation	$500,000
• Desuperheater would not eliminate inherent inefficiencies of operating a boiler which is grossly oversized for the district heating load	

5. Burn flax straw

• Capital cost (grinder, handling equipment, blower, burner, storage)	$500,000
• Revenue requirement	
- Amortization of investment, per annum	$ 50,000
- Amortization per M. lb.	$ 1.00
• Fuel cost per million Btu ($25/ton, delivered; 8,200 Btu/lb.)	$ 1.52
• Flax pellets could not be burned in current pulverized coal boiler, so pulverized flax straw was considered; due to nature of the fiber, it does not appear feasible	
• Only one known source of supply, and that source is reportedly experiencing financial difficulties; a single source of fuel supply may present unacceptable risk to the utility	

6. Convert boiler #2 to coal

- Does not appear to be technically feasible
- Would still require emissions controls
- Would provide back-up for #3 boiler
- Does not appear to be advantageous

Exhibit W-2
WORTHINGTON

7. Supply steam from Southwest Minnesota Community College

- Distance from the distribution system would require a larger capital expenditure for hookup than do some of the other alternatives.

8. Install "package" boiler

• Capital cost (10,000 #)	$200,000
• Revenue requirement	
- Amortization, per annum	$ 20,000
- Amortization/M. lb.	$ 0.40
• Would require burning gas or oil	
• Savings due to shutting down turbine in summer and avoidance of operating larger boilers inefficiently during low load periods	
• Would eliminate need to produce electricity and resultant cost penalty	$500,000
• Efficiency of 85% may be obtained	

9. Shut down system

• Non-avoidable costs	$ 15,000
• New heating systems would be required for customers	
- 130 at $4,000/system	$520,000
- 10 systems for which individual estimates were provided	$388,000
TOTAL	$908,000
• Operating cost of new systems	
- Amortization of investment in new systems (10% interest rate; amortized over 10 years)	$145,000
- Gas cost for 62,500 mcf (50,000 million Btu needed at 80% efficiency) at $2.50	$156,000
- Non-avoidable costs from shut-down	$ 15,000
- Elimination of incremental cost due to electric generating vs. purchase	($500,000)
TOTAL	($184,000)
- Annual cost per million Btu (excluding electric generation penalty and non-avoidable utility costs)	$ 6.02

Exhibit W-2
WORTHINGTON

Distribution system:

10a. Hot water conversion of distribution system - steel pipe

• Capital cost	$1,400,000
• Revenue requirement	
- Amortization of investment, per year	$140,000
- Amortization per million Btu sold	$ 2.80
• Assume efficiency of 90%	

10b. Hot water conversion of distribution system - fiberglass pipe

• Capital cost	$620,000
• Revenue requirement	
- Amortization of investment, per year	$ 62,000
- Amortization per million Btu sold	$ 1.24
• Delivery temperature limited to 230°F	
• Operating systems using fiberglass pipe have not been identified	
• Assume efficiency of 90%	

11. New steam distribution system

• Capital cost	$1,030,000
• Revenue requirement	
- Amortization of investment, per year	$103,000
- Amortization per M. lb. sold	$ 2.06
• Assume efficiency of 85%	

Customer systems:

12. Convert buildings to hot water

• Capital cost			
- Meter and service	$2,650		
- Customer conversion	$2,880		
	$5,530	x 130	$719,000
- 10 customers @ $20,00 each			$200,000
TOTAL			$919,000

• Revenue requirement	
- Amortization of investment, per year	$ 92,000
- Amortization per million Btu sold	$ 1.84

- Overall efficiency of hot water district heating somewhat better than steam but increased efficiency insufficient to justify large increase in required captial expenditures for plant conversions, distribution system, and building conversions

Other:

13. Rate increase

• Current steam rate per M. lb.	$ 4.58
• Average gas rate per mcf	$ 2.50
• Average gas rate at 80% efficiency	$ 3.12
• Average cost of new system	$ 4,000
- Amortization over 10 years, per year	$ 640
- Amortization per million Btu	$ 1.91
• Upper limit to steam change per M. lb. ($1.91 + $3.12)	$ 5.03
• Additional revenue which could be generated by $0.45 ($5.03 - $4.58) rate increase (assuming no lost customers)	$ 22,500
• Potential capital expenditure supported by increased revenues	$225,000

- Potential capital expenditures insufficient for even replacing distribution system
- Customer base has been declining and the decline could be expected to accelerate with any rate increase
- Note: rate had risen from $4.58 to $4.91 by March, 1980

14. Add customers

- May be able to flatten load curve
- May be able to spread fixed costs
- Several large candidates, all which would require major capital outlay
  - S.W. Minnesota Community College
  - New school
  - Campbell's Soup
  - Northland Mall
  - Holiday Inn

Exhibit W-2
WORTHINGTON

- Some candidate customers have electric heat and would be very expensive to convert
- Annual revenue requirement per foot of line extension to amortize cost of line to serve new customers — $ 10
  - Revenue requirement for 1,000 ft. line, per year — $ 10,000
  - Revenue requirement per M. lb. sold to cover fuel cost (costed on Btu basis, using gas at $1.97, and assuming 75% efficiency) — $ 2.63
  - Required sales, in M. lbs., to cover cost of fuel and line (ignoring all other costs and assuming a price of $4.58/M. lb.) — $ 5,200
  - Percent of current annual sales — 10%
- May be extremely difficult to attract customers in view of fact that 32 have withdrawn over last 3 years and system is scheduled for 9/81 shut down

15. Renegotiate demand charge with MBMPA

- Unlikely because Missouri Basin Municipal Power Agency (MBMPA) revenues are pledged to provide debt service on bonds used to finance new generating facilities

16. Sell electric production

- Cost of producing electricity after bringing plant into compliance appears to be above market price due to:
  - fuel cost
  - wheeling
  - baghouse amortization
- Does nothing to address the problem of inherent limitations of generation facilities
- Would forfeit MBMPA capacity credit (which doesn't expire until 1982)

Exhibit W-3
WORTHINGTON

- Alternative Scenarios -

Note: The following cost estimates are very preliminary: caution is recommended in comparing scenarios

	Cost per Million Btu
• Install "package" boiler	$ 0.40
Install desuperheater (for backup on unit #2)	0.15
New steam system	2.06
Fuel--gas*** [$1.97/(.85* x .85**)]	2.73
Other operating costs	0.75
TOTAL	$ 6.09
• Install baghouse	$ 6.00
Install two desuperheaters	0.30
New steam system	2.06
Fuel--coal [1.76/(.70 x .85)]	2.96
Other operating costs	0.75
TOTAL	$12.07
• Hot water conversion	
- Plant	$ 0.50
- Distribution system (fiberglass)	1.24
- Customers	1.84
Install "package" boiler	0.40
Fuel--gas*** [$1.97/(.85 x .90)]	2.58
Other operating costs	0.75
TOTAL	$ 7.31
• Shut down system	
- New individual heating systems	$ 2.90
- Fuel (gas)	3.12
TOTAL	$ 6.02

Note: The above scenarios ignore the estimated $500,000 annual cost savings resulting from discontinuation of electric generation. Such cost savings would accrue to all electric customers, as would any cost increases resulting from installation of emergency generating facilities.

* Assumed plant efficiency
** Assumed distribution system efficiency
*** There is no assurance that gas will be available for district heating usage in the future; if oil is burned, fuel cost per million Btu will increase by approximately 50% based upon current price differentials.

D. Most Promising Alternative

The most promising alternative, from the standpoint of minimizing rate increases while simultaneously attempting to minimize capital requirements, is the following:

- Replace the existing steam distribution system without condensate return; and
- Install two 10,000 lbs. per hour, 15 psi, gas/oil "package" boilers.

Tentative capital costs and fuel price estimates utilized in the analysis of preliminary alternatives were challenged and updated. The revised estimated costs for renovating and operating this system are:

	Capital Cost	Cost per 1000 lbs
Distribution system		
Material	$ 600,000	$ 1.20
Labor	360,000	0.72
Customer service connections	20,000	0.04
Plant		
Package boilers	90,000	0.18
Installation	155,000	0.31
Engineering and contingencies	185,000	0.37
Fuel (gas @ $2.04 per MCF; 85% boiler effeciency and 85% distribution system efficiency)		2.82
Other operating costs		0.75
TOTAL	$1,410,000*	$6.39

The above estimates do not include condensate return or new meters. Although neither is essential, new meters would be recommended for Worthington due to the definite possibility of undermetering of some customers. (A brief review of steam consumption data by customer was compared to a subjective evaluation of likely consumption and revealed

*Ignores estimated $500,000 savings from discontinuation of electric generation and potential added cost for emergency generation.

substantial discrepancies, probably due to metering error.) If condensate return and new meters are also installed, the following estimated costs result:

	Capital Cost	Cost per 1000 lbs
Base system	$1,410,000	$6.39
Condensate return		
Material	300,000	0.60
Labor	180,000	0.36
Engineering and contingencies	72,000	0.14
Savings due to condensate return		(0.15)
Meters	85,000	0.17
TOTAL	$2,047,000	$7.51

The above estimates are not based upon design but, rather, upon vendor estimates and extrapolations from other recent experience. Consequently, the final estimate could vary by as much as 20%. The estimate for the distribution system is based upon an assumption that the entire existing piping network would be replaced; however, a brief review of load concentration indicated that certain portions of the distribution system could be eliminated such that a minor reduction in the sales base would permit a much greater reduction in capital outlay. The lines affected would primarily be residential lines. The cost estimate for new meters assumes that the utility would provide installation at no additional cost.

Although the projected steam rate is nearly 50% higher than the current rate in Worthington, it is still only about one half of the current rate in Mountain Iron and less than rates prevailing for other Minnesota steam systems.

E. Institutional Considerations

The following issues should also be considered in evaluating whether to perpetuate district heating in Worthington:

- The overriding issue impacting the decision of whether to perpetuate district heating in Worthington is perhaps the impact on electric costs of providing steam to the system under the present arrangement. The Utility, in effect, utilizes the turbine generators as a means of reducing the pressure of the steam before introducing it to the steam system. Because of existing contracts with the Missouri Basin Municipal Power Agency (MBMPA) of which Worthington is a member, the Utility incurs additional cost generating energy. The workings of the contract force the utility to generate at an inefficient level in an already relatively high-cost plant. Recent estimates of the electric cost penalty are on the order of $500,000 per year which must be passed on to all electric customers of the electric utility. This cost disadvantage would likely not be substantially reduced or eliminated if the plant were operating at close to capacity. Additional discussion of this problem and existing contractual relationships is included in Appendix C.

- One concern expressed by several steam customers related to the vulnerability of the City should the Utility cease electric production and rely solely on MBMPA and the Western Area Power Authority (WAPA) for all electric requirements. It is entirely possible that a storm could interupt power to the City for an unacceptable period of time, and this is a legitimate concern. However, the community must also assess the question of how much it is willing to pay for such security and who should pay for it. One obvious solution is to install a diesel generator of sufficient capacity to start the plant in such circumstances. The cost of that alternative would certainly be less on an annual basis than the current electric generating penalty.

- A significant problem exists with respect to the market, if the decision is made to perpetuate and renovate the system. The customer base has been eroding badly in recent years and this trend is likely to accelerate due to the City's notice to customers of its intention to discontinue service in September, 1981. If major capital improvements are made at this time and necessitate an increase in rates of nearly 50%, customers will have further incentive to withdraw, particurly in view of the relatively low price of natural gas in Worthington. Serious consideration must be given to whether the trend in customer withdrawals can be arrested or reversed before proceeding with plans for renovation.

- Some downtown merchants are already feeling the impact of commercial development on the fringe of the City and do not feel that they are in a favorable position to incur the costs of installing alternate heating systems. The fact that some merchants rent from absentee landlords who may not be interested in making major capital expenditures for heating systems, and that some buildings lack chimneys, presents additional problems. However, the estimate for installing individual heating systems is less than the cost of renovating the central system. The annual cost per million Btu's with individual heating systems is somewhat less than the projected cost per 1000 pounds of steam delivered by the base renovated system ($6.02 vs. $6.39).

APPENDIX A

ILLUSTRATIVE EXAMPLE OF LIFE CYCLE COST ANALYSIS

The following example is used to illustrate how life cycle cost analysis can be employed in the investment decision process. As previously mentioned, this type of analysis was not employed for this study due to the extreme uncertainty about future fuel prices and the resultant complications for the decision process.

This example was based upon data from Worthington, but the principles could be applied to any of the three systems. Basic assumptions include:

- A hypothetical customer requiring 200 million Btu for space heating per year could choose between installing a new system or of receiving thermal energy from a newly renovated steam system.

- The customer could install a gas-fired system (Scenario I) for $4,000 which would provide the necessary heat with a combustion efficiency of 80%.

- The customer could finance the system over ten years at an interest rate of 10% per annum and could amortize the loan with level debt service payments.

- Maintenance on the system would be minor over the 20-year life of the system and such costs can be ignored.

- Tax impact is ignored.

- General price inflation will be experienced at the following rates:

  1981 - 10%
  1982 - 9%
  1983 - 8%
  1984 - 7%
  1985 to
  2000 - 6%

- Three fuel scenarios are analyzed for the utility:

  II-a - The utility will be able to purchase gas through 1984 and then will need to rely exclusively on #6 oil.

  II-b - The utility will be able to burn gas continuously from 1981 - 2000.

II-c - The utility will bring the plant into emissions compliance and will burn coal.

- The utility will not need to make any significant capital expenditures after the system is renovated.

- The system renovation will be financed by bonds at an interest rate of 8% per annum, amortized with level debt service payments over 20 years, and will not require a bond reserve fund.

- Fuel prices will escalate for gas, oil, and coal at average annual rates of 4.4%, 4.3%, and 2.5% respectively, in addition to the general inflation rate; the escalation in fuel prices was adopted from Minnesota Energy Agency projections released in January, 1980, and escalation rates are not uniform throughout the period.

- Assumed fuel rates for 1981 are:

- Gas (commerical, per MCF)	$3.16
- Gas (utility, per MCF)	2.30
- Oil, #6 (utility, per million Btu)	3.39
- Coal, Western (per million Btu)	1.92

- Utility operating costs will escalate by the general inflation rate.

- A discount factor of 12% per year is used to obtain a discounted life cycle cost.

Based upon the preceding assumptions, the following results were obtained:

Scenario	Total Cost	Discounted Cost
I. Individual gas system	$58,112	$16,942
II-a. Utility gas/oil steam system	$72,336	$19,728
II-b. Utility gas steam system	$59,260	$16,828
II-c. Utility coal steam system	$73,246	$23,535

Detail cost schedules follow in Exhibits A-1, A-2, A-3, and A-4.

It is interesting to note that the option with the lowest total cost, Scenario I, does not have the lowest discounted cost due to the timing of the cash flows. However, in view of the slight difference in discounted cost between Scenarios I and II-b and the numerous simplifying assumptions, no final conclusions should be drawn.

Scenario II-c, the scenario with the lowest fuel cost, has the highest total cost and discounted cost. This factor is graphically illustrated on Exhibits A-5 and A-6. Given the various assumptions made, Exhibit A-5 demonstrates that coal prices are clearly less than all other fuel alternatives, particularly over the 20 year analysis horizon. However, Exhibit A-6 demonstrates that the coal alternative is more costly when all costs are considered, primarily due to the high cost associated with the modifications required to bring the plant into compliance with air pollution control standards. The high discounted cost for the coal alternative also illustrates the fact that even though the total cost associated with coal is projected to be less expensive from 1993 onwards, that discounted future cost advantage is insufficient to offset the near-term cost disadvantage.

It may be worth noting that an implicit assumption in this analysis is that if the steam system was renovated, the current market would be fully retained. In actuality, one might expect that if the price of steam was increased (to cover cost of renovation), some customers would withdraw from the system and the fixed costs of renovation would then need to be allocated to a smaller customer base. Consequently, the price of steam would be even higher than originally anticipated, and the discounted life cycle costs for the renovation alternatives would be even greater than what is indicated.

Exhibit A-1

SCENARIO I
- Individual System -

Year	Fuel Cost	Amortization of System	Total Cost
1981	$ 790	$ 651	$ 1,441
1982	910	651	1,561
1983	1,028	651	1,679
1984	1,138	651	1,784
1985	1,248	651	1,899
1986	1,372	651	2,023
1987	1,512	651	2,163
1988	1,666	651	2,317
1989	1,836	651	2,487
1990	2,022	651	2,673
1991	2,230		2,230
1992	2,506		2,506
1993	2,818		2,818
1994	3,166		3,166
1995	3,560		3,560
1996	4,000		4,000
1997	4,348		4,348
1998	4,728		4,278
1999	5,138		5,138
2000	5,586		5,586
TOTAL	$51,602	$6,510	$58,112

Discounted annual life cycle cost @ 12% $16,942

Exhibit A-2

SCENARIO II-a
- Utility Gas/Oil Steam System -

Year	Fuel Cost	Operating Cost	Debt Service	Total Cost
1981	$ 638	$ 166	$ 564	$ 1,368
1982	734	180	564	1,478
1983	826	194	564	1,584
1984	916	208	564	1,688
1985	1,334	220	564	2,118
1986	1,482	234	564	2,280
1987	1,648	248	564	2,460
1988	1,834	262	564	2,660
1989	2,038	278	564	2,880
1990	2,268	294	564	3,126
1991	2,512	312	564	3,388
1992	2,784	332	564	3,680
1993	3,084	352	564	4,000
1994	3,418	372	564	4,354
1995	3,786	394	564	4,744
1996	4,160	418	564	5,142
1997	4,572	444	564	5,580
1998	5,026	470	564	6,060
1999	5,522	498	564	6,584
2000	6,070	528	564	7,162
TOTAL	$54,652	$6,404	$11,280	$72,336

Discounted annual life cycle cost @ 12% $19,728

Exhibit A-3

SCENARIO II-b
- Utility Gas Steam System -

Year	Fuel Cost	Operating Cost	Debt Service	Total Cost
1981	$ 638	$ 166	$ 564	$ 1,368
1982	734	180	564	1,478
1983	826	194	564	1,584
1984	916	208	564	1,688
1985	1,006	220	564	1,790
1986	1,106	234	564	1,904
1987	1,218	248	564	2,030
1988	1,342	262	564	2,168
1989	1,480	278	564	2,322
1990	1,630	294	564	2,488
1991	1,796	312	564	2,672
1992	2,020	332	564	2,916
1993	2,270	352	564	3,186
1994	2,550	372	564	3,486
1995	2,868	394	564	3,826
1996	3,224	418	564	4,206
1997	3,504	444	564	4,512
1998	3,808	470	564	4,842
1999	4,140	498	564	5,202
2000	4,500	528	564	5,592
TOTAL	$41,576	$6,404	$11,280	$59,260

Discounted annual life cycle cost @ 12% $16,828

Exhibit A-4

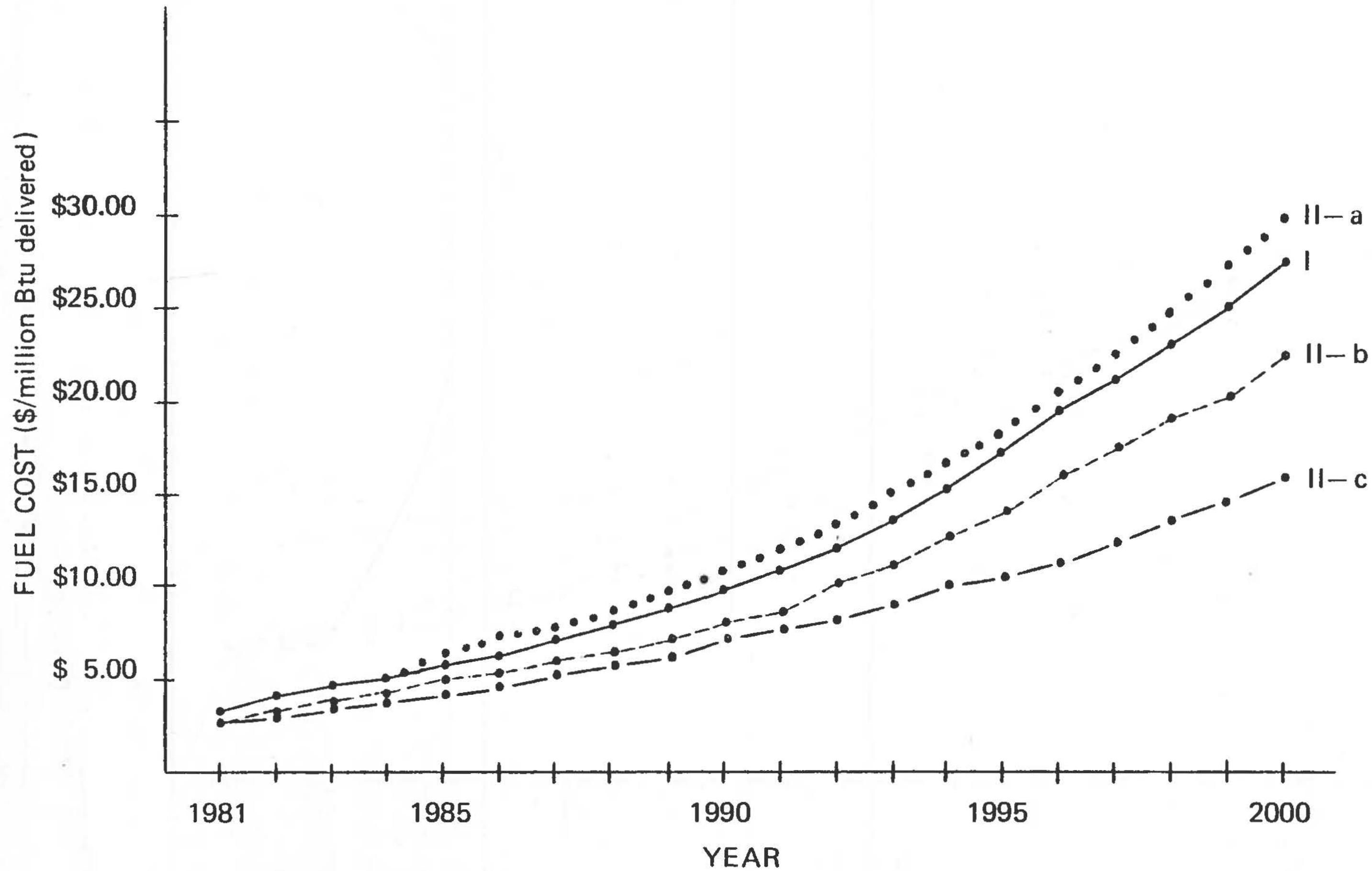
SCENARIO II-c
- Utility Coal Steam System -

Year	Fuel Cost	Operating Cost	Debt Service	Total Cost
1981	$ 496	$ 166	$ 1,672	$ 2,334
1982	718	180	1,672	2,570
1983	796	194	1,672	2,662
1984	866	208	1,672	2,746
1985	942	220	1,672	2,834
1986	1,038	234	1,672	2,944
1987	1,142	248	1,672	3,062
1988	1,230	262	1,672	3,164
1989	1,328	278	1,672	3,278
1990	1,468	294	1,672	3,434
1991	1,614	312	1,672	3,598
1992	1,742	332	1,672	3,746
1993	1,882	352	1,672	3,906
1994	2,032	372	1,672	4,076
1995	2,196	394	1,672	4,262
1996	2,372	418	1,672	4,462
1997	2,560	444	1,672	4,676
1998	2,766	470	1,672	4,908
1999	2,988	498	1,672	5,158
2000	3,226	528	1,672	5,426
TOTAL	$33,402	$6,404	$33,440	$73,246

Discounted annual life cycle cost @ 12% $23,535

EXHIBIT A–5

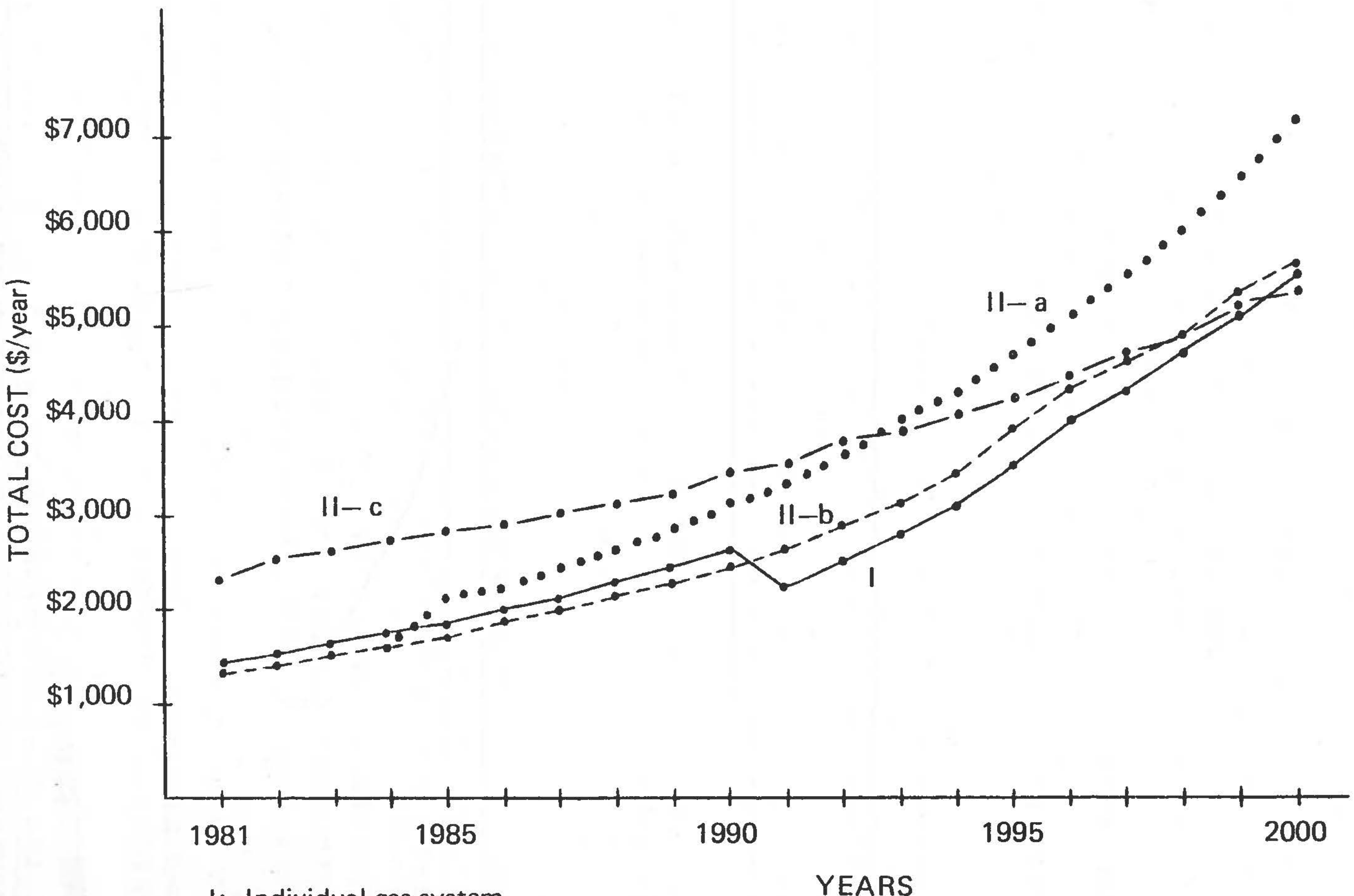
COMPARISON OF FUEL COST FOR THE
FOUR SCENARIOS OF THE ILLUSTRATIVE
EXAMPLE OF LIFE CYCLE COSTS



I: Individual gas system
II– a: Utility gas/oil steam system
II– b: Utility gas steam system
II– c: Utility coal steam system

EXHIBIT A–6

COMPARISON OF TOTAL COSTS FOR
FOUR SCENARIOS OF THE ILLUSTRATIVE
EXAMPLE OF LIFE CYCLE COSTS



I: Individual gas system
II– a: Utility gas/oil steam system
II– b: Utility gas steam system
II– c: Utility coal steam system

APPENDIX B

ELECTRIC HEATING AS AN ALTERNATIVE IN MOUNTAIN IRON

Some customers may elect to install electric space heating in their homes, rather than convert to a hot water or forced air system.

Mountain Iron is served by a municipal electric utility and operates a distribution system only. All power and energy requirements are purchased from Minnesota Power & Light Co. under its Wholesale Rate Schedule 01, Resale Service--Municipalities. Mountain Iron customers receive service through the utility 2400/4160 volt electric distribution system. A large portion of the older section of town is served by a 2400 volt distribution system, and this is also the area where most of the residential steam customers reside.

Discussions with the utility superintendent indicate that the 2400 volt system has sufficient line capacity to service the additional heating loads. Some additional distribution transformers would have to be installed where customers converted to electric heating and the electric service wires to these customers, in most cases, would be replaced by a higher capacity.

Some modifications would have to be made to the electric facilities of the customers who elect to install electric space heating, since many have only a 60 ampere capacity and a minimum of 150 ampere would be required.

At the present time, the Mountain Iron Electric Department does not offer an electric heating rate schedule, however, electric heating service is available under the residential service rate (R5), or the general service rate (GS) for commercial customers. Under the present residential rates schedule, electric heating energy would be purchased at an average rate of 3.6¢ per kwh, which is equivalent to approximately $10.55 per million Btu.

Although not a part of the study, consideration of the impact of the utility as a result of a substantial heating load would have to be analyzed with regard to the effect on purchased power costs. Mountain Iron is a "winter peaker", i.e., its maximum electric load normally occurs in December or January. Additional heating load will, therefore, be superimposed on the existing load. The wholesale rate schedule under which Mountain Iron receives service imposes a ratcheted demand charge on peak loads of the utility. That is, demand charges billed in months subsequent to the peak month will be no less than 90% of the peak month. This causes a problem in the recovery of all costs under an electric heating rate since a heating load occurs only during a seven to eight month period. Thus, although there are no heating revenues accruing to the utility in the summer months, the costs resulting from the winter heating peak are still being paid during summer months.

APPENDIX C

EFFECT OF MBMPA CONTRACTUAL AGREEMENTS ON WORTHINGTON'S ELECTRIC GENERATING CAPABILITIES

At the present time Worthington is purchasing power and energy from two sources (WAPA and MBMPA), as well as generating a portion by steam turbine generation at the Municipal Power Plant in conjunction with providing steam to the heating system. Because the production of steam and electricity at the power plant is limited by restrictions in existing power contracts, a brief discussion of the total power sources is germane to this Report.

The City has a contract with the Department of Energy-Western Area Power Administration (WAPA) under which WAPA will provide the City with up to 11,413 kilowatts of firm power and energy. The 11,413 KW is the maximum amount of power WAPA will provide for the City's system peak and the contract states that such power, and associated energy, will be taken on a load pattern basis. This means that the City must not "base load" the WAPA allotment at the 11,413 KW and "peak shave" with other sources, but rather should take power from WAPA in the proportion that the 11,413 KW bears to the system peak in the previous twelve months including the current month.

The agreement between the City and the Missouri Basin Municipal Power Agency (MBMPA) provides that MBMPA will provide and the City will purchase from MBMPA, all of its power and energy requirements in excess of what WAPA provides. Thus, if the peak month demand of the Worthington system was 23,000 KW, the City would be obligated to pay MBMPA demand charges on 11,587 KW (23,000 - 11,413). Energy taken from each supplier would be in the same proportion - 50.38% from MBMPA and 49.62% from WAPA.

Recognizing that strict adherence to the contract terms would impair the City's ability to provide steam to its heating customers, the agreement was amended to allow the City to generate up to 26 million KWH's each year on its steam turbines without penalty. The 26 million KWH's works out to an approximate 3,000 KW average hourly load on the operating steam turbine. The generation amendment was necessary in order that the utility could provide low pressure steam to the heating system through the extraction mechanism on either turbine. The turbines serve as a pressure reducing valve for steam entering the district heating system since the high pressure and temperature steam produced by either operational boiler cannot be safely injected into the heating system.

Although the City is excused from purchasing the 26,000,000 KWH's annually from MBMPA, it does not receive any credit for demand recession as a result of carrying the 3,000 KW load on the turbine. If, as in the above example, the City was carrying 3,000 KW on the turbine at the time of the 23,000 KW peak, the demand charge from the MBMPA would still be based on 11,587 KW (the difference between the system peak and the WAPA allotment). Thus, whether the turbine output at the time was 3,000, 5,000, 8,000 or 10,000 KW, the demand billing by MBMPA would be 11,587 KW since the City is required to take all of its power requirements in excess of WAPA's allotment from the basin.

The low load operation of the boilers and turbines have resulted in some operating inefficiencies. Steam production facilities operate most efficiently in the range of 85 to 100% of capacity. During winter periods, the largest boiler, No. 3, which has a continuous rating of 116,000 pounds per hour is used to produce steam for turbine No. 3, which has a 10,000 KW rating. The turbine generator, therefore, is operating at only a 30% capacity factor, which is at the lowest end of the efficiency scale. The operation of generating equipment at the low capacity factor results in energy generated at the power plant having a substantially higher cost than the cost of replacement energy from the MBMPA.

The question might, naturally, arise as to the reason the turbine is not operated at a higher output where efficiency is greater. Why not operate at a 8,500 - 10,000 KW level where the unit cost of energy produced is lower? The reason is, simply, that the power plant would then be generating energy for which the City has an obligation to purchase from the MBMPA and for which the Basin is under no obligation to give the City credit. To illustrate, assume the average hourly output of steam turbine generation was increased to 5,000 KW. On an annual basis, the energy production would be about 44,000,000 KWHS at this average load. Under terms of the MBMPA City Agreement only 26,000,000 KWHS of generation is permitted, therefore, the MBMPA need not give the City credit, or excuse the City's purchase of the additional 18,000,000 KWHS. The increase in generation, then, would be counterproductive in terms of cost savings in total energy acquisition.

The MBMPA agreement provides for the 26,000,000 KWHS of plant generation only through September 20, 1980 with the City purchasing total energy requirements in excess of that obtained from WAPA from the MBMPA. Although it would appear that a short-term extension of the generation provision would be possible, any extended period would have to be a matter of negotiation with and permission by the MBMPA.

WORTHINGTON

- SUMMARY OF PURCHASE AGREEMENTS -

Western Area Power Administration (WAPA)

Firm Power	11,413 KW
Transmission	By Interstate Power Company
Supply	To be taken on load pattern
Rates:	
Demand Charge	$1.20 per KW
Energy Charge	3.17 mills up to 60% load factor 5.18 mills over 60% load factor

Missouri Basin Municipal Power Agency (MBMPA)

Firm Power	Equal to difference between system peak and WAPA allotment
Transmission	By Interstate Power Company
Supply	On load pattern basis subject to the City generating 26,000,000 KWH annually in conjunction with providing steam to heating
Rates:	
Demand	$8.30 per KW
Energy	17.5 mills subject to Production Cost Adjustment

Note: The power and energy taken from MBMPA is subject to a 8% adjustment (add-on) for line losses between the Sioux Falls Substation and Worthington.

Capacity Credit From MBMPA: The City receives $31,735 per month from the MBMPA for dedicating 13,575 KW of generating capacity at the power plant to the power agency's use as needed.